ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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October 2, 2017

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Secretary

RE: **Docket No. 17-035-36 –** In the Matter of Glen Canyon Solar A, LLC and Glen Canyon Solar B, LLC's Request for Agency Action to Adjudicate Rights and Obligations under PURPA, Schedule 38 and Power Purchase Agreements with Rocky Mountain Power

Pursuant to Utah Public Service Commission's Order Granting Motion to Amend Procedural Schedule dated August 25, 2017, in the above referenced matter, the Company hereby submits for electronic filing its Written Surrebuttal Testimony. The filing consists of the written surrebuttal testimonies of Rick A. Vail, Kelcey A. Brown, and Daniel J. MacNeil.

As requested by the Public Service Commission of Utah for voluminous filings, Rocky Mountain Power is providing seven (7) printed copies of the filing via overnight delivery.

Rocky Mountain Power respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Rocky Mountain Power
Docket No. 17-035-36
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Rick A. Vail

October 2017

Q. Are you the same Rick A. Vail that filed direct and rebuttal testimonies on behalf of Rocky Mountain Power, a division of PacifiCorp, in this case?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will address certain arguments asserted by Glen Canyon's witness Keegan Moyer in his rebuttal testimony filed in this proceeding on September 25, 2017.

Q. What specifically will you be addressing?

A. In his rebuttal testimony, Mr. Moyer takes issue with several components of my direct testimony. Although I disagree with much of what Mr. Moyer claims, in this surrebuttal testimony, I address his claim that PacifiCorp's transmission function should assume some level of generation redispatch in the interconnection study process for the Glen Canyon qualifying facilities ("QFs"). Introducing generation redispatch into the interconnection process would conflict with Federal Energy Regulatory Commission ("FERC") precedent governing large generation interconnection procedures and with PacifiCorp's FERC-jurisdictional Open Access Transmission Tariff ("OATT"), which governs our processing of large generator interconnections in Utah under Schedule 38. I also explain why, even assuming it is appropriate to introduce generation redispatch into an interconnection study, that option is not available in this case because firm rights over the Glen-Canyon-to-Sigurd line cannot be redispatched. Finally, I briefly respond to the rebuttal testimony of Glen Canyon witness Mr. Hans Isern.

Q. Does Mr. Moyer accurately frame the issue presented by this case?

A. No. Mr. Moyer argues at lines 379-382 that: "The issue comes down to a decision as to which entity the Commission determines has the responsibility for arranging the delivery component of transmission service, and what actions that party should take to make sure that costs are minimized or wholly avoided in doing so." That statement completely misconstrues the nature of this case. Both parties agree that PacifiCorp is responsible for obtaining transmission service for the Glen Canyon QFs.

The issue in this case is Glen Canyon's attempt to avoid cost responsibility for network upgrades necessary to provide *interconnection* service by deferring those upgrades to the transmission-study phase or by inappropriately considering transmission-service generation re-dispatch in an interconnection study. Under either scenario, Glen Canyon is attempting to shift the cost responsibility for interconnection-related network upgrades—that are necessary only because the Glen Canyon QFs are seeking interconnection service on the Glen-Canyon-to-Sigurd transmission line and are therefore appropriately borne by Glen Canyon—to PacifiCorp's retail and third-party transmission customers.

Q. Please respond to Mr. Moyer's allegation that PacifiCorp's position in this case is discriminatory towards QFs.

A. That is simply not true. As PacifiCorp has explained numerous times in this case, QFs operate under the guiding principle of the Public Utility Regulatory Policies Act of 1978 ("PURPA")—that a utility's customers are supposed to be indifferent to the addition of a QF to the system. Mr. Moyer attempts to re-write this standard, encouraging the Commission to adopt a balancing of QF and existing customer interests. That is not what PURPA requires. *Customer* indifference is not a flexible standard that can give way to accommodate the needs of the QF. Making sure that QFs pay all appropriate interconnection costs is entirely consistent with that standard.

Q. In his testimony, Mr. Moyer now suggests that Glen Canyon only asks this Commission to borrow the redispatch concepts from the OATT's transmission-service provisions and use them in the interconnection context. Has this been Glen Canyon's position throughout this case?

A. No. Glen Canyon's position morphed in rebuttal testimony. Glen Canyon previously asserted that PURPA, Schedule 38, the OATT, PacifiCorp's avoided-cost pricing methodology, and an amendment to the network operating agreement between PacifiCorp's merchant and transmission functions (referred to as the "NOA Amendment") somehow imposed the *obligation* to model the NOA Amendment's redispatch option (applicable to transmission service) as part of Glen Canyon's interconnection studies.

Mr. Moyer now concedes that the "specific application of the NOA Amendment is limited to transmission service," but nonetheless argues that "there is no reason that the technical *principles* of redispatch discussed in the NOA Amendment cannot also be used in interconnection studies."[1]

Q. Is Mr. Moyer correct—can the *transmission* redispatch principles be used in the *interconnection* studies?

A. No. Mr. Moyer essentially argues that the deliverability analysis in the network resource ("NR") interconnection study is a *transmission service* assessment, so PacifiCorp should apply the transmission-service-related redispatch tool set forth in the NOA Amendment in Glen Canyon's interconnection study.[2] As was the case with Glen

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[1] Rebuttal Testimony of Keegan Moyer (Moyer Rebuttal) at 8, lines 154-157.

[2] Moyer Rebuttal, lines 262-267 ("Because interconnection studies for NR interconnection service study whether the interconnecting generator is capable of delivery to the aggregate of load—delivery that is the obligation of

Canyon's earlier attempts to justify this concept, Mr. Moyer's new theory also fails in two critical respects:

- FERC has made it abundantly clear that interconnection service—even NR interconnection service with deliverability analysis considerations—is *not* transmission service, and redispatch assumptions are *only* used for transmission service studies.
- A utility's obligation to make transmission arrangements to deliver QF power does not mean that a utility is required to use its existing transmission service rights to move that power, and the NOA Amendment did not change this.

Q. Can you expand on the first issue that redispatch assumptions are only used for transmission service studies?

A. Yes. By way of background, the type of redispatch Mr. Moyer is referring to is called planning redispatch, which involves a transmission provider's evaluation of whether out-of-merit-order generation-resource assumptions can be used to alter flows and create additional available transfer capability ("ATC") to grant a request for firm *transmission* service in a constrained area of the system without constructing new facilities or upgrades. Redispatch is explicitly referenced in the *transmission service* sections of the PacifiCorp OATT. Redispatch is not mentioned in the interconnection portions of the OATT,[3] nor is it a concept we use in the interconnection study process.

Q. Has FERC addressed whether generation redispatch should be part of an interconnection study?

A. Yes. FERC has explicitly held that generation redispatch is *not* considered in interconnection studies, even for NR interconnection service like Glen Canyon's:

RMP for QFs under PURPA—it is reasonable to require PacifiCorp Transmission to determine whether redispatch will ease existing transmission constraints, thereby eliminating the identification of unnecessary network upgrades.").

[3] *See, e.g.*, Large Generator Interconnection Procedures (OATT Part IV) or Large Generator Interconnection Agreement (OATT Appendix 6).

> In response to EEI, we clarify that the Interconnection Feasibility Study must consider transmission contingencies, **<u>but not generation redispatch</u>**. **Generation redispatch refers to decisions the system operator makes to manage congestion.** These decisions take into account the relative running costs of the available generating facilities. LGIP section 3.2.2.2 states that the approach used to study Network Resource Interconnection Service assumes that some portion of existing Network Resources is displaced by the output of the Generating Facility. However, because the purpose of the Network Resource Interconnection Service study is **<u>only to determine whether the aggregate of generation in the local area can be delivered to the aggregate of load on the Transmission System</u>**, consistent with the Transmission Provider's reliability criteria and procedures, the generation that is displaced for study purposes is selected on the basis of its impact on Transmission System operation, not on the basis of the generating facilities' relative costs of producing energy.[4]

FERC's explanation makes it clear that redispatch assumptions are not included in interconnection studies because interconnection service does not assess actual delivery. This is true even for NR interconnection studies that contain a deliverability analysis *component*—but it is a component that FERC emphasizes in the passage above is *only* to determine whether the aggregate of generation in the local area can be delivered to the aggregate of load on the system. Contrary to Mr. Moyer's claims, this is not a transmission-service-related assessment.

Q. But hasn't Glen Canyon argued that once a generator secures NR interconnection service, any future transmission service request will not require a study or additional upgrades?

A. Yes. Glen Canyon has attempted to confuse this issue throughout this proceeding. For example, in its Motion for Preliminary Injunction in this case, Glen Canyon quotes Section 4.1.2.2 of the PacifiCorp Large Generator Interconnection Agreement ("LGIA") for the following proposition:

[4] Order No. 2003-A at P 558 (emphasis added).

> [W]hen a QF—such as Glen Canyon Solar—"satisfies the requirements for obtaining Network Resource Interconnection Service, any future transmission service request for delivery from the [QF] within [PacTrans'] System of any amount of capacity and/or energy, up to the amount initially studied, will not require that any additional studies be performed or that any further upgrades associated with such [QF] be undertaken, regardless of whether or not such [QF] is ever designated by a Network Customer as a Network Resource and regardless of changes in ownership of the [QF]."[5]

What Glen Canyon does not acknowledge is that, in Order No. 2003-A, FERC cleared up any residual confusion over that provision by adding the following sentence to that same OATT provision: "The provision of Network Integration Transmission Service or firm Point to Point Transmission Service may require additional studies and the construction of additional upgrades."[6] Thus, contrary to Glen Canyon's claims, FERC has made explicitly clear that, even when a generator is interconnected using NR interconnection service, it is *not* a delivery service, and the separate transmission-service request for that project may reveal the need for additional upgrades to deliver the output to the designated loads.

Q. In addition to the fact that applying transmission service redispatch assumptions to NR interconnection studies would be contrary to FERC policies, can you describe the second reason that Mr. Moyer's theories are unworkable?

A. Yes. Mr. Moyer's claims that PacifiCorp must apply NOA-Amendment-type redispatch "principles" in QF interconnection studies essentially translate into a bold and unsupported requirement that Glen Canyon has continued to assert throughout the course of this proceeding: that PacifiCorp must use its existing transmission rights to

[5] Glen Canyon Solar's Motion for Preliminary Injunction at p. 7, ¶ 23.

[6] *See Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003-A, FERC Stats. & Regs.¶ 31,160 at PP 544-545 (2004)

reduce QF interconnection costs at the expense of PacifiCorp's customers and third-party transmission customers. Mr. Moyer is wrong. A utility's obligation to make transmission arrangements to deliver QF power has never included a requirement to use existing transmission service rights to move QF energy. And nothing in the NOA Amendment, PURPA, Schedule 38, avoided-cost pricing, or the OATT change this.

Q. The NOA Amendment doesn't require PacifiCorp to use its existing transmission service rights to deliver QF power?

A. No. Once PacifiCorp and a QF execute a power purchase agreement, PacifiCorp must submit a request for *new* transmission service to deliver QF power, and that request must be studied under the OATT process. If transmission service is requested in a constrained area of the system, then the OATT offers two options: planning redispatch or construction of upgrades to relieve the congestion and provide the firm transmission service. The NOA Amendment simply modified the type of planning redispatch options that could be considered if QFs have caused or contributed to the constraints at issue.

Q. But Mr. Moyer suggests that redispatch is based on common principles that "were not created by PacifiCorp out of whole cloth for the NOA Amendment." Is that accurate?

A. No. We actually did propose, and FERC approved, a modified version of traditional planning redispatch for the NOA Amendment. As I noted earlier, under the OATT, traditional planning redispatch contemplates a transmission provider studying whether existing resources could be delivered firm in a different manner, *i.e.*, through a redispatch that alters flows and creates additional ATC in a constrained area so a new transmission service request can be granted. In the NOA Amendment, PacifiCorp proposed a modification to traditional OATT planning redispatch to permit PacifiCorp's transmission function to grant new requests for transmission service in constrained areas without requiring upgrades (even if additional ATC could not be created using traditional planning redispatch[7]), as long as PacifiCorp's merchant function agrees to limit the operation of its designated network resources within existing transmission rights. As described in the FERC order approving the NOA Amendment:

> PacifiCorp states that the practice under its proposed amendment is distinguished from current OATT process because, while traditional planning redispatch contemplates delivering designated network resources in a different manner, the proposed Network Operating Agreement amendment involves a network customer (in this case, PacifiCorp Energy) agreeing to operate its network resources within certain limits because there is insufficient capacity to accommodate all of the designated network resources without limitation.[8]

This modification was narrowly tailored to address a specific problem– *i.e.*, PacifiCorp transmission's inability to grant new transmission service requests and ensure firm delivery without construction of upgrades in areas where QFs had caused or contributed to constraints. PacifiCorp's merchant function can choose this option to the extent it is more economic for customers than constructing upgrades caused solely by QF siting choices.

Q. Mr. Moyer claims that the NOA Amendment redispatch "principles" should also be used to reduce QF interconnection costs. Do you agree?

A. Absolutely not. Not only is applying any type of redispatch assumption to

[7] *PacifiCorp*, FERC Docket No. ER15-741, Transmittal Letter at p. 4. (Dec. 24, 2014) (explaining that if traditional planning redispatch cannot be used, upgrades will be necessary to create additional ATC and provide firm transmission service).
[8] *PacifiCorp*, 151 FERC ¶ 61,170 (2015).

interconnection studies inconsistent with FERC policies, but the type of redispatch assumptions in the NOA Amendment are also specifically designed to protect *customers* from *transmission* service costs, not to protect *QFs* from *interconnection* service costs by forcing a utility to assume it will use its existing transmission service rights for purposes of the interconnection study.

Q. Mr. Moyer testifies that Glen Canyon is not seeking to avoid interconnection costs. Do you agree?

A. I cannot speak to Glen Canyon's motivation, but the central tenet of their position is that any costs related to upgrading the transmission system should be handled in the transmission study process, not the interconnection study process. The reason that argument is important is because Glen Canyon wants to shift costs away from itself and onto PacifiCorp's customers.

Q. Mr. Moyer asserts that your direct testimony contradicts PacifiCorp's Business Practice #70, titled "Generation Interconnection Procedures for Qualifying Facility 200 Projects." Is that correct?

A. No. Mr. Moyer focuses on a single statement: "PacifiCorp Transmission will attempt to identify alternatives to alleviate any transmission capacity issues." But the following sentence clarifies the intent of the previous sentence: "Potential alternatives could include, but are not limited to, the construction of new transmission infrastructure or the implementation of a remedial action scheme ('RAS')." This passage makes no mention of generation redispatch (which, as discussed above, is only a transmission service study assumption), but instead focuses on transmission contingencies. PacifiCorp's transmission function, the author of that Business Practice, did not intend (nor did it write) that it would engage in generation redispatch in an interconnection study. Instead, that language can be taken at face value; that interconnection service requests often cannot be accommodated without transmission upgrades. That is the case with Glen Canyon. There is nothing inconsistent between that passage and PacifiCorp's position in this case.

Q. Mr. Moyer contests your claim that the only appropriate type of interconnection service for QFs is network resource interconnection service. How do you respond?

A. Although Mr. Moyer correctly notes that neither FERC nor this Commission have explicitly stated that a QF is *required* to obtain network resource interconnection service, Mr. Moyer conveniently fails address how any other approach shifts identification of *interconnection-related* network upgrades to the transmission service studies, which ultimately means PacifiCorp's customers and third-party transmission service customers bear those interconnection costs through rates. This means that the customer indifference standard simply cannot be met unless a QF is required to obtain network resource interconnection service, allowing the interconnection-related network upgrades to be appropriately borne by the cost-causing QF.

In addition, as I discussed at length in my direct testimony, network resource interconnection service is also appropriate given the FERC decision in the *Pioneer Wind* case, which requires utilities to use firm network transmission delivery for QFs.

Q. Mr. Moyer cites a passage in Order No. 2003-A for the proposition that a FERC-jurisdictional generator (*i.e.*, non-QF) can combine the "as-available" type of energy resource (ER) interconnection service with a request for network transmission service. Do you agree that approach would also work for QF interconnection customers?

A. No. That may work, as FERC suggests, for FERC-jurisdictional interconnections, but there are two major reasons it cannot work for QFs. The first reason is the shift in cost responsibility between the QF and a utility's customers, which I just discussed. The second reason is that the passages cited by Mr. Moyer include FERC's assumptions that the interconnection customer and the transmission-service customer are the same entity, and that single entity can submit the interconnection-service request and transmission-service request simultaneously. In the case of QFs, however, the interconnection customer is the QF and the transmission service customer is PacifiCorp's merchant function. Those two services are requested by different customers at different times, governed by different regulatory bodies (*i.e.*, the QF interconnection is state-jurisdictional, and the transmission service is FERC-jurisdictional), and subject to different cost-allocation rules.

Q. Is Mr. Moyer correct that there is significant "operational ATC" over the Glen-Canyon-to-Sigurd path?

A. No. "Operational ATC" is not an accepted concept. Mr. Moyer appears to have coined that phrase. Mr. Moyer conceded that "there is no long-term firm available transfer capability (ATC) on this Glen Canyon to PACE transmission path[.]"[9] That is the key

[9] Moyer Surrebuttal, lines 565-566.

for determining whether Glen Canyon's capacity could be delivered on a firm basis over this path in the interconnection study. The point Mr. Moyer appears to attempt to make is that there may be significant northbound transmission capacity available if not used by APS on any given day. But that simply means that there may be *non-firm* transmission capacity on the line. The existence of non-firm capacity has no bearing on the availability of long-term firm ATC.

Q. Mr. Moyer contends that southbound flows over the Glen-Canyon-to-Sigurd path create "counterflows" that should free up northbound ATC over that path, thus creating room for the output of the Glen Canyon projects. Is this correct?

A. No. Accounting for counterflows in determining firm ATC can create an oversubscribed condition. In compliance with NERC's MOD-001-1a, R1 requirement, PacifiCorp uses the "Rated System Path Methodology" described in MOD-029.[10] Counterflows are managed on a day-to-day operational basis; they are not a basis for long-term planning.

Q. Even if PacifiCorp engaged in some form of interconnection-level generation redispatch, would that help Glen Canyon?

A. No. As explained by Kelcey A. Brown in her direct testimony, PacifiCorp's merchant function does not have the requisite network transmission service over the Glen-Canyon-to-Sigurd transmission path year-round, and APS has a transmission service call option that prevent NOA Amendment redispatch "principles" from being applied to Glen Canyon's interconnection study. Regarding the first issue, PacifiCorp holds two seasonal reservations over the Glen-Canyon-to-Sigurd path. During the summer season, PacifiCorp holds a 95 MW point-to-point reservation over this path. The NOA-

[10] *See* http://www.nerc.com/files/MOD-029-1a.pdf.

Amendment-style redispatch is a creature of *network* transmission service, not point-to-point transmission service, so applying the NOA Amendment redispatch "principles" to Glen Canyon's interconnection study (even if that were appropriate, which it is not for the reasons I discussed above) would not work during the summer season. Second, Ms. Brown also discusses a legacy transmission contract that gives APS a call option on the Glen-Canyon-to-Sigurd path, which she explains means that PacifiCorp's existing transmission rights cannot be used to deliver non-curtailable QF power because they must be available if APS exercises its call option.

Q. Is the Glen-Canyon-to-Sigurd line the only constraint at issue? In other words, even if the transmission-service-type and legacy-contract issues were resolved, would that guarantee Glen Canyon interconnection service without upgrades?

A. No. Glen Canyon has—from the beginning—focused on PacifiCorp's 95 MW of transmission service rights on just this path, so that has been our focus in responding. But there are issues beyond that path. For example, in Glen Canyon's original, non-QF interconnection study, the addition of its projects at the Glen Canyon substation also required additional new transmission facilities north of the Sigurd substation. Specifically, if the QF interconnection study ultimately identifies the same requirements, Glen Canyon's NR interconnection would require the construction of a new 345 kV line of approximately 130 miles between the Emery and Oquirrh substations.[11] Those interconnection-related upgrades would not be avoided even if the issues on the Glen-Canyon-to-Sigurd path could be resolved.

[11] *See* Exhibit RMP ___ (RAV-1SR), System Impact Study Report.

Q. Mr. Hans Isern accused you of misleading this Commission in stating that, during a March 2, 2017 meeting with Glen Canyon, PacifiCorp informed Glen Canyon that the statement made in the September 23, 2016 email attached to Glen Canyon's motion for preliminary injunction was a mistake.[12] What is your response?

A. Although I did not personally attend the March 2, 2017 meeting, I was directly involved in preparing for the meeting with Mr. Brian Fritz and other members of the PacifiCorp team. Mr Fritz, as Mr. Isern notes, was present at the meeting in person. I was also well aware of what the company planned to discuss at the meeting, which included responding to a January 31, 2017 letter from sPower, Glen Canyon's owner. In that letter, Glen Canyon makes assertions based on the representations made in the September 23, 2016 email. As part of the meeting, the PacifiCorp team made it clear to Glen Canyon that the concepts in the email were mistaken and ESM's transmission-related NOA-Amendment redispatch tool would not be used in Glen Canyon's interconnection studies. A copy of sPower's January 31, 2017 letter is attached as Exhibit RMP___(RAV-2SR).

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[12] Rebuttal Testimony of Hans Isern at 3, lines 45-55.

Rocky Mountain Power
Exhibit RMP___(RAV-1SR)
Docket No. 17-035-36
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Rick A. Vail

System Impact Study Report

October 2017

Large Generator Interconnection
System Impact Study Report

Completed for

("Interconnection Customer")
Q0710

Proposed Point of Interconnection

PacifiCorp's Sigurd-Glen Canyon 230 kV transmission line

July 27, 2016

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1.0 DESCRIPTION OF THE GENERATING FACILITY

("Interconnection Customer") proposed interconnecting 240 MW of new generation to PacifiCorp's ("Transmission Provider") Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah. The project ("Project") will consist of 159 Power Electronics FS1500CU inverters for a total output of 240 MW. The requested commercial operation date is December 19, 2019.

Interconnection Customer will NOT operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the Project "Q0710."

2.0 SCOPE OF THE STUDY

The interconnection system impact study shall evaluate the impact of the proposed interconnection on the reliability of the transmission system. The interconnection system impact study will consider Base Case as well as all generating facilities (and with respect to (iii) below, an identified network upgrades associated with such higher queued interconnection) that, on the date the interconnection system impact study is commenced:

- (i) are directly interconnected to the transmission system;
- (ii) are interconnected to Affected Systems and may have an impact on the interconnection request;
- (iii) have a pending higher queued interconnection request to interconnect to the transmission system; and
- (iv) have no Queue Position but have executed an LGIA or requested that an unexecuted LGIA be filed with FERC.

The interconnection system impact study will consist of a short circuit analysis, a stability analysis, and a power flow analysis. The interconnection system impact study will state the assumptions upon which it is based; state the results of the analyses; and provide the requirements or potential impediments to providing the requested interconnection service, including preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. The interconnection system impact study will provide a list of facilities that are required as a result of the Interconnection Request and a non-binding good faith estimate of the cost responsibility and a non-binding good faith estimated time to construct.

3.0 TYPE OF INTERCONNECTION SERVICE

The Interconnection Customer has selected a *Network Resource (NR)* with *Energy Resource (ER)* type interconnection. The Interconnection Customer will select NR or ER prior to the Facilities Study.

4.0 Description of Proposed Interconnection

The Interconnection Customer's proposed Generating Facility is to be interconnected to Transmission Provider's existing Sigurd – Glen Canyon 230 kV line. Figure 1 is a one-line diagram that illustrates the interconnection of the proposed Generating Facility to the Transmission Provider's system.

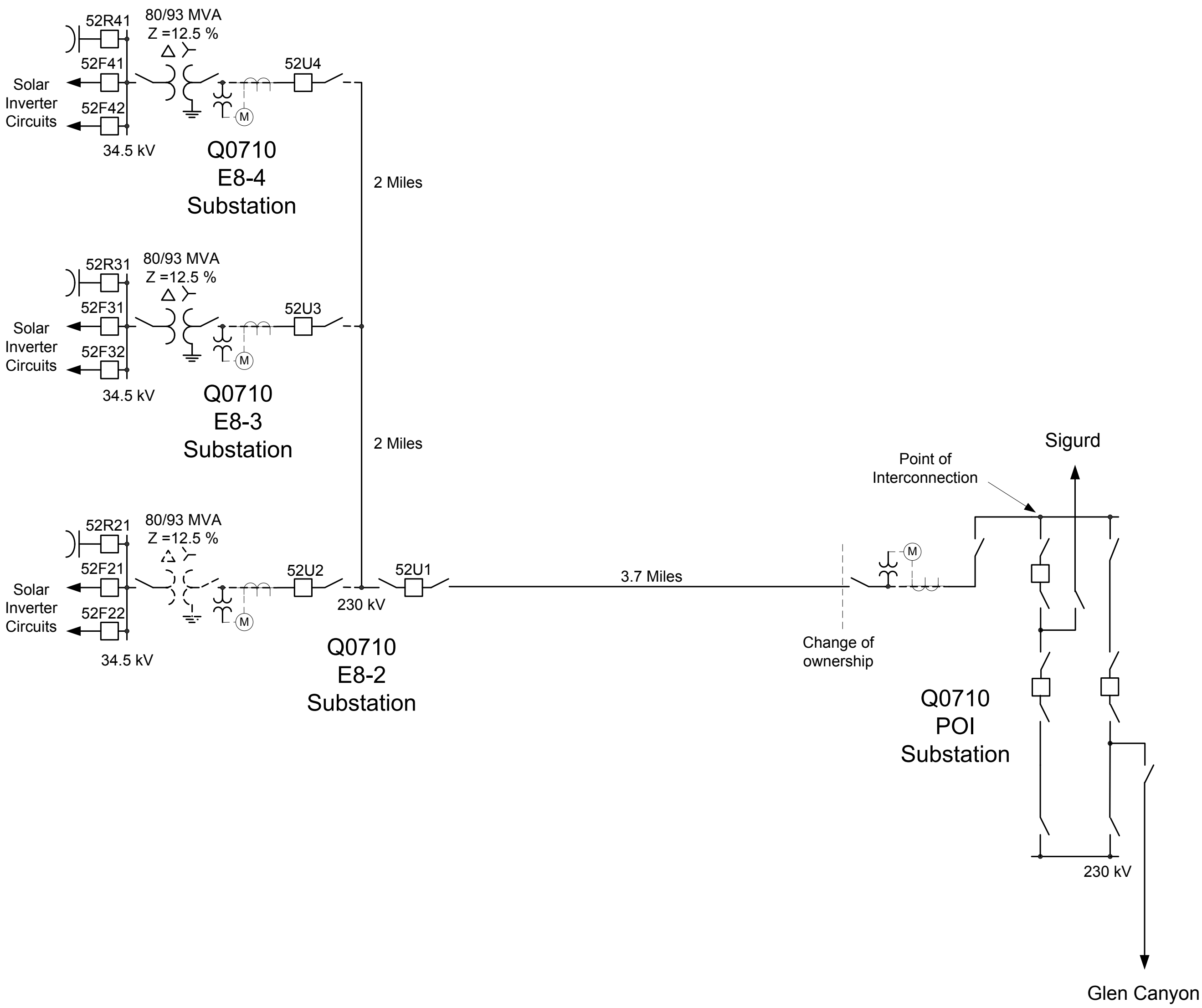

Figure 1: Simplified System One Line Diagram

4.1 Other Options Considered

The following alternative options were considered as potential points of interconnection for this Project: None.

5.0 STUDY ASSUMPTIONS

- All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are listed in Appendix 1. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, and the results and conclusions could significantly change.
- The Transmission Provider reserves the right to restudy this project should the interconnection customer request a change in status to a Qualifying Facility.
- For study purposes there are two separate queues:
  - Transmission Service Queue: To the extent practical, all network upgrades that are required to accommodate active transmission service requests submitted prior to the Interconnection Customer's generation interconnection request will be modeled in this study.
  - Generation Interconnection Queue: Interconnection facilities associated with higher queue interconnection requests will be modeled in this study.
- The Interconnection Customer's request for energy or network resource interconnection service in and of itself does not convey transmission service. Only a Network Customer may make a request to designate a generating resource as a Network Resource. Because the queue of higher priority transmission service requests may be different when a Network Customer requests network resource designation for this Generating Facility, the available capacity or transmission modifications, if any, necessary to provide Network Resource Interconnection Service may be significantly different. Therefore, the Interconnection Customer should regard the results of this study as informational rather than final.
- Under normal conditions, the Transmission Provider does not dispatch or otherwise directly control or regulate the output of Generating Facility. Therefore, the need for transmission modifications, if any, which are required to provide Network Resource Interconnection Service will be evaluated on the basis of 100 percent deliverability (i.e., no displacement of other resources in the same area).
- This study assumes the Project will be integrated into the Transmission Provider's system on the Sigurd – Glen Canyon 230 kV line.
- The Interconnection Customer will construct and own any facilities required between the Point of Change of Ownership and the Project unless specifically identified by the Transmission Provider.
- Generator tripping will be required for certain outages. Also, generation curtailment up to 100% of its capacity will be required to resolve any operational issues identified in the area.
- Additional system reconfiguration/improvements related to prior queued interconnection projects are assumed to be in-service:
  1. Looping the existing 230 kV line between Parowan and West Cedar in and out of the Three Peaks substation and converting operation to 138 kV

2. Installing a second 345/138 kV transformer at Three Peaks as identified in the Network Resource section of a prior queue
3. Adding a second 230/138 kV transformer at Parowan substation
4. Increasing the Sigurd – Q0634 POI line rating to at least 345 MVA by fixing the spans on the 230 kV line to increase clearance
5. Installing a remedial action scheme related to Q589, Q0634 (loss of any of the Sigurd 345/230 kV transformers, loss of the Sigurd – Q0634 POI 230 kV line)

- All facilities will meet or exceed the minimum Western Electricity Coordinating Council (“WECC”), North American Electric Reliability Corporation (“NERC”), and the Transmission Provider’s performance and design standards.
- This report is based on information available at the time of the study. It is the Interconnection Customer’s responsibility to check the Transmission Provider’s web site regularly for Transmission System updates at http://www.pacificorp.com/tran.html

6.0 Energy Resource (ER) Interconnection Service

Energy Resource Interconnection Service allows the Interconnection Customer to connect its Generating Facility to the Transmission Provider’s Transmission System and to be eligible to deliver electric output using firm or non-firm transmission capacity on an as available basis.

6.1 Requirements

6.1.1 Generating Facility Modifications

All interconnecting synchronous and non-synchronous generators are required to design their Generating Facilities with reactive power capabilities necessary to operate within the full power factor range of 0.95 leading to 0.95 lagging. This power factor range shall be dynamic and can be met using a combination of the inherent dynamic reactive power capability of the generator or inverter, dynamic reactive power devices and static reactive power devices to make up for losses.

For synchronous generators, the power factor requirement is to be measured at the Point of Interconnection (“POI”). For non-synchronous generators, the power factor requirement is to be measured at the high-side of the generator substation.

The Generating Facility must provide dynamic reactive power to the system in support of both voltage scheduling and contingency events that require transient voltage support, and must be able to provide reactive capability over the full range of real power output.

If the Generating Facility is not capable of providing positive reactive support (i.e., supplying reactive power to the system) immediately following the removal of a fault or other transient low voltage perturbations, the facility must be required to add dynamic voltage support equipment. These additional dynamic reactive devices shall have correct protection settings such that the devices will remain on line and active during and immediately following a fault event.

Generators shall be equipped with automatic voltage-control equipment and normally operated with the voltage regulation control mode enabled unless written authorization (or directive) from the grid operator is given to operate in another control mode (e.g. constant power factor control). The control mode of generating units shall be accurately represented in operating studies. The generators shall be capable of operating continuously at their maximum power output at its rated field current within +/- 5% of its rated terminal voltage.

As required by NERC standard VAR-001-1a, the Transmission Provider will provide a voltage schedule for the POI. In general, Generating Facilities should be operated so as to maintain the voltage at the POI, or other designated point as deemed appropriated by Transmission Provider, between 1.00 per unit to 1.04 per unit. The Transmission Provider may also specify a voltage and/or reactive power bandwidth as needed to coordinate with upstream voltage control devices such as on-load tap changers. At the Transmission Provider's discretion, these values might be adjusted depending on operating conditions.

Generating Facilities capable of operating with a voltage droop are required to do so. Voltage droop control enables proportionate reactive power sharing among Generating Facilities. Studies will be required to coordinate voltage droop settings if there are other facilities in the area. It will be the Interconnection Customer's responsibility to ensure that a voltage coordination study is performed, in coordination with Transmission Provider, and implemented with appropriate coordination settings prior to unit testing.

For areas with multiple Generating Facilities, additional studies may be required to determine whether or not critical interactions, including but not limited to control systems, exist. These studies, to be coordinated with Transmission Provider, will be the responsibility of the Interconnection Customer. If the need for a master controller is identified, the cost and all related installation requirements will be the responsibility of the Interconnection Customer. Participation by the Generating Facility in subsequent interaction/coordination studies will be required pre- and post-commercial operation in order ensure system reliability.

Phasor Measurement Units (PMUs) will be required at any Generating Facilities with an individual or aggregate nameplate capacity of 75 MVA or greater.

All generators must meet the Federal Energy Regulatory Committee (FERC) and WECC low voltage ride-through requirements as specified in the interconnection agreement.

As the Transmission Provider cannot submit a user written model to WECC for inclusion in base cases, a standard model from the WECC Approved Dynamic Model Library is required 180 days prior to trial operation. The list of approved generator models is continually updated and is available on the http://www.WECC.biz website.

6.1.2 Transmission System Modifications

Transmission system improvements required to interconnect Q0710 as an Energy Resource are as follows:

1. Construct a new three-breaker 230 kV ring bus substation at the POI on the Sigurd – Glen Canyon 230 kV line with switches and line terminations (see Figure 1).

Note: As this interconnection changes the system configuration and has the potential to affect a WECC rated transmission path, an in-depth special study will be required to identify if there is an interaction with TOT 2B1, TOT 2B2, TOT 2C, in coordination with neighboring utilities such as Los Angeles Department of Water and Power (LADWP), Arizona Public Service (APS), NV Energy and other interested parties. This study is mandatory prior to signing an interconnection agreement.

6.1.3 Existing Circuit Breaker Upgrades – Short Circuit

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 159 – 1500 kW inverters fed through 78 – 3 MVA 34.5 kV – 390 V transformers with 5.75% impedance then fed through three 230 – 34.5kV 80/93 MVA step-up transformer with 12.5 % impedance will not push the fault duty above the interrupting rating of any of the Transmission Provider's existing fault interrupting equipment.

6.1.4 Protection Requirements

The installation of protective relays for line fault detection will be required at the Transmission Provider's new 230 kV POI substation for the protection of the lines to the Interconnection Customer's collector substations and the lines to Sigurd and Glen Canyon substations. Transmission line current differential relay systems will be implemented on the line to the collector substation. The line relays to Sigurd and Glen Canyon substations will continue to use permission overreaching transfer trip logic. This will minimize the amount of relay work that will be required at Sigurd and Glen Canyon substations. The Transmission Provider will supply a panel containing line relays that will be installed at the collector substation E8-2. The relays in this panel will communicate with the relays at the POI substation over an optical fiber cable. This optical fiber cable will need to be installed on the transmission line between the POI and the collector substation E8-2. The Interconnection Customer will need to provide the outputs from two sets of current transformers on the tie line breaker at collector substation E8-2. These currents will be fed into the line relays. A three phase set of 230 kV voltage transformers will also be required at the collector substation for the line relays.

The Interconnection Customer will be responsible for the design, installation, and maintenance of the line protective relays for the 230 kV line between collector substations E8-2, E8-3 and E8-4. These relays will need to detect and clear 230 kV line faults in five cycles or less.

Elements in the line relays at the POI substation will monitor the voltage on the line to the collector substation. These elements will operate for under/over voltage and over/under frequency. If the voltage, magnitude or frequency, is outside of the normal operation range, these relays will send a transfer trip signal. The line relays at the E8-2 collector substation will receive the transfer trip signal and trip open all of the Interconnection Customer's 34.5 kV line breakers at that collector substation. This transfer trip signal will need to be forwarded on to the E8-3 and E8-4 collector substations to trip the 34.5 kV breakers at those substations.

6.1.5 Data (RTU) Requirements

In addition to the need for operational data and control at the POI substation data for the operation of the power system will be needed from the collector substations. This data can be acquired by installing RTUs at the collector substations.

Listed below is the data that will be acquired from the collector substations and from the POI and tie line substation.

From POI substation:
Analogs:

- Net Generation real power
- Net Generator reactive power
- Interchange energy register

From Collector substation E8-2

Analogs:

- E8-2 Transformer Net Generation real power
- E8-2 Transformer Net Generator reactive power
- E8-2 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power

- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

<u>Status:</u>
- 230 kV breaker 52U-1
- 230 kV breaker 52U-2
- 34.5 kV breaker 52R21
- 34.5 kV breaker 52F21
- 34.5 kV breaker 52F22
- Line relay alarm

From Collector substation E8-3
<u>Analogs:</u>
- E8-3Transformer Net Generation real power
- E8-3 Transformer Net Generator reactive power
- E8-3 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power
- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

<u>Status:</u>
- 230 kV breaker 52U-3
- 34.5 kV breaker 52R31
- 34.5 kV breaker 52F31
- 34.5 kV breaker 52F32

From Collector substation E8-4
<u>Analogs:</u>

- E8-4Transformer Net Generation real power
- E8-4 Transformer Net Generator reactive power
- E8-4 Transformer Interchange energy register
- 230 kV A phase voltage
- 230 kV B phase voltage
- 230 kV C phase voltage
- 34.5 kV feeder 1 real power
- 34.5 kV feeder 1 reactive power
- 34.5 kV feeder 2 real power
- 34.5 kV feeder 2 reactive power
- 34.5 kV capacitor reactive power
- Average Farm Atmospheric Pressure (Bar)
- Average Farm Temperature (Celsius)
- Irradiance (W/m2)

Status:

- 230 kV breaker 52U-4
- 34.5 kV breaker 52R41
- 34.5 kV breaker 52F41
- 34.5 kV breaker 52F42

6.1.6 Substation Requirements

POI Substation:

To support the requested interconnection, the Project will require a new 230kV, three breaker ring bus POI substation. The substation will be approximately 270’ x 470’ (fence dimensions) based on the customer provided facility requirements. The following is a list of the major equipment required for this project:

3 – 230kV Power Circuit Breakers
6 – 230kV CCVTs
3 – 230kV CT/VT Metering units
13 – 230kV Switches
9 – 230kV Lightning Arresters
1 – 230kV SSVT

Collector Stations E8-2, E8-3, E8-4:

The Interconnection Customer will provide a separate graded, grounded and fenced area along the perimeter of the Interconnection Customer’s Generating Facility for the Transmission Provider to install a control house for any required metering, protection or communication equipment. This area will share a fence and ground grid with the

Generating Facility and have separate, unencumbered access for the Transmission Provider. AC station service for the control house will be supplied by the Interconnection Customer. DC power for the control house will be supplied by the Transmission Provider.

6.1.7 Communication Requirements

OPGW fiber cable will be installed on the Customer constructed 230 kV line between the Q0710 POI substation and the Customer's E8-2, E8-3, and E8-4 substations.

OPGW fiber cable will also be installed between the WAPA Glen Canyon substation and the Q0710 POI substation to implement transfer trip from Transmission Provider's Sigurd substation to the Q0710 POI substation and to implement transfer trip from WAPA's Glen Canyon substation to the Q0710 POI substation for line protection.

In addition to the relaying requirements, electronic communications is required from the Q0710 POI substation to Transmission Provider's dispatch centers. The OPGW and electronics installed in each location will be used to provide:

- channels for connecting the Q0710 substations' RTUs,
- a channel for the Q0710 POI substation RTU and the primary meter to Transmission Provider's dispatch centers,
- channels for voice OPXs at the E8-2, the E8-3, the E8-4, and the Q0710 POI substations,
- a channel for the backup meter as an RTU and
- Ethernet connection for MV-90 meter data access

The Q0710 Interconnection Customer is to provide a 125 V dc battery and charger system that will support the electronic communications equipment with at least 24-hour backup at each of the three Q0710 substations.

The Q0710 Interconnection Customer is to provide property, near each of the Q0710 substation control houses, for Transmission Provider supplied buildings that will house the Transmission Provider communications and RTU equipment.

6.1.8 Metering Requirements

<u>Interchange Metering</u>

<u>Point of Interconnect Q0710 Substation:</u>

The interchange metering will be designed bidirectional and rated for the total net generation of the Project including metering the retail load (per tariff) delivered to the Interconnection Customer. The Transmission Provider will specify and order all interconnection revenue metering, including the instrument transformers, metering panels, junction box and secondary metering wire. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the Project.

The metering design package will include two revenue quality meters, test switch, with DNP real time digital data terminated at a metering interposition block. One meter will be designated as a primary SCADA meter and a second meter will be designated as backup with metering DNP data delivered to the alternate control center. The metering data will include bidirectional KWH KVARH, revenue quantities including instantaneous PF, MW, MVAR, MVA including per phase voltage and amps data.

An Ethernet connection is required for retail sales and generation accounting via the MV-90 translation system.

<u>Substation (E-8.2, E-8.3, E-8.4) Metering:</u>
The metering for each of the three substations will be rated for the collector's station maximum planned generation and will be located at the high side of the step-up transformer. The primary metering transformers shall be combination CT/VT extended range for high accuracy metering with ratio's to be determined during the design phase of the Project.

The Transmission Provider will design and procure the collector revenue metering panels. The collector substation metering design package will be specified identical to the interchange metering panel. The Interconnection Customer shall install the revenue metering panels, instrument transformers, junction box and secondary lead conductors. The collector substation metering design package will include two revenue quality meters, test switches, and all SCADA metering data terminated at a metering interposition block.

An Ethernet phone line is required for retail sales and generation accounting via the MV-90 translation system.

<u>Station Service/Construction Power</u>
The location of the project is not within the Transmission Provider service territory. The Interconnection Customer must arrange construction power with the electric service provider holding the certificated service territory rights for the area in which the load is physically located.

Please note, prior to back feed Interconnection Customer must arrange the retail meter service by the local provider for electricity consumed by the Project. Approval for back feed is contingent upon obtaining station service.

6.1.9 Transmission Line Requirements

<u>Transmission Provider Connection to Q0710 POI Substation</u>

Transmission Provider will loop the existing Glen Canyon – Sigurd 230kV transmission line through the new Q0710 POI substation. For the purposes of this study it has been assumed that the new Q0710 POI substation location is directly adjacent to the 230kV Transmission line near the town of Big Water.

Interconnection Customer Connection to Q0710 POI Substation

Transmission Provider will review the Interconnection Customer's design of the Interconnection Customer's transmission line connection to the Q0710 POI substation structure for general conformance with Transmission Provider's construction standards.

6.2 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

Energy Resource Interconnection – Direct Assignment Facilities	
Q0710 POI to E8 collector stations – Fiber on new line	$353,000
Q0710 POI substation – Add meter, dead-end structure, switch	$801,000
Q0710 E8-2 collector substation – Add relaying, metering, and RTU	$1,002,000
Q0710 E8-3 collector substation – Add metering and RTU	$874,000
Q0710 E8-4 collector substation – Add metering and RTU	$878,000
Sub-total Direct Assignment Costs	**$3,908,000**
Interconnection – Network Upgrade Costs	
Q0710 POI to Glen Canyon – Add fiber on existing line	$822,000
Q0710 POI substation – Add 230 kV ring bus	$10,079,000
WAPA Glen Canyon substation – Add new relay settings and communication	$113,000
Glen Canyon communication site – Install fiber node	$222,000
Sigurd substation – Add new relay settings	$38,000
Glen Canyon to Sigurd 230 kV line – Loop through POI substation	$566,000

Sub-total Network Upgrade Costs **$11,840,000**

Total Cost – ER Interconnection Service – Interconnection Only **$15,748,000**

*Any distribution line modifications identified in this report will require a field visit analysis in order to obtain a more thorough understanding of the specific requirements. The estimate provided above for this work could change substantially based on the results of this analysis. Until this field analysis is performed the Transmission Provider must develop the project schedule using conservative assumptions. The Interconnection Customer may request that the Transmission Provider perform this field analysis, at the Interconnection Customer's expense, prior to the execution of an Interconnection Agreement in order to obtain more cost and schedule certainty.

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Generator Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

6.3 Schedule

The Transmission Provider estimates it will require approximately 24 months to design, procure and construct the facilities described in the Energy Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the Facilities Study.

Please note, the time required to perform the scope of work identified in this report appears to result in a timeframe that does support the Interconnection Customer's requested Commercial Operation date of December 19, 2019.

6.3.1 Maximum Amount of Power that can be delivered into Network Load, with No Transmission Modifications (for informational purposes only)

Zero (0) MW can be delivered on firm basis to the Transmission Provider's network loads without system improvements as the Sigurd – Glen Canyon (TOT 2B2) path is fully subscribed.

6.3.2 Additional Transmission Modifications Required to Deliver 100% of the Power into Network Load (for informational purposes only)

In order to deliver 100% of the power into Network Load the following improvements are required: See Section 6.1.2 and Section 7.1.2. Additionally, it is assumed that all facilities identified for prior queued projects are in service.

7.0 NETWORK RESOURCE (NR) INTERCONNECTION SERVICE

Network Resource Interconnection Service allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's Transmission System in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers. The transmission system is studied under a variety of severely stressed conditions in order to determine the transmission modifications which are necessary in order to deliver the aggregate generation in the area of the POI to the Transmission Provider's aggregate load. Network Resource Interconnection Service in and of itself does not convey transmission service.

7.1 Requirements

7.1.1 Generating Facility Modifications

Refer to section 6.1.2

7.1.2 Transmission System Modifications

As the northbound transmission capacity on the existing Sigurd – Glen Canyon 230 kV (TOT 2B2) transmission line is fully subscribed, interconnecting as a network resource will require the existing Sigurd – Glen Canyon 230 kV line capacity to be increased by at least 240 MW. Figure 2 is a one-line diagram that illustrates the interconnection of the proposed Q0710 Project to the Transmission Provider's system. Due to excessive line losses related to the level of power transfers necessary to accommodate the Q0710 Project output (approximately 540 MW), a 230 kV line from the Q0710 POI to Sigurd is uneconomical. Therefore, voltage transformation from 230 kV to 345 kV will be necessary and the existing 230 kV line from the Q0710 POI to Sigurd will be converted to 345 kV operation. Because the Glen Canyon end of the existing 230 kV line is owned and operated by Arizona Public Service, no voltage transformation between Q0710 POI and Glen Canyon substation is being proposed; however, the line will need to be reconductored.

<u>Transmission improvements required to interconnect Q0710 as a Network Resource are as follows:</u>

1. Move the existing Sigurd line termination from the 230 kV yard to 345 kV yard, and install one 345 kV circuit breaker and two new 345 kV deadend lattice towers
2. Install two 560 MVA 230/345 kV transformers and 345 kV circuit breakers at the Q0710 POI

3. Rebuild approximately 144 miles of the existing 230 kV line between Sigurd and the new Q0710 POI substation at 345 kV to at least 560/620 MVA (continuous/emergency)
4. Install two 30 MVAr line reactors on the converted 345 kV line between Sigurd and Q0710 POI substations at each end to avoid inadvertent reactive power due to line charging on the 345 kV line under light load conditions
5. Install a four breaker 230 kV ring bus configuration at the Q0710 POI
6. Install a 300 MVA (continuous rating) /420 MVA (emergency rating) 230 kV phase shifting transformer at the Q0710 POI substation to accommodate the flow of 410 MW through the PST in the event of the loss of the 230 kV tie line between the Q0710 POI substation to Q0710 collector substation (See Figure 2)
7. Remove and dispose of existing phase shifting transformer at Sigurd
8. Reconductor the existing 230 kV line between Q0710 POI and Glen Canyon substations or achieve higher 115° rating to at least 360/428 MVA (continuous/emergency) to prevent overload of 107% above the existing emergency rating for an outage of Q0710 POI to Q0710 collector substation
9. Build a new 345 kV line from Emery to Oquirrh substation line reactors; approximately 130 miles (see North of Huntington/Sigurd discussion below)

<u>Note: As this interconnection changes the system configuration and has the potential to affect a WECC rated transmission path, an in-depth special study will be required to identify if there is an interaction with TOT 2B2, TOT 2B1, TOT 2C, in coordination with neighboring utilities such as Los Angeles Department of Water and Power (LADWP), Arizona Public Service (APS), NV Energy and other interested parties. This study is mandatory prior to signing an interconnection agreement.</u>

<u>North of Sigurd Transmission Constraint</u>
There are a total of five 345 kV lines from Huntington and Sigurd that form the North of Huntington/Sigurd cutplane. These lines are

(1) Huntington – Spanish Fork 345 kV line
(2) Emery – Spanish Fork 345 kV line
(3) Mona – Huntington 345 kV line
(4) Sigurd – Clover – Mona # 1 345 kV line
(5) Sigurd – Clover – Mona # 2 345 kV line

Transmission capacity across the North of Huntington/Sigurd cutplane is fully committed for existing and requested transmission service. In order to deliver 240 MW of generation from the Q0710 Project to network load, an increase in the North of Huntington/Sigurd transmission capacity is required. Increasing the transfer capacity of this path will require the addition of a new transmission line along with 345 kV circuit breakers at the line terminations. For the purposes of this study, it is assumed that the new line would be a 345 kV line of approximately 130 miles in length running between the Transmission

Provider's existing Emery and Oquirrh substations, constructed with 2 x 1272 ACSR conductors per phase.

Until a new line across the North of Huntington/Sigurd cutplane can be constructed, the Transmission Customer will be required to limit scheduled power from this area (including the new facility) to amounts within the Transmission Customer's existing rights across the constrained path.

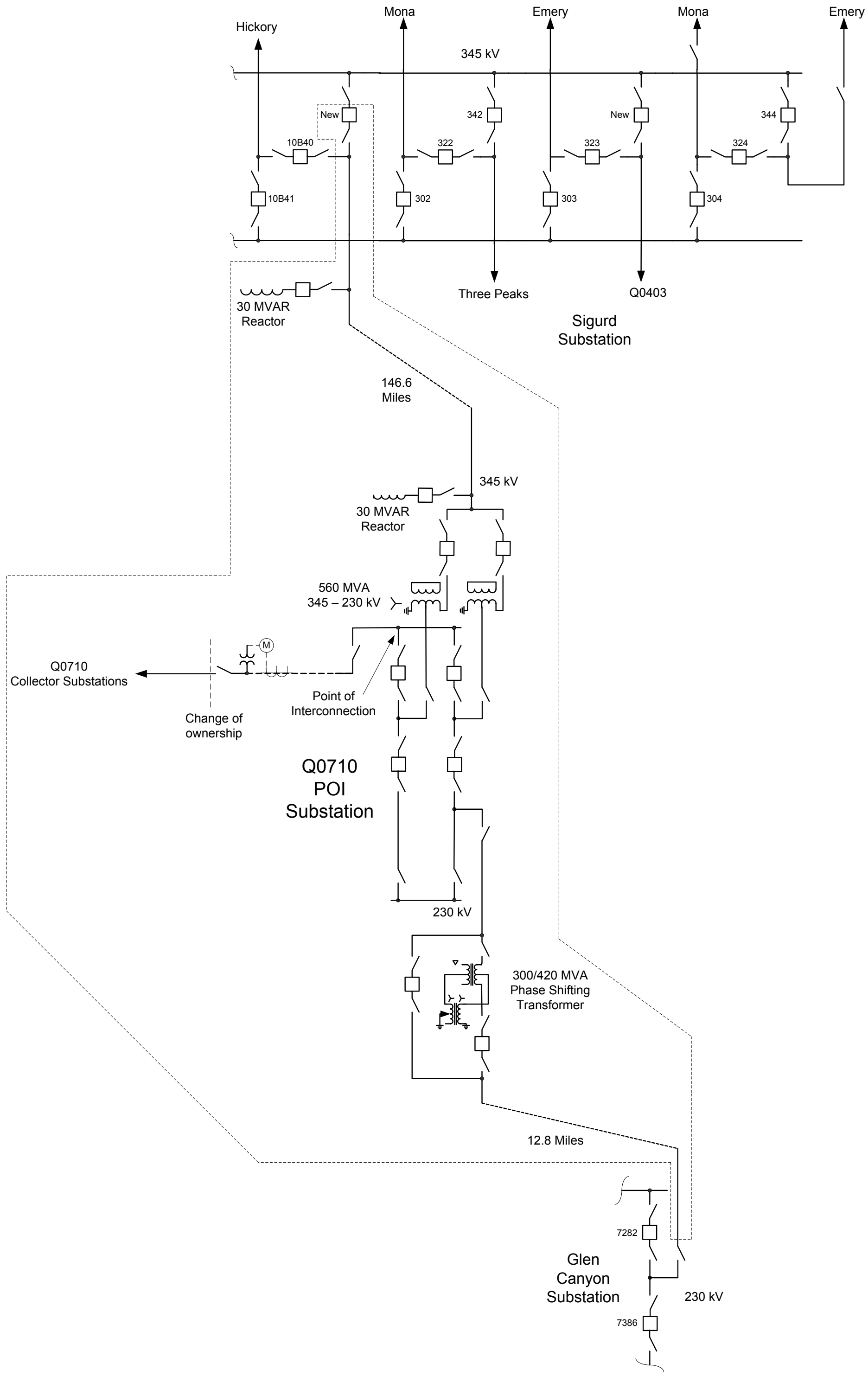

Figure 2: System One Line Diagram for Interconnecting Facility Operating as Network Resource (NR)

7.1.3 Existing Circuit Breaker Upgrades – Short Circuit

The increase in the fault duty on the system as a result of the addition of the Generating Facility with 159 – 1500 kW inverters fed through 78 – 3 MVA 34.5 kV – 390 V transformers with 5.75 % impedance then fed through three 230 – 34.5kV 80/93 MVA step-up transformer with 12.5 % impedance and then adding the transmission facilities to meet the requirement for the NR evaluation will not push the fault duty above the interrupting rating of any of the Transmission Provider's existing fault interrupting equipment.

7.1.4 Protection Requirements

At the Q0710 POI substation in addition to the protective relaying described in the ER section of this report the following will be required for the facilities to meet the NR requirements: Transformer relaying will be required for the phase shifting and the 345 – 230 kV transformers. The bus sections between the 230 kV ring bus and the three transformers will be protected with bus differential relay systems. Line current differential relay systems will be applied for the 345 kV line to Sigurd substation. The lines to Glen Canyon substation and the collector substations will continue to use the line protection systems described in the ER section. At Sigurd substation line current differential relays will be installed for the new 345 kV line.

7.1.5 Data (RTU) Requirements

At the POI substation the RTU planned for in the ER section will be expanded to accommodate the monitoring and control of the additional equipment that will be required. At Sigurd substation the existing RTU will be used to monitor and control the additional 345 kV breaker.

7.1.6 Substation Requirements

In addition to the substation modifications outlined in the ER section of this report, to support the above outlined transmission system modifications the following will be required for the facilities to meet the NR requirements: Remove the 230kV phase shifter yard at Sigurd substation and add a 345kV line position, with shunt reactor, for the Glen Canyon line conversion. At the new Q0710 POI substation, expand the substation to support a new 345kV line position (with shunt reactor), two new 345-230kV transformers, and a new 230kV phase shifter yard.

7.1.7 Communication Requirements

In addition to the ER electronic communications requirements, OPGW fiber cable will be installed on the 345 kV line between the Sigurd substation and the Q0710 POI substation to provide for the redundant line protection required on a 345 kV line. An optical repeater site, somewhere near the middle of the line, will be required due to the 147 mile fiber length.

Once the Q0710 POI substation site location has been finalized, it may be possible to install a cable from the Q0710 POI substation to the Sigurd substation. However, based on the preliminary POI location, the two existing Transmission Provider microwave site options available for microwave communications have no line-of-sight. This option may not be available to provide for the redundant electronic communications required for the protection of the 345 kV line, rather than the installation of approximately 147 miles of OPGW fiber.

7.2 Cost Estimate

The following estimate represents only scopes of work that will be performed by the Transmission Provider. Costs for any work being performed by the Interconnection Customer are not included.

Network Resource

Q0710 POI substation – Expand yard for 345 kV	$40,830,000
Q0710 Fiber repeater communication site – Add communication repeater	$540,000
Sigurd substation – Add new 345 kV position	$8,900,000
Emery substation – Add new 345 kV position	$10,400,000
Spanish Fork substation – Add communications	$220,000
Oquirrh substation – Add new 345 kV position	$12,440,000
Q0710 POI to Sigurd – Add new 345 kV transmission line	$121,560,000
Emery to Oquirrh – Add new 345 kV transmission line	$196,520,000
Q0710 POI to Glen Canyon 230 kV line – replace conductor	$2,970,000
Total Network Resource Costs	**$394,380,000**
Total Cost – Energy Resource and Network Resource	**$410,128,000**

Note: Costs for any excavation, duct installation and easements shall be borne by the Interconnection Customer and are not included in this estimate. This estimate is as accurate as possibly given the level of detailed study that has been completed to date and approximates the costs incurred by Transmission Provider to interconnect this Small Generator Facility to Transmission Provider's electrical distribution or transmission system. A more detailed estimate will be calculated during the Facilities Study. The Interconnection Customer will be responsible for all actual costs, regardless of the estimated costs communicated to or approved by the Interconnection Customer.

7.3 Schedule

The Transmission Provider estimates it could take up to 120 months to permit, design, procure and construct the facilities described in the Network Resource sections of this report following the execution of an Interconnection Agreement. The schedule will be further developed and optimized during the System Impact Study.

Please note, the time required to perform the scope of work identified in the Network Resource sections of this report does not support the Interconnection Customer's requested commercial operation date of December 19, 2019.

8.0 Participation by Affected Systems

Transmission Provider has identified the following affected systems: Arizona Public Service Electric Company (APS)

A copy of this report will be shared with the each Affected System.

9.0 Appendices

Appendix 1: Higher Priority Requests
Appendix 2: Property Requirements
Appendix 3: Study Results

9.1 Appendix 1: Higher Priority Requests

All active higher priority transmission service and/or generator interconnection requests will be considered in this study and are identified below. If any of these requests are withdrawn, the Transmission Provider reserves the right to restudy this request, as the results and conclusions contained within this study could significantly change.

Generation Interconnection Queue Requests considered:

Q#	MW
66	11
310	20
311	14
313	25
324	80
333	3.2
384	60
403	525
415	11
450	50
454	3
455	3
459	2.93
464	3
471	3
472	3
473	3
475	3
488	3
489	3
492	3
493	3
502	2.93
512	3
513	80
514	80
515	80
516	80
532	50

Q#	MW
539-A	80
539-B	50.4
551	80
564	80
582	130
589	80
631	99
632	2.99
634	99
636	99
641	58
642	58
649	10.3
684	20

9.2 Appendix 2: Property Requirements

Property Requirements for Point of Interconnection Substation

Requirements for rights of way easements
Rights of way easements will be acquired by the Interconnection Customer in the Transmission Provider's name for the construction, reconstruction, operation, maintenance, repair, replacement and removal of Transmission Provider's Interconnection Facilities that will be owned and operated by Transmission Provider. Interconnection Customer will acquire all necessary permits for the project and will obtain rights of way easements for the project on Transmission Provider's easement form.

Real Property Requirements for Point of Interconnection Substation
Real property for a POI substation will be acquired by an Interconnection Customer to accommodate the Interconnection Customer's project. The real property must be acceptable to Transmission Provider. Interconnection Customer will acquire fee ownership for interconnection substation unless Transmission Provider determines that other than fee ownership is acceptable; however, the form and instrument of such rights will be at Transmission Provider's sole discretion. Any land rights that Interconnection Customer is planning to retain as part of a fee property conveyance will be identified in advance to Transmission Provider and are subject to the Transmission Provider's approval.

The Interconnection Customer must obtain all permits required by all relevant jurisdictions for the planned use including but not limited to conditional use permits, Certificates of Public Convenience and Necessity, California Environmental Quality Act, as well as all construction permits for the project.

Interconnection Customer will not be reimbursed through network upgrades for more than the market value of the property.

As a minimum, real property must be environmentally, physically, and operationally acceptable to Transmission Provider. The real property shall be a permitted or permittable use in all zoning districts. The Interconnection Customer shall provide Transmission Provider with a title report and shall transfer property without any material defects of title or other encumbrances that are not acceptable to Transmission Provider. Property lines shall be surveyed and show all encumbrances, encroachments, and roads.

Examples of potentially unacceptable environmental, physical, or operational conditions could include but are not limited to:

1. Environmental: known contamination of site; evidence of environmental contamination by any dangerous, hazardous or toxic materials as defined by any governmental agency; violation of building, health, safety, environmental, fire, land use, zoning or other such regulation; violation of ordinances or statutes of

any governmental entities having jurisdiction over the property; underground or above ground storage tanks in area; known remediation sites on property; ongoing mitigation activities or monitoring activities; asbestos; lead-based paint, etc. A phase I environmental study is required for land being acquired in fee by the Transmission Provider unless waived by Transmission Provider.

2. Physical: inadequate site drainage; proximity to flood zone; erosion issues; wetland overlays; threatened and endangered species; archeological or culturally sensitive areas; inadequate sub-surface elements, etc. Transmission Provider may require Interconnection Customer to procure various studies and surveys as determined necessary by Transmission Provider.

Operational: inadequate access for Transmission Provider's equipment and vehicles; existing structures on land that require removal prior to building of substation; ongoing maintenance for landscaping or extensive landscape requirements; ongoing homeowner's or other requirements or restrictions (e.g., Covenants, Codes and Restrictions, deed restrictions, etc.) on property which are not acceptable to the Transmission Provider.

9.3 Appendix 3: Study Results

The Siemens PTI PSS/E version 33 program was used to evaluate the steady state performance of the system for each of the contingencies described in Table 1. The study area was limited to central and southern Utah. Since the POI is located on the existing Sigurd – Glen Canyon 230 kV line, the case was tuned to meet the maximum obligation on the following WECC Paths:

(1) Path 35 (TOT 2C): Path 35 consists of the 345 kV line between Red Butte and Harry Allen Substations. This path connects Southwest Utah to Nevada.
(2) Path 78 (TOT 2B1): Path 78 consists of the 345 kV line between Pinto and Four Corners Substations. This path connects southeast Utah into Arizona/New Mexico.
(3) Path 79 (TOT 2B2): Path 79 consists of the 230 kV line between Sigurd and Glen Canyon Substations. This path connects southern Utah to Arizona.

All three paths mentioned above have phase shifting transformers regulating in power flow control mode.

Study results indicate that system improvements/additions are required to interconnect the Q0710 Project. With the capacity on the Sigurd – Glen Canyon line fully allocated, interconnecting the 240 MW solar farm to feed network load requires rebuilding the existing 230 kV line from Sigurd to the POI to 345 kV with 2x30 MVAr line reactors (operation at 230 kV is not economical due to high losses), two 230/345 kV transformers at the Q0710 POI (560 MVA) to retain the TOT 2B2 transfer capacity of 300 MW and prevent generation trip as a part of one (N-1) 230/345 kV transformer outage at POI (which can be out of service for long duration), 230 kV line reconductor or achieve higher 115° rating between Q0710 POI and Glen Canyon substation to prevent overload, and 230 kV Phase Shifting Transformer at the Q0710 POI.

The POI – Glen Canyon line overloads to 107% above the existing emergency rating (360/428 MVA) for an outage of Q0710 POI to Q0710 collector substation. The phase shifting transformer (PST) should be rated at least 300 MVA (continuous rating) /420 MVA (emergency rating) to accommodate the flow of 410 MW through the PST following the loss of the 230 kV tie line between Q0710 POI to the Q0710 collector substation.

Using different cases considering the maximum obligation on the WECC Paths described above, both light load and heavy load conditions were studied.

Prior to interconnecting the Q0710 Project, no thermal and/or voltage issues are observed under N-0 conditions. Importantly, this assumes system modifications necessary to connect projects that are higher in the interconnection queue are in-service. These modifications include:

1. Looping the existing 230 kV line between Parowan and West Cedar in and out of the Three Peaks substation and converting operation to 138 kV
2. Installing a second 345/138 kV transformer at Three Peaks as identified in the Network Resource section of a prior queue

3. Adding a second 230/138 kV transformer at Parowan substation
4. Increasing the Sigurd – Q0634 POI line rating to at least 345 MVA by fixing the spans on the 230 kV line to increase clearance
5. Installing a remedial action scheme related to Q589, Q0634 (loss of any of the Sigurd 345/230 kV transformers, loss of the Sigurd – Q0634 POI 230 kV line)

Large Generator Interconnection

System Impact Study Report

Stability Study

Completed for

(“Interconnection Customer”)
Q0710

Proposed Point of Interconnection

PacifiCorp's Sigurd-Glen Canyon 230 kV transmission line

July 27, 2016

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Executive Summary

(“Interconnection Customer”) proposed interconnecting 240 MW of new generation to PacifiCorp’s (“Transmission Provider”) Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah. The project (“Project”) will consist of 160 Power Electronics FS1690CU inverters for a total output of 240 MW.

The requested commercial operation date is December 19, 2019.

The Interconnection Customer will not operate this generator as a Qualified Facility as defined by the Public Utility Regulatory Policies Act of 1978 (PURPA).

The Transmission Provider has assigned the project “Q0710.”

Transient stability analysis was simulated for various local area disturbances in the 230 kV and 345 kV transmission network. Results identified that the 240 MW Power Electronics PV inverters as modeled will ride through ALL simulated local area contingencies.

The Project is required to operate in the voltage control mode maintaining the voltage at the Point of Interconnection based on voltage schedule provided by the Transmission Provider. Along with the voltage control the Project should at least have sufficient reactive capability to maintain the interconnection reactive exchange between 0.95 leading/lagging power factor measured at the point of interconnection. It is the responsibility of the Interconnection Customer to ensure that the Project is capable of achieving this power factor during all conditions.

The Project modeling is based on data provided by the developer and/or the developer’s equipment suppliers.

1. Description of Project

The Interconnection Customer has proposed interconnecting a solar generation facility in Kane County, Utah, to the Transmission Provider owned existing Sigurd-Glen Canyon 230 kV transmission line. The Project includes three two-winding 230/34.5 kV transformers, three 34.5/0.42 kV transformers, and 159 Power Electronics FS1500CU inverters. A preliminary electrical single line diagram depicting the Project's interconnection at a new Point of Interconnection substation is shown in Figure 1.

Power from each inverter will be stepped up to 34.5 kV through a 3 MVA pad-mounted transformer. A 34.5 kV collection system will bring the combined power output to the collector substation where the power will be further increased to 230 kV through a 34.5/230 kV transformer.

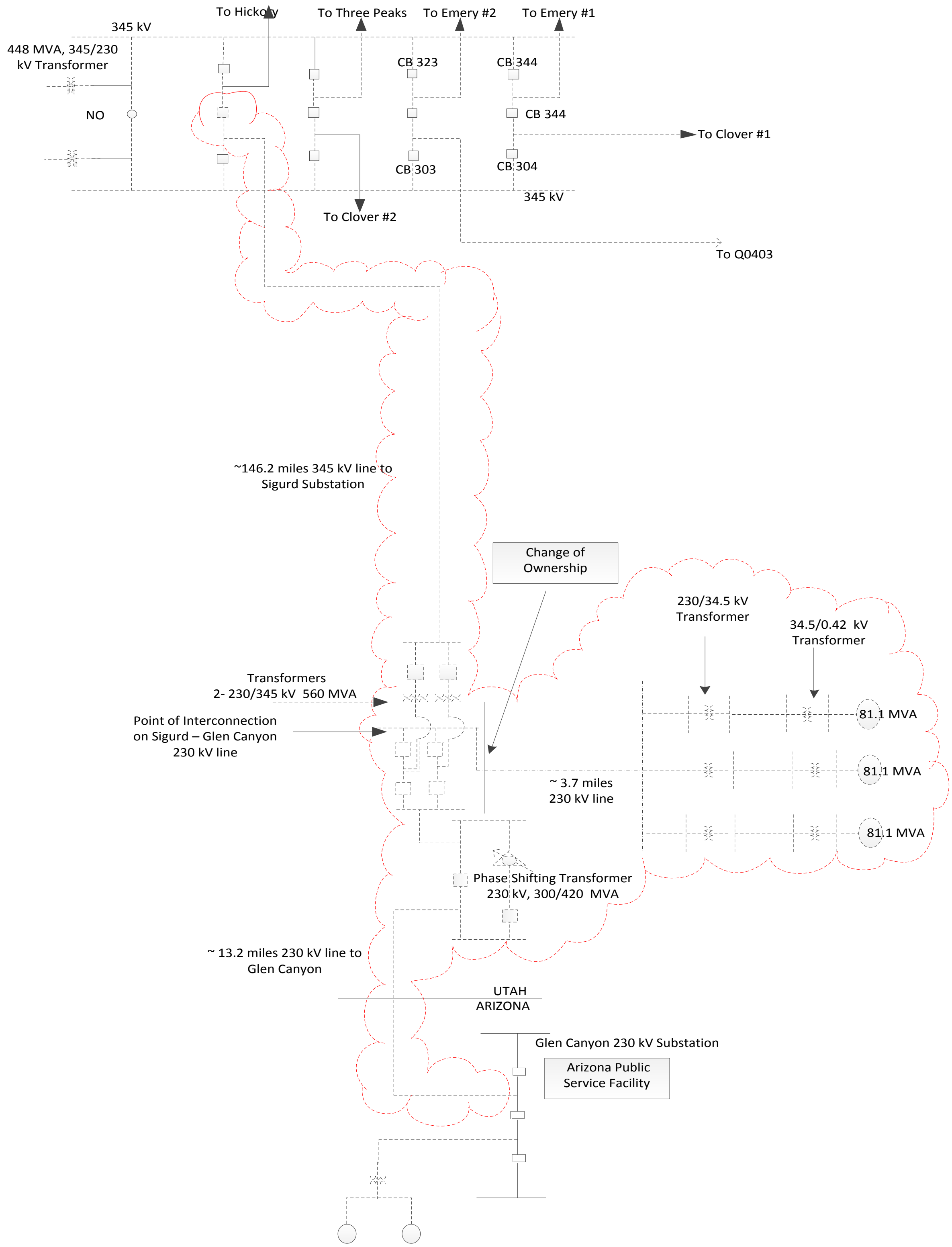


Figure 1. Single Line Diagram

2. Study Assumptions

The PSS/E version 33.4 program was used to evaluate system stability for each of the faults described in Table 1. In addition, the following assumptions were used in performing this study.

Study Period: The 2015 Heavy Summer WECC transmission power flow and dynamics data was used for this analysis.

Study Area: The study area was limited to the Project and the surrounding 345 kV and 230 kV transmission system in Southwest Utah.

Contingencies: The study simulated disturbances tabulated in Table 1.

Table 1. Transient Stability Analysis Contingencies

No.	Contingency Description
1	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)
2	Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)
3	Three-phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)
4	Three-phase fault on 230 kV bus at POI substation followed by loss of the POI – Glen Canton 230 kV circuit (4 cycles)
5	Three-phase fault on 230 kV bus at collector substation followed by loss of the POI – Collector substation 230 kV circuits (4 cycles).
6	Three-phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)
7	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)
8	Three-phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)
9	Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles).

Other Assumptions:

- Transient stability simulations were performed out to 10 seconds in order to determine system damping.
- Generating unit is a solid state inverter therefore the reactance data does not apply; the model assumes a very large reactance.
- The maximum reactive power capability of each inverter is specified at a power factor of +/- 0.95 at rated apparent power.
- The Power Electronics PV inverters are required to have zero voltage ride-through capability as shown in Figure 2; therefore, the inverters are designed to stay connected to the grid in the case of severe faults.
- In the study the full reactive capability of the generator at 0.9 power factor of full MW output was used for modeling purpose.
- It is assumed that under an islanding scenario the unit would automatically trip.
- Transient stability simulations were performed out to 10 seconds in order to determine system damping.
- Network upgrades identified from the power flow study were modeled in the case.
- For acceptable generator performance the Vdip CON (J) and Vup CON (J+1) has been changed to -99, 99 from 0.9, 1.1 as suggested by the PSLF model data base library.

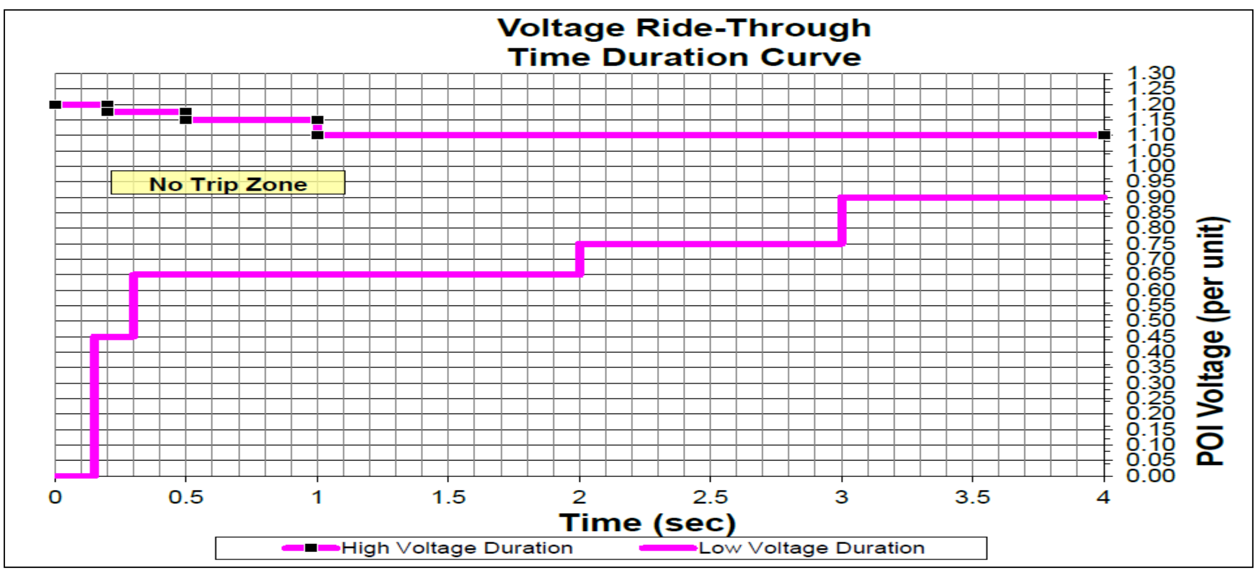


Figure 2. Voltage Ride-through Capability

3. Transient Analysis

The Generating Facility is required to ride through all 3-phase faults with normal clearing or single line-to-ground faults with delayed clearing for any event that doesn't disconnect the facility.

Transient stability results identified that ALL inverters with the model provided will ride through local area disturbances. A summary of contingency performance is provided in the following table.

Table 3. Transient Stability Analysis Contingencies

No.	Contingency Description	Stable
1	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)	Y
2	Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)	Y
3	Three-phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)	Y
4	Three-phase fault on 230 kV bus at collector substation followed by loss of the Q0710 POI – Collector substation 230 kV circuits (4 cycles).	Y
5	Three-phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)	Y
6	Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)	Y
7	Three-phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)	Y
8	Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles).	Y

Transient stability plots are provided in **Appendix A and Appendix B**.

The Interconnection Customer should ensure that this loss of reactive power in the collector system does not impact the interconnection requirement for the reactive capacity to maintain required voltage at Point of Interconnection. In the study the full reactive capability of the generator for 0.9 power factor was used for modeling purpose.

The transient analysis showed significantly high transient over voltage on buses between POI 230 kV and machine terminal buses above 1.1 p.u. for the loss of the 230 kV phase shifting transformer connected south of the Q0710 POI substation and loss of 230 kV line between phase shifting transformer bus and Glen Canyon substation. The transient high voltage last for a very short period of time at the POI, at the Project collector bus and Project's machine terminal. Please see plots in the appendix for contingency 3 (Three phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)) and contingency 8 (Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles)).

4. Conclusions

The following conclusions have been reached through this analysis:

The addition of 159 Power Electronics PV inverters interconnecting to the existing Sigurd-Glen Canyon 230 kV transmission line located in Kane County, Utah, does not result in transient instability and the Project will ride through ALL simulated local area contingencies.

Simulation results are based on data provided by the Interconnection Customer with modification (mentioned in the assumption section) at the time of the study. The results can be used to help determine whether or not the Project facilities will meet the performance criteria including ride-through requirements which will be defined in the Interconnection Agreement, and, in some cases, may indicate that additional equipment is required in order to meet these requirements. However, ultimately it is the Interconnection Customer's responsibility to meet these requirements during actual operation on a daily basis and failure to do so can result in loss of interconnection privileges. Therefore, the results of these simulations should be regarded as informational rather than definitive, and do not relieve the Interconnection Customer of any performance responsibilities.

Finally, if the assumptions utilized in this study significantly change, PacifiCorp reserves the right to perform a re-study. Significant changes include, but are not limited to, development of new models which may impact performance as well as changes to the base case assumptions for planned future but as yet uncommitted transmission line and generation facilities.

5. Appendices

Appendix A: Transient Stability Plots

Plotted Quantities in every plot in the Appendix

Plot A

Sr. No.	Trace Color	Plotted Quantity
1	Green	Voltage at Q0710 POI 230 kV in PU
2	Blue	Voltage at Sigurd 345 kV in PU
3	Cyan	Voltage at PST 230 kV in PU
4	Pink	Voltage at Clover 345 kV in PU
5	Black	Voltage at Huntington 345 kV in PU
6	Red	Voltage at Hickory 345 kV in PU

Plot B

Sr. No.	Trace Color	Plotted Quantity
1	Green	Voltage at Escalante Solar unit II
2	Blue	Voltage at Escalante Solar unit III
3	Cyan	Angle at Emery/Hunter unit 1
4	Pink	Angle at Huntington unit 1
5	Black	Angle at Lake Side I ST1
6	Red	Angle at Lake Side I ST1

Plot C

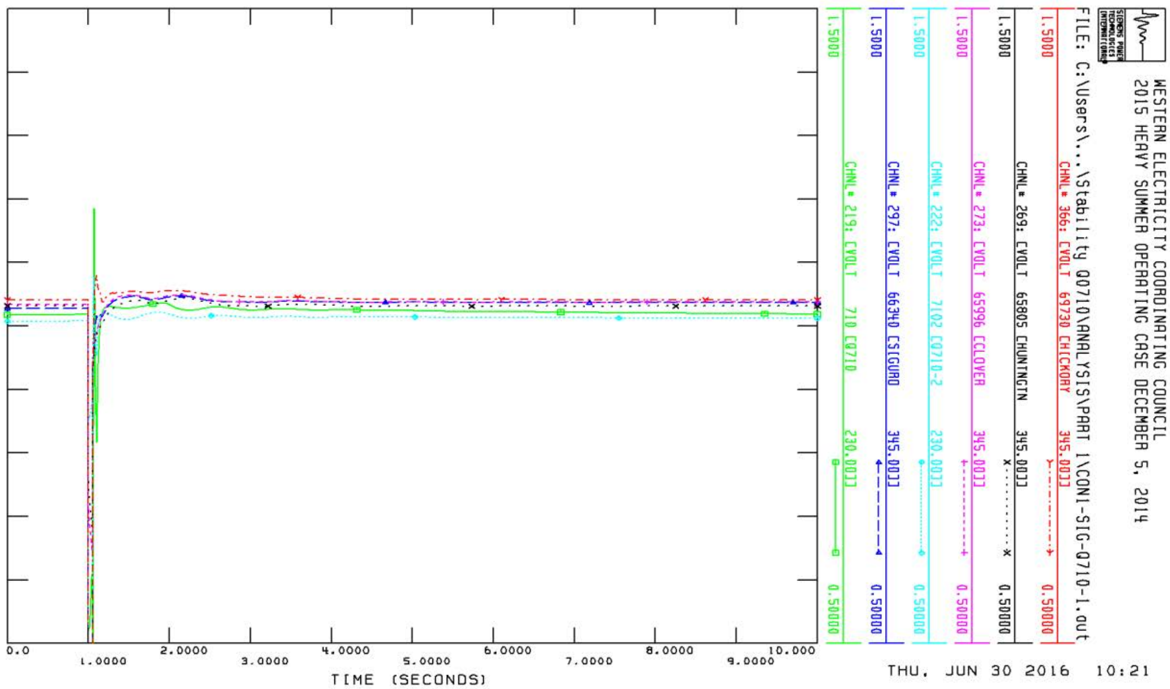
Sr. No.	Trace Color	Plotted Quantity
1	Green	Terminal voltage at G1
2	Blue	Terminal voltage at G2
3	Cyan	Terminal voltage at G3

Plot D

Sr. No.	Trace Color	Plotted Quantity
1	Green	Real Power through 34.5/.42 kV transformer Connected to Q0710 G1
2	Blue	Reactive through 34.5/.42 kV transformer Connected to Q0710 G1
3	Cyan	Real Power through 34.5/.42 kV transformer Connected to Q0710 G2
4	Pink	Reactive through 34.5/.42 kV transformer Connected to Q0710 G2
5	Black	Real Power through 34.5/.42 kV transformer Connected to Q0710 G3
6	Red	Reactive through 34.5/.42 kV transformer Connected to Q0710 G3

1. Three phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – POI 345 kV circuit (3 cycles)

Plot A



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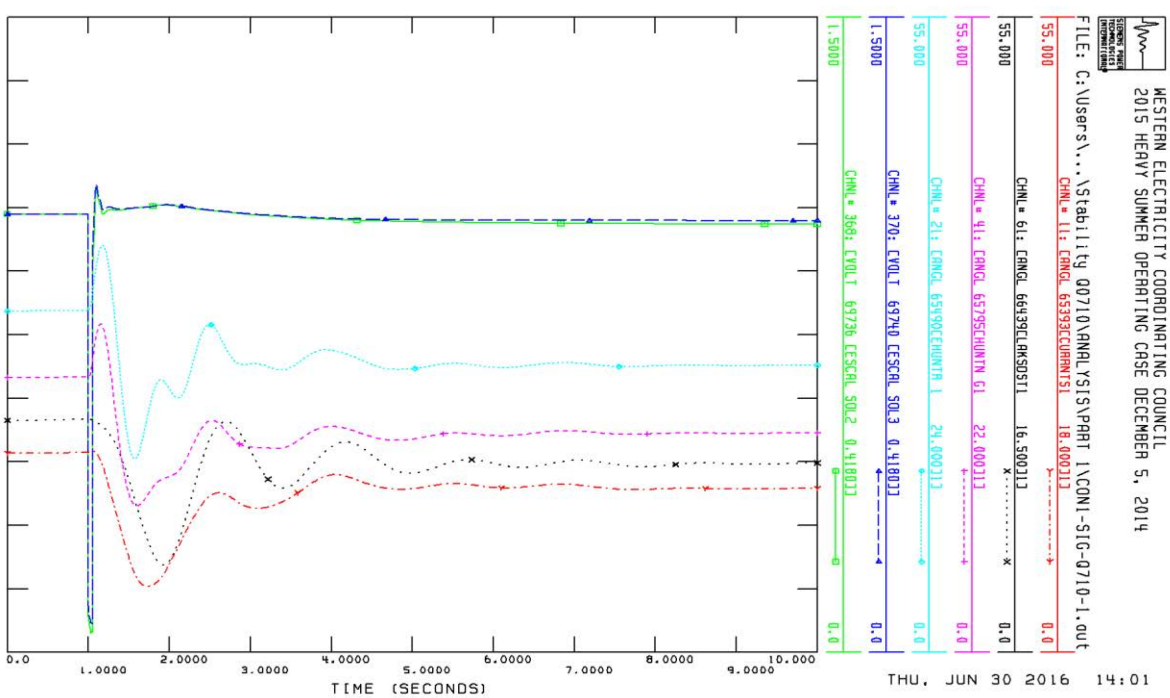

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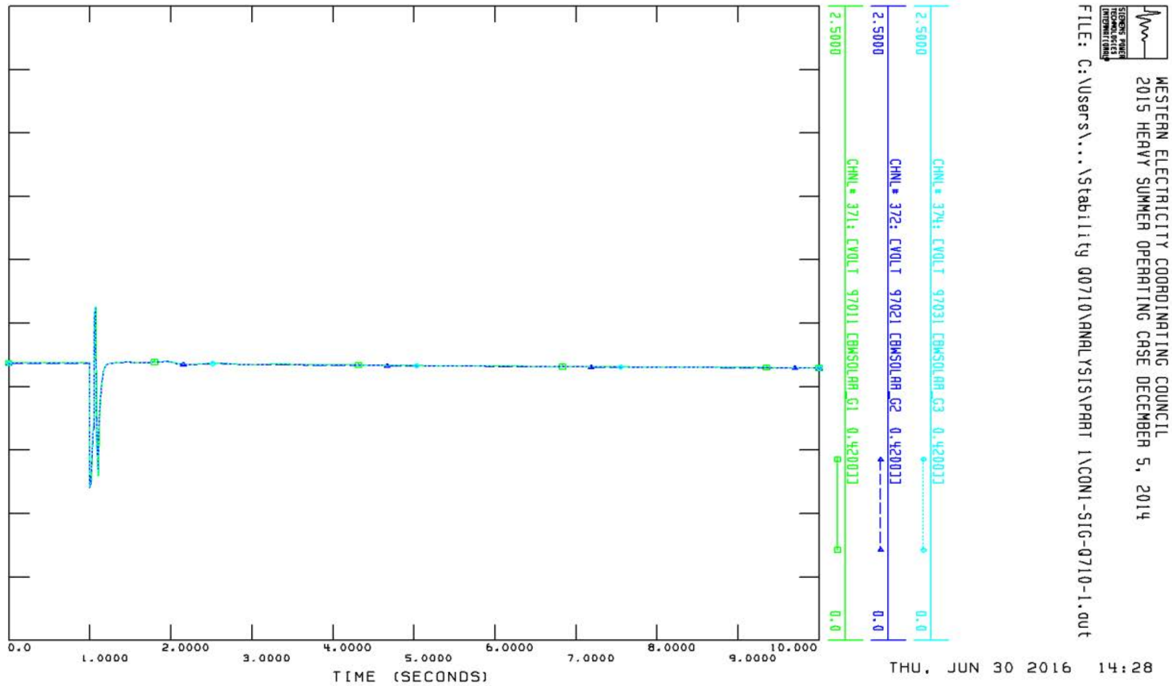
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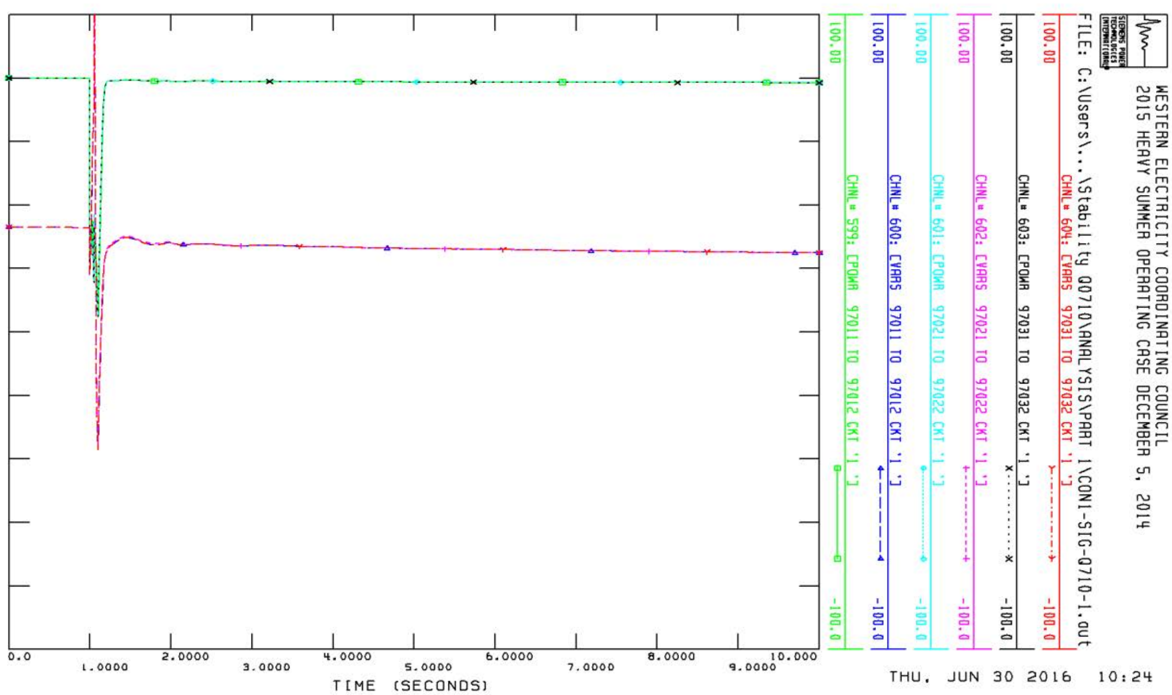
Plot D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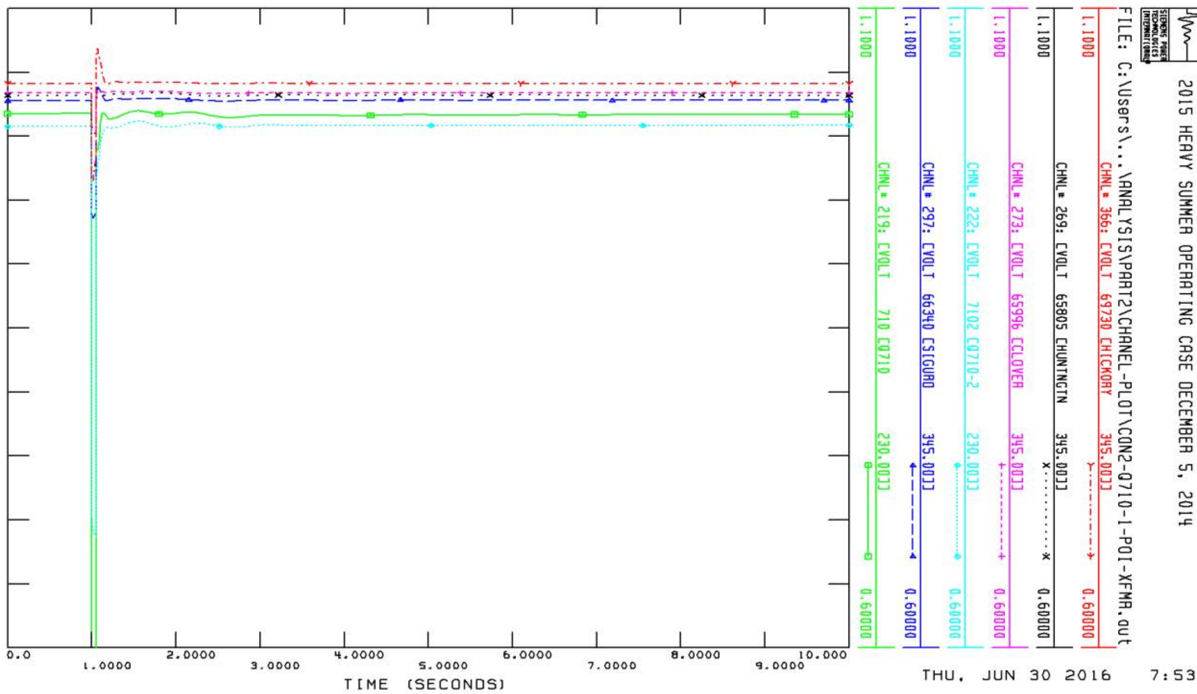
2. Three-phase fault on 345 kV bus at POI substation followed by loss of one 345/230 kV transformer (3 cycles)

Plot A



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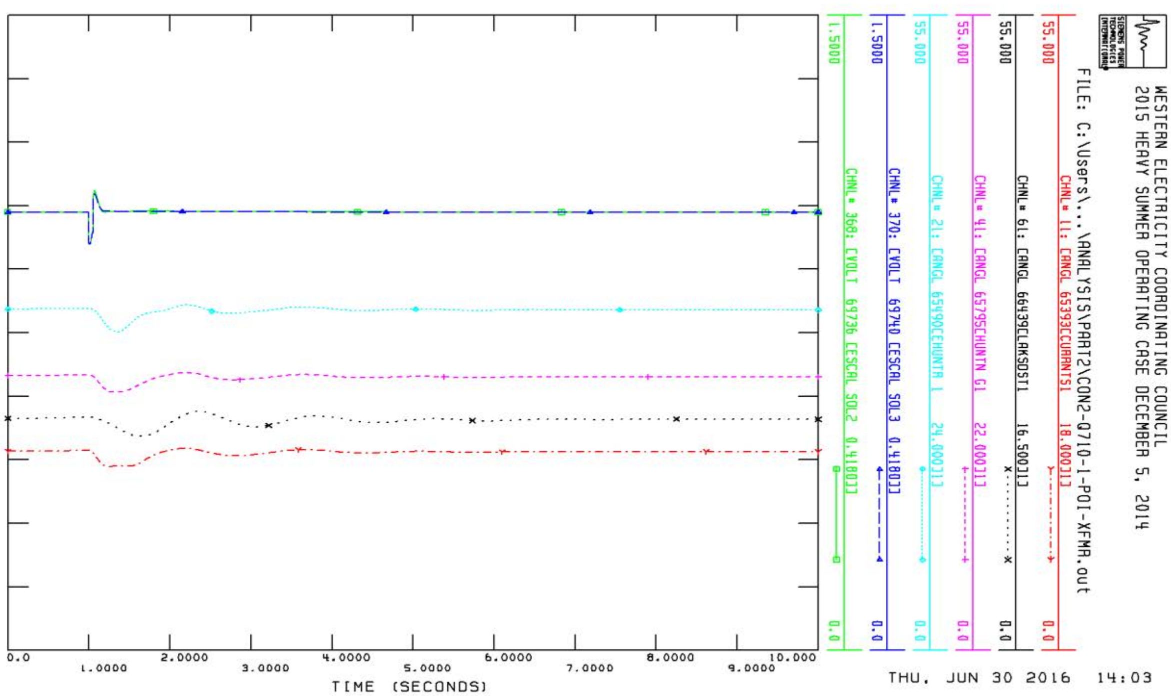

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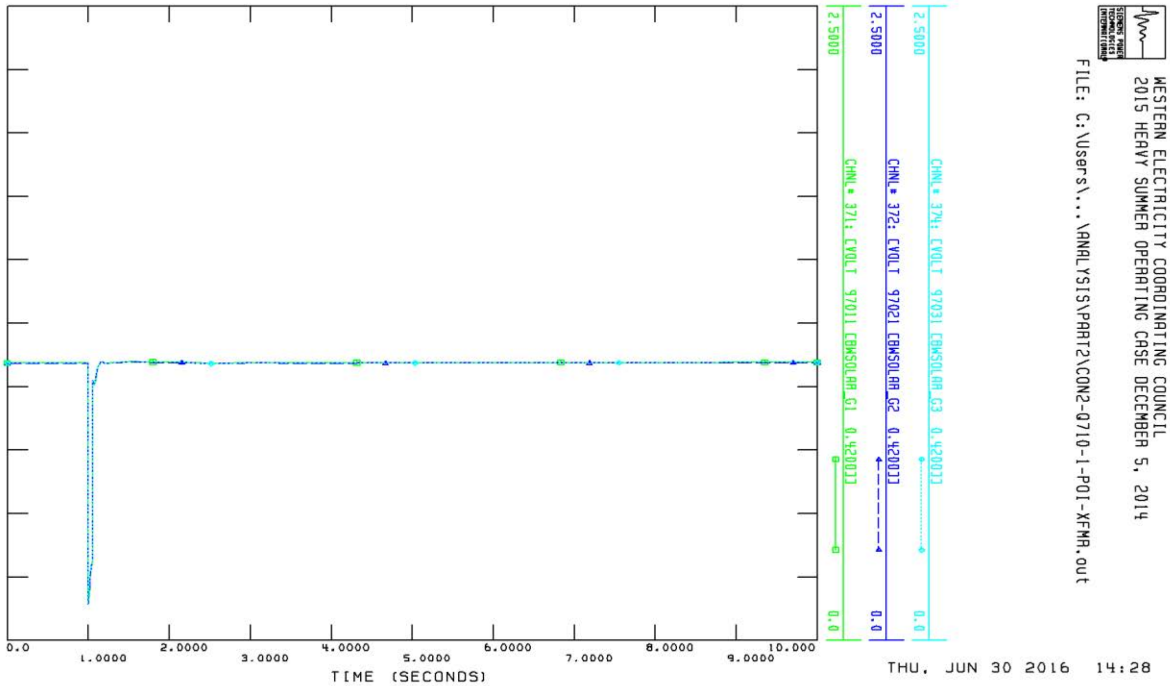
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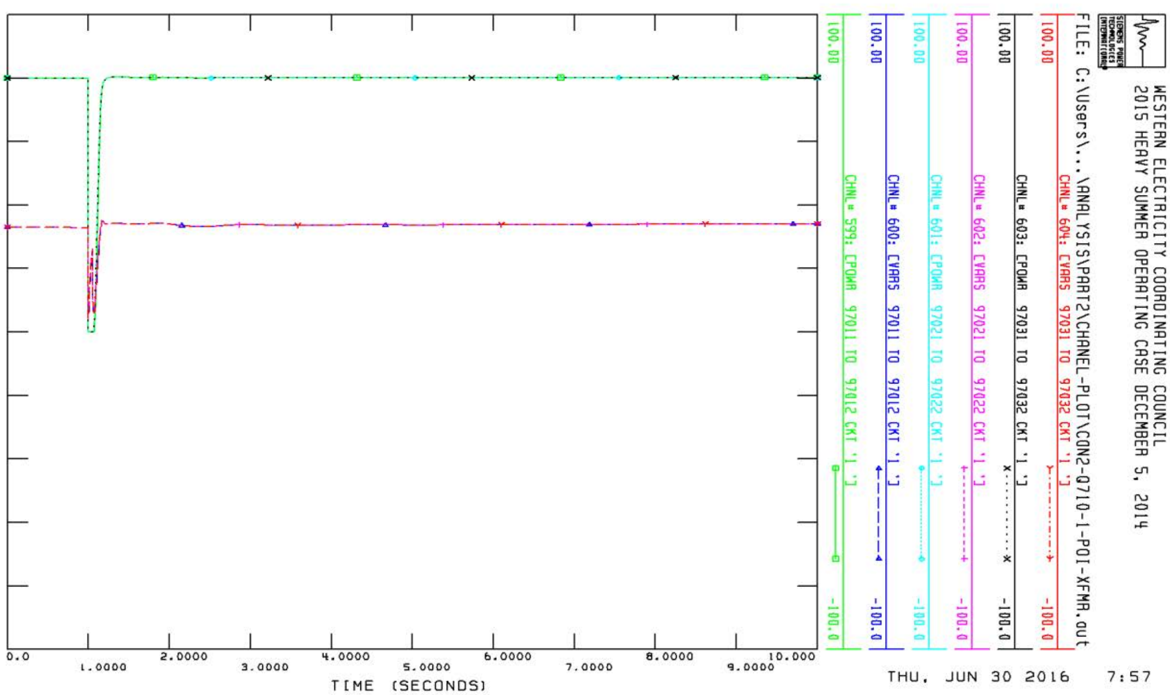
Plot D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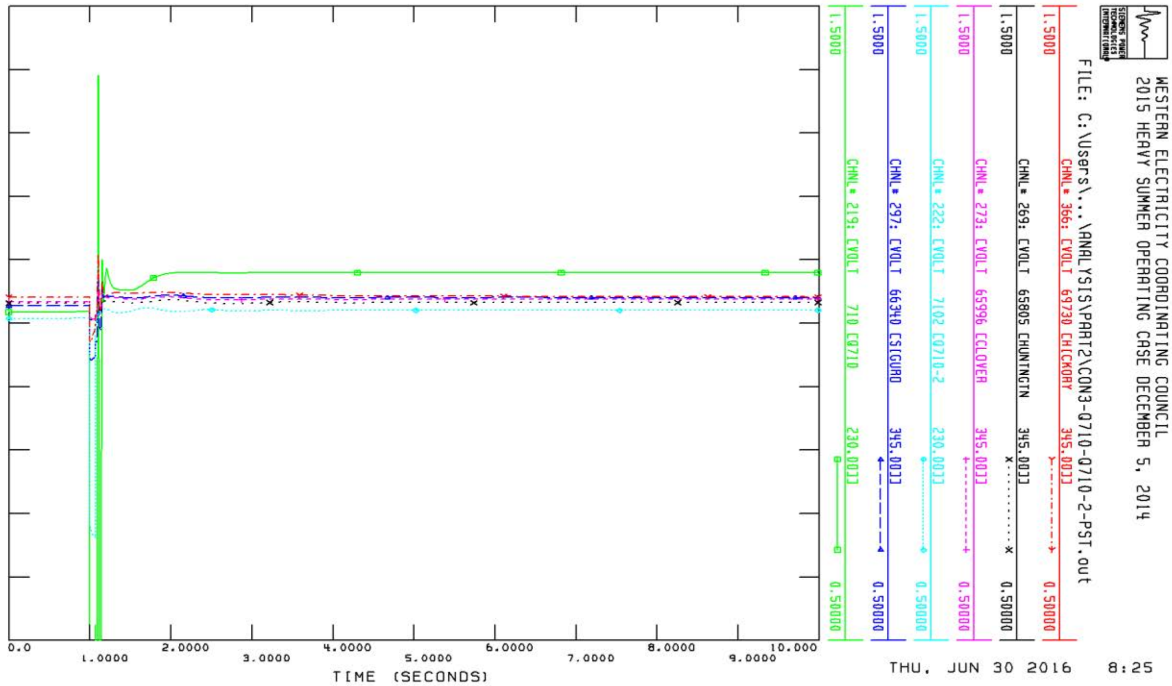
3. Three phase fault on 230 kV bus at POI substation followed by loss of the 230 kV phase shifter (4 cycles)

Plot A



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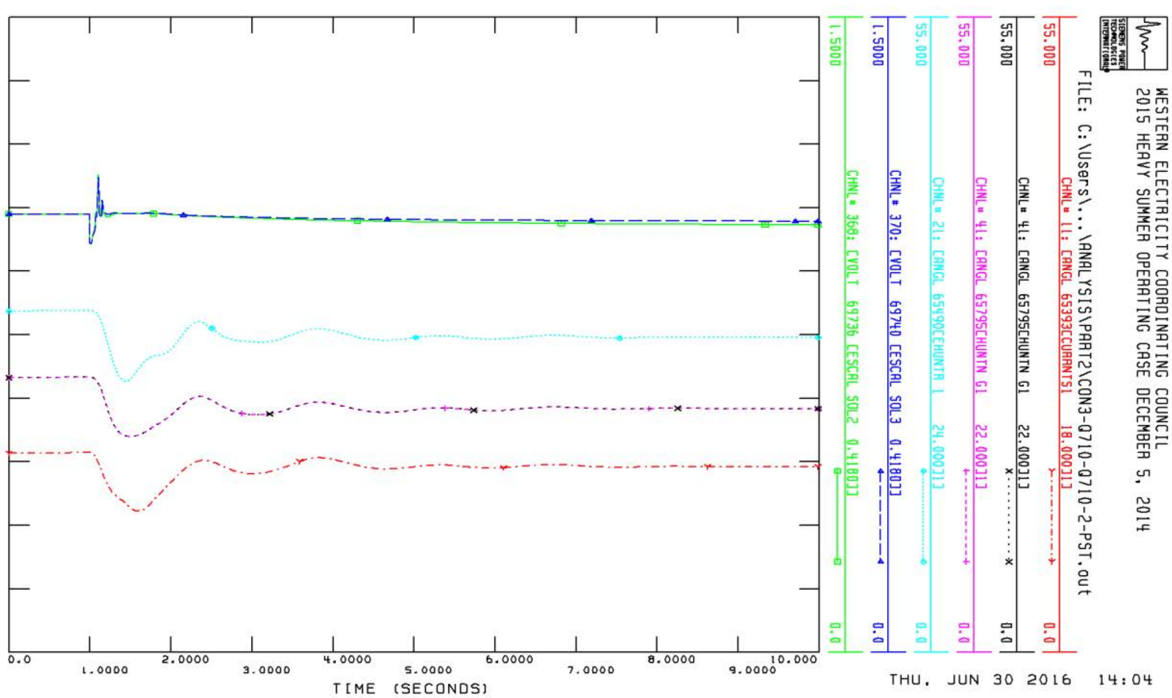

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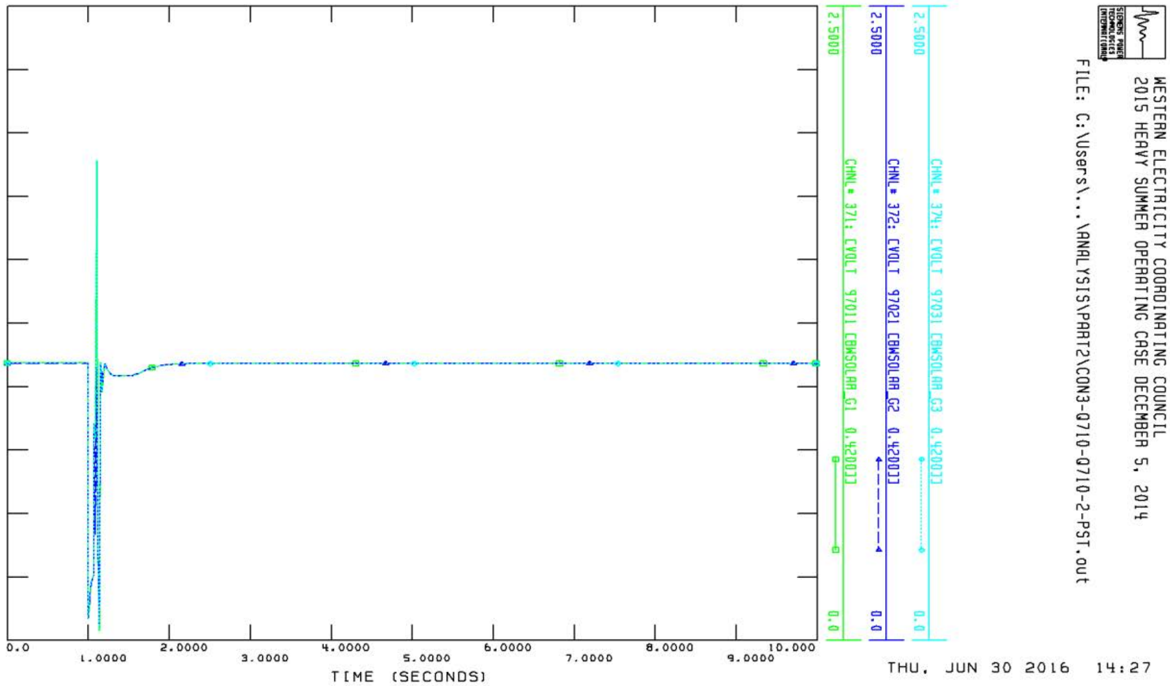
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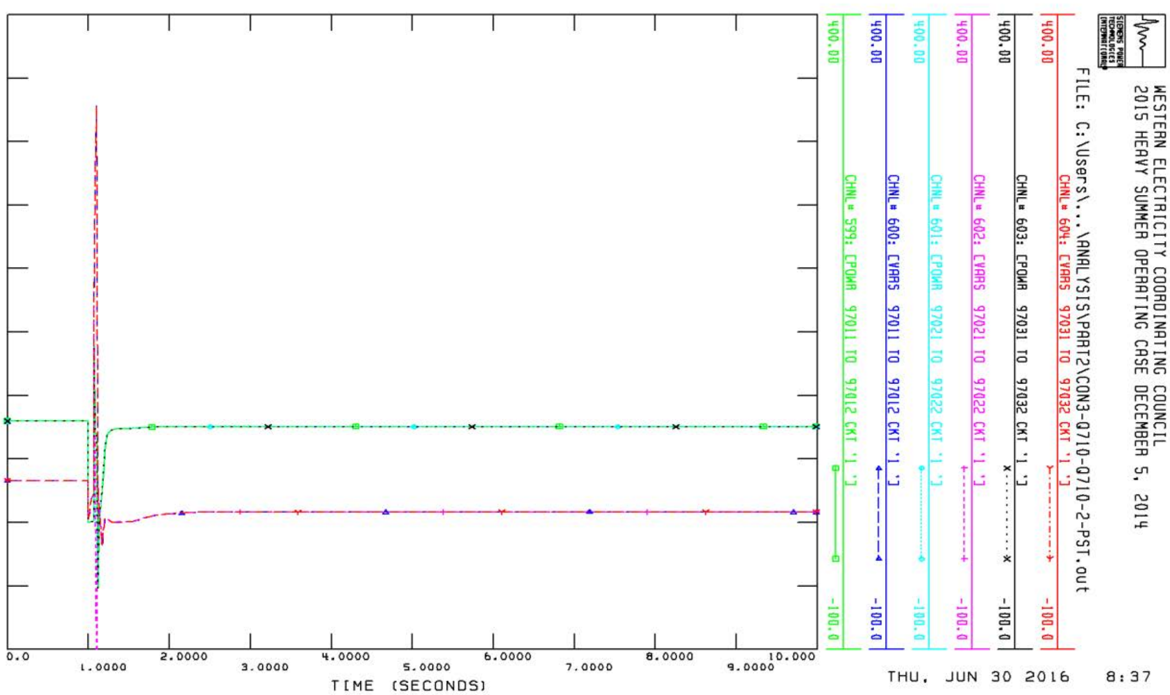
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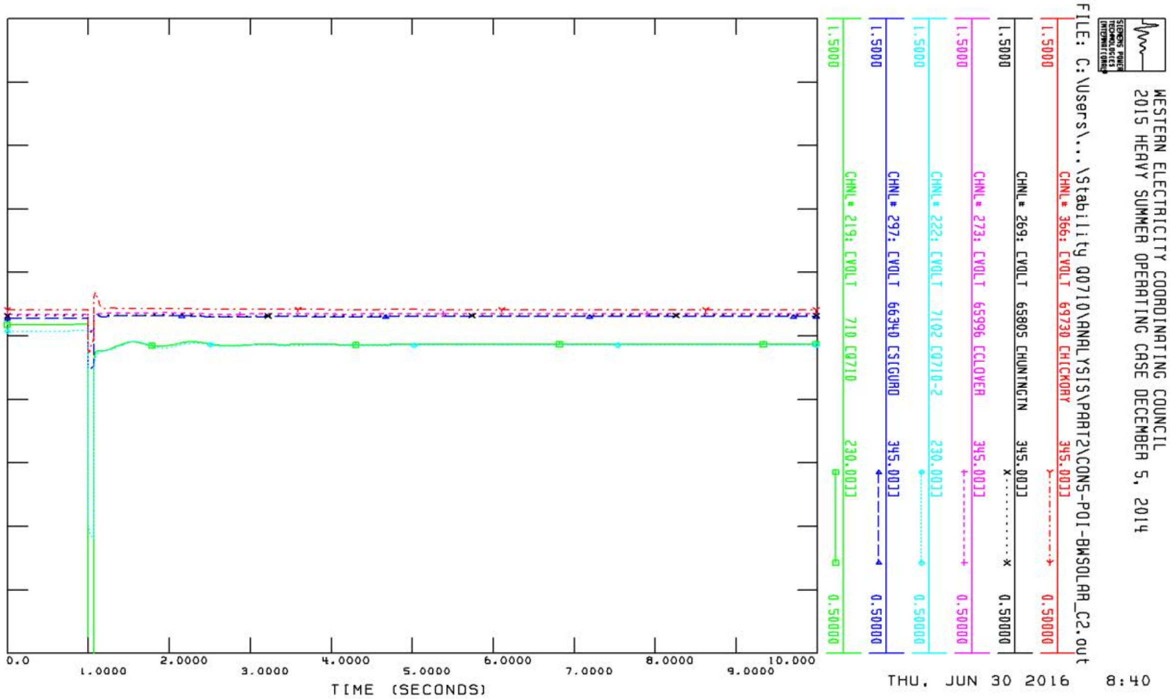
4. Three phase fault on 230 kV bus at collector substation followed by loss of the Q0710 POI – Collector substation 230 kV circuits (4 cycles)

Plot A



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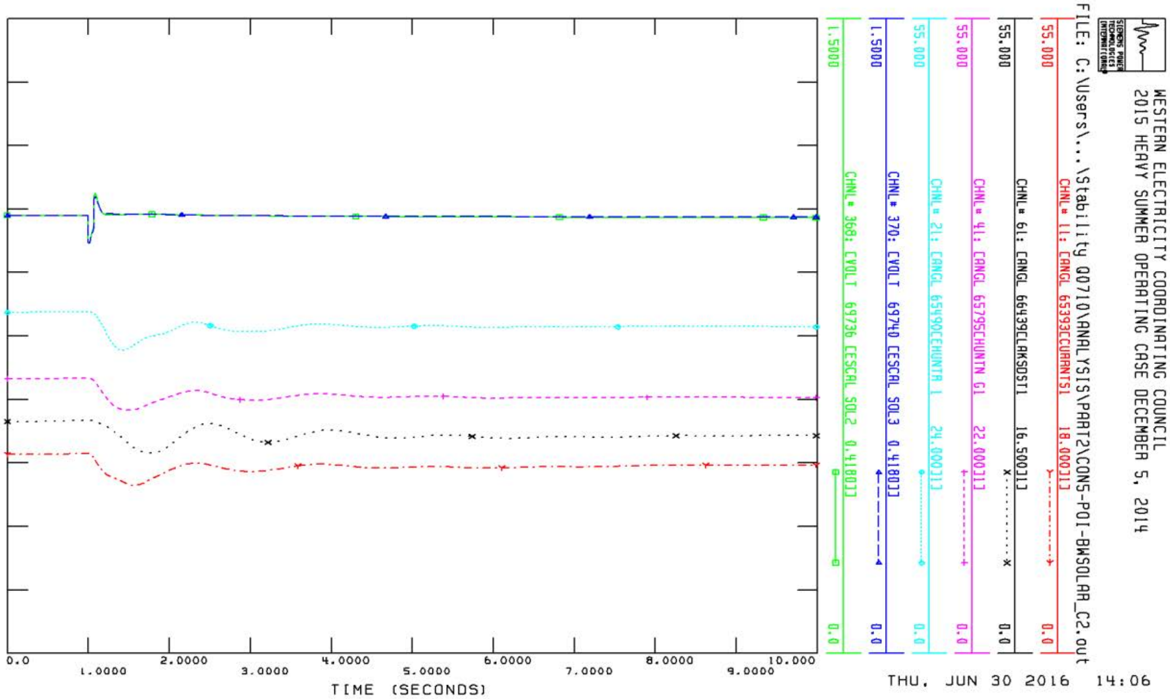

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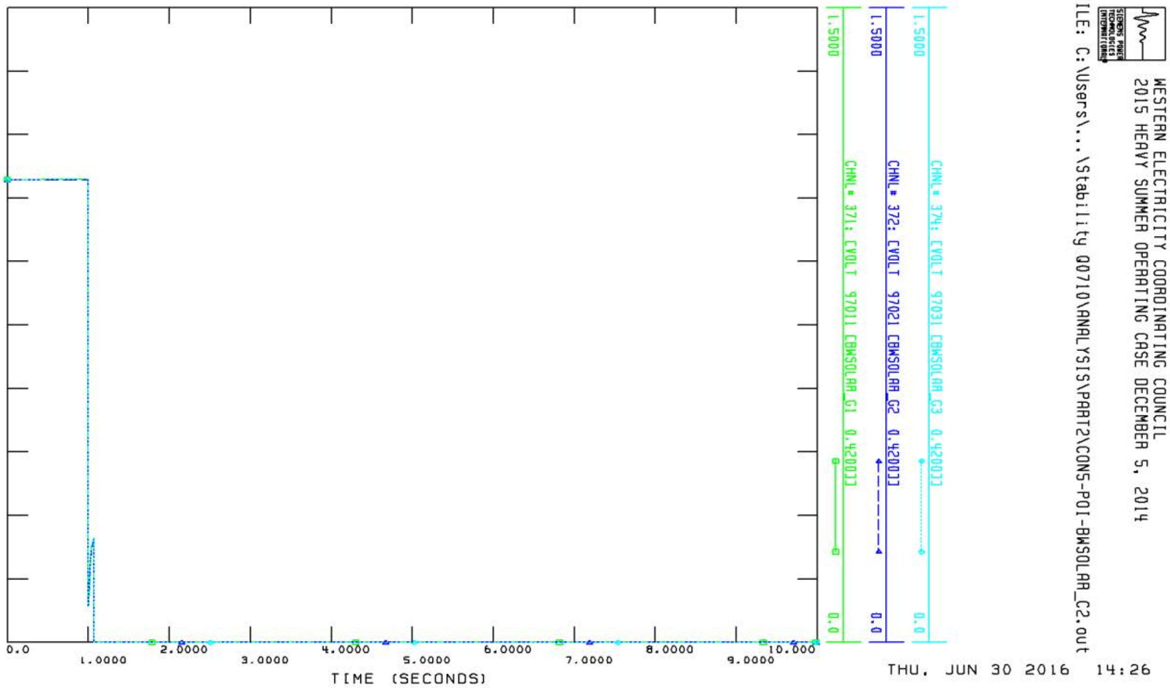
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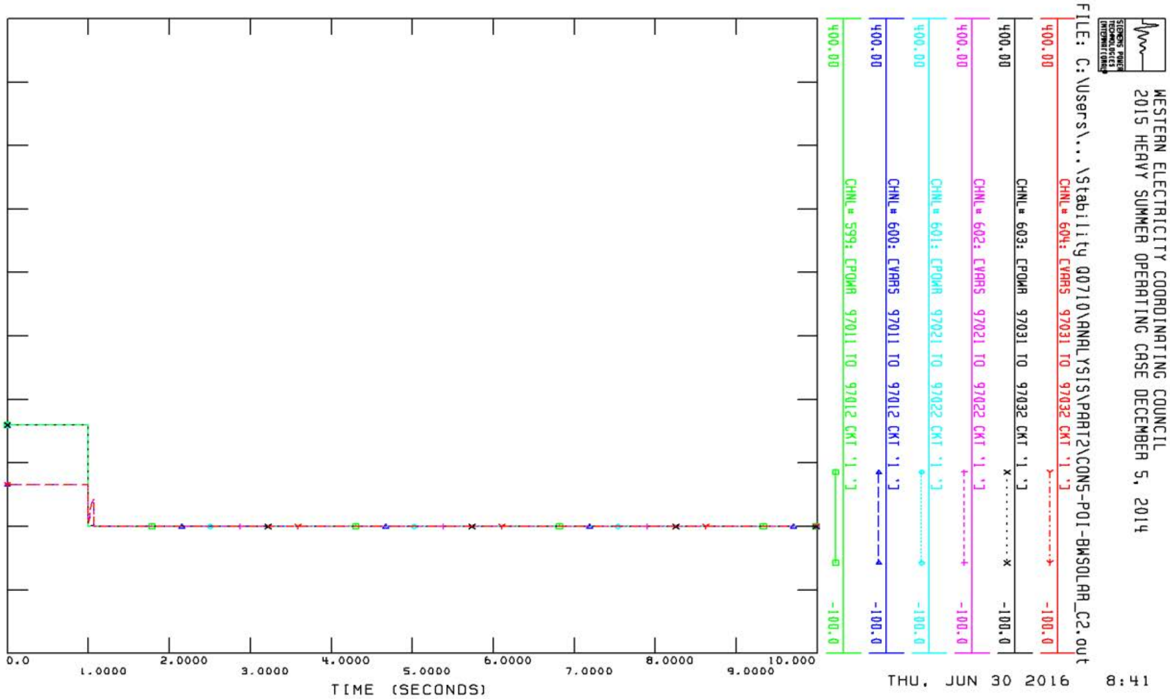
Plot D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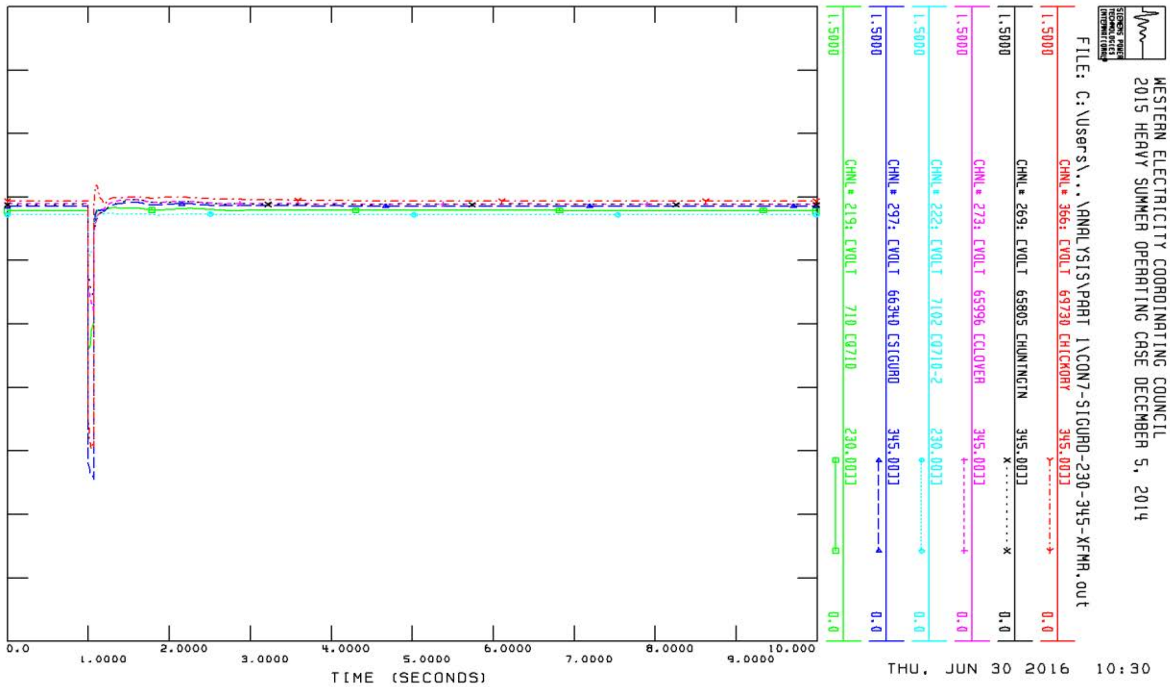
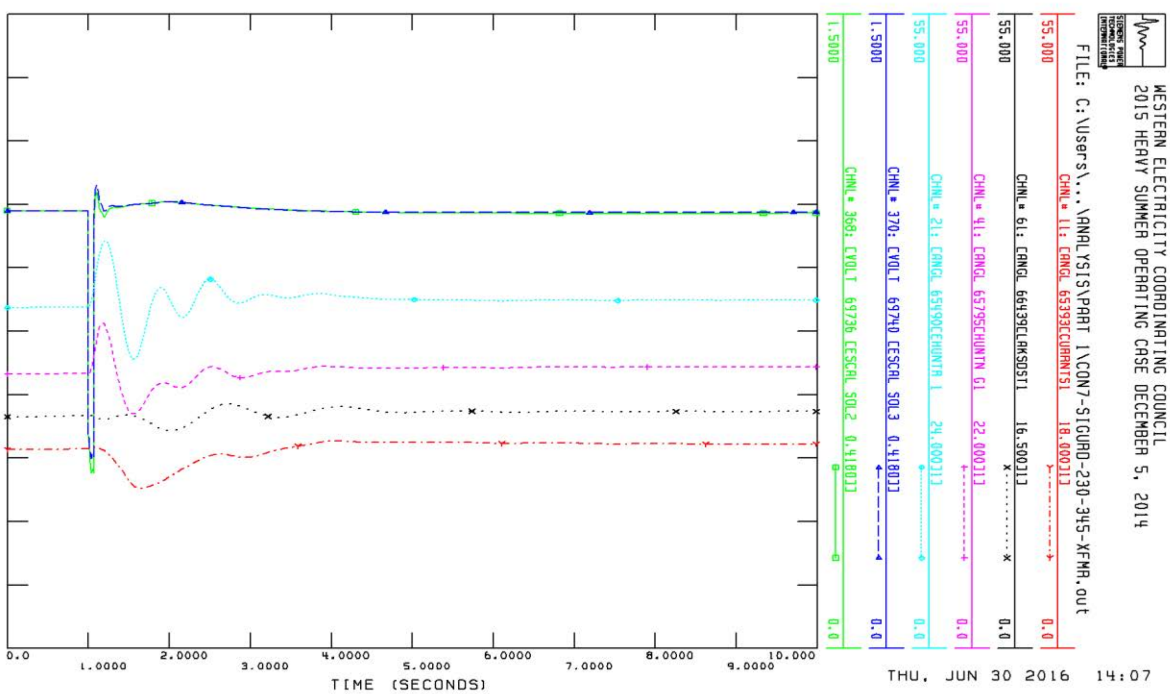
5. Three phase fault at the Sigurd 230 kV bus followed by loss of the Sigurd 345/230 kV transformer (4 cycles)

Plot A



Plot B



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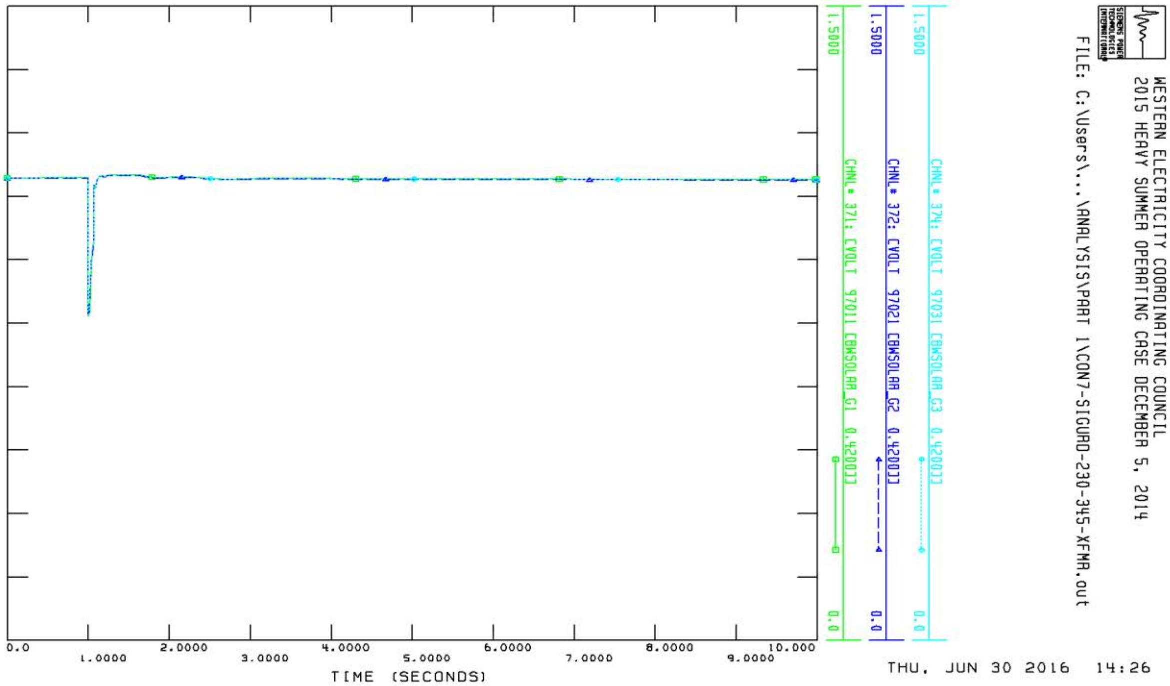
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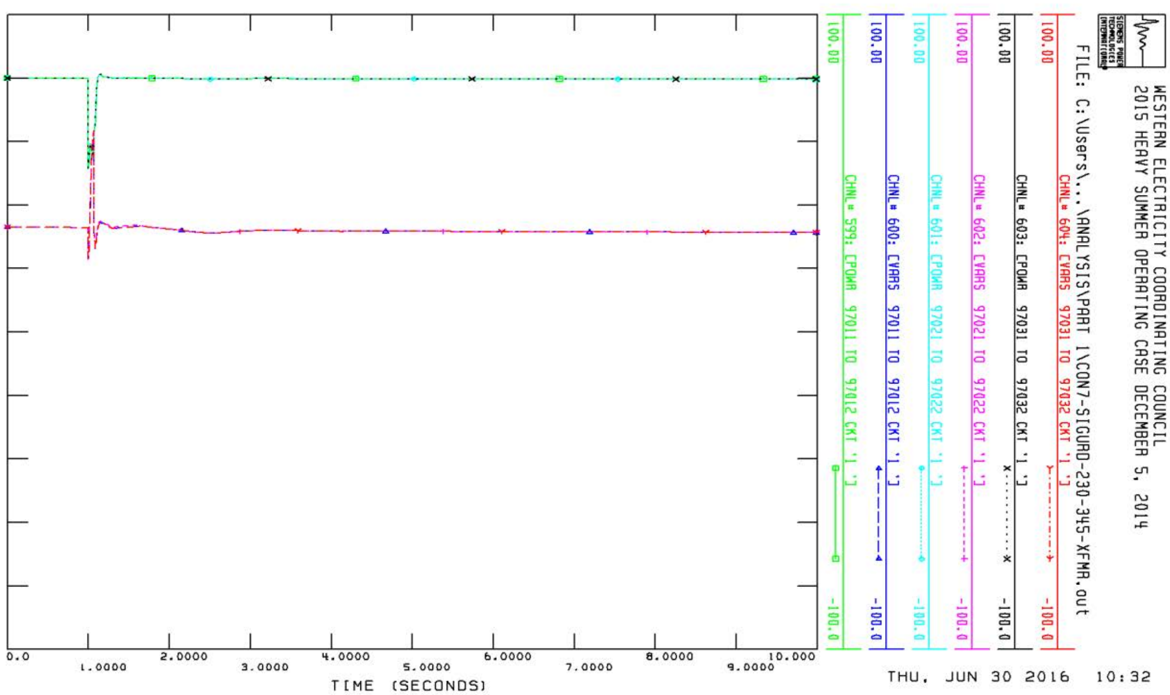
Plot D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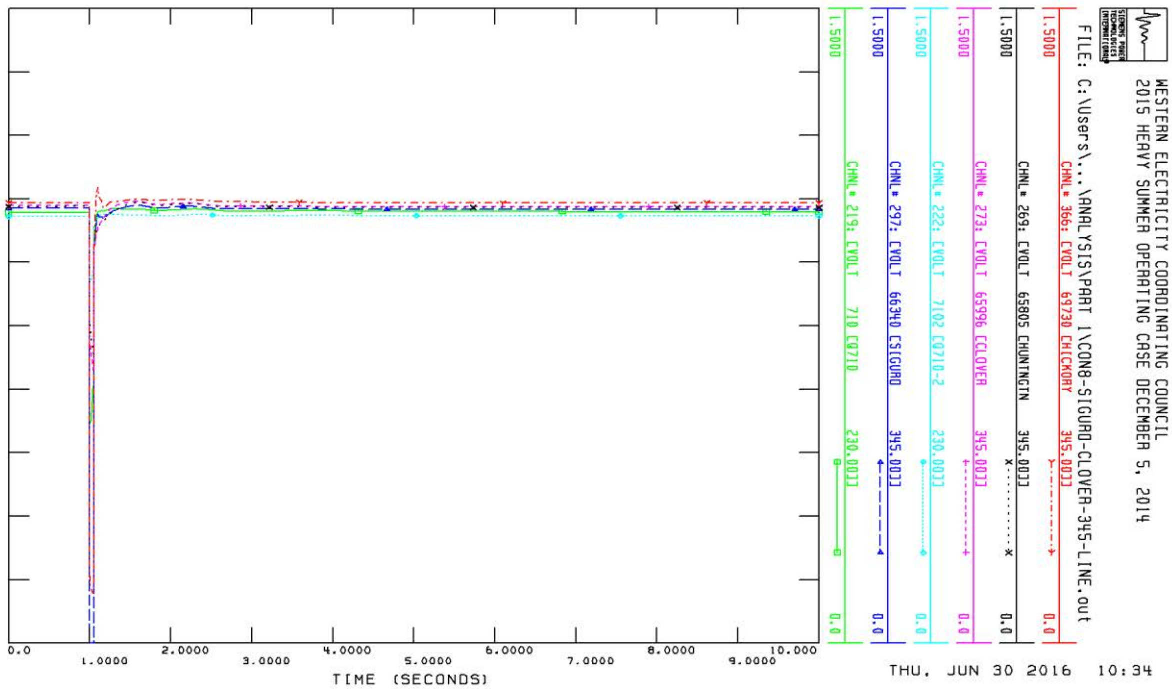
TIME (SECONDS)

6. Three-phase fault at the Sigurd 345 kV bus followed by loss of the Sigurd – Clover 345 kV circuit (3 cycles)

Plot A



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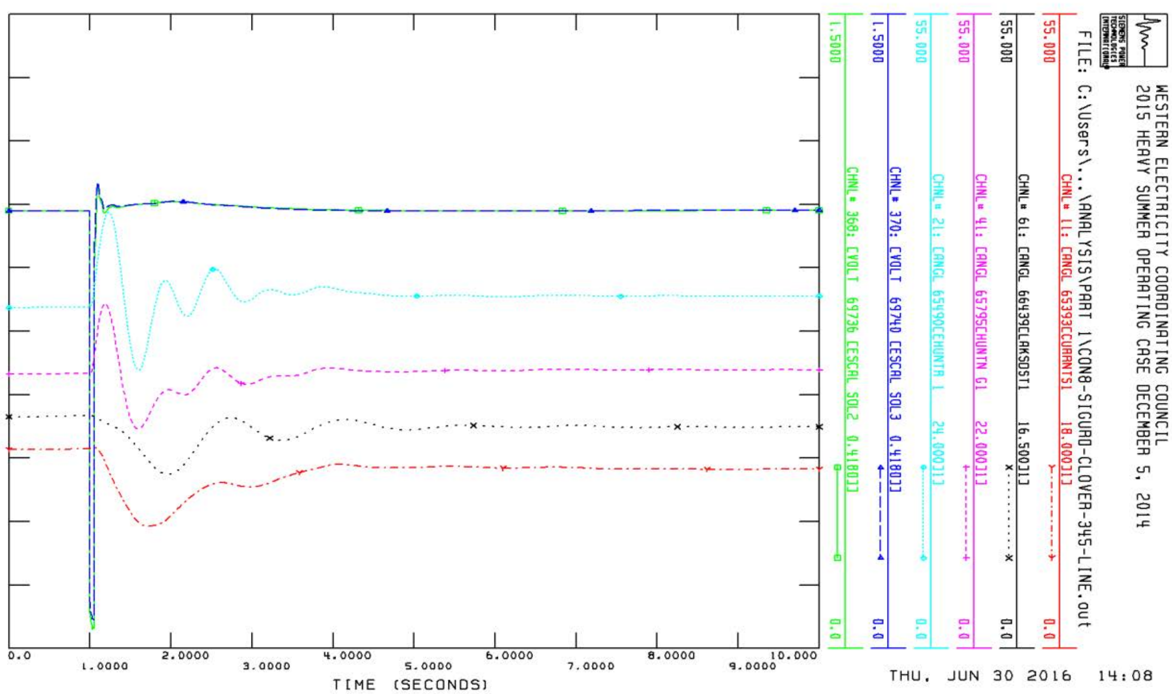

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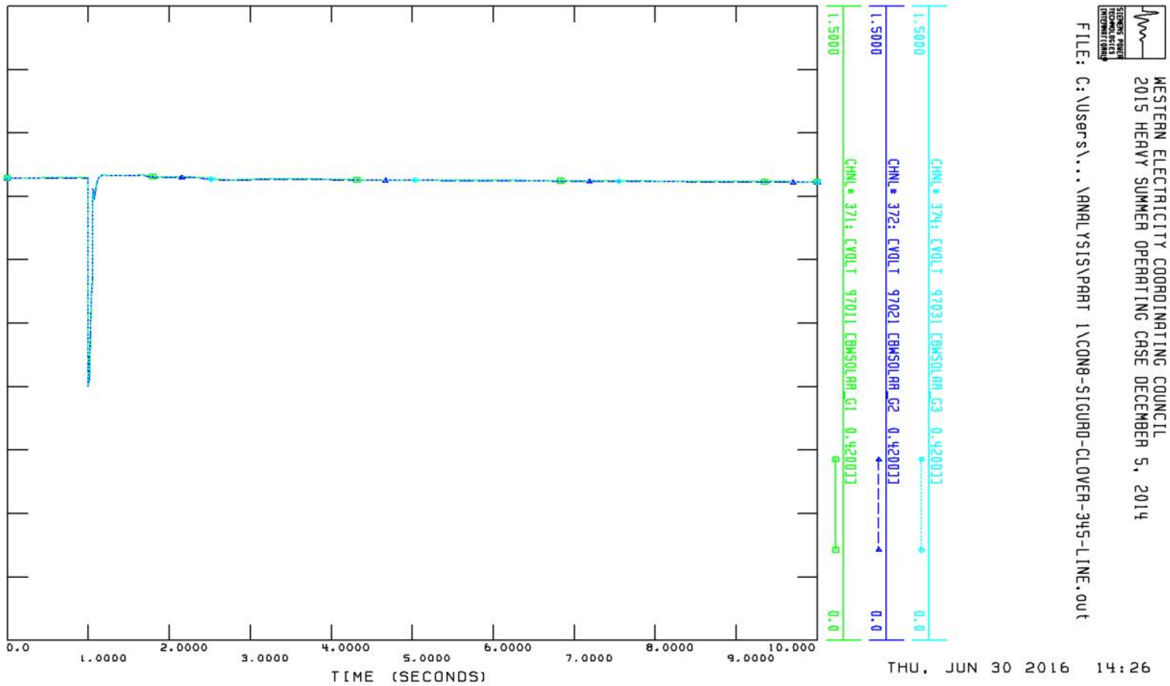
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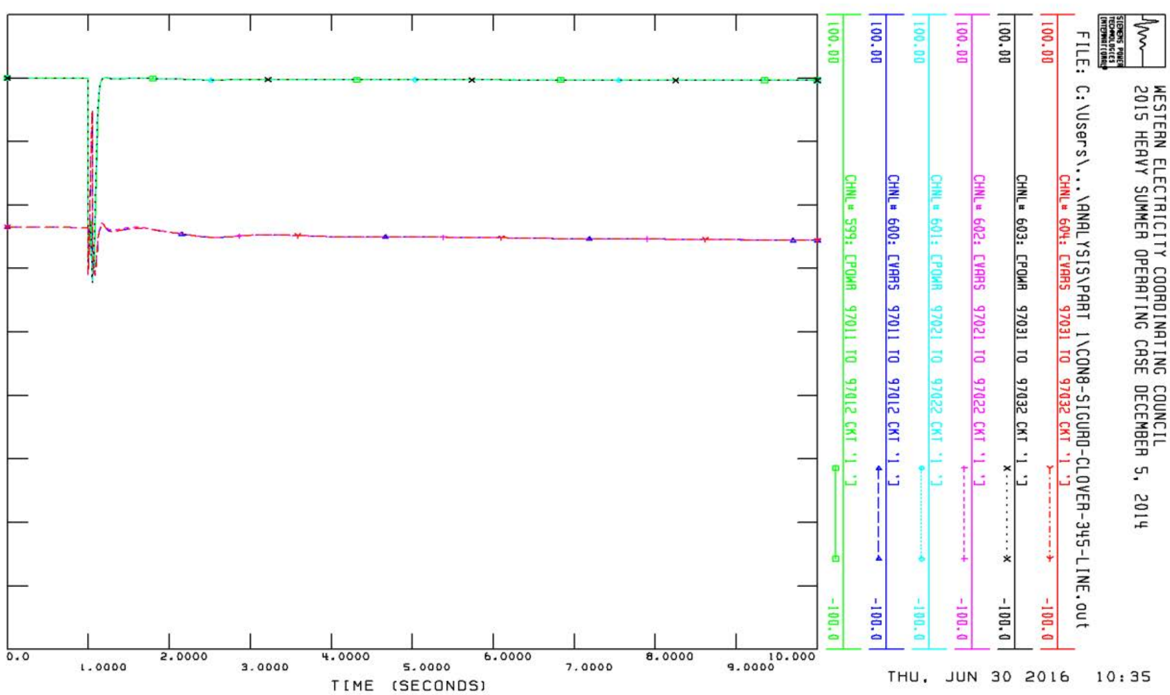
Plot D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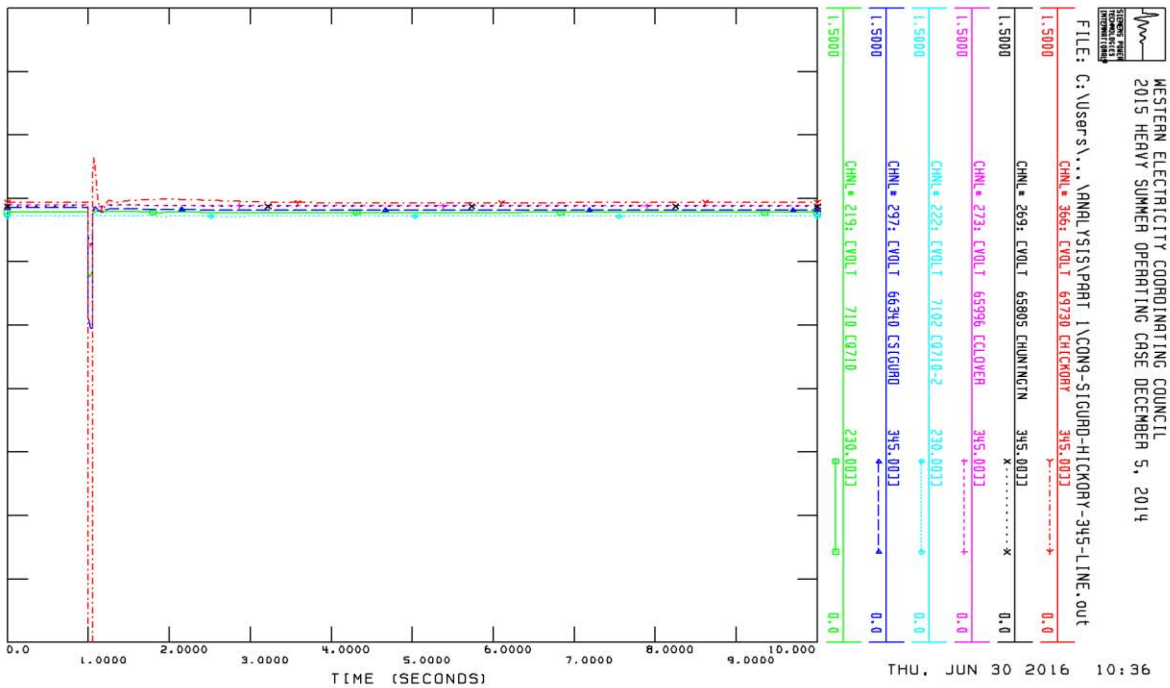
TIME (SECONDS)
THU, JUN 30 2016 10:35

7. Three phase fault at the Hickory 345 kV bus followed by loss of the Sigurd – Hickory 345 kV circuit (3 cycles)

Plot A



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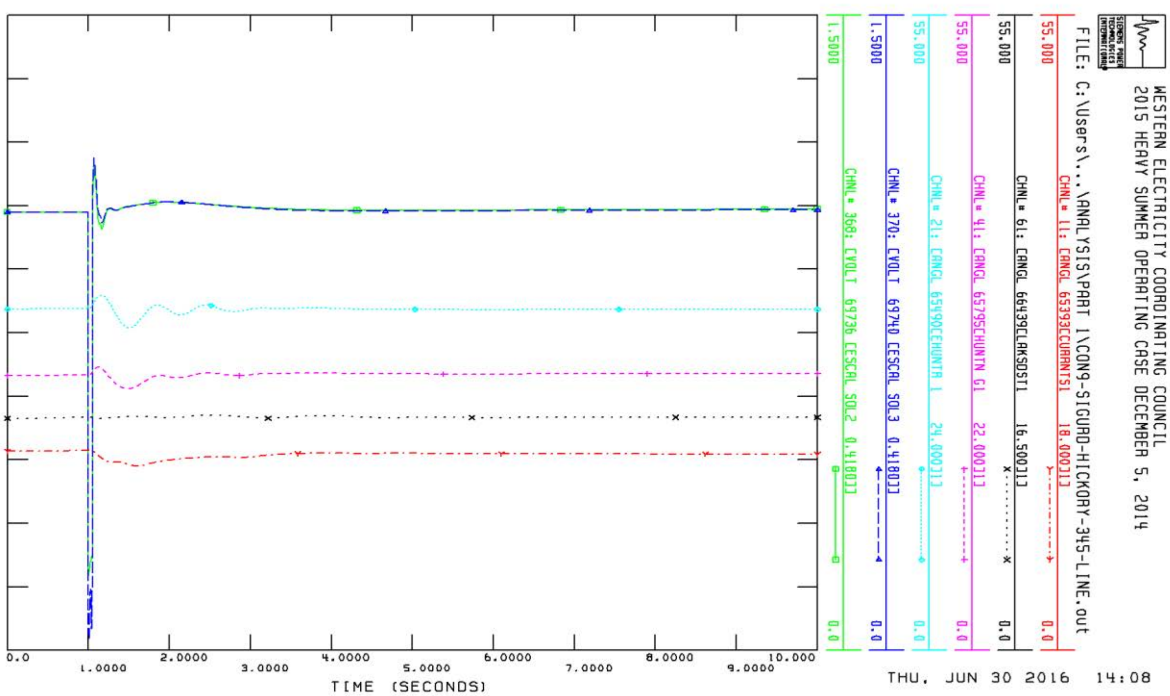
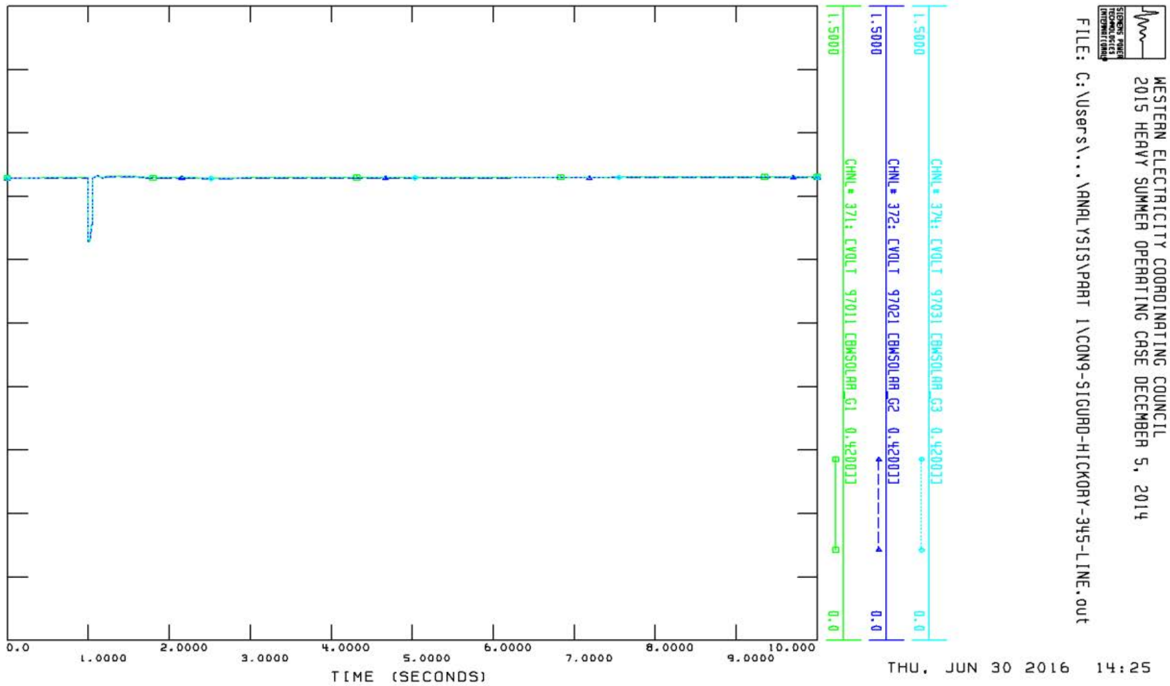


Plot C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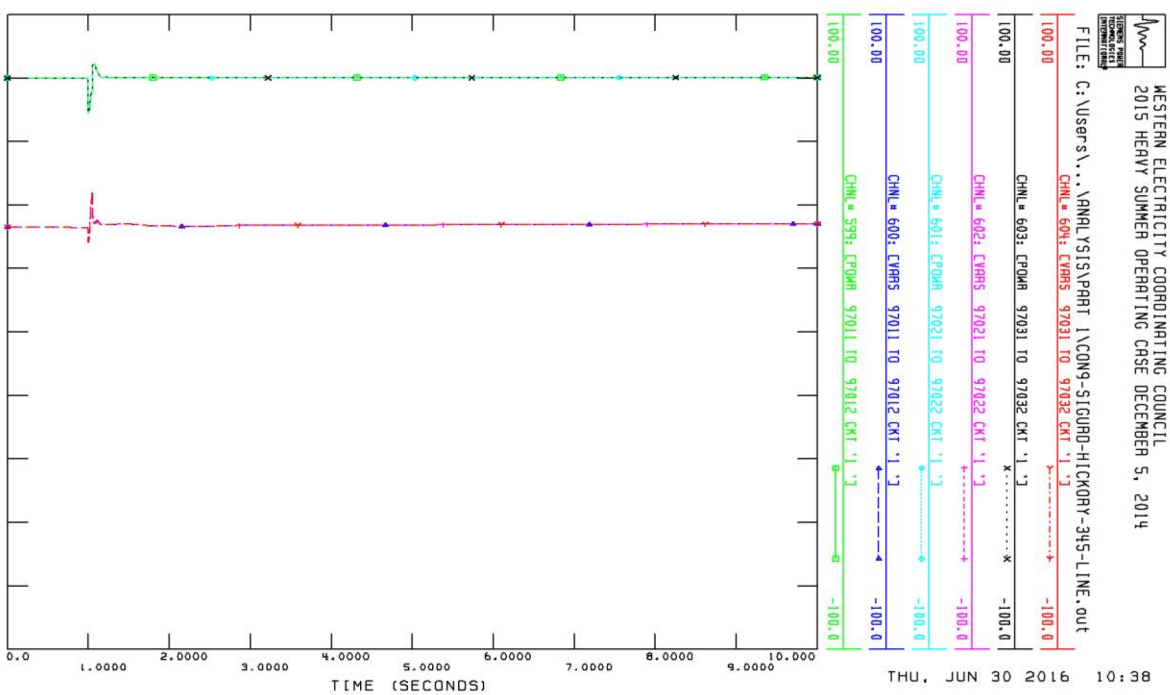
Plot D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2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
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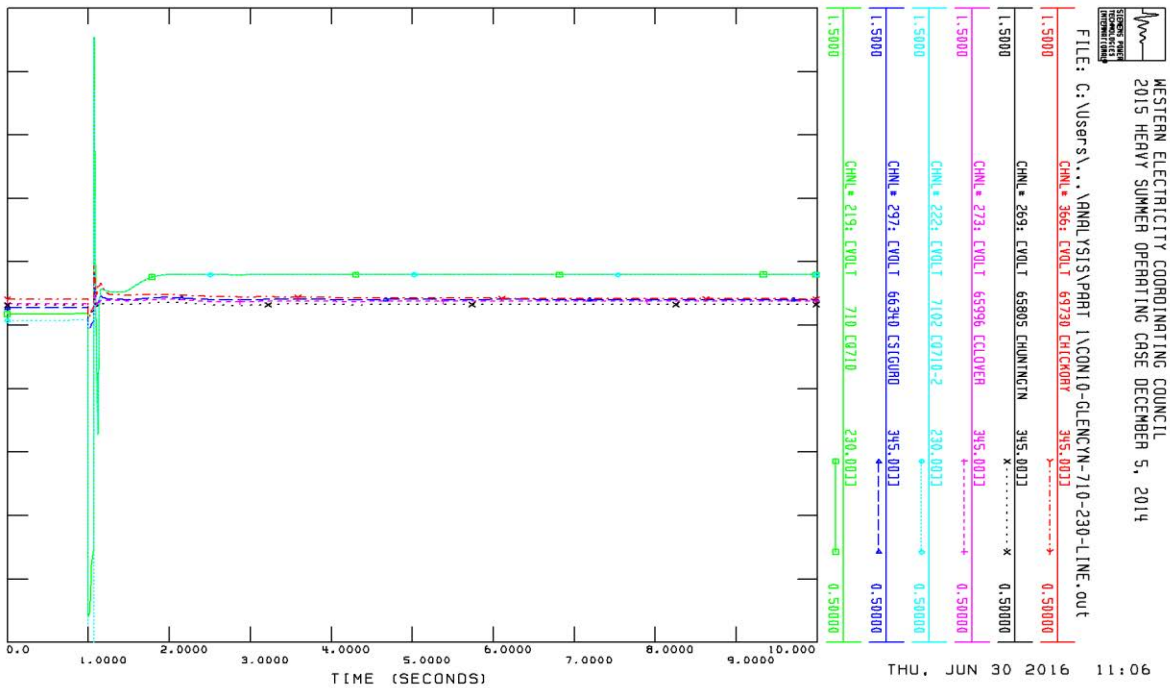
-100.0
THU, JUN 30 2016 10:38
TIME (SECONDS)

8 Three-phase fault at the Glen Canyon 230 kV bus followed by loss of the Glen Canyon – POI PST 230 kV circuits (6 cycles)

Plot A



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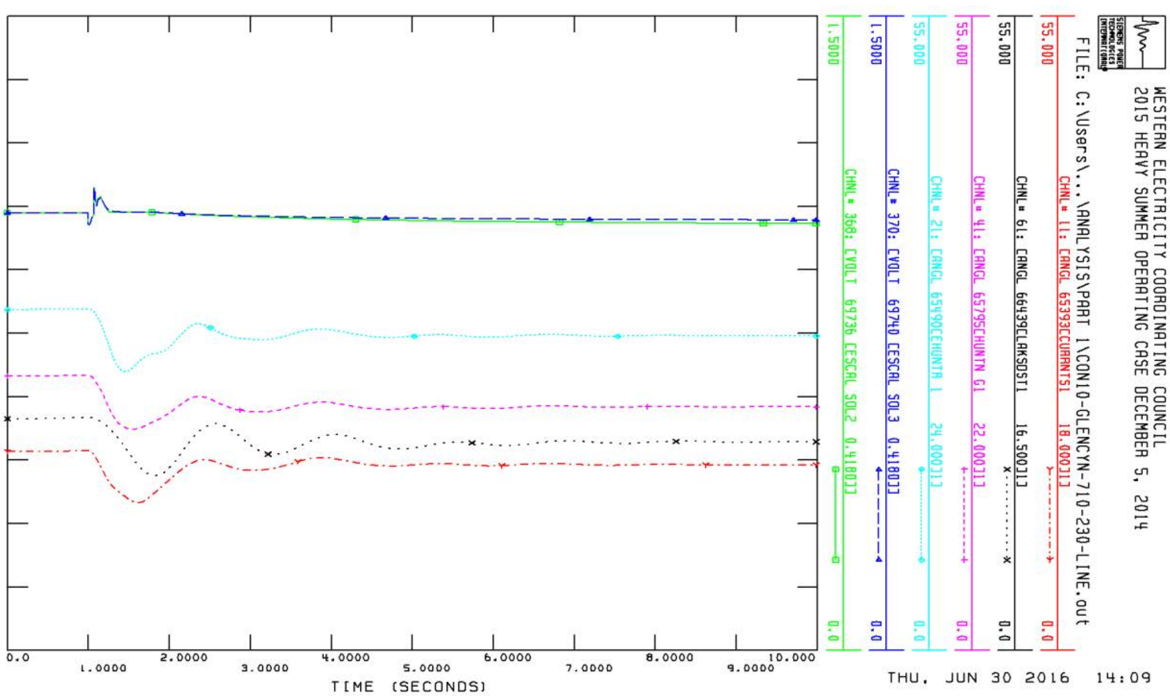

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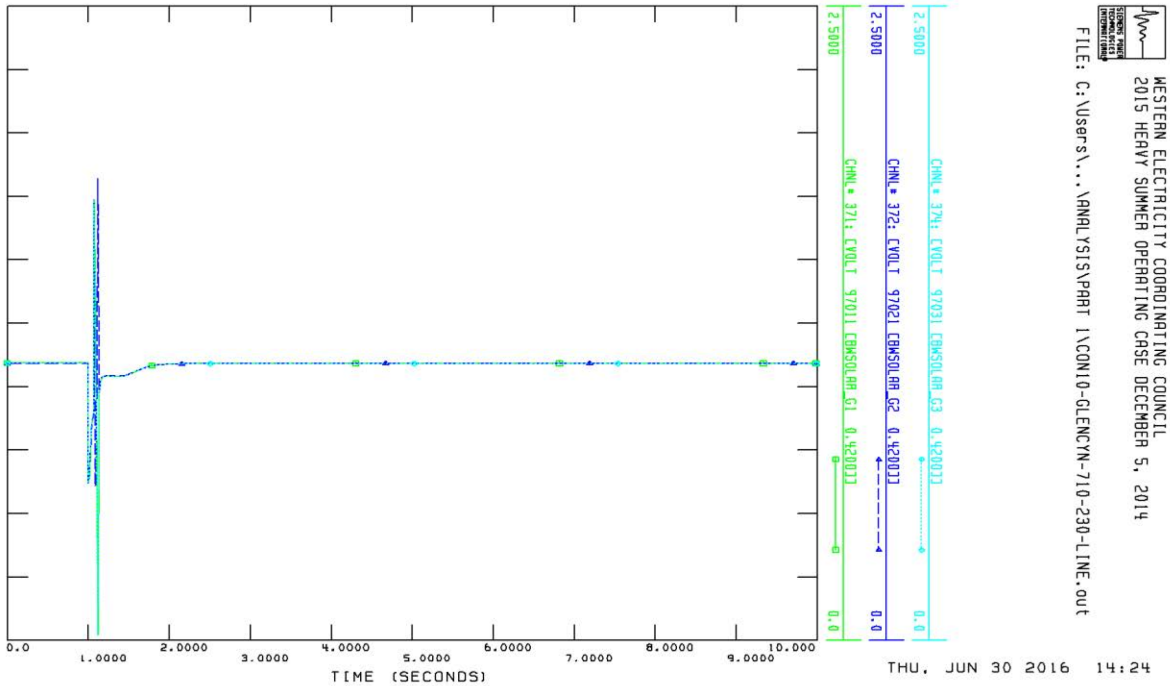
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2015 HEAVY SUMMER OPERATING CASE DECEMBER 5, 2014
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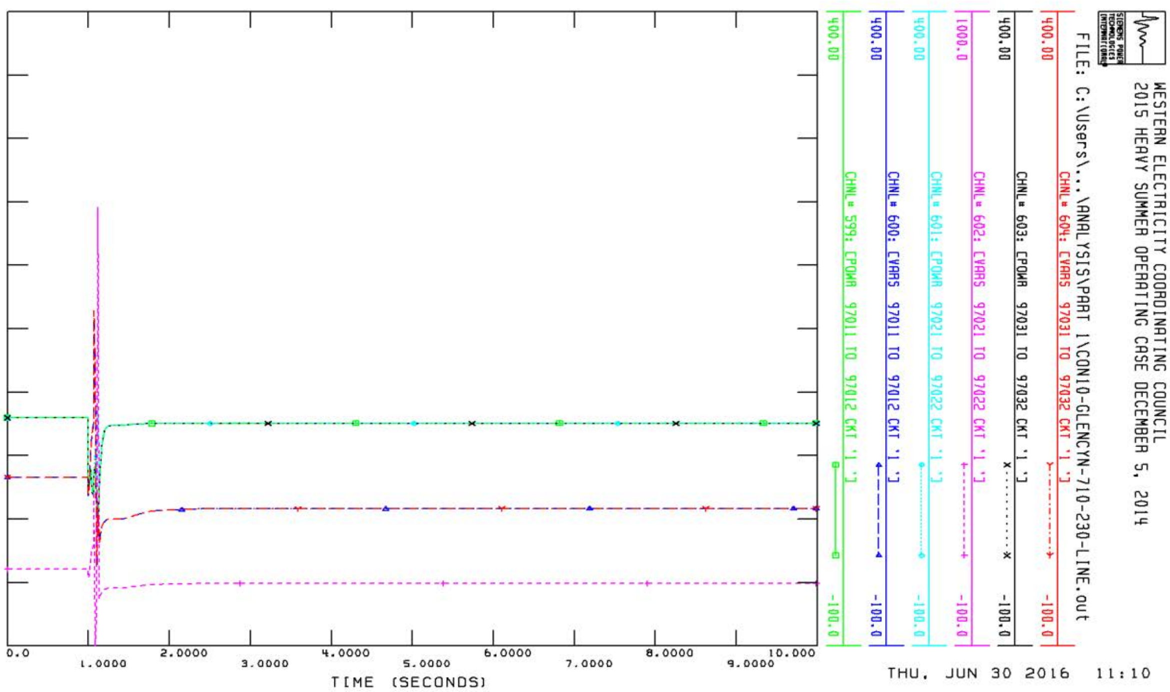
THU, JUN 30 2016 14:24

Plot D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TIME (SECONDS)
THU, JUN 30 2016 11:10

Rocky Mountain Power
Exhibit RMP___(RAV-2SR)
Docket No. 17-035-36
Witness: Rick A. Vail

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Rick A. Vail

sPower Letter Regarding Energy Resource Verses Network Resource Status

October 2017

S·POWER
SUSTAINABLE POWER GROUP

January 31, 2017

Gary Hoogeveen
Senior Vice President and Chief Commercial Officer
Rocky Mountain Power
1407 West North Temple, Suite 310
Salt Lake City, UT 84116

RE: Interconnection Request No. 710 and Network Resource Designation under Rocky Mountain Power Schedules No. 38 and No. 34

Dear Mr. Hoogeveen,

Sustainable Power Group ("sPower) is writing in regards to the above referenced interconnection request submitted by sPower via FTS Devco, LLC on September 17, 2015 to PacifiCorp Interconnection Service Requests ("PAC Interconnection").

sPower seeks to interconnect two solar electric generating Qualifying Facilities (QFs) of 95 MW of total capacity for interconnection with PacifiCorp's Rocky Mountain Power grid in Utah. sPower requested PAC Interconnection perform a System Impact Study under Network Resource (NR) and Energy Resource (ER) type interconnection assumptions for each facility. The study was originally conducted under the assumption that neither facility was a QF.

For ER Interconnection, the System Impact Study identified "Interconnection – Direct Assignment Facilities" costs of approximately \$3.9 million and "Interconnection – Network Upgrade Costs" of approximately \$11.8 million.[1] For NR Interconnection, the study identified "Total Network Resource Costs" of approximately \$394 million and "Total Cost – Energy Resource and Network Resource" at approximately \$410 million.[2] The Network Resource costs identified were attributed to creating new transmission rights to accommodate the facilities' full output capacity. sPower subsequently notified PAC Interconnection that the two facilities will be interconnecting as QFs and selling their entire output to PacifiCorp Energy ("PAC Energy"). sPower informed PAC Interconnection those Network Resource costs are therefore unnecessary because: (1) PAC Energy will not require new transmission rights to accommodate the QFs' output up to 95 MWac; and (2) sPower intends to limit deliveries to 95 MWac through maximum export settings on the generating facility inverters until such time that additional transmission capacity becomes available.

sPower informed PAC Interconnection of PAC Energy's intention for delivery and management of the QFs' output[3] and requested that PAC Interconnection revise the System Impact Study to reflect sPower's intention to use PAC Energy's existing transmission rights and integrate the QF energy according to the operating assumptions

1 System Impact Study at 12-13.
2 System Impact Study at 19.
3 Conversation via telephone call to Kris Bremer

2180 South 1300 East, Suite 600, Salt Lake City, UT 84106 P 801.679.3500 | F 801.679.3501

transmission rights and integrate the QF energy according to the operating assumptions stated above.[5] PAC Interconnection is subsequently in the process of re-studying the QFs wherein the expectations communicated to sPower will result in reclassification of the Network Resource Costs as Interconnection Direct Assignment Facilities Costs.[6] sPower again informed PAC Interconnection that PAC Energy would be the transmission customer and would be utilizing its existing transmission capacity rights to deliver the QFs energy. PAC Interconnection requested a written statement from PAC Energy stating that the Network Resource upgrades would not be necessary because PAC Energy will utilize existing transmission capacity rights.[7] sPower requested such a letter from PAC Energy, however, PAC Energy stated that it does not provide such letters.[8]

FERC precedent requires electric utilities, including PacifiCorp, to deliver a QF's power on a firm basis and prohibits curtailment of QF resources except under two very narrow circumstances: (1) system emergencies; and (2) extreme light loading conditions.[9] As the purchasing utility and a transmission customer, PAC Energy is responsible for procuring transmission services to deliver QF energy to its load or otherwise manage the QFs' output in accordance with PURPA and FERC precedent.[10] The obligation of a QF to a purchasing utility is limited to delivering the QF's output to the point of interconnection between the QF and the purchasing utility.[11] sPower has no obligation to provide transmission services on behalf of PAC Energy.[12] Instead, PAC Energy will provide transmission services pursuant to PacifiCorp's OATT and Network Operating Agreement through the designation of sPower's QFs' as designated network resources.

There appears to be a misunderstanding in the PAC Interconnection process that would prevent sPower from being able to proceed through the interconnection process as a QF resource; sPower is entitled to PAC Energy transmission allowances with or without a confirming letter from PAC Energy. Furthermore, sPower has provided

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5 Conversation via telephone call to Kris Bremer

6 Communicated verbally during results meeting. No meeting minutes were distributed

7 Verbal communication

8 Email from Kyle Moore to Joe Briney, Sept. 26, 2016.

9 *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at P. 38 (2013); *Entergy Servs. Inc.*, 137 FERC ¶ 61,199 at PP 52-58 (2011); *Order Accepting Proposed Network Operating Agreement*, 151 FERC ¶ 61,170 at P 27 (2015).

10 18 C.F.R. § 292.303; *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215; *Entergy Servs. Inc.*, 137 FERC ¶ 61,199; *Exelon Wind*, 140 FERC ¶ 61,152; *see also*, PacifiCorp Network Operating Agreement Amendment, effective February 22, 2015; *Order Accepting Proposed Network Operating Agreement*, 151 FERC ¶ 61,170 (2015) (PAC Energy is the "Network Customer" when it purchases power from a QF); *see also* PacifiCorp Open Access Transmission Tariff, FERC Electric Tariff, Volume No. 11 (Oct. 5, 2016) (*hereinafter* "PAC OATT") Section 32.3 "System Impact Study Procedures" (. . . [t]he System Impact Study shall identify . . . (2) redispatch options (when requested by an Eligible Customer) . . . ."). PAC Energy is the "eligible customer" and is authorized to request PAC Interconnection assess redispatch options in the System Impact Study.

11 *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at P. 38 (2013) ("The Commission has specifically held that: (1) the QF's obligation to the purchasing utility is limited to delivering energy to the point of interconnection by the QF with that purchasing utility; and (2) the QF is not required to obtain transmission service, either for itself or on behalf of the purchasing utility in order to deliver its energy from the point of interconnection with the purchasing utility to the purchasing utility's load.").

12 *Id.*

evidence via the PAC Energy curtailment study that PAC Energy intends to utilize its existing 95 MWac of transmission rights on this project as part of its QF contract.

In the event that PAC Energy and PAC Interconnection decide to construct the Network Resource Facilities identified by PAC Interconnection and use the increased transmission capacity to accommodate the integration of sPower's QFs, those Facilities are past the point of interconnection and those costs may not be assigned to sPower.[13] QF's are only responsible for interconnection costs.[14] The assignment of Network Resource costs—those at or beyond the point where the customer connects to the grid—to a QF violates FERC precedent, Rocky Mountain Power's Electric Service Schedule No. 38, and PacifiCorp's OATT.[15] ***Importantly here, however, is that those Network Resource costs are not necessary because PAC Energy intends to utilize existing transmission capacity and certain redispatch and curtailment assumptions PAC Energy has proposed to include in contracts with sPower for QF deliveries, which sPower is amenable to and has communicated such to PAC Interconnection***.

It is our understanding that pursuant to Rocky Mountain Power's Schedule No. 38 for Qualifying Facilities that the designation of a QF as a network resource by PAC Energy does not occur until after the power purchase agreement is executed.[16] It is also our understanding that PAC Interconnection is requesting confirmation of that designation prior to negotiating the interconnection agreement. Finally, it is our understanding that sPower may select ER Interconnection at this time in order to move forward with negotiating an interconnection agreement with PAC Interconnection, but that PAC Energy will designate sPower's QFs as network resources pursuant to Schedule No. 38.

Could you please confirm that (1) sPower may move forward with ER interconnection for these QF projects under the assumption that PAC Energy will designate them as network resources at a later date; (2) the Network Resource Facility costs identified previously are not assignable to sPower and such upgrades and associated costs should be removed from the system impact study; and (3) these Network Resource Facility costs will not be reflected in the avoided cost calculations for these QF projects?

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13 *Entergy Servs. v. FERC*, 391 F.3d 1240 (D.C. Cir. 2004); *Nevada Power Company*, 113 FERC ¶ 61,007, 61,016 (2005) ("Due to the integrated nature of the transmission grid, upgrades at or beyond the point where a customer connects to the grid benefit all users of that grid. Thus, we have rejected the direct assignment of grid facilities at or beyond the point where a customer connects to the grid.")

14 *Pioneer Wind Park I, LLC*, 145 FERC ¶ 61,215, at P. 38 (2013); Rocky Mountain Power, Electric Service Schedule No. 38, State of Utah, Qualifying Facility Procedures Part II B "The QF project owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis."

15 *Entergy Servs. v. FERC*, 391 F.3d 1240 (D.C. Cir. 2004); *Nevada Power Company*, 113 FERC ¶ 61,007, 61,016 (2005); Rocky Mountain Power, Electric Service Schedule No. 38, State of Utah, Qualifying Facility Procedures, Part II B (for interconnections greater than 20 MW, interconnection applications are processed according to PacifiCorp's OATT); PAC OATT Section 31.2 (The costs of new facilities required to interconnect a new Network Load designated by the Network Customer . . . shall be charged to the Network Customer in accordance with Commission policies."). As the Network Customer, PAC Energy bears the responsibility for network upgrades.

16 Rocky Mountain Power, Electric Service Schedule No. 38, State of Utah, Qualifying Facility Procedures, Part I B 8 (e).

Additionally, it is our understanding that projects participating under Schedule No. 34 would be treated the same as QFs for interconnection and transmission purposes. Therefore, if sPower elects to sell the power from these QFs or other projects under Schedule No. 34, sPower may select the ER Interconnection study process and that PAC Energy will designate those projects as network resources.

Could you please also confirm that, so long as PAC Energy holds sufficient existing transmission capacity to accommodate the full output of the projects, (1) projects selling power via Schedule No. 34 may select the ER Interconnection study process and that PAC Energy will designate those projects as network resources at a later date; (2) those projects would only be responsible for paying the interconnection costs identified through the ER Interconnection study process; and (3) any Network Resource Facility costs that would have been assessed under the NR Interconnection study process will not be reflected in any way in the calculation of the avoided cost or other agreed to pricing mechanism under Schedule 34.

Thank you for your attention to this matter. Please contact me with any questions.

Regards,

Sean McBride
General Counsel
Sustainable Power Group

Rocky Mountain Power
Docket No. 17-035-36
Witness: Kelcey A. Brown

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Kelcey A. Brown

October 2017

Q. Are you the same Kelcey A. Brown that submitted direct testimony on behalf of Rocky Mountain Power, a division of PacifiCorp, in this case?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. I will address arguments provided by Glen Canyon's witness Keegan Moyer in his rebuttal testimony filed in this proceeding. Specifically, I will address Mr. Moyer's misunderstanding of the contract rights held by Arizona Public Service Company ("APS") over the Glen-Canyon-to-Sigurd transmission path, with a particular focus on Mr. Moyer's incorrect assertion that PacifiCorp has the "flexibility" to decide how APS will schedule its call option on PacifiCorp's system. Once Mr. Moyer's misunderstandings are corrected, it is clear that Mr. Moyer failed to overcome the fact that APS has a firm transmission call option over the Glen-Canyon-to-Sigurd path whenever APS chooses to exercises it. PacifiCorp's merchant function (known as energy supply management or "ESM"), cannot use the same transmission rights on the Glen-Canyon-to-Sigurd path to simultaneously accommodate APS's transmission call option *and* deliver non-curtailable power from qualifying facility ("QF") projects like Glen Canyon's.

Q. Do you believe that Mr. Moyer misrepresented APS's rights under the restated Transmission Agreement?

A. Yes. Before discussing his misinterpretations or misrepresentations, however, I must clarify an important aspect of the Restated Transmission Agreement that Mr. Moyer confuses throughout his Rebuttal Testimony. As I explained in lines 115-131 of my direct testimony, APS's "call option" of net 100 MW of bidirectional service under the

Restated Transmission Agreement is a right that PacifiCorp must honor that is separate and apart from the power exchange rights PacifiCorp and APS each have under the Exchange Agreement.[1]

Mr. Moyer states: "The Restated Transmission Agreement between PacifiCorp and APS is intended to ***fulfill*** [the] power exchange agreement. . ."[2] and ". . . addresses transmission issues to ***facilitate*** the power exchanges identified in the Power Exchange Agreement."[3] These descriptions are incorrect. APS's right to call on its 100 MW of net rights over the Glen-Canyon-to-Sigurd path under the Restated Transmission Agreement is independent from: (1) whether PacifiCorp is receiving power from APS under the Exchange Agreement; and (2) the transmission arrangements (i.e., seasonal network and point-to-point transmission service) that PacifiCorp uses to deliver that exchange power. Mr. Moyer attempts to meld these two contracts into a single set of rights, presumably in hopes of imputing a level of scheduling flexibility under the Restated Transmission Agreement that does not exist. As my direct testimony makes clear, the Restated Transmission Agreement provides APS with a firm right over the Glen-Canyon-to-Sigurd path.

Q. You mention that there are other ways in which Mr. Moyer misinterprets the Restated Transmission Agreement. Please explain.

A. The most egregious example is Mr. Moyer's purported summary of the agreement where he states: "The contract requires PacifiCorp to honor an APS call option from either the Glen Canyon **or** Four Corners substations and PacifiCorp has flexibility to

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[1] I have attached a visual depiction of these rights as Exhibit RMP ___ (KAB-1SR).
[2] Rebuttal Testimony of Keegan Moyer at lines 442-444 (emphasis added).
[3] *Id.* at lines 450-452 (emphasis added).

decide how the power is scheduled through their system."[4] First, the contract does not use the word "or"; rather, it uses a "/" sign. Mr. Moyer uses this misrepresentation of the contract language to argue that PacifiCorp has flexibility to decide whether APS exercises its call option from Glen Canyon or Four Corners. Mr. Moyer is simply wrong on this point. Mr. Moyer offers no textual support in the agreement for his interpretation, not to mention that his interpretation would contradict prudent utility practice that requires consideration of both transmission and generation assets in scheduling energy across the electric transmission system.

Q. Can you please expand on what you mean by "prudent utility scheduling practices"?

A. Yes. When a utility schedules energy on the transmission system, there must be a generation resource that is providing the energy and transmission rights to deliver that energy to the destination. Applied here, for example, if APS chooses to exercise its call option under the Restated Transmission Agreement, it would have a power source and a transmission arrangement (likely over the APS system) to get that power to PacifiCorp's system at either the Four Corners substation or the Glen Canyon substation. APS would consider these factors when it chooses whether to schedule its Restated Transmission Agreement call option on the Glen Canyon or Four Corners path—factors that PacifiCorp would have no knowledge of, and that PacifiCorp would be interfering with if it tried to require APS to schedule power over a different path where APS may have no ability to deliver a generation resource because of, for example, a generation or transmission outage. The flexibility that the contract provides

[4] *Id.* at lines 36-38 (emphasis in original).

to *APS* to choose to schedule at the Glen Canyon and Four Corners substations allows APS to account for these kind of operational factors necessitating the use of a specific path.

Q. Where does the Restated Transmission Agreement address scheduling requirements?

A. Section 8 of the agreement places the obligation on APS to pre-schedule its intended power flows when it chooses to exercise its 100 MW call option. Glen Canyon suggests that, if APS pre-schedules its call option from Glen Canyon northbound, PacifiCorp has the right under the contract to simply redirect APS to use Four Corners as a starting point instead. That is incorrect. Such a right simply is not found in the agreement and, as discussed above, would deny APS its right to deliver energy to the Borah/Brady hub if it cannot schedule the delivery of energy to the Four Corners substation across its system.

Q. Mr. Moyer also presents an alternative theory that PacifiCorp could actually accommodate APS and Glen Canyon simultaneously on the Glen-Canyon-to-Sigurd path. Would this be possible?

A. No. What Mr. Moyer actually suggests is that, "When the Glen Canyon Solar QF projects are not generating at full power, which will frequently be the case, RMP can utilize its transmission rights to transmit APS power across the PacifiCorp Transmission system from the Glen Canyon substation, utilizing the Glen Canyon to PACE transmission path."[5] There is a significant problem with Mr. Moyer's theory. The Restated Transmission Agreement requires each party to pre-schedule "no later

[5] Rebuttal Testimony of Keegan Moyer at lines 534-538.

than 1000 hours MST on each work day observed by both Parties immediately preceding the day(s) of delivery," unless otherwise agreed. Therefore, this scheduling provision cannot accommodate the intermittent real-time fluctuations of the Glen Canyon QFs. Finally, giving Glen Canyon this type of priority changes APS's *firm* rights over the Glen-Canyon-to-Sigurd path to *non*-firm rights, available only when Glen Canyon does not use the capacity. PacifiCorp cannot unilaterally change APS's rights.

Q. Mr. Moyer states that APS rarely invokes its call option on the Glen-Canyon-to-Sigurd path. How does that impact APS's firm contract rights?

A. It does not impact those rights. The Restated Transmission Agreement gives firm rights to APS that are akin to firm point-to-point OATT rights. Failure to schedule its contract rights with any regularity does not require the party to relinquish its rights or mean that the party has somehow relinquished those rights due to lack of use.

Q. Mr. Moyer next claims that the APS contract should not act as a bar to granting Glen Canyon interconnection service that does not include interconnection-related network upgrades because the contract is scheduled to terminate only a year after Glen Canyon reaches commercial operation. Is his argument valid?

A. No. Mr. Moyer suggests that the anticipated retirement of the Cholla 4 generating unit would terminate the APS Restated Transmission Agreement in 2020, according to PacifiCorp's 2017 integrated resource plan ("IRP") filing. However, the retirement of Cholla 4 is not a certainty at this point in time, and certainly cannot be assumed for purposes of conducting an interconnection study. In fact, PacifiCorp's 2017 IRP filing states explicitly "that individual unit retirements reflected in the preferred portfolio, while reasonable for planning purposes, are not firm commitments for early unit closures."[6] The IRP also makes clear that all projected retirements are based on certain assumptions regarding market conditions that may not materialize.

Q. Do you have any changes to your direct testimony filed on August 31, 2017?

A. Yes. The wrong agreement was inadvertently attached and referenced in the testimony. On page 6, line 116, the testimony stating "The first agreement is a 1990 Asset Purchase and Power Exchange Agreement" should be replaced with "The first agreement is a Long-Term Power Transactions Agreement between PacifiCorp and Arizona Public Service Company." To avoid confusing the record in this docket, I am not replacing Exhibit RMP___(KAB-1), which was identified in footnote 1 on the same page of my direct testimony as the 1990 Asset Purchase and Power Exchange Agreement and an associated amendment. Instead, I am attaching the correct agreement to this testimony as Exhibit RMP___(KAB-3). Accordingly, the text of footnote 1 should be replaced with "The Long-Term Power Transactions Agreement is attached to my surrebuttal testimony as Exhibit___(KAB-3)."

Q. Does this change result in any other changes to your direct testimony?

A. No, this error does not require any other changes to or affect the substance of my direct testimony.

Q. Does this conclude your surrebuttal testimony?

A. Yes.

[6] PacifiCorp's 2017 Integrated Resource Plan, Docket No. 17-035-16, 2017 Integrated Resource Plan, Vol. 1 at 6 (April 11, 2017).

Rocky Mountain Power
Exhibit RMP___(KAB-1SR)
Docket No. 17-035-36
Witness: Kelcey A. Brown

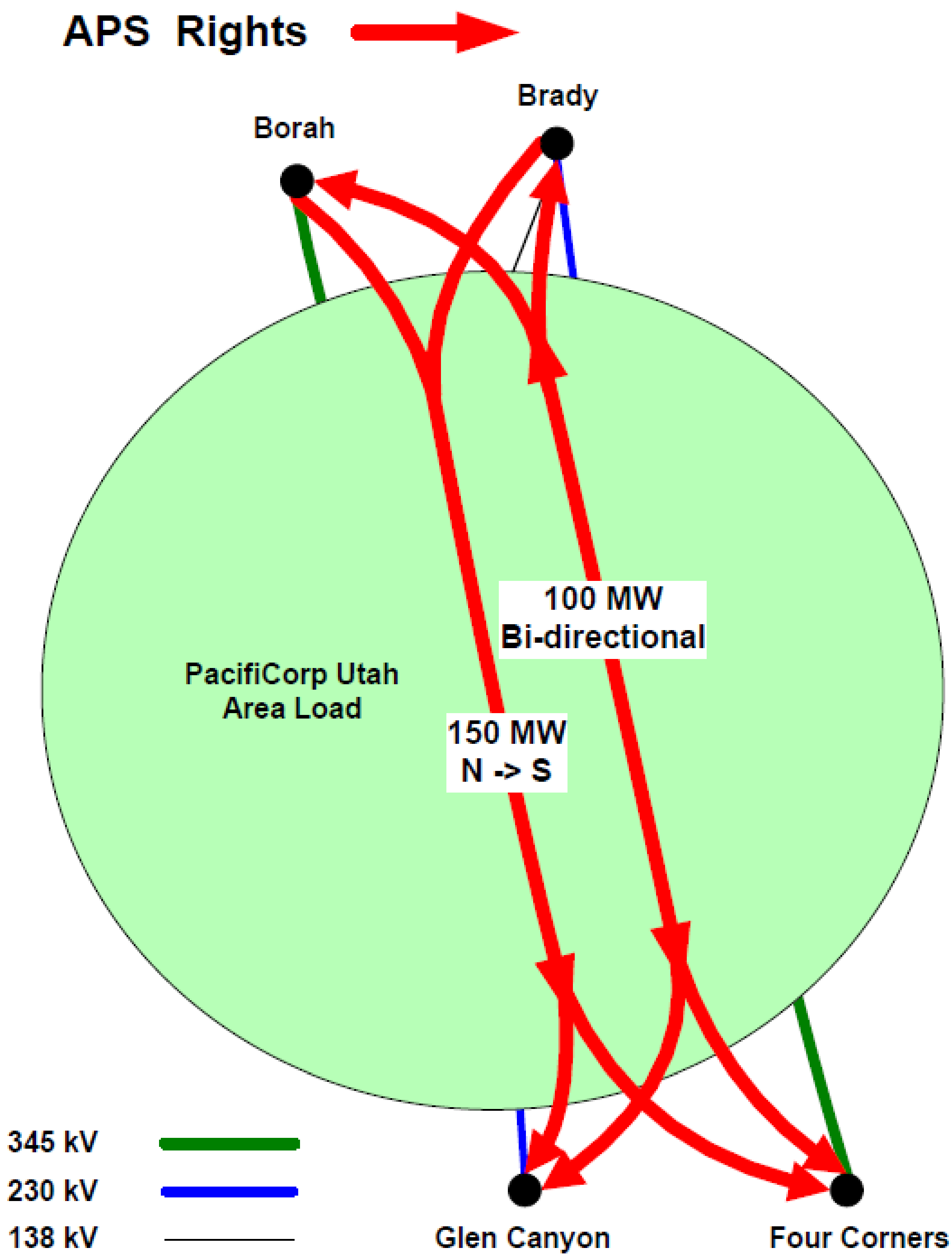
BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Kelcey A. Brown

Diagram Detailing APS Rights

October 2017


APS Rights
Brady
Borah
100 MW
Bi-directional
PacifiCorp Utah
Area Load
150 MW
N -> S
345 kV
230 kV
138 kV
Glen Canyon
Four Corners

Rocky Mountain Power
Exhibit RMP___(KAB-3)
Docket No. 17-035-36
Witness: Kelcey A. Brown

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Exhibit Accompanying Surrebuttal Testimony of Kelcey A. Brown

APS Long-Term Power Transaction Agreement
Dated September 21, 1990

October 2017

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

EXECUTION COPY

LONG-TERM POWER TRANSACTIONS AGREEMENT

BETWEEN

PACIFICORP

AND

ARIZONA PUBLIC SERVICE COMPANY

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LONG-TERM POWER TRANSACTIONS AGREEMENT
BETWEEN
PACIFICORP
AND
ARIZONA PUBLIC SERVICE COMPANY

THIS LONG-TERM POWER TRANSACTIONS AGREEMENT ("Agreement"), dated this 21st day of September, 1990, is between PacifiCorp Electric Operations, an assumed business name of PacifiCorp, an Oregon corporation (PacifiCorp) and Arizona Public Service Company, an Arizona corporation (APS). APS and PacifiCorp are sometimes referred to collectively as "Parties" and individually as "Party."

WHEREAS, PacifiCorp and APS are engaged in the generation, transmission and distribution of electric power and energy; and

WHEREAS, the Parties have resolved to enhance the efficient operation of their respective systems by taking advantage of the diversity of their respective loads and generation facilities; and

WHEREAS, the electric power needs of PacifiCorp's customers are highest in the winter months and the electric power needs of APS' customers are highest in the summer months; and

WHEREAS, the power supplies available to the Parties to meet their respective customer needs are diverse; and

WHEREAS, the Parties believe that various power transactions between interconnected electric utilities whose peak power needs and power supplies are different would be beneficial to the Parties' respective customers; and

WHEREAS, the Parties have entered into a series of contracts on this date to achieve such efficiencies; and

WHEREAS, the Parties intend to continue to study and discuss additional arrangements which will enhance efficiency and inure to the benefit of their respective customers,

NOW, THEREFORE, PacifiCorp and APS agree as follows:

Section 1: Definitions

As used herein, the following terms have the following meanings when used with initial capitalization, whether singular or plural:

1.1 "Agreement" means this agreement between PacifiCorp and APS.

1.2 "Annual Fixed Cost" for the calendar years 1996 through the Term of this Agreement, means the fully distributed weighted fixed cost, as determined and set forth in Appendix A, of the resources contained in the Resource Pool in such calendar year, with the costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix A.

1.3 "Annual Variable Cost" means, in the calendar years 1996 through the Term of this Agreement, the weighted variable cost, as determined and set forth in Appendix B, of the resources contained in the Resource Pool in such calendar year, with such costs of new resources, if any, added to the Resource Pool pursuant to Appendix C, being determined by a methodology substantially identical to that set forth in Appendix B.

1.4 "Asset Agreement" means the Asset Purchase and Power Exchange Agreement between the Parties dated September 21, 1990.

1.5 "Estimated Annual Fixed Cost" means PacifiCorp's estimate of the Annual Fixed Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.6 "Estimated Annual Variable Cost" means PacifiCorp's estimate of the Annual Variable Cost, based on the best information available to PacifiCorp at the time such estimates are made pursuant to Subsection 5.3, to be used for billing purposes as set forth in Section 8.

1.7 "Exchange Capacity" means capacity with Exchange Energy to be made available on a seasonal basis during the Term of this Agreement by each Party to the other and at no charge pursuant to the terms of Subsections 3.2 and 3.3.

1.8 "Exchange Energy" means energy associated with Exchange Capacity as set forth in Subsections 3.2 and 3.3.

1.9 "Firm Capacity" means capacity that is made available to APS by PacifiCorp to facilitate associated deliveries of Firm Energy as set forth in Section 3.

1.10 "Firm Energy" means the energy associated with Firm Capacity as set forth in Section 4.

1.11 "GNP Price Deflator" means the Gross National Product (GNP) Price Deflator (Implicit) as published by the Bureau of Economic Analysis (BEA).

1.12 "Natural Gas Price" means the Average Price of Natural Gas Delivered to Gas and Electric Utilities (30-day Supply Transactions)--delivered to California utilities as published by the "Natural Gas Intelligence Gas Price Index" or a comparable replacement index should such index become unavailable.

1.13 "Point of Delivery" for all transactions hereunder means (1) Four Corners and the point of interconnection between the Parties near Glen Canyon to be established as part of the Glen Canyon/Navajo Loop-in Project, (2) such other location(s) as may be established by mutual agreement of the Parties' dispatchers, schedulers, or authorized representatives and (3) the Cholla Generating Station 500 kV switchyard under the circumstances described in Subsection 15.03 of the Asset Agreement and Subsection 7.5 of this Agreement.

1.14 "Real Natural Gas Price" means the Natural Gas Price adjusted by the Producers Price Index from December 1990 published by the National Bureau of Statistics or a comparable replacement index if such index should become unavailable.

1.15 "Resource Pool" means a combination of resources available to PacifiCorp as defined in Appendix C.

1.16 "Seasonal Capacity Exchange" means the exchange of seasonal capacity as described in Subsections 3.2 and 3.3.

1.17 "Summer Season" means the May 1 through October 31 period of each of the calendar years of this Agreement.

1.18 "Supplemental Energy" means energy to be made available by APS to PacifiCorp as described in Section 6.

1.19 "Week" means a consecutive seven day period commencing on Sunday.

Section 2: Effective Date and Termination

2.1 Term of this Agreement. This Agreement shall be effective upon the Closing Date of the Asset Agreement and, except as provided in Subsections 2.2 and 3.2.4 and the final billing adjustment as provided in Subsection 8.2, shall terminate at 2400 hours MST, October 31, 2020.

2.2 Regulatory Approval and Termination.

2.2.1 Federal Energy Regulatory Commission Filing. PacifiCorp shall file this Agreement with the Federal Energy Regulatory Commission (FERC). APS shall file a letter of concurrence supporting PacifiCorp's filing of this Agreement with the FERC. If the FERC issues an order not accepting this Agreement for filing in its entirety and without material change, the Parties shall exercise best efforts to amend the Agreement to comply with the FERC order or negotiate a replacement agreement providing similar benefits to both Parties. In the event such amendment or replacement agreement is not executed by the Parties within sixty days following the

FERC's issuance of such order, or the Asset Agreement is terminated, this Agreement shall terminate.

Section 3: Capacity

3.1 Firm Capacity. For calendar years 1991 through 1995, PacifiCorp shall make available at the Point(s) of Delivery, and APS shall purchase 175 MW of Firm Capacity for the Summer Season of each calendar year. Except as provided in Subsection 3.2, commencing in calendar year 1996 and continuing through calendar year 1999, APS may increase the Firm Capacity amount up to a maximum amount equal to the rated capacity of Cholla Unit 4 for any year in increments of not less than 50 MW per calendar year upon providing PacifiCorp three years prior written notice. If APS increases its purchase of Firm Capacity under this Agreement above the 175 MW, such Firm Capacity amount will establish the then-effective Firm Capacity purchase requirement which may not be thereafter reduced. Except as provided in Subsection 3.2, the amount of Firm Capacity made available for calendar year 1999 will establish the Firm Capacity amount for the remaining Term of this Agreement. In the event of an Uncontrollable Force, deliveries of Firm Capacity hereunder shall have priority over PacifiCorp's other firm wholesale contracts with terms of 10 years or less and equal priority with PacifiCorp's other firm wholesale contracts with terms greater than 10 years.

3.2 Exchange Option. Upon providing PacifiCorp three years advance written notice, APS may convert all or portions thereof of the Firm Capacity, to Exchange Capacity in increments of not less than 50 MW per calendar year, and the parties shall engage in a one-for-one Seasonal Capacity Exchange for the remaining Term of this Agreement. Any such conversion shall not be effective prior to calendar year 1996 and shall be effective for a full Summer or Winter Period as set forth in Subsections 3.2.1 and 3.2.2, respectively. Any amounts of Firm Capacity which are converted to Exchange Capacity may not be converted back to Firm Capacity. Exchange Capacity shall be made available at no charge to either Party in accordance with the provisions set forth below.

3.2.1 Summer Deliveries. PacifiCorp shall make Exchange Capacity available to APS during the period of May 15 through September 15 ("Summer Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Summer Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for a portion of the Exchange Energy in lieu of returning it.

3.2.2 Winter Deliveries. APS shall make Exchange Capacity available to PacifiCorp from October 15 through the following February 15 ("Winter Period"). Associated deliveries of Exchange Energy shall not exceed a load factor of 50 percent for each Week or any partial Week at the beginning or end of the Winter Period, and shall not exceed a load factor of 40 percent for any month or partial month thereof. By mutual agreement, a Party may pay for Exchange Energy in lieu of returning it.

3.2.3 Delayed Return of Exchange Energy. The return of Exchange Energy delivered in the Winter or Summer Periods under Subsections 3.2.2 and 3.2.1 shall be delayed to the next following Summer or Winter Periods, respectively. The delivery of such Exchange Energy shall be coincident with and a part of any Exchange Capacity made available by the other Party under Subsections 3.2.1 and 3.2.2. Either Party's failure to schedule the return of such Exchange Energy owed to it from the preceding season shall operate as a waiver of the right to receive the return of such Exchange Energy, except that if such schedules cannot be made because of an Uncontrollable Force, it shall not constitute a wavier.

3.2.4 Final Settlement. At the end of the Term of this Agreement, if any Exchange Energy is owed to PacifiCorp from the immediate preceding season, the term of the Exchange Capacity obligations shall be extended until all Exchange Energy is returned, subject to the delivery rates set forth in Subsection 3.2.2.

3.3 Contingent Capacity Exchange. It is anticipated that increased transfer capability will be available between the Parties in the mid-1990's following completion of new transmission facilities of the sort described in the Transmission Agreement between the Parties dated September 21, 1990. Contingent on increased transmission capacity being available, the Parties shall enter into a 100 megawatt Seasonal Capacity Exchange. At such time, each Party shall have an additional 100 megawatts of Exchange Capacity to use for the balance of the Term of this Agreement along with any Exchange Capacity available as a result of the exchange option provided for in Subsection 3.2, subject to the same terms and conditions set forth in Subsections 3.2.1, 3.2.2, 3.2.3 and 3.2.4. Unless mutually agreed otherwise, such Seasonal Capacity Exchange shall not commence prior to calendar year 1996.

Section 4: Firm Energy

Delivery Provisions. Commencing May 1, 1991, and continuing through the Term of this Agreement, except as provided in Subsection 3.2, PacifiCorp shall make available Firm Energy associated with Firm Capacity as scheduled by APS at load factors not to exceed 100 percent per hour, 80 percent per month, and 70 percent per Summer Period and APS shall purchase such Firm Energy at load factors of not less than 40 percent per month, and 50 percent per Summer Period. Subsequent to 1996, the maximum monthly and Summer Period load factors of Firm Energy to be made available by PacifiCorp shall be increased to 100 percent and 85 percent respectively.

Section 5: Prices

APS shall be obligated to pay PacifiCorp for the Firm Capacity and Firm Energy as follows:

5.1 May 1, 1991 through October 31, 1995. During the Summer Season for each year of the calendar years 1991 through 1995, APS shall pay for all Firm Capacity the fixed prices expressed in $/KW/mo as set forth below:

Year	$/KW/mo
1991	10.87
1992	10.55
1993	10.19
1994	9.84
1995	9.51

The Firm Energy price for each of the calendar years 1991 through 1995 shall be the actual production expense for such year of Cholla Unit 4 as determined pursuant to the methodology set forth in Appendix B of this Agreement; provided, that in the event the capacity factor of Cholla Unit 4 in any calendar year is less than 40 percent, the Firm Energy price shall be the actual production expense of the resource having the highest actual production expense with a capacity factor equal to or greater than 40 percent for such year as determined pursuant to the methodology set forth in Appendix B among the other resources contained in the identified Resource Pool for 1996.

5.2 May 1, 1996 through October 31, 2020. During the Summer Season for each year of the calendar years 1996 through 2020, the payment prices for Firm Capacity as set forth in Subsection 3.1 and Firm Energy as set forth in Section 4 shall be the Annual Fixed Cost ($/KW/mo) and the Annual Variable Cost ($/MWh) respectively.

5.3 Estimated Capacity Price and Energy Price. Unless all Firm Capacity has been converted to Exchange Capacity pursuant to Subsection 3.2, PacifiCorp shall provide APS with the following capacity and energy price estimates to be used for billing purposes prior to the time that actual costs are available:

5.3.1 May 1, 1991 through October 31, 1995. PacifiCorp shall provide to APS no later than March 1, 1991 and by each March 1 thereafter through calendar year 1995, estimates of the Cholla Unit 4 production expense to be used for billing purposes for the following Summer Season.

5.3.2 May 1, 1996 through October 31, 2020. PacifiCorp shall provide to APS no later than April 15, 1993 and by each April 15 thereafter an estimate of the capacity price ("Estimated Annual Fixed Cost") and an estimate of the energy price ("Estimated Annual Variable Cost") for the third subsequent Summer Season. Such estimate shall be determined using the best information available to PacifiCorp at the time the estimate is made. If during any Summer Season PacifiCorp determines that the Estimated Annual Fixed Cost and the Estimated Annual Variable Cost used for billing purposes should be adjusted to reflect more accurate estimates, PacifiCorp shall notify APS as soon as possible. By mutual agreement of the Parties, PacifiCorp shall revise the Estimated Annual Fixed

Cost and the Estimated Annual Variable Cost used for billing purposes in subsequent billing periods to reflect the more accurate estimates. Upon request, PacifiCorp shall provide to APS appropriate work papers and documentation supporting the revised estimates.

Section 6: Supplemental Energy

6.1 Option to Purchase. During the Term of this Agreement, APS shall make available at the Point of Delivery and PacifiCorp shall have the option to purchase Supplemental Energy on the basis provided for in this Section 6.

6.2 Quantities. There shall be two categories of Supplemental Energy, "Supplemental Coal Energy" and "Other Supplemental Energy." APS shall offer Supplemental Coal Energy and Other Supplemental Energy to PacifiCorp in the following Annual quantities during the Term of this Agreement:

Period	Supplemental Coal Energy (GWh per Year)	Other Supplemental Energy (GWh per Year)
Each year until 10/31/96	876	219
11/1/96 until 10/31/01	657	438
11/1/01 until 10/31/06	438	657
11/1/06 until 10/31/20	219	876

The required quantities for the period commencing on the Closing Date of the Asset Agreement until October 31, 1991 shall be proportionate shares of the required Annual quantities for that period. For purposes of this Section 6, "Year" or "Annual" shall mean the period commencing November 1 and ending October 31. In any year, if despite best efforts, APS is unable to meet its annual obligation to make Supplemental Coal

Energy available to PacifiCorp, APS may delay offering up to a maximum of 20% of that year's annual requirement to the first 90 days of the next year. However, such deferred Supplemental Coal Energy shall be offered together with the next year's Supplemental Coal Energy, at rates of delivery not exceeding those set forth in Subsection 6.3

6.3 Rate of Delivery of Supplemental Coal Energy. APS may offer up to 250 MWh per hour of Supplemental Coal Energy to PacifiCorp. APS' annual obligation for each Year to offer Supplemental Coal Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6, regardless of whether such energy is purchased by PacifiCorp. Offered Supplemental Coal Energy which has been accepted and prescheduled by PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6, shall not reduce APS' annual obligation.

6.4 Rate of Delivery of Other Supplemental Energy. APS may offer up to 150 MWh per hour of Other Supplemental Energy to PacifiCorp. APS' Annual obligation for each Year to offer Other Supplemental Energy to PacifiCorp shall be reduced by the amount of Supplemental Coal Energy offered pursuant to Subsection 6.6 if it represents the lowest cost energy that is surplus to APS' system during that hour, regardless of whether such energy is purchased by PacifiCorp. Offered Other Supplemental Energy which has been accepted and prescheduled by

PacifiCorp but which APS is not able to deliver because of significant changes in its system conditions as set forth in Subsection 6.6 shall not reduce APS' annual obligation.

6.5 Simultaneous Delivery. APS shall not offer Supplemental Coal Energy and Other Supplemental Energy for delivery during the same hour.

6.6 Supplemental Energy Offer. APS shall offer Supplemental Energy to PacifiCorp before 1000 hours MST on the last work day observed by both Parties immediately preceding the day(s) such Supplemental Energy is proposed to be made available. Such offer shall identify the type(s) and amount(s) of such Supplemental Energy as well as the Supplemental Energy Price. PacifiCorp shall preschedule any desired amounts of Supplemental Energy pursuant to Subsection 7.3. Prescheduled amounts of Supplemental Energy may be changed by the Parties' dispatchers or schedulers only in the event of significant changes in the affected Party's load, generation or transmission capability. The Supplemental Energy price as established at the time of prescheduling shall not change.

6.7 Pricing of Supplemental Coal Energy. The price of Supplemental Coal Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and recorded in APS' system log and shall be derived from the best efforts forecast of the coal cost utilizing the incremental heat rate, together with incremental operating and maintenance expense associated with the generating unit producing such energy ("Incremental Cost"). Incremental Cost for purposes of establishing the price of Supplemental Coal Energy shall be computed in accordance with the methodology established in Appendix E, but in no event, except as provided below, shall such Incremental Cost exceed the Incremental Cost of Cholla Unit 3, or Cholla Unit 2, if Cholla Unit 3 has been retired from service. Until November 1, 1996, the price of Supplemental Coal Energy shall equal 115% of Incremental Cost. From November 1, 1996 through October 31, 2001, the price of Supplemental Coal Energy shall equal 120% of Incremental Cost. From November 1, 2001 through October 31, 2006, the price of Supplemental Coal Energy shall equal 125% of Incremental Cost. From November 1, 2006 through October 31, 2020, the price of Supplemental Energy shall equal 130% of Incremental Cost. Subsequent to October 31, 2010, if APS has constructed a base-load coal plant that is being used to provide utility service to APS' customers whose Incremental Cost is greater than that of Cholla Unit 3, the Parties shall negotiate in good faith to equitably adjust the Incremental Cost cap and multipliers provided for herein.

6.8 <u>Pricing of Other Supplemental Energy</u>. The price of Other Supplemental Energy for each transaction shall be as quoted by APS' dispatcher or scheduler prior to delivery and as recorded in APS' system log and shall be the higher of (1) the average price of Supplemental Coal Energy for the month prior to the month in question or (2) the result of the following equation:

$$C\left(1+\frac{.15Q}{I}\right)$$

Where: C = Incremental Cost of generating unit producing the Other Supplemental Energy derived pursuant to Appendix E

Q = Real Natural Gas Price for the first month of the quarter preceding the month of delivery of Other Supplemental Energy (and Q shall never be less than I)

I = Natural Gas Price for December 1990

Section 7: Scheduling

7.1 Projected Monthly Schedules. By December 1, 1990 and each December 1 thereafter, APS shall submit to PacifiCorp in writing the projected monthly amounts of Firm Energy associated with Firm Capacity to be delivered for the following Summer Season. Such projections shall represent a good faith estimate by APS of its anticipated deliveries hereunder; provided, that such estimates shall not be binding and shall be used by PacifiCorp for planning and information purposes only.

7.2 Daily Schedules by APS. APS shall preschedule all deliveries of Firm Energy associated with Firm Capacity and all deliveries of Exchange Energy associated with Exchange Capacity no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or day(s) of delivery, or as otherwise mutually agreed by the Parties' dispatchers or schedulers. PacifiCorp shall deliver in accordance with APS' preschedules which comply with the delivery provisions specified in Sections 3 and 4.

7.3 Daily Schedules by PacifiCorp. In the event the Parties commence a Seasonal Capacity Exchange(s) pursuant to Subsections 3.2 and/or 3.3, PacifiCorp shall preschedule deliveries of Exchange Energy associated with Exchange Capacity together with any deliveries of Supplemental Energy, no later than 1000 hours MST on each work day observed by both Parties immediately preceding the day or days on which such energy is to be delivered, or as mutually agreed by the Parties' dispatchers or schedulers. APS shall accept and deliver in accordance with those preschedules which comply with the delivery obligations specified in Subsection 3.2.2 and Section 6.

7.4 System Logs. All deliveries shall be deemed to be made during the hours and in the amounts as accounted for in the APS and PacifiCorp system logs; provided, that if scheduled deliveries are interrupted due to an Uncontrollable Force as defined in Section 14, such schedules shall be adjusted to reflect such interruption and any scheduled delivery so interrupted shall be rescheduled at a later date. Such rescheduling of interrupted deliveries shall be in amounts and at times as mutually agreed by the Parties' dispatchers or schedulers and shall not increase either Party's obligation pursuant to Sections 3 and 4.

7.5 Point of Delivery at Cholla. Prior to 1996 and prior to the completion of the Navajo/Glen Canyon Loop-in Project, if APS, despite its best efforts, is unable to deliver the full amount of Firm Capacity into its system from Four Corners, PacifiCorp shall deliver such amounts of Firm Capacity that APS is unable to deliver from Four Corners to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity from Cholla Unit 4 in excess of 200 MW. Commencing in 1996, to the extent APS is purchasing more than 200 MW of Firm Capacity, PacifiCorp shall deliver amounts of Firm Capacity in excess of 200 MW to APS at the Cholla Generating Station 500 kV switchyard to the extent it is able to do so from available generating capacity at Cholla Unit 4 in excess of 200 MW. For purposes of this Subsection, APS' best efforts shall not include a requirement that APS adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

Section 8: Billing

8.1 Payments. Commencing May 1, 1991 through the term of this Agreement that Firm Capacity is being made available, APS shall pay PacifiCorp in the appropriate month of each year for Firm Capacity and Firm Energy the amounts determined in Subsections 8.1 through 8.4.

8.1.1 Summer Season 1991-1995. For the Summer Season of calendar years 1991 through 1995, the payment for each month shall equal the sum of (a) the Firm Capacity as set forth in Subsection 3.1 as stated in kilowatts multiplied by the fixed price ($/KW/mo) for such year as set forth in Subsection 5.1 and, except as provided in Subsection 8.1.1.1, (b) the amount of Firm Energy stated in megawatt hours scheduled by APS pursuant to Section 4 during such month multiplied by the estimated Cholla Unit 4 production expense determined pursuant to Subsection 5.3.1.

8.1.1.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than a 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.2 Summer Season - 1996-2020. Except as provided for in Subsections 3.2 and 8.1.3, for the Summer Season of calendar years 1996 through 2020, the payment for each month shall equal the sum of (a) the Firm Capacity as set forth in Subsection 3.1 stated in kilowatts multiplied by the Estimated Annual Fixed Cost as determined pursuant to Subsection 5.3.2 and, except as provided for in Subsection 8.1.2.1, (b) the amount of Firm Energy stated in megawatt-hours scheduled during such month multiplied by the Estimated Annual Variable Cost as determined pursuant to Subsection 5.3.2.

8.1.2.1 Minimum Purchase Obligation. In the event the amount of Firm Energy scheduled by APS in any Summer Season is less than 50 percent load factor, an amount of Firm Energy will be deemed to have been scheduled and delivered during the month of October that would increase APS' energy amount received for the Summer Season to equal a 50 percent load factor. APS shall pay for all such energy deemed to have been scheduled and delivered as determined above.

8.1.3 Firm Capacity Payment Reduction. APS shall be entitled to a reduction in the payment provided for in Subsection 8.1.2 when all of the following occur:

(a) Firm Capacity is greater than 200 MW;

(b) Cholla Unit 4 is not operating for any reason;

(c) APS has no reasonable ability to adjust its system to accommodate delivery of more than 200 MW of Firm Capacity into its system through Navajo/Four Corners;

(d) PacifiCorp has combustion turbine capacity available to it in Arizona which it has elected not to utilize to provide APS with Firm Capacity in excess of 200 MW; and

(e) PacifiCorp has the ability to acquire power in Arizona from another entity which could be used to provide APS Firm Capacity in excess of 200 MW, but has elected not to acquire such power on APS' behalf.

For purposes of paragraph (c) above, APS shall not be required to adjust generating resources on its system such that higher-cost generating resources are operated and lower-cost resources are curtailed in order to accommodate deliveries.

The reduction in the required payment shall be computed for each hour of any month in which all of the aforementioned conditions occurred based upon the results of the following equation and the sum of the hourly reduction(s) shall equal the monthly reduction:

$$\frac{(C-200,000)X}{730}$$

Where: C = Firm Capacity, stated in kilowatts
X = Estimated Capacity Price, stated in dollars per kilowatt month

8.2 Annual Adjustments. By June 1 of each of the calendar years 1992 through 2021, PacifiCorp shall determine APS' payment obligation for the preceding calendar year's Summer Season based on prices determined in accordance with Section 5, applied except for calendar years 1991 through 1995 to Firm Capacity, pursuant to Subsection 3.1, and applied to the Firm Energy as set forth in Section 4. Such determination shall also reflect any payment reductions owing pursuant to Subsection 8.1.3. In the event the amount so determined is greater than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall add the amount of such difference, as adjusted for interest pursuant to Appendix D, to the May invoice. In the event the amount so determined is less than the amount actually paid by APS pursuant to Subsections 8.1.1 or 8.1.2, then PacifiCorp shall subtract the amount of such difference, as adjusted for interest pursuant to Appendix

D, from the May invoice. By June 1, 2021 PacifiCorp shall determine APS' payment obligation for the preceding Summer Season based on prices determined in accordance with Section 5, applied to Firm Capacity pursuant to Section 3, and the Firm Energy purchase obligations as set forth in Section 4. In the event the amount so described is different than the amount actually paid by APS pursuant to Subsection 8.1, then PacifiCorp shall refund or send APS an invoice for such difference, whichever is appropriate, as adjusted for interest pursuant to Appendix D. Such refund or invoice shall be submitted to APS by June 15, 2021.

8.3 Billing and Payment for Firm Capacity and Firm Energy. PacifiCorp shall bill APS by the fifteenth day of each month by regular mail for services provided during the preceding month. APS shall pay such amounts, by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all services provided hereunder are to be electronically wire transferred to United States National Bank of Oregon, Metropolitan Branch, 900 S.W. Sixth Avenue, Portland, Oregon 97204 (for credit to Pacific Power & Light Company, Account #070-000-169), Attention: Treasurer or such other financial institution or account number as specified by PacifiCorp in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

8.4 Billing and Payment for Supplemental Energy. For months during which PacifiCorp acquires Supplemental Energy, PacifiCorp shall pay APS the amounts determined in Subsections 8.4.1 and/or 8.4.2.

8.4.1 Supplemental Coal Energy. The payment for each month shall equal the sum of the individual hourly amounts of Supplemental Coal Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Supplemental Coal Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.7.

8.4.2 Other Supplemental Energy. The payment for each month shall equal the sum of the individual hourly amounts of Other Supplemental Energy stated in megawatt-hours scheduled by PacifiCorp during such month multiplied by the corresponding hourly Other Supplemental Energy price as established by the Parties' dispatchers or schedulers prior to the hour of delivery pursuant to Subsection 6.8.

8.5 Billing and Payment Schedules for Supplemental Energy. APS shall bill PacifiCorp by the fifteenth day of each month by regular mail for Supplemental Energy delivered during the preceding month. PacifiCorp shall pay such amounts,by electronic wire transfer, within fifteen days of receipt of such bill. Payments for all Supplemental Energy delivered hereunder are to be electronically wire transferred to Account No. 1-2079 at Valley National Bank, 241 North Central Avenue, Phoenix, Arizona 85004, or such other financial institution or account number as specified by APS in writing. Simple interest shall accrue on any unpaid amounts at a rate equal to 1.25 multiplied times the prime rate as established by The Morgan Guaranty Trust Company of New York during the period of delinquency, if any.

Section 9: Audit Rights

During the period of this Agreement that Firm Capacity is being made available, APS may review PacifiCorp's accounting records and supporting documents associated with any billing for Firm Capacity and Firm Energy made during the prior 18 months. During the Term of this Agreement, PacifiCorp may review appropriate portions of APS' system logs, and APS' accounting records or supporting documents associated with any billing for Supplemental Energy made during the prior 18 months. If either Party believes there are any errors in the determination of a bill including prices, it shall pay the full amount of such bill and the Parties shall meet to review the accounting records and supporting documents and agree on any adjustments that may be appropriate. If the Parties agree that the billing is incorrect, a corrected bill shall be prepared and the difference between the incorrect bill and corrected bill, including simple interest on the difference as provided herein, shall be paid promptly after such determination. The simple interest rate shall be equal to the time-weighted average prime rate as established by Morgan Guaranty Trust

Company of New York and calculated using the method described in Appendix D. The principal upon which interest rates are to be applied shall be limited to twenty-four months following the submittal of the incorrect bill. The Parties shall take all steps reasonably available to secure the confidentiality of each other's accounting records and supporting documents. Disclosure of accounting records and supporting documents to a Party is not intended to, and shall not be interpreted to, waive the other Party's right to maintain that such records and supporting document are privileged, confidential, proprietary, or otherwise protected from disclosure to the public. In the event such information is required in a legal or regulatory proceeding related to this Agreement, a Party shall advise the other Party of the requirement to disclose such information prior to disclosing it and at such other Party's request shall ask for confidentiality of any such information.

Section 10: Cost Determination Changes

The cost methodologies utilized for pricing purposes in this Agreement and the pricing formulae specified herein shall remain in effect through the term of this Agreement, and neither Party shall petition the FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act to amend such methodologies or formulae absent the agreement in writing of the other Party or support such a petition filed by any third party.

Section 11: Future Studies and Arrangements

No later than 60 days subsequent to the Closing Date of the Asset Agreement, the Parties shall meet to begin discussions of further transactions and arrangements that could benefit the Parties' respective customers. In addition to the types of transactions and arrangements already agreed to by the Parties, the discussions shall include other potential arrangements associated with generation and transmission planning and other potential operating efficiencies.

Section 12: Governing Law

This Agreement shall be subject to and be construed under the laws of the State of Arizona.

Section 13: Notices

All written notices hereunder, shall be directed as follows, and shall be considered delivered when deposited in the U.S. Mail, or other certified mail, return receipt requested:

To APS: Arizona Public Service Company
Corporate Secretary
P.O. Box 53999
Phoenix, AZ 85072-3999

To PacifiCorp: PacifiCorp Electric Operations
Vice President, Power Systems
920 S.W. Sixth Avenue
Portland, OR 97204-1236

The Parties may change the persons to whom notices are addressed, or their addresses, by providing notice thereof as specified in this Section.

Section 14: Uncontrollable Forces

Neither Party to this Agreement shall be considered to be in default in performance of any obligation hereunder if failure of performance shall be due to an Uncontrollable Force. The term "Uncontrollable Force" means any cause beyond the control of the Party affected, including, but not limited to, failure of facilities, flood, earthquake, storm, fire, lightning, epidemic, war, riot, civil disturbance, labor disturbance, sabotage, and restraint by court order or public authority, which by exercise of due foresight such Party could not reasonably have been expected to avoid, and which by exercise of due diligence it shall be unable to overcome. A Party shall not, however, be relieved of liability for failure of performance if such failure be due to causes arising out of its own negligence or to removable or remediable causes which it fails to remove or remedy with reasonable dispatch. Any Party rendered unable to fulfill any obligation by reason of an Uncontrollable Force shall exercise due diligence to remove such inability with all reasonable dispatch. Nothing contained herein, however, shall be construed to require a Party to prevent or settle a strike against its will.

Section 15: Waiver

Any waiver by a Party of its rights with respect to default hereunder, or with respect to any other matter arising in connection herewith, shall not be deemed to be a waiver with respect to any subsequent default or matter. Except as provided for in Subsection 3.2.3, no delay in asserting or enforcing any right hereunder shall be deemed a waiver of such right.

Section 16: Arbitration

16.1 The Parties shall make best efforts to settle all disputes arising under this Agreement as a matter of normal business and without recourse to either arbitration or litigation. If any dispute arises under this Agreement, the Parties shall arbitrate the matter before an arbitrator who is an attorney or engineer familiar with contracts governing the operation of electrical systems. Any arbitration shall be commenced within a year of when a dispute arises and shall be commenced by either Party submitting to the other a Notice of Arbitration. The Parties shall have 30 days following the submittal of a Notice of Arbitration by either Party to attempt to mutually agree upon an arbitrator. If the Parties are unable to agree on an arbitrator within that time, either Party may request that a judge of the United States Circuit Court for the Ninth Circuit designate an arbitrator.

16.2 The arbitrator shall have discretion to establish a schedule and procedure for the arbitration and may conduct the arbitration based upon written submittals. The arbitrator may afford the Parties any or all of the discovery rights provided for in the Federal Rules of Civil Procedure.

16.3 At the commencement of the arbitration hearing, each Party shall submit a proposed Arbitration Award and the arbitrator shall be required to adopt in full the proposed Arbitration Award of one of the Parties and the Arbitration Award selected shall be final and binding on the Parties.

16.4 The Party whose proposed Arbitration Award is not selected shall pay all the costs of the arbitration, including the costs and the attorneys' fees of the prevailing Party.

Section 17: Indemnification

Neither Party ("First Party") shall be liable, whether in warranty, tort, or strict liability, to the other Party ("Second Party") for any injury or death to any person, or for any loss or damage to any property, caused by or arising out of any electric disturbance of the First Party's electric system, whether or not such electric disturbance resulted from the First Party's negligent act or omission. Each Second Party releases the First Party from, and shall indemnify and hold harmless the First Party from, any such liability. As used in this Section, (1) the term "Party" means, in addition to such Party itself, its agents, directors, officers, and employees; (2) the term "damage" means all damage, including consequential damage; and (3) the term "persons" means any person, including those not connected with either Party to this Agreement.

Section 18: Entire Agreement

This Agreement constitutes the entire agreement of the Parties hereto with respect to the transaction addressed herein and supersedes all prior agreements, whether oral or written. This Agreement may be amended only by a written document signed by both Parties hereto.

Section 19: Assignment

Neither Party shall assign this Agreement without the prior written consent of the other Party, except:

(a) to any corporation into which or with which the Party making the assignment is merged or consolidated or to which the Party transfers substantially all of its assets;

(b) to any person or entity wholly owning, wholly owned by,or wholly owned in common with the Party making the assignment.

Nothing contained in this Section shall be construed to prevent the Parties from making a collateral assignment of the revenues due under the terms of this Agreement. No assignment, merger or consolidation shall relieve any Party of any obligation under this Agreement. Subject to the foregoing restrictions in this Section, this Agreement shall be binding upon, inure to the benefit of and be enforceable by the Parties and their respective successors and assigns.

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed in their respective names by their respective officers thereunder duly authorized.

PacifiCorp Electric Operations

By ______________________

Title: President

Arizona Public Service Company

By ______________________

Title: Chairman

APPROVED AS TO FORM
APS Legal Department
By J E Parrish
Date 9-20-90

APPENDIX A: ANNUAL FIXED COST

Introduction

This Appendix sets forth the elements and techniques to calculate Annual Fixed Cost.

The Annual Fixed Cost shall be the per-MW total of the following: (1) 70 MW multiplied by the Colstrip Project Annual Fixed Cost pursuant to Section A2 plus 350 MW multiplied by the Cholla Project Annual Fixed Cost pursuant to Section A4, plus 180 MW multiplied by the Hunter #2 Project Annual Fixed Cost pursuant to Section A6, plus 400 MW multiplied by the Hunter #3 Project Annual Fixed Cost pursuant to Section A8 and (2) dividing the above sum by 1000 MW.

The Annual Fixed Cost for PacifiCorp's share of the Colstrip Project, PacifiCorp's share of the Cholla Project, PacifiCorp's share of the Hunter #2 Project and PacifiCorp's share of the Hunter #3 Project is the per-MW sum of each Project's: (a) initial levelized annual fixed cost, (b) levelized annual fixed costs of subsequent capital additions, replacements and betterments (if any), and (c) other fixed annual charges directly related to the resources in the pool, including but not limited to property taxes, insurance, and taxes other than income tax.

Section A1: Discussion of Methodology

Levelized fixed charges are the basis of annual fixed costs hereunder. While actual capital-related charges associated with an investment may vary considerably from year to year, the levelized fixed charge translates these charges into a level annual amount which remains constant over time. The present values of the two streams (actual versus levelized) are equal.

The levelized fixed charge includes three basic components: (a) return on investment, given a specific capital structure and cost of capital; (b) recovery of investment, given the appropriate depreciation period related to the investment; and (c) income tax requirements, given tax law considerations. These components are commonly expressed as: (a) interest expense on debt and return required by shareholders, (b) book depreciation, and (c) income taxes incorporating the effects of investment tax credits and tax depreciation.

As of December 31, 1989, an initial levelized annual charge rate will be applied to the total investment of each Project. The rate will be recalculated effective each January 1 only in the event of a change during the preceding calendar year in any of the following: (a) the percentage of pollution control revenue bonds outstanding; (b) the interest rate on pollution control revenue bonds; (c) PacifiCorp's rate of return on common equity (ROE), as allowed by the Federal Energy Regulatory Commission (FERC), or (d) income tax law, but not to be applied retroactively.

Subsequent levelized annual fixed charge rates will be calculated each year to reflect the most current information and will be applied each year to the amount of capital additions, replacements (less credit for net salvage and insurance proceeds, if any) and betterments of each Project completed through the end of the preceding calendar year.

Section A2: Determination of Colstrip

Project Annual Fixed Cost

Colstrip Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A2.1 through A2.5, and (b) dividing the total by 140 MW ("Net Colstrip Capacity"), provided that, in the event the capacity of the

Colstrip Project increases or decreases as a result of additions, replacements or betterments the Net Colstrip Capacity will be adjusted to reflect such change.

A2.1 PacifiCorp's initial levelized annual fixed charge rate for the Colstrip Project determined annually in accordance with Section A3 of this Appendix, multiplied by the total investment in the Colstrip Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Colstrip Project is $195,862,376. Such total investment shall remain constant through the term of the Agreement.

A2.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A3, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Colstrip Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A2.3 All ad valorem taxes imposed upon the Colstrip Project.

A2.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Colstrip Project, excluding ad valorem taxes, state and federal income taxes.

A2.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Colstrip Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A3: Elements of Colstrip Project's Levelized Annual Fixed Charge Rates

A3.1 Capital Structure:

A3.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Colstrip Project is:

Long Term Debt and Pollution Control Revenue Bonds	52%
Preferred Stock	12%
Common Stock Equity	36%
Total Capital	100%

The proportion of Pollution Control Revenue Bonds A to Total Capital will be the quotient of (a) $45,000,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in January 1988) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989.

The proportion of Pollution Control Revenue Bonds B to Total Capital will be the quotient of (a) $8,500,000 (the principal amount of Pollution Control Revenue Bonds relating to the Colstrip Project issued in December 1986) divided by (b) $195,862,376, i.e., the sum of PacifiCorp's total investment cost of the Colstrip Project as of December 31, 1989. The proportion of Long Term debt to Total Capital will be the difference between (a) fifty-two percent (52%), (b) the proportion of Pollution Control Revenue

Bonds A as calculated above, and (c) the proportion of Pollution Control Revenue Bonds B as calculated above. If PacifiCorp's City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 or Series 1986 (Pacific Power & Light Company Colstrip Project), as referenced above, are prepaid, redeemed or exchanged for bonds, in their entirety, the interest of which is taxable under federal income tax laws, the capital structure will be adjusted to determine the initial levelized annual charge rates in the calendar years immediately succeeding the year of prepayment or redemption, such that the Pollution Control Revenue Bonds (A or B) proportion will be zero (0) and the Long-Term Debt proportion will be the difference between (a) Fifty-two percent (52%) and (b) the remaining proportion of Pollution Control Revenue Bonds A or B as calculated above. In the event that the above-referenced pollution control revenue bonds are exchanged for another issue of bonds, the interest of which is exempt under federal income tax laws, the capital structure consequent to the subsequent issue will be employed prospectively for calculations under this section.

<u>A3.1.2</u> PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	<u>46%</u>
Total Capital	100%

<u>provided</u>, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt

long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A3.2 Cost of Capital:

A3.2.1 Interest Rate for Debt: The interest rate for debt shall be equal to 1) the product of the proportion of Long Term Debt to Total Capital multiplied by the total Colstrip Project Investment multiplied by the bond interest rate (12.8%) as specified in Subsection A3.2.1.1, plus 2) the product of the amount of tax exempt Pollution Control Revenue Bonds A multiplied by the variable interest rate (which in 1989 was 6.48%) as specified in Subsection A3.2.1.2, plus 3) the product of the amount of tax exempt Pollution Control Revenue Bonds B multiplied by the variable interest rate (which in 1989 was 6.89%) as specified in Subsection A3.2.1.3; the sum of the products of 1) and 2) and 3) divided by the sum of 4) the product of the proportion of Long Term Debt to Total Capital as specified in Subsection A3.1.1 times the Total Colstrip Project investment, plus 5) the amount of tax exempt Pollution Control Revenue Bonds A, plus 6) the amount of tax exempt Pollution Control Revenue Bonds B.

A3.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be twelve and eight-tenths percent (12.8%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Colstrip Project, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A3.2.1.2 Pollution Control Revenue Bonds A: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and forty-eight hundredths percent (6.48%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $45,000,000 City of Forsyth, Rosebud County, Montana, Floating Rate Monthly Demand Pollution Control Revenue Bonds, Series 1988 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, in their entirety, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds A in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced Pollution Control Revenue Bonds A are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.1.3 Pollution Control Revenue Bonds B: Bond interest applicable in the calculation of the 1989 initial levelized annual fixed charge rate shall be six and eighty-nine hundredths percent (6.89%). Bond interest applicable in the calculation of the initial levelized annual fixed charge rate in each year from 1991 through 2010 shall be the average of that effective interest rate paid by PacifiCorp during the previous calendar year relating to its $8,500,000 City of Forsyth, Rosebud

County, Montana, Floating Rate Monthly demand Pollution Control Revenue Bonds, Series 1986 (Pacific Power & Light Company Colstrip Project). If such series of bonds is prepaid, redeemed, or exchanged for bonds, the interest of which is subject to federal income taxes, there will be no interest relating to Pollution Control Revenue Bonds B in the initial levelized annual fixed charge rates computed in the calendar year immediately following such prepayment or redemption. In the event that the above-referenced pollution control bonds B are exchanged for another issue, the interest of which is exempt from federal income taxes, the interest rate consequent to the subsequent issue shall be employed prospectively for calculations under this section.

A3.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be thirteen and three-tenths percent (13.3%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A3.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC.

From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A3.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35)-year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A3.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A3.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A3.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A3.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A3.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A3.4.5 Tax basis will be seventy-five percent (75%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A4: Determination of Cholla Project Annual Fixed Cost

Cholla Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Section A4.1 through A4.5, and (b) dividing the total by 350 MW ("Net Cholla Capacity"), provided that, in the event the capacity of the Cholla Project increases or decreases as a result of additions, replacements or betterments the Net Cholla Capacity will be adjusted to reflect such change.

A4.1 PacifiCorp's initial levelized annual fixed charge rate for Cholla Project will be determined annually in accordance with Section A5 of this Appendix multiplied by the Initial Net Book investment in the Cholla Project as of December 31, 1995. For purposes of this section, PacifiCorp's Initial Net Book investment in Cholla Project is the sum of PacifiCorp's initial investment of $221,000,000, less book depreciation, plus PacifiCorp's investments in capital additions, and replacement (less credit for net salvage and insurance proceeds, if any) less associated depreciation. Such total Initial Net Book investment shall remain constant through the term of the Agreement.

A4.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A5, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Cholla Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1996.

A4.3 All ad valorem taxes imposed upon the Cholla Project.

A4.4 Any tax, assessment, payment in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Cholla Project, excluding ad valorem taxes, state and federal income taxes.

A4.5 Administrative and General Expense shall be the greater of the amount of Administrative and General Expense charged by APS to PacifiCorp associated with PacifiCorp's investment in the Cholla Project, or an amount equal to the product of 1) the quotient of total PacifiCorp Administrative and General Expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Cholla Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A5: Elements of Cholla Project

Levelized Annual Fixed Charge Rates

A5.1 Capital Structure

A5.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Cholla Project is:

Long-Term Debt and Pollution Control Revenue Bonds	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

A5.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A5.2 Cost of Capital

A5.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be ten percent (10.00%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Cholla Project, in the most recent twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A5.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be nine and five-tenths percent (9.5%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A5.2.3 Common Stock Equity: For pricing purposes only, the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's the then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A5.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a twenty-five (25)-year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A5.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, that subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A5.4.1 The federal corporate income tax rate (46%) up through 1986, 40% in 1987, and 34% in 1988 and thereafter.

A5.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three (3)-factor formula for unitary allocation of state taxable income taxed upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A5.4.3 Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax Reform Act of 1986 shall be used in calculating subsequent levelized annual fixed charge rate.

A5.4.4 Investment Tax Credits shall be zero (0) in calculating each initial levelized annual fixed charge rate and Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

A5.4.5 Tax basis shall be one hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Section A6: Determination of Hunter #2

Project Annual Fixed Cost

Hunter #2 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A6.1 through A6.5, and (b) dividing the total by 235 MW ("Net Hunter #2 Capacity"), provided that, in the event the capacity of the Hunter #2 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #2 Capacity will be adjusted to reflect such change. The costs referred to above are:

A6.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 Project determined annually in accordance with Section A7 of this Appendix, multiplied by the total investment in the Hunter #2 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #2 Project is $174,355,375. Such total investment shall remain constant through the term of the Agreement.

A6.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A7, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any amounts incurred by PacifiCorp prior to January 1, 1990.

A6.3 All ad valorem taxes imposed upon the Hunter #2 Project.

A6.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #2 Project, excluding ad valorem taxes, state and federal income taxes.

A6.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #2 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A7: Elements of Hunter #2 Project's

Levelized Annual Fixed Charge Rates

A7.1 Capital Structure:

A7.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A7.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A7.2 Cost of Capital:

A7.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eleven and ninety-seven hundredths percent (11.97%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 Project, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A7.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be ten and ninety-six hundredths percent (10.96%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A7.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A7.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35)-year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A7.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

A7.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A7.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A7.4.3 Sum of the Years Digits method of tax depreciation shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A7.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A7.4.5 Tax basis will be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Section A8: Determination of Hunter #3

Project Annual Fixed Cost

Hunter #3 Project Annual Fixed Cost shall be determined by (a) adding the amounts calculated under Sections A8.1 through A8.5, and (b) dividing the total by 400 MW ("Net Hunter #3 Capacity"), provided that, in the event the capacity of the Hunter #3 Project increases or decreases as a result of additions, replacements or betterments the Net Hunter #3 Capacity will be adjusted to reflect such change. The costs referred to above are:

A8.1 PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 Project determined annually in accordance with Section A9 of this Appendix, multiplied by the total investment in the Hunter #3 Project as of December 31, 1989. For the purposes of this section, PacifiCorp's total investment in Hunter #3 Project is $453,116,692. Such total investment shall remain constant through the term of the Agreement.

A8.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, as calculated in accordance with Section A9, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from PacifiCorp's general accounting records, the required portions of which shall be provided by PacifiCorp each year, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

A8.3 All ad valorem taxes imposed upon the Hunter #3 Project.

A8.4 Any tax, assessment, payment, in lieu of taxes, or other charge imposed by any governmental body assessed or charged against PacifiCorp relating to the Hunter #3 Project, excluding ad valorem taxes, state and federal income taxes.

A8.5 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total investment in the Hunter #3 Project as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

Section A9: Elements of Hunter #3 Project's

Levelized Annual Fixed Charge Rates

A9.1 Capital Structure:

A9.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total Capital	100%

A9.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total Capital	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

A9.2 Cost of Capital:

A9.2.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be fourteen and fifty-two hundredths percent (14.52%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #3 Project, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

A9.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eleven and six-tenths percent (11.6%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

A9.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

A9.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a thirty-five (35)-year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment.

A9.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change.

A9.4.1 The federal corporate income tax rate, 46% up through 1986, 40% in 1987 and 34% in 1988 and thereafter.

A9.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

A9.4.3 Accelerated Cost Recovery System (ACRS) method of tax depreciation in accordance with the Tax Equity and Fiscal Responsibility Act of 1982 shall be used in calculating each initial levelized annual fixed charge rate and the Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating subsequent levelized annual fixed charge rates.

A9.4.4 Regular Investment Tax Credits allowed in accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits.

A9.4.5 Tax basis will be ninety-five percent (95%) of the book basis in calculating each initial levelized annual fixed charge rate and one-hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate. Such amounts will be adjusted for allowed Regular Investment Tax Credits.

Colstrip Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Colstrip Project

Colstrip Initial Project Investment		$195,862,376
Initial Levelized Annual Fixed Rate		13.02%
Initial Levelized Annual Fixed Charge		$25,499,323
Subsequent Investment - (1990 thru 1995)		$5,949,810
Subsequent Levelized Annual Fixed Rate		13.02%
Subsequent Levelized Annual Fixed Charge		$774,665
Ad Valorem Tax		$1,086,608
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Colstrip A & G Expense		$3,773,328
Total Fixed Cost		$31,133,924
Net Colstrip Capacity		140
Annual Fixed Cost per MW		$222,385
Monthly Fixed Cost per kW		$\boxed{\$18.53}$

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

52%	DEBT FINANCING @ 9.886%	$814	LEVELIZED DEFERRED TAXES	15	YEAR TAX LIFE - ACRS
12%	PREFERRED EQUITY @ 13.3%	$3,217	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
36%	COMMON EQUITY @ 12.36%	$999	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
11.19%	WEIGHTED COST OF CAPITAL	$2,784	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11467	CAPITAL RECOVERY FACTOR	10%	INVESTMENT TAX CREDIT (ITC)
$13,019	LEVELIZED ANNUAL COST	1985	IN SERVICE DATE	95%	ITC BASIS ADJUSTMENT
$13,019	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	75%	TAX BASIS (% OF ORIGINAL COST)
$2,148	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE - STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1985	0	0	0	2,857	4,861	1,509	4,208	718	5,384	19,557	17,589	3,563	94,559
1986	0	0	0	2,857	4,450	1,382	3,852	2,461	3,209	18,210	14,730	7,125	86,567
1987	0	0	0	2,857	4,204	1,105	3,639	1,835	2,394	16,234	11,810	6,413	81,776
1988	0	0	0	2,857	3,987	1,238	3,451	1,321	1,850	14,704	9,621	5,700	77,556
1989	0	0	0	2,857	3,790	1,177	3,280	1,058	1,978	14,140	8,321	4,988	73,723
1990	0	0	0	2,857	3,600	1,118	3,116	1,058	1,847	13,595	7,196	4,988	70,022
1991	0	0	0	2,857	3,416	1,061	2,957	795	1,984	13,070	6,222	4,275	66,453
1992	0	0	0	2,857	3,219	1,006	2,804	795	1,862	12,564	5,379	4,275	63,015
1993	0	0	0	2,857	3,063	951	2,651	795	1,741	12,058	4,643	4,275	59,577
1994	0	0	0	2,857	2,886	896	2,498	795	1,619	11,551	4,001	4,275	56,139
1995	0	0	0	2,857	2,709	841	2,345	795	1,498	11,045	3,440	4,275	52,701
1996	0	0	0	2,857	2,532	786	2,192	795	1,376	10,539	2,953	4,275	49,263
1997	0	0	0	2,857	2,356	731	2,039	795	1,255	10,033	2,528	4,275	45,824
1998	0	0	0	2,857	2,179	676	1,886	795	1,133	9,527	2,159	4,275	42,386
1999	0	0	0	2,857	2,002	622	1,733	795	1,012	9,021	1,839	4,275	38,948
2000	0	0	0	2,857	1,866	579	1,615	(781)	2,495	8,631	1,582	0	36,299
2001	0	0	0	2,857	1,770	550	1,532	(781)	2,429	8,357	1,378	0	34,437
2002	0	0	0	2,857	1,675	520	1,449	(781)	2,364	8,083	1,199	0	32,576
2003	0	0	0	2,857	1,579	490	1,367	(781)	2,298	7,809	1,041	0	30,714
2004	0	0	0	2,857	1,483	460	1,284	(781)	2,232	7,535	904	0	28,853
2005	0	0	0	2,857	1,388	431	1,201	(781)	2,166	7,261	783	0	26,991
2006	0	0	0	2,857	1,292	401	1,118	(781)	2,101	6,987	678	0	25,130
2007	0	0	0	2,857	1,196	371	1,035	(781)	2,035	6,713	586	0	23,268
2008	0	0	0	2,857	1,100	342	953	(781)	1,969	6,439	505	0	21,407
2009	0	0	0	2,857	1,005	312	870	(781)	1,903	6,165	435	0	19,545
2010	0	0	0	2,857	909	282	787	(781)	1,838	5,891	374	0	17,684
2011	0	0	0	2,857	813	253	704	(781)	1,772	5,617	321	0	15,822
2012	0	0	0	2,857	718	223	621	(781)	1,706	5,343	274	0	13,961
2013	0	0	0	2,857	622	193	538	(781)	1,640	5,069	234	0	12,100
2014	0	0	0	2,857	526	163	456	(781)	1,574	4,795	199	0	10,238
2015	0	0	0	2,857	431	134	373	(781)	1,509	4,522	169	0	8,377
2016	0	0	0	2,857	335	104	290	(781)	1,443	4,248	143	0	6,515
2017	0	0	0	2,857	239	74	207	(781)	1,377	3,974	120	0	4,654
2018	0	0	0	2,857	144	45	124	(781)	1,311	3,700	101	0	2,792
2019	0	0	0	2,852	48	15	41	(781)	1,246	3,426	84	0	931
TOTAL	0	0	0	100,000	68,411	21,240	59,215	0	67,549	316,416	113,541	71,250	
1985 NET PRESENT VALUE @ 11.19%													
	0	0	0	24,912	28,054	8,710	24,282	7,092	20,481	113,541	64,475	35,376	

PACIFICORP ELECTRIC OPERATIONS
COLSTRIP PROJECT

AUGUST 27, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1985	100,000	(2,857)	(7,500)	214	0	(738)	0	89,119	(175)	48.36%	5.000%	2.86%
1986	89,119	(2,857)	0	214	0	(2,461)	0	84,015	(584)	48.36%	10.000%	2.86%
1987	84,015	(2,857)	0	214	0	(1,865)	31	79,537	(251)	42.62%	9.000%	2.86%
1988	79,537	(2,857)	0	214	0	(1,351)	31	75,574	0	36.88%	8.000%	2.86%
1989	75,574	(2,857)	0	214	0	(1,089)	31	71,873	0	36.88%	7.000%	2.86%
1990	71,873	(2,857)	0	214	0	(1,089)	31	68,172	0	36.88%	7.000%	2.86%
1991	68,172	(2,857)	0	214	0	(826)	31	64,734	0	36.88%	6.000%	2.86%
1992	64,734	(2,857)	0	214	0	(826)	31	61,296	0	36.88%	6.000%	2.86%
1993	61,296	(2,857)	0	214	0	(826)	31	57,858	0	36.88%	6.000%	2.86%
1994	57,858	(2,857)	0	214	0	(826)	31	54,420	0	36.88%	6.000%	2.86%
1995	54,420	(2,857)	0	214	0	(826)	31	50,982	0	36.88%	6.000%	2.86%
1996	50,982	(2,857)	0	214	0	(826)	31	47,544	0	36.88%	6.000%	2.86%
1997	47,544	(2,857)	0	214	0	(826)	31	44,105	0	36.88%	6.000%	2.86%
1998	44,105	(2,857)	0	214	0	(826)	31	40,667	0	36.88%	6.000%	2.86%
1999	40,667	(2,857)	0	214	0	(826)	31	37,229	0	36.88%	6.000%	2.86%
2000	37,229	(2,857)	0	214	0	751	31	35,368	0	36.88%	6.000%	2.86%
2001	35,368	(2,857)	0	214	0	751	31	33,506	0	36.88%	0.000%	2.86%
2002	33,506	(2,857)	0	214	0	751	31	31,645	0	36.88%	0.000%	2.86%
2003	31,645	(2,857)	0	214	0	751	31	29,783	0	36.88%	0.000%	2.86%
2004	29,783	(2,857)	0	214	0	751	31	27,922	0	36.88%	0.000%	2.86%
2005	27,922	(2,857)	0	214	0	751	31	26,060	0	36.88%	0.000%	2.86%
2006	26,060	(2,857)	0	214	0	751	31	24,199	0	36.88%	0.000%	2.86%
2007	24,199	(2,857)	0	214	0	751	31	22,338	0	36.88%	0.000%	2.86%
2008	22,338	(2,857)	0	214	0	751	31	20,476	0	36.88%	0.000%	2.86%
2009	20,476	(2,857)	0	214	0	751	31	18,615	0	36.88%	0.000%	2.86%
2010	18,615	(2,857)	0	214	0	751	31	16,753	0	36.88%	0.000%	2.86%
2011	16,753	(2,857)	0	214	0	751	31	14,892	0	36.88%	0.000%	2.86%
2012	14,892	(2,857)	0	214	0	751	31	13,030	0	36.88%	0.000	2.86%
2013	13,030	(2,857)	0	214	0	751	31	11,169	0	36.88%	0.000%	2.86%
2014	11,169	(2,857)	0	214	0	751	31	9,307	0	36.88%	0.000%	2.86%
2015	9,307	(2,857)	0	214	0	751	31	7,446	0	36.88%	0.000%	2.86%
2016	7,446	(2,857)	0	214	0	751	31	5,584	0	36.88%	0.000%	2.86%
2017	5,584	(2,857)	0	214	0	751	31	3,723	0	36.88%	0.000%	2.86%
2018	3,723	(2,857)	0	214	0	751	31	1,861	0	36.88%	0.000%	2.86%
2019	1,861	(2,857)	0	214	0	751	31	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(2,500)	2,500	0	(1,010)	1,010		(1,010)		100.000%	100.00%

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n -1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = $0.1119\ (1 + 0.1119)^{35}/((1 + 0.1119)^{35} - 1)$ = 0.114701

(*2) BOOK DEPRECIATION = \$100,000/35 Years = \$2,857

(*3) TOTAL RETURN, (TR) = $A \times W_s$
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Commonm Stock
Let A = $(R_o + R_1)\ /2$
Where R_o = Rate Base (Year 0)
R_1 = Rate base (End of Year 1)
Let R_1 = $I_b + I_c/L_g - D - T$
I_c = Cumulative ITC (*9)
L_g = Book Life (35 years)
D = Cumulative Book Depreciation (*2)
T = Cumulative Deferred Tax (*5)
I_b = $E \times (1 - I_r \times I_s$ ITC Basis)
Where E = Capital Expenditure (\$100,000)
I_r = ITC Rate (0.10)

Therefore, I_b = \$100,000 (1-0.1 x 0.75) = \$92,500
R_1 = \$92,500 + \$7,500/35 - \$2,857 - \$738 = \$89,119
A = (\$100,000 + \$89,119) /2 = \$94,560
TR = \$94,560 x (.12 x .133 + .36 x .1236) = \$5,717

(*4) INTEREST, (I) = $A \times W_d$
Where W_d = Weighted Cost of Debtn
Therefore, I = \$94,562 x (.52 x .09886) = \$4,861

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R + B_a / L_g \times T_r$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
B_a = Basis Adjustment
Let B_a = \$100,000 $T_b \times I_s \times$ \$100,000

COLSTRIP PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment $= 1 - I_r/2 = 1 - 0.1/2 = 0.95$

T_b = Tax Basis (75%)

Therefore, B_a = \$100,000 - 0.75 x 0.95 x \$100,000 \$28,750

T = (\$3,563 - \$2,857) x .4836 + \$28,750/35 x .4836

T = \$738

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1-Tax rate))

INCOME TAX = (\$5,717 + \$2,857 + \$738 - \$3,563) x (.4836/(1-.4836)) = \$5,384

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = \$2,857 + \$5,717 + \$4,861 + \$738 + \$5,384 = \$19,557

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis

TAX DEPRECIATION = 5% x 0.95 x 0.75 x \$100,000 = \$3,563

(*9) ITC = IT Credit x ITC Basis x Cumulative Book

ITC = 10% x 75% x \$100,000 = \$7,500

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$

PRESENT WORTH ANNUAL COST = \$19,551 x $1/(1 + .1119)^1$ = \$17,589

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.114701 x \$113,541)/\$100,000 = 0.1302 = 13.02%

Cholla Project Annual Fixed Cost

(Estimated 1996 Price)

Initial Levelized Fixed Charge

Cholla Project

Cholla Initial Project Investment - Without Betterments		$184,166,667 /1
Initial Levelized Annual Fixed Rate		13.76%
Initial Levelized Annual Fixed Charge		$25,346,858
Subsequent Investment - Includes Betterments 1991 - 1995		$5,619,840 /2
Subsequent Levelized Annual Fixed Rate		13.76%
Subsequent Levelized Annual Fixed Charge		$773,459
Ad Valorem Tax		$1,897,865
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Cholla A & G Expense		$3,548,481
Total Fixed Cost		$31,566,664
Net Cholla Capacity		350
Annual Fixed Cost per MW		$90,190
Monthly Fixed Cost per kW		$\boxed{\$7.52}$

/1 - $221,000,000 x (25/30) = $184,166,667
/2 - $6,743,810 x (25/30) = $5,619,840

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC - 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

48%	DEBT FINANCING @ 10%	$145	LEVELIZED DEFERRED TAXES	20	YEAR TAX LIFE - MODIFIED ACRS
6%	PREFERRED EQUITY @ 9.5%	$3,186	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
46%	COMMON EQUITY @ 12.36%	$378	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
11.06%	WEIGHTED COST OF CAPITAL	$3,773	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.11922	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13,763	LEVELIZED ANNUAL COST	1996	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,763	LEVELIZED FIXED CAPITAL COSTS	25	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$2,081	LEVELIZED INCOME TAXES	25	YEAR BOOK LIFE - STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1996	0	0	0	4,000	4,706	559	5,575	(92)	3,676	18,423	16,589	3,750	98,046
1997	0	0	0	4,000	4,488	533	5,316	1,187	2,230	17,754	14,395	7,219	93,499
1998	0	0	0	4,000	4,244	504	5,027	987	2,244	17,006	12,416	6,677	88,411
1999	0	0	0	4,000	4,009	476	4,748	803	2,250	16,286	10,707	6,177	83,516
2000	0	0	0	4,000	3,782	449	4,480	632	2,248	15,592	9,230	5,713	78,799
2001	0	0	0	4,000	3,564	423	4,221	474	2,240	14,922	7,954	5,285	74,246
2002	0	0	0	4,000	3,353	398	3,971	327	2,225	14,275	6,851	4,888	69,845
2003	0	0	0	4,000	3,148	374	3,729	193	2,205	13,648	5,899	4,522	65,585
2004	0	0	0	4,000	2,947	350	3,491	170	2,074	13,033	5,072	4,462	61,404
2005	0	0	0	4,000	2,747	326	3,254	170	1,922	12,419	4,352	4,461	57,234
2006	0	0	0	4,000	2,547	302	3,017	170	1,769	11,806	3,725	4,462	53,064
2007	0	0	0	4,000	2,347	279	2,780	170	1,617	11,193	3,180	4,461	48,893
2008	0	0	0	4,000	2,147	255	2,543	170	1,464	10,579	2,707	4,462	44,723
2009	0	0	0	4,000	1,947	231	2,306	170	1,312	9,966	2,296	4,461	40,553
2010	0	0	0	4,000	1,746	207	2,069	170	1,159	9,352	1,940	4,462	36,383
2011	0	0	0	4,000	1,546	184	1,831	170	1,007	8,739	1,632	4,461	32,213
2012	0	0	0	4,000	1,346	160	1,594	170	855	8,125	1,367	4,462	28,042
2013	0	0	0	4,000	1,146	136	1,357	170	703	7,512	1,138	4,461	23,8[illegible]
2014	0	0	0	4,000	946	112	1,120	170	550	6,898	941	4,462	19,[illegible]
2015	0	0	0	4,000	746	89	883	170	398	6,285	772	4,461	15,532
2016	0	0	0	4,000	565	67	669	(652)	1,083	5,732	634	2,231	11,773
2017	0	0	0	4,000	424	50	502	(1,475)	1,798	5,300	528	0	8,837
2018	0	0	0	4,000	303	36	359	(1,475)	1,706	4,929	442	0	6,312
2019	0	0	0	4,000	182	22	215	(1,475)	1,614	4,557	368	0	3,787
2020	0	0	0	4,000	61	7	72	(1,475)	1,521	4,186	304	0	1,262
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
2024	0	0	0	0	0	0	0	0	0	0	0	0	0
2025	0	0	0	0	0	0	0	0	0	0	0	0	0
2026	0	0	0	0	0	0	0	0	0	0	0	0	0
2027	0	0	0	0	0	0	0	0	0	0	0	0	0
2028	0	0	0	0	0	0	0	0	0	0	0	0	0
2029	0	0	0	0	0	0	0	0	0	0	0	0	0
2030	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	54,986	6,530	65,130	0	41,870	268,516	115,437	100,000	
1996 NET PRESENT VALUE @ 11.06%	0	0	0	33,551	26,719	3,173	31,649	2,894	17,452	115,437	66,600	41,397	

PACIFICORP ELECTRIC OPERATIONS
CHOLLA PROJECT
1996 LFC - 25 YEAR REMAINING LIFE
SEPTEMBER 4, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1996	100,000	(4,000)	0	0	0	92	0	96,092	0	36.88%	3.750%	4.00%
1997	96,092	(4,000)	0	0	0	(1,187)	0	90,905	0	36.88%	7.219%	4.00%
1998	90,905	(4,000)	0	0	0	(987)	0	85,918	0	36.88%	6.677%	4.00%
1999	85,918	(4,000)	0	0	0	(803)	0	81,115	0	36.88%	6.177%	4.00%
2000	81,115	(4,000)	0	0	0	(632)	0	76,483	0	36.88%	5.713%	4.00%
2001	76,483	(4,000)	0	0	0	(474)	0	72,009	0	36.88%	5.285%	4.00%
2002	72,009	(4,000)	0	0	0	(327)	0	67,682	0	36.88%	4.888%	4.00%
2003	67,682	(4,000)	0	0	0	(193)	0	63,489	0	36.88%	4.522%	4.00%
2004	63,489	(4,000)	0	0	0	(170)	0	59,319	0	36.88%	4.462%	4.00%
2005	59,319	(4,000)	0	0	0	(170)	0	55,149	0	36.88%	4.461%	4.00%
2006	55,149	(4,000)	0	0	0	(170)	0	50,978	0	36.88%	4.462%	4.00%
2007	50,978	(4,000)	0	0	0	(170)	0	46,808	0	36.88%	4.461%	4.00%
2008	46,808	(4,000)	0	0	0	(170)	0	42,638	0	36.88%	4.462%	4.00%
2009	42,638	(4,000)	0	0	0	(170)	0	38,468	0	36.88%	4.461%	4.00%
2010	38,468	(4,000)	0	0	0	(170)	0	34,298	0	36.88%	4.462%	4.00%
2011	34,298	(4,000)	0	0	0	(170)	0	30,128	0	36.88%	4.461%	4.00%
2012	30,128	(4,000)	0	0	0	(170)	0	25,957	0	36.88%	4.462%	4.00%
2013	25,957	(4,000)	0	0	0	(170)	0	21,787	0	36.88%	4.461%	4.00%
2014	21,787	(4,000)	0	0	0	(170)	0	17,617	0	36.88%	4.462%	4.00%
2015	17,617	(4,000)	0	0	0	(170)	0	13,447	0	36.88%	4.461%	4.00%
2016	13,447	(4,000)	0	0	0	652	0	10,099	0	36.88%	2.231%	4.00%
2017	10,099	(4,000)	0	0	0	1,475	0	7,574	0	36.88%	0.000%	4.00%
2018	7,574	(4,000)	0	0	0	1,475	0	5,050	0	36.88%	0.000%	4.00%
2019	5,050	(4,000)	0	0	0	1,475	0	2,525	0	36.88%	0.000%	4.00%
2020	2,525	(4,000)	0	0	0	1,475	0	0	0	36.88%	0.000%	4.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2024	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2025	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2026	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2027	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2028	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2029	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2030	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = $0.1106\ (1 + 0.1106)^{25}/((1 + 0.1106)^{25} - 1)$ = 0.119261

(*2) BOOK DEPRECIATION = $100,000/25 Years = $4,000

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = $(R_o + R_1)$ /2
Where R_o = Rate Base (Year 0)
R_1 = Rate base (End of Year 1)
Let R_1 = $I_b + I_c/L_g - D - T$
I_c = Cumulative ITC (*9)
L_g = Book Life (25 years)
D = Cumulative Book Depreciation (*2)
T = Cumulative Deferred Tax (*5)
I_b = E x (1 - I_r x I_s ITC Basis)
Where E = Capital Expenditure ($100,000)
I_r = ITC Rate (0.10)

Therefore, I_b = $100,000 (1-0.1 x 0) = $100,000
R_1 = $100,000 + 0/25 - $4,000 - ($92) = $96,092
A = ($100,000 + $96,092) /2 = $98,046
TR = $98,046 x (.06 x .095 + .46 x .1236) = $6,133

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore, I = $98,046 x (.48 x .10) = $4,706

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R + B_a / L_g \times T_r$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (36.88%)
B_a = Basis Adjustment
Let B_a = $100,000 T_b x I_a x $100,000

CHOLLA PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = 1- $I_r/2$ = 1 - 0.0/2 = 0

T_b = Tax Basis (100%)

Therefore, B_a = \$100,000 - 1 x 1.00 x \$100,000 = 0

T = (\$3,750 - \$4,000) x 36.88 + 0/25 x 36.88

T = (\$92)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1-Tax rate))

INCOME TAX = (\$6,133 + \$4,000 + (\$92) - \$3,750) x (.3688/(1-.3688)) = \$3,675

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = \$4,000 + \$6,133 + \$4,706 + (\$92) + \$3,675 = \$18,423

(*8) TAX DEPRECIATION = (150% Declining Balance converting to Straight Line) x (1/2 yr. amort. in 1st year)

TAX DEPRECIATION = 1.50 x (\$100,000/20) /2 = \$3,750

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$

PRESENT WORTH ANNUAL COST = \$18,423 x $1/(1 + .1106)^1$ = \$16,589

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.119261 x \$115,437)/\$100,000 = 0.1376 = <u>13.76%</u>

Hunter #2 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(Estimated 1996 Price)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Initial Project Investment		$174,355,375
Initial Levelized Annual Fixed Rate		13.67%
Initial Levelized Annual Fixed Charge		$23,827,406
Subsequent Investment - (1990 thru 1995)		$5,296,480
Subsequent Levelized Annual Fixed Rate		13.67%
Subsequent Levelized Annual Fixed Charge		$724,029
Ad Valorem Tax		$2,160,314
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$3,358,992
Total Fixed Cost		$30,070,740
Net Hunter #2 Capacity		235
Annual Fixed Cost per MW		$127,961
Monthly Fixed Cost per kW		$\boxed{\$10.66}$

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

50%	DEBT FINANCING @ 11.97%	$1,187	LEVELIZED DEFERRED TAXES	22.5	YEAR TAX LIFE - SUM OF THE YEAR DIGITS
10%	PREFERRED EQUITY @ 10.96%	$3,966	LEVELIZED INTEREST EXPENSE	48.36%	TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40%	COMMON EQUITY @ 12.36%	$726	LEVELIZED PREFERRED RETURN	42.62%	TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
12.03%	WEIGHTED COST OF CAPITAL	$3,276	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.12255	CAPITAL RECOVERY FACTOR	10.00%	INVESTMENT TAX CREDIT (ITC)
$13,666	LEVELIZED ANNUAL COST	1980	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,666	LEVELIZED FIXED CAPITAL COSTS	35	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$1,939	LEVELIZED INCOME TAXES	35	YEAR BOOK LIFE - STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1980	0	0	0	2,857	5,879	1,077	4,857	676	4,612	19,672	17,560	4,255	98,233
1981	0	0	0	2,857	5,609	1,027	4,633	2,646	2,387	18,873	15,039	8,329	93,715
1982	0	0	0	2,857	5,285	968	4,366	2,461	2,266	17,917	12,744	7,946	88,305
1983	0	0	0	2,857	4,972	911	4,107	2,277	2,155	16,993	10,790	7,565	83,079
1984	0	0	0	2,857	4,670	855	3,858	2,095	2,051	16,101	9,126	7,190	78,036
1985	0	0	0	2,857	4,379	802	3,618	1,913	1,958	15,242	7,712	6,814	73,174
1986	0	0	0	2,857	4,100	751	3,386	1,729	1,878	14,414	6,510	6,432	68,496
1987	0	0	0	2,857	3,836	702	3,169	1,362	1,301	12,942	5,218	6,052	64,094
1988	0	0	0	2,857	3,593	658	2,968	1,040	912	11,743	4,226	5,676	60,036
1989	0	0	0	2,857	3,364	616	2,779	900	917	11,147	3,581	5,297	56,209
1990	0	0	0	2,857	3,143	576	2,597	761	925	10,574	3,032	4,921	52,522
1991	0	0	0	2,857	2,931	537	2,421	621	941	10,022	2,565	4,540	48,974
1992	0	0	0	2,857	2,727	499	2,253	482	959	9,492	2,169	4,164	45,565
1993	0	0	0	2,857	2,531	464	2,091	342	984	8,983	1,832	3,784	42,296
1994	0	0	0	2,857	2,344	429	1,936	202	1,013	8,497	1,547	3,406	39,167
1995	0	0	0	2,857	2,165	397	1,789	63	1,047	8,032	1,305	3,027	36,177
1996	0	0	0	2,857	1,995	365	1,648	(93)	1,077	7,563	1,097	2,649	33,335
1997	0	0	0	2,857	1,835	336	1,516	(263)	1,104	7,099	919	2,270	30,6[illegible]
1998	0	0	0	2,857	1,685	308	1,392	(432)	1,138	6,661	770	1,892	28,[illegible]
1999	0	0	0	2,857	1,545	283	1,276	(602)	1,177	6,250	645	1,514	25,807
2000	0	0	0	2,857	1,415	259	1,169	(771)	1,223	5,865	540	1,135	23,636
2001	0	0	0	2,857	1,295	237	1,070	(941)	1,274	5,506	453	757	21,635
2002	0	0	0	2,857	1,185	217	979	(1,111)	1,332	5,174	380	378	19,804
2003	0	0	0	2,857	1,086	199	897	(1,280)	1,395	4,868	319	0	18,142
2004	0	0	0	2,857	991	182	819	(1,280)	1,339	4,623	270	0	16,364
2005	0	0	0	2,857	897	164	741	(1,280)	1,284	4,377	229	0	14,98[illegible]
2006	0	0	0	2,857	803	147	663	(1,280)	1,228	4,132	193	0	13,41[illegible]
2007	0	0	0	2,857	708	130	585	(1,280)	1,172	3,887	162	0	11,832
2008	0	0	0	2,857	614	112	507	(1,280)	1,117	3,641	135	0	10,359
2009	0	0	0	2,857	519	95	429	(1,280)	1,061	3,396	113	0	8,67[illegible]
2010	0	0	0	2,857	425	78	351	(1,280)	1,005	3,151	93	0	7,10[illegible]
2011	0	0	0	2,857	331	61	273	(1,280)	950	2,905	77	0	5,521
2012	0	0	0	2,857	236	43	195	(1,280)	894	2,660	63	0	3,948
2013	0	0	0	2,857	142	26	117	(1,280)	838	2,415	51	0	2,369
2014	0	0	0	2,857	47	9	39	(1,280)	783	2,169	41	0	291
TOTAL	0	0	0	100,000	79,283	14,519	65,493	0	47,694	296,986	111,507	99,993	
1980 NET PRESENT VALUE @ 12.03%													
	0	0	0	23,314	32,358	5,925	26,730	9,689	15,823	111,507	111,507	44,160	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 PROJECT

AUGUST 28, 1990

			INVESTMENT TAX CREDIT			DEFERRED TAXES						
YEAR	BEGINNING RATE BASE	BOOK DEPREC	CREDIT	RESTORED	RECAPTURE	CURRENT	RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1980	100,000	(2,857)	(286)	286	0	(676)	0	96,467	(160)	48.36%	4.255%	2.86%
1981	96,467	(2,857)	(286)	286	0	(2,646)	0	90,964	(628)	48.36%	8.329%	2.86%
1982	90,964	(2,857)	(286)	286	0	(2,461)	0	85,646	(584)	48.36%	7.946%	2.86%
1983	85,646	(2,857)	(286)	286	0	(2,277)	0	80,512	(540)	48.36%	7.565%	2.86%
1984	80,512	(2,857)	(286)	286	0	(2,095)	0	75,560	(497)	48.36%	7.190%	2.86%
1985	75,560	(2,857)	(286)	286	0	(1,913)	0	70,789	(454)	48.36%	6.814%	2.86%
1986	70,789	(2,857)	(286)	286	0	(1,729)	0	66,203	(410)	48.36%	6.432%	2.86%
1987	66,203	(2,857)	(286)	286	0	(1,362)	0	61,985	(183)	42.62%	6.052%	2.86%
1988	61,985	(2,857)	(286)	286	0	(1,040)	0	58,088	0	36.88%	5.676%	2.86%
1989	58,088	(2,857)	(286)	286	0	(900)	0	54,331	0	36.88%	5.297%	2.86%
1990	54,331	(2,857)	(286)	286	0	(761)	0	50,713	0	36.88%	4.921%	2.86%
1991	50,713	(2,857)	(286)	286	0	(621)	0	47,235	0	36.88%	4.540%	2.86%
1992	47,235	(2,857)	(286)	286	0	(482)	0	43,896	0	36.88%	4.164%	2.86%
1993	43,896	(2,857)	(286)	286	0	(342)	0	40,697	0	36.88%	3.784%	2.86%
1994	40,697	(2,857)	(286)	286	0	(202)	0	37,637	0	36.88%	3.406%	2.86%
1995	37,637	(2,857)	(286)	286	0	(63)	0	34,717	0	36.88%	3.027%	2.86%
1996	34,717	(2,857)	(286)	286	0	77	16	31,954	0	36.88%	2.649%	2.86%
1997	31,954	(2,857)	(286)	286	0	217	46	29,359	0	36.88%	2.270%	2.86%
1998	29,359	(2,857)	(286)	286	0	356	76	26,935	0	36.88%	1.892%	2.86%
1999	26,935	(2,857)	(286)	286	0	495	106	24,679	0	36.88%	1.514%	2.86%
2000	24,679	(2,857)	(286)	286	0	635	136	22,593	0	36.88%	1.135%	2.86%
2001	22,593	(2,857)	(286)	286	0	775	166	20,677	0	36.88%	0.757%	2.86%
2002	20,677	(2,857)	(286)	286	0	914	196	18,930	0	36.88%	0.378%	2.86%
2003	18,930	(2,857)	(286)	286	0	1,054	226	17,353	0	36.88%	0.000%	2.86%
2004	17,353	(2,857)	(286)	286	0	1,054	226	15,776	0	36.88%	0.000%	2.86%
2005	15,776	(2,857)	(286)	286	0	1,054	226	14,198	0	36.88%	0.000%	2.86%
2006	14,198	(2,857)	(286)	286	0	1,054	226	12,621	0	36.88%	0.000%	2.86%
2007	12,621	(2,857)	(286)	286	0	1,054	226	11,044	0	36.88%	0.000%	2.86%
2008	11,044	(2,857)	(286)	286	0	1,054	226	9,466	0	36.88%	0.000%	2.86%
2009	9,466	(2,857)	(286)	286	0	1,054	226	7,889	0	36.88%	0.000%	2.86%
2010	7,889	(2,857)	(286)	286	0	1,054	226	6,312	0	36.88%	0.000%	2.86%
2011	6,312	(2,857)	(286)	286	0	1,054	226	4,735	0	36.88%	0.000%	2.86%
2012	4,735	(2,857)	(286)	286	0	1,054	226	3,157	0	36.88%	0.000%	2.86%
2013	3,157	(2,857)	(286)	286	0	1,054	226	1,580	0	36.88%	0.000%	2.86%
2014	1,580	(2,857)	(286)	286	0	1,054	226	3	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(3,455)	3,458		(3,458)		99.990%	100.00%

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n -1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = $0.1203\ (1 + 0.1203)^{35}/((1 + 0.1203)^{35} - 1)$ = 0.12260

(*2) BOOK DEPRECIATION = $100,000/35 Years = $2,857

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Commonm Stock
Let A = Beginning Investment - (D+T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = $100,000
A = $100,000 - (2857 + 676) /2 = $98,234
TR = $98,234 x (.10 x .1096 + .40 x .1236) = $5,933

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore, I = $98,234 x (.50 x .1197) = $5,879

(*5) DEFERRED TAX, (T) = $(T_d - D) \times T_R$
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
Let T = (4,255 - 2,857) x .4836 = $676

HUNTER #2 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1-Tax rate)

INCOME TAX = ($5,933 + $2,857 + $676 - $4,255 - $285) x (.4836/(1-.4836 = $4,612

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC

ANNUAL COST = $2,857 + $5,933 + $5,879 + $676 + $4,612 - 285 = $19,672

(*8) TAX DEPRECIATION = (Sum of the Year's Digits) = Year's remaining/sum of Digits) x (Beginning Investment - Cumulative Tax Depreciation)

Where Sum of Digits in yr. 1 = 264.5 (For 22.5 year tax life)

TAX DEPRECIATION = (22.5/264.5) x (100,000 - 0) = $8,510
Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Beginning Investment x ITC Rate/Book Life
ITC = $100,000 x 0.10/35 = $285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$
PRESENT WORTH ANNUAL COST = $19,672 x $1/(1 + .1203)^1$ = $17,560

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.1226 x $111,507)/$100,000 = 0.1367 = 13.67%

Hunter #3 Project Annual Fixed Cost

(Based on 1989 Actual Costs)
(1996 Estimated Price)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Initial Project Investment		$453,116,692
Initial Levelized Annual Fixed Rate		14.76%
Initial Levelized Annual Fixed Charge		$66,870,961
Subsequent Investment - (1990 thru 1995)		$13,764,557
Subsequent Levelized Annual Fixed Rate		14.76%
Subsequent Levelized Annual Fixed Charge		$2,031,649
Ad Valorem Tax		$5,210,051
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #3 A & G Expense		$8,729,385
Total Fixed Cost		$82,842,046
Net Hunter #3 Capacity		400
Annual Fixed Cost per MW		$207,105
Monthly Fixed Cost per kW		$17.26

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

50% DEBT FINANCING @ 14.52%	$1,329 LEVELIZED DEFERRED TAXES	15 YEAR TAX LIFE - ACRS
10% PREFERRED EQUITY @ 11.6%	$4,925 LEVELIZED INTEREST EXPENSE	48.36% TAX RATE PRIOR TO 1987 (46% FEDERAL, 4.36% STATE)
40% COMMON EQUITY @ 12.36%	$787 LEVELIZED PREFERRED RETURN	42.62% TAX RATE IN 1987 (40% FEDERAL, 4.36% STATE)
13.36% WEIGHTED COST OF CAPITAL	$3,354 LEVELIZED COMMON RETURN	36.88% TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000 CAPITAL INVESTMENT	0.13532 CAPITAL RECOVERY FACTOR	10.00% INVESTMENT TAX CREDIT (ITC)
$14,758 LEVELIZED ANNUAL COST	1983 IN SERVICE DATE	95% ITC BASIS ADJUSTMENT
$14,758 LEVELIZED FIXED CAPITAL COSTS	35 YEAR ESTIMATED LIFE	100% TAX BASIS (% OF ORIGINAL COST)
$1,792 LEVELIZED INCOME TAXES	35 YEAR BOOK LIFE - STRAIGHT LINE	100% BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1983	0	0	0	2,857	7,121	1,138	4,849	984	4,488	21,151	18,657	4,750	98,079
1984	0	0	0	2,857	6,758	1,080	4,602	3,281	1,905	20,199	15,717	9,500	93,089
1985	0	0	0	2,857	6,329	1,011	4,310	2,822	2,027	19,071	13,090	8,550	87,180
1986	0	0	0	2,857	5,934	948	4,041	2,363	2,175	18,032	10,918	7,600	81,731
1987	0	0	0	2,857	5,580	892	3,800	1,677	1,701	16,220	8,663	6,650	76,854
1988	0	0	0	2,857	5,259	840	3,581	1,452	1,048	14,751	6,950	6,650	72,432
1989	0	0	0	2,857	4,959	792	3,377	1,101	1,251	14,051	5,840	5,700	68,299
1990	0	0	0	2,857	4,671	746	3,181	1,101	1,110	13,381	4,906	5,700	64,341
1991	0	0	0	2,857	4,384	700	2,985	1,101	969	12,711	4,111	5,700	60,382
1992	0	0	0	2,857	4,096	655	2,790	1,101	828	12,041	3,435	5,700	56,424
1993	0	0	0	2,857	3,809	609	2,594	1,101	687	11,371	2,861	5,700	52,466
1994	0	0	0	2,857	3,522	563	2,398	1,101	545	10,701	2,375	5,700	48,508
1995	0	0	0	2,857	3,234	517	2,203	1,101	404	10,030	1,964	5,700	44,549
1996	0	0	0	2,857	2,947	471	2,007	1,101	263	9,360	1,617	5,700	40,591
1997	0	0	0	2,857	2,660	425	1,811	1,101	122	8,690	1,324	5,700	36,633
1998	0	0	0	2,857	2,453	392	1,670	(1,124)	2,050	8,013	1,077	0	33,787
1999	0	0	0	2,857	2,327	372	1,585	(1,124)	1,989	7,719	915	0	32,055
2000	0	0	0	2,857	2,201	352	1,499	(1,124)	1,927	7,426	777	0	30,3[illegible]
2001	0	0	0	2,857	2,076	332	1,413	(1,124)	1,865	7,133	658	0	28,5[illegible]
2002	0	0	0	2,857	1,950	312	1,328	(1,124)	1,803	6,839	557	0	26,856
2003	0	0	0	2,857	1,824	291	1,242	(1,124)	1,741	6,546	470	0	25,124
2004	0	0	0	2,857	1,698	271	1,156	(1,124)	1,680	6,253	396	0	23,391
2005	0	0	0	2,857	1,572	251	1,071	(1,124)	1,618	5,959	333	0	21,658
2006	0	0	0	2,857	1,447	231	985	(1,124)	1,556	5,666	279	0	19,926
2007	0	0	0	2,857	1,321	211	899	(1,124)	1,494	5,373	234	0	18,193
2008	0	0	0	2,857	1,195	191	814	(1,124)	1,433	5,079	195	0	16,460
2009	0	0	0	2,857	1,069	171	728	(1,124)	1,371	4,786	162	0	14,728
2010	0	0	0	2,857	943	151	642	(1,124)	1,309	4,493	134	0	12,995
2011	0	0	0	2,857	818	131	557	(1,124)	1,247	4,199	111	0	11,262
2012	0	0	0	2,857	692	111	471	(1,124)	1,185	3,906	91	0	9,530
2013	0	0	0	2,857	566	90	385	(1,124)	1,124	3,612	74	0	7,797
2014	0	0	0	2,857	440	70	300	(1,124)	1,062	3,319	60	0	6,064
2015	0	0	0	2,857	314	50	214	(1,124)	1,000	3,026	48	0	4,332
2016	0	0	0	2,857	189	30	128	(1,124)	938	2,732	38	0	2,599
2017	0	0	0	2,857	63	10	43	(1,124)	876	2,439	30	0	866
TOTAL	0	0	0	100,000	96,420	15,406	65,661	0	48,792	316,278	109,065	95,000	
1983 NET PRESENT VALUE @ 13.36%	0	0	0	21,114	36,398	5,816	24,282	9,818	13,243	109,065	109,065	42,334	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #3 PROJECT

AUGUST 28, 1990

YEAR	BEGINNING RATE BASE	BOOK DEPREC	INVESTMENT TAX CREDIT CREDIT	INVESTMENT TAX CREDIT RESTORED	INVESTMENT TAX CREDIT RECAPTURE	DEFERRED TAXES CURRENT	DEFERRED TAXES RESTORED	ENDING RATE BASE	EXCESS DEFERRED	INCOME TAX RATE	TAX DEPREC	BOOK DEPREC
1983	100,000	(2,857)	(286)	286	0	(984)	0	96,158	(234)	48.36%	5.000%	2.86%
1984	96,158	(2,857)	(286)	286	0	(3,281)	0	90,020	(779)	48.36%	10.000%	2.86%
1985	90,020	(2,857)	(286)	286	0	(2,822)	0	84,341	(670)	48.36%	9.000%	2.86%
1986	84,341	(2,857)	(286)	286	0	(2,363)	0	79,121	(561)	48.36%	8.000%	2.86%
1987	79,121	(2,857)	(286)	286	0	(1,677)	0	74,587	(226)	42.62%	7.000%	2.86%
1988	74,587	(2,857)	(286)	286	0	(1,452)	0	70,278	0	36.88%	7.000%	2.86%
1989	70,278	(2,857)	(286)	286	0	(1,101)	0	66,320	0	36.88%	6.000%	2.86%
1990	66,320	(2,857)	(286)	286	0	(1,101)	0	62,361	0	36.88%	6.000%	2.86%
1991	62,361	(2,857)	(286)	286	0	(1,101)	0	58,403	0	36.88%	6.000%	2.86%
1992	58,403	(2,857)	(286)	286	0	(1,101)	0	54,445	0	36.88%	6.000%	2.86%
1993	54,445	(2,857)	(286)	286	0	(1,101)	0	50,487	0	36.88%	6.000%	2.86%
1994	50,487	(2,857)	(286)	286	0	(1,101)	0	46,528	0	36.88%	6.000%	2.86%
1995	46,528	(2,857)	(286)	286	0	(1,101)	0	42,570	0	36.88%	6.000%	2.86%
1996	42,570	(2,857)	(286)	286	0	(1,101)	0	38,612	0	36.88%	6.000%	2.86%
1997	38,612	(2,857)	(286)	286	0	(1,101)	0	34,654	0	36.88%	6.000%	2.86%
1998	34,654	(2,857)	(286)	286	0	1,001	123	32,921	0	36.88%	0.000%	2.86%
1999	32,921	(2,857)	(286)	286	0	1,001	123	31,188	0	36.88%	0.000%	2.86%
2000	31,188	(2,857)	(286)	286	0	1,001	123	29,455	0	36.88%	0.000%	2.86%
2001	29,455	(2,857)	(286)	286	0	1,001	123	27,723	0	36.88%	0.000%	2.86%
2002	27,723	(2,857)	(286)	286	0	1,001	123	25,990	0	36.88%	0.000%	2.86%
2003	25,990	(2,857)	(286)	286	0	1,001	123	24,257	0	36.88%	0.000%	2.86%
2004	24,257	(2,857)	(286)	286	0	1,001	123	22,525	0	36.88%	0.000%	2.86%
2005	22,525	(2,857)	(286)	286	0	1,001	123	20,792	0	36.88%	0.000%	2.86%
2006	20,792	(2,857)	(286)	286	0	1,001	123	19,059	0	36.88%	0.000%	2.86%
2007	19,059	(2,857)	(286)	286	0	1,001	123	17,327	0	36.88%	0.000%	2.86%
2008	17,327	(2,857)	(286)	286	0	1,001	123	15,594	0	36.88%	0.000%	2.86%
2009	15,594	(2,857)	(286)	286	0	1,001	123	13,861	0	36.88%	0.000%	2.86%
2010	13,861	(2,857)	(286)	286	0	1,001	123	12,129	0	36.88%	0.000%	2.86%
2011	12,129	(2,857)	(286)	286	0	1,001	123	10,396	0	36.88%	0.000%	2.86%
2012	10,396	(2,857)	(286)	286	0	1,001	123	8,663	0	36.88%	0.000%	2.86%
2013	8,663	(2,857)	(286)	286	0	1,001	123	6,931	0	36.88%	0.000%	2.86%
2014	6,931	(2,857)	(286)	286	0	1,001	123	5,198	0	36.88%	0.000%	2.86%
2015	5,198	(2,857)	(286)	286	0	1,001	123	3,465	0	36.88%	0.000%	2.86%
2016	3,465	(2,857)	(286)	286	0	1,001	123	1,733	0	36.88%	0.000%	2.86%
2017	1,733	(2,857)	(286)	286	0	1,001	123	0	0	36.88%	0.000%	2.86%
TOTAL		(100,000)	(10,000)	10,000	0	(2,469)	2,469		(2,469)		100.000%	100.00%

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = 0.1336 (1 + 0.1336) ^{35}/((1 + 0.1336) ^{35} - 1) = 0.13528

(*2) BOOK DEPRECIATION = $100,000/30 Years = $2,857

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Rate Base; and
W_s = Weighted Cost of Preferred and Commonm Stock
Let A = Beginning Investment - (D+T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = $100,000
A = $100,000 - (2857 + 984) /2 = $98,080
TR = $98,080 x (.10 x .1160 + .40 x .1236) = $5,987

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore, I = $98,080 x (.50 x .1452) = $7,121

(*5) DEFERRED TAX, (T) = (T_d -D) x T_R
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (48.36%)
B^t = $100,000 - T^b x I_s x $100,000
L_B = Book Life (35 years)

HUNTER #3 PROJECT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)

Where I_a = ITC Adjustment = $1 - I_r/2 = 1 - 0.1/2 = 0.95$

I_r = ITC Rate (0.10)

T_b = Tax Basis (100%)

Therefore, B_a = \$100,000 - 1.00 x 0.95 x \$100,000
\$5,000

T = (\$4,750 - \$2,857) x .4836 + 5000/35 x .4836 = \$984

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation + ITC) x Tax rate/(1-Tax rate)

INCOME TAX = (\$5,987 + \$2,857 + \$984 - \$4,750 - \$285) x (.4836/(1-.4836 = \$4,488

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax + ITC

ANNUAL COST = \$2,857 + \$5,987 + \$7,121 + \$984 + \$4,488 - 285 = \$21,151

(*8) TAX DEPRECIATION = (ACRS Percentages 15 Year Public Utility) x Original Tax Basis

TAX DEPRECIATION = 5% x 0.95 x 1.00 x \$100,000 = \$4,750

(*9) ITC = Beginning Investment x ITC Rate/Book Life

ITC = \$100,000 x 0.10/^{35} = \$285

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$

PRESENT WORTH ANNUAL COST = \$21,151 x $1/(1 + .1336)^1$ = \$18,657

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost

INITIAL LEVELIZED FIXED CHARGE RATE = (0.13528 x \$109,065)/\$100,000 = 0.1476 = 14.76%

Annual Fixed Cost

Annual Fixed Cost

	Pool Size (mw)	Monthly Fixed Cost ($/kW/Mo.)	Weighted Average
Colstrip	70	18.53	$1,297
Cholla	350	7.52	$2,632
Hunter #2	180	10.66	$1,919
Hunter #3	400	17.26	$6,904
Total	1000	NA	$12,752

Annual Fixed Cost ,$/kW/mo.	$12.75
System Transmission Component =	$0.00
W/ System Transmission, $/kW/Mo. =	$12.75
Transmission Loss Factor =	1
Annual Fixed Cost Adjusted for Losses =	$12.75

APPENDIX B: ANNUAL VARIABLE COST

This Appendix sets forth the elements and techniques to calculate the Annual Variable Cost.

Section B1: Determination of Annual Variable Cost

The Annual Variable Cost shall be the $/MWh result of the following: (1) the product of 70 MW multiplied by the Colstrip annual load factor multiplied by the Colstrip Project Annual Variable Cost plus the product of 350 MW multiplied by the Cholla annual load factor multiplied by the Cholla Project Annual Variable Cost plus the product of 180 MW multiplied by the Hunter #2 annual load factor multiplied by the Hunter #2 Project Annual Variable Cost plus the product of 400 MW multiplied by the Hunter #3 annual load factor multiplied by the Hunter #3 Project Annual Variable Cost, (2) dividing the above sum by the total of 70 MW multiplied by the Colstrip annual load factor plus 350 MW multiplied by the Cholla annual load factor plus 180 MW multiplied by the Hunter #2 annual load factor plus 400 MW multiplied by the Hunter #3 annual load factor.

Section B2: Determination of Colstrip Project Annual Variable Cost, Cholla Project Annual Variable Cost, Hunter #2 Project Annual Variable Cost and, Hunter #3 Project Annual Variable Cost

The Colstrip Project Annual Variable Cost, the Cholla Project Annual Variable Cost, the Hunter #2 Project Annual Variable Cost and the Hunter #3 Project Annual Variable Cost shall be determined, for each Project, by (a) adding the amounts as set forth in Sections B2.1 through B2.2 (plus B2.3 for Hunter #2 and plus B2.4 for Hunter #3) and (b) dividing each Project total by PacifiCorp's share of the associated Project's annual energy production as filed with the Federal Energy Regulatory Commission (FERC) in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.1 Production Expenses shall be equal to the production expenses of resources in the Resource Pool as filed in PacifiCorp's FERC Form No. 1, or its successor thereto.

B2.2 In lieu of payments shall consist of any assessment, payment in lieu of taxes or other charge which is imposed against PacifiCorp by governmental authority and related to the operation and maintenance of each Project.

B2.3 Hunter #2 Project allocated mining expenses, to be determined by adding the amounts calculated under Sections B2.3.1 through B2.3.4 below:

B2.3.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #2 project mining investment multiplied by the Hunter #2 project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #2 project mining is $22,748,496. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #2 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #2 fuel cost.

B2.3.2 The sum of all subsequent annual levelized fixed charges, each of which shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for each year, for the Hunter #2 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #2 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.3.3 All ad valorem taxes imposed upon the Hunter #2 Project mining investment.

B2.3.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #2 Project mining investment.

B2.4 Hunter #3 Project allocated mining expenses, to be determined by adding the amounts calculated under Section B2.4.1 through B2.4.4 below:

B2.4.1 PacifiCorp's adjusted initial levelized annual fixed charge rate for the Hunter #3 Project mining investment multiplied by the Hunter #3 Project mining initial investment, determined pursuant to Section B3, as of December 31, 1989. For purposes of this section, PacifiCorp's total investment in Hunter #3 project mining is $38,720,844. Such total investment shall remain constant through the book life (14 years) and shall be $0 afterwards. Such adjusted initial levelized annual fixed charge rate shall be determined by subtracting book depreciation (1/book life) from PacifiCorp's initial levelized annual fixed charge rate for the Hunter #3 project mining investment determined annually in accordance with Section B4, below. Such book depreciation is reflected in Hunter #3 fuel cost.

B2.4.2 Each subsequent annual levelized fixed charge shall be determined by multiplying (a) PacifiCorp's subsequent levelized annual fixed charge rate for the Hunter #3 Project mining investment, as calculated in accordance with Section B4, below, by (b) the dollar investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments of the Hunter #3 Project allocated mining investment, completed during the calendar year immediately preceding establishment of such subsequent levelized annual fixed charge. Such dollar investment, to be determined from data contained in PacifiCorp's FERC Form 1 or its successor thereto, shall not include any dollar amounts incurred by PacifiCorp prior to January 1, 1990.

B2.4.3 All ad valorem taxes imposed upon the Hunter #3 Project mining investment.

B2.4.4 Administrative and General Expense shall be an amount equal to the product of 1) the quotient of total PacifiCorp administrative and general expenses to total PacifiCorp electric plant in service; and 2) the total Hunter #3 Project mining investment.

Section B3: Allocation of Mining Investment to Hunter #2 and Hunter #3 Projects

Hunter #2 mining initial investment and Hunter #3 mining initial investment shall be determined by (a) multiplying the dollar amount as set forth in Section B3.1 by (b) the ratio of PacifiCorp's share of the associated Project's capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW). Hunter #2 mining subsequent investment and Hunter #3 mining subsequent investment shall be determined by (a) multiplying the dollar amounts as set forth in Section B3.2 by (b) the ratio of PacifiCorp's share of the associated Projects capability (235 MW for Hunter #2 Project and 400 MW for Hunter #3 Project) divided by the total capability of all Projects served by the mines (presently 1995 MW).

B3.1 Gross coal plant, as reported in FERC account 399 as "Total Other Tangible Property" in PacifiCorp's FERC Form 1 as of December 31, 1989.

B3.2 Each subsequent coal mine investment in capital additions, replacements (less credit for net salvage and insurance proceeds, if any), and betterments, as determined pursuant to data contained in PacifiCorp's FERC Form 1 or its successor thereto.

Section B4: Elements of Hunter #2 and Hunter #3 Project Mining Investment
Levelized Annual Fixed Charge Rates

B4.1 Capital Structure:

B4.1.1 For purposes of calculating initial levelized annual fixed charge rates, PacifiCorp's capital structure will remain constant. The capital structure for Hunter #2 and Hunter #3 Project is:

Long Term Debt	50%
Preferred Stock	10%
Common Stock Equity	40%
Total	100%

B4.1.2 PacifiCorp's capital structure will remain constant for purposes of calculating subsequent levelized annual fixed charge rates and is as follows:

Long-Term Debt	48%
Preferred Stock	6%
Common Stock Equity	46%
Total	100%

provided, that if any part of PacifiCorp's portion of the capital additions, replacements, or betterments which occasioned a subsequent levelized annual fixed charge cost is financed by long-term debt, the interest of which is exempt from federal income taxes, the long-term debt portion of the above capital structure shall be apportioned between the long-term debt and the tax exempt long-term debt accordingly. In no case shall the long-term debt portion exceed fifty percent (50%) of total capitalization.

B4.2 Cost of Capital:

B4.2.1.1 Long-Term Debt: Bond interest applicable in the calculation of each initial levelized annual fixed charge rate will be eight and forty-seven hundredths percent (8.47%). Bond interest applicable in the calculation of each subsequent levelized annual fixed charge rate for future capital additions, replacements, or betterments shall be the effective cost rate to PacifiCorp of the most recent issue of long-term bonds, excluding special-purpose issues not related to the Hunter #2 and Hunter #3 Project Mining Investment, in the twelve (12)-month period prior to the date of the completion of construction of the capital additions, replacements or betterments for which the subsequent levelized annual fixed charge rate is calculated. In the event there are no bond issues within the said twelve (12)-month period, then an estimated bond interest rate will be used in the billings, based upon the bond rating then applicable to PacifiCorp until such time as there is a bond issue, at which time all future billings will reflect the actual cost to PacifiCorp of such bond issue. In the event such bond issue is subsequently exchanged for other bonds, the new bond rate shall be used for subsequent billings.

B4.2.2 Preferred Stock: Return on preferred stock applicable in the calculation of each initial levelized annual fixed charge rate shall be eight and twenty-four hundredths (8.24%). Return on preferred stock applicable in the calculation of subsequent levelized annual fixed charge rates for future capital additions, replacements, or betterments shall be the same as for bond interest used in calculation of subsequent annual fixed charge rate, plus fifty (50) basis points.

B4.2.3 Common Stock Equity: For pricing purposes only the component for return on common stock equity (ROE) applicable in the calculation of the initial levelized annual fixed charge rate and each subsequent levelized annual fixed charge rate for any calendar year shall be equal to PacifiCorp's then effective rate of return on common equity (ROE) which has been authorized by the FERC. From the effective date of this Agreement until the date

PacifiCorp receives an authorized return on common equity (ROE) under FERC Docket Nos. ER89-393-000 and ER89-394-000, PacifiCorp shall use an estimated ROE of twelve and thirty-six hundredths percent (12.36%) for the determination of the initial levelized fixed charge. Subsequent to PacifiCorp's receipt of an authorized (ROE) under the above dockets, PacifiCorp shall make a timely filing with the FERC for a change of rates to reflect the authorized (ROE). Upon PacifiCorp's receipt of an order under such filing, PacifiCorp shall credit or invoice APS the difference between the estimated levelized fixed charge using the estimated (ROE) and the actual levelized fixed charge using PacifiCorp's authorized (ROE). Interest at the rate set forth in Appendix D shall be applied to any credit or additional charges.

B4.3 Book Depreciation: Book depreciation charges shall be at a straight-line rate based on a fourteen (14) year life in calculating the initial levelized annual fixed charge rates. Book depreciation charges for subsequent levelized annual fixed charge rates shall be based on the estimated remaining service life of the Project including the effects on such life due to the subsequent investment. Because book depreciation is reflected in the Hunter #2 and #3 fuel cost, an adjustment is made to the initial levelized annual fixed charge rate for the Hunter #2 and #3 project mining investment, pursuant to Subsections B2.3.1 and B2.4.1.

B4.4 Income Tax Requirements: Income Tax Requirements applicable in calculating both initial and subsequent levelized annual fixed charge rates shall be based on the following items; provided, subsequent changes in tax laws shall be incorporated in computing levelized annual fixed charge rates for periods following such tax law change:

B4.4.1 The federal corporate income tax rate, of 34%.

B4.4.2 A state corporate income tax rate equal to the estimated composite weighted average of PacifiCorp's (3) three-factor formula for unitary allocation of state taxable income based upon payroll, property, and revenue in each state in which PacifiCorp provides retail service.

B4.4.3 The Modified Accelerated Cost Recovery System (modified ACRS) method of tax depreciation in accordance with the Tax reform act of 1986 shall be used in calculating both the initial and subsequent levelized annual fixed charge rates.

B4.4.4 Regular Investment Tax Credits allowed in) accordance with the provisions of the Internal Revenue Code of 1954, as amended, regardless of whether PacifiCorp is able to use such credits shall be used when calculating subsequent levelized annual fixed charge rates.

B4.4.5 Tax basis shall be one-hundred percent (100%) of the book basis in calculating each initial levelized annual fixed charge rate and one hundred percent (100%) of the book basis in calculating each subsequent levelized annual fixed charge rate.

Colstrip Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Colstrip Project	
Annual Energy Production (MWh)	1,052,975
Production Expenses	
Operation, Supervision and Engineering	$180,275
Fuel	$7,394,559
Steam Expenses	$722,304
Electric Expenses	$330,429
Misc. Steam Power Expenses	$875,183
Rents	($74,887)
Maintenance, Supervision and Engineering	$225,070
Maintenance of Structures	$207,729
Maintenance of Boiler Plant	$1,315,261
Maintenance of Electric Plant	$261,013
Maintenance of Misc. Steam Plant	$244,057
Subtotal	$11,680,993
In Lieu of Payments *	$219,107
Total Variable Costs Colstrip Project	$11,900,100
Colstrip Project Annual Variable Cost	$11.30 per MWh

* Montana Electrical Energy License Tax

Cholla Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Cholla Project	
Annual Energy Production (MWh)	4,913,599
Production Expenses	
Operation, Supervision and Engineering	$391,540
Fuel	$84,460,268
Steam Expenses	$3,263,082
Electric Expenses	$834,325
Misc. Steam Power Expenses	$1,553,024
Rents	$139,392
Maintenance, Supervision and Engineering	$2,829,620
Maintenance of Structures	$504,564
Maintenance of Boiler Plant	$9,343,026
Maintenance of Electric Plant	$1,975,652
Maintenance of Misc. Steam Plant	$1,479,085
Subtotal	$106,773,578
In Lieu of Payments	-
Total Variable Costs Cholla Project	$106,773,578
Cholla Annual Variable Cost	**$21.73 per MWh**

Note: Example Purposes Only - Reflects Total Cholla Plant

Hunter #2 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #2 Project	
Annual Energy Production (MWh)	1,653,390
Production Expenses	
Operation, Supervision and Engineering	$139,904
Fuel	$14,927,530
Steam Expenses	$1,457,346
Electric Expenses	$577,512
Misc. Steam Power Expenses	$623,071
Rents	$27
Maintenance, Supervision and Engineering	$373,099
Maintenance of Structures	$242,519
Maintenance of Boiler Plant	$1,974,717
Maintenance of Electric Plant	$336,814
Maintenance of Misc. Steam Plant	$468,726
Subtotal	$21,121,265
Allocated Mining Expenses	$2,189,452 *
In Lieu of Payments	-
Total Variable Costs Hunter #2 Project	$23,310,717
Hunter #2 Project Annual Variable Cost	**$14.10 per MWh**

* See Attached sheets for details

Hunter #3 Project Annual Variable Cost

(Based on 1989 FERC Form 1)

Hunter #3 Project	
Annual Energy Production (MWh)	2,743,379
Production Expenses	
Operation, Supervision and Engineering	$231,997
Fuel	$24,859,535
Steam Expenses	$2,517,785
Electric Expenses	$1,179,383
Misc. Steam Power Expenses	$897,027
Rents	$2,437
Maintenance, Supervision and Engineering	$715,529
Maintenance of Structures	$431,445
Maintenance of Boiler Plant	$4,837,672
Maintenance of Electric Plant	$686,521
Maintenance of Misc. Steam Plant	$958,473
Subtotal	$37,317,804
Allocated Mining Expenses	$3,726,731 *
In Lieu of Payments	-
Total Variable Costs Hunter #3 Project	$41,044,535
Hunter #3 Project Annual Variable Cost	$14.96 per MWh

* See attached sheets for details

Annual Variable Cost

Project Annual Load Factors

	1989 Generation (Mwh)	Capacity MW	Load Factor
Colstrip	1,052,975	140	86%
Cholla	6,910,089	940	84%
Hunter #2	1,653,390	235	80%
Hunter #3	2,743,379	400	78%

Weighted Variable Cost

	Capacity MW	Load Factor	Variable Cost $/MWh	Numerator	Denominator
Colstrip	70	86%	11.30	679	60
Cholla	350	84%	21.73	6,382	294
Hunter #2	180	80%	14.10	2,038	145
Hunter #3	400	78%	14.96	4,685	313
Total				13,785	812

Numerator = Capacity x Load Factor x Variable Cost

Denominator = Capacity x Load Factor

Weighted Variable Cost = 13,785 + 812 = $16.99

Adjusted for Losses = $16.99 + 1

Annual Variable Cost = $\boxed{\$16.99}$

Hunter #2 Project Allocated Mining Expense

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #2 Project

Hunter #2 Mining Investment		$22,748,496
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$1,535,751
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$228,367
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #2 A & G Expense		$425,334
Total Fixed Cost		$2,189,452

Hunter #3 Project Allocated Mining Expense

(Based on 1989 Actual Costs)

Initial Levelized Fixed Charge

Hunter #3 Project

Hunter #3 Mining Investment		$38,720,844
Adjusted Initial Levelized Annual Fixed Rate		6.75%
Initial Levelized Annual Fixed Charge		$2,614,044
Subsequent Investment		$0
Subsequent Levelized Annual Fixed Rate		0.00%
Subsequent Levelized Annual Fixed Charge		$0
Ad Valorem Tax		$388,714
Taxes, assessments and in lieu of taxes		$0
Administrative & General Expenses:		
1989 Total PacifiCorp A&G Expense	$139,130,109	
1989 Total PacifiCorp Electric Plant In Service	$7,441,216,075	
A&G Expense as a percent of Investment	1.87%	
Hunter #3 A & G Expense		$723,972
Total Fixed Cost		$3,726,731

Hunter #2 and #3 Mining Investment

Allocation Calculation

Gross Coal Plant	$193,120,211

Power Plants Served By Mines:

	MW
Huntington #1	400
Huntington #2	415
Hunter #1 UPL	366
Hunter #1 Provo	24
Hunter #2 UPL	235
Hunter #2 DG&T	155
Hunter #3 UPL	400
Total	1,995

Hunter #2 Mining Investment =	235	+	1995	x	$193,120,211	=	$22,748,496
Hunter #3 Mining Investment =	400	+	1995	x	$193,120,211	=	$38,720,844

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 MINING INVESTMENT

AUGUST 27, 1990

50%	DEBT FINANCING @ 8.47%	$978	LEVELIZED DEFERRED TAXES	7	YEAR TAX LIFE - MODIFIED ACRS
10%	PREFERRED EQUITY @ 8.24%	$2,138	LEVELIZED INTEREST EXPENSE	N/A	TAX RATE PRIOR TO 1987
40%	COMMON EQUITY @ 12.36%	$416	LEVELIZED PREFERRED RETURN	N/A	TAX RATE IN 1987
10.00%	WEIGHTED COST OF CAPITAL	$2,496	LEVELIZED COMMON RETURN	36.88%	TAX RATE AFTER 1987 (34% FEDERAL, 4.36% STATE)
$100,000	CAPITAL INVESTMENT	0.13577	CAPITAL RECOVERY FACTOR	0%	INVESTMENT TAX CREDIT (ITC)
$13,894	LEVELIZED ANNUAL COST	1989	IN SERVICE DATE	100%	ITC BASIS ADJUSTMENT
$13,894	LEVELIZED FIXED CAPITAL COSTS	14	YEAR ESTIMATED LIFE	100%	TAX BASIS (% OF ORIGINAL COST)
$724	LEVELIZED INCOME TAXES	14	YEAR BOOK LIFE - STRAIGHT LINE	100%	BOOK BASIS (% OF ORIGINAL COST)

YEAR	O&M EXPENSE	A&G EXPENSE	PROP TAXES	BOOK DEPREC	INTEREST EXPENSE	PREF RETURN	COMMON RETURN	INCOME TAXES DEFERRED	INCOME TAXES CURRENT	ANNUAL COST	NPV COST	TAX DEPREC	AVERAGE RATE BASE
1989	0	0	0	7,143	4,028	784	4,702	2,636	570	19,862	18,056	14,290	95,111
1990	0	0	0	7,143	3,534	688	4,126	6,398	(3,585)	18,303	15,126	24,490	83,451
1991	0	0	0	7,143	3,015	587	3,520	3,816	(1,416)	16,665	12,519	17,490	71,201
1992	0	0	0	7,143	2,590	504	3,024	1,972	89	15,322	10,464	12,490	61,164
1993	0	0	0	7,143	2,232	434	2,606	659	1,117	14,191	8,810	8,930	52,706
1994	0	0	0	7,143	1,902	370	2,220	655	858	13,148	7,421	8,920	44,906
1995	0	0	0	7,143	1,571	306	1,835	659	591	12,105	6,211	8,930	37,106
1996	0	0	0	7,143	1,276	248	1,490	(989)	2,005	11,172	5,211	4,460	30,128
1997	0	0	0	7,143	1,050	204	1,226	(2,634)	3,470	10,459	4,435	0	24,797
1998	0	0	0	7,143	859	167	1,003	(2,634)	3,318	9,856	3,799	0	20,288
1999	0	0	0	7,143	668	130	780	(2,634)	3,166	9,253	3,242	0	15,780
2000	0	0	0	7,143	477	93	557	(2,634)	3,014	8,650	2,755	0	11,271
2001	0	0	0	7,143	286	56	334	(2,634)	2,862	8,047	2,330	0	6,763
2002	0	0	0	7,143	95	19	111	(2,634)	2,710	7,444	1,960	0	2,254
2003	0	0	0	0	0	0	0	0	0	0	0	0	0
2004	0	0	0	0	0	0	0	0	0	0	0	0	0
2005	0	0	0	0	0	0	0	0	0	0	0	0	0
2006	0	0	0	0	0	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0	0	0	0	0	0
2010	0	0	0	0	0	0	0	0	0	0	0	0	0
2011	0	0	0	0	0	0	0	0	0	0	0	0	0
2012	0	0	0	0	0	0	0	0	0	0	0	0	0
2013	0	0	0	0	0	0	0	0	0	0	0	0	0
2014	0	0	0	0	0	0	0	0	0	0	0	0	0
2015	0	0	0	0	0	0	0	0	0	0	0	0	0
2016	0	0	0	0	0	0	0	0	0	0	0	0	0
2017	0	0	0	0	0	0	0	0	0	0	0	0	0
2018	0	0	0	0	0	0	0	0	0	0	0	0	0
2019	0	0	0	0	0	0	0	0	0	0	0	0	0
2020	0	0	0	0	0	0	0	0	0	0	0	0	0
2021	0	0	0	0	0	0	0	0	0	0	0	0	0
2022	0	0	0	0	0	0	0	0	0	0	0	0	0
2023	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	0	0	0	100,000	23,586	4,589	27,534	0	18,769	174,479	102,338	100,000	
1989 NET PRESENT VALUE @ 10%	0	0	0	52,611	15,748	3,064	18,384	2,202	5,330	102,338	67,289	72,139	

PACIFICORP ELECTRIC OPERATIONS
HUNTER #2 & #3 MINING INVESTMENT

AUGUST 27, 1990

	BEGINNING	BOOK	INVESTMENT TAX CREDIT			DEFERRED TAXES		ENDING	EXCESS	INCOME	TAX	BOOK
YEAR	RATE BASE	DEPREC	CREDIT	RESTORED	RECAPTURE	CURRENT	RESTORED	RATE BASE	DEFERRED	TAX RATE	DEPREC	DEPREC
1989	100,000	(7,143)	0	0	0	(2,636)	0	90,221	0	36.88%	14.290%	7.14%
1990	90,221	(7,143)	0	0	0	(6,398)	0	76,681	0	36.88%	24.490%	7.14%
1991	76,681	(7,143)	0	0	0	(3,816)	0	65,722	0	36.88%	17.490%	7.14%
1992	65,722	(7,143)	0	0	0	(1,972)	0	56,607	0	36.88%	12.490%	7.14%
1993	56,607	(7,143)	0	0	0	(659)	0	48,805	0	36.88%	8.930%	7.14%
1994	48,805	(7,143)	0	0	0	(655)	0	41,007	0	36.88%	8.920%	7.14%
1995	41,007	(7,143)	0	0	0	(659)	0	33,205	0	36.88%	8.930%	7.14%
1996	33,205	(7,143)	0	0	0	989	0	27,051	0	36.88%	4.460%	7.14%
1997	27,051	(7,143)	0	0	0	2,634	0	22,543	0	36.88%	0.000%	7.14%
1998	22,543	(7,143)	0	0	0	2,634	0	18,034	0	36.88%	0.000%	7.14%
1999	18,034	(7,143)	0	0	0	2,634	0	13,526	0	36.88%	0.000%	7.14%
2000	13,526	(7,143)	0	0	0	2,634	0	9,017	0	36.88%	0.000%	7.14%
2001	9,017	(7,143)	0	0	0	2,634	0	4,509	0	36.88%	0.000%	7.14%
2002	4,509	(7,143)	0	0	0	2,634	0	0	0	36.88%	0.000%	7.14%
2003	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2004	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2005	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2006	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2007	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2008	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2009	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2010	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2011	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2012	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2013	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2014	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2015	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2016	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2017	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2018	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2019	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2020	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2021	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2022	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
2023	0	0	0	0	0	0	0	0	0	36.88%	0.000%	0.00%
TOTAL		(100,000)	0	0	0	0	0		0		100.000%	100.00%

HUNTER #2 & #3 MINE INVESTMENT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE

(Sample Calculations based on Year 1 and shown rounded to nearest whole dollar)

(*1) CAPITAL RECOVERY FACTOR, (CRF) = $i(1+i)^n/(1+i)^n - 1$
Where i = weighted cost of capital and n = ave.. life of plant.

CRF = 0.1000 (1 + 0.1000) ^{14}/((1 + 0.1000) ^{14} - 1) = 0.13575

(*2) BOOK DEPRECIATION = $100,000/14 Years = $7,143

(*3) TOTAL RETURN, (TR) = A x W_s
Where A = Average Net Investment; and
W_s = Weighted Cost of Preferred and Common Stock
Let A = Beginning Investment - (D+T) /2
Where Beginning Investment = Previous year's beginning investment - previous year's D and T.

D = Book Depreciation (*2)
T = Deferred Tax (*5)
Therefore, beginning investment = $100,000
A = $100,000 - (7,143 + 2636) /2 = $95,111
TR = $95,111 x (.10 x .0824 + .40 x .1236) = $5,486

(*4) INTEREST, (I) = A x W_d
Where W_d = Weighted Cost of Debt
Therefore, I = $95,111 x (.50 x .0847) = $4,028

(*5) DEFERRED TAX, (T) = (T_d -D) x T_R
Where T_D = Tax Depreciation (*8)
T_R = Tax Rate (36.88%)
Let T = (14,290 - 7,143) x .3688 = $2,636

**HUNTER #2 AND #3 MINE INVESTMENT
FORMULAS FOR CALCULATING
INITIAL LEVELIZED FIXED CHARGE RATE
(Con't.)**

(*6) INCOME TAX = (Total Return + Book Depreciation + Deferred Tax - Tax Depreciation) x (Tax rate/(1-Tax rate)

INCOME TAX = ($5,486 + $7,143 + $2,636 - $14,290) x (.3688/(1-.3688 = $570

(*7) ANNUAL COST = Book Depreciation + Total Return + Interest + Deferred Tax + Income Tax

ANNUAL COST = $7,143 + $5,486 + $4,028 + $2,636 + $570 = $19,862

(*8) TAX DEPRECIATION = (Modified ACRS) x Original Investment
TAX DEPRECIATION = 14.29% x 1.00 x $100,000 = $14,290
Adjusted for 1/2 year = $8,510/2 = $4,255

(*9) ITC = Not Applicable

(*10) PRESENT WORTH ANNUAL COST = Annual Cost x $1/(1+i)^n$
PRESENT WORTH ANNUAL COST = $19,862 x $1/(1 + .1000)^1$ = $18,056

where i = weighted cost of capital and n = first year.

(*11) INITIAL LEVELIZED FIXED CHARGE RATE = (CRF x Total Present Worth Annual Cost) /Total Original Book Cost
INITIAL LEVELIZED FIXED CHARGE RATE = (0.13575 x $102,338)/$100,000 = 0.1389 = 13.89%

HUNTER #2 AND #3 MINE INVESTMENT
CALCULATION OF ADJUSTED INITIAL
FIXED CHARGE RATE
(Based on $100,000 of Capital Expenditure)

CAPITAL STRUCTURE:

Component	Structure	Rate
Debt	50%	8.47%
Preferred	10%	8.24%
Common	40%	12.36%
Weighted Cost of Capital		10.00%

INPUT DATA:

INVESTMENT TAX CREDIT	Not	Applicable
SALVAGE VALUE	0	
BOOK LIFE (Straight Line)	14	years
TAX LIFE (MACRS)	7	years
TAX RATE	36.88%	(includes state Corp. tax)
TAX BASIS	100.00%	of Book
PW RATE	10.00%	

CALCULATED DATA:

CAPITAL RECOVERY FACTOR = 0.13575 (1*)

INITIAL LEVELIZED FIXED CHARGE RATE = 0.1394 ≐ 13.94% (*11)

ADJUSTED INITIAL LEVELIZED FIXED CHARGE RATE* = 13.94% less book depreciation, where book depreciation = 1/14 years = 0.0714 = 7.14% = 13.89% = 6.75%

*Book depreciation is reflected in fuel cost.

Appendix C: "Resource Pool"

This Appendix sets forth the amount of capacity (MW) and the combination of resources which may be included in the Resource Pool which shall be the basis for determining the prices for Firm Capacity and associated Firm Energy under Section 5 of this Agreement commencing with calendar year 1996.

The Resource Pool shall contain 1000 megawatts of capacity, which, until October 31, 2010, shall always contain an amount of capacity equal to the current rated capacity of Cholla Unit 4 and PacifiCorp's associated Cholla Unit 4 capital costs as derived pursuant to Appendix A. On May 1, 1996, the Resource Pool shall contain 650 megawatts of the following other resources:

Resource	Capacity (MW)
Colstrip Project	70
Hunter No. 2 Project	180
Hunter No. 3 Project	400
Total	650 MW

Provided, that commencing May 1, 1997 and on each May 1 thereafter through the term of this Agreement, PacifiCorp may replace up to a maximum of 200 megawatts of such other resources with other cost resources it owns or may acquire, including, but not limited to, thermal generation it owns or leases and firm power purchases under contracts with a term of three years or more. Subsequent to October 31, 2010, through the term of this Agreement, PacifiCorp may replace both the other resources and Cholla Unit 4 with other cost resources. Such other cost resources contained in the Resource Pool shall only be resources (1) that PacifiCorp acquires through prudent utility management practices, (2) that are being used to provide utility service to PacifiCorp's customers, and (3) that have been declared to be in commercial operation prior to May 1 of the calendar year in which such resources are included in the Resource Pool.

APPENDIX D: EXAMPLE CALCULATION

ESTABLISHING ADJUSTMENTS FOR INTEREST

Simple interest "Midyear Convention" shall be utilized in calculating the amount of the adjustments for interest.

Assumptions for Example Calculations:

(1)	Total Annual Payment Difference for calendar year 1995	$12,000
(2)	Prime Rate	9%
(3)	Time of Adjustment	June 1, 1996

Adjustments for Interest

Year	Prime Rate [1]	Factor [2]		Interest Rate
1995	9.0% multiplied by	1/2	=	4.50%
1996	9.0% multiplied by	5/12	=	3.75%
				8.25%

8.25% x $12,000 = $990 Adjustment For Interest

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[1] The prime rate shall be the time weighted average prime rate for the period. For the example above it would be for the period January 1995 through May 1996. The prime rate shall be as established by Morgan Guaranty Trust Company of New York.

[2] 1995 mid-year convention 1/2 year
1996 5 months (January through May)

APPENDIX E: INCREMENTAL COST OF SUPPLEMENTAL ENERGY AND UNUSED CHOLLA CAPABILITY

This Appendix sets forth the method for establishing Incremental Cost ($/MWh) of Supplemental Energy to be made available by APS pursuant to Subsections 6.7 and 6.8 of this Agreement and the Incremental Cost ($/MWh) of energy associated with either Party's use of the other Party's unused generating capability at the Cholla Generating Station ("Unused Cholla Capability") pursuant to Subsection 13.06 of the Asset Agreement.

The Incremental Cost for each megawatt-hour of each transaction shall equal the sum of (1) the deemed incremental operating and maintenance expense ($/MWh) as determined in Section 1.0 below, and (2) the Incremental Fuel Cost ($/MWh) as determined in Section 2.0 below.

1.0 Incremental Operating and Maintenance Expense. The incremental operating and maintenance expense associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

1.1 Supplemental Coal Energy. For all Supplemental Coal Energy, the incremental operating and maintenance expense shall be deemed to be $2.00 per megawatt-hour; provided, that on January 1, 1992 and on each January 1 thereafter through the term of this Agreement, such amount shall be adjusted in accordance with the percentage change in the GNP Price Deflator over the immediate preceding twelve month period.

1.2 Other Supplemental Energy. For all Other Supplemental Energy, the incremental operating and maintenance expense shall be deemed to be $.05 per megawatt-hour for gas and oil fired steam units, $3.00 for all single cycle combustion turbines and $1.90 for all combined cycle units; provided, that on January 1, 1992 and on each January 1 thereafter through the term of this Agreement, such amount shall be adjusted in accordance with the percentage change in the GNP Price Deflator over the immediate twelve month period. Within three years of the Effective Date of this Agreement, the parties shall review the appropriateness of the foregoing deemed values and make adjustments that are equitable.

1.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental operating and maintenance expense shall be deemed to be $2.00 per megawatt-hour; provided, that on January 1, 1992 and on each January 1 thereafter through the term of the Asset Agreement, such amount shall be adjusted in accordance with the percentage change in the GNP Price Deflator over the immediate preceding twelve month period.

2.0 Incremental Fuel Cost. The incremental fuel cost associated with Supplemental Energy and energy associated with either Party's use of the other Party's Unused Cholla Capability shall be as follows:

2.1 Supplemental Coal Energy. For all Supplemental Coal Energy the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based on his best-efforts forecast of the incremental coal cost and the incremental heat rate associated with the lowest cost generating unit(s) expected to be producing such energy.

2.2 Other Supplemental Energy. For all other Supplemental Energy, the incremental fuel cost ($/MWh) shall be determined by the APS dispatcher or scheduler based upon his best-efforts forecast of the incremental fuel cost, either Natural Gas, Oil or Coal, utilizing the incremental heat rate associated with the lowest cost generating unit(s) that is expected to be producing such energy.

2.3 Unused Cholla Capability. For all energy associated with either Party's use of the other Party's Unused Cholla Capability, the incremental fuel cost ($/MWh) shall be determined by the Party's dispatcher or scheduler having such Unused Cholla Capability based on his best-efforts forecast of the incremental coal cost utilizing the incremental heat rate of the generating unit(s) that would produce such energy.

Rocky Mountain Power
Docket No. 17-035-36
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Surrebuttal Testimony of Daniel J. MacNeil

October 2017

Q. Are you the same Daniel J. MacNeil who presented direct and rebuttal testimony in this proceeding?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. My testimony responds to the rebuttal testimony filed by Keegan Moyer on behalf of Glen Canyon Solar A, LLC and Glen Canyon Solar B, LL (together, "Glen Canyon" or the "Glen Canyon QFs") on September 25, 2017.

Q. Mr. Moyer has testified that the avoided-cost modeling used for the Glen Canyon QFs included a transmission constraint resulting from the fact PacifiCorp ("Company") has only 95 MW of transmission rights between Glen Canyon and the Company's loads in central Utah and that this 95 MW of transmission was sufficient for the Glen Canyon QF to serve the Company's load.[1] Is this an accurate description of the avoided cost modeling?

A. No. The avoided-cost study never studied the Glen Canyon QFs at 95 MW of output and includes more than 95 MW of transfer capability out of the transmission area in which the Glen Canyon QFs are located. While these assumptions would both have increased the likelihood of the modeled transfer capability within the GRID model being sufficient to transfer the Glen Canyon QFs out of their transmission area, the avoided-cost study still included periods when the assumed output of the Glen Canyon QFs exceeded the available transfer capability out of the Glen Canyon transmission area.

[1] Direct Testimony of Keegan Moyer at 5, lines 108-112.

Q. Please describe the avoided-cost modeling that was performed to determine the avoided-cost prices for the Glen Canyon QFs.

A. In August 2016, an avoided-cost study was prepared with the Glen Canyon A project modeled as a 74 MW resource. In December 2016, an avoided-cost study was prepared with the Glen Canyon B resource modeled as a 21 MW resource; however, at the request of Glen Canyon, this study also assumed that Glen Canyon A was 68 MW. Thus, in the Glen Canyon B study, the total capacity for both QFs was 89 MW. Before executing its power-purchase agreements ("PPA") with PacifiCorp, Glen Canyon A was modified back to 74 MW, again at Glen Canyon's request.

Although the Glen Canyon B study assumed both QFs had a cumulative nameplate capacity of 89 MW, the combined output of Glen Canyon A and B was always less than 88 MW. For avoided cost studies, the company uses what is referred to as the 12 months by 24-hour ("12x24") output profile, which reflects an average of a range of expected conditions that impact generation, *e.g.*, clouds, dust, and outages. Because the 12x24 generation profiles represent average conditions, they rarely, if ever, result in modeled output that is equal to the proposed project size. In actual operations, output would vary above and below the average.

Q. Please describe the modeling of transmission capability in the Glen Canyon avoided-cost studies.

A. The Glen Canyon avoided cost studies include PacifiCorp's merchant function's (energy supply management or "ESM") 95 MW of long-term transmission capability out of the transmission area in which the Glen Canyon QFs are proposed to be located. In addition, the GRID model includes transfer capability based on PacifiCorp ESM's historical short-term and non-firm reservations. This includes capacity reserved on PacifiCorp's transmission system as well as capacity reserved on the transmission systems of other utilities. The GRID model does not distinguish between network and point-to-point rights; between PacifiCorp and third-party transmission systems; or between long-term, short-term, and non-firm transmission capability.

Q. How are short-term firm and non-firm transmission rights reflected in the GRID model?

A. The average level of historical short-term and non-firm transmission reservations between each pair of transmission areas in the GRID model are included in each hour of the study. The GRID model does not include any wheeling costs or transmission loss obligations associated with the use of these transmission rights.

Q. How much short-term firm and non-firm transmission was reflected in the avoided-cost pricing studies for Glen Canyon?

A. The avoided-cost pricing for Glen Canyon A included 20 MW of short-term firm and non-firm transfer capability out of the Pinnacle Peak-Glen Canyon ("PP-GC") transmission area in which the Glen Canyon projects are located. The avoided-cost pricing for Glen Canyon B included 18 MW of short-term firm and non-firm transfer capability out of the PP-GC transmission area. Because the GRID model had been updated to include more recent history by the time the pricing for Glen Canyon B was prepared, it was based on historical data from the 48 months ending June 2016, while that for Glen Canyon A reflected historical data from the 48 months ending December 2015.

Q. What other resources in the avoided-cost studies can use transfer capability out of the PP-GC transmission area?

A. PacifiCorp receives deliveries from Arizona Public Service Company ("APS") during the winter season under a contract with APS. A portion of these deliveries are assumed to be received in the PP-GC transmission area. In addition, the GRID model also allows the Cholla 4 coal plant and market transactions or other resources in the Four Corners transmission area to be transferred into the PP-GC transmission area. Finally, the GRID model includes a small amount of short-term transfer capability into the PP-GC transmission area.

Q. Did the avoided-cost pricing provided to the Glen Canyon QFs reflect PacifiCorp ESM's obligation to provide transfer capability to APS?

A. Yes. APS has the option to schedule resources across the PacifiCorp system from two locations, represented as the Four Corners and PP-GC transmission areas in the GRID model. The GRID model cannot account for the optionality in APS's rights, and therefore (for simplicity) these rights have been represented as a reduction in the transfer capability out of the Four Corners transmission area, an assumption that has not changed in many years and is not specific to the Glen Canyon avoided-cost studies.

Q. What does the avoided-cost pricing assume about a QF's interconnection and the transmission of the QF's power?

A. As discussed in my direct testimony, the avoided-cost methodology assumes the QF resource has secured an interconnection, and it also includes certain high-level assumptions, as described above, about known transmission constraints and PacifiCorp's merchant function's transmission rights to better estimate the cost savings of backing down other PacifiCorp resources to accommodate the QF's power. This allows the company to develop a reasonable avoided-cost price, but does not and is not intended to predict or govern actual system operation.

Q. Does avoided cost pricing inherently assume that QFs are deliverable?

A. Yes, which is appropriate given our must-purchase obligations under PURPA. But QFs are only actually paid for delivered output.

Q. Was all of the expected output of the Glen Canyon QFs assumed to be delivered to PacifiCorp?

A. No. Imports and exports to other transmission areas are the only means the GRID model has to balance the resources and requirements in Glen Canyon's transmission area, as it does not contain any dispatchable resources or markets. When resources in an area exceed load and export capability, the GRID model considers any remaining imbalance between resources and requirements as "trapped energy." In the Glen Canyon B QF avoided cost study, a small amount of trapped energy was identified in Glen Canyon's transmission area when the Glen Canyon B QF was added, bringing the total QF capacity to 89 MW. The associated trapped energy volumes were assumed not to have been delivered to the Company.

Q. If a QF's output is expected to be undeliverable under certain circumstances, does that mean the avoided-cost price will be zero for those periods?

A. No. If a QF's output is expected to be undeliverable under certain circumstances, then both the QF's output and the estimated avoided cost would be removed from the avoided-cost calculation for those undeliverable periods. This means there is no "zero price" for those undeliverable periods. Rather, the avoided cost and output for the undeliverable hours are simply removed, which could result in a lower *or* higher avoided-cost rate.

For example, if undeliverable output was expected to occur during periods when avoided costs were projected to be higher than average, then the average avoided cost of the remaining delivered output would be *lower*, resulting in a *lower* avoided-cost price. If, on the other hand, the undeliverable output was expected to occur during periods when avoided costs were projected to be lower than average, then the average avoided cost of the remaining delivered output would be *higher*, resulting in a *higher* avoided-cost price. It is likely that undeliverable output would occur under a range of conditions, and that the net impact on the avoided-cost price would be small, particularly if the undeliverable output were a small portion of the total hours during the life of the contract.

Q. Can you describe some modeling assumptions that would cause the undeliverable output identified in the avoided-cost pricing studies to increase?

A. Yes. The following changes would have resulted in the GRID model identifying more of Glen Canyon's output as undeliverable:

- Modeling Glen Canyon A and B at the contracted total capacity of 95 MW, rather than the 89 MW of capacity in the Glen Canyon B avoided-cost pricing study.
- Modeling the full range of expected QF output, rather than the 12x24 average.
- Modeling APS's scheduling rights through the PP-GC transmission area, instead of the Four Corners transmission area.

- Reducing or removing short-term and non-firm transmission capability from the PP-GC transmission area.
- Modeling transmission line derates and outages.

Q. How would avoided-cost pricing be impacted if the modeling changes described above were implemented and caused an increase in undeliverable output?

A. The impact would vary based on a number of factors, as described above. In general, each additional increment of output results in declining avoided costs, so the last increment of output in a given hour is the least valuable. Undeliverable output under these circumstances would likely be less valuable than the average, which would result in higher avoided costs. On the other hand, APS usage of its scheduling rights and PacifiCorp ESM's scheduling of APS exchange receipts are likely to occur in intervals with relatively high avoided costs. Undeliverable output under these circumstances would likely be more valuable than the average, which would result in lower avoided costs.

Q. Does this conclude your rebuttal testimony?

A. Yes.

CERTIFICATE OF SERVICE

Docket No. 17-035-36

I hereby certify that on October 2, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

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