C A N A D A

PROVINCE OF PRINCE EDWARD ISLAND

BEFORE THE ISLAND REGULATORY AND APPEALS COMMISSION

IN THE MATTER of Section 20 of the Electric Power Act (R.S.P.E.I. 1988, Cap. E-4) and **IN THE MATTER** of the Application of Maritime Electric Company, Limited for an order approving the Open Access Transmission Tariff for the period beginning January 1, 2017 and for certain approvals incidental to such an order.

REPORT ON ISSUES ASSOCIATED WITH THE OPEN ACCESS TRANSMISSION TARIFF OF MARITIME ELECTRIC COMPANY, LIMITED

BY

WILLIAM H. DUNN, JR.
SUNSET POINT, LLC

INDEX

INDEX

Report on Issues Associated with the Open Access Transmission Tariff ("OATT") of Maritime Electric Company Limited ("MECL") by William H. Dunn, Jr., Sunset Point, LLC

A. Introduction

I, William H. Dunn, Jr. of Sunset Point, LLC, was requested by Key Murray Law, on behalf of Summerside Electric ("SE"), to review the OATT filed by MECL with the Island Regulatory and Appeals Commission ("IRAC") on July 8, 2016 from the point of view of a Transmission Customer ("TC") serving load. For clarity, I view both SE's and MECL's retail businesses as TCs (as are Generators). I was asked to specifically review the aspects of the OATT that I do not support.

This review was conducted independently, based on information received from Key Murray Law (the July 8, 2016 MECL OATT filing, the September 22, 2016 Technical Hearing presentations and audio CD, MECL's answers to SE's January 4, 2017 questions, West Cape Farm Agreement and various maps and one-line diagrams) and on my own research described below. I have finished my review of the information I have received and do not agree with: (i) the facilities included in the OATT rate; (ii) the planning process included in the OATT; (iii) the provision of discounts for exports under the OATT; and (iv) the penalties associated with scheduling imbalances. Below I will summarize my review with respect to these issues.

B. Facilities Included in the OATT

When looking at the facilities eligible for inclusion in a transmission utility's OATT I looked for guidance from the U.S. Federal Energy Regulatory Commission ("FERC"). I did this since MECL indicated[1] they were filing an OATT for the provision of transmission services to TCs on Prince Edward Island ("PEI") that was compliant with FERC guidelines. In particular, I was looking for relevant experience with respect to treatment of radial lines. At a high level, these are lines that are not part of the integrated bulk transmission system as they do not provide service to all TCs. As part of its review of facilities that should NOT be included in an OATT's rate, FERC developed two tests; the Seven Factor Test and the Mansfield Test.

FERC Seven Factor Test

The Seven Factor Test is used by FERC, such as when resolving a complaint from a TC, to determine which facilities of a Transmission Owner ("TO") should be included in the cost of its distribution system or directly assigned and NOT included in the rates for use of its transmission system under the terms and conditions of its OATT. Conceptually, these are facilities that are used to serve local load and not used for bulk power transmission or reliability. The seven factors are:[2]

1) Local distribution facilities are normally in close proximity to retail customers;
2) Local distribution facilities are primarily radial in character;

[1] In Section 3.2 of their July 8, 2016 filing MECL indicates that their "OATT document generally aligns with FERC Orders 888, 889 and 890 as well as other FERC orders".

[2] See, for example, paragraph 4 on page 3 of the December 31, 2015 Order on Local Distribution Determination in Southern California Edison Docket No. RC15-1-00 available at: http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14087859. See Tab A.

3) Power flows into local distribution systems, and rarely, if ever, flows out;
4) When power enters a local distribution system, it is not reconsigned or transported onto some other market;
5) Power entering a local distribution system is consumed in a comparatively restricted geographic area;
6) Meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and
7) Local distribution systems will be of reduced voltage.

Mansfield Test

The Mansfield Test resulted from the November 1, 2001 FERC Opinion and Order No. 454[3]. This Order was the result of a complaint filed by the Mansfield Municipal Electric Department ("Mansfield") and the North Attleborough Electric Department ("NAED"), both TCs, against the New England Power Company ("NEPCO"). In this Order, FERC accepted a recommendation of FERC staff that five factors be used to determine if a facility is integrated with the rest of the network. These five factors are:

1) Whether the facilities are radial or whether they loop back into the transmission system;
2) Whether energy flows only in one direction, from the transmission system to the customer over the facilities, or in both directions, from the transmission system to the customer, and from the customer to the transmission system;
3) Whether the transmission provider is able to provide transmission service to itself or other transmission customers . . . over the facilities in question;
4) Whether the facilities provide benefits to the transmission grid in terms of capability or reliability, and whether the facilities can be relied on for coordinated operation of the grid; and
5) Whether an outage on the facilities would affect the transmission system.

While this case was with respect to the Mansfield's and NAED's desire to directly pay for the radial facilities serving their respective systems, the same logic should apply on the MECL system, with each group of customers paying for the facilities providing service to them: (i) the radial facilities serving the MECL customers are providing service only to the MECL customers and should therefore be paid for by the MECL customers; (ii) the radial facility serving the SE customers (the T-11 line) is providing service only to the SE customers and should therefore be paid for by the SE customers; and (iii) the bulk networked transmission facilities are providing service to both groups of customers and should therefore be supported by both groups of customers. This decision is established precedent and has been cited numerous times.

Legal Precedent

I next reviewed some of the numerous legal precedents and Tariffs in the U.S. on the treatment of radial lines. I will summarize some of them below.

Entergy

Entergy has five affiliates that own transmission facilities that are part of the market of the Midwest Independent System Operator ("MISO")[4]. These are: Entergy Arkansas, Entergy Louisiana, Entergy

[3] Available at: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=6002818. See Tab B.
[4] The 4/28/17 "As Filed" MISO Tariff is 58 MB and available at https://www.misoenergy.org/Library/Tariff/Pages/Tariff.aspx. See Tab C for relevant sections.

Mississippi, Entergy New Orleans, and Entergy Texas (not part of the Electric Reliability Council of Texas or "ERCOT"). All of them have Attachment O filings as part of the MISO Tariff that indicate that they exclude radial lines (see Note M on file pages 3804 [Entergy Arkansas], 3872 [Entergy Louisiana], 3943 [Entergy Mississippi], 4008 [Entergy New Orleans] and 4075 [Entergy Texas] of the 4/28/17 MISO Tariff).

Florida Municipal Power Agency ("FMPA")

FMPA challenged a compliance filing of Florida Power & Light Company ("FP&L"). On January 25, 2005 FERC issued an Order with respect to this complaint[5]. In paragraph 12 on page 4 FERC indicates that "In the compliance filing we order herein, FP&L should apply the test to exclude from transmission rate base all radial facilities (and associated equipment), regardless of how many customers are served by the facility." In a subsequent Order[6], on December 15, 2005, FERC reiterates, in paragraph 5 on page 2, that in its original filing "FP&L: (1) failed to exclude all radial facilities and associated equipment." Later, in paragraph 20 on page 7, FERC acknowledges that in the new compliance filing "FP&L did remove from its transmission rates all radial transmission facilities."

MidAmerican

In a FERC Order[7] dated July 16, 2012 FERC responded to a request from MidAmerican to include in the MISO Tariff some non-radial 69 kV facilities of the City of Pella. In several paragraphs (see paragraphs 3 and 5 on page 2, paragraph 6 on page 3, paragraphs 14 and 15 on page 4, and paragraphs 17 and 18 on page 5) there is considerable discussion of how MISO generally only includes non-radial lines in their transmission tariff. There is also a discussion in paragraph 19 of the FERC Seven Factor Test that I discussed above.

Southern Companies

Over the years Southern has had numerous disputes in front of FERC over its transmission rates. Their current OATT[8] reflects a range of FERC Orders and FERC acceptance of settlements. Attachment M, starting on file page 655, is the Formula Rate Manual. On page 5 of Attachment M are definitions for Bulk Retail Radial Facility, Rehabilitated Bulk Radial Facility and Bulk Fixed Rate Base Adjustment. The rest of Attachment M removes the various costs (gross cost, depreciation, working capital, O&M, taxes, wages & salaries, etc.) associated with the Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities, which are radial facilities placed in service in Rate Year 2011 and later, from the transmission revenue requirements. As part of the negotiations, the Bulk Fixed Rate Base Adjustment of $139,300,000 is removed from the transmission revenue requirement to cover radial facilities placed in service in Rate Years 2003 through 2010.

Southwest Power Pool ("SPP")

On September 30, 2005 FERC issued an Order[9] to SPP with respect to proposed changes to its OATT. There is a discussion of the treatment of radial lines starting with paragraph 26 on page 8. The bottom line is that radial lines are not included in the transmission revenue requirement. The current SPP

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[5] Available at: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=10378743. See Tab D.
[6] Available at: https://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=10906527. See Tab E.
[7] Available at: https://elibrary.ferc.gov/idmws/common/OpenNat.asp?fileID=13028539. See Tab F.
[8] The 1/1/17 Southern OATT is available at: http://www.oasis.oati.com/SOCO/SOCOdocs/Southern-OATT_current.pdf. See Tab G for relevant sections.
[9] Available at: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=10828286. See Tab H.

OATT[10] indicates in Section II of Attachment AI (AI, not A1) on file page 5389 that various facilities can be included in the revenue requirement, including "All existing non-radial power lines, substations, and associated facilities, operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more Eligible Customers not Affiliates of each other."

SPP/Tri-County

An October 16, 2014 FERC Order[11] verifies the information above with respect to SPP. In this case Tri-County tried to have some facilities that did not meet the criteria of Section II of Attachment AI of the SPP OATT included in the transmission revenue requirement of their local transmission owner, Southwestern Public Service Company ("SPS"). FERC rejected the attempt. There is another discussion of the FERC Seven Factor Test starting in paragraph 86 on page 41 and later. There is also a cross-reference in paragraph 100 (among others) to the MidAmerican/City of Pella case that I covered above.

Application of Seven Factor Test to MECL Facilities

The review above raised the question as to how the FERC Seven Factor Test would apply to MECL facilities. When applying these factors to the facilities of MECL there are logical groupings of facilities with different characteristics. What follows is the application of the FERC Seven Factor Test to these different categories of facilities. I am looking at the MECL system prior to commercial operation of the new cables to New Brunswick and new line Y-104, both of which I understand are not yet in commercial operation.

Category 1 - Pure MECL Local Load Facilities

These purely local load serving facilities clearly meet the FERC seven factors and do not provide service to TCs other than MECL's customers: (1) these facilities are in close proximity to retail customers; (2) these facilities are all radial in nature; (3) power flows into these facilities and cannot flow out since there is no local generation of any size[12]; (4) these facilities do not serve as a transmission path to other markets; (5) once the power flows into these facilities it is consumed in a relatively small geographic area; (6) meters are irrelevant for these facilities as the facilities on both sides of the transmission/distribution demarcation point are owned by MECL and therefore do not need to be metered; and (7) these facilities are at 69 kV, which is less than the bulk PEI transmission voltage of 138 kV[13].

<u>The Ultimate TCs are MECL's Customers</u>

1. Tap[14] on T-21 to O'Leary;
2. Tap on T-5 to Wellington;
3. Tap on T-5 to St. Eleanors;

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[10] The 4/17/17 SPP Tariff is available at: http://app.spp.org/etfdocs/MasterTariffs//5FullTariff.pdf. See Tab I for relevant sections.

[11] Available at: https://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=13661424. See Tab J.

[12] Note that FERC has found that distribution level generation can occasionally be transmitted to the broader network transmission system without changing the status of these facilities. See Paragraph 22 of the December 31, 2015 Southern California Edison Decision in Docket No. RC15-1-000, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14087859, which is the same document linked in Footnote 2. See Tab A.

[13] That said, note that FERC has found long radial lines serving remote load at higher voltages to be distribution. See Paragraphs 20 and 21 of the December 31, 2015 Southern California Edison Decision in Docket No. RC15-1-000, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14087859, which is the same document linked in Footnote 2. See Tab A.

[14] I use the term "Tap" to refer to a connection from the specified transmission line (e.g., T-21) to the subject facility (e.g., O'Leary).

4. Tap on T-5 to T-7 to Slemon Park (shown on MECL's geographic diagram but not on MECL's one-line diagram[15]);
5. Tap on T-1 to Cavendish Farms (shown on MECL's one-line diagram but not on MECL's geographic diagram);
6. Tap on T-1 to Kensington;
7. Tap on T-1 to Rattenbury;
8. Tap on T-1 to Hunter River;[16]
9. Tap and breaker on T-13 to UPEI (shown on MECL's one-line diagram but not on MECL's geographic diagram);
10. Tap and breaker on T-15 to Airport (shown on MECL's one-line diagram but not on MECL's geographic diagram);
11. Tap on T-4 to Scotchfort;
12. Tap on T-2 to Crossroads;
13. Breaker at Lorne Valley feeding the T-10 line and all of the facilities off that line all the way to Dover, including the tap on T-10 to Victoria Cross;
14. Tap on T-8 to Georgetown; and
15. Tap on T-8 to Souris.

Category 2 - MECL & Summerside Local Load and Generation Facilities

These are local load serving facilities that, in addition, serve local SE or MECL generation. They also clearly meet the FERC seven factors and do not provide service to TCs other than, separately, MECL's or SE's customers: (1) these facilities are in close proximity to retail customers; (2) these facilities are all radial in nature; (3) power flows into these facilities and, while there is some local generation, power flows mostly into these facilities[17]; (4) these facilities do not serve as a transmission path to other markets; (5) once the power flows into these facilities it is consumed in a relatively small geographic area; (6) except for the MECL/Summerside interface, which is metered, meters are irrelevant for the rest of these facilities as the facilities on both sides of the transmission/distribution demarcation point for these remaining facilities are owned by MECL and therefore do not need to be metered; and (7) these facilities are at 69 kV, except for the high side of the stepdown transformer at Borden and its associated breaker bay, which is less than the bulk PEI transmission voltage of 138 kV.

<u>The Ultimate TCs are SE's Customers</u>

1. Tap and breaker at Sherbrooke feeding the T-11 to Summerside;

<u>The Ultimate TCs are MECL's Customers</u>

2. 138/69 kV transformer and all 69 kV facilities at Borden (providing connections for CT1 & CT2 and the feed to T-3 and McCains and Albany); and
3. Facilities at Charlottetown associated with CTGS and CT3.

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[15] MECL has been asked about this and other differences between the one-line diagrams and the geographic diagrams and as of this date there has been no response.

[16] Note that the geographic diagram for post new cables/Y-104 commercial operation shows a tap on T-1 to New Glasgow, near the Hunter River tap, which is not shown on MECL's one-line diagram for post new cables/Y-104 commercial operation, nor on either of the diagrams for pre-commercial operation of the new cables/Y-104.

[17] Note that FERC has found that even when power can occasionally flow out of these facilities during certain periods (e.g., low loads and high generation), if the preponderance of flow is into these facilities they are considered distribution. See Paragraph 22 of the December 31, 2015 Southern California Edison Decision in Docket No. RC15-1-000, http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=14087859, which is the same document linked in Footnote 2. See Tab A.

Category 3 - Radial Line Facilities that also Serve Independent Wind Generation

These are facilities that make possible the export of wind power from North Cape and East Cape. This does not include the T-23, T-25, Y-108, Y-112 and Y-115 facilities (including the breakers feeding these facilities) which I understand are supported directly by the wind generators and/or the Province.

The FERC Seven Factor Test is not readily applicable to these facilities since they do not appear to be directly load related. However, that does not mean they should be supported by all the PEI TCs and especially not by any TCs who have no relationship to these facilities. If it were not for the generation, these facilities would clearly be radial facilities serving local load and they would be included in Category 1 above as they do not provide service to TCs other than MECL's customers. And, if the generators were owned by MECL they would clearly be Category 2 above.

The addition of the generation would normally put them in Category 2 above, except possibly for the fact that these wind generators operate more frequently than the embedded MECL and SE thermal generation and are somewhat larger with respect to the local load (but still only ~30$^+$ MW in the North Cape area and ~60 MW in the East Cape area). This can make it such that power could in-flow into Sherbrooke from the T-5 line and into Lorne Valley from the T-8 line from time to time. However, to the extent that the addition of these wind generators did not require any upgrading of facilities that they are not paying for directly, then these facilities should continue to be in Category 2 above and not included in the OATT rate. Stated another way: if, prior to the installation of these new wind generators, these lines would have been considered radial as in Category 1 above and, if no upgrades were required as a result of the installation of the wind generation, then these lines should still be considered radial. In effect, they are simply another facility that would be in Category 2 above.

To the extent that the addition of these generators required upgrading facilities other than the direct assignment facilities, the generators should have paid for those upgrades and the remaining cost of the pre-existing facilities should still be considered distribution under Category 1 or Category 2 above. It would be ironic if MECL paid for those upgrades as their OATT proposes that they only pay for upgrades for TCs taking firm service (see In Summary point 2 below) and not only are the wind generators not necessarily taking firm service[18], they are proposed to pay a discounted transmission rate (see Section D below on Discounts).

In any event, these are facilities that do not provide any service or benefits to TCs other than the MECL TCs and therefore should not be included in the OATT rate paid by other TCs.

The Ultimate TCs are MECL's Customers

1. The tap and breaker at Sherbrooke feeding the T-5 and T-21 lines and the facilities associated with those lines to and including Alberton (excluding the taps at O'Leary, Wellington, St. Eleanors and the tap to T-7 to Slemon Park covered earlier in Category 1); and
2. Breaker at Lorne Valley feeding the T-8 line and all of the facilities off that line all the way to Church Road (excluding the taps on T-8 to Georgetown and Souris covered earlier in Category 1).

As an aid to understanding the facilities I am saying should be eliminated from the OATT transmission rate, Attachment 1 includes color coded copies of the geographic and one-line diagrams I received from MECL, via Key Murray Law, indicating the different categories of facilities. As indicated in Footnote 15,

[18] See file page 95 of the September 22, 2016 Technical Hearing (a file I was sent containing all of the MECL presentations in one file) where the MECL presenter indicated that the wind generators were taking 33.7 MW of non-firm transmission service in 2014. All of the presentations at the Technical Hearing are included in Tab K.

there are differences in facilities between the two MECL provided diagrams that we have not been able to resolve.

In Summary

Based on the information presented above, I believe IRAC should remove all radial lines from the MECL OATT and each TC should pay for the service provided by the radial lines used by that TC. There are a variety of reasons for excluding the radial lines from the OATT:

Fairness and Equity

1. Ensure fairness, in that each class of customers pays for the cost of the facilities that only serve that class. In other words, SE's customers pay the cost of the T-11 radial line that only serves them and MECL's customers pay the cost of the radial lines that only serve them. Both classes of customers would share in the cost of the networked transmission lines that serve all customers on PEI.

2. Ensure equitable sharing of upgrade costs as loads increase. In other words, SE's customers would pay for the costs of any upgrading of the T-11 line and MECL's customers would pay for the costs of upgrading any of the radial lines serving them. With the T-11 line apparently in need of upgrading within the next few years, if radial lines are included in the tariff MECL may only be willing to roll in the cost of that upgrade to the extent that SE is taking firm Network or Point to Point ("PtP") service. My understanding is that SE does not take or need firm transmission service for all of its transmission requirements. Instead, I understand SE takes a combination of firm and non-firm PtP transmission service.

   Another aspect of this concern over who pays for the upgrading of radial facilities relates to what the OATT itself says about upgrading. This is a concern because OATT Section 13.5 (OATT page 28 or file page 274) says MECL will upgrade the system to provide firm service, whereas under OATT Section 14.5 (OATT page 33 or file page 279) MECL "undertakes no obligation under the OATT to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-to-Point Transmission Service." So, even if all radials are included in the OATT rate, SE may still be exposed to paying 100% of the cost of upgrading of the radial T-11 line serving it while, at the same time, sharing in the cost of upgrading all the radial lines serving only MECL's customers.

3. In September 2007 a White Paper was issued that was commissioned by the Working group for Investment in Reliable and Economic electric Systems (WIRES), a U.S.-based non-profit trade group composed of transmission owners, customers, technology companies, vendors, and grid management organizations, whose purpose was to raise the visibility of the transmission sector and to promote needed investment in electric transmission (www.wiresgroup.com). This blue ribbon panel recommended a variety of principles with respect to transmission and the first principle was that "All viable methods of allocating the costs of new network transmission require a study of who benefits from, and who should pay for, enhancements of the grid." The same principle should apply to existing facilities.[19]

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[19] On pages 4-6 of: https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=1&cad=rja&uact=8&ved=0ahUKEwiloP22p4vUAhUK44MKHYk6AmoQFggkMAA&url=https%3A%2F%2Fpdfs.semanticscholar.org%2F6c1e%2Fdee029442316f11bf755f1a7633c83f8383d.pdf&usg=AFQjCNG9D36VQZYBWdKOKj-DqftT2dejdQ&sig2=vbvSRaokVZoylbkHOrl41A. See Tab L.

FERC Standards and Orders

4. There is extensive precedent for not rolling in the cost of radial lines in a FERC compliant OATT. I discussed in detail some of these precedents above, indicating that including radial lines is not consistent with FERC Orders, the Seven Factor Test and the Mansfield Test. In addition, including radial lines is not consistent with the concept of the transmission tariffs used in New England where all distribution customers share in supporting only the New England-wide bulk transmission facilities and then the customers of each sub-region of New England share the costs of the transmission facilities in their sub-region.

Canadian Experience

5. Note that, in its Decision in Matter 271[20] on May 13, 2016, the New Brunswick Energy and Utilities Board accepted the recommendation to "directly allocate sole use transmission facilities to the rate class of customers served by those facilities" (see paragraphs 72-74 on page 11 and paragraph 99a on page 15). MECL witness Marshall does not mention this Decision in his testimony, even though NB Power is the utility to which the PEI cables connect. Note however, on page 28 of his presentation at the 9/22/16 Technical Briefing (file page 31), he does indicate that British Columbia, Alberta and Manitoba do NOT include radial lines in their transmission tariffs.[21]

6. In Ontario there are three cost "pools:" (i) a "Network Pool" for bulk transmission facilities; (ii) a "Connection Pool" for radial line connections to the Network Pool facilities; and (iii) a "Transformation Pool" for transformer service. If a TC is paying for its connection to the Network Pool it is only subject to supporting the cost of the facilities in the Network Pool. If this concept were applied on PEI, the MECL customers would pay for the cost of the radial lines connecting them to the bulk transmission network and SE's customers would pay for the cost of the radial line connecting them to the bulk transmission network and both sets of customers would pay for the cost of the bulk transmission network (non-radial) facilities.[22]

Finally, I would note that MECL is proposing that all loads in the Province share in the transmission losses on a pro-rata basis. To the extent that radial lines are removed from the MECL OATT, similar treatment should be ordered for transmission losses. In other words: (i) all customers should pay for the losses on the networked lines that serve all customers on PEI; (ii) SE's customers should pay for the losses on the T-11 radial line that only serves them; and (iii) MECL's customers should pay for the losses on the radial lines that only serve them.

C. Planning

Attachment K of the proposed MECL OATT (starting on OATT page 161 or file page 585) on transmission planning is an improvement over the previous MECL OATT. However, there are a few adjustments needed to clarify and improve it:

1. While Attachment K discusses the involvement of others in the development of a specific year's Baseline Plan, much of that involvement occurs AFTER that year's Baseline Plan has been developed. There should be a meeting of the Transmission System Users Group

[20] Available at: http://www.nbeub.ca/opt/M/browserecord.php?-action=browse&-recid=456 and then click on the Decision. See Tab M.

[21] See Tab K.

[22] Described in Exhibits H1 and H2 of a May 31, 2016 Hydro One filing available at: http://www.hydroone.com/RegulatoryAffairs/EB20160160/HONI_Tx_UpApp_Ex_H_20160720.pdf. See Tab N.

BEFORE a year's Baseline Plan is developed to discuss and hopefully agree on the data, information, assumptions, etc. that will be used in developing that year's Baseline Plan. This would be consistent with activities elsewhere in the industry which encourage an open transmission planning process. In fact, FERC is encouraging more regional planning than MECL is proposing (see page 20 of his testimony or file page 57 where MECL witness Marshall indicates that, since MECL is radial off the NB Power system, MECL is not willing to plan regionally until NB Power is willing to take on the role of coordinating regional activities). Marshall does note that there is a Maine and Atlantic Technical Planning Committee that attempts to coordinate regional planning, but it is voluntary with no agreed cost allocation methodology.

2. With respect to the definition of Information Exchange on page 1 of Attachment K (OATT page 161 or file page 585), this definition needs to make it clear that it applies not just to Network Customers, but also to PtP Customers, Generators and the Affiliates of MECL. As I indicated above, most transmission planning processes are moving to a more open transmission planning process involving all players in the electricity markets and transmission systems.

3. In Ontario, consultations are conducted by the Independent Electricity System Operator ("IESO") that include not only the transmission company, but also the local distribution companies, the public and First Nations communities.[23]

4. In Alberta, there are currently four TOs (AltaLink, ENMAX, Epcor and ATCO Electric). However, overall transmission planning is carried out by the Alberta Electricity System Operator ("AESO"). The mandate for the AESO is provided for in the Alberta Electric Utilities Act and its Regulations. This legislation requires that the AESO prepare a 20-year transmission plan and refresh this plan every two years and in carrying out its planning the Act also requires that the AESO consult broadly and begin its consultation early in the process.[24]

5. An open mechanism for coordinating transmission planning that involves Investor Owned Utilities ("IOUs"), municipal utilities (like SE) and cooperative utilities has been operating for many years in North Carolina, so proposing a more open process is not an out of the ordinary concept. This mechanism, the North Carolina Transmission Planning Collaborative, is still in operation (see their website at http://www.nctpc.org/nctpc/).

6. Certain capitalized terms need to be defined, such as Integrated Electrical System and Proximate Area.

In addition to these adjustments, it should be noted that a more open transmission planning process would help ensure that any transmission expansion plan is supported by ALL TCs on PEI (e.g., which TCs will benefit from the new Y-104 line). This only makes sense since ALL Transmission Customers will pick-up a share of the associated costs, certainly for networked transmission facilities and possibly for radial transmission (if these lines are included in the tariff; see Section B above on facilities that should and should not be included in the OATT).

[23] http://www.ieso.ca/en/get-involved/regional-planning/about-regional-planning/how-the-process-works. "LDCs" are Local Distribution Companies (i.e. distribution utilities). See Tab O for relevant sections copied from the IESO website.

[24] http://www.auc.ab.ca/acts-regulations-and-auc-rules/rules/Documents/Rule007.pdf. See Appendix 1 Participant Involvement Program Guidelines. AESO Consultation Principles are posted at https://www.aeso.ca/aeso/about-the-aeso/consultation-principles/. See Tab P for relevant sections, with the Principles copied from the AESO website.

D. Discounts

MECL is proposing transmission discounts for exporting generators when the cables are not constrained (which they should never be in the exporting direction with the current load and generation balance on PEI). While this has been done in some jurisdictions, my belief is that this was done to encourage additional development on the exporting system such that the additional revenues from the additional development would offset the cost of the discounts. In fact, MECL witness Marshall indicates, on page 36 of his testimony (file page 73), that "The objective of discounts is to increase usage of the system and therefore reduce rates for all customers . ." It appears that not only did the Province pick-up much of the cost of the facilities to West Cape, MECL is now proposing to possibly discount the rates charged to them and other exporters.

In the case of MECL, the decreased revenues that result from any discounts provided to exporters are made up by the remaining TCs on PEI and those customers receive no benefits from paying those higher rates. In a related manner, I would note that traditionally in markets, such as the one in New England, entities exporting have paid the hourly equivalent of the same Regional Network Service ("RNS") rate paid by entities within New England. That said, several years ago New England and New York agreed to waive export charges each way on their interface to encourage more transactions between their markets. Therefore, to be equivalent, waiving or discounting of exports from PEI would have to be offset by waiving or discounting by NB Power of exports to PEI. The NB Power OATT does provide for discounts for exports, but not waivers. According to MECL witness Marshall in his presentation at the 9/22/16 Technical Briefing, both Manitoba Hydro and British Columbia Hydro have discounts for exports.[25] In addition, so does Nova Scotia, but it does not appear discounts are offered by Alberta, Ontario or Québec.

The bottom line is that the discounts MECL is offering exporting generators on PEI only serve to increase the share of transmission costs borne by the other TCs on PEI. MECL should be required to provide cost justification for offering such discounts.

E. Penalties Associated with Scheduling Imbalances

While NB Power, the supplier of Imbalance Energy to all entities on PEI except when the cables are import constrained, has no scheduling penalties, MECL proposes to impose scheduling penalties on its Transmission Customers. It proposes in its Schedule 4 (starting on OATT page 92 or file page 338) that:

Band 1: Hourly imbalances of less than +/- 1.5% or 2 MW be netted for the month and settled at the incremental or decremental cost;

Band 2: Hourly imbalances greater than +/- 1.5% up to 7.5% (or greater than 2 MW up to 10 MW) be settled hourly at 110% of the incremental cost or 90% of the decremental cost; and

Band 3: Hourly imbalances greater than +/- 7.5% (or 10 MW) be settled hourly at 125% of the incremental cost or 75% of the decremental cost.

Schedule 4 later indicates that "For purposes of this Schedule, incremental cost and decremental cost represent the Transmission Provider's [MECL's] actual average hourly cost of the last MW dispatched for any purpose. For greater clarity, it is the hourly marginal cost of the Control Area Operator [NB Power] when the transmission interface between the MECL system and the NB Power system is not constrained

[25] See page 30 (Marshall presentation page 27) of the September 22, 2016 Technical Hearing. All of the presentations at the Technical Hearing are included in Tab K.

and it is the marginal cost of the MECL system when the interface is constrained." The logistics of how this average is determined (is it monthly or hourly) and is applied in the first band, when the imbalances are netted for the month, and for bands two and three, when the monthly average is applied to hourly imbalances, are not clear.

There are a variety of problems with this penalties proposal:

1. This makes no sense since MECL incurs no costs except, possibly, when the cables are import constrained (rare, and more rare when the new cables come into operation). Also, as indicated earlier, NB Power's OATT does not include any scheduling penalties and it is from NB Power that most imbalance energy is obtained.

2. It is not clear if this would apply equally to MECL's distribution business. For example (ignoring any exporting wind farms), if SE has a +5 MW imbalance and MECL has a -5 MW imbalance, the imbalance with NB Power will be zero. Will MECL charge SE an imbalance penalty but not the MECL distribution business (since 5 MW is probably more than 1.5% of SE's load but less than 1.5% of MECL's load). What if SE has no imbalance and MECL's distribution business has an imbalance >1.5%? Will the MECL distribution business pay MECL a penalty, even though MECL only settles with NB Power at the imbalance price? That really has no practical effect.

3. MECL grants a waiver from the highest (>7.5%/10 MW) band for wind generators but not, apparently, for TCs with embedded wind generation (like SE). If waivers are to be granted, they should be applied to all scheduled wind farm output, stand-alone or embedded.

4. MECL indicated in answer to SE's January 4, 2017 questions that its own distribution business does not have embedded wind farms as it purchases its wind power from PEI Energy. However, MECL also indicated that if scheduling errors by PEI Energy cause MECL to incur scheduling penalties it would simply pass on the charges to PEI Energy. It is not at all clear how that would work, especially if the error in scheduling load and the error in scheduling wind output were both in the same direction (e.g., if the load was 10 MW too high and the generation was 10 MW too low, the scheduling error would be 20 MW).

5. If SE was directly connected to the cables and therefore to NB Power, it would not suffer any scheduling penalties. It is only because MECL acts like a middleman, even when it suffers no impact, that SE is exposed to penalties.

6. MECL does not indicate what it will do with any penalties it collects from SE and others.

MECL should be required to provide operational and economic justification for its proposal to include scheduling penalties in its OATT when there are none in the NB Power OATT and NB Power is the provider of imbalance energy.

F. Conclusion

While the OATT filed by MECL on July 8, 2016 has some improvement over the existing OATT, it still suffers from inequitable treatment of all TCs. In my independent opinion, to create a FERC compliant OATT and to address the problems described above, the OATT should be modified to:

1. Remove all radial lines from the OATT rate;
2. Improve the transparency and consultation associated with the planning process;

3. Not allow MECL to offer discounts to exporting generators until they provide IRAC with an economic study showing the benefits of such discounts to the PEI ratepayers; and
4. Not allow MECL to implement the scheduling penalties until they provide IRAC with operational and economic justification for such penalties.

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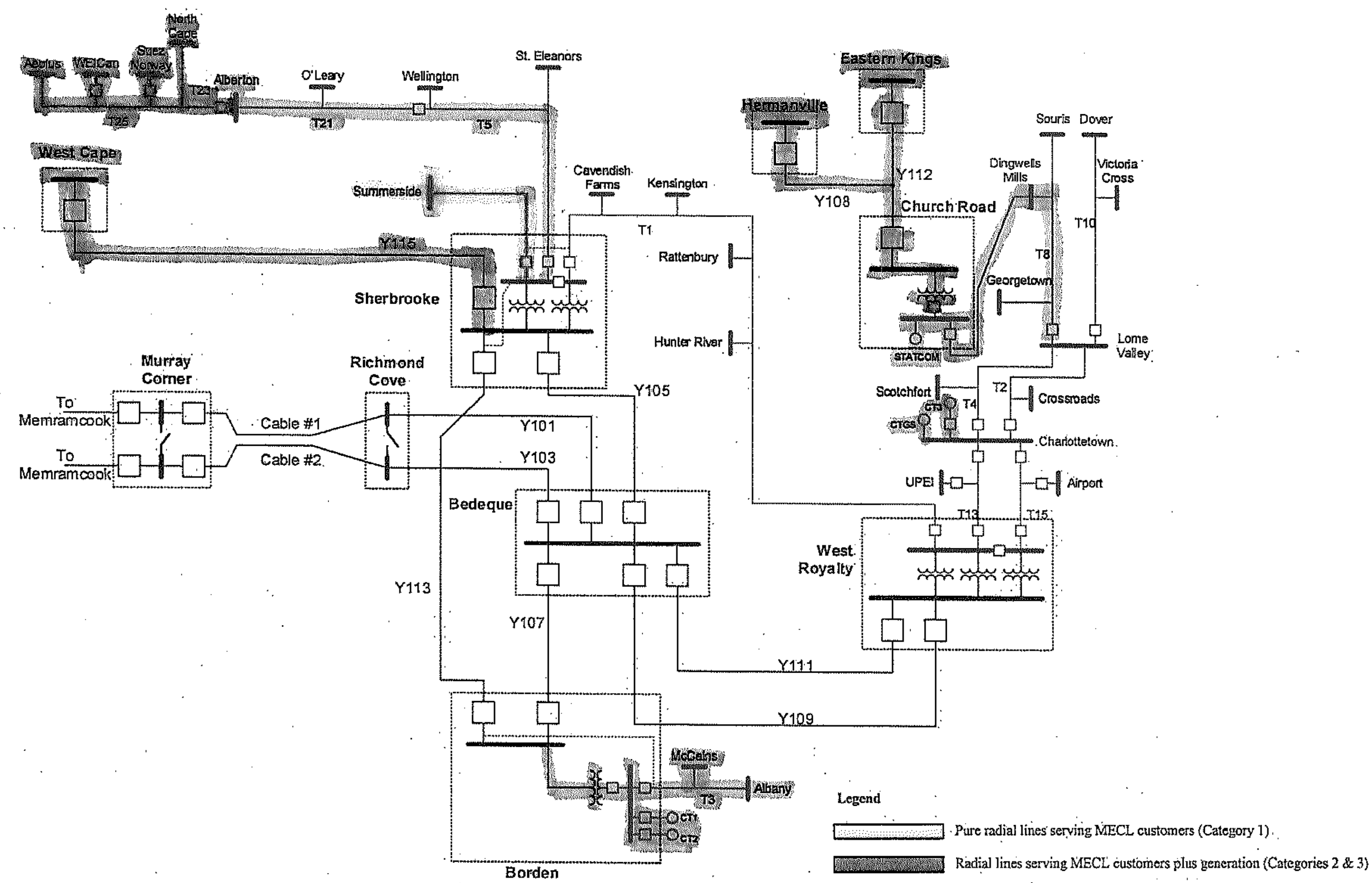
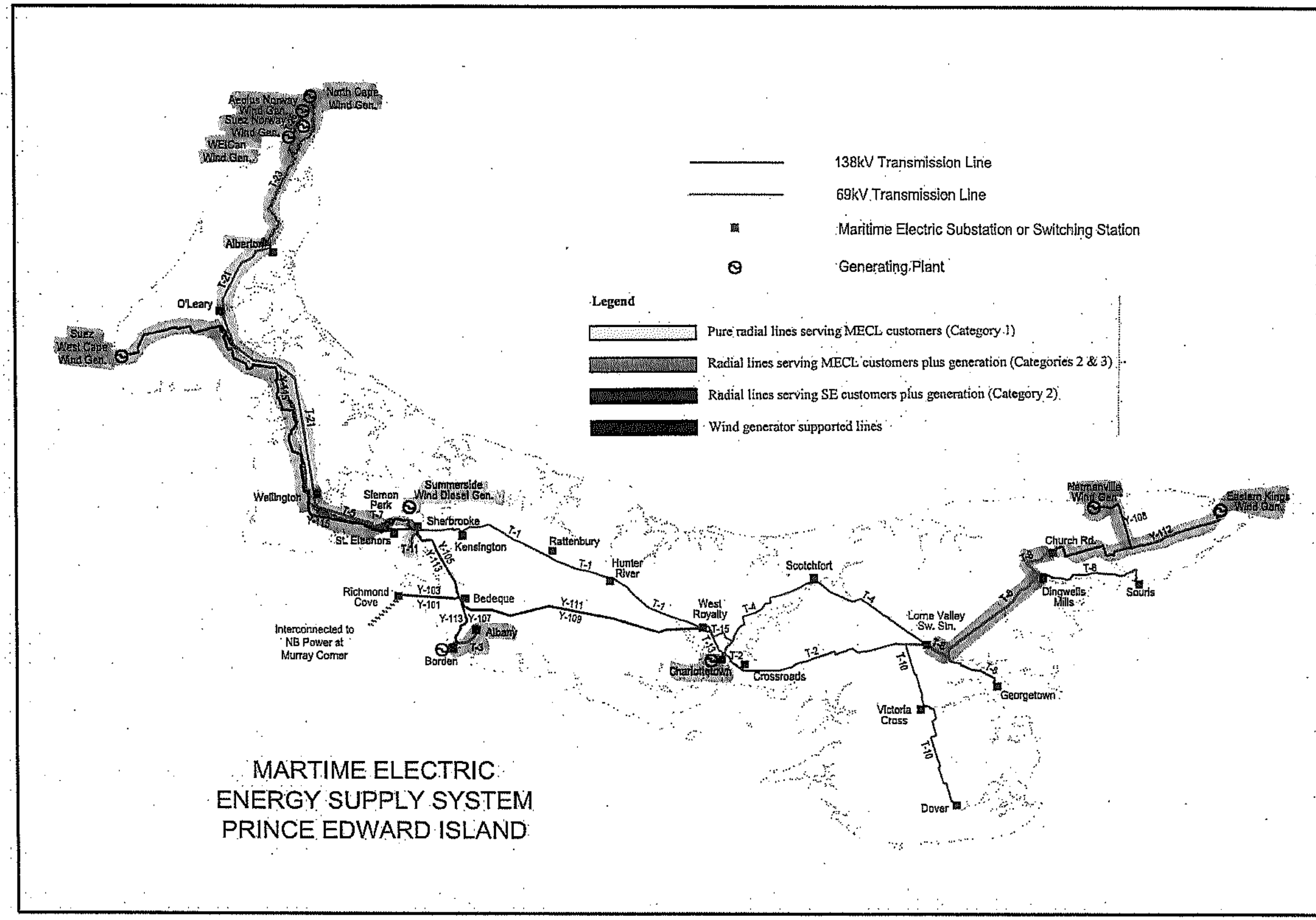
System pre-Y104





138kV Transmission Line
69kV Transmission Line
Maritime Electric Substation or Switching Station
Generating Plant
Legend
Pure radial lines serving MECL customers (Category 1)
Radial lines serving MECL customers plus generation (Categories 2 & 3)
Radial lines serving SE customers plus generation (Category 2)
Wind generator supported lines
North Cape Wind Gen.
Aeolus Norway Wind Gen.
Suez Norway Wind Gen.
WEICan Wind Gen.
Alberton
O'Leary
Suez West Cape Wind Gen.
T-21
Wellington
Slemon Park
T-7
Summerside Wind Diesel Gen.
Sherbrooke
St. Eleanors
T-11
Kensington
Rattenbury
T-1
Hunter River
Richmond Cove
Y-103
Y-101
Bedeque
Y-105
Y-113
Y-107
Albany
T-3
Borden
Interconnected to NB Power at Murray Corner
Y-111
Y-109
West Royalty
T-15
Charlottetown
T-2
Crossroads
Scotchfort
T-4
Lorne Valley Sw. Stn.
T-10
Victoria Cross
Dover
Georgetown
Dingwells Mills
Church Rd.
T-8
Souris
Y-108
Y-112
MARTIME ELECTRIC
ENERGY SUPPLY SYSTEM
PRINCE EDWARD ISLAND

A

153 FERC ¶ 61,384
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Norman C. Bay, Chairman;
Cheryl A. LaFleur, Tony Clark,
and Colette D. Honorable.

Southern California Edison Company | Docket No. RC15-1-000

ORDER ON LOCAL DISTRIBUTION DETERMINATION

(Issued December 31, 2015)

1. In this order, the Commission grants in part and denies in part Southern California Edison Company's (SoCal Edison) application for a Commission determination of whether certain facilities owned and operated by SoCal Edison are "used in local distribution of electric energy" pursuant to section 215 of the Federal Power Act (FPA).[1] As discussed below, based on the current use of the facilities as described in SoCal Edison's application and data request response, the Commission finds that the SoCal Edison's facilities at issue are used in local distribution, with the exception of certain discrete protection systems and the segments of the associated transmission lines located within the yards of two substations in the North of Lugo system.

I. **Background**

2. In section 215(a)(1) of the FPA, Congress exempted "facilities used in the local distribution of electric energy" from Commission jurisdiction.[2] However, whether facilities are used in local distribution or transmission raises a question of fact, which the Commission has jurisdiction to determine.[3]

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[1] 16 U.S.C. § 824o (2012).

[2] 16 U.S.C. § 824o(a)(1) (2012).

[3] *E.g., FPC v. Southern California Edison Co.*, 376 U.S. 205, 210 n.6 (1964) (stating whether facilities are used in local distribution is a question of fact to be decided by the Commission).

3. In Order No. 773, the Commission approved modifications to the North American Electric Reliability Corporation's (NERC) definition of "bulk electric system."[4] The revised definition has a bright-line threshold that includes all facilities operated at or above 100 kV and specific categories of facilities and configurations as inclusions and exclusions to the definition. The Commission indicated in Order No. 773 that the application of the core definition and the exclusions should serve to exclude most facilities used in local distribution from the bulk electric system.[5] The Commission also recognized that there may be some rare instances that present a factual question as to whether a facility that remains in the bulk electric system after applying the "core" definition and the four exclusions should nonetheless be excluded because it is used in local distribution.[6] The Commission determined that, in such instances, the Commission itself should resolve the factual question of whether the facilities are used in local distribution. Thus, entities must apply to the Commission for a determination of whether an element is used in local distribution. Further, the Commission concluded that it would make jurisdictional determinations on a case-by-case basis and would apply the seven factor test as set forth in Order No. 888[7] to make such determinations.

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[4] *Revisions to Electric Reliability Organization Definition of Bulk Electric System and Rules of Procedure*, Order No. 773, 141 FERC ¶ 61,236 (2012); *order on reh'g*, Order No. 773-A, 143 FERC ¶ 61,053, *order on reh'g and clarification*, 144 FERC ¶ 61,174 (2013), *aff'd sub nom. People of the State of New York and the Pub. Serv. Comm'n of New York v. FERC,* 783 F.3d 946 (2d. Cir. 2015).

[5] The core definition states: "Unless modified by the lists shown below, all Transmission Elements operated at 100 kV or higher and Real Power and Reactive Power resources connected at 100 kV or higher. This does not include facilities used in the local distribution of electric energy." Order No. 773, 141 FERC ¶ 61,236 at P 12.

[6] Order No. 773, 141 FERC ¶ 61,236 at P 79.

[7] *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, FERC Stats. & Regs. ¶ 31,036 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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).

4. The factors of the seven factor test are: (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems, and rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported onto some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographic area; (6) meters are based at the transmission/local distribution interface to measure flow into the local distribution system; and (7) local distribution systems will be of reduced voltage.[8] Further, in Order No. 773 the Commission also determined that, consistent with Order No. 888, the factors identified in the seven factor test are not exclusive when determining whether an element is used in local distribution. The Commission indicated that use of the seven factor test would be a "starting point" but that the Commission would take into consideration other case-specific factors in particular situations.[9]

II. SoCal Edison Application

5. SoCal Edison is an investor-owned electric utility company serving 4.9 million customers in Southern California.[10] In its application, SoCal Edison includes testimony and supporting exhibits, which, according to SoCal Edison, provide a complete analysis needed to resolve the question of whether the facilities at issue are used in local distribution. SoCal Edison states that it built its higher voltage transmission system to efficiently connect these lower voltage distribution systems serving relatively rural and sparsely populated areas. SoCal Edison explains that it operates its integrated transmission system delivering bulk power from around the Western Interconnection principally at 500 kV, 220 kV, 161 kV alternating current and 1000 kV direct current. SoCal Edison also states that its local distribution facilities operate at 115 kV down to 4 kV. SoCal Edison explains that at issue in this proceeding are its 115 kV systems and facilities that are not integrated with the transmission system.

6. According to SoCal Edison, the 115 kV facilities were designed to operate at higher voltages to reduce line losses over the long distances in remote areas, and are radial to the integrated transmission network to provide increased reliability, voltage stability and safety, as well as provide additional operational flexibility. SoCal Edison

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[8] Order No. 888, FERC Stats. & Regs. ¶ 31,036.

[9] Order No. 773, 141 FERC ¶ 61,236 at P 71.

[10] SoCal Edison is designated in the NERC compliance registry as a distribution provider, generator owner, generator operator, load-serving entity, resource planner, transmission owner, transmission operator and transmission planner.

adds that, at the formation of the California Independent System Operator, Inc. (CAISO), the Commission recognized these 115 kV SoCal Edison facilities as local distribution.[11] SoCal Edison states that those 115 kV facilities take power off of the CAISO's integrated transmission network at only a single point and transform it down for use in localized areas to serve SoCal Edison's customers.

7. SoCal Edison operates its local distribution networks radially from the bulk electric system in order to maintain a high level of transmission network resiliency and distribution system operational flexibility. SoCal Edison asserts that this distinctive design, in which a single substation serves as the interface between the integrated transmission network and each radial local distribution system or facilities, maintains electrical isolation between SoCal Edison's radial local distribution systems. SoCal Edison explains that each system has normally open circuit breakers that maintain electrical isolation from neighboring systems. The normally open circuit breakers exist to "roll" (i.e., transfer) load to a neighboring system. According to SoCal Edison, this minimizes the impacts of any unforeseen forced outages on SoCal Edison's customers, and ensures that these distribution facilities do not negatively impact the reliability of the bulk electric system.

8. SoCal Edison seeks a determination of the following seven 115 kV facility configurations (collectively, "the 115 kV Facilities"):

> (i) Devers 115 kV system - covers approximately 1,120 square miles of service area and is comprised of twenty four 115 kV substations connected to one another by 188 circuit miles of power lines servicing approximately 511 MW of peak load, 2.2 percent of SoCal Edison's 2014 peak demand.
>
> (ii) El Casco 115 kV system - covers approximately 50 square miles of service area comprised of seven load-serving substations and 82 circuit

[11] *Pacific Gas and Electric Co., et al.*, 77 FERC ¶ 61,077 (1996). SoCal Edison indicates that all the facilities at issue in this proceeding were deemed to be local distribution with the exception of the reconfigured Devers and Mirage 115 kV systems. According to SoCal Edison these facilities were initially configured as CAISO grid facilities, but in 2013 were split into two radial distribution systems and re-classified as non-ISO. SoCal Edison represents that the remaining 115 kV facilities have been classified as non-ISO, local distribution since the onset of the CAISO. SoCal Edison Application at 2 & n.3.

miles of power lines and related facilities that support approximately 188 MW of peak load, 0.8 percent of SoCal Edison's 2014 peak demand.

(iii) Mirage 115 kV system - covers approximately 112 square miles of service area comprised of six 115 kV substations and 78 circuit miles of power lines and related facilities that support approximately 480 MW of peak load, 2 percent of SoCal Edison's 2014 peak demand.

(iv) Valley 115 kV system - covers approximately 844 square miles of Riverside County, and is comprised of 25 load-serving substations with close to 387 circuit miles of power lines and related facilities that support roughly 1825 MW of peak load, 7.9 percent of SoCal Edison's 2014 peak demand.

(iv) Victor 115 kV system - covers approximately 300 square miles in San Bernardino County, and is comprised of 14 substations with close to 200 circuit miles of power lines and related facilities that support nearly 750 MW of peak load, 3.3 percent of SoCal Edison's 2014 peak demand.

(vi) Vista 115 kV system - covers approximately 90 square miles of service area, and is comprised of 11 load-serving substations and 136 circuit miles of power lines, and related facilities that support approximately 435 MW of peak load, 1.9% of SoCal Edison's 2014 peak demand.

(vii) North of Lugo region - SoCal Edison states that there are three 115 kV subsystems and several radial substations that SoCal Edison operates north of its Lugo 500/220 kV substation. The 115 kV subsystems are the Inyokern 115 kV, Kramer 115 kV, and Control 115 kV subsystems, and a portion of each subsystem is integrated with the transmission network and is under the operational control of the CAISO. SoCal Edison states that it does not seek a determination regarding the portions under CAISO's operational control. However, SoCal Edison seeks a determination of the SoCal Edison-controlled radial portions of the Inyokern, Kramer, and Control subsystems and the North of Lugo radial substations. According to SoCal Edison, these facilities are comprised of 13 substations and include over 1400 circuit miles that support approximately 290 MW of peak load. Approximately 16 percent of the load customers are modeled as large non-conforming retail load customers. SoCal Edison explains that these large customers include a cement plant, glass manufacturer, military facility, and aerospace manufacturer that connect directly at 115 kV. SoCal Edison adds that this region also serves many smaller retail load customers. The total SoCal Edison-controlled North of Lugo 115 kV service area is approximately 400 square miles and includes portions of San Bernardino, Kern, Inyo, Tulare, and Mono Counties. Currently, there is 158.8 MW of cogeneration and 54.6 MW of hydro generation connected to the facilities located throughout the North of Lugo region.

9. SoCal Edison asserts that, unlike transmission facilities, the 115 kV Facilities generally do not operate in parallel with the integrated transmission network (i.e., are not looped with the transmission network). SoCal Edison adds that this is an important design feature that eliminates the possibility of power flowing into the local distribution facilities and back onto the transmission network, and thus prevents the local distribution facilities from negatively affecting the reliability of the integrated transmission network. SoCal Edison states that it analyzed each of the systems separately, applied the seven factor test and concluded that all 115 kV Facilities met all seven factors.

III. Notice of Filing, Responsive Pleadings and Data Request

10. Notice of the application was published in the *Federal Register*, 80 Fed. Reg. 23,265 (2015), with interventions and protests due on or before May 18, 2015. Portland General Electric Company and the City of Moreno Valley, California filed motions to intervene, raising no issues. The Edison Electric Institute (EEI) filed a motion to intervene out-of-time. NERC and Western Electricity Coordinating Council (WECC) jointly filed a motion to intervene and comments. SoCal Edison filed reply comments.

A. Comments and Reply Comments

11. NERC and WECC comment that additional information is necessary to establish a complete record before an accurate determination can be made regarding the impact of the 115 kV Facilities on the bulk electric system. NERC and WECC identify the types of additional information they claim that SoCal Edison should provide before the Commission makes a determination, including a discussion of the potential reliability impact on the bulk electric system for the failure of SoCal Edison's local network protection systems, particularly, the protection systems associated with the 500/115 kV and 230/115 kV transformers connected to these networks.[12]

12. In reply, SoCal Edison provides certain additional information and asserts that such information supports its position that the 115 kV Facilities are used in local distribution, as well as the uniqueness of SoCal Edison's system design and operation. Regarding the question of failure of the protection systems, SoCal Edison explains that potential reliability impacts on the interconnected transmission network for the failure of

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[12] NERC/WECC Comments at 8.

the local network protection systems are dependent on the substation design serving the radial 115 kV system or facilities. Each of the substations serving the Devers, El Casco, Kramer, Mirage, Valley, and Victor 115 kV facilities have a 115 kV bus configuration that involves a "breaker- and-a-half arrangement" while the substation serving the Vista 115 kV system has a 115 kV bus configuration that involves a double-bus-double-breaker arrangement.

13. SoCal Edison explains the design for the Control and Inyokern 115 kV substations is referred to as a double-bus-single-breaker arrangement.[13] According to SoCal Edison, the two substations do not have either a 500/115 kV or 230/115 kV transformer connected to them. SoCal Edison explains that remote protection would involve isolating fault conditions on radial 115 kV facilities by disconnecting the operating bus that is connected to the line where the primary protection system failed. SoCal Edison contends that such operation does not have an adverse impact to the reliability of the interconnected transmission network as analysis of bulk electric system facilities and the sectionalizing breakers already evaluates contingencies that result in the same operation. SoCal Edison avers that, although the failure of the Control and Inyokern protection systems during a fault will result in transmission facilities being taken out of service, loss of these facilities will not have an adverse impact on the bulk electric system.

B. <u>Data Request</u>

14. On September 2, 2015, Commission staff issued a data request for additional information: (1) studies SoCal Edison performed to show that protection system failures at Control and Inyokern would not have an adverse impact on bulk electric system reliability; (2) further explanation of SoCal Edison's request to categorize protection facilities as local distribution when their misoperation would cause the loss of bulk electric system transmission lines; (3) procedures SoCal Edison uses to close its normally open breakers; (4) emergencies that would result in SoCal Edison closing the normally open breakers and the instances it has closed them in recent years; and (5) SoCal Edison's exposure to fault induced delayed voltage recovery following contingencies in its 115 kV Facilities.

C. <u>SoCal Edison Response and Errata</u>

15. On September 30, 2015, SoCal Edison filed its response to the data request. SoCal Edison explains that it performs studies that mimic the results for the failure of the protection systems in question and that no Reliability Standards violations resulted from the misoperations. SoCal Edison defines an emergency that would result in a normally

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[13] SoCal Edison Reply Comments, Ex. SCE-1 at 8-9.

open breaker being closed, as any system condition whereby an exceedance (or an expected exceedance) of an established limit is realized. SoCal Edison explains, that the "incidents that would result in a normally open breaker being closed on the seven 115 kV distribution systems include not only emergencies, but also construction and maintenance outages."[14] SoCal Edison provides information for each of the 115 kV Facilities, noting that the "vast majority" of instances in which SoCal Edison closed normally open breakers in the 115 kV Facilities over the past five years were for rolling (i.e. transferring) load during construction or maintenance outages.[15]

16. Separately, SoCal Edison filed an errata to its application. In the errata, SoCal Edison explains that it was not accurate when it stated that its normally open breakers are only closed for emergencies; SoCal Edison also closes its normally open breakers for construction and routine maintenance. Furthermore, SoCal Edison states that power would only flow in and out of SoCal Edison's local networks simultaneously during abnormal system conditions when the normally open breakers are closed. Finally, SoCal Edison clarifies that at no point does power simultaneously enter and exit the 115 kV Facilities under normal operating conditions.

IV. Discussion

A. Procedural Matters

17. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding.[16] In addition, pursuant to Rule 214(d) of the Commission's Rules of Practice and Procedure, we grant EEI's late-filed motion to intervene, given its interest in the proceeding, the early stage of the proceeding, and the absence of any undue prejudice or delay.[17] Rule 213(a)(2) of the Commission's Rules of Practice and Procedure prohibits answers to protests and answers to answers unless otherwise ordered by the decisional authority.[18] We accept SoCal Edison's reply comments because they provided information that assisted us in our decision-making process.

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[14] SoCal Edison Data Request Response at 8.

[15] *Id.*

[16] 18 C.F.R. § 385.214 (2015).

[17] 18 C.F.R. § 385.214(d).

[18] 18 C.F.R. § 385.213(a)(2) (2015).

B. Commission Determination

18. For the reasons discussed below, we grant in part and deny in part SoCal Edison's application for a determination that SoCal Edison's 115 kV Facilities are "used in local distribution of electric energy" pursuant to section 215 of the FPA. Based on the specific facts presented in this case, and applying the seven factor test articulated in Order No. 773, we find that SoCal Edison's 115 kV Facilities are used in local distribution with the exception of the protection systems and the segments of the associated transmission lines located within the yards of the Control and Inyokern's 115 kV substations located in SoCal Edison's North of Lugo system. We conclude that these specific facilities are not used in local distribution. Our determinations in this proceeding are based on the current use of the SoCal Edison facilities as described in SoCal Edison's application and data request responses. SoCal Edison must report to the Commission if there is a material change in the utilization of the facilities that is relevant to the determination of their use as local distribution.

19. As discussed above, in Order No. 773, the Commission established a process by which an entity can seek a Commission determination whether facilities are "used in local distribution" as set forth in the FPA on a case-by-case basis.[19] When reviewing such an application, the Commission applies the "seven factor" test, as well other factors that should be taken into account in a particular situation.[20] The seven factor test is not subject to formulaic application or categorical standards.[21] Rather, the test requires comprehensive consideration of how the totality of the circumstances bears on each of the seven factors.[22] Below, we apply the seven factor test and other relevant factors, first to the bulk of SoCal Edison's 115 kV Facilities and, second, to the specific protection systems and associated lines within the yards of the Control and Inyokern 115 kV substations.

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[19] Order No. 773, 141 FERC ¶ 61,236 at PP 66-73.

[20] *See id.* P 71.

[21] *See* Order No. 888, FERC Stats. & Regs. ¶ 31,036, App. G at 31,980-81.

[22] *See California Pacific Electric Co., LLC*, 133 FERC ¶ 61,018, at PP 45-48 (2010).

1. Seven Factor Test Analysis

a. Factor one - proximity of facilities to retail customers

20. We conclude that SoCal Edison's 115 kV Facilities are generally in close proximity to the retail customers they serve. We find that the terrain and population patterns in the seven 115 kV facilities, which are primarily in the desert region between Los Angeles and the Nevada border, warrant the use of higher than 100 kV for distribution. In addition, SoCal Edison uses single interface substations that are the sole source of energy from the integrated transmission system into each local distribution system, and bring power into the distribution system from the transmission system. The design is materially the same as SoCal Edison's lower voltage (e.g., 66 kV) systems, which are fed power from single interface substations connected to SoCal Edison's 220 kV network.[23]

b. Factor two - primarily radial in character

21. We conclude that the 115 kV Facilities are not planned or designed to form parallel paths between the systems and the bulk electric system. SoCal Edison explains that each of the 115 kV Facilities radiates from a single substation in the integrated transmission network. Each system has "normally open" circuit breakers that maintain electrical isolation from neighboring systems.[24] We are persuaded by SoCal Edison's assertion that the normally open switches breakers exist to transfer load to a neighboring system during emergencies and construction and maintenance outages. To implement load rolling, i.e., transferring load to a neighboring system as needed to avoid service interruptions, SoCal Edison creates a momentary parallel with the adjacent system. SoCal Edison typically does this by closing a normally open breaker, then breaking the parallel by opening a different, normally closed breaker, thus resulting in load being rolled from one system to another with continuous service to the load. SoCal Edison states that at no point does power simultaneously enter and exit any of the 115 kV Facilities under normal operating conditions. While SoCal Edison indicates that there have been occasions where it closed a normally open breaker, the closures were infrequent and for the purpose of preserving reliability during outages.[25]

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[23] SoCal Edison Application, Ex. SCE-1 at 20.

[24] A "normally open" switch is a switch between two separate sets of facilities that, each standing alone, are radial systems that are connected by a switch that is set to the open position but occasionally is closed to maintain reliability.

[25] *See* SoCal Edison Application, Ex. SCE-1 at 21.

c. Factor three - power flows into local distribution systems, and rarely, if ever, flows out

22. We find that power flows into the 115 kV Facilities from the integrated transmission network through a single point. While SoCal Edison indicates that the flow at the point of interconnection with the transmission system is unidirectional, its direction can vary based on distribution system conditions.[26] In this case, the flow direction can be from the distribution system to the transmission network when the local generation exceeds the load (e.g., during some low load periods excess wind power flows from the Devers 115kV system) to the bulk electric system. Nevertheless, while that power may flow to the transmission system from the distribution system during low load periods as a result of increased generation on the distribution system, SCE explains that "the flow is, in most cases, always inbound from the integrated transmission network to the 115 kV Facilities."[27] Thus, we conclude that the flow of power out of the 115 kV Facilities meets this factor.[28]

d. Factor four - when power enters a local distribution system, it is not reconsigned or transported onto some other market

23. It is clear from SoCal Edison's application that power entering from the interconnected transmission network operated by the CAISO typically remains within the 115 kV Facilities and the radial nature of those facilities otherwise prevents this power from being transported back to the integrated transmission network for consignment to another market during normal operating conditions.[29] Further, SoCal Edison states that "generator owners interconnected to any of [SoCal Edison's] 115 kV distribution facilities are provided distribution service from the point of interconnection to the [CAISO]-controlled grid where it could then be transported through the [CAISO] system the ultimate buyer of the resource."[30] SoCal Edison asserts that factor four is satisfied as follows:

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[26] SoCal Edison Application at 31.

[27] SoCal Edison Application at 22.

[28] *See* SoCal Edison Application, Ex. SCE-1 at 23.

[29] *Id.*

[30] *Id.*

> While actual generation offsets local system or substation load, the delivery of the power to the ultimate buyer is provided by the California ISO even if the buyer is the same entity whose load is offset. The role of the radial 115 kV systems and facilities with respect to this factor, however, remain unchanged. The California ISO is the Transmission Provider for SCE. Under the system conditions where power enters any radial 115 kV system or facilities, the local load exceeds the level of generation, if any. This power has been procured by SCE for SCE's customers and is not reconsigned or transported onto some other market. Further, the California ISO does not rely upon any of the radial 115 kV Facilities to serve the load of other transmission customers.[31]

24. Based on SoCal Edison's petition, we conclude that power entering SoCal Edison's 115 kV Facilities from the interconnected transmission network operated by the CAISO is not transported back to the integrated transmission network for consignment to another market. However, with regard to power produced by generators located on SoCal Edison's 115 kV Facilities, the explanation is less clear. While SoCal Edison asserts that this power is not "transported" because it is delivered at the CAISO interface and the actual power produced is consumed locally, it appears that power produced by such generators may be transported from the border of SoCal Edison's 115 kV Facilities, through CAISO's transmission facilities, to the ultimate purchaser. Nevertheless, we conclude that – on balance – it does not change our overall determination that the SoCal Edison 115 kV Facilities are used in local distribution.

e. **Factor five - consumption of power entering the distribution system is in a restricted area**

25. We find that the power entering into the 115 kV Facilities is consumed in a comparatively restricted geographical area, as evidenced by the relative proximity of the 115 Facilities to the retail customers. We also find that power entering a 115 kV Facility is used within the system or respective radial substation and is unable to serve load outside the respective area, except in the infrequent moments when normally open breakers on the 115 kV Facilities are closed and power flows to a neighboring SoCal Edison system.[32]

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[31] *Id.*

[32] *Id.* at 24; SoCal Edison Response at 6.

f. Factor six - meters are based at the transmission/local distribution interface to measure flow into the local distribution system

26. We conclude that SoCal Edison's metering of the 115 kV Facilities at or near the point of interconnection to the CAISO-controlled integrated transmission network is consistent with factor six. We are persuaded by SoCal Edison's explanation that the meters between the integrated transmission network and the 115 kV Facilities are necessary to enable reliable transfer of energy between the operational control jurisdictions of the CAISO and SoCal Edison and support reliable operations.[33] We also conclude that the meters are connected to the transformer banks for each 115 kV system measuring the flow into the 115 kV Facilities.

g. Factor seven - local distribution will be of reduced voltage

27. While SoCal Edison's transmission system consists of 500 kV, 220 kV, 161 kV AC and 1000 kV DC but also include some 115 kV, 66 kV and 55 kV facilities, we find that SoCal Edison's use of the 115 kV Facilities is for "reduced voltage," given the longer distances that must be traversed in serving retail load in these portions of SoCal Edison's service territory.[34]

28. In sum, given the totality of the circumstances and based on the specific facts presented here, we find that SoCal Edison's 115 kV Facilities "are used in local distribution" as set forth in section 215 of the FPA, except for the discrete facilities discussed immediately below.

2. Protection Systems at Control and Inyokern

a. North of Lugo facility configuration

29. SoCal Edison's North of Lugo facility configuration includes three 115 kV subsystems: Inyokern 115 kV, Kramer 115 kV, and Control 115 kV. In its application,

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[33] SoCal Edison Application at 33; Ex. SCE-1 at 24.

[34] *See, e.g.*, *City of Holland, Michigan Board of Public Works,* 139 FERC ¶ 61,055 (2012); *reh'g denied*, 145 FERC ¶ 61,054 (2013); *City of Holland, Michigan Board of Public Works v. FERC*, No. 13-1306 (D.C. Cir. filed Dec. 16, 2013, held in abeyance).

SoCal Edison states that it considers portions of each as bulk electric system facilities. Specifically, the Control and Inyokern 115 kV buses are integrated with the transmission network and are part of the bulk electric system. However, certain 115 kV lines that emanate from the buses in each substation are ones that SoCal Edison considers to be for use in local distribution. Starting from the buses, the lines and downstream radial facilities have been designated as local distribution facilities since the formation of the CAISO. For each of the lines connecting SoCal Edison's local distribution facilities with the Control and Inyokern 115 kV bulk electric system buses, respectively, the lines are connected on opposite buses separated by one or two circuit breakers. Each of SoCal Edison's two 115 kV buses at the Control substation is protected from faults on the other bus by two bus-sectionalizing circuit breakers, and likewise, each of SoCal Edison's two 115 kV buses at Inyokern substation is protected from faults on the other via a single bus-tie circuit breaker.

b. SoCal Edison Pleadings

30. SoCal Edison asserts that treating the local protection systems as local distribution facilities does not present a reliability gap. SoCal Edison explains that it owns the facilities at both ends of the lines, it has exclusive control over all protection settings, and the protection systems on the 115 kV lines (or any of the facilities that interface with the bulk electric system) do not meet any of the applicability requirements of Reliability Standard PRC-005-2 since their purpose is to protect local facilities that are not currently considered part of the bulk electric system. In comments, NERC/WECC expressed concern that SoCal Edison needs to address the potential reliability impact for the failure of the local network protection systems, particularly, the protection systems associated with the 500/115 kV and 230/115 kV transformers.[35] In reply, SoCal Edison states:

> the design for the Control and Inyokern 115 kV substations is referred to as a double-bus-single-breaker arrangement. These two substations do not have either a 500/115 kV or 230/115 kV transformer connected to them. Remote protection would involve isolating fault conditions on radial 115 kV facilities by disconnecting the operating bus which is connected to the line where the primary protection system failed. Such operation does not have an adverse impact to the reliability of the BPS as analysis of BES facilities and the sectionalizing breakers already evaluates contingencies that result in the same operation.[36]

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[35] NERC and WECC comments at 8.

[36] SoCal Edison Reply Comments, Ex. SCE-16 at 7. *See also* SoCal Edison Data Request Response No. 2 at 4-6 and Response No. 7 at 13-15.

In sum, SoCal Edison asserts that, though the failure of the Control and Inyokern protection systems during a fault will result in certain bulk electric system transmission lines being taken out of service, loss of these lines will not have an adverse impact on the bulk electric system.

31. In the data request, SoCal Edison was asked to provide studies supporting the assertion that the triggering of remote protection for failed line protection systems at Control and Inyokern substations and thus the resulting loss of bulk electric system lines will not have an adverse impact on the bulk electric system. SoCal Edison responded, in part, as follows:

> SoCal Edison believes that the local distribution protection facilities are appropriately categorized as local distribution even though their misoperation would cause the loss of BES transmission elements because they meet the FERC functional tests and there is no adverse impact to the reliability of the Bulk Power System. … There may be a marginal reduction in the exposure of the integrated transmission network to low probability contingencies affecting the loss of the Control or Inyokern 115 kV buses if the interfacing protection facilities on the local distribution lines were required to meet NERC Reliability Standards for protection equipment maintenance. However, more significantly, the inclusion of these interfacing local distribution protection facilities as part of the BES will have no effect on the resiliency of the integrated transmission network, the magnitude of impact from loss of a bus section at Control or Inyokern 115 kV substations, nor the duration of forced outages due to the loss of a bus section at Control or Inyokern 115 kV substations….[37]

32. SoCal Edison states that it has performed transmission planning studies showing that, while misoperations of the protection systems at Control and Inyokern would result in the loss of bulk electric system transmission lines, SoCal Edison would still meet the performance requirements of NERC's Transmission Planning (TPL) Reliability Standards.[38]

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[37] SoCal Edison Data Request Response No. 2 at 5-6. SoCal Edison provides the results of studies that mimic the failure of the non-bulk electric system protection at Control and Inyokern. These results indicate that no Reliability Standards are violated by the misoperations.

[38] SoCal Edison Application, Ex. SCE-1 at 32-33.

c. Commission Determination

33. For the reasons discussed below, we conclude that SoCal Edison's protection systems and the segments of the associated transmission lines located within the yards of the Control and Inyokern's 115 kV substations located in SoCal Edison's North of Lugo system are not used in local distribution. In reaching this conclusion, pursuant to Order No. 773 we applied the seven factor test, as well as "other factors" that we consider appropriate in the particular situation before us.[39] Although the 115 kV Facilities pass the seven factor test, we also took into consideration other factors relevant to the record in this case, namely the reliability concern that arises due to a misoperation of the protection systems at the Control and Inyokern substations. We determine that, given the totality of the circumstances, the reliability concerns specific to the particular configuration weigh in favor of the Commission finding that the protection systems and segments of associated lines within the Control and Inyokern 115 kV are not "facilities used in the local distribution of electric energy." Further, while the Commission previously determined that these facilities are used in local distribution,[40] the protection system reliability concern discussed herein was not considered when these facilities were previously addressed by the Commission. We conclude that the consideration of this reliability concern justifies a departure from our earlier determination.

34. In particular, we are concerned that the failure of the primary protection systems during a single fault at Control and Inyokern will result in the loss of multiple bulk electric system transmission lines. As SoCal Edison acknowledges, "[r]emote protection would involve isolating fault conditions on radial 115 kV facilities by disconnecting the operating bus which is connected to the line where the primary protection system failed."[41] In other words, all sources to the bus have to be disconnected at the remote ends to isolate the bus where the distribution line fault has occurred. The Control and Inyokern station diagrams provided in SoCal Edison's application show bulk electric system transmission lines terminating at the same bus as facilities currently classified as distribution, which means that multiple bulk electric system lines would have to be taken out of service to isolate a fault on the distribution line if the distribution line protection fails.

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[39] Order No. 773, 141 FERC ¶ 61,236 at P 71.

[40] *Pacific Gas and Electric Co., et al.,* 77 FERC ¶ 61,077 (1996). *See also* SoCal Edison Application at 2 & n.3 and 17 & n.42.

[41] SoCal Edison Reply Comments, Ex. SCE-16 at 9.

35. We are not persuaded by SoCal Edison's argument that there can be no adverse impact on the bulk electric system so long as the system performance requirements of the TPL Reliability Standards are met. The bus configuration shown in the one line diagrams of Control and Inyokern 115 kV substations included in the record of this proceeding show that with the failure of the protection system associated with one of the non-bulk electric system facilities, at least two 115 kV bulk electric system facilities would be forced out of service. While the loss of these multiple 115 kV bulk electric system elements may still result in system performance that meets the requirements of the TPL Reliability Standards, this fact alone is not dispositive in determining whether facilities are used in the local distribution of electric energy. Because a relay misoperation could result in the loss of multiple bulk electric system elements, we find that, under these specific circumstances, the segments of the transmission lines associated with the individual protection systems at the Control and Inyokern substations are not "used in local distribution."

36. We note that the Control and Inyokern 115 kV substations are the only two SoCal Edison substations that use this configuration in which a non-bulk electric system line causes remote bulk electric system protection systems to operate resulting in forced outages of bulk electric system lines. Thus, we are not persuaded by SoCal Edison's concern that requiring this protection system to be treated as bulk electric system will lead to the designation of more SoCal Edison's facilities to also be included as part of the bulk electric system.[42]

37. Therefore, based on the totality of the circumstances, we conclude that the segments of the transmission lines associated with the individual protection systems at the Control and Inyokern substations are not "used in local distribution." This designation only applies to the segments from the bus to the substation fence of the 115 kV lines located in the Control and Inyokern 115 kV substations.

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[42] We note that the instant proceeding is used to determine whether the facilities in SoCal Edison's application are used in local distribution. The determination of whether facilities are part of the bulk electric system is based on application of NERC's definition and the exceptions process administered by NERC.

<u>The Commission orders</u>:

The Commission hereby approves in part and denies in part SoCal Edison's application, as discussed above.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

Document Content(s)

B

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

Mansfield Municipal Electric Department and
North Attleborough Electric Department

v. Docket No. EL00-73-001

New England Power Company

OPINION NO. 454

OPINION AND ORDER
AFFIRMING INITIAL DECISION

Issued: November 7, 2001

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OPINION AND ORDER
AFFIRMING INITIAL DECISION

APPEARANCES

Margaret A. McGoldrick, Alan J. Roth, Alisa N. Stein and *Scott H. Strauss* for Mansfield Municipal Electric Department and North Attleborough Electric Department

Robert M. Ivanauskas, Kenneth G. Jaffe and *Richard P. Sparling* for New England Power Company

Diane Beaudry Schratwieser and *James R. Keegan* for the Federal Energy Regulatory Commission

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
William L. Massey, Linda Breathitt,
and Nora Mead Brownell.

Mansfield Municipal Electric Department and
North Attleborough Electric Department

v. Docket No. EL00-73-001

New England Power Company

OPINION NO. 454

OPINION AND ORDER
AFFIRMING INITIAL DECISION

(Issued November 7, 2001)

I. Introduction

In this order we affirm an Initial Decision that: (1) finds that the rate methodology New England Power Company (NEP) uses to compute charges for certain transmission services provided to two municipal customers is unjust, unreasonable and unduly discriminatory, and (2) sets a new rate. The order serves the public interest because it assures the municipal customers the just and reasonable rates they are entitled to under the Federal Power Act (FPA).

II. Background

A. Procedural Background

On May 5, 2000, Mansfield Municipal Electric Department (Mansfield) and North Attleborough Electric Department (North Attleborough)(collectively, Municipals) filed a complaint against New England Power Company (NEP) challenging NEP's use of a rolled-in transmission rate in computing their bills. The Municipals claimed that they should be charged based on a direct assignment of costs covering only those facilities that they contend provide them with service to connect to NEP's pool transmission facilities (PTF), and excluding the costs of NEP's other facilities. The Commission issued an order setting the complaint for hearing and established a refund effective date of July 4, 2000. [1] The Presiding Judge issued an Initial Decision on March 28, 2001, largely finding for the Municipals, finding that: (1) it was unjust and unreasonable for NEP to charge the Municipals a rolled-in local network service (LNS) charge under NEP's Transmission Tariff No. 9 and that the costs of the radial facilities should be directly assigned; (2) it is unduly discriminatory for NEP to charge the Municipals the rolled-in LNS rate; and (3) the appropriate rate NEP should charge the Municipals is NEP's currently filed formula rate for direct assignment facilities under Tariff No. 9, Schedule DAF (with the Municipals paying a rolled-in LNS rate for service at the non-PTF level for a transition period, on a declining basis, in the same manner as other PTF-connected customers). [2]

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[1] Mansfield Municipal Electric Department and North Attleborough Electric Department v. New England Power Company, 93 FERC ¶ 61,077 (2000).

[2] Mansfield Municipal Electric Department and North Attleborough Electric Department v. New England Power Company, 94 FERC ¶ 63,023 (2001) (Initial Decision).

In this order, the Commission addresses the issues on exception from the Initial Decision. [3] As we explain below, we affirm the conclusions contained in the Initial Decision. [4]

B. Factual Background

At issue in this proceeding are the charges relating to the facilities that connect the Municipals to PTF. As described by the presiding judge, [5] the New England Power Pool (NEPOOL) divides transmission facilities into either PTF or non-PTF. Facilities that qualify as PTF are those that are rated 69 kilovolts (kV) or higher, excluding those that provide little or no "parallel capability to the regional transmission system." Transmission facilities that do not qualify as PTF are designated non-PTF facilities. [6] Service from the PTF is provided through the NEPOOL Open Access Transmission Tariff (OATT). The Municipals do not dispute payment of the PTF charges, which are calculated under the NEPOOL OATT on a rolled-in basis.

North Attleborough is connected to the PTF via two NEP-owned 115kV non-PTF lines that link to the North Attleborough Sherman Substation. This connection has been

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[3] Exceptions were filed by NEP in which NEP asks the Commission to reverse the findings that (1) it was unjust and unreasonable for NEP to charge the Municipals a rolled-in local network service (LNS) charge under NEP's Transmission Tariff no. 9 and that the costs of the radial facilities should be directly assigned; and (2) it is unduly discriminatory for NEP to charge the Municipals the rolled-in LNS rate. Exceptions were also filed by the Municipals in which the Municipals ask the Commission to reverse the judge's finding that they had not shown the DAF rate to be unjust and unreasonable. NEP, the Municipals and Commission staff filed briefs opposing exceptions. Staff would have the Commission affirm the Presiding Judge's decision in all respects. On September 12, 2001, Municipals filed a request for a prompt ruling on the exceptions to the Initial Decision, pointing out that the statutory 15-month limit on the refund effective period under section 206 of the FPA ends October 4, 2001.

[4] While we affirm the presiding judge's conclusions, as discussed below, we do not agree entirely with his analysis of all issues.

[5] Initial Decision at 65,168.

[6] Non-PTF facilities consist of both lower voltage and higher voltage facilities. Some higher voltage facilities are designated non-PTF because they do not provide parallel capability to the NEPOOL transmission grid.

in use since 1969. Each of the two lines is roughly 400 feet in length. NEP also owns two 115 kV circuit breakers, isolating switches on either side of the breakers, 115 kV metering transformers, supporting structures, a control house with protective relaying and metering equipment, and a small plot of land on which the control house is located.

Mansfield is connected to the PTF by two NEP-owned 115 kV non-PTF lines that link to Mansfield's Substation No. 381. This connection was energized in 1975. Each of the two lines is roughly 5000 feet in length. NEP also owns two 115 kV circuit switchers, 115 kV metering transformers, supporting structures, and certain protective relaying and metering equipment located in a shared control house.

Prior to 1996, and following 1986, the Municipals paid for NEP transmission service under NEP Tariff No. 4. The Municipals were supplied network transmission service over NEP's PTF, and paid the "STS-PTF" rate. The Municipals paid a STS-1 charge, which was based on the costs of the facilities connecting them to the PTF grid, in proportion to the extent that the connected customers used them.

Following the issuance of Order No. 888, NEP's new transmission tariff, Tariff No. 9, superseded Tariff No. 4 with respect to the Municipals' use of non-PTF facilities. In contrast to paying proportional charges under Tariff No. 4, Tariff No. 9 calls for a single, rolled-in, local network service ("LNS") rate for use of NEP's non-PTF facilities. The Municipals also take and pay for PTF network service under the NEPOOL OATT.

III. Discussion

Three issues are raised on exceptions to the initial decision: (1) whether the presiding judge correctly determined that it is unjust and unreasonable for NEP to charge the Municipals a rolled-in LNS rate under NEP's Transmission Tariff No. 9; (2) whether the judge correctly determined that it is unduly discriminatory for NEP to charge the Municipals the rolled-in LNS rate; (3) whether the judge correctly determined that the Municipals had not shown that NEP's currently filed formula rate for direct assignment facilities under Tariff No. 9, Schedule DAF is unjust and unreasonable and thus must be changed. As discussed below, we affirm the judge's conclusions, but not all of his reasoning.

A. It is unjust and unreasonable for NEP to charge the Municipals a rolled-in LNS rate under NEP's Transmission Tariff No. 9.

The presiding judge determined that it was unjust and unreasonable for NEP to charge the Municipals a rolled-in LNS rate under NEP's Transmission Tariff No. 9.

Commission policy is that transmission rates should be assessed on a rolled-in basis absent a showing that particular facilities are not integrated with the transmission system as a whole. Staff and Municipals maintain that the facilities at issue here are not integrated into NEP's non-PTF system, while NEP claims that they are.

In the Initial Decision, the judge, citing Niagara Mohawk Power Corporation, 42 FERC ¶ 61,143 at 61,531(1988), stated that the Commission favors a rolled-in method of transmission allocation, "except where 'special circumstances' exist. In cases where the Commission has authorized direct allocation, the 'special circumstances' cited have generally been the lack of a fully integrated system." Initial Decision at 65,169.

The judge continued that the designation of the 115kV lines by NEP as transmission does not determine their function. Id. The judge looked to five factors suggested by a staff witness to determine whether a facility is integrated with the rest of the network:

> 1. Whether the facilities are radial, or whether they loop back into the transmission system;
>
> 2. Whether energy flows only in one direction, from the transmission system to the customer over the facilities, or in both directions, from the transmission system to the customer, and from the customer to the transmission system;
>
> 3. Whether the transmission provider is able to provide transmission service to itself or other transmission customers . . . over the facilities in question;
>
> 4. Whether the facilities provide benefits to the transmission grid in terms of capability or reliability, and whether the facilities can be relied on for coordinated operation of the grid; and[,]
>
> 5. Whether an outage on the facilities would affect the transmission system.

The judge found that the facilities in question meet each of these tests:

1. No witness disputed that Municipals' lines are radial in nature.

2. It is obvious that energy only flows in one direction from the high voltage transmission system to the Municipals' substation.

3. NEP, the transmission provider, is not able to use the transmission lines to provide service to itself or any other customer.

4. Despite NEP's contention, there is no evidence that the facilities provide benefits to the transmission grid in terms of reliability or capability. The power only flows into the facilities; none flows out; and,

5. An outage on the Municipals' facilities would not have any effect on the transmission system. There is no alternative path from the transmission grid to the Municipals' facilities. [[7]]

The judge rejected NEP's claim that the lines carrying power to the Municipals were intended to serve anyone other than the Municipals. [8] The judge also rejected NEP's argument that Section 16.3 of the NEPOOL Restated Agreement requires a rolled-in rate design. Finally, the judge acknowledged that, in approving the NEPOOL settlement in New England Power Pool, [9] the Commission had approved rolled-in rates for these facilities for a transition period, but stated that this does not support rolled-in rates following the transition. The judge concluded the Municipals' radial lines are non-integrated facilities that should be directly assigned and that the existing rolled-in methodology for these facilities thus was unjust and unreasonable. [10]

On exceptions, NEP challenges the judge's factual conclusion that the facilities in question are not integrated. NEP also excepts to the judge's conclusion that the

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[7]Initial Decision at 65,170. The judge also looked to seven indicators that facilities are local distribution listed in Order No. 888 to support his conclusion that the non-PTF facilities at issue are not integrated. Those indicators were not specifically designed to determine whether facilities are integrated, but were designed to determine what facilities were used for local distribution in the context of unbundled retail service. Thus those indicators are not relevant here. We specifically do not rely on that part of the judge's reasoning.

[8]Initial Decision at 65,171.

[9]83 FERC ¶ 61,045 (1998).

[10]Id.

Municipals qualify for the exception to the rolled-in rate requirement set forth in Section 16.3iii of the Restated NEPOOL Agreement. Finally, NEP argues that switching Municipals, and other municipal customers who are electrically configured in the same way, to a direct assignment rate will mean that other Tariff No. 9 customers will pay higher rates. NEP concludes that affirming the Initial Decision on this issue will in essence be rewriting the 1998 NEPOOL settlement.

We do not agree. Nothing raised on exceptions by NEP warrants reversing the judge's conclusion that the existing rolled-in methodology for these facilities is unjust and unreasonable. First, as to NEP's argument that the facilities are integrated, we affirm the law judge. NEP points to testimony from its witness, Mr. Taglianetti, that NEP's transmission system was designed and built to integrate resources over a large geographic area and to deliver power to local distribution systems. The judge found:

> There is no evidence in this case that NEP intended for the facilities to serve anyone other than the Municipals or that they could be used for other loads. Although NEP witness Taglianetti testified that the lines were not built for the Municipals alone, he acknowledged that NEP had no plans to add generation or customers to these lines. Tr. at 138-141. The Municipals argued in their complaint that the "sole purpose for which these lines were constructed was to allow each of the Municipal Complainants to receive service at the 'high side' of the municipally owned substation transformer (rated at 115kV) rather than the low side, and that is still their sole function." Staff R.B. at 7 (citing Complaint at 11). NEP did not successfully contradict this allegation.[[11]]

We affirm the judge's conclusion that the facilities are not integrated.

Next, we address NEP's arguments that the judge erred in finding that section 16.3 of the Restated NEPOOL Agreement does not require rolled-in rates. The judge found:

> NEP argues that this paragraph requires a rolled-in rate design. However that is not an universal requirement. Section 16.3 (iii) provides an exception to the rolled-in rate. Under this subsection, certain municipals which own facilities directly connecting them to the PTF grid are exempt from paying non-PTF charges except during the transition period. The Municipal Complainants are similarly connected to the PTF. The only

[11]Initial Decision at 65,171.

> difference is that they do not own the connecting lines but would be paying the costs through direct assignment of the radial lines. [[12]]

NEP's argument that "the only difference" cited by the judge, i.e., that Municipals do not own the connecting lines, is an important difference, essentially acknowledges that section 16.3 does not in all cases require rolled-in rates. We affirm the judge's finding.

Next, we address NEP's argument that the Municipals and other municipals switching to directly assigned rates will result in higher rates for remaining Tariff No. 9 customers. In answer, we simply note that nothing in the Initial Decision applies to any municipal customers other than Municipals. [13] Moreover, it is a fundamental basis of Commission ratemaking that costs should be recovered in the rates of those customers who utilize the facilities and thus cause the cost to be incurred.[14] Thus, the shift of costs to other customers is appropriate.

Finally, NEP's reliance on the NEPOOL settlement is misplaced. NEP points to nothing in the Commission's order approving the NEPOOL settlement indicating that the Commission intended to bind Municipals to a rolled-in methodology for nonintegrated non-PTF facilities indefinitely. Nor do we find support for this argument elsewhere.

In conclusion, we affirm the presiding judge's conclusion that it is unjust and unreasonable for NEP to charge the Municipals a rolled-in LNS rate under NEP's Transmission Tariff No. 9.

B. It is unduly discriminatory for NEP to charge the Municipals the rolled-in LNS rate.

The judge concluded that similarly-situated customers receive a differing rate treatment from NEP and that this differing rate treatment is unduly discriminatory within the meaning of the FPA.

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[12] Id.

[13] The Initial Decision applies only to Municipals. If other customers believe that their current rates are unjust and unreasonable, or unduly discriminatory, and that they are entitled to a direct assignment rate, a complaint and a Commission decision in their favor would be required before any effect on other customers would take effect.

[14] Norther States Power Company, 64 FERC ¶ 61,324 at 63,379 (1993), reh'g denied, 74 FERC ¶ 61,106 (1996).

The judge compared the Municipals, which were described as being connected to NEP-owned PTF through non-PTF facilities owned by NEP, to two other types of NEP transmission customers.[15] He stated that to find rate discrimination, the complainants must show that two classes of customers receive different rate treatment, that they are similarly situated and there is no factual consideration that would justify such differential treatment.

The judge concluded:

> While NEP would like to argue that the facilities at issue are, in fact, different, and should receive differing rate treatment, their distinction is not well drawn. NEP goes to great lengths to highlight the differences between the Municipals' connections and the other customers who either own their own connection to the PTF or have a pre-existing agreement to pay for non-PTF facilities on a declining basis. The key to this proceeding is not whether the lines are owned by NEP or the customer, or whether there was a pre-existing agreement, but whether the *service* rendered to the customer is similar. Another factor to consider is whether the electrical configuration of the two sets of customers are similarly situated. The record in this proceeding conclusively shows that the service and electrical configuration of the Municipals, and the service and electrical configuration of the previously mentioned customers, are similarly situated, and therefore should be subject to similar rate treatment. [[16]]

On exceptions, NEP argues that the Municipals are not situated similarly to other customers. NEP points to three types of customers: (1) the Municipals and others that are connected to NEP-owned PTF through non-PTF facilities owned by NEP; (2) customers who are connected to NEP-owned PTF through support payments under pre-existing agreements; and (3) customers who are connected to the NEP-owned PTF through facilities they own. NEP argues that rate disparity is justified for each of these classes.

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[15]Initial Decision at 65,172.

[16]Id.

We disagree. While a rate disparity may be justified for the customers that are subject to pre-existing agreements, [17] a rate disparity between the Municipals and others connected to NEP-owned PTF through non-PTF facilities owned by NEP and those connected to NEP-owned PTF through similar facilities that are customer-owned is not justified. The judge found that NEP had not distinguished the Municipals from customers that own their own lines connecting them to NEP PTF facilities. The judge reasoned that ownership of connecting line does not change the benefit Municipals receive from non-PTF facilities. In essence, customers connected to NEP-owned PTF by non-PTF lines which are not integrated, should pay only for the non-integrated non-PTF rather than all of NEP's non-PTF regardless of who owns the connection. We agree and affirm the judge on this issue.

C. <u>The Municipals did not show that NEP's currently filed formula rate for direct assignment facilities under Tariff No. 9, Schedule DAF is unjust and unreasonable and thus must be changed</u>.

The judge, after having found that the Municipals had shown that the rolled-in LNS rate was unjust and unduly discriminatory, next determined what was the appropriate rate that NEP should charge. [18] He noted that NEP's Tariff No. 9, Schedule DAF directly assigns to customers the cost of facilities that are built for their sole use and benefit. The judge noted that he had found that the subject radial lines had been built for the sole use and benefit of the Municipals. The judge found that Schedule DAF is the currently existing rate for direct assignment facilities and has been approved by the Commission as just and reasonable. The DAF applies a fixed charge rate, which includes a depreciation component based upon NEP's system average depreciation to NEP's gross investment in the specific facilities. The judge continued that because the existing Schedule DAF was previously found by the Commission to be just and reasonable, the Municipals have the burden of showing that the existing DAF Schedule results in unjust and unreasonable rates. He found that Municipals had not met that burden. He concluded that the rate NEP should charge the Municipals is NEP's currently filed formula rate for direct assignment facilities under Tariff No. 9, Schedule DAF (with the Municipals paying a rolled-in LNS rate for service at the non-PTF level for a transition period, on a declining basis, in the same manner as other PTF connected customers).

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[17]In Order No. 888, the Commission allowed customers to continue taking service under pre-existing agreements, even when a rate disparity would result.

[18]Initial Decision 65,174-76.

Municipals claim that the judge erred in not comparing the methodology Municipals advocate (using actual depreciation instead of average system depreciation) with the existing Schedule DAF to determine which more accurately tracks Municipals' costs. Municipals claim that there is no requirement that they show that they would overpay if Schedule DAF is used to set the Municipals' direct assignment charges. We agree with the judge's analysis of the issue and affirm the judge.

The Commission orders:

(A) The Initial Decision in this proceeding is hereby affirmed, as discussed in the body of this order.

(B) Within 30 days from the date of the issuance of this order, NEP shall make a compliance filing with the Commission reflecting the requirements of this order and showing the refunds due Municipals.

By the Commission.

(S E A L)

David P. Boergers,
Secretary.

C

ATTACHMENT O - Entergy Arkansas, Inc.

For the 12 Months Ended 12/31/20__

Formula Rate -- Appendix A			Notes	FERC Form 1 Page # or Reference	True-up	Projected
A	B	C	D	E	F	G	H

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in a Worksheet 7 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by 1/(1-T). Excess Deferred Income Taxes reduce income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T). Permanent Differences in Income Taxes increases income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T) for differences in the income taxes due under the Federal and State calculations and the income taxes recorded on the Company's financial statements. A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income. If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

J The base ROE shall be as established by FERC and is subject to change consistent with the outcome of proceedings in FERC Docket No. EL15-45, a final order concerning the ROE issue raised in MDEA v. FERC, (D.C. Circuit Case No. 14-1030), and otherwise subject to change pursuant to a FPA section 205 or 206 proceeding. A 50 basis point adder for RTO participation may be added to the ROE provided the maximum ROE may not to exceed the upper end of the zone of reasonableness established by FERC in EL14-12 or other proceeding.

K General Advertising expenses that may be included are those associated with safety, education and outreach expenses relating to transmission, for example siting or billing.

L The 12CP peak is the average of the 12 monthly system peaks in a calendar year, coincident with the MISO Transmission Pricing Zone's monthly transmission system peaks, calculated as the native load plus Network Service customers' monthly network loads plus the reserve capacity of all Long Term Firm Point-to-Point Customers.

M Transmission plant excluded from rates will include Step-Up Facilities, Supplemental Upgrades, Radial lines and Generator Interconnection facilities. Radial lines will be reported in a supporting work paper and will be updated annually as part of the annual rate update process to identify the radial facilities included in transmission rate base for the relevant rate year and Entergy will indicate any changes to the listing from the prior year. If new radial facilities are added or changes made to facilities identified on the work paper, the status of those new or changed facilities as radial transmission facilities will be assessed using the criteria identified in Section 3 of MISO's Business Practice Manual 28, Transmission Determination Process for Prospective or Existing Unregulated Transmission Owner's Facilities, Application for Transmission Determination of FERC Seven Factors Test for Local Distribution ("BPM-028"). Entergy will report Generator Interconnection Facilities in a work paper and must remove from transmission rates those ~~on~~ facilities constructed or purchased by Entergy on or after March 15, 2000 (FERC Order 2003: Docket RM02-1-000, issued July 24, 2003, page 154).

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole. Entergy will provide a supporting work paper.

O The formula rate shall exclude all expenses associated with (i) MISO Schedule 10 and MISO Schedule 10-FERC, for which Load Serving Entities ("LSEs") are billed separately by MISO and (ii) all other expenses recovered by MISO through direct charges to transmission owners and transmission users pursuant to separate schedules under the MISO Tariff or otherwise. For rate years 2015 and beyond, the Entergy Operating Companies do not expect to incur any FERC annual fees directly.

P The depreciation and amortization rates to be used for all of the Entergy Operating Companies will be the current blended depreciation and amortization rates. Entergy Services commits to make a limited Section 205 filing(s) no later than November 1, 2015, proposing updated depreciation and amortization rates for all of the Entergy Operating Companies to become effective no later than January 1, 2016. Once approved by the Commission, the updated depreciation and amortization rates will be used in the Entergy Operating Companies' MISO Attachment O formula rates.

Q The gains and losses on hedges shall be removed from the Long-Term Debt Cost calculation unless inclusion of such hedges has been accepted by the FERC pursuant to a FPA Section 205 or 206 filing.

R Include only the balances associated with long-term debt and exclude balances associated with short-term debt.

S Entergy shall not include any inputs in the formula for Asset Retirement Obligations (AROs) such as, ARO assets, ARO depreciation expense, accumulated provision for depreciation of ARO assets, ARO accretion expense, or ARO cost of removal/negative salvage, absent Commission approval pursuant to a section 205 or 206 filing.

T Removes the dollar amount of revenue requirements for facilities calculated pursuant to Attachment GG of the MISO Tariff. The True-up amount in Column G is based on the True-up result in the GG template. The Projected amount in Column H is based on the Projected result in the GG Template.

U Removes the dollar amount of revenue requirements for facilities calculated pursuant to Attachment MM of the MISO Tariff. The True-up amount in Column G is based on the True-up result in the MM template. The Projected amount in Column H is based on the Projected result in the MM Template.

V Unfunded Reserves are Reserves that are charged to accounts recovered in the formula rate, and are offset (reduced) by any contra accounts that are not deposited into trusts or restricted accounts.

W Reserved for future use.

X Charges to Account 930.2 shall be subject to review and challenge as part of the protocols procedures. Notwithstanding the specific language of the protocols, charges related directly or indirectly to transmission service should be included and charges not directly or indirectly related to transmission (wholly retail-related items, wholly production-related items, and/or wholly distribution-related items) are subject to challenge and should be excluded.

Y The Entergy Operating Companies will not adopt an allocation factor for Common Plant and Expenses absent Commission approval pursuant to a section 205 filing.

Z Removes from revenue credits those revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff.

AA Removes from revenue credits those revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff.

BB Reserved for future use.

CC As of the effective date of this formula, the Entergy Operating Companies may include CIAC-related ADIT for transmission facilities in ADIT assignable to the transmission function so long as the associated facilities that create such ADIT constitute Network Upgrade Facilities under Order No. 2003, and do not constitute Network Upgrade Facilities for which Network Credits are paid or payable to the contributing customer.

DD The gain or loss on the sale of a transmission or general plant asset is only included if the asset has been included as a component of the transmission formula rate base.

EE Per Settlement Agreement in ER13-948 Accounts 5611 through 5618 are not included in Transmission Expense.

FF In conformance with Section II of the Entergy Operating Company's Annual Update, Information Exchange and Challenge Procedures, Entergy shall provide a supporting work paper with accompanying detailed descriptions of the need for each adjustment. Entergy will include in the description the docket number in which FERC approved each adjustment. No adjustments will be included absent FERC approval.

GG Revenue Requirement associated with credits received by Network Customers for their integrated transmission facilities under Section 30.9.

HH The components of capitalization for the Projected Rate determined in the Annual Update shall be based on end-of-year values for the historical calendar year. The True-up for the same historical calendar year shall be based upon 13-month average balances.

II General Advertising expenses recorded in Account 930.1 and associated solely with safety, education and outreach shall be included, except that General Advertising expenses that are 100% recovered at or allocable to retail will not be included.

JJ Use average of beginning-of-year and end-of-year balances for the True-up column. Use end-of-year balances for Projected column.

KK Use 13-month average balance for both the True-up and Projected columns.

END

ATTACHMENT O - Entergy Louisiana, LLC

For the 12 Months Ended 12/31/20__

Formula Rate -- Appendix A				Notes	FERC Form 1 Page # or Reference	True-up	Projected
A	B	C	D	E	F	G	H

J The base ROE shall be as established by FERC and is subject to change consistent with the outcome of proceedings in FERC Docket No. EL15-45, a final order concerning the ROE issue raised in MDEA v. FERC, (D.C. Circuit Case No. 14-1030), and otherwise subject to change pursuant to a FPA section 205 or 206 proceeding. A 50 basis point adder for RTO participation may be added to the ROE provided the total or maximum ROE may not to exceed the upper end of the zone of reasonableness established by FERC in EL14-12 or other proceeding.

K General Advertising expenses that may be included are those associated with safety, education and outreach expenses relating to transmission, for example siting or billing.

L The 12CP peak is the average of the 12 monthly system peaks in a calendar year, coincident with the MISO Transmission Pricing Zone's monthly transmission system peaks, calculated as the native load plus Network Service customers' monthly network loads plus the reserve capacity of all Long Term Firm Point-to-Point Customers.

M Transmission plant excluded from rates will include Step-Up Facilities, Supplemental Upgrades, Radial lines and Generator Interconnection facilities. Radial lines will be reported in a supporting work paper and will be updated annually as part of the annual rate update process to identify the radial facilities included in transmission rate base for the relevant rate year and Entergy will indicate any changes to the listing from the prior year. If new radial facilities are added or changes made to facilities identified on the work paper, the status of those new or changed facilities as radial transmission facilities will be assessed using the criteria identified in Section 3 of MISO's Business Practice Manual 28, Transmission Determination Process for Prospective or Existing Unregulated Transmission Owner's Facilities, Application for Transmission Determination of FERC Seven Factors Test for Local Distribution ("BPM-028"). Entergy will report Generator Interconnection Facilities in a work paper and must remove from transmission rates those facilities constructed or purchased by Entergy on or after March 15, 2000 (FERC Order 2003: Docket RM02-1-000, issued July 24, 2003, page 154).

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole. Entergy will provide a supporting work paper.

O The formula rate shall exclude all expenses associated with (i) MISO Schedule 10 and MISO Schedule 10-FERC, for which Load Serving Entities ("LSEs") are billed separately by MISO and (ii) all other expenses recovered by MISO through direct charges to transmission owners and transmission users pursuant to separate schedules under the MISO Tariff or otherwise. For rate years 2015 and beyond, the Entergy Operating Companies do not expect to incur any FERC annual fees directly.

P The depreciation and amortization rates to be used for all of the Entergy Operating Companies will be the current blended depreciation and amortization rates. Entergy Services commits to make a limited Section 205 filing(s) no later than November 1, 2015, proposing updated depreciation and amortization rates for all of the Entergy Operating Companies to become effective no later than January 1, 2016. Once approved by the Commission, the updated depreciation and amortization rates will be used in the Entergy Operating Companies' MISO Attachment O formula rates.

Q The gains and losses on hedges shall be removed from the Long-Term Debt Cost calculation unless inclusion of such hedges has been accepted by the FERC pursuant to a FPA Section 205 or 206 filing.

R Include only the balances associated with long-term debt and exclude balances associated with short-term debt.

S Entergy shall not include any inputs in the formula for Asset Retirement Obligations (AROs) such as, ARO assets, ARO depreciation expense, accumulated provision for depreciation of ARO assets, ARO accretion expense, or ARO cost of removal/negative salvage, absent Commission approval pursuant to a section 205 or 206 filing.

T Removes the dollar amount of revenue requirements for facilities calculated pursuant to Attachment GG of the MISO Tariff. The True-up amount in Column G is based on the True-up result in the GG template. The Projected amount in Column H is based on the Projected result in the GG Template.

U Removes the dollar amount of revenue requirements for facilities calculated pursuant to Attachment MM of the MISO Tariff. The True-up amount in Column G is based on the True-up result in the MM template. The Projected amount in Column H is based on the Projected result in the MM Template.

V Unfunded Reserves are Reserves that are charged to accounts recovered in the formula rate, and are offset (reduced) by any contra accounts that are not deposited into trusts or restricted accounts.

W Reserved for future use.

X Charges to Account 930.2 shall be subject to review and challenge as part of the protocols procedures. Notwithstanding the specific language of the protocols, charges related directly or indirectly to transmission service should be included and charges not directly or indirectly related to transmission (wholly retail-related items, wholly production-related items, and/or wholly distribution-related items) are subject to challenge and should be excluded.

Y The Entergy Operating Companies will not adopt an allocation factor for Common Plant and Expenses absent Commission approval pursuant to a section 205 filing.

Z Removes from revenue credits those revenues that are distributed pursuant to Schedules associated with Attachment GG of the MISO Tariff.

AA Removes from revenue credits those revenues that are distributed pursuant to Schedules associated with Attachment MM of the MISO Tariff.

BB Reserved for future use.

CC As of the effective date of this formula, the Entergy Operating Companies may include CIAC-related ADIT for transmission facilities in ADIT assignable to the transmission function so long as the associated facilities that create such ADIT constitute Network Upgrade Facilities under Order No. 2003, and do not constitute Network Upgrade Facilities for which Network Credits are paid or payable to the contributing customer.

DD The gain or loss on the sale of a transmission or general plant asset is only included if the asset has been included as a component of the transmission formula rate base.

EE Per Settlement Agreement in ER13-948 Accounts 5611 through 5618 are not included in Transmission Expense.

FF In conformance with Section II of the Entergy Operating Company's Annual Update, Information Exchange and Challenge Procedures, Entergy shall provide a supporting work paper with accompanying detailed descriptions of the need for each adjustment. Entergy will include in the description the docket number in which FERC approved each adjustment. No adjustments will be included absent FERC approval.

GG Revenue Requirement associated with credits received by Network Customers for their integrated transmission facilities under Section 30.9.

HH The components of capitalization for the Projected Rate determined in the Annual Update shall be based on end-of-year values for the historical calendar year. The True-up for the same historical calendar year shall be based upon 13-month average balances.

II General Advertising expenses recorded in Account 930.1 and associated solely with safety, education and outreach shall be included, except that General Advertising expenses that are 100% recovered at or allocable to retail will not be included.

JJ Use average of beginning-of-year and end-of-year balances for the True-up column. Use end-of-year balances for Projected column.

KK Use 13-month average balance for both the True-up and Projected columns.

END

ATTACHMENT O - Entergy Mississippi, Inc.

For the 12 Months Ended 12/31/20__

Formula Rate -- Appendix A			Notes	FERC Form 1 Page # or Reference	True-up	Projected
A B	C	D	E	F	G	H
	Revenue Credits & Interest on Network Credits					
	Rent from Electric Property					
176	Transmission			WP17 Rev Line 2 Column C	-	-
177	General Plant			WP17 Rev Line 2 Column E	-	-
178	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
179	Total Transmission Allocated General Plant			(Line 177 * Line 178)	-	-
180	Revenue Credits from Rent of Electric Property			(Line 176 + Line 179)	-	-
	Other Electric Revenue					
181	Transmission Service Other Revenue Credits			WP17 Rev Line 7 Column C	-	-
182	Transmission Network & LTF Service Revenues			WP17 Rev Line 7 Column D	-	-
183	Transmission Service Revenue Credits			(Line 181 + Line 182)	-	-
184	General Plant			WP17 Rev Line 7 Column E	-	-
185	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
186	Total Transmission Allocated General Plant			(Line 184 * 185)	-	-
187	Total Revenue Credits			(Line 183 + 186)	-	-
188	Less Transmission Network & LTF Service Revenues			(Line 182)	-	-
189	Less Rev. Credits from Schedules assoc. w/ Attachment GG		(Note Z)	WP17 Rev Line 6.38 Column C	-	-
190	Less Rev. Credits from Schedules assoc. w/ Attachment MM		(Note AA)	WP17 Rev Line 6.39 Column C	-	-
191	Revenue Credits - Transmission Service Other Revenue Credits			(Line 187 - Line 188 - Line 189 - Line 190)	-	-
192	Interest on Network Credits		(Note N)		-	-
193	**Net Revenue Requirement**			**(Line 175 - Line 180 - Line 191 + Line 192)**	-	-
194	True-up with Interest	(Over)/Under Collection		WP01 True-up Line 29 (EOY) Column E		-
195	**Net Adjusted Revenue Requirement**			**(Line 193 + Line 194)**		-
196	Network Customer OATT Section 30.9 Facilities Credits					
197	Network Customer 1		(Note GG)			-
198	Network Customer 2		(Note GG)			-
199	Total Net Adjusted Revenue Requirement			(Line 195 + Line 197 + Line 198)		-
	Annual Point-to-Point Transmission Rate					
200	Average of the 12 CP (kW)		(Note L)	WP19 Load Line 25 Column N		-
201	Annual Point-to-Point Transmission Rate			(Line 199 / Line 200)		0.00
202	Monthly rate			(Line 201 / 12)		-

Notes

A Electric portion only

B The projected charges for the Annual Update shall be based on end-of-year plant-related values for the historical base year plus new plant (excluding capital additions that will be recovered through MISO rate Schedules other than Schedules 7, 8 and 9) that is projected to be placed into service in the immediately subsequent calendar year weighted by the number of months the new plant is projected to be in service. The True-up calculation for each calendar year shall be based upon 13-month average plant-related balances. Supporting work papers will be provided.

C Only the Transmission portion will be included.

D The Entergy Operating Company's total company PBOP expense to be allocated in part to transmission each year shall not be changed absent a filing under Section 205 or 206 of the Federal Power Act, unless the Entergy Operating Company is authorized to use pay-as-you-go accounting for PBOPs.

E Includes all Regulatory Commission Expenses

F Property Insurance excludes prior period adjustments for the first year, calendar year 2014, of the formula's operation . Property Insurance includes prior period adjustments, if any, in calendar year 2015 and subsequent years.

G FERC regulatory expenses itemized in the FERC Form No. 1 at 351.h that are directly related to transmission service, RTO filings, OATT compliance and maintenance of the transmission formula rate and retail regulatory expenses associated with siting and certification of qualifying transmission facilities.

H Cash working capital allowance is 0.00% of O&M

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in a Worksheet 7 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by 1/(1-T). Excess Deferred Income Taxes reduce income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T). Permanent Differences in Income Taxes increases income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T) for differences in the income taxes due under the Federal and State calculations and the income taxes recorded on the Company's financial statements. A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income. If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

J The base ROE shall be as established by FERC and is subject to change consistent with the outcome of proceedings in FERC Docket No. EL15-45, a final order concerning the ROE issue raised in MDEA v. FERC, (D.C. Circuit Case No. 14-1030), and otherwise subject to change pursuant to a FPA section 205 or 206 proceeding. A 50 basis point adder for RTO participation may be added to the ROE provided the total or maximum ROE may not to exceed the upper end of the zone of reasonableness established by FERC in EL14-12 or other proceeding.

K General Advertising expenses that may be included are those associated with safety, education and outreach expenses relating to transmission, for example siting or billing.

L The 12CP peak is the average of the 12 monthly system peaks in a calendar year, coincident with the MISO Transmission Pricing Zone's monthly transmission system peaks, calculated as the native load plus Network Service customers' monthly network loads plus the reserve capacity of all Long Term Firm Point-to-Point Customers.

M Transmission plant excluded from rates will include Step-Up Facilities, Supplemental Upgrades, Radial lines and Generator Interconnection facilities. Radial lines will be reported in a supporting work paper and will be updated annually as part of the annual rate update process to identify the radial facilities included in transmission rate base for the relevant rate year and Entergy will indicate any changes to the listing from the prior year. If new radial facilities are added or changes made to facilities identified on the work paper, the status of those new or changed facilities as radial transmission facilities will be assessed using the criteria identified in Section 3 of MISO's Business Practice Manual 28, Transmission Determination Process for Prospective or Existing Unregulated Transmission Owner's Facilities, Application for Transmission Determination of FERC Seven Factors Test for Local Distribution ("BPM-028"). Entergy will report Generator Interconnection Facilities in a work paper and must remove from transmission rates those facilities constructed or purchased by Entergy on or after March 15, 2000 (FERC Order 2003: Docket RM02-1-000, Issued July 24, 2003, page 154).

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole. Entergy will provide a supporting work paper.

O The formula rate shall exclude all expenses associated with (i) MISO Schedule 10 and MISO Schedule 10-FERC, for which Load Serving Entities ("LSEs") are billed separately by MISO and (ii) all other expenses recovered by MISO through direct charges to transmission owners and transmission users pursuant to separate schedules under the MISO Tariff or otherwise. For rate years 2015 and beyond, the Entergy Operating Companies do not expect to incur any FERC annual fees directly.

ATTACHMENT O - Entergy New Orleans, Inc.

For the 12 Months Ended 12/31/20__

Formula Rate -- Appendix A			Notes	FERC Form 1 Page # or Reference	True-Up	Projected
A	B C	D	E	F	G	H
	Revenue Credits & Interest on Network Credits					
	Rent from Electric Property					
176	Transmission			WP17 Rev Line 2 Column C	-	-
177	General Plant			WP17 Rev Line 2 Column E	-	-
178	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
179	Total Transmission Allocated General Plant			(Line 177 * Line 178)	-	-
180	Revenue Credits from Rent of Electric Property			(Line 176 + Line 179)	-	-
	Other Electric Revenue					
181	Transmission Service Other Revenue Credits			WP17 Rev Line 7 Column C	-	-
182	Transmission Network & LTF Service Revenues			WP17 Rev Line 7 Column D	-	-
183	Transmission Service Revenue Credits			(Line 181 + Line 182)	-	-
184	General Plant			WP17 Rev Line 7 Column E	-	-
185	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
186	Total Transmission Allocated General Plant			(Line 184 * 185)	-	-
187	Total Revenue Credits			(Line 183 + 186)	-	-
188	Less Transmission Network & LTF Service Revenues			(Line 182)	-	-
189	Less Rev. Credits from Schedules assoc. w/ Attachment GG		(Note Z)	WP17 Rev Line 6.38 Column C	-	-
190	Less Rev. Credits from Schedules assoc. w/ Attachment MM		(Note AA)	WP17 Rev Line 6.39 Column C	-	-
191	Revenue Credits - Transmission Service Other Revenue Credits			(Line 187 - Line 188 - Line 189 - Line 190)	-	-
192	Interest on Network Credits		(Note N)		-	-
193	**Net Revenue Requirement**			**(Line 175 - Line 180 - Line 191 + Line 192)**	-	-
194	True-up with Interest	(Over)/Under Collection		WP01 True-Up Line 29 (EOY) Column E		-
195	**Net Adjusted Revenue Requirement**			**(Line 193 + Line 194)**		-
196	Network Customer OATT Section 30.9 Facilities Credits					
197	Network Customer 1		(Note GG)			-
198	Network Customer 2		(Note GG)			-
199	Total Net Adjusted Revenue Requirement			(Line 195 + Line 197 + Line 198)		-
	Annual Point-to-Point Transmission Rate					
200	Average of the 12 CP (kW)		(Note L)	WP19 Load Line 25 Column N		-
201	Annual Point-to-Point Transmission Rate			(Line 199 / Line 200)		-
202	Monthly rate			(Line 201 / 12)		-

Notes

A Electric portion only

B The projected charges for the Annual Update shall be based on end-of-year plant-related values for the historical base year plus new plant (excluding capital additions that will be recovered through MISO rate Schedules other than Schedules 7, 8 and 9) that is projected to be placed into service in the immediately subsequent calendar year weighted by the number of months the new plant is projected to be in service. The True-up calculation for each calendar year shall be based upon 13-month average plant-related balances. Supporting work papers will be provided.

C Only the Transmission portion will be included.

D The Entergy Operating Company's total company PBOP expense to be allocated in part to transmission each year shall not be changed absent a filing under Section 205 or 206 of the Federal Power Act, unless the Entergy Operating Company is authorized to use pay-as-you-go accounting for PBOPs.

E Includes all Regulatory Commission Expenses

F Property Insurance excludes prior period adjustments for the first year, calendar year 2014, of the formula's operation . Property Insurance includes prior period adjustments, if any, in calendar year 2015 and subsequent years .

G FERC regulatory expenses itemized in the FERC Form No. 1 at 351.h that are directly related to transmission service, RTO filings, OATT compliance and maintenance of the transmission formula rate and retail regulatory expenses associated with siting and certification of qualifying transmission facilities.

H Cash working capital allowance is 0.00% of O&M

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in a Worksheet 7 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by 1/(1-T). Excess Deferred Income Taxes reduce income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T). Permanent Differences in Income Taxes increases income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T) for differences in the income taxes due under the Federal and State calculations and the income taxes recorded on the Company's financial statements. A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income. If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

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K General Advertising expenses that may be included are those associated with safety, education and outreach expenses relating to transmission, for example siting or billing.

L The 12CP peak is the average of the 12 monthly system peaks in a calendar year, coincident with the MISO Transmission Pricing Zone's monthly transmission system peaks, calculated as the native load plus Network Service customers' monthly network loads plus the reserve capacity of all Long Term Firm Point-to-Point Customers.

M Transmission plant excluded from rates will include Step-Up Facilities, Supplemental Upgrades, Radial lines and Generator Interconnection facilities. Radial lines will be reported in a supporting work paper and will be updated annually as part of the annual rate update process to identify the radial facilities included in transmission rate base for the relevant rate year and Entergy will indicate any changes to the listing from the prior year. If new radial facilities are added or changes made to facilities identified on the work paper, the status of those new or changed facilities as radial transmission facilities will be assessed using the criteria identified in Section 3 of MISO's Business Practice Manual 28, Transmission Determination Process for Prospective or Existing Unregulated Transmission Owner's Facilities, Application for Transmission Determination of FERC Seven Factors Test for Local Distribution ("BPM-028"). Entergy will report Generator Interconnection Facilities in a work paper and must remove from transmission rates those facilities constructed or purchased by Entergy on or after March 15, 2000 (FERC Order 2003: Docket RM02-1-000, Issued July 24, 2003, page 154).

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole. Entergy will provide a supporting work paper.

O The formula rate shall exclude all expenses associated with (i) MISO Schedule 10 and MISO Schedule 10-FERC, for which Load Serving Entities ("LSEs") are billed separately by MISO and (ii) all other expenses recovered by MISO through direct charges to transmission owners and transmission users pursuant to separate schedules under the MISO Tariff or otherwise. For rate years 2015 and beyond, the Entergy Operating Companies do not expect to incur any FERC annual fees directly.

ATTACHMENT O - Entergy Texas, Inc.

For the 12 Months Ended 12/31/20__

Formula Rate -- Appendix A			Notes	FERC Form 1 Page # or Reference	True-up	Projected
A	B C	D	E	F	G	H
	Revenue Credits & Interest on Network Credits					
	Rent from Electric Property					
176	Transmission			WP17 Rev Line 2 Column C	-	-
177	General Plant			WP17 Rev Line 2 Column E	-	-
178	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
179	Total Transmission Allocated General Plant			(Line 177 * Line 178)	-	-
180	Revenue Credits from Rent of Electric Property			(Line 176 + Line 179)	-	-
	Other Electric Revenue					
181	Transmission Service Other Revenue Credits			WP17 Rev Line 7 Column C	-	-
182	Transmission Network & LTF Service Revenues			WP17 Rev Line 7 Column D	-	-
183	Transmission Service Revenue Credits			(Line 181 + Line 182)	-	-
184	General Plant			WP17 Rev Line 7 Column E	-	-
185	Wages & Salary Allocator			(Line 11)	0.0000%	0.0000%
186	Total Transmission Allocated General Plant			(Line 184 * 185)	-	-
187	Total Revenue Credits			(Line 183 + 186)	-	-
188	Less Transmission Network & LTF Service Revenues			(Line 182)	-	-
189	Less Rev. Credits from Schedules assoc. w/ Attachment GG		(Note Z)	WP17 Rev Line 6.38 Column C	-	-
190	Less Rev. Credits from Schedules assoc. w/ Attachment MM		(Note AA)	WP17 Rev Line 6.39 Column C	-	-
191	Revenue Credits - Transmission Service Other Revenue Credits			(Line 187 - Line 188 - Line 189 - Line 190)	-	-
192	Interest on Network Credits		(Note N)		-	-
193	**Net Revenue Requirement**			**(Line 175 - Line 180 - Line 191 + Line 192)**	-	-
194	True-up with Interest	(Over)/Under Collection		WP01 True-up Line 29 (EOY) Column E		-
195	**Net Adjusted Revenue Requirement**			**(Line 193 + Line 194)**		-
196	Network Customer OATT Section 30.9 Facilities Credits					
197	Network Customer 1		(Note GG)			-
198	Network Customer 2		(Note GG)			-
199	Total Net Adjusted Revenue Requirement			(Line 195 + Line 197 + Line 198)		-
	Annual Point-to-Point Transmission Rate					
200	Average of the 12 CP (kW)		(Note L)	WP19 Load Line 25 Column N		-
201	Annual Point-to-Point Transmission Rate			(Line 199 / Line 200)		0.00
202	Monthly rate			(Line 201 / 12)		-

Notes

A Electric portion only

B The projected charges for the Annual Update shall be based on end-of-year plant-related values for the historical base year plus new plant (excluding capital additions that will be recovered through MISO rate Schedules other than Schedules 7, 8 and 9) that is projected to be placed into service in the immediately subsequent calendar year weighted by the number of months the new plant is projected to be in service. The True-up calculation for each calendar year shall be based upon 13-month average plant-related balances. Supporting work papers will be provided.

C Only the Transmission portion will be included

D The Entergy Operating Company's total company PBOP expense to be allocated in part to transmission each year shall not be changed absent a filing under Section 205 or 206 of the Federal Power Act, unless the Entergy Operating Company is authorized to use pay-as-you-go accounting for PBOPs.

E Includes all Regulatory Commission Expenses

F Property Insurance excludes prior period adjustments for the first year, calendar year 2014, of the formula's operation. Property insurance includes prior period adjustments, if any in calendar year 2015 and subsequent years .

G FERC regulatory expenses itemized in the FERC Form No. 1 at 351.h that are directly related to transmission service, RTO filings, OATT compliance and maintenance of the transmission formula rate and retail regulatory expenses associated with siting and certification of qualifying transmission facilities.

H Cash working capital allowance is 0.00% of O&M

I The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = "the percentage of federal income tax deductible for state income taxes". If the utility includes taxes in more than one state, it must explain in a Worksheet 7 the name of each state and how the blended or composite SIT was developed. Furthermore, a utility that elected to use amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) multiplied by 1/(1-T). Excess Deferred Income Taxes reduce income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T). Permanent Differences in Income Taxes increases income tax expense revenue requirement by the amount of the expense multiplied by 1/(1-T) for differences in the income taxes due under the Federal and State calculations and the income taxes recorded on the Company's financial statements. A utility must not include tax credits as a reduction to rate base and as an amortization against taxable income. If the tax rates change during a calendar year, an average tax rate will be used - calculated based on the number of days each was effective in the calendar year.

J The base ROE shall be as established by FERC and is subject to change consistent with the outcome of proceedings in FERC Docket No. EL15-45, a final order concerning the ROE issue raised in MDEA v. FERC, (D.C. Circuit Case No. 14-1030), and otherwise subject to change pursuant to a FPA section 205 or 206 proceeding. A 50 basis point adder for RTO participation may be added to the ROE provided the total or maximum ROE may not to exceed the upper end of the zone of reasonableness established by FERC in EL14 12 or other proceeding.

K General Advertising expenses that may be included are those associated with safety, education and outreach expenses relating to transmission, for example siting or billing.

L The 12CP peak is the average of the 12 monthly system peaks in a calendar year, coincident with the MISO Transmission Pricing Zone's monthly transmission system peaks, calculated as the native load plus Network Service customers' monthly network loads plus the reserve capacity of all Long Term Firm Point-to-Point Customers.

M Transmission plant excluded from rates will include Step-Up Facilities, Supplemental Upgrades, Radial lines and Generator Interconnection facilities. Radial lines will be reported i a supporting work paper and will be updated annually as part of the annual rate update process to identify the radial facilities included in transmission rate base for the relevant rate year and Entergy will indicate any changes to the listing from the prior year. If new radial facilities are added or changes made to facilities identified on the work paper, the status o those new or changed facilities as radial transmission facilities will be assessed using the criteria identified in Section 3 of MISO's Business Practice Manual 28, Transmission Determination Process for Prospective or Existing Unregulated Transmission Owner's Facilities, Application for Transmission Determination of FERC Seven Factors Test for Local Distribution ("BPM-028"). Entergy will report Generator Interconnection Facilities in a work paper and must remove from transmission rates those facilities constructed or purchased by Entergy on or after March 15, 2000 (FERC Order 2003: Docket RM02-1-000, issued July 24, 2003, page 154).

N Outstanding Network Credits is the balance of Network Facilities Upgrades Credits due Transmission Customers who have made lump-sum payments (net of accumulated depreciation) towards the construction of Network Transmission Facilities consistent with Paragraph 657 of Order 2003-A. Interest on the Network Credits as booked each year is added to the revenue requirement to make the Transmission Owner whole. Entergy will provide a supporting work paper.

O The formula rate shall exclude all expenses associated with (i) MISO Schedule 10 and MISO Schedule 10-FERC, for which Load Serving Entities ("LSEs") are billed separately by MISO and (ii) all other expenses recovered by MISO through direct charges to transmission owners and transmission users pursuant to separate schedules under the MISO Tariff or otherwise. For rate years 2015 and beyond, the Entergy Operating Companies do not expect to incur any FERC annual fees directly.

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110 FERC ¶ 61,058
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Pat Wood, III, Chairman;
Nora Mead Brownell, and Joseph T. Kelliher.

Florida Power & Light Company

Docket Nos. ER93-465-033
ER96-417-002
ER96-1375-003
OA96-39-010
OA97-245-003

ORDER ON COMPLIANCE FILING

(Issued January 25, 2005)

1. This order addresses a compliance filing by Florida Power and Light Company (FP&L), submitted in response to the Commission's order issued in this proceeding on December 16, 2003,[1] that directed FP&L to revise its proposed rate schedules to exclude those FP&L facilities that fail to meet the same integration test applied to its network service customer, Florida Municipal Power Agency (FMPA), in Docket Nos. EL93-51 and TX93-4.[2] In this order, we accept the compliance filing in part, reject it in part, and direct a further compliance filing. This order benefits customers because it ensures that comparable facilities receive comparable rate treatment.

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[1] *Florida Power and Light Company*, 105 FERC ¶ 61,287 (2003) (December 16 Order), *reh'g denied,* 106 FERC ¶ 61,204 (2004).

[2] *Florida Municipal Power Agency v. Florida Power & Light Company*, 65 FERC ¶ 61,125, *reh'g dismissed*, 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *clarified*, 74 FERC ¶ 61,006 (1996), *reh'g denied*, 96 FERC ¶ 61,130 (2001), *aff'd*, *Florida Municipal Power Agency v. FERC*, 315 F.3d 362 (D.C. Cir. 2003), *cert. denied*, 124 S. Ct. 386 (2003) (TX Case).

I. **Background**

2. This case has a long procedural history dating back to 1993, when FP&L completed a comprehensive restructuring of its then-existing tariff structure, including a new open access transmission tariff. On January 18, 1996, in Docket No. ER96-417-000, the Commission accepted for filing, and suspended FP&L's network integration transmission service tariff, thus allowing FMPA to start taking network transmission service from FP&L.[3] On September 18, 2000, in Docket No. ER93-465-000, *et al.*, the Commission accepted a settlement agreement that fully resolved most of the rate issues related to the network integration transmission service tariff.[4]

3. The Commission addressed the three remaining issues in the December 16 Order, and directed FP&L "to make a compliance filing within 90 days of the date of this order, of a proposed rate schedule which does not include those FP&L facilities that fail to meet the same integration test applied to FMPA facilities in the TX Case."[5] The Commission also required that FP&L, in the "compliance filing should identify, as to those FP&L facilities whose costs were included in the rates which were objected to by FMPA, why they should be included in the rates and why they are or are not comparable to FMPA's facilities."[6] On March 11, 2004, the Commission granted FP&L's request for a 60-day extension of time to make its compliance filing.

4. On May 14, 2004, FP&L submitted a revised proposed rate schedule. FP&L states that it analyzed facilities beginning at the 69 kV voltage level, using a 1998 test year. FP&L also explains that it distilled the network integration transmission test to four factors (TX Case Factors) and that a facility must pass each of these tests to be considered integrated.

5. Notice of FP&L's filing was published in the *Federal Register*,[7] with protests and interventions due on or before June 4, 2004. On May 27, 2004, FMPA requested a two-week extension of time to file comments. On June 1, 2004, FP&L filed an answer to that motion. On June 1, 2004, the Commission granted an extension of time until June 18, 2004 for the filing of protests.

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[3] *Florida Power & Light Co.*, 74 FERC ¶ 61,021 (1996).

[4] *Florida Power & Light Co.*, 92 FERC ¶ 61,241 (2000).

[5] December 16 Order at P 16.

[6] *Id.* (citation omitted).

[7] 69 Fed. Reg. 30,290 (2004).

6. June 18, 2004, FMPA filed a protest to FP&L's May 14 filing. On July 6, 2004, FP&L filed an answer. On July 20, 2004, FMPA filed an answer to FP&L's July 6 answer. On July 27, 2004, FP&L filed an answer to FMPA's July 20 answer.

7. FMPA asserts that the compliance filing does not achieve comparability. Rather, FMPA argues, FP&L devised its own network integration test that includes all the facilities owned by FP&L and excludes those owned by FMPA as redundant and non-integrated. FMPA argues that FP&L must exclude facilities from rate base if they do not provide a transmission service as generally defined - for example, generator leads that primarily benefit only a company's generation marketing function or facilities that solely benefit servicing a company's retail load.

8. In addition, FMPA argues that FP&L must exclude all lines that are used exclusively to supply FP&L's local distribution facilities, and those other customers, from the backbone transmission system. These local load-serving transmission facilities are comprised of FP&L's 138 kV, 115 kV, and 69 kV facilities, and some 230 kV radial lines. FMPA also contends that FP&L must exclude its investments that are radial in nature and are like FMPA investments serving retail load (including those that serve more than one customer), as well as associated substations and related investments. Finally, FMPA asserts that refunds are owed for periods when FP&L transmission investment ought to have been excluded from rates based on comparability principles.

II. Discussion

A. Procedural Matters

9. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2004), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will not accept the July 6, 2004 and July 27, 2004 answers by FP&L and the July 20, 2004 answer by FMPA because they do not add any additional information to assist us in our decision-making process.

B. Compliance Issues

1. Comparability

10. FP&L states that it relied on 1998 cost data and transmission system diagrams. However, use of 1998 as a base year does not meet comparability with respect to the determination of the integration of FMPA facilities in the TX Case; to achieve comparability in determining the integration of the transmission facilities, FP&L must

examine its system using the same base year as was used in that proceeding.[8] Therefore, we will direct FP&L to make a further compliance filing that satisfies this comparability requirement.

11. We accept, in concept, FP&L's four TX Case Factors test as a just and reasonable way to ensure rate treatment comparability between its own and FMPA's facilities. However, as discussed in more detail below, FP&L has not applied its four factor test properly to its own facilities. In the compliance filing, FP&L must properly apply the test to its facilities.

12. FP&L's first TX factor analyzes whether facilities at issue are interconnected with the FP&L transmission system at single points that are used only to transfer power between the FP&L transmission system and one customer. This test is comparable to the test FP&L applied to FMPA facilities in Docket No. TX93-4 and that it applied earlier in this proceeding.[9] However, when applying this test in its compliance filing, FP&L limited the test to radial facilities that serve only a single customer. This is not comparable to the test applied to FMPA facilities. In the compliance filing we order herein, FP&L should apply the test to exclude from transmission rate base all radial facilities (and associated equipment), regardless of how many customers are served by the facility. Furthermore, as discussed below, the appropriate system to which the test

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[8] We also note that FMPA argues that many of its facilities which were not integrated in 1993 are integrated now. However, that fact is irrelevant to the issue of comparability of the FP&L system to the FMPA system as it was evaluated in the TX Case.

[9] FP&L argued that single interconnection cities (Key West, Lake Worth, Clewiston, Green Cove, and Jacksonville Beach) are only interconnected with FP&L. Their facilities consist of internal transmission used to distribute power from the point of delivery and from their internal generation to their customers. "[T]hese utilities can be thought of as a 'dead-end' off the [FP&L] system, in that, just as with the [FP&L] distribution substations, power delivered from the [FP&L] transmission system necessarily must be consumed wholly within the city; *i.e.,* the internal facilities do not provide a parallel path for [FP&L]." Exh. FP&L-1A (KA-103), July 4, 1994 in Docket No. ER93-465-000 (FP&L-1A), at 49. "[F]rom the perspective of planning the [FP&L] transmission system, the system can be represented electrically simply as a load (and, where applicable, a generating resource) located at the delivery point interconnected with the [FP&L] system; *i.e.,* without any internal transmission facilities." *Id.* at 49-50. "The size and type of these internal facilities are immaterial as they have no impact on [FP&L's] planning process. None of the internal facilities are or will be used by [FP&L] to integrate [FP&L's] load and generation." *Id.* at 52. Therefore, they are not integrated.

should be applied is the system modeled by FP&L to analyze the integration of FMPA's Fort Pierce-Vero Beach line.

13. The second TX factor states that a facility that provides only unneeded redundancy is not eligible for cost recovery. This test is consistent with the test FP&L applied to FMPA facilities.[10] However, in its compliance filing, FP&L specifically applies this test only to Georgia Ties and Turkey Point lines and, for the rest of its system, FP&L simply makes a general statement that the facilities "do not provide unneeded redundancy." (Sanchez Affidavit at 17). This is insufficient. Thus, in the compliance filing we order herein, FP&L should apply the test to each of its transmission facilities as they existed in the model used by FP&L to analyze Vero Beach-to-Forth Pierce line's integration, and demonstrate, through modeling the system with and without the facility, that each facility included in its transmission rate base was needed to deliver power to customers in the area where the facility is located and to other FP&L load centers.

14. We accept FP&L's argument that Georgia Ties -- the major transmission facilities connecting Florida to the rest of the eastern interconnection -- should not be excluded from base transmission rates. We agree with FP&L's argument that it is not relevant to the case whether or not these lines were built to import electricity from Georgia. The only relevant question is whether the facilities at issue are part of the transmission provider's integrated grid. FP&L and FP&L's transmission customers (*i.e.*, Seminole, FMPA, and others) rely on and utilize these lines to transmit power from numerous network resources to their respective loads.[11] Contrary to FMPA's claims, these facilities improve stability and reliability for all utilities in Florida by substantially minimizing the

[10] With regard to the Fort Pierce-Vero Beach 138 kV line, FP&L argued that the line "enables one city to receive power from the local generation of the other city." FP&L witness Adjemian testified that "from [FP&L's] transmission planning perspective, the line does not change the fact that Vero Beach and Fort Pierce consist of load and resources interconnected directly at [FP&L] delivery points," FP&L-1A at 51, that FP&L would not have built the 138 kV line to provide reliable service to Vero Beach and/or Fort Pierce, that the line has a negligible electrical impact on FP&L's ability to transmit power to and from the two cities, and that, even without the line, FP&L is able to deliver power to customers in that area and other FP&L load centers. FP&L June 10, 1994 Motion for Clarification in Docket No. TX93-4-002, Adjemian Affidavit (Adjemian Affidavit) at 13. He modeled the FP&L system with and without the line and ascertained that the line would not allow FP&L to defer or cancel any facilities then included in FP&L's ten-year transmission expansion plan. *Id.*

[11] *See, e.g.*, Adjemian Affidavit at 22-24.

number of times that load must be shed by underfrequency load shedding as a result of Florida separating from the eastern interconnection.

15. We also agree with FP&L's statement that Turkey Point lines should be included in the transmission rates, because they connect to the FP&L transmission system at numerous points and are part of multiple and nested loops. As FP&L explained, all of these lines are needed to reliably serve the loads located in southeast Florida, even when the Turkey Point Plant is not fully available or dispatched, and to provide reliable wholesale and transmission service to others independent of whether all the generation is available and dispatched at the Turkey Point Plant.[12]

16. The third TX factor maintains that, if a facility is integrated into the transmission provider's plans or operations, it is an indication that the facility is integrated with the transmission grid. The last, fourth TX factor, asserts that if a transmission facility is used to integrate resources and loads on the transmission provider's network, it is an indication that the facility is integrated. FMPA argues that these factors should be rejected because they only test the ownership, and not whether a given facility is integrated with the network. We disagree. FP&L points out that it has given credits to lines owned by Seminole Electric Cooperative, Inc. and Lee County Electric Cooperative, Inc. as part of the FP&L integrated transmission system, using these tests.[13] Moreover, while FMPA is correct that these two factors test ownership, ownership alone is not enough; as proposed by FP&L, the four TX Case Factors must *all* be satisfied for an FP&L facility to be considered integrated.

2. Tariff Methodology

17. We will accept the FP&L proposed net plant methodology (NPM) for adjusting the network transmission rate through the use of a ratio, as a reasonable proxy for the traditional cost based adjustment, because of the lack of a traditional cost base rate.[14]

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[12] *See, e.g.*, Adjemian Affidavit at 27-31.

[13] *See Florida Power & Light Company*, 107 FERC ¶ 61,176 (2004).

[14] FP&L argues that a traditional method based on revenue is not applicable in this case, because the current rate for network service under FP&L's open-access transmission tariff was established by a black-box settlement. As a result, there is no body of cost, financial and/engineering data. Instead, FP&L proposes to use the NPM to adjust the network rate charged to FMPA. Under the NPM, FP&L computes the ratio of (a) the net plant of the FP&L facilities that are not integrated with the rest of the FP&L grid to (b) the net plant associated with all FP&L transmission facilities in service. FP&L then

(continued...)

The NPM assumes that the revenue requirements for the facilities at issue are proportional to the total network revenue requirements on a net plant basis. Using this method to remove the costs of the facilities at issue from the network service rate charged to FMPA, FP&L removes all costs associated with the excluded facilities, including any allocated administrative and general expenses, depreciation, and operations and maintenance expenses. Furthermore, FMPA does not object to the proposed method. Therefore, we will allow FP&L to use the proposed net plant method to adjust the settlement rate but will require FP&L to demonstrate the integration of its transmission facilities as of 1993 and adjust the settlement rate established in 2000 using 1993 plant cost data.

The Commission orders:

FP&L is hereby directed to make a further compliance filing, as discussed in the body of this order, within 90 days of the date of this order.

By the Commission. Commissioner Kelly not participating.

(S E A L)

Magalie R. Salas,
Secretary.

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applies this ratio to the settlement agreement network service rate to determine the adjustment to the network rate charged to FMPA. That adjustment amount is then deducted from the current settlement rate to determine the new charge that will apply to FMPA on a going forward basis.

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113 FERC ¶ 61,263
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Florida Power & Light Company

Docket Nos. ER93-465-034
ER96-417-003
ER96-1375-004
OA96-39-011
OA97-245-004

ORDER ON COMPLIANCE FILING

(Issued December 15, 2005)

1. This order addresses a compliance filing by Florida Power and Light Company (FP&L), submitted in response to the Commission's order issued in this proceeding on January 25, 2005,[1] that accepted a prior compliance filing in part, rejected it in part, and directed FP&L to make a further compliance filing. In this order, we accept FP&L's instant compliance filing in part, reject it in part, and direct the submission of a further compliance filing.

Background

2. This case has a long procedural history dating back to 1993, when FP&L completed a comprehensive restructuring of its then-existing tariff structure, including a new open access transmission tariff. On January 18, 1996, in Docket No. ER96-417-000, the Commission accepted for filing, and suspended, FP&L's network integration transmission service tariff.[2] On September 18, 2000, in Docket No. ER93-465-000, *et al.*, the Commission accepted a settlement agreement that fully resolved most of the rate issues related to the network integration transmission service tariff.[3]

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[1] *Florida Power and Light Company*, 110 FERC ¶ 61,058 (2005) (January 25 Order).

[2] *Florida Power and Light* Company, 74 FERC ¶ 61,021 (1996).

[3] *Florida Power and Light* Company, 92 FERC ¶ 61,241 (2000). Although the active parties reached an agreement in principle, negotiations have continued to prepare (continued...)

3. The Commission addressed the three remaining issues on December 16, 2003,[4] and directed FP&L to make a compliance filing revising its proposed rate schedules to exclude those FP&L facilities that fail to meet the same integration test applied to its network service customer, Florida Municipal Power Agency (FMPA), in Docket Nos. EL93-51 and TX93-4.[5] The Commission also required that FP&L, in the "compliance filing should identify, as to those FP&L facilities whose costs were included in the rates which were objected to by FMPA, why they should be included in the rates and why they are or are not comparable to FMPA's facilities."[6]

4. On May 14, 2004, FP&L submitted a revised proposed rate schedule, in which it proposed to reduce FMPA's network transmission rate by approximately $20 million. FP&L explained that it had analyzed facilities, beginning at the 69 kV voltage level, using a 1998 test year. FP&L also explained that it distilled the network integration transmission test to four factors (TX Case Factors) and that a facility had to pass each of these tests to be considered integrated. FMPA protested, arguing that the filing did not achieve comparability.

5. In the January 25 Order, the Commission agreed that the filing did not satisfy the comparability requirement. Specifically, the Commission found that use of 1998 as a base year did not meet comparability with respect to the determination of the integration of FMPA facilities in the TX Case.[7] The Commission also found that, while FP&L's TX Case Factors test could be a just and reasonable way to ensure rate treatment comparability between its own and FMPA's facilities, FP&L did not properly apply the test to its own facilities. Specifically, the Commission found that FP&L: (1) failed to exclude all radial facilities and associated equipment; and (2) did not test its transmission

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the interchange service schedules that would fully implement the parties' settlement in principle. On June 27, 2005, FP&L notified the Commission that it will endeavor to file a new settlement agreement shortly after July 14, 2005.

[4] *Florida Power and Light Company*, 105 FERC ¶ 61,287 (2003) (December 16 Order), *reh'g denied,* 106 FERC ¶ 61,204 (2004).

[5] *Florida Municipal Power Agency v. Florida Power & Light Company*, 65 FERC ¶ 61,125, *reh'g dismissed*, 65 FERC ¶ 61,372 (1993), *final order*, 67 FERC ¶ 61,167 (1994), *clarified*, 74 FERC ¶ 61,006 (1996), *reh'g denied*, 96 FERC ¶ 61,130 (2001), *aff'd, Florida Municipal Power Agency v. FERC,* 315 F.3d 362 (D.C. Cir. 2003), *cert. denied*, 124 S. Ct. 386 (2003) (TX Case).

[6] December 16 Order at P 16 (citation omitted).

[7] January 25 Order at P 10.

facilities for unneeded redundancy.[8] The Commission did accept FP&L's proposed net plant methodology method to adjust the settlement rate, but required FP&L to demonstrate the integration of its transmission facilities as of 1993 and adjust the settlement rate established in 2000 using 1993 plant cost data.[9] FP&L was given 90 days to make a new compliance filing.

6. On April 25, 2005, FP&L made the instant compliance filing. In support, FP&L states that, as a result of its analysis in accordance with the January 25 Order, it now proposes to remove from the rate it charges FMPA for network transmission service approximately $29 million in costs. FP&L states that a portion of the filing contains Critical Energy Infrastructure Information (CEII), and requests that the Commission so designate that portion.

7. Notice of the filing was published in the *Federal Register*,[10] with comments due on or before May 16, 2005. On May 10, 2005, FMPA filed a motion for an extension of time to file comments until May 31, 2005, and stated that FP&L had consented to that extension. The extension was granted on May 13, 2005.

8. On May 31, 2005, FMPA filed a protest.[11] FMPA states that, because of FP&L's CEII redaction, FMPA also redacts certain materials, but challenges the need for CEII treatment. In addition, FMPA argues that FP&L has still not complied with the Commission's directive to ensure comparability.[12] FMPA maintains that FP&L failed to demonstrate, as directed, that each facility included in its transmission rate base was needed to deliver power to other FP&L load centers; FMPA argues that the vast majority of the 115 kV and 138kV lines FP&L includes, in fact, provide only very localized load-serving capability and only local redundancy. In addition, FMPA believes it likely that FP&L did not, contrary to what it led the Commission to believe, model its system in

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[8] *Id.* at P 11.

[9] *Id.* at P 17.

[10] 70 Fed. Reg. 23,860 (2005).

[11] FMPA also states that it "would have no objection" if the Commission orders that some of the redacted and deleted material contained in its filing be made public. FMPA Protest at 2. On June 3, 2005, FP&L filed an answer "disagree[ing] that it would be appropriate to make public any of th[at] information." FP&L June 3 Answer at 2.

[12] However, FMPA believes that FP&L should reduce rates and pay the refunds that it admits it owes in the April 25 Compliance Filing.

1994 to determine FMPA's entitlement to credits. Moreover, FMPA continues, even if FP&L did such a study, but can no longer retrieve it, FP&L "did not do what the Commission said it should do," *i.e.*, "study its system applying the same tests that it applied to exclude the Ft. Pierce-Vero Beach line for credits."[13] FMPA further argues that the new test FP&L uses is far different from the standards FP&L applied to FMPA's facilities. In fact, FMPA states, when FMPA applied this new test to its own Ft Pierce-Vero Beach transmission line, that line passed the same test that FP&L applied to itself. FMPA also asserts that FP&L ignored the Commission's requirement that it demonstrate that each of its transmission rate base facilities is needed both to serve local load and to serve load in other load centers. Finally, FMPA maintains that, because of FP&L's failure to comply, FMPA's affidavit of Joe N. Linxwiler, Jr. provides the only record evidence of the appropriate transmission rate base reduction, and the Commission should order the results it recommends. If the Commission disagrees, FMPA argues that "the shortness of life militates against allowing [FP&L] a third try to get things right,"[14] and the Commission should appoint an administrative law judge, acting as a special master, to advise the Commission on the appropriate rate reduction or other relief.

9. On June 3, 2005, FP&L filed an answer to FMPA's CEII challenge, maintaining that it would not be appropriate to make any of the material it redacted public.

10. On June 13, 2005 FMPA filed a pleading continuing to dispute the CEII designation, and requests that the Commission or its CEII Coordinator make public its protest.

11. On June 15, 2005, FP&L filed an answer to the protest. FP&L reiterates its position that the "issues in these long and complicated proceedings have been distilled to one: Which of [FP&L's] looped transmission facilities, if any, provide only 'unneeded redundancy,' and thus are not eligible for cost recovery,"[15] and FP&L maintains that its compliance filing supplied that analysis. FP&L disagrees with FMPA's challenges to its "use of a 1994 vintage load flow model."[16] Additionally, FP&L maintains that it has shown that each looped transmission facility provides more than unneeded redundancy and that the Commission should reject FMPA's arguments related to the criteria FP&L used to test for unneeded redundancy.

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[13] FMPA Protest at 9 (italics omitted).

[14] *Id.* at 17.

[15] FP&L June 15 Answer at 1.

[16] *Id.* at 5.

12. On June 30, 2005, FMPA filed an answer to the June 15 Answer. FMPA argues that FP&L's June 15 Answer does not meet the Commission's standards for waiver of Rule 213 of the Commission's Rules of Practice and Procedure; nevertheless, FMPA maintains that, if the Commission does allow the June 15 Answer, it should also consider this reply. FMPA believes that the "core issue" in this case is "whether [FP&L] complied with the Commission's orders that it must treat FMPA's transmission comparably to its own."[17] FMPA alleges that:

> [i]t is apparent that [FP&L] does not have and admits that it does not have the test that it used in 1996 to deny FMPA credits. [FP&L] certainly does not supply it. Instead, it applies a test to its own facilities that it surmises is the one – or like the one – that Mr. Adjemian used in 1996. But it does not even attempt to apply that same test to FMPA. An attempt to achieve comparability by only measuring [FP&L's] own facilities is like attempting to cut with scissors having one blade.[[18]]

13. FMPA also maintains that, by framing the issue as whether its facilities provide unneeded redundancy, FP&L isolates the question of the usefulness of its facilities from whether it is providing parallel treatment to FMPA. FMPA believes that FP&L has acknowledged that the Ft. Pierce-Vero Beach line passes its usefulness test. Finally, FMPA asserts that Mr. Adjemian's affidavit has no probative value, as he states "to the best of my recollection, *I believe*" and "*logically,*" rather than that he remembers.[19]

14. On July 15, 2005, FP&L filed an answer to the June 30 Answer. FP&L reiterates its belief that the core issue here is unneeded redundancy; FP&L alleges that FMPA is continuing to seek credits. FP&L asserts that it applied the same test (data models, standards, and methodology) to its facilities in 2005 that it applied to FMPA's facilities in 1994, and attaches an affidavit from Hector Sanchez so stating. FP&L alleges that "[i]f any doubt remains in this regard, FMPA is merely tilting at windmills rather than abiding by its acknowledgment that it would accept [FP&L's] conclusions regarding [FP&L] transmission facilities so long as [FP&L] applied the same test to FMPA's facilities."[20]

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[17] FMPA June 30 Answer at 2.

[18] *Id.* at 3 (citation omitted).

[19] *Id.* at 11 (emphasis in FMPA June 30 Answer).

[20] FP&L July 15 Answer at 6, *citing* FMPA June 30 Answer at 5.

15. Additionally, FP&L reiterates that there is a difference between its and FMPA's facilities regarding the "local benefits" they provide.[21] FP&L disputes FMPA's claim that the Ft. Pierce-Vero Beach line passes FP&L's usefulness test, and argues that FMPA obtained this result because it changed the model Mr. Sanchez used. Finally, FP&L defends Mr. Adjemian's affidavit.

16. On August 1, 2005, FMPA filed an answer to FP&L's July 15 Answer. FMPA argues that the Commission should reject FP&L's third round of pleadings, where, it maintains, FP&L is proffering new evidence. FMPA also reiterates its position that FP&L is attempting to avoid comparability.

17. On August 10, 2005, FP&L filed an answer to FMPA's August 1 Answer. FP&L states that "[e]ach piece of evidence [FP&L] has provided has been responsive to the [January 25 Order], or has been provided to correct the record clouded by FMPA's assertions, and should be accepted."[22]

Discussion

18. Notwithstanding that Rule 213(a)(2) of the Commission's Rules of Practice and Procedure[23] generally prohibits answers to answers unless otherwise ordered by the decisional authority, we will accept the additional responses in this case, as they assist in our decision-making process. In particular, we note that these additional pleadings resolve FMPA's concerns about whether FP&L employed the same test to analyze its looped transmission facilities that it used to test FMPA's transmission facilities in 1994.[24]

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[21] *Id.* at 6-8.

[22] FP&L August 10 Answer at 1.

[23] 18 C.F.R. § 385.213(a)(2) (2005).

[24] We note that FMPA did not in its August 1 Answer challenge FP&L's interpretation of FMPA's statement in the June 30 Answer that it "would accept [FP&L's] proffered standards that include all of its lines in rate base for the reasons that are advocated by [FP&L]," FMPA June 30 Answer at 5, to mean that, as FP&L "has demonstrated that it employed the same test to analyze its facilities as it used to test FMPA's facilities in 1994, FMPA must "abid[e] by its acknowledgement that it would accept . . . FP&L's conclusions." FP&L July 15 Answer at 6.

CEII Designation

19. We agree with FP&L's designation of a portion of its filing as CEII, and will deny FMPA's request to publish the redacted materials. CEII is defined in 18 C.F.R. § 388.113(c)(1) (2005) as "information about proposed or existing critical infrastructure that (i) relates to the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on critical infrastructure; (iii) is exempt from mandatory disclosure under the Freedom of Information Act [FOIA], 5 U.S.C. § 552; and (iv) does not simply give the location of the critical infrastructure." The information at issue includes technical information that relates to the transmission of energy that could be useful to a person planning an attack on critical infrastructure, and show, not merely the location of critical infrastructure, but also the interrelationship of FP&L's transmission facilities.[25]

Comparability

20. We will accept FP&L's compliance filing in part, reject it in part, and direct a further compliance filing. As we directed in the January 25 Order, in this filing, FP&L did remove from its transmission rates all radial transmission facilities. However, as explained in more detail below, it is not clear whether FP&L failed to test its non-radial facilities in a manner comparable to the way it tested FMPA's facilities.[26]

21. In the January 25 Order, we directed FP&L to "demonstrate, through modeling the system with and without the facility, that each facility included in its transmission rate base was needed to deliver power to customers in the area where the facility is located *and* to other FP&L load centers."[27] In its April 25, 2005 compliance filing, FP&L describes the test it applied as follows:

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[25] Moreover, although the information requested is CEII, it may be released to requesters with a legitimate need for the information. The Commission must balance the requester's need for the information against the sensitivity of the information. While the Commission's regulation at 18 C.F.R. § 388.113(d)(3)(i) (2005) requires that requesters assert a need for and intended use of the information, the primary purpose of the rule is to ensure that information deemed CEII stays out of the possession of terrorists.

[26] Specifically, FP&L's second TX Case Factor states that a facility which provides only unneeded redundancy is ineligible for cost recovery. *See* January 25 Order at P 13.

[27] *Id.* (emphasis added).

> Mr. Sanchez removed the transmission facility being tested from the base models . . . and performed a load flow simulation . . . to determine whether any reliability criteria violations occurred for a first contingency (*i.e.*, for a sudden loss of a single transmission line, transformer, or generator) . . . Following single contingencies load should continue to be served, transmission facilities should be at or below 100 percent of their applicable respective thermal ratings, and voltages at substations should be at or above 95% of normal voltage. Mr. Sanchez thus tested to ensure that these criteria, which are consistent with those used by FPL in identifying its transmission facility needs and are in accordance with North American Electric Reliability Council [(NERC)] and [Florida Reliability Coordinating Council (FRCC)] reliability criteria, were satisfied.[28]

22. Our review of FP&L's compliance filing does not convince us that FP&L has applied the test in accordance with NERC and FRCC reliability criteria. Current NERC standards allow for "planned or controlled interruption of electric supply to radial customers or some local network customers, connected to or supplied by the faulted element or by the affected area, in certain areas without impacting the overall reliability of the interconnected transmission systems."[29] In 1994, these standards were essentially no different. In 1994, Florida Coordinating Group, the predecessor to FRCC, had the following planning criteria in place:

> The bulk electric power system in the State of Florida shall be planned to meet the following criteria: A. MORE PROBABLE CONTINGENCIES – To be sustained without loss of load (*other than the load connected to the line or transformer which is lost*) . . . .[30]

23. It is not clear whether FP&L's compliance filing comports with these standards; specifically, it is not clear whether FP&L interprets loss of load not directly connected to the affected line or transformer, due to a contingency, as a violation of reliability criteria. In Exhibits 3 and 4, FP&L lists the facilities that it tested for unneeded redundancy. For each test period, FP&L indicates a number of facilities that, during contingencies, violated one the following reliability criteria: (1) load was shed; (2) thermal ratings were violated; or (3) voltages at substations were at or above 95% of normal voltage.

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[28] FP&L April 25, 2005 Compliance Filing at 8.

[29] NERC Standard TPL-002-0 – System Performance Following Loss of a Single BES Element, Table 1.

[30] FP&L's 1994 FERC Form 715 filing, section V (emphasis added).

However, our review of FP&L's compliance filing has revealed that there are a number of test cases,[31] in which the only reliability violations are what FP&L describes as "unserved load," and which do not demonstrate any thermal rating or voltage violations.[32] Since FP&L does not indicate whether it is referring to load that is directly connected to or supplied by the faulted element *and/or* load in other FP&L load centers, we need clarification that FP&L's test is indeed compliant with the January 25 Order and the applicable NERC and FRCC standards.

24. This is critical, because the January 25 Order was intended to ensure consistency of FP&L's test of its own facilities with the redundancy test FP&L has devised and applied to FMPA. Specifically, with regard to the Fort Pierce-Vero Beach line, FP&L had stated that, even without the line, FP&L is able to deliver power to customers in that area and to other FP&L load centers.[33]

25. Accordingly, we will direct FP&L to submit a compliance filing within 60 days of the date of this order clarifying the definition of "unserved load," and, excluding those facilities that do not result in violation of NERC and FRCC reliability criteria following single contingencies. FP&L can justify the inclusion in transmission rate base of a test case facility if it can demonstrate specifically the "unserved load" in question is not connected to the line or transformer which constitutes a first contingency.[34]

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[31] By "test case" we mean simulations in which the tested facility is assumed not to exist so as to determine if the facility is redundant – *i.e.*, whether FP&L's transmission system meets NERC and FRCC reliability criteria without that particular facility.

[32] To the extent that by "unserved load" FP&L is referring to load attached to transmission that is taken out of service as a first contingency, we note that the loss of such load is not a NERC or FRCC reliability criteria violation.

[33] We reject FMPA's argument that the Ft. Pierce-Vero Beach line passes the usefulness test, as outside the scope of this proceeding. The issue of which FMPA facilities to include was decided in the TX Case.

[34] We note that our determination of which facilities are not eligible for transmission rate base inclusion is a very narrow determination aimed at achieving comparability to the test FP&L devised to test FMPA's facilities in the TX Case. In other circumstances, we would typically find these looped facilities to be integrated transmission facilities. *See, e.g., Northeast Texas Electric Cooperative, Inc.,* 111 FERC ¶ 61,189 at P 13-19 (2005).

<u>The Commission orders</u>:

(A) We hereby deny FMPA's request to publish the material designated CEII, as discussed in the body of this order.

(B) FP&L is hereby required to submit a compliance filing, as discussed in the body of this order, within 60 days of the date of this order.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.

F

140 FERC ¶ 61,028
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony T. Clark.

MidAmerican Energy Company Docket No. EL12-57-000

ORDER ON PETITION FOR DECLARATORY ORDER

(Issued July 16, 2012)

1. On April 20, 2012, as supplemented on June 8, 2012, MidAmerican Energy Company (MidAmerican) filed a petition for declaratory order requesting the Commission to approve its proposed re-delineation and re-classification of its electric facilities between transmission and local distribution (2011 Delineation). In this order, we grant the petition, as discussed below.

I. **Background**

2. MidAmerican is a public utility engaged in the production, transmission, and distribution of electricity for domestic, commercial, and industrial use in the States of Iowa, Illinois, and South Dakota and the sale of and distribution of natural gas at retail in the States of Iowa, Illinois, South Dakota, and Nebraska. MidAmerican owns and operates electric transmission and distribution facilities. MidAmerican integrated its electric generation and transmission facilities with the Midwest Independent Transmission System Operator, Inc. (MISO). Transmission service across MidAmerican's facilities is pursuant to MISO's Open Access Transmission, Energy and Operating Reserve Markets Tariff (Tariff).

3. MidAmerican states that its first application of the Commission's seven-factor test[1] to analyze MidAmerican's electrical facilities and delineate them between

[1] *See 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, FERC Stats. & Regs. ¶ 31,036, at 31,771 (1996), *order on reh'g*, Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *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*

(continued...)

transmission and distribution, was in 1998 in the context of the Illinois retail access program (1998 Delineation).[2] In *MidAmerican Energy Company*, the Commission granted MidAmerican's request for classification, deferring to recommendations of the Iowa Utilities Board (Iowa Commission) and the Illinois Commerce Commission (Illinois Commission) and approving the 1998 Delineation. MidAmerican further states that the 1998 Delineation generally classified non-radial 345 kV and 161 kV facilities as transmission with the exception of certain local area load-serving high voltage facilities which were classified as distribution along with all of the radial 345 kV and 161 kV facilities and all of the 69 kV and 34.5 kV facilities.

4. On July 2, 2010, the City of Pella (Pella) filed a petition for a declaratory order and a complaint against MISO and MidAmerican asking the Commission to reclassify Pella's non-radial 69 kV facilities as transmission facilities eligible for inclusion under the MISO Tariff and to find that MISO and MidAmerican violated the Federal Power Act (FPA) and Commission policy by failing to recognize Pella's 69 kV facilities as integrated transmission facilities (Pella proceeding). The Commission determined that Pella's 69 kV facilities constituted transmission facilities, but that those facilities were not integrated with MISO's transmission facilities and, as a result, Pella was not eligible to receive credits for those facilities.[3] The Commission further found that neither MISO nor MidAmerican violated any of the applicable provisions of the Tariff or the FPA. MidAmerican, Pella, and the MISO Transmission Owners filed motions for clarification or requests for rehearing of the Commission's order, which remain pending before the Commission.

5. On January 30, 2012, MidAmerican filed a Settlement Agreement entered into by MidAmerican, Pella and MISO (Pella Settlement). The Pella Settlement is pending before the Commission and is intended to dispose of all issues that were raised or could have been raised in the Pella proceeding and to terminate the proceeding in its entirety. The Pella Settlement requires MidAmerican to file the 2011 Delineation with the Commission. The Pella Settlement also requires MidAmerican to take certain steps that will result in inclusion of the Pella 69 kV non-radial facilities and the MidAmerican 69 kV non-radial facilities as part of the MISO transmission system.

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).

[2] *MidAmerican Energy Co.*, 90 FERC ¶ 61,105 (2000).

[3] *City of Pella, Iowa v. Midwest Indep. Transmission Sys. Operator, Inc. and MidAmerican Energy Co.*, 134 FERC ¶ 61,081 (2011).

6. In the April 20, 2012 filing, MidAmerican states that approval of the 2011 Delineation will fulfill the objectives of the Pella Settlement.[4] MidAmerican therefore, proposes to reclassify the following from distribution facilities to transmission facilities: (1) non-radial 69 kV facilities; and (2) non-radial 161 kV facilities connecting to such 69 kV facilities. In support, MidAmerican includes a Technical Report for Delineation of Transmission and Local Distribution Facilities (2011 Delineation Report), and the Iowa Commission's approval and recommendation that the Commission approve MidAmerican's 2011 Delineation.

7. According to MidAmerican, there have been substantial changes in the use of the MidAmerican electrical system between the time that the 1998 Delineation was prepared and the 2011 Delineation was conducted. MidAmerican states that the 2011 Delineation Report shows that the previous determinations with respect to non-radial 345 kV and 161 kV facilities being classified as transmission are still appropriate. In addition, the 2011 Delineation Report shows that the high voltage distribution facilities should be reclassified from local distribution to transmission.

8. On June 8, 2012, MidAmerican filed a supplement informing the Commission of the Illinois Commission's approval of the 2011 Delineation.

II. Notice of Filing and Responsive Pleadings

9. Notice of the filing was published in the Federal Register, 77 Fed. Reg. 29,633 (2012), with answers, interventions, and protests due on or before May 21, 2012. MISO, Missouri River Energy Services, and Iberdrola Renewables, Inc. filed timely motions to intervene. Pella and the Indianola Municipal Utilities Board of Trustees, Iowa (the Indianola Board) each filed timely motions to intervene and comments in support of the filing.

10. Pella states that, as is required by the Pella Settlement, Pella confirms that it does not contest re-delineation of MidAmerican's 69 kV networked facilities and that it

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[4] MidAmerican also states that approval of the 2011 Delineation will fulfill the objectives of a settlement with Clipper Windpower Development Company, LLC. *See MidAmerican Energy Co.*, 138 FERC ¶ 61,028 (2012) (approving a settlement agreement between MidAmerican and Clipper Windpower Development Company, LLC, as modified).

supports and seeks an expedited Commission consideration and ruling on this case. Pella further states that it is pleased to make this confirmation and that a re-delineation is appropriate and supports the public interest.

11. The Indianola Board states that it supports the filing and seeks expedited Commission consideration.

III. Discussion

A. Procedural Matters

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

B. Substantive Matters

1. MidAmerican's Filing

13. MidAmerican states that the 2011 Delineation Report applies each of the seven factors of the Commission's seven-factor test to MidAmerican's transmission and distribution plant, using a variety of types of analytical methods, including power flow analysis, estimates of distances between facilities, and current facility utilization. The facilities studied were those with voltages of 345 kV, 161 kV, 69 kV, and 34.5 kV and below.

14. MidAmerican states that there were many consistent results in the 1998 and 2011 analyses. Specifically, both analyses showed the same results for certain facilities: (1) all non-radial 345 kV and 161 kV lines perform a transmission function and should be categorized as transmission facilities; (2) 345 kV and 161 kV substations which connect 345 kV and 161 kV transmission lines together perform a transmission function and should be categorized in whole or in part as transmission facilities; (3) the 161 kV portion of load-serving substations should be classified as transmission facilities; and (4) radial 345 kV and 161 kV lines, as well as radial 69 kV lines and all of the 34.5 kV lines should remain categorized as distribution facilities.

15. However, MidAmerican states that there is one group of key differences related to the 69 kV facilities. MidAmerican explains that, since the 1998 Delineation, MidAmerican, as well as other utilities interconnected with MidAmerican, have participated in the MISO real time and day-ahead energy markets. As a result, the generation across the market footprint is used to efficiently serve the load in the market footprint and the MidAmerican system has seen increased transfers in support of the market. MidAmerican states that the result of this change is that MidAmerican's networked facilities, including those with voltages at 69 kV and above, serve a broader

area than previously. MidAmerican explains that consequently the 2011 Delineation Report concludes that all non-radial 69 kV lines should be categorized as transmission facilities and certain associated 69 kV substations should also be categorized as transmission. MidAmerican adds that the result of the delineation of these 69 kV facilities to transmission accounts is that all MidAmerican non-radial 345 kV, 161 kV, and 69 kV facilities have been determined to perform transmission functions.

16. MidAmerican states that, to determine which substations should be classified as transmission, MidAmerican classifies substations consistent with the facilities connecting to each substation; when both transmission and distribution lines connect to a substation, it is considered a combination substation and a specific methodology was used to allocate the investment between transmission and distribution accounts. MidAmerican explains that combination substations where all components are transmission remain or are reclassified as transmission.

17. According to MidAmerican, it is a significant effort to account for combination substations as opposed to substations classified as 100 percent distribution. This additional effort stems from the complexity of accounting to both transmission and distribution accounts for new capital projects at substations with both types of facilities. Thus, MidAmerican used a "three or more" test to classify portions of 69 kV substations as transmission when at least three 69 kV or greater non-radial lines or at least two non-radial 69 kV lines and one 69 kV capacitor connect to the substation. The 69 kV substations which do not pass the "three or more" test remain classified as 100 percent distribution. Common facilities, such as substation land, rock, fence, and control buildings are allocated between transmission and distribution by pro-rating based on the original cost of the transmission and distribution facilities located in the substation. MidAmerican explains that the reclassification will cause the additional non-radial 161 kV and 69 kV facilities to be accounted for and ultimately reflected in FERC-jurisdictional transmission rates.

18. MidAmerican states that, should the Commission approve the 2011 Delineation, MidAmerican expects to execute an Agency Agreement for Open Access Transmission Service Offered by the Midwest ISO for Non-transferred Transmission Facilities (Appendix G of the MISO Transmission Owners Agreement) that will subject its networked 69 kV facilities to MISO functional control. MidAmerican further states it expects to take such other actions required of it as identified in Article III of the Pella Settlement in order to effectuate the inclusion of non-radial 69 kV facilities in transmission rates and in revenue sharing agreements with municipal utilities owning such facilities.

2. <u>Commission Determination</u>

19. The Commission has jurisdiction over the "transmission of electric energy in interstate commerce" and "the sale of electric energy at wholesale in interstate

commerce."[5] The Commission does not, however, have jurisdiction over facilities used in local distribution.[6] In Order No. 888, the Commission articulated a so-called seven-factor test to determine what facilities would be subject to the Commission's jurisdiction.[7] The Commission stated that it examines the following seven factors that indicate facilities are local distribution rather than transmission facilities: (1) local distribution facilities are normally in close proximity to retail customers; (2) local distribution facilities are primarily radial in character; (3) power flows into local distribution systems; it rarely, if ever, flows out; (4) when power enters a local distribution system, it is not reconsigned or transported onto some other market; (5) power entering a local distribution system is consumed in a comparatively restricted geographical area; (6) meters are based at the transmission/local interface to measure flows into the local distribution system; and (7) local distribution systems will be of reduced voltage.[8] The Commission further stated that it would defer to state commission recommendations provided such recommendations are consistent with the essential elements of Order No. 888.[9]

20. The Illinois Commission and the Iowa Commission have approved the 2011 Delineation. Consistent with Order No. 888, we are persuaded to defer to the state commissions and adopt their determinations regarding the facilities that are the subject of the application before us in this proceeding.[10] Accordingly, we will grant MidAmerican's petition for declaratory order.

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[5] 16 U.S.C. § 824(b)(1) (2006).

[6] *Id.*

[7] Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,771.

[8] *Id.*

[9] *Id.* at 31,783-784. *See, e.g., MidAmerican Energy Co.*, 90 FERC ¶ 61,105; *Northeast Utilities Service Co.*, 107 FERC ¶ 61,246 (2004); *Nevada Power Co.*, 88 FERC ¶ 61,234 (1999).

[10] We note that MidAmerican indicates that certain 69 kV combination substations are networked facilities, but that MidAmerican does not propose to reclassify them for reasons of accounting practicality. However, as that classification is outside the scope of this petition, we are not addressing the classification of those 69 kV combination substations or MidAmerican's proposal to use the "three or more" test to continue to classify these substations as distribution. Moreover, to the extent that Applicants were to make future filings before the Commission to assess the costs of such facilities to

(continued...)

21. Although we accept the state commissions' classification, we reiterate our finding in Order No. 888 that, to the extent any facilities, regardless of their original nominal classification, in fact, prove to be used by public utilities to provide transmission service in interstate commerce in order to deliver power and energy to wholesale purchases, such facilities become subject to this Commission's jurisdiction and review.[11] In addition, the rates, terms, and conditions of all wholesale and unbundled retail transmission service provided by public utilities in interstate commerce are subject to this Commission's jurisdiction and review.[12]

<u>The Commission orders</u>:

MidAmerican's petition for a declaratory order is hereby granted, as discussed in the body of this order.

By the Commission.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

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wholesale transmission customers, MidAmerican would have to demonstrate that the proposed pricing methodology for such facilities (direct assignment or otherwise) is appropriate. *See MidAmerican Energy Co.*, 90 FERC ¶ 61,105 at 61,338.

[11] In Order No. 888, the Commission explained that "a public utility's facilities used to deliver electric energy to a wholesale purchaser, whether labeled 'transmission,' 'distribution,' or 'local distribution,' are subject to the Commission's exclusive jurisdiction under sections 205 and 206 of the FPA." Order No. 888, FERC Stats. & Regs. ¶ 31,036 at 31,969.

[12] Transmission service in interstate commerce by public utilities, including the rates, terms, and conditions for such service, remains within this Commission's exclusive jurisdiction. 16 U.S.C. §§ 824, 824d, 824e (2006).

G

ATTACHMENT M

Formula Rate Manual

Section 0.1 **<u>Description and Purpose</u>:** This Formula Rate Manual ("Manual") establishes the procedures and methodology for deriving the charges ("Bulk Transmission Charges") for the following services provided under the Tariff on the Transmission Provider's bulk transmission facilities (those above 44/46 kV and excluding generator step-up transformers, interconnection facilities constructed by the Transmission Provider (after March 15, 2000) for the purpose of interconnecting a generating facility owned by the Transmission Provider, the portion of any customer-funded network upgrade for which the Transmission Provider is obligated to provide transmission service credits or otherwise repay, and the facilities set forth in Sections 2.1.a and 2.1.b) ("Bulk Transmission Facilities"): Firm Point-To-Point Transmission Service; Non-Firm Point-To-Point Transmission Service; and Network Integration Transmission Service. This Manual also establishes the procedures and methodology for deriving the charges ("Subtransmission Charges") for the following services provided under the Tariff on the Transmission Provider's subtransmission lines (those at 44/46 kV, excluding generator step-up transformers, interconnection facilities constructed by the Transmission Provider (after March 15, 2000) for the purpose of interconnecting a generating facility owned by the Transmission Provider, the portion of any customer-funded network upgrade for which the Transmission Provider is obligated to provide transmission service credits or otherwise repay, and those facilities set forth in Sections 3.1.a and 3.1.b) ("Subtransmission Facilities"): Firm Point-To-Point Transmission Service; Non-Firm Point-To-Point Transmission Service; and Network Integration Transmission Service. The Manual is divided into articles as follows:

Section 0.2 **Uniform System of Accounts:** The FERC Accounts set forth in this Manual are prescribed in the "Uniform System of Accounts Prescribed for Public Utilities and Licensees" (18 C.F.R. Part 101) effective as of December 31, 2002. Changes to these FERC Accounts may be addressed in the manner provided in Attachment N of the Tariff, or through a filing pursuant to Section 205 of the Federal Power Act.

ARTICLE I

PROCEDURES GOVERNING OPERATION OF FORMULA RATE

Section 1.1 **Rate Year for Transmission Charges:** The charges for the use of the Transmission Provider's Bulk Transmission Facilities and Subtransmission Facilities shall be effective for the period of January 1 through December 31 ("Rate Year"). The only exceptions to this January 1 to December 31 application are (1) a delay in filing the Annual Informational Filing until after December 31 in accordance with Attachment N, footnote 3; and (2) the recovery of the cost component for the FERC Annual Charge, which will be effective from October 1 of one Rate Year through September 30 of the following Rate Year.

Section 1.2 **<u>Basis for Annually Updated Bulk Transmission Charges and Subtransmission Charges</u>:** On or before November 1 preceding each Rate Year, the Transmission Provider shall follow the methodology and procedures set forth in this Manual and in Attachment N to the Tariff to calculate updated Bulk Transmission Charges and updated Subtransmission Charges for the Rate Year ("Annual Informational Filing"). This Annual Informational Filing will be based upon projected data drawn from the most recent information that is being used to prepare the corporate budgets of the Transmission Provider for the Rate Year, together with other necessary data developed in a manner consistent with the Transmission Provider's customary practices and procedures. Where applicable (<u>i.e.,</u> investment components), data inputs shall be based upon a simple average of (i) the balance for December 31 of the year immediately prior to the Rate Year and (ii) the balance for December 31 of the Rate Year. The Annual Informational Filings made pursuant to the Settlement in Docket No. ER02-851 shall not constitute rate change filings under Section 205 of the Federal Power Act.

Section 1.3 **<u>Basis for Annual True-Up Informational Filing for Bulk Transmission Charges and Subtransmission Charges:</u>** On or before May 1 of the year immediately subsequent to each Rate Year, the Transmission Provider shall follow the methodology and procedures set forth in this Manual and in Attachment N to the Tariff to make a True-Up Informational Filing with the Commission that calculates actual charges for the Rate Year ("True-Up Filing"). This True-Up Filing will be based on actual costs, loads, and other inputs for the Rate Year, and, to the extent available, applicable data will be drawn from the FERC Form No. 1 filings of the Transmission Provider and otherwise from their books and records. Where applicable, (<u>i.e.,</u> investment components) data inputs shall be based upon a simple average of (i) the balance for December 31 of the year immediately prior to the Rate Year and (ii) the balance for December 31 of the Rate Year. The True-Up Filings made pursuant to the Settlement in Docket No. ER02-851 shall not constitute rate change filings under Section 205 of the Federal Power Act.

Section 1.4 **Basis for FERC Annual Charge:** The cost component that recovers the FERC Annual Charge (18 C.F.R. Part 382) will be updated to be effective October 1 of each year to reflect the most recently received FERC invoices for that charge.

Section 1.5 **Informational Schedules:** The updated charges associated with the Annual Informational Filing and the charges associated with the True-Up Filing shall be set forth on the Informational Schedules described in Article VI of this Manual. A copy of the updated Informational Schedules shall be provided to customers taking Network Integration Transmission Service, customers taking Long-Term Firm Point-to-Point Transmission Service, and other interested parties upon request and shall also be made available on the Transmission Provider's OASIS.

Section 1.6 **Revisions to Manual:** The Transmission Provider shall have the right to make revisions to this Manual as provided in Section 9 of the Tariff.

ARTICLE IIA

DERIVATION OF ANNUAL REVENUE REQUIREMENT FOR THE BULK TRANSMISSION FACILITIES FOR NETWORK INTEGRATION TRANSMISSION SERVICE AND NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

Section 2.1 **Overview:** This article of the Manual establishes the formula methodology and procedures for deriving the annual revenue requirement for the Bulk Transmission Facilities for purposes of calculating charges for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service. When used in this Manual, the capitalized terms set forth in Sections 2.1.a through 2.1.c have the meanings specified below:

Section 2.1.a **<u>Bulk Retail Radial Facility</u>:** A physically radial bulk transmission facility above 44/46 kV used exclusively to serve the Transmission Provider's retail load that is placed into service in Rate Year 2011 and thereafter.

Section 2.1.b **<u>Rehabilitated Bulk Radial Facility</u>:** A physically radial bulk transmission facility above 44/46 kV that is the subject of a capital replacement, repair, re-conductoring, or some other rehabilitation occurring in Rate Year 2011 and thereafter.

Section 2.1.c **<u>Bulk Fixed Rate Base Adjustment</u>:** A fixed adjustment to the Transmission Provider's Gross Plant in Service in the amount of $139,300,000 related to investment in those bulk retail radial facilities rated above 44/46 kV used exclusively to serve the Transmission Provider's retail load that were placed into service in Rate Years 2003 through 2010.

Section 2.2 **<u>Formula for Deriving Annual Revenue Requirement for the Bulk Transmission Facilities for Purposes of Calculating Charges for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service</u>:** The derivation of the annual revenue requirement for the Bulk Transmission Facilities is based on the Transmission Provider's investment and expenses related to the Bulk Transmission Facilities and the associated cost of capital and income taxes. The derivation of the Transmission Provider's total annual revenue requirement for the Bulk Transmission Facilities for purposes of calculating charges for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service is expressed in the following formula:

RR_{B1}	=	Annual revenue requirement for the Bulk Transmission Facilities ($).
	=	Σ CRR_B - RC_{B1}

Where:

CRR_B	=	Individual operating company revenue requirement for its Bulk Transmission Facilities ($).
	=	(RB_B x R) + IT_B + E_B
RB_B	=	Rate base (The beginning and end of year average transmission investment for Bulk Transmission Facilities) ($).
R	=	The composite rate of return (%).
IT_B	=	Income taxes associated with Bulk Transmission Facilities ($).
	=	(RB_B x R) x CIT - ITC_B
CIT	=	Income tax requirement associated with the preferred stock and common equity weighted cost of capital (%).
ITC_B	=	Investment tax credit adjustment for Bulk Transmission Facilities ($).
E_B	=	Annual expenses for Bulk Transmission Facilities ($).
RC_{B1}	=	Revenue credits associated with Bulk Transmission Facilities ($) for purposes of calculating charges for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service.

The sources of the Transmission Provider's investment and expense data that are incorporated in the above formula (including FERC Account numbers, description of allocation procedures, and calculation of the cost of capital) are as follows:

RATE BASE ("RB_B") COMPONENTS

Section 2.2.1 **Gross Plant in Service** includes Gross Transmission Investment associated with the Bulk Transmission Facilities and allocated General and Intangible Investment. Gross Transmission Investment associated with the Bulk Transmission Facilities is the summation of FERC Accounts 350 through 359 multiplied by the Transmission Plant (TP_B) allocator described in Section 2.2.16.a to remove investment associated with generator step-up transformers, interconnection facilities constructed by the Transmission Provider (after March 15, 2000) for the purpose of interconnecting a generating facility owned by the Transmission Provider, the portion of any customer-funded network upgrade for which the Transmission Provider is obligated to provide transmission service credits or otherwise repay, the Bulk Fixed Rate Base Adjustment, and Subtransmission Facilities, with the resulting amount then being adjusted further to remove amounts associated with investment in Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities. Allocated General and Intangible Investment is the summation of FERC Accounts 301 through 303 and 389 through 399, excluding fuel supply/handling facilities and equipment and items that are solely retail-related (e.g., retail conservation and load management systems and retail customer service and information systems),[1] multiplied by the Wages and Salaries (W/S_B) allocator described in Section 2.2.16. c.

Section 2.2.2 **Accumulated Depreciation** is the depreciation recorded in FERC Account 108 associated with the Gross Plant in Service defined above. The accumulated depreciation associated with transmission is multiplied by the TP_B allocator, with the resulting amount then being adjusted further to remove the accumulated depreciation associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities. Accumulated depreciation associated with general plant is allocated to bulk transmission based on the W/S_B allocator.

Section 2.2.3 **Net Plant in Service** is the difference between Section 2.2.1 (Gross Plant in Service) and Section 2.2.2 (Accumulated Depreciation).

[1] Only with respect to Alabama Power Company, production-related expenses of these types may be recorded in Account 399 and thus are excluded from that account.

Section 2.2.4 **Adjustments to Rate Base** include portions of the following accounts that are added to Rate Base: FERC Accounts 181, 182.3, 189, and 190. Portions of the following accounts are deducted from Rate Base: FERC Accounts 254, 257, 282, and 283. FERC Accounts 190, 282, and 283 are allocated based on the Gross Plant (GP_B) allocator described in Section 2.2.16.d. The allocated portion of FERC Account 282 is adjusted to remove the accumulated deferred income tax amounts associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities. The portions of Accounts 182.3 and 254 that are subject to Financial Accounting Standards Board Standard 109 are also allocated using the GP_B allocator. FERC Accounts 181, 189, and 257 are allocated to the Bulk Transmission Facilities based on the Net Plant (NP_B) allocator described in Section 2.2.16.e.

Section 2.2.5 **Land Held For Future Use** is the portion of FERC Account 105 associated with transmission multiplied by the TP_B allocator.

Section 2.2.6 **Working Capital** is the summation of cash working capital, materials and supplies, and prepayments. The working capital for the Bulk Transmission Facilities consists of the following components: (1) cash working capital, which is one-eighth (45/360) of the O&M expenses, developed as explained in Section 2.2.8; (2) materials and supplies (M&S), consisting of materials and operating supplies recorded in FERC Account 154 that are related to the Bulk Transmission Facilities as determined by multiplying M&S - Transmission by the TP_B allocator and adjusting the resulting amount to remove materials and supplies associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities; (3) M&S identified with Construction, Other, and Undistributed Stores, allocated to the Bulk Transmission Facilities by multiplying the balance of those three components by the W/S_B allocator; (4) prepayments as reported in FERC Accounts 165 and 128 (Special Funds - Prepaid Pensions and Other Postretirement Benefits), allocated to the Bulk Transmission Facilities on the basis of the GP_B allocator; and, (5) the jurisdictional portion of prepaid pensions accrued in FERC Account 128 since May 1, 2003, allocated to the Bulk Transmission Facilities on the basis of the GP_B allocator; provided however, the reversal of prepaid pension amounts accrued in FERC Account 128 (as reflected by charges to FERC Account 926) is limited to the jurisdictional portion of the prepaid pension asset accrued after May 1, 2003; and, any amounts associated with "Other Postretirement Benefits" otherwise recorded in FERC Account 128 are specifically excluded from this formula rate component.

Section 2.2.7 **Rate Base** represents the direct and allocated investments that are associated with the Bulk Transmission Facilities and is the summation of Section 2.2.3 (Net Plant in Service) through Section 2.2.6 (Working Capital). This is the value for "RB_B" in the formula in Section 2.2.

EXPENSE ("E_B") COMPONENTS

Section 2.2.8 **Bulk Transmission Operation and Maintenance (O&M) Expenses** include Transmission O&M associated with the Bulk Transmission Facilities and allocated Administrative & General (A&G) expenses. Bulk Transmission O&M expenses are derived by summing FERC Accounts 560 through 574, excluding Account 561 (Load Dispatching), Account 565 (Transmission of Electricity by Others), the amount of Electric Power Research Institute ("EPRI") membership dues that are booked to transmission accounts, and the amount of EPRI-related research, development, and demonstration expenses that are booked to transmission accounts. The resulting figure is then multiplied by the TP_B allocator, with the resulting amount then being adjusted further to remove the O&M expense amounts associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities.

A&G expenses include FERC Accounts 920 through 935, but exclude the portion of Account 923 associated with Southern Nuclear Operating Company's performance of services, the portion of Account 924 associated with nuclear property insurance reimbursements, Account 927, Account 928, Account 930.1, and the portions of Account 930.2 associated with EEI and EPRI dues. A&G Expenses in Account 924 are allocated based on the GP_B allocator. The remainder of A&G Expenses is allocated based on the W/S_B allocator.

Section 2.2.9 **__Depreciation Expense__** includes FERC Accounts 403 through 405. The depreciation expense for transmission plant is derived for the Bulk Transmission Facilities by multiplying transmission depreciation expense by the TP_B allocator, with the resulting amount then being adjusted further to remove depreciation expenses associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities. The depreciation expense associated with general plant is allocated to the Bulk Transmission Facilities based on the W/S_B allocator.

Section 2.2.10 **__Taxes Other than Income Taxes__** include amounts recorded in FERC Account 408.1--Electric, excluding taxes and fees associated solely with retail service, fuel-related taxes, and energy-use-related taxes, and are developed as follows: Payroll taxes are allocated to the Bulk Transmission Facilities based on the W/S_B allocator. Property taxes are allocated to the Bulk Transmission Facilities based on the GP_B allocator (which such allocator also reflects the exclusion of property taxes associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities). The taxes based on retail gross receipts are not allocated to the Bulk Transmission Facilities. The remaining taxes recorded in Account 408.1 not specified above are allocated to the Bulk Transmission Facilities based on the NP_B allocator.

Section 2.2.11 Other Expenses include the portions of the net of Amortization of Loss on Reacquired Debt (Account 428.1), Amortization of Premium on Debt (Account 429), and

Amortization of Gain on Reacquired Debt (Account 429.1) associated with the Bulk Transmission Facilities, as allocated using the NP_B allocator.

Section 2.2.12 **<u>Total Bulk Transmission Expenses</u>** represent the direct and allocated fixed expenses associated with the Bulk Transmission Facilities considered herein and are the summation of Section 2.2.8 (Bulk Transmission Operation and Maintenance Expenses) through Section 2.2.11 (Other Expenses). These costs are represented by the value for "E_B" in the formula in Section 2.2.

Section 2.2.13 **<u>The Rate of Return ("R")</u>** is computed in the following manner:

	R	=	[(DR x i) + (PR x p) + (ER x c)]
Where:			DR + PR + ER = 1.0
	DR	=	Ratio of Long-Term Debt (includes FERC Accounts 221 through 224).
	PR	=	Ratio of Preferred Stock (Account 204).
	ER	=	Ratio of common equity (Proprietary Capital less Preferred Stock and Unappropriated Undistributed Subsidiary Earnings (Account 216.1)).
	i	=	Long-Term Interest (Accounts 427 and 428) divided by Long-Term Debt (%).
	p	=	Preferred Dividends (Account 437) divided by Preferred Stock (%).
	c	=	Return on Common Equity (11.25%).

INCOME TAX ("IT") COMPONENT

2.2.14 <u>The Composite Income Taxes ("CIT") Associated with Preferred Stock and Common Equity Weighted Cost of Capital</u> are computed in the following manner:

$$CIT = \frac{T}{1-T} \times [1 - WCLTD/R]$$

Where:

For Alabama Power and SEGCo

$$T = \frac{FIT + SIT - (2 \times FIT \times SIT)}{1 - FIT \times SIT}$$

Where:

For all other companies

$$T = 1 - [(1 - FIT) \times (1 - SIT)]$$

WCLTD = Weighted Cost of Long Term Debt (%).

R = Rate of Return (%).

FIT = Federal Income Tax Rate (%).

SIT = State Income Tax Rate (%).

Section 2.2.15 <u>Income Taxes</u> are calculated as the composite income tax rate ("CIT") times R times RB_B, and reduced by amortization of the Investment Tax Credit ("ITC_B"). ITC_B is an adjustment for the amount of amortized investment tax credits in Account 411.4 (Investment Tax Credit Adjustments, Utility Operations) associated with the Bulk Transmission Facilities on the basis of the NP_B allocator.

ALLOCATORS

Section 2.2.16 <u>Allocators</u> used in the formula are as follows:

Section 2.2.16.a <u>The Transmission Plant (TP_B) Allocator</u> is derived by adjusting the total transmission plant to exclude facilities that are not considered Bulk Transmission Facilities (which exclusions include generator step-up transformers, interconnection facilities constructed by the Transmission Provider (after March 15, 2000) for the purpose of interconnecting a generating facility owned by the Transmission Provider, the portion of any customer-funded network upgrade for which the Transmission Provider is obligated to provide transmission service credits or otherwise repay, Subtransmission Facilities (including Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities), the Bulk Fixed Rate Base Adjustment, and the Subtransmission Fixed Rate Base Adjustment) and then dividing that result by the total transmission plant.

Section 2.2.16.b **<u>The Transmission Expense (TE_B) Allocator</u>** is derived by reducing the Transmission O&M expenses by Account 561 and then multiplying that result by the TP_B allocator. The product is then divided by the Transmission O&M expenses.

Section 2.2.16.c **<u>The Wages and Salaries (W/S_B) Allocator</u>** is derived by multiplying the Wages and Salaries expenses associated with the transmission function by the TE_B allocator described above, and then reducing the resulting number by the Wages and Salaries expense associated with Bulk Retail Radial Facilities and Rehabilitated Bulk Radial Facilities to derive the portion of Wages and Salaries expenses associated with the Bulk Transmission Facilities. This amount then is divided by the Wages and Salaries expenses for all functions except A&G to produce the W/S_B allocator.

Section 2.2.16.d **<u>The Gross Plant (GP_B) Allocator</u>** is derived by dividing the Gross Plant in Service associated with the Bulk Transmission Facilities by the total company gross plant.

Section 2.2.16.e **<u>The Net Plant (NP_B) Allocator</u>** is derived by dividing the Net Plant in Service associated with the Bulk Transmission Facilities by the total company net plant.

OTHER COMPONENTS

Section 2.2.17 **Revenue Credits (RC_{B1})** for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service reflect the following items: (i) rental payments and reimbursements received for use or rental of specific Bulk Transmission Facilities, but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (ii) all transmission-related other revenues associated with the use or rental of Bulk Transmission Facilities (e.g., rental payments by telecommunications companies for use of transmission facilities; transmission plant rental fees; right-of-way use charges), but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (iii) a proportional share of the income associated with the portion of General Plant that is included in the formula rate (e.g., facilities rental income and payments for use of telecommunications facilities and equipment); and (iv) revenues received for non-firm and short-term firm point-to-point transmission service provided on the Bulk Transmission Facilities under the Tariff.

ARTICLE IIB

DERIVATION OF ANNUAL REVENUE REQUIREMENT FOR THE BULK TRANSMISSION FACILITIES FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE

Section 2.2.21 **Overview:** This article of the Manual establishes the formula methodology and procedures for deriving the annual revenue requirement for the Bulk Transmission Facilities for purposes of calculating charges for Firm Point-to-Point Transmission Service.

Section 2.2.22 **Formula for Deriving Annual Revenue Requirement for the Bulk Transmission Facilities for Firm Point-to-Point Transmission Service:** The derivation of the annual revenue requirement for the Bulk Transmission Facilities is based on the Transmission Provider's investment and expenses related to the Bulk Transmission Facilities and the associated cost of capital and income taxes. The derivation of the Transmission Provider's total annual revenue requirement for the Bulk Transmission Facilities for purposes of calculating charges for Firm Point-to-Point Transmission Service is expressed in the following formula:

RR_{B2}	=	Revenue Requirement associated with Bulk Transmission Facilities for purposes of calculating charges for Firm Point-to-Point Transmission Service.
	=	$\Sigma\, CRR_B - RC_{B2}$

Where:

CRR_B	=	Individual operating company revenue requirement for its Bulk Transmission Facilities ($).
	=	$(RB_B \times R) + IT_B + E_B$

Section 2.2.23 **<u>CRR_B</u>** shall have the same meaning as in Section 2.2.

Section 2.2.24 **<u>Revenue Credits (RC_{B2})</u>** for Firm Point-to-Point Transmission Service reflect the following items: (i) rental payments and reimbursements received for use or rental of specific Bulk Transmission Facilities, but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (ii) all transmission-related other revenues associated with the use or rental of Bulk Transmission Facilities (<u>e.g.</u>, rental payments by telecommunications companies for use of transmission facilities; transmission plant rental fees; right-of-way use charges), but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (iii) a proportional share of the income associated with the portion of General Plant that is included in the formula rate (<u>e.g.</u>, facilities rental income and payment for use of telecommunications facilities and equipment); and (iv) revenues received for non-firm and short-term firm point-to-point transmission service provided on the Bulk Transmission Facilities under the Tariff except that revenues associated with non-firm use of transmission capacity set aside as Capacity Benefit Margin shall not be included in these revenue credits (RC_{B2}).

ARTICLE III

DERIVATION OF ANNUAL REVENUE REQUIREMENT FOR THE SUBTRANSMISSION FACILITIES

Section 3.1 **Overview:** This article of the Manual establishes the formula methodology and procedures for deriving the annual revenue requirement for the Subtransmission Facilities. When used in this Manual, the capitalized terms set forth in Sections 3.1.a through 3.1.c have the meanings specified below:

Section 3.1.a **Subtransmission Retail Radial Facility:** A physically radial Subtransmission Facility used exclusively to serve the Transmission Provider's retail load that is placed into service in Rate Year 2011 and thereafter.

Section 3.1.b **Rehabilitated Subtransmission Radial Facility:** A physically radial Subtransmission Facility that is the subject of a capital replacement, repair, re-conductoring, or some other rehabilitation occurring in Rate Year 2011 and thereafter.

Section 3.1.c **Subtransmission Fixed Rate Base Adjustment:** A fixed adjustment to the Transmission Provider's Gross Plant in Service in the amount of $36,100,000 related to investment in those subtransmission retail radial facilities used exclusively to serve the Transmission Provider's retail load that were placed into service in Rate Years 2003 through 2010.

Section 3.2 **Formula for Deriving Annual Revenue Requirement for the Subtransmission Facilities:** The derivation of the annual revenue requirement for the Subtransmission Facilities is based on the Transmission Provider's investment and expenses related to the Subtransmission Facilities and the associated cost of capital and income taxes. The derivation of the Transmission Provider's total annual revenue requirement for the Subtransmission Facilities is expressed in the following formula:

RR_S	=	Annual revenue requirement for the Subtransmission Facilities ($).
	=	$\Sigma\, CRR_S - RC_S$

Where:

CRR_S	=	Individual operating company revenue requirement for its Subtransmission Facilities ($).
	=	$(RB_S \times R) + IT_S + E_S$
RB_S	=	Rate base (The beginning and end of year average transmission investment for Subtransmission Facilities) ($).
R	=	The composite rate of return (%).
IT_S	=	Income taxes associated with Subtransmission Facilities ($).
	=	$(RB_S \times R) \times CIT - ITC_S$
CIT	=	Income tax requirement associated with the preferred stock and common equity weighted cost of capital (%).
ITC_S	=	Investment tax credit adjustment for Subtransmission Facilities ($).
E_S	=	Annual expenses for Subtransmission Facilities ($).
RC_S	=	Revenue credits associated with Subtransmission Facilities ($).

The sources of the Transmission Provider's investment and expense data that are incorporated in the above formula (including FERC Account numbers, description of allocation procedures, and calculation of the cost of capital) are as follows:

RATE BASE (“RB_S”) COMPONENTS

Section 3.2.1 **Gross Plant in Service** includes Gross Transmission Investment associated with the Subtransmission Facilities and allocated General and Intangible Investment. Gross Transmission Investment associated with the Subtransmission Facilities is the summation of FERC Accounts 350 through 359 multiplied by the Transmission Plant (TP_S) allocator described in Section 3.2.16.a to remove investment associated with generator step-up transformers, interconnection facilities constructed by the Transmission Provider (after March 15, 2000) for the purpose of interconnecting a generating facility owned by the Transmission Provider, the portion of any customer-funded network upgrade for which the Transmission Provider is obligated to provide transmission service credits or otherwise repay, the Subtransmission Fixed Rate Base Adjustment, and Bulk Transmission Facilities, with the resulting amount then being adjusted further to remove amounts associated with investment in Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities. Allocated General and Intangible Investment is the summation of FERC Accounts 301 through 303 and 389 through 399, excluding fuel supply/handling facilities and equipment and items that are solely retail-related (e.g., retail conservation and load management systems and retail customer service and information systems), multiplied by the Wages and Salaries (W/S_S) allocator described in Section 3.2.16.c.

Section 3.2.2 **Accumulated Depreciation** is the depreciation recorded in FERC Account 108 associated with the Gross Plant in Service defined above. The accumulated depreciation associated with transmission is multiplied by the TP_S allocator, with the resulting amount then being adjusted further to remove the accumulated depreciation associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities.

Accumulated depreciation associated with general plant is allocated to subtransmission based on the W/S_S allocator.

Section 3.2.3 **Net Plant in Service** is the difference between Section 3.2.1 (Gross Plant in Service) and Section 3.2.2 (Accumulated Depreciation).

Section 3.2.4 **Adjustments to Rate Base** include portions of the following accounts that are added to Rate Base: FERC Accounts 181, 182.3, 189, and 190. Portions of the following accounts are deducted from Rate Base: FERC Accounts 254, 257, 282, and 283. FERC Accounts 190, 282, and 283 are allocated based on the Gross Plant (GP_S) allocator described in Section 3.2.16.d. The allocated portion of FERC Account No. 282 is adjusted to remove the accumulated deferred income tax amounts associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities. The portions of Accounts 182.3 and 254 that are subject to Financial Accounting Standards Board Standard 109 are also allocated using the GP_S allocator. FERC Accounts 181, 189, and 257 are allocated to the Subtransmission Facilities based on the Net Plant (NP_S) allocator described in Section 3.2.16.e.

Section 3.2.5 **Land Held For Future Use** is the portion of FERC Account 105 associated with transmission multiplied by the TP_S allocator.

Section 3.2.6 **Working Capital** is the summation of cash working capital, materials and supplies, and prepayments. The working capital for the Subtransmission Facilities consists of the following components: (1) cash working capital, which is one-eighth (45/360) of the O&M expenses, developed as explained in Section 3.2.8; (2) materials and supplies (M&S), consisting of materials and operating supplies recorded in FERC Account 154 that are related to the Subtransmission Facilities as determined by multiplying M&S - Transmission by the TP_S allocator and adjusting the resulting amount to remove materials and supplies associated with

Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities; (3) M&S identified with Construction, Other, and Undistributed Stores, allocated to the Subtransmission Facilities by multiplying the balance of those three components by the W/S_S allocator; (4) prepayments as reported in FERC Accounts 165 and 128 (Special Funds - Prepaid Pensions and Other Postretirement Benefits), allocated to the Subtransmission Facilities on the basis of the GP_S allocator; and, (5) the jurisdictional portion of prepaid pensions accrued in FERC Account 128 since May 1, 2003, allocated to the Subtransmission Facilities on the basis of the GPS allocator; provided however, the reversal of prepaid pension amounts accrued in FERC Account 128 (as reflected by charges to FERC Account 926) is limited to the jurisdictional portion of the prepaid pension asset accrued after May 1, 2003; and, any amounts associated with "Other Postretirement Benefits" otherwise recorded in FERC Account 128 are specifically excluded from this formula rate component.

Section 3.2.7 **Rate Base** represents the direct and allocated investments that are associated with the Subtransmission Facilities and is the summation of Section 3.2.3 (Net Plant in Service) through Section 3.2.6 (Working Capital). This is the value for "RB_S" in the formula in Section 3.2.

EXPENSE ("E_S") COMPONENTS

Section 3.2.8 **Subtransmission Operation and Maintenance (O&M) Expenses** include Transmission O&M associated with the Subtransmission Facilities and allocated Administrative & General (A&G) expenses. Subtransmission O&M expenses are derived by summing FERC Accounts 560 through 574, excluding Account 561 (Load Dispatching), Account 565 (Transmission of Electricity by Others), the amount of Electric Power Research Institute ("EPRI") membership dues that are booked to transmission accounts, and the amount of

EPRI-related research, development, and demonstration expenses that are booked to transmission accounts. The resulting figure is then multiplied by the TP_S allocator, with the resulting amount then being adjusted further to remove the O&M expense amounts associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities.

A&G expenses include FERC Accounts 920 through 935, but exclude the portion of Account 923 associated with Southern Nuclear Operating Company's performance of services, the portion of Account 924 associated with nuclear property insurance reimbursements, Account 927, Account 928, Account 930.1, and the portions of Account 930.2 associated with EEI and EPRI dues. A&G Expenses in Account 924 are allocated based on the GP_S allocator. The remainder of A&G Expenses is allocated based on the W/S_S allocator.

Section 3.2.9 **<u>Depreciation Expense</u>** includes FERC Accounts 403 through 405. The depreciation expense for transmission plant is derived for the Subtransmission Facilities by multiplying transmission depreciation expense by the TP_S allocator, with the resulting amount then being adjusted further to remove depreciation expenses associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities. The depreciation expense associated with general plant is allocated to the Subtransmission Facilities based on the W/S_S allocator.

Section 3.2.10 **<u>Taxes Other than Income Taxes</u>** include amounts recorded in FERC Account 408.1--Electric, excluding taxes and fees associated solely with retail service, fuel-related taxes, and energy-use-related taxes, and are developed as follows: Payroll taxes are allocated to the Subtransmission Facilities based on the W/S_S allocator. Property taxes are allocated to the Subtransmission Facilities based on the GP_S allocator (which such allocator also reflects the exclusion of property taxes associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities). The taxes based on retail gross receipts are not allocated to the Subtransmission Facilities. The remaining taxes recorded in Account 408.1 not specified above are allocated to the Subtransmission Facilities based on the NP_S allocator.

Section 3.2.11 Other Expenses include the portions of the net of Amortization of Loss on Reacquired Debt (Account 428.1), Amortization of Premium on Debt (Account 429), and Amortization of Gain on Reacquired Debt (Account 429.1) associated with the Subtransmission Facilities, as allocated using the NP_S allocator.

Section 3.2.12 **<u>Total Subtransmission Expenses</u>** represent the direct and allocated fixed expenses associated with the Subtransmission Facilities considered herein and are the summation of Section 3.2.8 (Subtransmission Operation and Maintenance Expenses) through Section 3.2.11 (Other Expenses). These costs are represented by the value for "E_S" in the formula in Section 3.2.

Section 3.2.13 **<u>The Rate of Return ("R")</u>** is computed in the following manner:

R	=	[(DR x i) + (PR x p) + (ER x c)]
Where:		DR + PR + ER = 1.0
DR	=	Ratio of Long-Term Debt (includes FERC Accounts 221 through 224).
PR	=	Ratio of Preferred Stock (Account 204).
ER	=	Ratio of common equity (Proprietary Capital less Preferred Stock and Unappropriated Undistributed Subsidiary Earnings (Account 216.1)).
i	=	Long-Term Interest (Accounts 427 and 428) divided by Long-Term Debt (%).
p	=	Preferred Dividends (Account 437) divided by Preferred Stock (%).
c	=	Return on Common Equity (11.25%).

INCOME TAX ("IT") COMPONENT

3.2.14 <u>The Composite Income Taxes ("CIT") Associated with Preferred Stock and Common Equity Weighted Cost of Capital</u> are computed in the following manner:

$$CIT = \frac{T}{1-T} \times [1 - WCLTD/R]$$

Where:

For Alabama Power and SEGCo

$$T = \frac{FIT + SIT - (2 \times FIT \times SIT)}{1 - FIT \times SIT}$$

Where:

For all other companies

$$T = 1 - [(1 - FIT) \times (1 - SIT)]$$

WCLTD = Weighted Cost of Long Term Debt (%).

R = Rate of Return (%).

FIT = Federal Income Tax Rate (%).

SIT = State Income Tax Rate (%).

Section 3.2.15 **<u>Income Taxes</u>** are calculated as the composite income tax rate ("CIT") times R times RB_S, and reduced by amortization of the Investment Tax Credit ("ITC"). ITC is an adjustment for the amount of amortized investment tax credits in Account 411.4 (Investment Tax Credit Adjustments, Utility Operations) associated with the Subtransmission Facilities on the basis of the NP_S allocator.

ALLOCATORS

Section 3.2.16 **<u>Allocators</u>** used in the formula are as follows:

Section 3.2.16.a **<u>The Transmission Plant (TP_S) Allocator</u>** is derived by adjusting the total transmission plant to exclude facilities, including the Subtransmission Fixed Rate Base Adjustment, that are not considered Subtransmission Facilities and then dividing that result by the total transmission plant.

Section 3.2.16.b **<u>The Transmission Expense (TE_S) Allocator</u>** is derived by reducing the Transmission O&M expenses by Account 561 and then multiplying that result by the TP_S allocator. The product is then divided by the Transmission O&M expenses.

Section 3.2.16.c **<u>The Wages and Salaries (W/S_S) Allocator</u>** is derived by multiplying the Wages and Salaries expenses associated with the transmission function by the TE_S allocator described above, and then reducing the resulting number by the Wages and Salaries expense associated with Subtransmission Retail Radial Facilities and Rehabilitated Subtransmission Radial Facilities to derive the portion of Wages and Salaries expenses associated with the Subtransmission Facilities. This amount then is divided by the Wages and Salaries expenses for all functions except A&G to produce the W/S_S allocator.

Section 3.2.16.d **<u>The Gross Plant (GP_S) Allocator</u>** is derived by dividing the Gross Plant in Service associated with the Subtransmission Facilities by the total company gross plant.

Section 3.2.16.e **<u>The Net Plant (NP_S) Allocator</u>** is derived by dividing the Net Plant in Service associated with the Subtransmission Facilities by the total company net plant.

OTHER COMPONENTS

Section 3.2.17 **<u>Revenue Credits</u>** reflect the following items: (i) rental payments and reimbursements received for use or rental of specific Subtransmission Facilities, but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (ii) all transmission-related other revenues associated with the use or rental of

Subtransmission Facilities (e.g., rental payments by telecommunications companies for use of transmission facilities; transmission plant rental fees; right-of-way use charges), but only to the extent the costs of such facilities are included in the development of charges under the formula rate; (iii) a proportional share of the income associated with the portion of General Plant that is included in the formula rate (e.g., facilities rental income and payments for use of telecommunications facilities and equipment); and (iv) revenues received for non-firm and short-term firm point-to-point transmission service provided on the Subtransmission Facilities under the Tariff.

ARTICLE IVA

DERIVATION OF BULK TRANSMISSION LOAD FOR NETWORK INTEGRATION TRANSMISSION SERVICE AND NON-FIRM POINT-TO-POINT TRANSMISSION SERVICE

Section 4.1 **Overview:** This article establishes the methodology to determine the Load ("L_{B1}") used to derive the Bulk Transmission Charges for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service.

Section 4.2 **Twelve Month Average Coincident Peak Methodology:** The Load ("L_{B1}") used to derive the charges under Sections 6.3 (for Non-Firm Point-to-Point Transmission Service provided on the Bulk Transmission Facilities) and 6.4 (for Network Integration Transmission Service provided on the Bulk Transmission Facilities) of this Manual for purposes of the Annual Informational Filing is the average of the twelve monthly coincident peak (CP) loads (kW) on the Bulk Transmission System for the Rate Year, as forecasted by the Transmission Provider. The Load used to derive the charges under Sections 6.3 and 6.4 of this Manual for purposes of the True-Up Filing is the average of the actual 12 CP loads (kW) on the Bulk Transmission System for the Rate Year. Adjustments made to the 12 CP load calculation are as follows: (1) the load of the City of Dalton is removed because it is a transmission owner of the Georgia Integrated Transmission System; (2) losses in the Bulk Transmission System are removed; and (3) loads for Network Customers that are not already included in the Transmission Provider's territorial load calculation and long-term firm point-to-point reservations are added to the 12 CP load calculation.

ARTICLE IVB

DERIVATION OF BULK TRANSMISSION LOAD FOR FIRM POINT-TO-POINT TRANSMISSION SERVICE

Section 4.3 **Overview:** This article establishes the methodology to determine the Load ("L_{B2}") used to derive the Bulk Transmission Charges for Firm Point-to-Point Transmission Service.

Section 4.4 **Twelve Month Average Coincident Peak Methodology:** The Load ("L_{B2}") used to derive the charges under Sections 6.2 (for Firm Point-to-Point Transmission Service provided on the Bulk Transmission Facilities) of this Manual for purposes of the Annual Informational Filing is the average of the twelve monthly coincident peak (CP) loads (kW) on the Bulk Transmission System for the Rate Year, as forecasted by the Transmission Provider. The Load used to derive the charges under Sections 6.2 of this Manual for purposes of the True-Up Filing is the average of the actual 12 CP loads (kW) on the Bulk Transmission System for the Rate Year. Adjustments made to the 12 CP load calculation are as follows: (1) the load of the City of Dalton is removed because it is a transmission owner of the Georgia Integrated Transmission System; (2) losses in the Bulk Transmission System are removed; (3) loads for Network Customers that are not already included in the Transmission Provider's territorial load calculation and long-term firm point-to-point reservations are added to the 12 CP load calculation; and (4) the amount (kW) of capacity on the Bulk Transmission Facilities set aside by the Transmission Provider and/or Network Customer(s) for Capacity Benefit Margin use are added to the 12 CP load calculation.

ARTICLE V

DERIVATION OF SUBTRANSMISSION LOAD

Section 5.1 **Overview:** This article establishes the methodology to determine the Load ("L_S") used to derive the Subtransmission Charges.

Section 5.2 **Twelve Month Average Coincident Peak Methodology:** The Load ("L_S") used to derive the charges under Sections 6.5, 6.6, and 6.7 of this Manual is the average of the 12 CP territorial loads (kW) at Level 2 (i.e., native load excluding bulk transmission losses) on the Transmission System for the Rate Year as forecasted by the Transmission Provider, in an Annual Informational Filing or the actual load in a True-Up Filing, multiplied by the ratio of subtransmission load to territorial load on the Transmission System that is set forth in the Transmission Provider's most recent cost-of-service load flow study and adjusted to the subtransmission output level as follows: (1) losses on the Subtransmission System are removed; (2) the loads for Network Customers at the subtransmission level that are not included in the Transmission Provider's territorial load calculation are added; and (3) the loads for subtransmission level long-term firm point-to-point reservations are added.

ARTICLE VI

CALCULATION OF BULK TRANSMISSION CHARGES, SUBTRANSMISSION CHARGES, AND FERC ANNUAL CHARGE

Section 6.1 **Overview:** This article shows the derivation of the specific Bulk Transmission Charges, and Subtransmission Charges, including the cost component to recover the FERC Annual Charge.

Section 6.2 **Charges for Firm Point-To-Point Transmission Service Provided on the Bulk Transmission Facilities:** The derivation of charges for Firm Point-To-Point Transmission Service provided on the Bulk Transmission Facilities is expressed in the following formula:

$$B2R_{YF} = \frac{RR_{B2}}{L_{B2}}$$

$$B2R_{MF} = \frac{RR_{B2}}{L_{B2} \times 12}$$

$$B2R_{WF} = \frac{RR_{B2}}{L_{B2} \times 52}$$

$$B2R_{DF,\ on\text{-}peak} = \frac{B2R_{WF}}{5}$$

$$B2R_{DF,\ off\text{-}peak} = \frac{B2R_{WF}}{7}$$

Where:

RR_{B2} = The annual revenue requirement for the Bulk Transmission Facilities for purposes of calculating charges for Firm Point-to-Point Transmission Service derived under Article IIB of this Manual ($).

L_{B2} = The Load derived under Article IVB of this Manual (kW).

$B2R_{YF}$ = The bulk transmission charge for yearly Firm Point-To-Point Transmission Service ($/kW-year).

$B2R_{MF}$ = The bulk transmission charge for monthly Firm Point-To-Point Transmission Service ($/kW-month).

$B2R_{WF}$ = The bulk transmission charge for weekly Firm Point-To-Point Transmission Service ($/kW-week).

$B2R_{DF,\ on\text{-}peak}$ = The bulk transmission charge for on-peak daily Firm Point-To-Point Transmission Service ($/kW-day).

$B2R_{DF,\ off\text{-}peak}$ = The bulk transmission charge for off-peak daily Firm Point-To-Point Transmission Service ($/kW-day).

These charges will be updated to become effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule A, the form of which is Exhibit A to the Tariff.

Section 6.3 **<u>Charges for Non-Firm Point-To-Point Transmission Service Provided on the Bulk Transmission Facilities</u>:** The derivation of the charges for Non-Firm Point-To-Point Transmission Service provided on the Bulk Transmission Facilities is expressed in the following formula:

$$B1R_M = \frac{RR_{B1}}{L_{B1} \times 12}$$

$$B1R_W = \frac{RR_{B1}}{L_{B1} \times 52}$$

$$B1R_{D,on\text{-}peak} = \frac{B1R_W}{5}$$

$$B1R_{D,\ off\text{-}peak} = \frac{B1R_W}{7}$$

$$B1R_{H,\ on\text{-}peak} = \frac{B1R_{D,\ on\text{-}peak}}{16} \times 1000$$

$$B1R_{H,\ off\text{-}peak} = \frac{B1R_{D,\ off\text{-}peak}}{24} \times 1000$$

Where:

RR_{B1}	=	The annual revenue requirement for the Bulk Transmission Facilities for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service derived under Article IIA of this Manual ($).
L_{B1}	=	The Load derived under Article IVA of this Manual (kW).
$B1R_M$	=	The bulk transmission charge for monthly Non-Firm Point-To-Point Transmission Service ($/kW-month).
$B1R_W$	=	The bulk transmission charge for weekly Non-Firm Point-To-Point Transmission Service ($/kW-week).

$B1R_{D,\text{ on-peak}}$ = The bulk transmission charge for on-peak daily Non-Firm Point-To-Point Transmission Service (\$/kW-day).

$B1R_{D,\text{ off-peak}}$ = The bulk transmission charge for off-peak daily Non-Firm Point-To-Point Transmission Service (\$/kW-day).

$B1R_{H,\text{ on-peak}}$ = The bulk transmission charge for on-peak hourly Non-Firm Point-To-Point Transmission Service (mills/kWh).

$B1R_{H,\text{ off-peak}}$ = The bulk transmission charge for off-peak hourly Non-Firm Point-To-Point Transmission Service (mills/kWh).

These charges will be updated to be effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule B, the form of which is Exhibit B to the Tariff.

Section 6.4 **<u>Charges for Network Integration Transmission Service Provided on the Bulk Transmission Facilities</u>:** The derivation of the charges for Network Integration Transmission Service provided on the Bulk Transmission Facilities is expressed in the following formula:

$$B1R_Y = \frac{RR_{B1}}{L_{B1}}$$

$$B1R_M = \frac{RR_{B1}}{L_{B1} \times 12}$$

Where:

RR_{B1} = The annual revenue requirement for the Bulk Transmission Facilities for Network Integration Transmission Service and Non-Firm Point-to-Point Transmission Service derived under Article IIA of this Manual (\$).

L_{B1} = The Load derived under Article IVA of this Manual (kW).

$B1R_Y$ = The bulk transmission charge for yearly Network Integration Transmission Service (\$/kW-year).

$B1R_M$ = The bulk transmission charge for monthly Network Integration Transmission Service (\$/kW-month).

These charges will be updated to be effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule C, the form of which is Exhibit C to the Tariff.

Section 6.5 **Charges for Firm Point-To-Point Transmission Service Provided on the Subtransmission Facilities:** The derivation of charges for Firm Point-To-Point Transmission Service provided on the Subtransmission Facilities is expressed in the following formula:

$$SR_{SY} = \frac{RR_S}{L_S}$$

$$SR_M = \frac{RR_S}{L_S \times 12}$$

$$SR_W = \frac{RR_S}{L_S \times 52}$$

$$SR_{D,\text{ on-peak}} = \frac{SR_W}{5}$$

$$SR_{D,\text{ off-peak}} = \frac{SR_W}{7}$$

Where:

RR_S = The annual revenue requirement for the Subtransmission Facilities derived under Article II of this Manual ($).

L_S = The Load derived under Article V of this Manual (kW).

SR_Y = The subtransmission charge for yearly Firm Point-To-Point Transmission Service ($/kW-year).

SR_M = The subtransmission charge for monthly Firm Point-To-Point Transmission Service ($/kW-month).

SR_W = The subtransmission charge for weekly Firm Point-To-Point Transmission Service ($/kW-week).

$SR_{D,\ on\text{-}peak}$ = The subtransmission charge for on-peak daily Firm Point-To-Point Transmission Service (\$/kW-day).

$SR_{D,\ off\text{-}peak}$ = The subtransmission charge for off-peak daily Firm Point-To-Point Transmission Service (\$/kW-day).

These charges will be updated to become effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule A, the form of which is Exhibit A to the Tariff.

Section 6.6 **Charges for Non-Firm Point-To-Point Transmission Service Provided on the Subtransmission Facilities:** The derivation of the charges for Non-Firm Point-To-Point Transmission Service provided on the Subtransmission Facilities is expressed in the following formula:

$$SR_M = \frac{RR_S}{L_S \times 12}$$

$$SR_W = \frac{RR_S}{L_S \times 52}$$

$$SR_{D,on\text{-}peak} = \frac{SR_W}{5}$$

$$SR_{D,\ off\text{-}peak} = \frac{SR_W}{7}$$

$$SR_{H,\ on\text{-}peak} = \frac{SR_{D,\ on\text{-}peak}}{16} \times 1000$$

$$SR_{H,\ off\text{-}peak} = \frac{SR_{D,\ off\text{-}peak}}{24} \times 1000$$

Where:

RR_S = The annual revenue requirement for the Subtransmission Facilities derived under Article III of this Manual (\$).

L_S = The Load derived under Article V of this Manual (kW).

SR_M = The subtransmission charge for monthly Non-Firm Point-To-Point Transmission Service (\$/kW-month).

SR_W = The subtransmission charge for weekly Non-Firm Point-To-Point Transmission Service (\$/kW-week).

$SR_{D,\text{ on-peak}}$ = The subtransmission charge for on-peak daily Non-Firm Point-To-Point Transmission Service (\$/kW-day).

$SR_{D,\text{ off-peak}}$ = The subtransmission charge for off-peak daily Non-Firm Point-To-Point Transmission Service (\$/kW-day).

$SR_{H,\text{ on-peak}}$ = The subtransmission charge for on-peak hourly Non-Firm Point-To-Point Transmission Service (mills/kWh).

$SR_{H,\text{ off-peak}}$ = The subtransmission charge for off-peak hourly Non-Firm Point-To-Point Transmission Service (mills/kWh).

These charges will be updated to be effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule B, the form of which is Exhibit B to the Tariff.

Section 6.7 **<u>Charges for Network Integration Transmission Service Provided on the Subtransmission Facilities</u>:** The derivation of the charges for Network Integration Transmission Service provided on the Subtransmission Facilities is expressed in the following formula:

$$SR_Y = \frac{RR_S}{L_S}$$

$$SR_M = \frac{RR_S}{L_S \times 12}$$

Where:

RR_S = The annual revenue requirement for the Subtransmission Facilities derived under Article III of this Manual (\$).

L_S = The Load derived under Article V of this Manual (kW).

SR_Y = The subtransmission charge for yearly Network Integration Transmission Service (\$/kW-year).

SR_M = The subtransmission charge for monthly Network Integration Transmission Service ($/kW-month).

These charges will be updated to be effective on January 1 of each Rate Year (subject to Attachment N, footnote 3) based on the formula and will be set forth on Informational Schedule C, the form of which is Exhibit C to the Tariff.

Section 6.8 **<u>FERC Annual Charge and Attachment K Costs</u>:** The cost components to recover the FERC Annual Charge (18 C.F.R. Part 382) and the Transmission Provider's costs incurred in implementing its requirements, duties, and activities under Attachment K, the Southeastern Regional Transmission Planning Process, are in addition to the applicable charges specified above in Sections 6.2 through 6.7. The cost component for the FERC Annual Charge shall consist of the Charge Factor(s) shown on the Commission's invoices submitted to the Transmission Provider on or about August 1 of each calendar year. If more than one Charge Factor is shown on such invoices, then the appropriate Charge Factor will be applied to the corresponding type of service. The cost component for the recovery of the Transmission Provider's costs incurred in implementing its requirements, duties, and activities under Attachment K, the Southeastern Regional Transmission Planning Process, shall consist of a charge factor comprised by those total costs incurred for the prior calendar year divided by the total amount (MWh) of metered Network Integration Transmission Service and Point-to-Point Transmission Service taken under the Tariff the prior calendar year. These components will be set forth on Informational Schedule D, the form of which is attached as Exhibit D of the Tariff, will be updated to be effective on October 1 of each year, and is assessed on the basis of megawatt hours associated with a Transmission Customer's deliveries of energy.

ARTICLE VII

Updated Analysis of Losses and CBM Usage

Section 7.1 Updated Information Relating to Losses on the Transmission System and the Usage of Capacity Benefit Margin to Meet Generation Deficits:

At two year intervals after August 1, 2004, the Transmission Provider will make available an updated analysis of losses for the Transmission System based on the following data: (i) power flow simulations using the Summer Peak Base Cases for the Bulk Transmission Facilities (i.e., those above 44/46 kV) adjusted to simulate the average 12 CP loads and the average annual load on the Bulk Transmission Facilities; (ii) power flow simulations on the Subtransmission Facilities (i.e., those at 44/46 kV) adjusted to simulate the average 12 CP loads and the average annual load on the Subtransmission Facilities; and (iii) the most recent cost-of-service load flow study. In addition, the Transmission Provider will also make available the instances (if any) over the prior two calendar years that transmission capacity set aside as CBM has been called upon to meet emergency generation deficits, including OASIS reference numbers, duration and amount of transmission capacity. A copy of the updated analysis of losses and CBM usage will be provided to customers taking Network Integration Transmission Service, customers taking Long-Term Firm Point-to-Point Transmission Service, and other interested parties upon request and shall also be made available on the Transmission Provider's OASIS.

EXHIBIT A

FORM OF INFORMATIONAL SCHEDULE A

Charges For Long-Term and Short-Term Firm Point-To-Point Transmission Service

A. Charges for Bulk Transmission Service: For Firm Point-to-Point Transmission service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity for the use of the Transmission Provider's Bulk Transmission Facilities (voltage levels above 44/46 kV) at the sum of the applicable charges set forth below:

		Bulk Transmission (voltage levels above 44/46 kV)
(1)	**Yearly delivery:**	$____ /kW of Reserved Capacity per year.
(2)	**Monthly delivery:**	$____ /kW of Reserved Capacity per month.
(3)	**Weekly delivery:**	$____ /kW of Reserved Capacity per week.
(4)	**On-Peak Daily delivery:**	$____ /kW of Reserved Capacity per day.
(5)	**Off-Peak Daily delivery:**	$____ /kW of Reserved Capacity per day.

B. Charges for Subtransmission Service: For Firm Point-to-Point Transmission service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity for the use of the Transmission Provider's Subtransmission Facilities (voltage levels at 44/46 kV) at the sum of the applicable charges set forth below:

Subtransmission
(voltage levels at 44/46 kV)

(1) **Yearly delivery:** $____ /kW of Reserved Capacity per year.

(2) **Monthly delivery:** $____ /kW of Reserved Capacity per month.

(3) **Weekly delivery:** $____ /kW of Reserved Capacity per week.

(4) **On-Peak Daily delivery:** $____ /kW of Reserved Capacity per day.

(5) **Off-Peak Daily delivery:** $____ /kW of Reserved Capacity per day.

C. Description of On-Peak and Off-Peak Daily delivery periods: The on-peak daily delivery charge is applicable to daily service provided on a Monday through Friday of any given week, except for the six (6) holidays recognized by NERC. The off-peak daily delivery charge is applicable to service provided on a Saturday, Sunday, and any of the six (6) holidays recognized by NERC. For service at the bulk transmission level, the total demand charge in any week, pursuant to reservation(s) for daily service, shall not exceed the weekly delivery charge specified in the Bulk Transmission table above times the highest amount in kilowatts of Reserved Capacity at the bulk transmission service level on any given day during such week. In addition, for service at the subtransmission level, the total demand charge in any week, pursuant to reservation(s) for daily service, shall not exceed the weekly delivery charge specified in the Subtransmission table above times the highest amount in kilowatts of Reserved Capacity at the subtransmission service level on any given day during such week.

D. Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by any customer's wholesale merchant or an affiliate) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

EXHIBIT B

FORM OF INFORMATIONAL SCHEDULE B

Charges For Bulk Non-Firm Point-To-Point Transmission Service

A. Charges for Bulk Transmission Service: For Non-Firm Point-To-Point Transmission Service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity for the use of the Transmission Provider's Bulk Transmission Facilities (voltage levels above 44/46 kV) at the sum of the applicable bulk charges set forth below:

		Bulk Transmission (voltage levels above 44/46 kV)
(1)	**Monthly delivery**:	$____ /kW of Reserved Capacity per month.
(2)	**Weekly delivery**:	$____ /kW of Reserved Capacity per week.
(3)	**On-Peak Daily delivery**:	$____ /kW of Reserved Capacity per day.
(4)	**Off-Peak Daily delivery**:	$____ /kW of Reserved Capacity per day.
(5)	**On-Peak Hourly delivery**:	$____ /kW of Reserved Capacity per hour.
(6)	**Off-Peak Hourly delivery**:	$____ /kW of Reserved Capacity per hour.

B. Charges for Subtransmission Service: For Non-Firm Point-To-Point Transmission Service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity for the use of the Transmission Provider's Subtransmission Facilities (voltage levels at 44/46 kV) at the sum of the applicable bulk charges set forth below:

Subtransmission
(voltage levels at 44/46 kV)

(1)	**Monthly delivery**:	$____ /kW of Reserved Capacity per month.
(2)	**Weekly delivery**:	$____ /kW of Reserved Capacity per week.
(3)	**On-Peak Daily delivery**:	$____ /kW of Reserved Capacity per day.
(4)	**Off-Peak Daily delivery**:	$____ /kW of Reserved Capacity per day.
(5)	**On-Peak Hourly delivery**:	$____ /kW of Reserved Capacity per hour.
(6)	**Off-Peak Hourly delivery**:	$____ /kW of Reserved Capacity per hour.

C. Description of On-Peak and Off-Peak Daily delivery periods: The on-peak daily delivery charge is applicable to daily service provided on a Monday through Friday of any given week, except for the six (6) holidays recognized by NERC. The off-peak daily delivery charge is applicable to service provided on a Saturday, Sunday, and any of the six (6) holidays recognized by NERC. For service at the bulk transmission level, the total demand charge in any week, pursuant to reservation(s) for daily service, shall not exceed the weekly delivery charge specified in the Bulk Transmission table above times the highest amount in kilowatts of Reserved Capacity at the bulk transmission service level on any given day during such week. In addition, for service at the subtransmission level, the total demand charge in any week, pursuant to reservation(s) for daily service, shall not exceed the weekly delivery charge specified in the Subtransmission table above times the highest amount in kilowatts of Reserved Capacity at the subtransmission service level on any given day during such week.

D. Description of On-Peak and Off-Peak Hourly delivery periods: The on-peak hourly delivery charge is applicable to hourly service provided during the sixteen (16) hour period from 6:00 a.m. to 10:00 p.m. (Prevailing Central Time), on a Monday through Friday, except on the six (6) holidays recognized by NERC. The off-peak hourly charge is applicable to service provided during the eight (8) hour period from 10:00 p.m. to 6:00 a.m. (Prevailing Central Time) and during all hours of a Saturday, Sunday, and any of the six (6) holidays recognized by NERC. For service at the bulk transmission level, the total demand charge in any day, pursuant to reservation(s) for hourly service, shall not exceed the on-peak daily delivery charge specified in the Bulk Transmission table above times the highest amount in kilowatts of Reserved Capacity at the bulk transmission service level in any given hour during such day and shall not exceed the on-peak daily delivery charge specified in the Bulk Transmission table for Firm Point-to-Point Transmission Service in Informational Schedule A times the highest amount in kilowatts of Reserved Capacity at the bulk transmission level on any given hour during such day. In addition, for service at the subtransmission level, the total demand charge in any day, pursuant to reservation(s) for hourly service, shall not exceed the on-peak daily delivery charge specified in the Subtransmission table above times the highest amount in kilowatts of Reserved Capacity at the subtransmission service level in any given hour during such day and shall not exceed the on-peak daily delivery charge specified in the Subtransmission table for Firm Point-to-Point Transmission Service in Informational Schedule A times the highest amount in kilowatts of Reserved Capacity at the subtransmission level on any given hour during such day.

E. Discounts: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by any customer's wholesale merchant or an affiliate) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

EXHIBIT C

FORM OF INFORMATIONAL SCHEDULE C

Charges for Bulk Network Integration Transmission Service

A. Charges for Bulk Transmission Service: For Network Integration Transmission Service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for the use of the Transmission Provider's Bulk Transmission Facilities (voltage levels above 44/46 kV) at the applicable charges set forth below:

1) **Yearly delivery:** $_____ /kW-year.

2) **Monthly delivery:** $_____/kW-month.

B. Charges for Subtransmisison Service: For Network Integration Transmission Service provided during the period January 1, _____ through December 31, _____, the Transmission Customer shall compensate the Transmission Provider each month for the use of the Transmission Provider's Subtransmission Facilities (voltage levels at 44/46 kV) at the applicable charges set forth below:

1) **Yearly delivery:** $_____ /kW-year.

2) **Monthly delivery:** $_____/kW-month.

EXHIBIT D

FORM OF INFORMATIONAL SCHEDULE D

Charges for Recovery of the FERC Annual Charge and Attachment K Costs

For service provided during the period October 1, _____ through September 30, _____, the Transmission Customer shall compensate the Transmission Provider each month for: (i) the FERC Annual Charge at the following Charge Factor(s) provided by the Federal Energy Regulatory Commission in its invoices to the Transmission Provider:

Charge Factor: $_____/MWh for energy deliveries per month;

Charge Factor (if more than one Charge Factor is set forth on the invoices from FERC): $_____/MWh for energy deliveries per month;

and (ii) the Transmission Provider's costs for the prior calendar year in implementing its requirements, duties, and activities under Attachment K, the Southeastern Regional Transmission Planning Process:

Charge Factor: $_____/MWh for energy deliveries per month.

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112 FERC ¶61,355
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Joseph T. Kelliher, Chairman;
Nora Mead Brownell, and Suedeen G. Kelly.

Southwest Power Pool, Inc. Docket No. ER05-1285-000

ORDER ON PROPOSED TARIFF REVISIONS

(Issued September 30, 2005)

1. In this order, the Commission accepts, as modified, Southwest Power Pool, Inc.'s (SPP) proposed changes to its open access transmission tariff (Tariff) to modify the definition of Transmission Facilities. The Commission also accepts SPP's proposed Tariff revisions to satisfy the Commission's requirements that SPP: (1) provide for the distribution of revenue between multiple entities owning transmission facilities in a single zone, and (2) eliminate multiple scheduling charges (pancaked rates) for a single reservation or transaction.[1]

I. Background

2. SPP is an approved regional transmission organization (RTO)[2] and submits the proposed Tariff revisions under section 205 of the Federal Power Act (FPA)[3] in response to Commission orders addressing SPP's RTO application. SPP files three sets of revisions to its Tariff: (1) to modify the definition of Transmission Facilities by adding a new Attachment AI and revising the Definitions section; (2) to revise Attachment L to provide for the distribution of revenue between multiple entities owning transmission facilities in a single zone (sometimes referred to as compensation for customer-owned transmission facilities); and (3) to revise Schedule 1 (Scheduling, System Control and Dispatch Service) to eliminate assessment of multiple scheduling charges for a single reservation or transaction and to revise Attachment L (Treatment of Revenues) to provide

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[1] *Southwest Power Pool*, 106 FERC ¶ 61,110 at P 115, 156 (February 10 Order), *order on reh'g*, 109 FERC ¶ 61,010 at P 53, 103 (2004); *Southwest Power Pool, Inc.*, 108 FERC ¶ 61,003 (July 2 Order) (2004), *order on reh'g*, 110 FERC 61,138 (2005).

[2] *Southwest Power Pool, Inc.*, 109 FERC ¶ 61,009 (2004), *order on reh'g*, 110 FERC ¶ 61,137 (2005).

[3] 16 U.S.C. § 824d (2000).

for the allocation of scheduling revenue under the new rate design.[4] Regarding the modifications to the definition of Transmission Facilities, SPP states that the proposed changes provide a uniform basis for the: application of formula rates; exercise of functional control of the transmission system; planning and expansion of the transmission system; compensation of new Transmission Owners; three-year period to apply the seven-factor test, if requested, for deviations from the bright line definition.

3. SPP states that each of the revisions was developed through SPP's stakeholder process, with initial responsibility for developing the proposed revisions assigned to SPP's Regional Tariff Working Group (RTWG). As of July 7, 2005, the RTWG had approved the proposed revisions to the Definitions section of SPP's Tariff, Schedule 1, Attachment L, as well as the new Attachment AI. The RTWG then forwarded each of the proposed revisions to SPP's Markets and Operations Policy Committee (MOPC) for further review. MOPC directed the SPP Regional State Committee (RSC) to review the definition of transmission. No official vote was taken by the RSC, but no individual RSC members expressed opposition. MOPC then sent a recommendation to the SPP Board that the revisions be approved. Finally, SPP explains that the SPP Board modified the MOPC-approved definition as described below. SPP maintains, however, that all of the material revisions have been thoroughly vetted through the SPP stakeholder process.[5]

4. SPP requests an effective date of October 1, 2005, for the revised Schedule 1, Attachment L, and section IV of Attachment AI. SPP further requests that the revisions to the Definitions section and sections I, II, and III of Attachment AI become effective when SPP files its formula rates or otherwise notifies the Commission.

II. Notice of Filing and Responsive Pleadings

5. Notice of SPP's August 2, 2005 filing was published in the *Federal Register*, 70 Fed. Reg. 48,117 (2005), with interventions, comments, and protests due on or before August 23, 2005. The Louisiana Public Service Commission filed a notice of intervention. Timely interventions were filed by: Westar Energy, Inc. and Kansas Gas and Electric Company; The City, Water, and Light Plant of Jonesboro, Arkansas; Kansas City Power & Light Company; and Oklahoma Gas & Electric Company. Timely interventions and comments were filed by: American Electric Power Service Corporation (AEP); Lafayette Utilities Systems (Lafayette); and Midwest Energy, Inc. (Midwest Energy). Timely interventions and protests were filed by The City of Independence, Missouri, Oklahoma Municipal Power Authority and West Texas Municipal Power Agency (collectively, TDU Intervenors); East Texas Electric Cooperative, Inc., Northeast Texas Electric Cooperative, Inc., and Tex-La Electric

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[4] Transmittal letter at 11.

[5] *Id.* at 2-3.

Cooperative of Texas, Inc. (collectively, East Texas Cooperatives); Empire District Electric Company (Empire); and Golden Spread Electric Cooperative, Inc. (Golden Spread).

6. Kansas Municipal Utilities filed a motion to intervene out of time. Xcel Energy Services, Inc. on behalf of Southwestern Public Service Company (Southwestern Public Service) (collectively, Xcel), filed a motion to intervene and protest out of time.

7. SPP and TDU Intervenors filed answers. Lafayette filed an answer to SPP's answer. SPP filed an answer to Lafayette's answer.

III. Discussion

A. Procedural Matters

8. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2005), the notice of intervention and timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Further, we find good cause to grant the motions to intervene out of time because they do not prejudice any party or cause undue delay in the proceeding.

9. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2005), prohibits answers to protests and answers to answers unless otherwise ordered by the decisional authority. We will accept SPP's, TDU Intervenors' and Lafayette's answers because they have provided information that assisted us in our decision-making process.

B. Definition of Transmission Facilities and Attachment AI

10. SPP proposes to revise the Definitions section and add a new Attachment AI setting forth the definition of Transmission Facilities to be used by SPP to provide transmission service under its Tariff. The proposal is the product of SPP's stakeholder process regarding the definition of transmission, with two exceptions. The SPP Board added the word "existing" to the first sentence of the first paragraph of section II of Attachment AI. The SPP Board also added the following sentence, "All facilities operated at 60 [kilovolt (kV)] and above constructed after October 1, 2005 would be included" to this same paragraph. The inserted language is shown underlined immediately below.[6]

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[6] Transmittal letter at 3.

> All existing non-radial power lines, substations, and associated facilities operated at 60 kV or above, plus all radial lines and associated facilities operated at or above 60 kV that serve two or more eligible customers not Affiliates of each other. All facilities operated at 60 kV and above constructed after October 1, 2005 would be included.

11. Section II of Attachment AI then specifies that Transmission Facilities must include: (a) all facilities used to interconnect various internal zones to each other and that interconnect SPP with other surrounding entities; (b) control equipment and facilities to control and protect facilities qualifying as transmission facilities; (c) for substations connected to power lines qualified as Transmission Facilities, where power is transformed from a voltage higher than 60 kV to a voltage lower than 60 kV, facilities on the high voltage side of the transmission will be included with the exception of transformer isolation equipment; (d) portions of direct current interconnect with areas outside SPP's region (DC tie) that are owned by a Transmission Owner in the SPP region, including portions of the DC tie that operate below 60 kV; and (e) all facilities operated below 60 kV that have been determined to be transmission using the Commission's seven factor test.[7]

12. Section III of Attachment AI describes facilities that are not Transmission Facilities: (a) generator step-up transformers and generator leads; (b) radial lines from a generating station to a single substation or switching station on the Transmission System; and (c) direct assignment facilities.

13. Under section IV of Attachment AI, Transmission Owners shall file within three years from the Commission's acceptance of the new definition, requests based on Attachment AI criteria with appropriate regulatory authorities (or with SPP, if not subject to a regulatory authority) for a determination as to which facilities are Transmission Facilities. Transmission Owners must then use reasonable efforts to adjust the applicable transmission service rates as soon as possible after such a determination is made.

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[7] *See 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, FERC Stats. & Regs. ¶ 31,036 at 31,771, 31,981 (1996), *order on reh'g*, Order No. 888-A, 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 (1996), *aff'd in part sub nom. Transmission Access Policy Study Group v. FERC*, 225 F.3d 667 (D.C. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

14. Finally, SPP proposes to define "Affiliate" (a term that is used in the new definition of Transmission Facilities quoted above) as "with respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity." SPP states that the Commission previously approved similar definitions for "Affiliates" for other RTOs.[8] SPP proposes other minor revisions to the Definitions section in order to accommodate the new definitions of Transmission Facilities and Affiliate.

15. In summary, we will accept the revisions to the Definitions section and the new Attachment AI, as modified subject to the discussion below, and require a further compliance filing, in accordance with Order No. 614,[9] within 60 days.

1. <u>Issue - Adhering to Procedures Respecting the Stakeholder Process</u>

16. Empire and Xcel raise issues regarding the SPP Board's modification to the MOPC-approved definition of transmission facilities. Empire argues that the Commission should not defer to the SPP Board's revisions and should reject the SPP Board's modification, since it was not fully considered by the SPP stakeholders and is not supported by a broad consensus.[10] Similarly, Xcel asserts that the proposed definition was not vetted through the normal stakeholder process because the SPP Board "significantly and unilaterally modified the RTWG Definition adopted through the stakeholder process." Xcel asks that at minimum, the Commission require SPP to submit the revised definition to a stakeholder process before the definition is accepted.[11]

17. TDU Intervenors answer that Oklahoma Municipal Power Authority (OMPA), which was active throughout the stakeholder process on this issue, had sought inclusion of all facilities 60 kV and above in the definition of Transmission Facilities, but was outvoted in the various stakeholder working groups and committees (which are not subject to the balanced stakeholder representation requirements applicable to the SPP Members Committee). They say that OMPA submitted its minority position to the SPP

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[8] *See* Transmittal letter at 12, citing Midwest Independent Transmission System Operator, Inc. Open Access Transmission and Energy Markets Tariff at section 1.5 and New York ISO Tariff at section 1.0c.

[9] *Designation of Electric Rate Schedule Sheets*, Order No. 614, 65 Fed. Reg. 18,221, FERC Stats. and Regs. ¶ 31,096 (2000).

[10] Empire Protest at 5-6.

[11] Xcel Protest at 7.

Board for consideration.[12] The SPP Board adopted a compromise version, which is the version submitted to the Commission for acceptance. TDU Intervenors say that they support the version as a reasonable compromise by the SPP Board in exercising its independent judgment.

18. SPP answers that SPP's Board has the authority to "not only vote on recommendations by SPP committees but also to modify those recommendations as it did here." It also states that while SPP's Board typically prefers to rely on recommendations from its committees, the SPP Board used its independent judgment to resolve an issue regarding one of those recommendations.[13]

Commission Determination

19. Empire and Xcel's arguments do not persuade us that anything improper was done. The stakeholder process was extensive, involving all affected parties. It resulted in a compromise definition submitted for SPP Board approval, which was not universally supported. In response to a minority position presented to the SPP Board, the SPP Board forged a further compromise between the minority position and the MOPC-proposed definition, polled its Member Committee on the compromise position, and received an eight to six majority vote for its compromise definition. We also agree with SPP that the SPP Board has the authority to modify recommendations and exercised its independence in an appropriate manner, consistent with the Bylaws.[14]

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[12] TDU Intervenors Answer at 3. TDU Intervenors cite the posted minutes of the July 26, 2005 SPP Board meeting, when an informal straw vote was taken of the SPP Members Committee. The MOPC draft received a vote of 5 for, 7 against, and 2 abstentions, while OMPA's minority draft received a vote of 8 for, 4 against, and 2 abstentions. *See* SPP's Board Minutes, available at www.spp.org/publications/BOD0705.pdf

[13] SPP Answer at 3-4.

[14] SPP Bylaws section 4.1 states that:

> The Board of Directors shall solicit and consider a straw vote from the Members Committee as an indication of the level of consensus among Members in advance of taking any actions other than those occurring in executive session. See also, section 4.1 (h) which states "Act on appeals pursuant to section 3.10." Section 3.10 authorizes the SPP members to submit alternative recommendations to the Board if it disagrees with actions or recommendations by any Organizational Group.

2. Issue - Whether Umbrella and Joint Action Agencies Should Be Treated As Affiliates

20. AEP requests clarification that members of umbrella and joint action agencies should not be viewed as separate customers, but as the equivalent of affiliates. East Texas Cooperatives ask that the Commission reject AEP's request because the question was not raised in the stakeholder process and AEP's view is inconsistent with Commission precedent.[15] East Texas Cooperatives argue that no affiliate relationship exists between itself and its members, or between the members and their distribution cooperative members. Golden Spread is concerned that a facility could lose its designation as a transmission facility if two or more customers served by the facility, such as large end users or cooperatives, decide to merge.[16]

21. SPP answers that its definition is similar to previously approved definitions for "Affiliates" for other RTOs.[17]

Commission Determination

22. The clarification that AEP seeks conflicts with Order Nos. 888 and 888-A. In Order No. 888, we limited our requirement for non-public utilities to provide reciprocal open access transmission to corporate affiliates. We also stated: "[i]f a [generation and transmission] cooperative seeks open access transmission service from the transmission provider, then only the [generation and transmission] cooperative, and not its member distribution cooperatives, would be required to offer transmission service. However, if a member distribution cooperative itself receives transmission service from the transmission provider, then it (but not its [generation and transmission] cooperative) must offer reciprocal transmission service over its interstate transmission facilities."[18]

23. In Order No. 888-A, we did not view the generation and transmission cooperative and its distribution member to be a single economic unit for purposes of stranded cost

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[15] *Citing* Order No. 888-A at 30,366; *Avista Corp., et al.*, 96 FERC ¶ 61,058 at 61,173 (2001).

[16] AEP Comments at 5; East Texas Cooperatives Protest at 11-12; Golden Spread Protest at 6.

[17] *Supra* n.8.

[18] *See* Order No. 888 at 31,763.

recovery. Instead, we found that a generation and transmission cooperative seeking to recover stranded costs from a departing customer of a member distribution cooperative would in effect be seeking recovery of such costs from an indirect customer.[19]

24. We are not persuaded to view the relationship between generation and transmission cooperatives and their member cooperatives, or the member cooperatives and other member cooperatives, differently (*i.e.*, as affiliates) here. Accordingly, AEP's request to treat members of umbrella joint action agencies as corporate affiliates is refused.

25. SPP does not answer Golden Spread regarding the concern that a facility may lose its designation if two or more end-use customers decide to merge. We will require that SPP clarify the matter in its compliance filing.

3. Issue - Treatment of Radial Lines

26. Xcel and Golden Spread argue that the proposal fails to define radial lines. They also say that SPP's footprint includes some transmission lines that were constructed as looped facilities, but that have been operated as radials, through the opening of a circuit, for operational reasons, and ask how these would be treated.[20]

27. AEP requests clarification that existing radials serving less than two non-affiliated customers cannot become eligible for reclassification as transmission facilities simply by converting into looped configurations and thereby shifting significant costs. Alternatively, AEP asks the Commission to direct SPP to develop reliability criteria for such conversion in order to remove an incentive to shift costs.[21]

28. East Texas Cooperatives suggest that "existing" be removed from the definition because "existing" calls into question whether an existing radial or set of radials that is later looped in would be included as part of the transmission system. Without clarification, it is uncertain whether future loops would be eligible for cost sharing. If closed through, they will perform the same function as existing closed loops and will be indistinguishable from existing closed loops.[22]

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[19] *See* Order No. 888-A at 30,366. The Commission described an indirect customer as a customer of a wholesale requirements customer of the utility.

[20] Golden Spread Protest at 5; Xcel Protest at 9.

[21] AEP Comments at 4-5.

[22] East Texas Cooperatives Protest at 7-8.

29. TDU Intervenors advise the Commission to reject AEP's requested clarification barring reclassification of existing radial lines that become looped in the future. However, they welcome SPP's development and application of comprehensive criteria dealing with all aspects of reliability and ensuring service to all loads at comparable rates and with comparable reliability.[23]

30. SPP answers that the treatment of "open loops" was discussed at length during the RTWG's deliberation on this definition and it was decided that "open loops" would be considered radial lines. SPP also clarifies that if a future loop contains an existing radial, that existing radial would be eligible for inclusion in rates.[24]

Commission Determination

31. We find that the definition and SPP's subsequent clarification adequately address the parties' questions regarding "radial lines." We will require, however, that SPP modify its proposal to incorporate the clarifications in its Answer into the definition.

32. We note that not treating as Transmission Facilities lines normally operated as open is similar to treatment of facilities in ISO New England, Inc.[25] Regarding concerns raised by parties as to future development of radial lines into looped configurations, we note that SPP must perform regional transmission planning studies and seasonal assessments of the reliability and economic operation of the SPP Transmission System. We will rely on this independent process to identify existing radial lines that should be expanded into looped configurations and then treated as Transmission Facilities under the Tariff.

4. **Issue - Prior Determinations of Facilities**

33. Midwest Energy seeks clarification that SPP's new definition of Transmission Facilities does not require Transmission Owners to seek from their state commissions repetitive and duplicate determinations to satisfy the Commission's seven factor test. It proposes that the seven factor test not be required again for facilities that have already been determined under the seven factor test to meet the new definition of Transmission Facilities.[26]

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[23] TDU Intervenors Answer at 5.

[24] SPP Answer at 8.

[25] ISO New England Inc., FERC Electric Tariff No. 3, Open Access Transmission Tariff, section II.H. – Other Transmission Provisions, section II.49 – Definition of PTF, Original Sheet No. 610.

[26] Midwest Energy Comments at 2-3.

34. SPP responds that section IV of Attachment AI will apply only to facilities that have not previously been determined under the seven factor test to meet the definition of Transmission Facilities.[27]

Commission Determination

35. We accept SPP's clarification in response to Midwest Energy's concern and find that no modification to the language in section IV is necessary.

5. Issue - Classification of Facilities

36. Some parties argue that the proposed definition of Transmission Facilities inconsistently applies the Commission's seven factor test by requiring that it be applied to facilities below 60 kV but not to facilities at and above 60 kV.[28] They argue that the language inserted by the SPP Board, categorizing as transmission all facilities at and above 60 kV constructed after October 1, 2005, is not just and reasonable because it includes facilities that the SPP ordinarily excludes from its transmission plan.[29] Golden Spread states that such criteria, based on the date of construction, will likely lead to disputes over what constitutes "construction."[30]

37. Xcel and Golden Spread fault the proposal for excluding existing transmission facilities that were built to serve load while including identical facilities constructed after October 1, 2005 in the definition of Transmission Facilities. Golden Spread asserts that more than half of its delivery points are served from radial lines, yet most of these facilities have been considered part of the Southwestern Public Service transmission system. Similarly, Xcel states that Southwestern Public Service serves agricultural and energy production-related loads over a large geographical area with radial facilities and the related assets are a significant portion of the Southwestern Public Service system. Golden Spread asserts that if its radial lines were suddenly declared no longer to be part of the SPP transmission system, this would result in a cost shift, and Golden Spread's load would become entirely responsible for those facilities while still having to pay a share of the cost of similar facilities in SPP that serve other load.[31] Golden Spread also asserts that differing treatment of new and existing facilities creates incentives for

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[27] SPP Answer at 9-10.

[28] Golden Spread Protest at 5; Xcel Protest at 8; Empire Protest at 7-8.

[29] Empire Protest at 9; Xcel Protest at 8;Western Farmers Comments at 3.

[30] Golden Spread Protest at 6; Xcel Protest at 6-7.

[31] Golden Spread Protest at 3-4; Xcel Protest at 5.

Transmission Owners to discriminate by prioritizing construction of transmission upgrades to serve their own load ahead of upgrades that would serve their wholesale customers.[32]

38. In its Answer, SPP states that its proposed definition will only determine which existing facilities will be rolled in for cost sharing purposes. It is not meant to be the determinative test for future facilities, since under SPP's cost allocation plan, which was recently approved by the Commission, future facilities that operate at 60 kV or above must also be Base Plan Upgrades under section 1.3(h) of the SPP Tariff in order for their revenue requirements to be subsidized by the SPP transmission system.[33] SPP also clarifies that the construction will be deemed to be concluded when a facility is placed into commercial operation.

39. Regarding allegations that the proposal applies the Commission's seven factor test inconsistently, SPP answers that nothing in the filing is intended to preclude the submission of a request to the Commission or the appropriate state regulatory agency to classify or de-classify a facility operating at or above 60 kV as a Transmission Facility.[34]

40. Regarding comments that the proposal treats new and existing transmission facilities differently, SPP contends that the Commission has allowed different treatment of facilities that are already in existence. SPP cites the Commission's statement that, prior to turning functional control of their transmission facilities over to an independent operator, Transmission Owners made transmission investment decisions based on their own needs, not the needs of the region, and that such decisions were designed to minimize the cost of power, not the cost of transmission as a stand alone commodity.[35] In response to Golden Spread's assertion that transmission owners have incentives to discriminate by prioritizing construction of transmission upgrades, SPP states that SPP will determine which facilities need to be constructed, not the Transmission Owners. SPP concludes that its decision to treat existing facilities at 60 kV and above differently is consistent with Commission precedent and is just and reasonable.[36]

Commission Determination

41. We find that the sentence inserted by the SPP Board is inconsistent with SPP's expressed intent for Attachment AI to determine only which existing facilities will go

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[32] Golden Spread Protest at 6-7.

[33] *See* SPP Answer at 6.

[34] *Id.* at 7.

[35] *Citing New England Power Pool*, 83 FERC ¶ 61,045 at 61,237-39 n.76 (1998).

[36] SPP Answer at 6.

into transmission rates on a going forward basis, while deferring to the approved SPP Tariff section 1.3(h) for the rate treatment for future transmission upgrades. This is because SPP's proposed sentence appears to pre-judge the outcome of the section 1.3(h) process by stating that '[a]ll facilities operated at 60 kV and above constructed after October 1, 2005 would be included' even though it is possible that certain such facilities would not be included under section 1.3(h) because they are not Base Plan Upgrades. Accordingly, we direct SPP to revise this sentence to simply state that the rate treatment for transmission upgrades completed after October 1, 2005 will be determined pursuant to section 1.3(h).

42. We agree with SPP that the definition does not limit application of the Commission's seven factor test to facilities below 60 kV. SPP has explained that parties are not precluded from seeking determination from this Commission or state commissions regarding the status of any facilities. Lastly, we disagree with Golden Spread that the proposal permits discrimination in construction scheduling since defining facilities is different from construction scheduling. SPP has a SPP Board-approved RTO Transmission Expansion Plan process, and we expect any facilities constructed under the plan would be scheduled in a non-discriminatory manner consistent with Good Utility Practice, as defined in SPP's Tariff.

C. <u>Distribution of Revenue to Multiple Transmission Owners In a Single Zone</u>

43. SPP proposes amendments to Attachment L to comply with our requirement in the February 10 and July 2 Orders that it provide for the distribution of revenue between multiple entities owning transmission facilities in a single zone. Specifically, sections II and IV of Attachment L have been revised to allocate revenue for Network Integration Transmission Service (NITS), Point-To-Point (PTP) service, and Schedule 1 System Control and Dispatch services.

44. Revisions to section II govern the distribution of revenue for NITS. Additions to section II(A) preserve the rights of parties to Grandfathered Agreements by stating that nothing in Attachment L is intended to supersede or otherwise affect their rights. In addition, SPP proposes to distribute revenues associated with Grandfathered Agreements by reducing a transmission seller's owner-specific existing zonal annual revenue requirement (OEZRR) by the revenues associated with the Grandfathered Agreements to the extent that they are not already excluded from its OEZRR. Likewise, the OEZRR of a Transmission Owner who purchases NITS under a Grandfathered Agreement will have its OEZRR increased to reflect the purchase of services under the Grandfathered Agreement. Attachment L, section II (B)(2)(b).

45. New section II (B) governs the revenue distribution for NITS for single owner and multi-owner zones. In single owner zones, the Transmission Owner in the zone receives all revenue. For multi-owner zones, revenues will be distributed in proportion to the

respective share of the Transmission Owners' Existing Zonal Revenue Requirement (EZRR), adjusted for the Grandfathered Agreement revenue noted above. For a Transmission Owner that does not take NITS for its native load customers, section II (B)(2)(c) provides that SPP shall compute hypothetical NITS payments equal to the cost to serve its native load as if those customers paid for service under Schedule 9 (Network Integration Transmission Service). SPP will then compute the hypothetical payments, add any distributed Schedule 9 charges, and subtract the Transmission Owner's EZRR. If the amount is positive, the Transmission Owner will pay SPP this amount. If it is negative, SPP will pay the Transmission Owner.[37]

46. New section II (C) governs revenue distribution for PTP service. Where the source and sink are in a single zone, 50 percent of the revenue shall be distributed to the Transmission Owners in proportion to their EZRR. The other 50 percent shall be distributed to the Transmission Owners in proportion to the MW mile impacts incurred by each Transmission Owner.[38] For all other PTP services, 50 percent of the revenues will be distributed in proportion to their respective shares of the sum of the OEZRRs for all zones, and 50 percent in proportion to the MW mile impacts incurred by each Transmission Owner.

47. Lafayette states that it supports the multi-owner compensation provisions as a fair and reasonable compromise; however, it also asks that the Commission consider whether the scope of the revisions should be broader. Lafayette says that the proposal does not address the issue of establishing a new Transmission Owner as a separate pricing zone; rather it only deals with compensation for new Transmission Owners in an existing pricing zone. Lafayette says that this separate zone option is important to Lafayette because its ability to avail itself of the multi-owner revenue distribution option is doubtful. It cannot participate in the SPP, since SPP requires a direct electrical connection.

48. SPP answers that if Lafayette is able to transfer operational control of its transmission facilities to SPP, SPP will work with Lafayette to resolve its concerns.

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[37] These provisions apply to all zones except Zone 1, the AEP zone. AEP has a stated NITS rate rather than a rate calculated based on a load ratio share. If, however, a Transmission Owner establishes an OEZRR, under the proposal it will be entitled to receive revenue in a proportionate amount.

[38] Attachment S (Procedure For Calculation of MW-Mile Impacts for Use in Revenue Allocation and Determination of Losses) sets forth SPP's MW-mile methodology.

Commission Determination

49. We accept SPP's proposed changes to Attachment L, finding that they are just and reasonable and have not been shown to be unjust, unreasonable, unduly discriminatory, or preferential. Moreover, most parties urged Commission acceptance of the revisions. Further, we find the proposed revenue distribution procedures to be equitable because they will compensate Transmission Owners in a manner that attempts to match transmission use with a Transmission Owner's cost. Specifically, the proposal recognizes that all transmission use affects the costs for all Transmission Owners, and 50 percent of the revenue is distributed to all proportionally; the balance is then distributed based on the MW-Mile methodology, which reflects actual use of the system. Accordingly, we shall accept the revisions for filing.

50. Lafayette's concern regarding the scope of the revisions and its ability to participate fully in the SPP RTO is beyond the scope of this proceeding. However, we encourage Lafayette to pursue efforts to participate in the SPP RTO, and we encourage SPP to work with Lafayette to accomplish this. If Lafayette transfers operational control of its transmission facilities to SPP, the issue of whether a separate pricing zone is appropriate for Lafayette can then be addressed.

D. Removal of Pancaked Rates for Schedule 1 Charges

51. SPP proposes that for customers taking firm or non-firm PTP transmission service for through and out transactions, the Schedule 1 charge will be the product of the capacity reserved, expressed in megawatts (MW), and either the monthly, weekly, daily, or hourly rate for on-peak service or the daily or hourly rate for off-peak service.[39]

52. For customers taking firm or non-firm PTP transmission service for transactions into and within SPP's transmission system, the Schedule 1 charge will be the charge under the approved rate schedule of the zone that is the point of delivery. For customers taking NITS, the Schedule 1 charge will be the charge under the approved rate schedule of the zone in which the load is located.[40]

53. SPP further proposes a new Addendum 1 to Schedule 1 to provide that revenue from the provision of Schedule 1 service for customers taking firm or non-firm PTP transmission service for through and out transactions will be allocated to Transmission

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[39] Second Revised Sheet No. 94, Southwest Power Pool FERC Electric Tariff, Fourth Revised Volume No. 1.

[40] Second Revised Sheet No. 94, Southwest Power Pool FERC Electric Tariff, Fourth Revised Volume No. 1.

Owners in proportion to the respective scheduling revenue requirement of each such Transmission Owner. SPP used previously approved scheduling revenue requirement amounts and 2004 loads to develop the rates for through and out service in Schedule 1.[41]

54. SPP makes a corresponding modification to section 4 of Attachment L, Distribution of Other Revenues, to clarify the allocation of Schedule 1 revenues under the proposed rate design. Schedule 1 revenues for through and out transactions will be allocated to the providers of the service in proportion to the respective scheduling revenue requirement of each provider, as specified in Addendum 1 to Schedule 1.[42]

55. Finally, SPP proposes that Schedule 1 will continue to be applied only to customers taking service under Schedules 7, 8, and 9 and to exclude the bundled retail and bundled wholesale loads of the Transmission Owners service under section 39.[43]

Commission Determination

56. We find that SPP has complied with the Commission's directive to eliminate duplicative Schedule 1 charges, and we accept the amended Schedule 1 for filing.

57. This pricing will permit only one scheduling charge to be assessed for any particular reservation or schedule. Customers with transactions sinking within SPP will pay only one scheduling charge, that of the sink zone, at rates that have already been accepted or approved. Customers taking through or out service will pay only one scheduling charge, based on the average approved cost of all such providers within SPP. This design will minimize cost shifting by allowing each control area operator to continue to be compensated at a rate that reflects its particular costs of the required scheduling function. This design also preserves the choice made by some Transmission Owners not to have scheduling charges.

58. Finally, we find that the proposed language conforms with our policy that Transmission Owners, on behalf of their entire load, including grandfathered wholesale and bundled retail loads, take service under the non-rate terms and conditions in the SPP Tariff as a prerequisite for SPP obtaining RTO status.[44]

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[41] First Revised Sheet No. 94A, Southwest Power Pool FERC Electric Tariff, Fourth Revised Volume No. 1.

[42] Transmittal letter at 6.

[43] Transmittal letter at 12.

[44] February 10 Order at P 108.

E. Effective Dates

59. SPP requests an effective date of October 1, 2005, for the revised Schedule 1, Attachment L, and section IV of Attachment AI. It requests that the revisions to the Definitions section and sections I, II and III of Attachment AI become effective when SPP files formula rates or otherwise notifies the Commission. SPP states that this delayed effective date is to demonstrate that the proposed definition of Transmission Facilities is not intended to change currently effective rates or the scope of service provided and that it will provide time for the conversion of rates and services to conform to the new definitions. SPP says that it plans to file formula rates within the next six months and will rely on our acceptance of the new definitions in developing its rates.

60. Lafayette argues that SPP's request to make certain revisions effective at such time that SPP files formula rates or otherwise notifies the Commission is too vague and open-ended. It requests that SPP implement a more definite and specific approach to avoid future controversy. East Texas Cooperatives state that SPP's requested effective date may hinder their efforts to become new Transmission Owners in the near future because such acceptance would delay eligibility for compensation for the facilities turned over to SPP. East Texas Cooperatives ask the Commission to clarify that the proposed effective date will not prevent new companies from joining SPP as Transmission Owners until SPP files its formula rates. TDU Intervenors likewise request that the effective date apply to new Transmission Owners, effective October 1, 2005. TDU Intervenors and Lafayette also argue that the delay was not vetted with stakeholders.[45]

61. SPP clarifies that sections I, II, and III of Attachment AI will apply to new Transmission Owners as of October 1, 2005, but requests that they not apply to existing Transmission Owners until SPP files formula rates or otherwise notifies the Commission. SPP reiterates that the proposed revisions to the definition are not intended to change currently effective rates or the scope of services provided and that the conversion of rates and services to conform to the new definition will take some time.

Commission Determination

62. We will accept SPP's proposed revisions to Schedule 1, Attachment L, and section IV of Attachment AI to become effective October 1, 2005, as requested. We find that the proposed delayed implementation for sections I, II, and III of Attachment AI as clarified by SPP is reasonable, since the delay will not affect new Transmission Owners. We agree with SPP that the implementation of the definition is not intended to change

[45] Lafayette Comments at 10; East Texas Cooperatives Protest at 8-9; TDU Intervenors Protest at 5-10.

current rates and that conversion of the transmission rates will take some time. We also find that SPP's clarification renders moot TDU Intervenors' and Lafayette's concern that the delayed implementation was not vetted in the stakeholder process.

<u>The Commission orders</u>:

(A) The proposed revisions to the Schedule 1 and Attachment L are hereby accepted for filing.

(B) The proposed revisions to the Definitions section and the new Attachment AI, as modified, are accepted for filing.

(C) SPP must file, within 60 days of the date of this order, revised Tariff sheets to incorporate the modifications to the new Attachment AI.

By the Commission.

(S E A L)

Magalie R. Salas,
Secretary.