PACIFIC POWER
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March 27, 2014

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Public Utility Commission of Oregon
3930 Fairview Industrial Dr. S.E.
Salem, OR 97302-1166

Attention: Filing Center

RE: LC 57—Responses to OPCU Bench Request Nos. 1-13

PacifiCorp d/b/a Pacific Power encloses for filing in the above-referenced docket its Responses to OPUC Bench Request Nos. 1-13. Also enclosed is Attachment OPUC Bench Requests 6, 11, and 12. Enclosed on the Confidential CD are Confidential Attachments OPUC Bench Requests 3, 4, 5, and 6a. The confidential attachments are designated as confidential under Order No. 13-095 and may only be disclosed to qualified persons as defined in that order.

As indicated on the attached certificate of service, a copy of this filing is being served on all parties on the service list.

If you have questions about this filing, please contact Bryce Dalley at (503) 813-6389.

Sincerely,

R. Bryce Dalley/

R. Bryce Dalley
Vice President, Regulation

Enclosures

cc: Service List—LC 57

OPUC Bench Request 1

A. TPL-002 Standard

With the cancellation of the supply agreement between NV Energy, Inc. and Utah Associated Municipal Power Systems (UAMPS),[1] is Pacific Power in compliance with the North American Electric Reliability Corporation's (NERC) TPL-002 performance standard today?

(a) If Pacific Power is in compliance with the TPL-002 standard today, please explain why and how it is in compliance.

(b) If Pacific Power is not in compliance today, please explain why and how it is not in compliance.

Response to OPUC Bench Request 1

(a) With the planned addition of the second Sigurd to Red Butte transmission line, PacifiCorp is in compliance with the TPL-002 Reliability Standard through the 10-year planning horizon. As part of its TPL compliance study process, PacifiCorp includes "existing and planned facilities[2]" in the power flow model for each study year. Since the second Sigurd-Red Butte 345 kV line is planned to be in service before summer 2015, it is represented in the 2015, 2018, and 2023 "heavy summer" base cases used in the TPL studies.

The TPL-002 Standard requires that "The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I [of the standard]." These contingency conditions include events that result in the loss of a single element (a generator, transmission circuit, or transformer). Following loss of a single element, the standard requires the system to be stable, all bus voltages to be within applicable limits, and all lines and transformers to be within their applicable thermal ratings. Further, the standard does not allow loss of demand or curtailment of firm transfers except under a limited set of conditions, which has been recently revised by the Federal Energy Regulatory Commission.

Based on the load forecast provided in on page 5 of the confidential attachment to PacifiCorp's Response to Commission Staff's Data Request 36 (referenced in OPUC Bench Request 2), if the second Sigurd to Red Butte 345 kV line was not included in

[1] As referenced in Pacific Power's Response to Staffs Data Request 149.
[2] See TPL-002-2b requirement R1.3.8: "Include existing and planned facilities."

these base cases, loss of either one of the two existing 345 kV lines serving the area would not directly result in loss of demand (load) in the Red Butte area before 2018, and no deficiency regarding the NERC TPL-002-0b performance standard would occur. Once the area load increases to 580 MW or more, however, potential load shedding could be required for this outage and compliance with TPL-002 would be in doubt.

Additionally, with the existing system, any time a segment of the existing Sigurd-Three Peaks-Red Butte 345 kV line is out-of-service, customers served from Red Butte are no longer connected to the generating resources in the system north and east of Sigurd. These customers must therefore be served by resources from or through the NV Energy system for the duration of the outage. This condition also exposes up to 120,000 customers to a potential outage since all Red Butte area customers are served from a single 345 kV radial line from NV Energy's system. The addition of the second Sigurd to Red Butte 345 kV line will mitigate this exposure.

(b) Not applicable. Please refer to the Company's response to subpart (a) above.

OPUC Bench Request 2

A. TPL-002 Standard

A handout provided to the Commission by Pacific Power during a public meeting in 2012 suggests that if the existing Sigurd to Red Butte Line goes out of service, up to 580 MW of load in the Red Butte area can be served with power delivered north over the TOT 2C Line from the Harry Allen Substation.[1] The exhibit provided on page 5 of Pacific Power's Confidential Response to Commission Staffs Data Request 36 in this docket suggests that forecasted loads in the Red Butte area will be below 580 MW through 2017.

(a) Is 2018 the first year that Pacific Power forecasts not being able to serve peak load in the Red Butte area in the event that the existing Sigurd to Red Butte Line is out of service?

(b) Is 2018 the first year that Pacific Power forecasts being out of compliance with the TPL-002 performance standard?

(c) How is the N-1 contingency analysis for the Sigurd to Red Butte Line conducted?

Response to OPUC Bench Request 2

(a) Yes. As the exhibit referenced in this response indicates, the sum of forecasted non-coincident peak loads provided in 2012 by PacifiCorp's network customers for this area exceeds 580 MW in 2018. Since actual load growth over time may be and often is different than forecasted growth, it is difficult to construct long lead-time projects so the respective in-service dates are exactly timed with actual need. Since actual need can change, it is considered prudent to plan projects so that they are placed into service coincident with the forecasted demand, rather than run the risk that actual demand will vary and the project will not be in-service to meet the load.

(b) Yes. Please refer to PacifiCorp's response to OPUC Bench Request 1(a). Since the TPL studies include the second Sigurd to Red Butte 345 kV line, PacifiCorp is in compliance with the TPL-002 Reliability Standard through the 10-year planning horizon. Without this line, compliance with TPL-002 would be in doubt once the area load increases to 580 MW or more, which is forecasted to be in 2018.

(c) The N-1 contingency analysis for the Sigurd to Red Butte Line assumes peak load in the Red Butte area and is studied with maximum transfer conditions on Western Electricity Coordinating Council (WECC) Path TOT 2C in both the north and south

[1] The handout, provided by Pacific Power during its November 5, 2012 public input meeting on the company's transmission, stochastic modeling, and preferred portfolio selection, is available at the following URL: http://v;ww.pacificoro.com/content/dant/pacificoro/doc/Energy Sources/Integrated Resource Plan/2013IRP/2013IRP DTG-4 5-SWUTAreaTransmissionBuilld 11-5-12.pdf

directions. For load service at Red Butte, the limiting condition is loss of either section of the existing Sigurd-Three Peaks-Red Butte 345 kV line which results in Red Butte being served radially from NV Energy's system on the Harry Allen-Red Butte 345 kV line. The load that can be served from this line is limited to the established and accepted south-to-north rating of the TOT 2C path, or 580 MW, limited further by the total amount of any available transmission capacity that exists at the time.

OPUC Bench Request 3

A. TPL-002 Standard

If the NV Energy supply agreement was still in effect today, would power delivery to Red Butte be limited by the 580 MW capacity of the TOT 2C Line?

(a) Is the limiting factor to meeting future peak load in the Red Butte area solely with power deliveries from the Harry Allen Substation (1) the capacity of the TOT 2C Line, (2) the availability of a power supply agreement, or (3) both?

Response to OPUC Bench Request 3

Yes, if the NV Energy interconnection and emergency supply agreement (the "Interconnection Agreement") were still in effect today, power delivery to Red Butte would be limited by the 580 MW capacity of the TOT 2C Line. Under Service Schedule A, Emergency Assistance, of the Interconnection Agreement, either party was obligated to supply as emergency assistance, upon the other party's request, an amount of power and energy needed for the other party to protect or restore services to its respective customers. This supply was subject to its availability and intervening third-party transfer limitations, as well as the condition that the supply would not have impaired the supplier's system, customers, or third-party commitments. In return, the receiving party would have paid the supplying party the sum of a series of enumerated components, provided that the payment for items (1)-(3) were not less than 107.5 percent of the market price of deliveries to a third-party that the supplying party interrupted to supply the emergency service: (1) 115 percent of the incremental cost of fuel to generate the energy required to provide the emergency assistance; (2) 115 percent of incremental operation and maintenance costs per kwh; (3) the estimated cost of "making ready, starting up and shutting down" the units started to provide emergency service; (4) transmission losses incurred over third-party systems; (5) wheeling charges incurred by the supplying party over third-party systems; and (6) taxes and other expenses directly incurred as a result of the supply.

Regardless of whether or not the NV Energy agreement is in effect, power deliveries from Harry Allen to Red Butte are limited to the Western Electricity Coordinating Council (WECC) path rating limit of 580 MW and may be further limited to the amount of any available transfer capability on NV Energy's transmission system at the time the emergency power deliveries were requested.

(a) As a point of clarification, service of future Red Butte peak load was never intended to be met solely by power deliveries from Harry Allen. The agreement between UAMPS and NV Energy provides an alternate means in an emergency for UAMPS to serve its Red Butte load, which is particularly important in the event of an outage of the existing Sigurd-Three Peaks-Red Butte 345 kV line, as it is currently the only transmission line into the area. A power supply agreement and TOT 2C capacity are both factors in being able to use the TOT 2C path to serve load in the Red Butte area.

For scheduling purposes, PacifiCorp's ownership of path 35 (TOT 2C) is only between Red Butte and the Utah-Nevada border. Therefore, to move energy into or out of the Harry Allen 345 kV substation, point-to-point transmission capacity must be requested and purchased by the transmission customer through NV Energy's transmission tariff to or from another receipt or delivery point.

As a transmission provider, PacifiCorp has an obligation to identify upgrades and other investments necessary to reliably serve, over the planning horizon, network customers' resource and load growth expectations for designated network load. The Sigurd to Red Butte Project is part of the plan to meet this obligation because the majority of the Company's network customers' network resources are located in other parts of the east side of PacifiCorp's system (see confidential Figure 1, provided as Confidential Attachment OPUC Bench Request 3). In the event of an outage of the existing Sigurd-Three Peaks-Red Butte 345 kV line, PacifiCorp cannot deliver these resources.

The confidential attachment is designated as confidential under Order No. 13-095 and may only be disclosed to qualified persons as defined in that order.

OPUC Bench Request 4

A. TPL-002 Standard

What explains the differences in the forecasted average annual rate of growth in peak loads served by Pacific Power, Deseret Generation & Transmission Cooperative, Inc. (Deseret), and (UAMPS) in the Red Butte area?[1]

(a) By year, what would be the combined peak load forecast for the Red Butte area assuming a 4 percent average annual rate of growth in UAMPS peak loads from 2012 to 2021?

(b) By year, what would be the combined peak load forecast for the area assuming a 3 percent average annual rate of growth in UAMPS peak loads from 2012 to 2021?

(c) By year, what would be the combined peak load forecast for the area assuming the same average annual rate of growth in peak demand in the UAMPS area as for Pacific Power's Utah service territory from 2012 to 2021?

Response to OPUC Bench Request 4

Under PacifiCorp's Open Access Transmission Tariff ("OATT") Attachment K Section 2.3.1.2., each network customer must provide a good-faith ten-year load and resource forecast to the transmission provider (PacifiCorp). The forecasted average annual load growth rates submitted by the various network customers for the Red Butte area are different, and PacifiCorp is not given the details about how the forecasts are generated. Importantly, the OATT does not permit PacifiCorp to modify a network customer's load forecast because the forecast is provided in good faith and is presumably the best estimate of future anticipated load growth at the time. Network customers are in a position to be the most knowledgeable about their respective loads and anticipated growth.

For PacifiCorp's native network load, the annual load and resource forecast is based upon historical load levels, the prior rate of peak load growth, future load growth expectations and weather. Summer temperatures in this southern Utah region can be extreme, exceeding 110 degrees. In keeping with good industry practice, transmission providers and network customers must be mindful of extreme weather in planning to meet peak demand.

In addition, please refer to PacifiCorp's Response to OPUC Bench Request 13 for a description of joint planning efforts for southwestern Utah.

(a)–(c) Please refer to Confidential Attachment OPUC Bench Request 4.

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[1] *See* Pacific Power's Confidential Response to Staffs Data Request 36 at 5-6 (Exhibits 1 and 2).

The confidential attachment is designated as confidential under Order No. 13-095 and may only be disclosed to qualified persons as defined in that order.

OPUC Bench Request 5

A. TPL-002 Standard

What are the underlying assumptions driving the UAMPS and Deseret peak load forecasts for the relevant area? Have any sensitivity analyses been run on UAMPS and Deseret peak load forecasts in the area? What evaluations, if any, have been conducted of the UAMPS and Deseret load forecasts? Has Pacific Power conducted any independent analyses to verify the UAMPS and Deseret load forecasts? Please provide any analyses and work papers related to the UAMPS and Deseret load forecasts.

Response to OPUC Bench Request 5

As a transmission provider, PacifiCorp is obligated to operate in accordance with the provisions of its Open Access Transmission Tariff ("OATT"). Network customers such as UAMPS and Deseret are required under the OATT to provide annual information regarding their network loads and network resources, which the company then uses in its planning processes to ensure that it can provide safe, reliable service to meet those load and resource needs. The transmission provider is not responsible for verifying the accuracy of a network customer's load and resource forecast but, more importantly, is also not allowed to adjust or reject a network customer's forecast. Section 31.6 of the OATT however, does require that a network customer provide the transmission provider with timely written notice of material changes in any information, including information related to loads and resources, provided in its application for network integration transmission service.

That being said, during PacifiCorp's annual Load and Resource Study process a comparison of the historical load and forecasts is conducted and is provided to network customers for all relevant areas at the completion of the study (please refer to Confidential Attachment OPUC Bench Request 5, which consists of an excerpt from PacifiCorp's 2012 Load and Resource Study responsive to this request). Over time, network customers may modify their forecasts to more accurately reflect observed historical trends. However, historical trends may or may not reflect extreme weather conditions and are not necessarily predictive of future growth.

The confidential attachment is designated as confidential under Order No. 13-095 and may only be disclosed to qualified persons as defined in that order.

OPUC Bench Request 6

B. Alternatives to a Second Sigurd to Red Butte Line

Provide all communications, work papers, and analyses regarding any Pacific Power or other utility efforts to renegotiate the NV Energy Supply Agreement that was canceled in 2012.

(a) Provide all analyses and work papers for Pacific Power's evaluation of securing firm transmission service and firm power from NV Energy on a going-forward basis in lieu of building a second Sigurd to Red Butte Line.

Response to OPUC Bench Request 6

The NV Energy Supply Agreement canceled in 2012 was an Interconnection Agreement between NV Energy and the Utah Associated Municipal Power Systems ("UAMPS") dated June 17, 1991. PacifiCorp was not a party to this agreement and therefore was not involved in any efforts to renegotiate this agreement on behalf of its transmission customer, UAMPS.

On May 23, 2011, Nevada Power Company (NV Energy's predecessor) provided written notification to UAMPS that they were cancelling the Interconnection Agreement, effective November 19, 2011. The Federal Energy Regulatory Commission ("FERC") suspended the filing for hearing and/or settlement procedures. The two entities filed a subsequent settlement agreement on May 10, 2012.

For reference, PacifiCorp provides Attachment OPUC Bench Request 6, which contains the following four filings at FERC:

- Cancellation of FERC Electric Rate Schedule No. 56 (August 3, 2011)
- UAMPS Motion to Intervene (August 31, 2011)
- FERC Order (November 17, 2011)
- Settlement Agreement between Nevada Power Company and UAMPS (May 10, 2012)

(a) An alternative to the Sigurd to Red Butte 345 kV Project included a firm transmission wheeling option from the south that would be purchased from NV Energy combined with an energy purchase option in case neither transmission proposal from the north was built. However, the maximum capacity that could be supplied from the south is 580 MW, which is the limit of the TOT 2C path. If peak load exceeded 580 MW, this would not be a viable long-term option. Thus, this alternative presented significant risk.

The cost of obtaining 580 MW of firm transmission wheeling from NV Energy would amount to a present value cost of $104 million over twenty years (annual cost of

$9.7 million) based on published NV Energy Long-Term and Short-Term Point-To-Point Transmission Service Rates. The estimated energy purchase option also assumed a twenty-year period with a net present value amount of $465 million. Please refer to PacifiCorp's Confidential Attachment OPUC Bench Request 6a for details supporting the calculations. Although this was evaluated as an option to provide a cost comparison to constructing the Sigurd to Red Butte 345 kV Project for purposes of company governance, it was not a viable option for PacifiCorp as the transmission provider to pursue because PacifiCorp would not obtain wheeling or an energy option on behalf of a network customer because it is not allowed or required under PacifiCorp's OATT.

The confidential attachment is designated as confidential under Order No. 13-095 and may only be disclosed to qualified persons as defined in that order.

OPUC Bench Request 7

B. Alternatives to a Second Sigurd to Red Butte Line

In response to Staffs Data Request 149, Pacific Power states: "UAMPS is a party to the May 9, 2013, WSPP agreement filed and accepted under FERC's order of June 6, 2013, in Docket No. ER13-1349-000 which administers a multilateral, standardized agreement applicable to capacity and/or energy transactions between members and is available to entities which qualify for membership." Does the WSPP agreement help to ensure that peak loads can be served in the Red Butte area in the event of an outage on the existing Sigurd to Red Butte Line? Why or why not?

Response to OPUC Bench Request 7

No, the Western Systems Power Pool (WSPP) agreement does not ensure that peak loads can be served in the Red Butte area in the event of an outage on the existing Sigurd to Red Butte line. As stated in the Company's response to OPUC Staff Data Request 149, the WSPP is a multilateral, standardized agreement applicable to capacity and/or energy transactions that identifies standard terms and conditions, including terms and conditions related to billing, invoicing, dispute resolution, and applicable service schedules. Parties to the WSPP agreement are not obligated to transact (either buy or sell) any product. Transactions under the WSPP agreement are memorialized by a "confirm," which documents that the parties transacting mutually agree to transact a specific WSPP service schedule (i.e., a specific product), at a specific price, for a specific volume, and over a specific term. The WSPP agreement only provides a contracting vehicle allowing WSPP members to transact expeditiously via a "confirm" without having to individually negotiate standard terms and conditions (e.g., billing, invoicing, dispute resolution, etc.). In addition, any transactions would still need to be capable of being delivered on available transmission capacity, which would be arranged separate from the WSPP agreement and be purchased under a transmission provider's open access transmission tariff.

OPUC Bench Request 8

B. Alternatives to a Second Sigurd to Red Butte Line

What options other than constructing a second Sigurd to Red Butte Line were considered and evaluated by all affected utilities?

Response to OPUC Bench Request 8

The Company took steps to identify and implement alternatives that delayed the need for the Sigurd to Red Butte 345 kV Project by completing interim projects that added major equipment to the existing Three Peaks substation in 2009, which improved the 345 kV system operation and improved reliability for serving the general area. In 2011, the Company added major equipment and devices to the existing Red Butte substation to increase system capacity, improve voltage support, and maintain the reliability of the system in the general area. Also in 2011, additional facilities were added to the Harry Allen substation. These projects have allowed the Company to delay the second Sigurd to Red Butte line.

The 2011 Southwest Utah Joint Study Report conducted in association with UAMPS, Deseret Power, and Rocky Mountain Power determined that a future transmission line beyond the proposed Sigurd to Red Butte 345 kV Project will be needed between Sigurd and St George when load and reliability requirements reach a critical point beyond 2025. The alternative to building the Sigurd to Red Butte 345 kV Project would be to build the future line now; however, it is 185 miles in length compared to the 170 miles for the current project and connects to four substations instead of two. Ultimately, all three lines will be required to reliably provide service to the St. George area.

The Company has a tariff obligation to plan transmission systems and upgrades according to customers' load and resource submittals. An option to build local generation in southwest Utah was not given detailed consideration because there is no Open Access Transmission Tariff ("OATT") mechanism for installation of generation facilities to avoid construction of transmission lines that are required to meet reliable load service obligations. PacifiCorp cannot substitute a proxy resource to offset a transmission obligation as part of the services it is required to provide under the OATT.

As discussed in PacifiCorp's Response to OPUC Bench Request 6(a), the Company considered a third alternative that included a firm transmission wheeling option from the south purchased from NV Energy combined with an energy purchase option to provide energy in case neither transmission proposal from the north was built. However, the maximum capacity that could be supplied from the south is 580 MW, which would provide capacity coverage only through mid-2019. After 2019, the coincident peak forecast is estimated to exceed 580 MW. This would not be a viable long-term option because of the significant risks beyond 2019. Moreover, this option is not consistent with PacifiCorp's transmission obligations under the OATT. Please refer to PacifiCorp's

Response to OPUC Bench Request 6(a) for estimated costs associated with this alternative.

OPUC Bench Request 9

B. Alternatives to a Second Sigurd to Red Butte Line

What resource options have UAMPS and Deseret considered, plan to take, or are taking to meet increased loads in the area?

Response to OPUC Bench Request 9

PacifiCorp, as a transmission provider, does not have the authority or ability to influence or determine the resource plans of UAMPS and Deseret. PacifiCorp's understanding is that multiple cities in southwest Utah have invested in the construction of locally owned and operated generation facilities to meet increased loads in the area. These generation facilities were built to provide reliable electrical service to critical loads. These investments were needed because the transmission service into Washington County was not redundant and lengthy power outages had been experienced—and can be expected to continue to be experienced—until additional transmission is built.

OPUC Bench Request 10

B. Alternatives to a Second Sigurd to Red Butte Line

What demand response and conservation programs are in place to reduce the peak demands of customers of UAMPS and Deseret in the area? What are the annual savings from those programs?

Response to OPUC Bench Request 10

UAMPS and Deseret members in southwest Utah (cities of Santa Clara, St. George, Washington, Hurricane, and Dixie) built and now own and operate several local generators, netting up to approximately 150 MW, that provide electrical service to critical loads such as hospitals, law enforcement, and large commercial loads. The local generation is designed for limited load service, is not able to serve the cities' entire load and can be characterized as emergency generation for power outages caused by the failure of the transmission system. This generation also serves to reduce loads on PacifiCorp's transmission system during peak demand.

The City of St. George, the largest southwest Utah load, has implemented numerous conservation and energy efficiency programs. These programs include:

- Automated Energy Software—Allows customers to manage their electrical use and demand. This is a new program being introduced so annual savings have not yet been identified.
- Net Metering—For customers with solar panels installed. For fiscal year 2011, an additional $2,000 per kW rebate was offered with a total of $259,760 being paid out before the rebate period terminated. There is currently 822.54 kW behind the customer meter with three additional projects in process.
- Appliance Efficiency Rebates—Annual savings information was not readily available for this program.
- Rebate Program—Rebates to encourage added insulation in homes, more efficient air conditioning units, and variable speed swimming pool pumps. Annual savings information was not readily available for this program.

In addition to these programs, the City of St. George has also given away free compact fluorescent lamps (CFL's) to the public during home show expos, garden festivals, public power weeks, as well as donations to Habitat for Humanity homes being built in the City of St. George service territory.

UAMPS has participated in similar efficiency rebate programs designed and managed by UAMPS members' government agencies. UAMPS' involvement in these programs is solely from an administrative perspective; ensuring that rebates due to UAMPS members are credited to monthly settlement statements.

OPUC Bench Request 11

C. Federal Energy Regulatory Commission (FERC) and Cost Allocation

Does FERC allow a transmission provider to require up-front contributions from entities requesting transmission service prior to constructing a new transmission line? Please explain, and provide relevant FERC decisions.

Response to OPUC Bench Request 11

FERC does not allow a transmission provider to require up-front contributions from entities requesting transmission service before constructing a new transmission line if the new or upgraded transmission facilities are determined to be network upgrades and the transmission provider must charge an embedded transmission rate. While the following overview touches on some of the concepts relevant to this question, the pertinent FERC policy statement is the *Inquiry Concerning the Commission's Pricing Policy for Transmission Services Provided by Public Utilities Under the Federal Power Act; Policy Statement*, 59 Fed. Reg. 55,031 at 55037 (Nov. 3, 1994), FERC Stats. & Regs. ¶ 31,005 at 31,146 (1994), *order on reconsideration*, 71 FERC ¶ 61,195 (1995) (Transmission Pricing Policy Statement). Please refer to Attachment OPUC Bench Request 11 for copies of the aforementioned documents.

If a transmission provider must construct new transmission facilities or upgrade existing facilities to accommodate a transmission service request as required by the transmission provider's Open Access Transmission Tariff ("OATT"), then the transmission provider must determine whether those facilities are network upgrades or direct assigned facilities for purposes of cost allocation between the transmission provider and the transmission customer. This determination involves an analysis of factors such as whether the relevant facilities are integrated with the transmission network and whether the facilities provide benefits to the network as a whole, among other factors. To that end, in determining whether a transmission upgrade or new transmission facility provides benefits to the network, FERC has stated that "[a] benefit need not be large to be significant."[1]

PacifiCorp's OATT defines "Network Upgrades" as "[m]odifications or additions to transmission related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users" and "Direct Assigned Facilities" as "[f]acilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer[.]" (OATT Sections 1.27 and 1.11, respectively). FERC has indicated that if there is any degree of integration with the network, the facilities should be considered network facilities.[2]

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1 *Northeast Texas Elec. Coop.*, 111 FERC ¶ 61,189 at P 4 (2005) *("NTEC")*.

2 *NTEC*, 111 FERC ¶ 61,189 at P 4 (2005).

The difference between the two designations can be demonstrated by an example. If a transmission facility addition is a radial line from the transmission customer's facilities connecting into the transmission provider's substation, the line would be considered a Direct Assigned Facility because the radial line is for the sole purpose of supporting the individual customer and there is no use by or benefit to other transmission customers. Conversely, if the transmission facility additions also included a breaker to be added to the existing substation in order to connect the new radial line, this addition is integrated with the transmission system and provides a benefit to the overall transmission system that is also realized by other transmission customers because there are new facilities in the flow path of the network used by all transmission customers. Under these circumstances, the breaker would be designated as a Network Upgrade. The new Sigurd to Red Butte transmission line interconnects and supports the existing transmission system, is not a radial line as discussed in the example above, and can be used by other transmission customers and is therefore appropriately designated as a Network Upgrade.

If the new or upgraded facilities are not Network Upgrades, then the transmission provider can directly assign the costs to upgrade or build the facilities to the requesting transmission customer. If, on the other hand, the new or upgraded facilities are Network Upgrades, then the transmission provider includes the cost of the transmission facility in its overall transmission revenue requirement and will charge the transmission customer a "rolled-in" embedded transmission rate that includes the upgrade costs. This rate is paid by all transmission customers. FERC has identified an additional cost allocation option for Network Upgrades which a transmission provider may use when the Network Upgrades are associated with a point-to-point transmission service request. In that case, the transmission provider may charge an incremental transmission service rate.

Incremental transmission rates are designed based upon the specific value of the Network Upgrade, whereas an embedded rate is the rate produced by embedding the cost of the Network Upgrade into the transmission provider's overall transmission rate base and revenue requirement. Incremental rates must be set forth in the point-to-point transmission service agreement with the transmission customer, which must be filed and approved by FERC. The transmission service agreement terms for incremental rates could include an upfront lump sum payment, a monthly payment based on estimated incurred costs, a monthly payment based on actual incurred costs or some other type of payment schedule agreed to by both parties and approved by FERC. In the case of the new Sigurd to Red Butte transmission line, there were no transmission service requests associated with point-to-point transmission service. Thus, the option to pursue incremental transmission rates was not available.

OPUC Bench Request 12

C. Federal Energy Regulatory Commission (FERC) and Cost Allocation

Does the ability of a transmission provider to require up-front contributions from entities requesting transmission service prior to Pacific Power constructing a new transmission line vary by whether the requested service is point-to-point or network transmission? Is the transmission provider precluded from requiring an entity requesting network transmission service to explore other less cost alternatives? Please explain and provide relevant FERC decisions.

Response to OPUC Bench Request 12

In response to the first question included as part of this bench request, please refer to PacifiCorp's Response to OPUC Bench Request 11.

There is no requirement for a transmission provider to require an entity requesting network transmission service to explore lower-cost alternatives. The Open Access Transmission Tariff ("OATT") requires PacifiCorp to offer the transmission service requested by the transmission customer. See, e.g., OATT Section III, 28.2 Network Integration Transmission Service Transmission Provider Responsibilities, which provides: "The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System… shall include the Network Customer's Network Load in its Transmission System planning… and place into service sufficient transfer capability to deliver the Network Customer's Network Resource to serve its Network Load…."

It is the responsibility of the transmission provider to determine what actions must be taken to provide the requested service, including whether transmission facility additions or upgrades are needed. As part of the transmission service request studies performed to determine if the service can be provided on the existing transmission system or if new additions are required, a review of transmission solutions to provide the service is explored by the transmission provider. Although not required by the OATT, as a matter of prudent utility practice the transmission provider will move forward with the least-cost option to provide the requested service and maintain the lowest possible transmission rates for all transmission customers that will be required to pay the embedded transmission service rate. The OATT has no requirement that the party requesting transmission service explore other lower-cost options for service. Further, FERC Order No. 739 provides: "Transmission providers will continue to be obligated to offer available transfer capability to customers, including available transfer capability associated with purchased but unused capacity. Transmission providers also will continue to be obligated to construct new facilities to satisfy requests for service if those requests cannot be satisfied using existing capacity." *Promoting a Competitive Market for*

Capacity Reassignment, Order No. 739, 132 FERC ¶ 61,238 at P 27 (2010). A copy of Order No. 739 is provided as Attachment OPUC Bench Request 12.

OPUC Bench Request 13

C. Federal Energy Regulatory Commission (FERC) and Cost Allocation

Have there been any discussions or negotiations between Pacific Power, UAMPS, and Deseret regarding alternative funding arrangements for the construction of the Sigurd to Red Butte Line (such as the sharing of upfront capital costs)?

Response to OPUC Bench Request 13

PacifiCorp, UAMPS, and Deseret, as well as local distribution utilities from the area, have undertaken joint planning for southwest Utah since the early 1990s. This joint planning was mandated by the Public Service Commission of Utah after disagreements about how to reliably serve the area in the late 1980s. After carefully considering load forecasts, load patterns, local generation, and many other factors, this planning group concluded that the construction of an additional Sigurd to Red Butte 345 kV transmission line was necessary to reliably serve the loads in the area.

PacifiCorp is required to provide safe, cost-efficient, and reliable transmission service to all network customers under its Open Access Transmission Tariff ("OATT"). As legacy network customers, UAMPS and Deseret are required to provide an accurate load and resource submittal to support PacifiCorp in the provision of this obligation and to enable PacifiCorp to effectively study and plan its transmission system. UAMPS and Deseret have been diligent in providing this annual submittal (and any necessary updates throughout the year). Necessary network upgrades identified during the annual load and resource submittal and review process would be scheduled and costs allocated under PacifiCorp's OATT as required by the Federal Energy Regulatory Commission's cost allocation policies for network facility upgrades. Please refer to PacifiCorp's Response to OPUC Bench Request 11. Therefore, no discussion or negotiation with UAMPS and Deseret regarding project funding was necessary or appropriate.

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Responses to Bench Request Nos. (1-13) on the parties listed below via electronic mail in compliance with OAR 860-001-0180.

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Dated this 27th of March 2014.

Amy Eissler
Coordinator, Regulatory Operations

132 FERC ¶ 61,238
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

18 CFR Part 35

[Docket No. RM10-22-000; Order No. 739]

Promoting a Competitive Market for Capacity Reassignment

(Issued September 20, 2010)

AGENCY: Federal Energy Regulatory Commission.

ACTION: Final Rule.

SUMMARY: The Federal Energy Regulatory Commission lifts the price cap for all electric transmission customers reassigning transmission capacity based on the Commission's experience to date and a two-year study, released April 15, 2010. The removal of the price cap is intended to help facilitate the development of a market for electric transmission capacity reassignments as a competitive alternative to transmission capacity acquired directly from the transmission owner.

EFFECTIVE DATE: This rule will become effective upon publication in the *Federal Register* or at 12:00 a.m. on October 1, 2010 whichever is sooner.

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SUPPLEMENTARY INFORMATION:

132 FERC ¶ 61,238
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

Promoting a Competitive Market for Capacity Reassignment — Docket No. RM10-22-000

ORDER NO. 739

FINAL RULE

(Issued September 20, 2010)

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1. Based on the Commission's experience to date and a two-year study, released April 15, 2010,[1] the Federal Energy Regulatory Commission in this Final Rule makes permanent the lifting of price caps for transmission customers reassigning electric transmission capacity. This action is intended to facilitate the development of a market for electric transmission capacity reassignments as a competitive alternative to primary transmission capacity.

I. Background

2. In Order No. 888, the Commission concluded that a transmission provider's *pro forma* Open Access Transmission Tariff (OATT) must permit explicitly the voluntary reassignment of all or part of a holder's firm point-to-point capacity rights to any eligible customer.[2] The Commission also found that allowing holders of firm transmission capacity rights to reassign that transmission capacity would help parties manage the financial risks associated with their long-term commitment, reduce the market power of

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[1] FERC Staff, *Staff Findings on Capacity Reassignment* (2010), *available at* http://www.ferc.gov (Staff Report).

[2] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities*, Order No. 888, 61 FR 21540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036, at 31,696 (1996), *order on reh'g*, Order No. 888-A, 62 FR 12274 (March 14, 1997), FERC Stats. & Regs. ¶ 31,048 (1997), *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

transmission providers by enabling customers to compete, and foster efficient transmission capacity allocation.

3. With respect to the appropriate rate for transmission capacity reassignment, the Commission concluded it could not permit reassignments at market-based rates because it was unable to determine that the market for reassigned transmission capacity was sufficiently competitive so that resellers would not be able to exert market power. Instead, the Commission capped the rate at the highest of: (1) the original transmission rate charged to the purchaser (assignor); (2) the transmission provider's maximum stated firm transmission rate in effect at the time of the reassignment; or (3) the assignor's own opportunity costs capped at the cost of expansion (price cap). The Commission further explained that opportunity cost pricing had been permitted at "the higher of embedded costs or legitimate and verifiable opportunity costs, but not the sum of the two (i.e., 'or' pricing is permitted; 'and' pricing is not)."[3] In Order No. 888-A, the Commission explained that opportunity costs for transmission capacity reassigned by a customer should be measured in a manner analogous to that used to measure the transmission provider's opportunity cost.[4]

4. To foster the development of a more robust secondary market for transmission capacity, the Commission, in Order No. 890, concluded that it was appropriate to lift the

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[3] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,740.

[4] Order No. 888-A, FERC Stats. & Regs. ¶ 31,048 at 30,224.

price cap for all transmission customers reassigning transmission capacity.[5] The Commission stated that this would allow transmission capacity to be allocated to those entities that value it most, thereby sending more accurate price signals to identify the appropriate location for construction of new transmission facilities to reduce congestion.[6] The Commission also found that market forces, combined with the requirements of the *pro forma* OATT as modified in Order No. 890, would limit the ability of resellers, including affiliates of the transmission provider, to exert market power.

5. To enhance oversight and monitoring activities, the Commission adopted reforms to the underlying rules governing transmission capacity reassignments.[7] First, the Commission required that all resales or reassignments of transmission capacity be conducted through or otherwise posted on the transmission provider's OASIS on or before the date the reassigned service commences.[8] Second, the Commission required that assignees of transmission capacity execute a service agreement prior to the date on

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[5] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 FR 12266 (March 15, 2007), FERC Stats. & Regs. ¶ 31,241, at P 808 (2007), *order on reh'g*, Order No. 890-A, 73 FR 2984 (January 16, 2008), FERC Stats. & Regs. ¶ 31,261 (2007), *order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228 (2009), *order on clarification,* Order No. 890-D, 129 FERC ¶ 61,126 (2009).

[6] Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 808.

[7] *Id*. P 815.

[8] *Id*.

which the reassigned service commences.[9] Third, in addition to existing OASIS posting requirements, the Commission required transmission providers to aggregate and summarize in an electric quarterly report the data contained in these service agreements.[10]

6. The Commission also directed staff to closely monitor the reassignment-related data submitted by transmission providers in their quarterly reports to identify any problems in the development of the secondary market for transmission capacity and, in particular, the potential exercise of market power.[11] Thus, the Commission directed staff to prepare, within six months of receipt of two years of quarterly reports, a report summarizing its findings.[12] In addition, the Commission encouraged market participants to provide feedback regarding the development of the secondary electric transmission capacity market and, in particular, to contact the Commission's Enforcement Hotline if concerns arise.

7. In Order No. 890-A, the Commission affirmed its decision to remove the price cap on reassignments of electric transmission capacity but granted rehearing to limit the

[9] *Id*. P 816.

[10] *Id*. P 817.

[11] *Id*. P 820.

[12] *Id*.

period during which reassignments may occur above the cap.[13] The period was limited so that the Commission could review the Staff Report to see if changes were needed based on the actual operation of the reassignment program. Accordingly, the Commission amended section 23.1 of the *pro forma* OATT to reinstate the price cap as of October 1, 2010.[14]

8. The Commission also clarified that, as of the effective date of the reforms adopted in Order No. 890, all reassignments of electric transmission capacity must take place under the terms and conditions of the transmission provider's OATT. As a result, there was no longer a need for the assigning party to have on file with the Commission a rate schedule governing reassigned capacity. To the extent that a reseller has a market-based rate tariff on file, the provisions of that tariff, including a price cap or reporting obligations, will not apply to the reassignment since such transactions no longer take place pursuant to the authorization of that tariff.

9. In Order No. 890-B, the Commission clarified that the *pro forma* OATT does not, and will not, permit the withholding of transmission capacity by the transmission provider and that it effectively establishes a price cap for long-term reassignments at the transmission provider's cost of expanding its system.[15] The Commission further found

[13] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 388, 390.

[14] *Id*. P 390.

[15] Order No. 890-B, 123 FERC ¶ 61,299 at P 78.

that the fact that a transmission provider's affiliate may profit from congestion on the system does not relieve the transmission provider of its obligation to offer all available transmission capacity and expand its system as necessary to accommodate requests for service.[16] The Commission pointed out that customers that do not wish to participate in the secondary market may continue to take service from the transmission provider directly, just as if the price cap had not been lifted.[17]

10. With regard to the Staff Report, the Commission clarified that staff should focus on the competitive effects of removing the price cap for reassigned electric transmission capacity.[18] The Commission stated that staff should consider the number of reassignments occurring over the study period, the magnitude and variability of resale prices, the term of the reassignments, and any relationship between resale prices and price differentials in related energy markets. In addition, the Commission directed staff to examine the nature and scope of reassignments undertaken by the transmission provider's affiliates and include in its report any evidence of abuse in the secondary market for transmission capacity, whether by those affiliates or other customers.

11. The Commission also granted rehearing and directed each transmission provider to include in its electric quarterly report the identity of the reseller and indicate whether the

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[16] *Id*.

[17] *Id*. P 79.

[18] *Id*. P 83.

reseller is affiliated with the transmission provider.[19] The Commission also directed each transmission provider to include in its electric quarterly reports the rate that would have been charged under its OATT had the secondary customer purchased primary service from the transmission provider for the term of the reassignment.[20] The Commission directed transmission providers to submit this additional data for all resales during the study period and to update, as necessary, any previously-filed electric quarterly reports on or before the date they submitted their next electric quarterly reports.

12. On April 15, 2010, Commission staff published its report on the two-year study period.[21] The Staff Report took a comprehensive look at electric point-to-point transmission capacity reassignment that occurred over the period from the second quarter of 2007 through the fourth quarter of 2009. Staff examined all reported electric transmission reassignments during this period on both a national and a regional basis. These almost 35,000 transactions encompassed 65 TWh of total volume transferred. Staff looked at the data in a number of ways, in order to better understand the market and to look for evidence of abuse. In doing so, staff looked at the magnitude and variability of resale prices, and focused on trends in those numbers over time and by region. Staff

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[19] *Id*. P 84.

[20] *Id*.

[21] FERC Staff, *Staff Finding on Capacity Reassignment* (2010), *available at* http://www.ferc.gov (Staff Report).

compared resale prices to the maximum tariff rates that would have otherwise been in effect for those transactions. Further, staff looked at reassignments by term – hourly, daily, monthly, and yearly and looked at differences in term by transmission provider and by volume. Where the receipt and delivery points of transactions had reported price indices with sufficient data, staff compared the prices of reassignments to the energy market spread (differential in prices between the two locations) over the same time periods.

13. Staff also compared resale prices for transactions involving affiliates versus non-affiliates. Staff compared the rate of transactions above the cap for both affiliates and non-affiliates. Staff looked for additional forms of affiliate abuse such as a transmission provider providing preferential treatment in the allocation of reassigned capacity to an affiliate. Staff also checked for complaints of the abuse in affiliate transactions, as well as for capacity reassignment in general.

14. Two weeks after the release of the Staff Report, based on the Commission's experience in the natural gas transportation market and the Staff Report's conclusion that the secondary market had grown substantially and that resale prices reflected market fundamentals rather than the exercise of market power, the Commission issued a Notice of Proposed Rulemaking (NOPR) proposing to lift the price cap for all electric transmission customers reassigning transmission capacity beyond October 1, 2010. In addition, the Commission proposed to direct transmission providers to submit corresponding revisions to their OATTs within 30 days of publication of the Final Rule in

the *Federal Register*. The Commission also sought comment as to whether there are any other reforms that it should undertake to create a more efficient and vibrant secondary market for electric transmission capacity. In response to these NOPR proposals, the Commission received comments from 13 parties, which are addressed below.[22]

II. Discussion

A. Removal of the Price Cap

1. Comments

15. Several commenters support the Commission's proposal to remove the price cap on transmission reassignments permanently.[23] They contend that removal of the cap will encourage the development of a more robust secondary market, resulting in appropriate price signals and an efficient allocation of transmission capacity. Cargill comments that the resale of transmission capacity at negotiated rates is consistent with other Commission reforms in favor of market-based pricing.

16. Despite their general support for the Commission's proposal, EPSA and PG&E raise concerns about the staff study and the need for transparency. EPSA states that the Staff Report shows some gaps that will require further analysis; such as limited numbers of transmission providers reported and the majority of transactions being from Bonneville. PG&E expresses a lingering concern about the potential for transmission

[22] A list of commenters is provided in Appendix A.

[23] *E.g.* Bonneville, Cargill, EPSA, FIEG, PG&E, PGE, Powerex, Seattle.

service providers to raise power prices in locations where there is insufficient competition. EPSA and PG&E urge the Commission to continue to monitor the capacity reassignment market as it matures so that the Commission will be informed and therefore able to direct necessary reforms to the market, as the needed reforms reveal themselves. EPSA further urges the Commission to look at ways of increasing transparency for transmission capacity available for reassignments as a way of promoting the secondary market for reassignment. Powerex comments that there are already a number of safeguards including requirements that transmission providers report reassignments on their systems on OASIS and in the electronic quarterly reports (EQR) that should help limit abuses. Similarly, Seattle comments that reconciliation of EQRs, audits, and OASIS transactions would go a long way to ensure that resale markets are functioning without affiliate abuse.

17. Bonneville agrees that lifting the price cap on transmission capacity reassignments appears to support the goal of a more robust secondary market for that capacity but asks the Commission to recognize the position of non-jurisdictional entities, such as itself. Bonneville contends that non-jurisdictional entities may have to place conditions upon the removal of the cap in order to obtain reciprocity and comply with their applicable statutory requirements. Bonneville contends that if its administrator determines that behavior associated with transmission capacity reassignments is occurring on its system in a manner that frustrates or is otherwise inconsistent with the administrator’s statutory requirements to make all excess capacity available to utilities on a fair and

nondiscriminatory basis, the administrator must be able to act promptly to stop that behavior. Thus, Bonneville suggests that any revision to section 23 of Bonneville's OATT permanently lifting the price cap must be conditioned upon the administrator's express authority to carry out this mandate including the right to reinstate the cap expeditiously if necessary.

18. Other commenters argue against removal of the price cap, contending that staff's two-year study provides insufficient evidence to support a finding that the secondary market is sufficiently competitive to lift the price caps or that market forces or other factors will be effective to adequately protect consumers.[24] These commenters point out that, although the Final Rule would apply to an estimated 132 public utilities, the Staff Report included data from only 26 with 79 percent of the reported transactions coming from Bonneville. These commenters also point out that the study was performed during a recession with concomitant reductions in the demand for electricity, and that Bonneville is atypical, given that it is dependent on large hydroelectric projects. APPA further comments that because there were so few sales made during the study period by affiliates above the rate cap, it would appear that reinstitution of the cap would not significantly dampen resales of capacity by affiliates of transmission providers.

19. TAPS states that the staff study did not examine both prices offered and accepted such that the Commission could determine the level of market interest in reassigned

[24] *E.g.* APPA, NRECA, SCE, TAPS, Outland, and TDU Systems.

capacity, whether prices increased, the cause of price changes, and whether those prices remained in the zone of reasonableness. It notes that the staff study compared resale prices during the study period to the tariff rate, but not to the opportunity cost cap, which is likely higher. It argues that accordingly, the study does not show that the price cap constrained any prices, and thus it prevents a finding that the price cap is unjust and unreasonable. SCE requests that the Commission reconcile its proposal with findings in the Staff Report that removal of the price cap does not appear to be primarily responsible for the observed growth in the secondary market. It also states that the Staff Report did not definitively conclude that there was not abuse by resellers, even in a period with very low demand and no supply scarcity. SCE states that this is not sufficient evidence to lift the price cap. APPA, SCE and TAPS suggest that, if the Commission wishes to lift the price cap, it should only do so as a continuation of the experiment.

20. NRECA, TAPS, and TDU Systems argue that the Staff Report does not provide a sufficient factual basis for the Commission to conclude that the OATT section 23.1, which reinstates the price cap on October 1, 2010, is unjust and unreasonable or to conclude that proposed revision is just and reasonable. Moreover, TAPS and TDU Systems comment that market-based reassignment of transmission capacity should not be available to entities to the extent they lack market-based rate authority in the area in which the transmission reservation is located. TDU Systems states that each secondary transmission capacity market should be looked at individually, and that there is no single, national market for secondary transmission capacity rights. It questions why the Staff

Report considers Public Service of New Hampshire (PSNH) to be an aberration, while the nearby Central Vermont Public Service Corporation (Central Vermont) system is presented as representing national trends.

21. TAPS and TDU Systems further contend that, to permit market-based rates, the Commission remains bound by the requirement that market-based rates be supported by empirical proof that existing competition would ensure that the actual price is just and reasonable.[25] TDU Systems comments that courts have held that undocumented reliance on market forces is insufficient grounds for authorizing market-based rates.[26] Moreover, TAPS and TDU Systems argue that the Commission has a requirement to make an *ex ante* finding of the absence of market power and sufficient post-approval requirements.[27] SCE agrees that the Commission should engage in an *ex ante* competitive analysis to find that the transmission reseller lacks market power, or take sufficient steps to mitigate market power, as well as adopt sufficient post-approval reporting requirements.

22. Outland states that the pilot project has allowed resellers to acquire capacity "for pennies and then hold up the first renewable energy generator that comes along looking

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[25] *Citing Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486, 1510 (D.C. Cir. 1984)(*Farmers Union*).

[26] *Citing Transwestern Pipeline*, 43 FERC ¶ 61,240, at 61,250 (1988).

[27] *Citing California ex. Rel. Lockyer v. FERC*, 383 F.3d 1006, 1013 (9th Cir. 2004).

to use it."[28] It states that parties acquire transmission when they do not need it for a real generation project, to the detriment of real projects.

23. NRECA, TAPS, and TDU Systems urge the Commission, at a minimum, to retain the price cap on transmission capacity reassignments for transmission provider affiliates and retail/merchant functions. TAPS states that the pattern of affiliate pricing reveals more about corporate strategy selected by a few corporate entities and general conditions during an atypical period, than confirming the Commission's assumption that the rates for primary capacity or competition in the reassignment market will restrain prices. It states that assuming that the customer may always take service from the transmission provider directly is cold comfort if the available capacity has been assigned to the transmission provider's affiliate. NRECA states that a larger portion of affiliate than non-affiliate transactions occurred over the cap, and points to the PSNH system where all reported transactions originated with an affiliate and occurred over the price cap.

24. In its supplemental comments, Powerex expresses concern that Bonneville might reinstate the price cap as of October 1, 2010, regardless of Commission action in this proceeding. Powerex asks the Commission to address the possible adverse consequences of non-jurisdictional transmission providers reinstating price caps on transmission reassignments and to provide guidance to customers seeking to reassign transmission on the systems of non-jurisdictional transmission providers that elect not to adopt any

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[28] Outland at 1.

reforms the Commission directs. To address this issue, Powerex requests the Commission to clarify that its seller-specific market-based rate schedule for transmission reassignment remains operative. Alternatively, Powerex seeks guidance on how to price capacity reassignments based on the customer's opportunity cost capped at the transmission provider's cost of expansion.

2. Commission Determination

a. Removal of the Price Cap

25. The Commission hereby adopts its NOPR proposal to lift the price cap for all reassignments of electric transmission capacity to become effective October 1, 2010. Removal of the price cap will help foster the development of a more robust secondary market for transmission capacity because point-to-point transmission service customers will have increased incentives to resell their service whenever others place a higher value on it. Existing transmission, therefore, may be put to better, more efficient use.

26. Moreover, removal of the price cap will promote the efficient construction of new capacity. Prices serve as signals indicating where capacity shortages exist and where potentially profitable construction can take place. The Commission has previously addressed the need for new transmission and established incentives for its construction.[29] Removing the price cap on sales of secondary electric transmission capacity is one way to

[29] *Promoting Transmission Investment through Pricing Reform*, Order No. 679, 71 FR 43294 (July 31, 2006), FERC Stats. & Regs. ¶ 31,222 (2006), *order on reh'g*, Order No. 679-A, 72 FR 1152 (January 10, 2007), FERC Stats. & Regs. ¶ 31,236 (2006), *order on reh'g*, 119 FERC ¶ 61,062 (2007).

create the proper incentives for new transmission investment in this industry. Areas with congestion tend to have higher prices and thus signal the need for investment.[30] However, if prices for reassigned capacity exceed the cost of construction of new transmission, the customer could request service from the transmission provider which would support investment in new transmission and lower costs prospectively by relieving constrained transmission capacity. Thus, the price of reassigned capacity will remain effectively capped at the cost of new transmission. We therefore reaffirm the Commission's finding in Order No. 890-A that removal of the price cap for reassigned capacity will help establish a competitive market for secondary transmission capacity that will send more accurate signals and that such price signals will promote more efficient use of the electric transmission system.[31]

27. Our continued regulatory oversight will also limit the potential for the exercise of market power. We are not deregulating or otherwise adopting market-based rates for the provision of transmission service under the *pro forma* OATT. Transmission providers will continue to be obligated to offer available transfer capability to customers, including available transfer capability associated with purchased but unused capacity. Transmission providers also will continue to be obligated to construct new facilities to

[30] *See Interstate Nat'l Gas Ass'n of America v. FERC*¸ 285 F.3d 18, 32-34 (D.C. Cir. 2002) (*INGAA*) ("[B]rief spikes in moments of extreme exigency are completely consistent with competition, reflecting scarcity rather than monopoly.").

[31] Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 at P 388.

satisfy requests for service if those requests cannot be satisfied using existing capacity. Furthermore, the rates for transmission service provided under the *pro forma* OATT will continue to be determined on a cost-of-service basis unless the transmission provider can demonstrate, on a case-specific basis, that it lacks market power. Nothing in this Final Rule affects the obligations of transmission providers to offer service under the *pro forma* OATT at cost-based rates. The availability of firm and non-firm service from transmission providers, therefore, will limit the ability of reassignors to exercise market power. In *INGAA*, the Court of Appeals for the District of Columbia Circuit recognized that the maintenance of regulated rates for primary service would protect against the potential for the exercise of market power in the capacity release market.[32]

28. The Commission disagrees with suggestions that affiliates of the transmission provider be treated differently than non-affiliated customers with respect to reassignments of transmission capacity. The Commission's Standards of Conduct are designed to prevent the transmission provider and its affiliate from acting in concert to

[32] 285 F.3d at 32 ("[i]f holders of firm capacity do not use or sell all of their entitlement, the pipelines are required to sell the idle capacity as interruptible service to any taker at no more than the maximum rate - which is still applicable to the pipelines"); *see also*, *Promotion of a More Efficient Capacity Release Market*, Order No. 712, 73 FR 37058 (June 30, 2008), FERC Stats. & Regs. ¶ 31,271, at P48-49 (2008), *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008).

exercise market power.[33] Commenters did not identify any affiliate concerns that these obligations, along with the monitoring discussed below, would not address.

29. The Commission takes seriously the possibility that resellers may attempt to exercise market power in the secondary market for transmission. We continue to find, however, that the regulatory protections in place and our increased oversight of this market will limit the potential for market power abuse. Prices for secondary transmission capacity may rise above prices for primary transmission capacity but this alone does not indicate an abuse of market power. On the contrary, courts have recognized that prices in a competitive market should rise during periods when capacity is truly scarce in order to ensure that transmission capacity is being allocated appropriately.[34] Nevertheless, the Commission will continue to monitor the secondary transmission capacity market to

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[33] *See Standards of Conduct for Transmission Providers*, Order No. 717, 73 FR 63796 (October 27, 2008), FERC Stats. & Regs. ¶ 31,280 (2008), *order on reh'g*, Order No. 717-A, 74 FR 54463 (October 22, 2009), FERC Stats. & Regs. ¶ 31,297 (2009), *order on reh'g*, Order No. 717-B, 129 FERC ¶ 61,123 (2009), *order on reh'g*, Order No. 717-C, 131 FERC ¶ 61,045 (2010). The Commission's Standards of Conduct establish that a transmission provider must (1) treat all customers, affiliated and non-affiliated, on a not unduly discriminatory basis, (2) not make or grant any undue preference or advantage to any person, and (3) not subject any person to any undue prejudice or disadvantage with respect to transmission of electric energy. This would include avoiding undue prejudice or disadvantage in the initial allocation of capacity to affiliates, thereby allowing those affiliates to gain market power and then to exercise it when reassigning capacity.

[34] *INGAA*¸ 285 F.3d at 32-34 ("[B]rief spikes in moments of extreme exigency are completely consistent with competition, reflecting scarcity rather than monopoly.").

ensure that participants are not exercising market power.[35] The Commission also will monitor for abuse by transmission providers in concert with their affiliates. If a customer has evidence of an exercise of market power or other abuse, it should bring the matter to the Commission's attention through a complaint or other appropriate procedural mechanism. Absent such evidence, the Commission concludes that the continued rate regulation of the primary market for electric transmission capacity and the transmission provider's obligation to expand its system to accommodate service requests adequately mitigates any market power that resellers may have in the long-term secondary market.

30. The Staff Report did not raise any concerns with removal of the price cap that would warrant its reimposition given the regulatory protections and increased market oversight discussed above. The report included a comprehensive examination of the assignments that took place during the study period which included both the period prior to the economic downturn starting in September 2008 and the period after the downturn. Although the Staff Report did not conclusively demonstrate that the price cap inhibited the growth of the secondary market, the data showed a marked growth in reassignments, with both the number of transactions and the volume increasing during the two and one half year time span. The number of reassignments grew from just over 200 in 2007 to almost 32,000 in 2009. During this same period, the volume reassigned grew from 3 TWh to 36 TWh.

[35] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 815.

31. The data do not suggest the exercise of market power. The prices during the test period appear consistent with pricing differentials between locational markets, indicating that the transactions reflect market fundamentals, not the exercise of market power.[36] Moreover, the Staff Report found that 99 percent of reassignments were priced at or below the transmission provider's maximum firm transmission rate, an indication that prices reflect market conditions and competition rather than the exercise of market power.[37] The brief spikes above the price cap are consistent with a competitive market, indicating scarcity rather than market power.[38]

32. We disagree with comments suggesting that the Staff Report does not provide enough evidence to support a finding that the market is sufficiently competitive to lift the price cap because it relied on data from a limited number of transmission providers. While capacity reassignments occurred on a limited number of transmission systems, the lack of data for other transmission providers indicates a lack of reassignments on those systems, not an exercise of market power or lack of potential competition for capacity reassignment. Where reassignment is currently non-existent or occurring at a lower level,

[36] *See INGAA*, 285 F.3d at 31 (indicating that differentials in prices between receipt and delivery points are indicative of the value of the transportation between those points).

[37] Because 99 percent of the prices were below the tariff rate, these prices are almost certainly lower than opportunity costs which TAPS suggests are likely higher than the tariff rate.

[38] *INGAA*, 285 F.3d 18, 32 ("A surge in the price of candles during a power outage is no evidence of monopoly in the candle market").

potential reassignment of transmission in these areas, should it develop, would face competition associated with transmission that can be acquired from other customers. Such reassignment also would compete with capacity available from the transmission provider. Although the data in the Staff Report included extensive data from Bonneville and Central Vermont, the greater number of such assignments may be due to differences in market dynamics (such as the extensive use of hydroelectric power in the Bonneville region) or reporting conventions (in the case of Central Vermont).[39] It also may indicate that capacity reassignment is more developed in those areas. The volume of capacity reassignments on these two systems provides an example of what may be possible in other areas of the country. As for arguments that the time period under review was atypical due to the economic downturn and, thus, not representative, we note that study began the second quarter of 2007, well before the downturn began.

33. The Staff Report also did not show evidence of affiliate abuse. Ninety-nine percent of reassignments by affiliates of the transmission provider were at or below the transmission provider's maximum rate. The percentage of such reassignments over the maximum firm transmission rate by affiliates was comparable to that by non-affiliates (0.5 percent versus 0.4 percent).

[39] The Staff Report states that "the large number of [Central Vermont] transactions may be due, in part, to reporting conventions. For EQR reporting purposes, each line of data is counted as one transaction." *See* Staff Report at 4.

34. While it is true, as some of the commenters point out, that the reassignment transactions were limited to certain areas and utilities, we see no reason to expect different results as capacity reassignment expands. There have not been allegations of the exercise of market power in reassignment markets, and commenters do not provide any data to suggest that market power may be more prevalent as capacity reassignment increases on other transmission systems. Development of a more robust reassignment market in areas where reassignments are not prevalent should raise, rather than lower, the level of competition in markets. Moreover, we will continue to monitor the market and if anomalies develop in certain areas, they can be addressed.

35. We disagree with the comments that a market power study or other empirical competition analyses are required to lift the price cap on transmission capacity reassignments. Contrary to commenters' assertions, market power analyses are not the only method to ensure that market-based rates remain just and reasonable.[40] In *INGAA*,[41] the D.C. Circuit affirmed the Commission's removal of price ceilings for short-term

[40] *See Alternatives to Traditional Cost-of-Service Ratemaking for Natural Gas Pipelines and Regulation of Negotiated Transportation Services of Natural Gas Pipelines*, 74 FERC ¶ 61,076, at 61,227-36 (1996). The Commission ultimately determined in that case that a market power analysis was required in order to allow a pipeline to use market-based pricing instead of cost-of-service rates. The Commission has not proposed to allow transmission providers to engage in sales of primary capacity at market-based rates and, as explained below, sufficient protections exist to ensure the secondary market for transmission capacity remains sufficiently competitive without requiring market power analyses from each reseller.

[41] *Interstate Nat'l Gas Ass'n of American v. FERC*, 285 F.3d at 33 (D.C. Cir. 2002).

capacity releases by shippers in the natural gas market without requiring sellers to submit market power analyses. The court recognized that non-cost factors such as the need to facilitate movement of capacity into the hands of those who value it most may also justify the removal of price ceilings. The court concluded that these non-cost factors, combined with the limitation of negotiated rates to the secondary market, distinguished the case from *Farmers Union* in which the court had reversed a Commission determination to implement lighthanded regulation of the oil industry.[42]

36. *Farmers Union* itself did not require a market power study to support a move to a more market-based regulatory regime. The court found that rates should be within a "zone of reasonableness, where [they] are neither less than compensatory nor excessive."[43] Moreover, the court found that the Commission could justify a move to a more market-based focus "by a showing that under circumstances the goals and purposes of [the Commission's statutory mandate] will be accomplished through substantially less regulatory oversight."[44] Here, the Commission is relying on competition in the market for transmission capacity, together with the regulatory protections discussed above, to ensure just and reasonable rates. Protections, such as continuing rate regulation of the

[42] *Interstate Nat'l Gas Ass'n of America v. FERC*, 285 F.3d 18 at 31-34 (D.C. Cir. 2002), *order on remand*, 101 FERC ¶ 61,127 (2002), *order on reh'g*, 106 FERC ¶ 61,088 (2004), *aff'd sub nom. American Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

[43] *Farmers Union*, 734 F.2d at 1502; *see also*, *INGAA*, 285 F.3d at 31.

[44] *Farmers Union*, 734 F.2d at 1510.

transmission provider's primary capacity, retention of the requirement for transmission owners to build additional capacity at cost-based rates, competition among resellers, reforms to the secondary market for transmission capacity, and reporting requirements combined with enforcement proceedings, audits, and other regulatory controls, will assure that prices in the secondary market for electric transmission capacity remain within a zone of reasonableness.[45]

b. Implementation of the Requirement

37. Because the current OATTs reinstate the price cap as of October 1, 2010, transmission providers will need to revise section 23 of the *pro forma* OATT, as indicated in Appendix B. We direct transmission providers to file these changes within 30 days from publication of this Final Rule in the *Federal Register*. Bonneville requests a blanket waiver of the requirement for non-jurisdictional entities that are unable to satisfy reciprocity conditions with regard to the reassignment of transmission capacity. Whether the particular terms and conditions of a non-jurisdictional transmission provider's reciprocity tariff satisfy the Commission's open access principles must be determined on a case-by-case basis. Therefore, the Commission denies, without prejudice, Bonneville's request for a blanket waiver.

[45] *See* Order No. 890, FERC Stats. & Regs. ¶ 31,241 at P 811; *see also* Order No. 712, 73 FR 37058 (June 30, 2008), FERC Stats. & Regs. ¶ 31,271 at P 39 (2008), *order on reh'g*, Order No. 712-A, FERC Stats. & Regs. ¶ 31,284 (2008), *aff'd sub nom. Interstate Natural Gas Ass'n of America*, No. 09-1016 (D.C. Cir. Aug. 13, 2010).

38. We find Powerex's concern that Bonneville will reinstate the price cap as of October 1, 2010 to be premature, since Bonneville has not made a final decision at this point. Moreover, when Bonneville submitted its tariff revisions pursuant to Order No. 890, it declined to adopt certain *pro forma* provisions related to the reassignment of transmission capacity and several transmission customers within Bonneville, including Powerex, filed stand-alone rate schedules allowing them to sell transmission capacity above the price cap.[46] These customers may submit any necessary revisions to their rate schedules before October 1, 2010 and request waiver of the prior notice requirement, if they find such action to be necessary and appropriate.

B. Non-Rate Reforms to Promote Secondary Market

1. NOPR Proposal

39. In the NOPR, the Commission sought comment as to whether there are any reforms, other than removal of the price cap, that it should undertake to create a more efficient and vibrant secondary market for transmission capacity. The Commission asked if there are non-price limitations or regional factors that may be continuing to limit the utility of reassignment. By way of an example, the Commission asked if there are

[46] *See Portland General Electric Co.*, Docket No. ER09-93-000 (Dec. 3, 2008) (unpublished letter order); *Idaho Power Co.*, Docket No. ER09-524-000 (Mar. 5, 2009) (unpublished letter order); *Puget Sound Energy, Inc.*, Docket No. ER09-528-000 (Mar. 5, 2009) (unpublished letter order); *Avista Corp.*, ER09-729-000 (May 12, 2009) (unpublished letter order); *PacifiCorp*, Docket No. ER09-921-001 (Sept. 29, 2009) (unpublished letter order); *Powerex Corp.*, Docket No. ER09-926-000 (May 21, 2009) (unpublished letter order).

reforms to the redirect process that would enable all firm customers to use their firm capacity more flexibly and thereby facilitate capacity reassignment by making point changes by the buyer of reassigned capacity more efficient.

2. Comments

40. Although FIEG supports the Commission's proposal to allow redirects of reassigned capacity, several other commenters raise concerns. Powerex admits that the ability to modify receipt and delivery points of reassigned capacity may make the capacity more attractive to a potential third-party assignee but warns that this practice would erode the priority that firm capacity should be accorded. NRECA expresses similar concern that this proposal may give higher priority to point-to-point customers who wish to redirect by awarding them service over those non-firm customers who do not redirect and over secondary network customers. APPA contends that any reforms to firm point-to-point service proposed to increase the attractiveness of re-sales of firm point-to-point capacity would have to be carefully assessed to ensure that they do not result in a degradation of the quality of network integration transmission service. TAPS and TDU Systems urge the Commission to not use a narrowly focused rulemaking to implement a sweeping change to point-to-point transmission service.

41. Commenters offered suggestions about various other reforms as well. Bonneville and Seattle argue that requiring transmission providers to act as financial intermediaries in capacity reassignments imposes an undue burden and complicates settlements. Powerex and Bonneville raise concerns about transmission providers failing to

recalculate available transfer capability or available flowgate capability in a timely manner, thereby inhibiting reassignments. Bonneville recommends that a firm redirect request receive a credit for any available flowgate capability the parent reservation has on the flowgates impacted by the firm redirect request. TAPS suggests that the Commission require the posting of transmission capacity available for reassignment on the transmission provider's OASIS. Cargill recommends that the reseller not remain responsible or liable to the transmission provider for the reassigned capacity if it is a complete reassignment (the full quantity of capacity for the remainder of the reservation) or if the reseller performs a long-term assignment of the reservation for any quantity up to the full amount of the capacity of the reservation.

42. Seattle advocates a transition from comma separated data to structured XML data in order to enhance data exchange and validation between "front-end" and "back-end systems" used by transmission customers and providers. It also advocates more meaningful forms of transaction umbrella agreements, such as the WSPP agreement. EPSA advocates consistent rules about posting the entities and market participants that have active umbrella agreements with the transmission provider. It says that such postings would give competitive suppliers transparency about which market participants can purchase reassigned capacity.

3. Commission Determination

43. The Commission declines to implement the non-rate reforms proposed in this proceeding at this time. Although some of these proposals may have merit, we are

unable to make a determination that they are appropriate at this time based on the record in this proceeding. With respect to the issues raised by Seattle and EPSA regarding data structures, such issues are best addressed through the standards development process of the North American Energy Standards Board, which sets voluntary wholesale electric market standards including those related to data exchanges and posting requirements.

III. Information Collection Statement

44. The following collection of information contained in this proposed rule is subject to review by the Office of Management and Budget (OMB) under section 3507(d) of the Paperwork Reduction Act of 1995.[47] OMB's regulations require OMB to approve certain information collection requirements imposed by agency rule.[48]

Burden Estimate: The public reporting and records retention burdens for the reporting requirements and the records retention requirement are as follows.[49] The Commission solicited comments on the need for this information and did not receive any specific comments regarding its burden estimates. Where commenters raised concerns that specific information collection requirements would be burdensome to implement, the Commission has addressed those concerns elsewhere in the rule.

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[47] 44 U.S.C. § 3507(d) (2006).

[48] 5 C.F.R. § 1320.11 (2010).

[49] These burden estimates apply only to this Final Rule and do not reflect upon all of FERC-516 or FERC-717.

Data Collection	Number of Respondents	Number of Responses	Hours per Response	Total Annual Hours
Conforming tariff changes	132	1	10	1,320

Cost to Comply: $150,480
1,320 hours @ $114 an hour (average cost of attorney ($200 per hour), consultant ($150), technical ($80), and administrative support ($25))

OMB's regulations require it to approve certain information collection requirements imposed by an agency rule. The Commission is submitting a copy of this Final Rule to OMB for their review approval of the information collection requirements.

Title: FERC-516, Electric Rate Schedules and Tariff Filings;

FERC-717 Standards for Business Practices and Communication Protocols for Public Utilities.

Action: Collection

OMB Control Nos. 1902-0096 and 1902-0173

Respondents: Transmission Providers

Frequency of responses: One time.

Necessity of the Information:

45. The Federal Energy Regulatory Commission is adopting amendments to the *pro forma* OATT to ensure that transmission services are provided on a basis that is just, reasonable and not unduly discriminatory or preferential. The purpose of this rulemaking is to strengthen the *pro forma* OATT by encouraging more robust competition. The Final

Rule achieves this goal by removing the price cap previously imposed on reassignments of transmission capacity.

46. Interested persons may obtain information on the reporting requirements by contacting the following: Federal Energy Regulatory Commission, 888 First Street, NE, Washington, DC 20426, [Attention: Michael Miller, Office of the Executive Director, Phone: (202) 502-8415, fax: (202) 273-0873, e-mail: michael.miller@ferc.gov.]

47. For submitting comments concerning the collections of information and the associated burden estimate(s), please send your comments to the contact listed above and to the Office of Information and Regulatory Affairs, Office of Management and Budget, 725 17th Street, NW, Washington, DC 20503 [Attention: Desk Officer for the Federal Energy Regulatory Commission, phone: (202) 395-4638, fax: (202) 395-7285. Due to security concerns, comments should be sent electronically to the following e-mail address: oira_submission@omb.eop.gov. Please reference the docket number of this rulemaking in your submission.

IV. Environmental Analysis

48. The Commission is required to prepare an Environmental Assessment or an Environmental Impact Statement for any action that may have a significant adverse effect on the human environment.[50] The Commission concludes that neither an Environmental

[50] *Regulations Implementing the National Environmental Policy Act*, Order No. 486, 52 FR 47897 (December 17, 1987), FERC Stats. & Regs., Regulations Preambles 1986-1990 ¶ 30,783 (1987).

Assessment nor an Environmental Impact Statement is required for this Final Rule under section 380.4(a)(15) of the Commission's regulations, which provides a categorical exemption for approval of actions under sections 205 and 206 of the Federal Power Act (FPA) relating to the filing of schedules containing all rates and charges for the transmission or sale subject to the Commission's jurisdiction, plus the classification, practices, contracts and regulations that affect rates, charges, classifications and services.[51]

V. Regulatory Flexibility Act

49. The Regulatory Flexibility Act of 1980 (RFA)[52] generally requires a description and analysis of Final Rules that will have significant economic impact on a substantial number of small entities. This Final Rule applies to public utilities that own, control, or operate interstate transmission facilities, not to electric utilities per se. The total number of public utilities that, absent waiver, would have to modify their current OATTs by filing the revised *pro forma* OATT is 176.[53] Of these only six public utilities, or less than two percent, dispose of four million MWh or less per year.[54] The Commission does not consider this a substantial number, and in any event, these small entities may seek waiver

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[51] 18 CFR § 380.4(a)(15) (2010).

[52] 5 U.S.C. § 601-612 (2006).

[53] The sources for this figure are FERC Form No. 1 and FERC Form No. 1-F data.

[54] *Id*.

of these requirements.[55] Moreover, the criteria for waiver that would be applied under this rulemaking for small entities is unchanged from that used to evaluate requests for waiver under Order Nos. 888 and 889. Thus, small entities who have received waiver of the requirements to have on file an open access tariff or to operate an OASIS would be unaffected by the requirements of this proposed rulemaking.

VI. Document Availability

50. In addition to publishing the full text of this document in the Federal Register, the Commission provides all interested persons an opportunity to view and/or print the contents of this document via the Internet through FERC's Home Page (http://www.ferc.gov) and in FERC's Public Reference Room during normal business hours (8:30 a.m. to 5:00 p.m. Eastern time) at 888 First Street, NE, Room 2A, Washington DC 20426.

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[55] The Regulatory Flexibility Act defines a "small entity" as "one which is independently owned and operated and which is not dominant in its field of operation." *See* 5 U.S.C. 601(3) and 601(6)(2000); 15 U.S.C. 632(a)(1) (2000). In *Mid-Tex Elec. Coop. v. FERC*, 773 F.2d 327, 340-343 (D.C. Cir. 1985), the court accepted the Commission's conclusion that, since virtually all of the public utilities that it regulates do not fall within the meaning of the term "small entities" as defined in the Regulatory Flexibility Act, the Commission did not need to prepare a regulatory flexibility analysis in connection with its proposed rule governing the allocation of costs for construction work in progress (CWIP). The CWIP rules applied to all public utilities. The revised *pro forma* OATT will apply only to those public utilities that own, control or operate interstate transmission facilities. These entities are a subset of the group of public utilities found not to require preparation of a regulatory flexibility analysis for the CWIP rule.

51. From FERC's Home Page on the Internet, this information is available on eLibrary. The full text of this document is available on eLibrary in PDF and Microsoft Word format for viewing, printing, and/or downloading. To access this document in eLibrary, type the docket number excluding the last three digits of this document in the docket number field.

52. User assistance is available for eLibrary and the FERC's website during normal business hours from FERC Online Support at (202) 502-6652 (toll free at 1-866-208-3676) or email at ferconlinesupport@ferc.gov, or the Public Reference Room at (202) 502-8371, TTY (202) 502-8659. E-mail the Public Reference Room at public.referenceroom@ferc.gov.

VII. Effective Date and Congressional Notification

53. These regulations shall become effective upon publication in the *Federal Register* or at 12:00am on October 1, 2010, whichever is sooner. Section 553(d) of the Administrative Procedure Act (APA) generally requires a rule to be effective not less than 30 days after publication in the *Federal Register* unless, *inter alia*, the rule relieves a restriction or good cause is otherwise found to shorten the time period.[56] Section 553(b)B) of the APA authorizes agencies to dispense with certain procedures when the agency, for good cause, finds that those procedures are "impracticable, unnecessary, or

[56] 5 U.S.C. § 553(d) (2006).

contrary to public interest."[57] For the following reasons the Commission is using the "Good Cause" exemption. This Final Rule must become effective by 12:00 a.m. on October 1, 2010 or the price cap on reassignments of electric transmission capacity will be reinstated. Reinstating the price cap would impose a restriction on the rights of transmission customers. Thus, this Final Rule relieves a restriction. Furthermore, the Commission finds that good cause exists to make this Final Rule effective immediately because allowing the price cap to be reinstated temporarily could disrupt the efficient management of the secondary market for electric transmission capacity and reduce opportunities for further reduction of transmission congestion.

54. The Commission has determined, with the concurrence of the Administrator of the Office of Information and Regulatory Affairs of OMB, that this rule is not a "major rule" as defined in section 351 of the Small Business Regulatory Enforcement Fairness Act of 1996.

<u>List of subjects in 18 CFR Part 35</u>

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[57] 5 U.S.C. § 553(b)(B) (2006).

Appendix A

List of Commenters

Commenter Name	Abbreviation
American Public Power Association	APPA
Bonneville Power Administration	Bonneville
Cargill Power Markets, LLC	Cargill
Electric Power Supply Association	EPSA
Financial Institutions Energy Group	FIEG
National Rural Electric Cooperative Association	NRECA
Outland Renewable Energy LLC	Outland
Pacific Gas & Electric Co.	PG&E
Portland General Electric Co.	PGE
Powerex Corp.	Powerex
Southern California Edison Co.	SCE
Seattle City Light	Seattle
Transmission Access Policy Study Group	TAPS
Transmission Dependent Utility Systems	TDU Systems

Appendix B

RM05-17-001, -002 & RM05-25-001, -002
(Issued)

PRO FORMA OPEN ACCESS TRANSMISSION TARIFF

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service:

(a) ~~Subject to Commission approval of any necessary filings, a~~A Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. ~~Compensation to Resellers shall not exceed the higher of (i) the original rate paid by the Reseller, (ii) the Transmission Provider's maximum rate on file at the time of the assignment, or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion; provided that, for service prior to October 1, 2010, c~~Compensation to Resellers shall be at rates established by agreement between the Reseller and the Assignee.

(b) The Assignee must execute a service agreement with the Transmission Provider governing reassignments of transmission service prior to the date on which the reassigned service commences. The Transmission Provider shall charge the Reseller, as appropriate, at the rate stated in the Reseller's Service Agreement with the Transmission Provider or the associated OASIS schedule and credit the Reseller with the price reflected in the Assignee's Service Agreement with the Transmission Provider or the associated OASIS schedule; provided that, such credit shall be reversed in the event of non-payment by the Assignee. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.