City of Los Angeles Department of Water and Power

2017 Reform of Electric Transmission Tariff and Electric Transmission Rates

General Manager's Certificate

May 4, 2017

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EXECUTIVE SUMMARY

On January 17, 2017, the Los Angeles Department of Water and Power ("LADWP") commenced a public-stakeholder process regarding proposed amendments to the wholesale-transmission rates and non-rate terms of LADWP's Open Access Transmission Tariff ("OATT"), DWP No. BP 01-017 (Aug. 14, 2014).[1]

LADWP posted a cost of service study ("COSS") performed by independent, third-party consultants, which assessed LADWP's costs for providing wholesale-electric transmission service. The COSS utilized LADWP's most recently available audited financial data from fiscal year 2014-15 (July 1, 2014 through June 30, 2015) and financial data from LADWP's General Ledger and other accounting databases to develop proposed rates that are consistent with traditional principles, process and procedures of cost-of-service ratemaking. The COSS was supplemented by testimony explaining the COSS and its results, and the COSS was supported by a functional analysis of LADWP's transmission and related facilities to determine the facilities classified for ratemaking purposes as transmission, consistent with FERC's Seven-Factor Test and *Mansfield* analyses.

LADWP also posted proposed amendments to the OATT's non-rate terms and conditions. The Federal Energy Regulatory Commission's ("FERC") *pro forma* OATT, FERC Order No. 1000 concerning regional planning and cost allocation, and FERC Order No. 764 concerning intra-hour scheduling, guided the proposed non-rate amendments to the OATT. On February 21, 2017, LADWP posted additional proposed OATT amendments that included the addition of network integration transmission service and generation redispatch provisions, incorporating real power losses (previously codified in business practices), and adding power factor requirements for non-synchronous generation to LADWP's Large Generator Interconnection Agreement and Large Generator Interconnection Procedures.

LADWP conducted five public stakeholder meetings addressing the COSS and OATT amendments, and responded to 372 stakeholder requests for information. LADWP received written stakeholder comments from Powerex Corporation, the Cities of Anaheim, Azusa, Banning, Colton, Pasadena and Riverside (Six Cities), and the Cities of Burbank and Glendale. LADWP appreciates the robust stakeholder participation and constructive stakeholder feedback during the process.

The General Manager's Certificate responds to stakeholders' comments and contains the General Manager's recommended OATT amendments.[2] The General Manager deems the undisputed portions of LADWP's proposed OATT amendments as accepted and supported by the record. The General Manager has also recommends changes to the proposed wholesale

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[1] The stakeholder process is set forth in LADWP's transmission business practice, "LADWP, Procedures for Public Participation in Tariff Changes for the Department of Water and Power of the City of Los Angeles, Version 1 (Mar. 7, 2016), https://www.oasis.oati.com/LDWP/LDWPdocs/Public_Participation_in_LADWP_Tariff_Revision_2016_3_7.pdf.

[2] The General Manager's Certificate (including its attachments) are available on the LADWP Open Access Same-Time Information System in the DWP Notices folder: https://www.oasis.oati.com/ldwp/index.html.

transmission rate and non-rate terms and conditions of the OATT upon consideration of stakeholders' comments. As noted below and discussed in detail in this General Manager's Certificate, the General Manager recommends changes to the COSS that are designed to better align the rate methodology with FERC precedent, and recommends changes to the non-rate terms and conditions of the OATT that are designed to better align the OATT with FERC precedent and industry practice.

<u>The General Manager's rate-related changes are summarized as follows:</u>

- **Rate Divisor**: Calculation of the rate divisor was moved from 12 Coincident Peaks ("CP") to 4 CP.
- **Capital Structure**: Moved from a hypothetical capital structure to actual.
- **Ancillary Services/Purchase Obligations**: Revised the purchase obligations from 99% to 95% confidence intervals for regulating reserves provided under ancillary service rate Schedules 3 and 10. Also, a 4 CP-rate divisor is used to re-calculate the purchase obligations and capacity charges for Schedules 3, 5, 6, and 10. LADWP's "VER study" and its application is consistent with FERC precedent. All power plants included in ancillary service rates generated energy and were capable of providing the indicated services during the test year.
- **Prepaid Energy Costs**: Prepaid energy and prepaid transmission costs were re-allocated between transmission and production functions to more closely mirror cost causation, and 13-month averages were used.
- **Receiving Stations**: Reallocated additional receiving station costs to distribution based on a correction to the allocation of the Valley transformer.
- **Scattergood Sales Tax**: Reassigned capitalized sales tax on Scattergood units 4-7 equipment from plant in service to Construction Work in Progress ("CWIP") since these units were not in service during the test period. The capitalized cost will remain in rate base as CWIP, but minor adjustments were made to depreciation, accumulated depreciation, and plant values used in the reactive power calculations.
- **Input/Formula Corrections**: Minor modeling corrections made with immaterial rate impact.

<u>The General Manager's non-rate related changes are summarized as follows:</u>

A. **Attachment C "Methodology to Assess Available Transfer Capability"**: Rewrote Attachment C to align with FERC *pro forma* and moved algorithms used to determine available transfer capability to a separate document as required by FERC.

B. **Attachment K "Transmission Planning Process"**: Cross-reference corrections to Attachment K. The initial proposal included a rewritten Attachment K based upon the requirements of FERC Order No. 1000 and incorporating WestConnect's regional transmission planning processes and the Western Interconnection's interregional transmission coordination procedures.

C. **Attachment L "Creditworthiness Procedure"**: Modified Attachment L to align with FERC *pro forma*.

D. **Attachment M "Large Generator Interconnection Procedures"**: Modified Attachment M to align with FERC *pro forma* and to address lessons learned from implementation. The initial proposal included the FERC *pro forma* Large Generation Interconnection Procedures.

E. **Interest**: Moved from not paying interest on deposited funds to paying interest at the FERC rate to align with FERC *pro forma*.

F. **Municipal Tax Exempt Bonds and Private Use Restrictions**: Point-to-Point transmission service provisions vary from *pro forma* due to concerns with public use restrictions associated with outstanding municipal bonds. However, changes provide Transmission Customers with additional flexibility in the use of transmission service in a manner consistent with Internal Revenue Service ("IRS") safe harbor rules.

The General Manager recommends that the OATT amendments become effective on the first day of the month, two months following the date of the Los Angeles City Council ("City Council") approval. However, to allow for software upgrades, process changes and training, Part III of the OATT, "Network Integration Transmission Service," and its associated definitions and Attachments are recommended to become effective by no later than February 1, 2019 following City Council approval.

The General Manager recognizes that transmission customers with rollover rights may not be able to comply with notice provisions set forth in the amended OATT as the OATT requires that notice be provided farther in advance than is required in the existing OATT. Accordingly, the General Manager finds that existing transmission service agreements with a rollover right at the time of effectiveness of the amended OATT may exercise their next rollover based on the existing notice rules. However, to ensure compliance with the IRS safe harbor provisions, which preserve the tax-exempt status of LADWP's outstanding municipal bonds, the transmission customer must meet the requirements applicable to new transmission service agreements under the amended OATT.

Table 1 summarizes LADWP's current OATT rates, the January 17, 2017 proposed OATT rates, and the proposed final rates recommended by the General Manager in the General Manager's Certificate.

Table 1: Summary of Wholesale Electric Transmission Rates Adopted by the General Manager and Recommended to the Board of Water and Power Commissioners and Los Angeles City Council

Rate Schedule	Rates Currently Effective ($/kw-month)	Rates Proposed, Jan.17, 2017 ($/kw-month)	Rates Proposed Final ($/kw-month)
Schedule 1 – Scheduling, System Control and Dispatch	$0.109	$0.147	$0.119
Schedule 2 – Reactive Supply and Voltage Control	$0.416	$0.220	$0.173

Table 1: Summary of Wholesale Electric Transmission Rates Adopted by the General Manager and Recommended to the Board of Water and Power Commissioners and Los Angeles City Council			
Rate Schedule	Rates Currently Effective ($/kw-month)	Rates Proposed, Jan.17, 2017 ($/kw-month)	Rates Proposed Final ($/kw-month)
Schedule 3 – Regulation and Frequency Response	$9.668 1.1% purchase obligation	$7.931 3.496% purchase obligation	$6.247 1.885% purchase obligation
Schedule 5 – Operating Reserve – Spinning Reserve	$7.84 6.4% purchase obligation	$12.849 6.0% purchase obligation	$10.218 4.874% purchase obligation
Schedule 6 – Operating Reserve – Supplemental Reserve	$0.865 5.3% purchase obligation	$2.965 6.0% purchase obligation	$2.325 4.874% purchase obligation
Schedules 7 & 8 – Long-Term Firm, Short-Term Firm, and Non-Firm Transmission	$3.749	$3.686	$2.936
Schedule 10 – Generator Regulation and Frequency Response	$9.688 6.5% purchase obligation (variable resources) 1.059% purchase obligation (dispatchable resources)	$7.931 9.278% purchase obligation (variable resources) 3.496% purchase obligation (dispatchable resources)	$6.247 6.627% purchase obligation (variable resources) 1.885% purchase obligation (dispatchable resources)

The General Manager finds based on the record developed in the stakeholder process that the 2017 OATT amendments, as adjusted in the General Manger's Certificate, establish rates, and terms and conditions of service that are comparable to those under which LADWP provides transmission services and ancillary services to itself and that are not unduly discriminatory or preferential. Accordingly, the General Manager certifies that the final proposed OATT amendment were developed using traditional principles, processes and procedures of cost-of-service rate making, and recommends that LADWP's Board of Water and Power Commissioners and the City Council approve the 2017 OATT amendments.

General Manager's Certificate

PART I: INTRODUCTION

Pursuant to Section 10(b) of the Procedures for Public Participation in Tariff Changes for the Department of Water and Power for the City of Los Angeles,[3] the General Manager of the Los Angeles Department of Water and Power ("LADWP") hereby certifies and provides the following statement with regard to the attached changes to LADWP's Open Access Transmission Tariff ("OATT") (collectively "Tariff Revisions," individually "Proposed Rates" and "Proposed Tariff).[4] Since LADWP initiated the process for Tariff Revisions on January 17, 2017, stakeholders have provided numerous written comments, submitted over one hundred data requests, and participated in several forums and technical conferences on the Tariff Revisions. LADWP appreciates the constructive feedback provided by stakeholders, and notes that multiple stakeholder comments have now been incorporated into the Proposed Tariff. Specifically, the attached Tariff Revisions include the following changes to earlier drafts of the OATT provided to stakeholders on January 17, 2017 and February 21, 2017:

- **Rates:**
  - Rate Divisor of four Coincident Peaks ("CP")
  - Actual Capital Structure
  - Purchase obligation for ancillary services recalculated at four CP and a 95th percentile confidence interval
  - Pre-Paid Energy and Transmission Cost Corrections
  - Revised Scattergood gross plant in service and corresponding Scattergood Construction Work in Progress ("CWIP") balance
  - Revised Receiving station allocation percentages
  - Miscellaneous corrections
- **Non-Rate Terms and Conditions:**
  - Attachment C moved to *pro forma* OATT
  - Real Power Losses study commenced
  - Interest payment moved to *pro forma* OATT
  - Support 15-minute scheduling on Pacific DC Intertie

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[3] LADWP, Procedures for Public Participation in Tariff Changes for the Department of Water and Power of the City of Los Angeles, Version 1 (Mar. 7, 2016), https://www.oasis.oati.com/LDWP/LDWPdocs/Public_Participation_in_LADWP_Tariff_Revision_2016_3_7.pdf ("Public Participation Business Practices").

[4] Per § 10(b) of the Public Participation Business Practices, it is required that if the General Manager concludes that new tariff rates or terms should be put into effect by LADWP's Governance, the General Manager must issue a "statement setting forth the principal factors on which the General Manager's decision was based. The statement shall include an explanation responding to the major comments, criticisms, and alternatives offered during the comment period." The General Manager is also required to "certify that the rates of the Tariff Proposal were developed using traditional principles, processes and procedures of cost-of-service rate making." *Id.* [hereinafter, collectively, "General Manager's Certificate"].

- Addressed Six Cities[5] requests
- Attachment L moved to *pro forma* OATT
- Attachment M moved to *pro forma* OATT

The General Manager certifies that the Tariff Revisions were developed using traditional principles, processes and procedures of cost-of-service rate making, and recommends that the Board of Water and Power Commissioners ("Board") of LADWP and the Los Angeles City Council ("City Council") accept the Tariff Revisions as revised below.

PART II: BACKGROUND

A. Authority of the Board of Water and Power Commissioners and the City of Los Angeles to Establish LADWP's OATT Rates and Terms and Conditions of Service.

The City of Los Angeles is a municipal corporation and charter city organized under provisions of the California Constitution. LADWP is a proprietary department of the City of Los Angeles that operates a municipal utility and owns extensive electricity generation, distribution, and transmission assets both within and outside of the State of California.[6] LADWP's primary purpose is to provide reliable electricity service to LADWP's native load customers.[7]

LADWP is governed by a five-member Board. The Board has the power and duty to make and enforce all necessary rules and regulations governing the construction, maintenance, operation, connection to, and use of LADWP's Water and Power Assets.[8] Los Angeles Administrative Code ("LAAC") Section 23.134 authorizes the Board "to establish and set all tariffs, terms, conditions and charges, subject to approval by a simple majority vote of the City Council."[9]

The proposed Tariff Revisions, if approved, would govern the operation of LADWP's facilities used in "the transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce."[10] The transmission services and rates set forth in the OATT and the proposed Tariff Revisions would be FERC-jurisdictional, absent LADWP's status as non-jurisdictional or non-public utility under the Federal Power Act

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[5] The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (collectively, the "Six Cities").

[6] Los Angeles City Charter §§ 600-601 ("City Charter").

[7] *Id.*

[8] *Id.* §§ 672, 675.

[9] LAAC § 23.134 states "Notwithstanding any other ordinance, rule or law of the City of Los Angeles to the contrary, the Board of Water and Power Commissioners shall have authority to establish and set all tariffs, terms, conditions and charges, subject to approval by a simple majority vote of the City Council, which relate to transmission services which would otherwise fall within the jurisdiction of the Federal Energy Regulatory Commission, or when necessary to avoid the exercise of the jurisdiction of the Federal Regulatory Commission under Section 211 of the Federal Power Act."

[10] 16 U.S.C. § 824(a).

("FPA").[11] As a non-public utility under the FPA, LADWP is responsible for establishing its own rates, terms, and conditions of service, but the FPA requires that LADWP's OATT ensures that third-party customers are treated comparably to LADWP and that its actions are not unduly discriminatory or preferential.[12] However, LADWP is not required to file its rate schedules at the Federal Energy Regulatory Commission ("FERC" or "Commission") under Section 205's "just and reasonable standard" of review. Section 10(b) of the Public Participation Business Practices requires the General Manager to "certify that the rates of the Tariff Proposal were developed using traditional principles, processes and procedures of cost-of-service rate making." The body of reported FERC orders and opinions constitutes the most significant publicly available source of the "traditional principles, processes and procedures of cost-of-service rate making" with respect to wholesale transmission and ancillary services and is therefore used as a reference point for the General Manager's Certificate throughout this document. Citations to FERC precedent are not intended to suggest or imply that LADWP is subject to Section 205 or 206 of the FPA, or the precedent established under the "just and reasonable" statutory language contained therein.

As discussed in more detail below, LADWP's proposed Tariff Revisions reflect rates that were developed using traditional principles, processes and procedures of cost-of-service rate making, and provide for service to OATT customers on a comparable and not unduly discriminatory or preferential basis.

B. <u>Development of the Proposed Tariff Revisions</u>

LADWP has adopted transmission business practices for the development of tariff changes.[13] The attached Tariff Revisions were developed following the process set forth in the Public Participation Business Practices for a "Major Rate Adjustment" and a "Major Tariff Change." That process, and LADWP's adherence to it, is described below.

1. Advance Announcement of Major Rate Adjustment or Major Tariff Change[14]

Prior to the actual release of Major Rate Adjustments or Major Tariff Changes, the Public Participation Business Practices require LADWP to issue an advance announcement containing "pertinent and reasonably detailed information relevant to the Rate Adjustment and/or Major Tariff Change" through, at a minimum, posting on the open access same-time information

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[11] *Id.* § 824(f).

[12] FPA § 211, 16 U.S.C. § 824j-1(b) ("[T]he Commission may, by rule or order, require an unregulated transmitting utility to provide transmission services-- (1) at rates that are comparable to those that the unregulated transmitting utility charges itself; and (2) on terms and conditions (not relating to rates) that are comparable to those under which the unregulated transmitting utility provides transmission services to itself and that are not unduly discriminatory or preferential.").

[13] *See* Public Participation Business Practices.

[14] *Id.* § 3.

system ("OASIS") and direct e-mail contact with stakeholders.[15] The advance announcement provides stakeholders with an independent opportunity to comment, separate from the comment process discussed below.

LADWP issued its advance announcement on January 3, 2017, noting its intent to consider revisions to its OATT, including rates for transmission and ancillary services.[16] The announcement included a proposed timeline for certifying and approving Tariff Revisions, and indicated to stakeholders how to subscribe to e-mail notifications and/or register contact information with LADWP.

2. Notice of Proposed Rates or Proposed Tariff Change[17]

The Public Participation Business Practices require that the General Manager provide notice to stakeholders, including identifying the Proposed Rates or Proposed Tariff, providing clean and marked versions of the revisions, explaining the need for and derivation of the Proposed Rates or Proposed Tariff, information on posting and viewing documents used to develop the Proposed Rates or Proposed Tariff, information on initially scheduled public forums, and noting where and how to submit written comments or requests to be informed of LADWP actions. LADWP also must provide stakeholders with copies of principal documents, in native formats if possible, used to develop the Proposed Rates.

LADWP issued its Notice of Proposed Tariff Changes on January 17, 2017.[18] Consistent with the Public Participation Business Practices, the January 17 Proposal identified and discussed in detail the specific rates, terms, and conditions for which revisions were being contemplated. The January 17 Proposal included clean and redline versions of the LADWP OATT, the Cost of Service Study ("COSS") (including exhibits and testimony), and information to obtain both Internet and physical access to documents ("January 17 Proposal").[19] As discussed further in II.B.3 below, LADWP also included within the January 17 Proposal a schedule including two public information forums, two public comment forums, and proposed dates for data requests and informal discovery, as well as proposed dates for consideration by the LADWP General Manager, LADWP Board, and the City Council ("Procedural Schedule"). In accordance with the Procedural Schedule, on February 21, 2017, LADWP posted additional Major Tariff Changes ("February 21 Proposal").

3. Public Information Forums[20]

The Public Participation Business Practices specify that LADWP hold at least one public information forum, in which LADWP presents its Proposed Rates or Proposed Tariff to stakeholders, for Major Rate Adjustments and Major Tariff Changes. The first such forum must be held within 15 business days of LADWP giving notice to stakeholders of the proposed rate or tariff changes. LADWP has the discretion to set the number, dates, and locations of such forums

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[15] *Id.*

[16] LADWP, Advance Announcement of Major Tariff Change and Rate Adjustments (Jan. 3, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/2017_01_03_advanced_announcement.pdf ("January 3 Notice").

based upon anticipated or demonstrated interest, with notice due no later than 10 business days in advance of such forums. Questions raised at a public information forum must be answered by LADWP no later than 10 business days before the end of the consultation and comment period (with certain questions that are data-intensive or involve proprietary information requiring non-disclosure agreements, or an opportunity for in-person review at LADWP's offices). All such forums must be transcribed or recorded; additionally, documents introduced, as well as questions and written answers, must be posted on the Internet.

As provided in its January 3 Notice, LADWP's first public information forum was held on January 25, 2017 ("January 25 Public Information Forum"),[21] within 15 business days of the January 17 Proposal. During that forum, as specified in the agenda which was released on January 23, 2017, LADWP introduced the COSS Model and results as well as an overview of the Proposed Tariff.[22] Following these topics, the forum included question-and-answer sessions on both the COSS Model and the Proposed Tariff. A transcript for the January 25 Public Information Forum has been posted on LADWP's OASIS site.[23]

LADWP also held a second public information forum on March 8, 2017 ("March 8 Public Information Forum").[24] Presentations from LADWP,[25] and both Burbank Water and

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[17] Public Participation Business Practices § 4.

[18] Letter from David H. Wright, LADWP – General Manager, to Customers and Stakeholders (Jan. 17, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/LADWP_COSS_OATT_2017_REVISION_TRANSMITTAL_LETTER.pdf.

[19] All materials referenced in the January 17 Proposal are available at https://www.oasis.oati.com/ldwp/index.html, under DWP Notices > LADWP 2017 OATT Stakeholder Process > 2017 01 17 COSS OATT Letter and Appendixes.

[20] Public Participation Business Practices § 6.

[21] *See* LADWP, Recording Report Open Access Transmission Tariff (OATT) Stakeholder Meeting Agenda (Jan. 25, 2017) ("January 25 Transcript"), https://www.oasis.oati.com/LDWP/LDWPdocs/1_25_17_OATT_STAKEHOLDER_MEETING_TRANSCRIPTION.pdf

[22] LADWP, Open Access Transmission Tariff Stakeholder Forum 1 Meeting Agenda for January 25, 2017, at 2 (Jan. 23, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Stakeholder_Meeting_Agenda_Jan_23_2017.pdf.

[23] *See* January 25 Transcript.

[24] LADWP, Open Access Transmission Tariff Stakeholder Information Forum #2 Meeting Agenda (Mar. 8, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Stakeholder_Public_Information_Forum_No.2_Meeting_Agenda_March_8,_2017.pdf.

[25] LADWP, Public Information Forum #2 Presentation (Mar. 8, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/LADWP_OATT_Public_Information_Forum_2.pdf.

Power ("Burbank") and Glendale Water and Power ("Glendale")[26] are posted on LADWP's OASIS, as well as a transcript.[27]

4. Public Comment Forums[28]

The Public Participation Business Practices specify that at least one public comment forum (in which stakeholders present views, data, and arguments to LADWP) will be held for Major Rate Adjustments and Major Tariff Changes. LADWP has the discretion to set the number, dates, and locations of such forums based upon anticipated or demonstrated interest, with notice no later than 15 business days in advance of such forums. At the forums, LADWP representatives have an opportunity to engage in a dialogue with stakeholders. All such forums are transcribed or recorded.

LADWP held two public comment forums, the first on February 15, 2017[29] and the second on March 23, 2017.[30] Both forums were announced over 15 business days in advance. The March 23 Public Comment Forum was initially scheduled for March 9, but was rescheduled for March 23 based upon the request of stakeholders Glendale and Burbank. No stakeholder objected to this schedule change. Transcripts of both public comment forums are available on LADWP's OASIS site.[31]

5. Technical Conference

Although not specifically required by the Public Participation Business Practices, in addition to the public information and public comment forums noted above, LADWP held a

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[26] Burbank Water and Power & Glendale Water and Power, Preliminary Findings of BWP and GWP Regarding LADWP's 2017 Revisions to Its Open Access Transmission Tariff Presentation (Mar. 8, 2017) ("March 8 Presentation"), https://www.oasis.oati.com/LDWP/LDWPdocs/BWP-GWP_-_Presentation_for_3-8-17_final.pdf.

[27] LADWP, Recording Report Open Access Transmission Tariff (OATT) Stakeholder Meeting (Mar. 8, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/2017_3_8_OATT_STAKEHOLDER_MEETING_TRANSCRIPTION.pdf.

[28] Public Participation Business Practices § 7.

[29] LADWP, Open Access Transmission Tariff Stakeholder Public Comment Forum #1 Meeting Agenda (Feb. 15, 2017) ("February 15 Public Comment Forum"), https://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Stakeholder_Comment_Forum_No.1_Meeting_Agenda_February_15,_2017.pdf.

[30] LADWP, Open Access Transmission Tariff Stakeholder Public Comment Forum #2 Meeting Agenda (Mar. 23, 2017), ("March 23 Public Comment Forum"), https://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Stakeholder_Technical_Comment_Forum_No.2_Meeting_Agenda_March_23,_2017.pdf.

[31] LADWP, Recording Report Open Access Transmission Tariff (OATT) Stakeholder Meeting (Feb. 15, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/2017_2_15_OATT_STAKEHOLDER_MEETING_TRANSCRIPTION.pdf; LADWP, Recording Report Open Access Transmission Tariff (OATT) Stakeholder Meeting (Mar. 23, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/2017_3_23_OATT_STAKEHOLDER_MEETING_TRANSCRIPTION.pdf.

technical conference on the Tariff Revisions on February 10, 2017.[32] This was done at the request of Burbank and Glendale. The technical conference specifically offered stakeholders the opportunity to ask questions and provide comments relating to the COSS Model, which was used to compute the Proposed Rates. Stakeholders could also ask questions and provide comments on the Proposed Tariff. A transcript of this technical conference has been posted on LADWP's OASIS site.[33]

6. Consultation and Comment Period[34]

The Public Participation Business Practices specify that stakeholders must be able to consult with and obtain information from LADWP, examine backup data, and suggest revisions to proposed Major Rate Adjustments or Major Tariff Changes for:

- at least 45 days after the Public Information Forum;
- at least 15 days after any answer is provided by LADWP to stakeholders regarding questions raised at a public information forum; and
- at least 15 days after the close of the last public forum.

LADWP's Procedural Schedule for the Tariff Revisions adhered to these requirements for consultation and comment, including informal discovery via data requests.[35] Following the initial January 25 Public Information Forum was an initial stakeholder comment date of April 7, 2017 (more than the requisite 45 days). Based upon stakeholder feedback from Burbank and Glendale the comment date was extended until April 14, 2017.[36] LADWP's final responses to questions raised at the public information forums, as well as its final responses to data requests, were completed on a rolling basis with the final responses issued on March 31, 2017. This date was extended from the originally proposed March 24, 2017, based upon stakeholder requests from Burbank and Glendale.[37] LADWP met this deadline,[38] and the March 31, 2017 date for LADWP's responses fell within the required 15 days before the final stakeholder comment date of April 14, 2017. Additionally, the final public forum in the OATT revision process was a

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[32] LADWP, Open Access Transmission Tariff Stakeholder Technical Conference Meeting Agenda (Feb. 10, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/OATT_Stakeholder_Technical_Conference_Meeting_Agenda_February_10,_2017.pdf.

[33] LADWP, Recording Report Open Access Transmission Tariff (OATT) Stakeholder Meeting (Feb. 10, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/2017_2_10_OATT_STAKEHOLDER_MEETING_TRANSCRIPTION.pdf.

[34] Public Participation Business Practices § 5.

[35] January 17 Proposal at 3-17; LADWP Revised Schedule Updated March 7, 2017, ("March 7 Revised Schedule") http://www.oatioasis.com/LDWP/LDWPdocs/Revised_Schedule_%2803.07.2017%29_v2.pdf .

[36] March 7 Revised Schedule at 2.

[37] *Id.*. at 1-2.

[38] LADWP, Response to Data Request (Mar. 31, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/Response_to_Data_Request_-_3.31.17.pdf ("March 31 Response").

public comment forum, held on March 23, 2017—again, more than 15 days before the April 14, 2017 stakeholder comment deadline.

During the consultation and comment period, LADWP received discovery requests from Burbank and Glendale. Burbank and Glendale submitted 135 data requests, many of which included sub-sections, bringing the total to 372 individual requests for information ("Data Requests"):[39] i.e.,

- Burbank and Glendale Data Request 1: Received February 1, 2017 – Questions 1 through 29;
- Burbank and Glendale Data Request 2: Received February 14, 2017 – Questions 30 through 46;
- Burbank and Glendale Data Request 3: Received February 17, 2017 – Questions 47 through 65;
- Burbank and Glendale Data Request 4: Received February 24, 2017 – Questions 66 through 88;
- Burbank and Glendale Data Request 5: Received March 8, 2017 – Questions 89 through 121;
- Burbank and Glendale Data Request 6: Received March 17, 2017 – Questions 122 through 132; and
- Burbank and Glendale Data Request 7: Received March 21, 2017 – Questions 133 through 135.

No other stakeholder submitted data requests. As noted above, the Public Participation Business Practices required LADWP to respond to data requests by March 31, 2017, which LADWP satisfied for all Data Requests. Additionally, LADWP went beyond this requirement for many of the Data Requests by responding well in advance of the March 31 deadline. By using best efforts to respond to Data Requests on a rolling basis rather than waiting until the March 31 deadline, LADWP emphasized its commitment to providing stakeholders with as much time as possible to consider the responses before the consultation and comment period ended.[40]

As of the close of stakeholder comments on April 14, 2017, LADWP received formal written comments from the following stakeholders:

- Powerex Corporation ("Powerex"),[41]
- Six Cities,[42] and
- Cities of Glendale and Burbank.[43]

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[39] *Id.*

[40] *See generally* January 25 Transcript.

[41] Powerex Comments on LADWP January 17, 2017 OATT Revisions (Mar. 3, 2017) ("Powerex Comments"), https://www.oasis.oati.com/LDWP/LDWPdocs/Powerex_LADWP_Jan_17_OATT_Revisions_Comments.pdf.

[42] Six Cities Comments (Mar. 23, 2017), http://www.oatioasis.com/LDWP/LDWPdocs/Six_Cities"_Comments_-_LADWP_OATT_Revisions_3-23-2017.pdf.

To provide additional time to consider the comments submitted by stakeholders, to the extent necessary, on April 19, 2017, LADWP extended the proposed date for the posting of the General Manager's Certificate from May 4, 2017 to May 11, 2017.[44]

C. Description of LADWP's Proposal

The attached Proposed Rates were submitted to ensure that LADWP's OATT rates are developed using traditional principles, processes, and procedures of cost-of-service ratemaking, and reflect the most recent, audited cost of providing OATT services. The Tariff Revisions were proposed in two stages, consisting of the January 17 Proposal and the February 21 Proposal. More detail on the derivation of the Proposed Rates is provided in the supporting testimony and exhibits, which are identified on Attachment A, and as summarized below.

1. January 17 Proposed Tariff Revisions

(a) Proposed Changes to Rates for Transmission and Ancillary Services

In developing the Proposed Rates identified in the January 17 Proposal, LADWP retained a team of consultants to develop cost of service rates for the transmission and ancillary services offered under Schedules 1, 2, 3, 5, 6, 7, 8, and 10 of the LADWP OATT using a historical test period corresponding to the July 1, 2014 through June 30, 2015 fiscal year ("Test Period"). The consultants utilized financial data from LADWP's General Ledger and other accounting databases to develop Proposed Rates that are consistent with traditional principles, processes and procedures of cost-of-service ratemaking. Specifically, witnesses David B. Cohen and Ed Lucero of Navigant Consulting, along with Thomas E. Washburn, Donna S. Painter, and Frederick F. Haddad, Jr. from nFront Consulting, have prepared and supported relevant cost of service Statements AA-BM for the Test Period, which are similar to the cost support that would be required of a jurisdictional utility under Section 35.13(h) of FERC's regulations.[45] These cost support statements are included in a workable Microsoft Excel file as Exhibit No. DWP-104.[46]

In addition to the Test Period financial data provided by LADWP, the cost of service Statements AA-BM prepared by witnesses Cohen, Lucero, Washburn, Painter, and Haddad Jr. also reflect the testimony and supporting exhibits of several additional consultants. Dr. David S. Habr of Habr Economics has provided testimony and exhibits[47] in support of the rate of return ("ROR") (Statement AV) to be applied to LADWP's rate base, including a return on equity ("ROE") determined using a discounted cash flow ("DCF") analysis performed in a manner

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[43] Brief of the Cities of Burbank California and Glendale, California Departments of Water and Power (Apr. 14, 2017) http://www.oatioasis.com/LDWP/LDWPdocs/BWP-GWP_Brief_4-14-17_FINAL_Redacted.pdf ("Glendale and Burbank Brief" or "April 14 Brief").

[44] LADWP Revised Schedule Updated Apr. 19, 2017, http://www.oatioasis.com/LDWP/LDWPdocs/Revised_Stakeholder_Schedule_(updated_04.19.17).pdf.

[45] 18 C.F.R. § 35.13(h) (2016).

[46] *See* Exh. No. DWP-100, *et seq*.

[47] Exh. No. DWP-200, *et seq*.

consistent with FERC's most recent guidance in litigated electric rate proceedings.[48] Nancy Heller Hughes, of NewGen Strategies and Solutions, LLC, performed a study of the mortality characteristics of LADWP's depreciable utility property to develop new depreciation rates.[49] Dan T. Stathos of Navigant Consulting provided testimony in support of utilizing the new depreciation rates determined by Ms. Hughes to calculate the depreciation expense to include in LADWP's proposed transmission and ancillary service rates instead of the actual Test Period accruals.[50] The new depreciation accruals from Ms. Hughes depreciation study are reflected in Statement AJ–New Rates in Exhibit No. DWP-104. Jennifer Tripp of nFront Consulting performed a functional analysis of LADWP's transmission and related facilities to determine which facilities should be classified for ratemaking purposes as transmission, consistent with FERC's Seven-Factor Test[51] and *Mansfield*[52] analyses.[53] The re-classification of assets pursuant to Ms. Tripp's functional analysis is reflected in the "7 Factor Summary" tab of Exhibit No. DWP-104. And Larry Riegle, of Navigant Consulting, provided testimony in support of continuing to use index-based pricing to settle energy and generator imbalance under Schedules 4 and 9 of the LADWP OATT, consistent with FERC precedent and the practice of other transmission providers in the Western Interconnection that are not participating in California Independent System Operator, Inc.'s ("CAISO") energy imbalance market.[54]

The January 17, 2017 Proposed Rates were reflected on the Statement BL tab of Exhibit No. DWP-104, and are summarized in Table 1, above. LADWP proposed to decrease its rate for transmission service under Schedules 7 and 8 and ancillary services provided under Schedules 2, 3, and 10 and increase the rates for ancillary service Schedules 1, 5, and 6.

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[48] *See Coakley v. Bangor-Hydro Elec. Co.*, Opinion No. 531, 147 FERC ¶ 61,234, *order on paper hearing*, Opinion No. 531-A, 149 FERC ¶ 61,032 (2014), *reh'g denied*, Opinion No. 531-B, 150 FERC ¶ 61,165 (2015), *vacated and remanded Emera Maine v. FERC*, ___ F.3d ___, Nos. 15-1118, *et al.*, 2017 WL 1364988 (D.C. Cir. Apr. 14, 2017); *Midcontinent Indep. Sys. Operator, Inc.*, Opinion No. 551, 156 FERC ¶ 61,234 (2016). LADWP notes that Opinion No. 531 was recently vacated and remanded by the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") in *Emera Maine v. FERC*. However, it was not vacated on grounds that are at issue in this proceeding, and FERC guidance on remand will not be available for some time.

[49] Exh. No. DWP-300, *et seq.*

[50] Exh. No. DWP-400, *et seq.*

[51] *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, 1991–1996 FERC Stats. & Regs., Regs. Preambles ¶ 31,036, at p. 31,771 (1996), *order on reh'g*, Order No. 888-A, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,048, *order on reh'g*, Order No. 888-B, 81 FERC ¶ 61,248 (1997), *reh'g denied*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in part and remanded in 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).

[52] *Mansfield Mun. Elec. Dep't*, Opinion No. 454, 97 FERC ¶ 61,134 (2001), *reh'g denied*, Opinion No. 454-A, 98 FERC ¶ 61,115 (2002).

[53] Exh. No. DWP-500, *et seq.*

[54] Exh. No. DWP-600, *et seq.*

(b) Proposed Revisions to the Non-Rate Terms and Conditions of the OATT

In addition to the Proposed Rates changes described above, in its January 17 Proposal, LADWP submitted a Proposed Tariff with a significant number of non-rate terms and conditions of the OATT, which are illustrated in the red-lined OATT attached hereto as Appendix A. This Proposed Tariff relies on guidance from FERC's *pro forma* OATT,[55] including modifications implemented by Order No. 1000's regional planning and cost allocation reforms[56] and Order No. 764's intra-hour scheduling requirements.[57] In all cases, LADWP's proposed revisions are intended to establish non-rate terms and conditions of service that are "comparable to those under which [LADWP] provides transmission services to itself and that are not unduly discriminatory or preferential," consistent with section 211A of the FPA.[58]

The Proposed Tariff also consolidates stand-alone tariff documents and business practices for ease of customer reference and for consistency with the *pro forma* OATT. The consolidated provisions include: (i) Attachment L–Creditworthiness Procedure (09.01.2014); (ii) Transmission Credit Policy Business Practice (08.18.2014); (iii) LADWP Transmission and Ancillary Service Rates (09.01.2014); (iv) Real Power Loss Factors (09.01.2014); (v) Attachment C–Methodology To Assess Available Transfer Capability (09.01.2014); (vi) Attachment E–Index of Point-To-Point Transmission Service Customers; (vii) Attachment K–Transmission Planning Process (09.01.2014); (viii) Generator Interconnection Agreement (January 2014); (ix) Large Generator Interconnection Procedures (08.14.2014); and (x) SP15 Prices for Loss Calculation (06.10.2015). These prior stand-alone documents will be cancelled as of the effective date of the Tariff Revisions, to the extent the documents are incorporated into the final OATT.

2. February 21, 2017 OATT Revisions

On February 21, 2017, LADWP proposed additional OATT sections that govern network integration transmission service ("NITS"), and include provisions for generator redispatch, incorporate language on real power losses (previously codified in business practices) into Schedules 4 and 9, and add power factor requirements for non-synchronous generation to

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[55] *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,241, *order on reh'g and clarification*, Order No. 890-A, 2006–2007 FERC Stats. & Regs., Regs. Preambles ¶ 31,261 (2007), *order on reh'g and clarification*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g and clarification*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009), *appeal vol. dismissed*, *Nat'l Rural Elec. Coop. Ass'n v. FERC* (D.C. Cir. No. 08-1278).

[56] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 2008–2013 FERC Stats & Regs., Regs. Preambles ¶ 31,323 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132, *order on reh'g and clarification*, Order No. 1000-B, 141 FERC ¶ 61,044 (2012), *aff'd sub nom. S.C. Pub. Serv. Auth. v. FERC*, 762 F.3d 41 (D.C. Cir. 2014).

[57] *Integration of Variable Energy Resources*, Order No. 764, 2008–2013 FERC Stats. & Regs., Regs. Preambles ¶ 31,331 (2012), *order on reh'g and clarification*, Order No. 764-A, 141 FERC ¶ 61,232 (2012), *order on reh'g and clarification*, Order No. 764-B, 144 FERC ¶ 61,222 (2013).

[58] 16 U.S.C. § 824j-1(b)(2).

LADWP's Large Generator Interconnection Agreement and Large Generator Interconnection Procedures. The February 21 Proposal is included in Attachment M.

The NITS provisions of the Proposed Tariff allow Network Customers to designate Network Resources and serve Network Load on LADWP's transmission system. Specifically, "[NITS] allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Native Load Customers."[59] Under the Proposed Tariff, Network Customers using NITS will not incur incremental charges to deliver energy purchases to Network Load, and LADWP will be required to designate loads and resources for its own native load in the same manner as other Network Customers.[60] This Proposed Tariff includes the necessary terms and conditions for NITS, including the application process and associated service and operating agreements, necessary Network Resource and Network Customer information, applicable real power loss factors, and required studies. Additionally, LADWP made corresponding revisions to its redispatch rules, given that NITS is closely tied to redispatch, as Network Customers agree to redispatch Network Resources if requested by the Transmission Provider on a least-cost, non-discriminatory basis.[61]

This Proposed Tariff more closely aligns LADWP's OATT with FERC's *pro forma* OATT.

3. Topics Excluded from These Revisions

The Tariff Revisions do not include small generator interconnection procedures or a standardized small generator interconnection agreement. LADWP has not received any requests for small generator interconnections to date. Nevertheless, LADWP is committed to offering these small generator interconnections at terms and conditions that are comparable and not unduly discriminatory or preferential. If any customer wishes to interconnect a small generator (less than 20 MW), LADWP urges any such customer to contact Jan Lukjaniec at (213) 367-2382 at LADWP to arrange for service.

PART III: DECISION ON RATE ISSUES RAISED IN STAKEHOLDER COMMENTS

This section discusses the rate aspects of LADWP's Tariff Revisions that are disputed by stakeholders, and the General Manager's decision on those matters. The undisputed rate portions of LADWP's Tariff Revisions are deemed accepted and supported by LADWP.

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[59] Preamble to Proposed § III, Network Integration Transmission Service (Feb. 21, 2017).

[60] Proposed § 28.2.

[61] Proposed § 30.5.

A. Rate Divisor

1. LADWP Proposal

LADWP used the average of the twelve coincident peak loads ("12 CP") during the Test Period as the denominator to develop the OATT transmission and ancillary service rates in the January 17 Proposal.[62] The average of LADWP's twelve monthly peaks during the Test Period (LADWP retail load plus long-term firm point-to-point reservations under the OATT) is 4,978 MW. The proposed use of 12 CP is consistent with the design of LADWP's existing OATT rates, and LADWP found that the continued use of 12 CP appropriately and accurately reflects the year-round diversity of system stresses and the relative contributions of LADWP retail native load and third-party users to the factors that drive system planning.

In response to Burbank and Glendale Data Request No. 27a, LADWP explained in detail its justification for its proposal to use 12 CP.[63] LADWP explained that, while LADWP is not subject to FPA section 205, the use of a 12 CP rate divisor is consistent with FERC precedent as applied to jurisdictional utilities. As FERC explained in Order No. 888:

> We are reaffirming the use of twelve monthly coincident peak (12-CP) allocation method because we believe the majority of utilities plan their systems to meet their twelve monthly peaks. Utilities that plan their systems to meet annual system peak . . . are free to file another method if they demonstrate that it reflects their transmission system planning.[64]

LADWP further noted that the Commission has also considered the entire operational realities of a utility on a fact-specific basis in deciding the appropriate divisor, and that the Commission's consideration of these operational realities has included an analysis of several statistical screens that were developed more than 30 years ago in the context of bundled wholesale service. These statistical screens have been applied to evaluate a utility's load profile to determine the appropriateness of 12 CP versus a seasonal or annual peak rate divisor and include: (1) the difference between the ratios of the average summer peak demand to the annual peak and the average of the off-peak demands to the annual peak ("On and Off Peak Test"); (2) the ratio of the minimum monthly peak to the annual peak ("Low to Annual Peak Test"); (3) the ratio of the average of the twelve monthly peaks to the annual peak ("Average to Annual Peak Test"); and (4) the number of times the peak demands in the non-summer months exceeds the peak demands in the summer months.[65]

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[62] Exh. No. DWP-104, Statement BB.

[63] March 31 Response at 35-36 (LADWP Response to Burbank and Glendale Data Request 27a).

[64] Order No. 888 at p. 31,736; *see also Consumers Energy Co.*, 86 FERC ¶ 63,004, at p. 65,034 (1999) (noting that this language in Order No. 888 "point[s] squarely in the direction of the use of the 12-CP for the load ratio share calculation"), *aff'd in relevant part*, 98 FERC ¶ 61,333 (2002).

[65] *See, e.g., Commonwealth Edison Co.*, 15 FERC ¶ 63,048, at pp. 65,196-99 (1981), *aff'd*, Opinion No. 165, 23 FERC ¶ 61,219 (1983); *Golden Spread Elec. Coop., Inc. v. Sw. Pub. Serv. Co.*, Opinion No. 501-A, 144 FERC ¶ 61,132, at PP 54-57 (2013). There are two variations of the fourth test: (i) the number of times the non-summer

LADWP acknowledged that, as applied to LADWP's loads during the Test Period,[66] these statistical screens, viewed in a vacuum, would suggest the use of a seasonal peak rate divisor. However, LADWP also explained that FERC has recognized that these load profile tests alone are not dispositive and are but one factor used to evaluate a utility's operational realities. Indeed, "the Commission has not established hard and fast rules for determining whether the . . . 12-CP allocation method is appropriate" and has instead looked to the "full range of a company's operating realities."[67] For instance, in *Entergy*, in recognition of the need to consider the full operating realities of a utility, the Commission rejected a proposal to shift the divisor from 12 CP to 4 CP, explaining that the fact that

> Entergy was and continues to be a summer peaking system does not by itself warrant a change to the current allocation methodology; every system peaks at one time or another during the course of a year, and that fact alone does not dictate the use of a particular allocation factor or mean that a 12 CP method is not appropriate.[68]

Accordingly, although the load-related screens tended to support the use of a seasonal peak rate divisor, LADWP also evaluated other operational realities and, on balance, found that the full spectrum and totality of LADWP's operating realities would support the use of a 12 CP divisor to develop OATT rates for both transmission and ancillary services.[69] In particular, LADWP explained that it had found the use of 12 CP to be appropriate because the operational realities of running a transmission system today are much different than they were when FERC adopted the statistical screens, and many of the specific operational realities associated with LADWP's system supported the use of 12 CP. Among other operational realities, LADWP explained that it no longer plans solely for native load, and its OATT Attachment K planning process requires it to engage in local, regional, and interregional planning based on third-party needs and to construct upgrades that require the availability of its system on a static, year-round basis. LADWP also explained that North American Electric Reliability Corporation ("NERC") standards require LADWP to plan for a variety of contingencies throughout the year other than just for peak periods. In addition, LADWP explained that its renewable energy capacity has significantly increased due to state renewable portfolio standard ("RPS") requirements, and that these substantial increases in the amount of renewable capacity scheduled into or directly interconnected with LADWP require a transmission system that is available on a year-round basis to deliver renewables and to provide ancillary services to integrate the renewables.

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monthly peak demand exceeds the summer monthly peak demand, and (ii) the number of times the non-summer monthly peak demand exceeds the summer monthly peak demand in the preceding year. *See Golden Spread*, Opinion No. 501-A, 144 FERC ¶ 61,132 at PP 54-57.

[66] Exh. No. DWP-104, Statement BB.

[67] *Golden Spread Elec. Coop., Inc. v. Sw. Pub. Serv. Co.*, Opinion No. 501, 123 FERC ¶ 61,047, at P 75 (2008), *on reh'g*, Opinion No. 501-A, 144 FERC ¶ 61,132.

[68] *La. Pub. Serv. Comm'n v. Entergy Servs., Inc.*, Opinion No. 480-A, 113 FERC ¶61,282, at P 92 (2005), *aff'd in part, La. Pub. Serv. Comm'n v. FERC*, 522 F.3d 378 (D.C. Cir. 2008).

[69] *See* March 31 Response at 35-36 (LADWP Response to Burbank and Glendale Data Request No. 27a).

2. Comments Received

In their March 8 presentation at the second Public Information Forum[70] and in the April 14 Brief, Burbank and Glendale argued that the use of 12 CP for calculating LADWP rates is not appropriate because LADWP failed three of the load-related screens that FERC has analyzed to determine whether 12 CP is appropriate. Specifically, Glendale and Burbank commented that LADWP failed the following tests:

- **Test No. 1:** On and Off Peak Test – This test first compares the average of the coincidental peaks in the months during the peak period as a percentage of the annual system peak. Second, it compares the average of the coincidental peaks in the non-peak months as a percentage of the annual system peak.[71] Glendale and Burbank note that a 12 CP allocation is considered appropriate where the difference between these two percentages is 19% or less.[72] According to Glendale and Burbank, LADWP's result is 38% and thus does not pass the threshold for a 12 CP system.[73]
- **Test No. 2:** Low to Annual Peak Test – Compares the lowest monthly peak as a percentage of the annual system peak.[74] A range of 66% or higher is considered indicative of a 12 CP system.[75] According to Glendale and Burbank, LADWP's result is 54% and thus does not pass the threshold for a 12 CP system.[76]
- **Test No. 3:** Average to Annual Peak Test – Compares the average of the twelve monthly peaks as a percentage of the annual system peak.[77] A range of 81% or higher is

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[70] March 8 Presentation at 8.

[71] Glendale and Burbank Brief at 9-10.

[72] *Id.* at 12.

[73] *Id.* LADWP notes that this screen was misapplied by Glendale and Burbank and that LADWP's actual result is 25.2%. In conducting Test No. 1, Glendale and Burbank defined the peak and off-peak periods as the three highest and three lowest CP months, and thus improperly inflated LADWP's result. *See id.* However, Commission precedent requires that this test compare the average of the purported peak months against the average of *all* of the non-peak months—not just the lowest three. Thus, for LADWP, this would entail comparing the four peak months to the eight non-peak months. This is how this test has been applied in other cases in which 4 CP was deemed appropriate and how the test should be conducted in order to make the 19% benchmark meaningful. *See, e.g.*, *Commonwealth Edison*, 15 FERC ¶ 63,048, at p. 65,196 (for Test No. 1, calculating the difference between the average of the four summer months, as a percentage of the annual peak, to the average of the eight nonsummer months, as a percentage of the annual peak); *Golden Spread*, Opinion No. 501-A, 144 FERC ¶ 61,132 at P 27 n.28. Accordingly, LADWP's actual statistical screen result is 25.2%, which was derived by comparing the average of the four peak months, as a percentage of the annual peak (88%), to the eight non-peak months, as a percentage of the annual peak (62.8%).

[74] Glendale and Burbank Brief at 10.

[75] *Id.* at 12.

[76] *Id.*

[77] *Id.* at 10.

considered indicative of a 12 CP system.[78] According to Glendale and Burbank, LADWP's result is 71% and thus does not pass the threshold for a 12 CP system.[79]

In their April 14 Brief, Glendale and Burbank also contend that LADWP's scheduled maintenance, unscheduled outages, reserve requirements, and diversity of generation resources indicated that the summer is a peak period for LADWP, and thus 12 CP would not be appropriate.[80]

In lieu of 12 CP, Glendale and Burbank claim that use of 1 CP would be more appropriate based on their contention that "LADWP peaks once a year in the summer."[81]

3. General Manager's Decision

LADWP will use 4 CP to calculate the rate divisor in Statement BB, which will in turn be used to calculate the rate in Statement BL. LADWP has decided to move to 4 CP, in part, because LADWP's load data during the Test Period did not pass the statistical screens that have been previously applied by FERC for the use of 12 CP. Although these screens do not provide a "hard and fast rule" and are but one factor considered by FERC in analyzing operational realities, LADWP finds that the load data during the Test Period support the use of 4 CP. Thus, while the totality of operational realities could support either the use of 12 CP or 4 CP, Glendale's and Burbank's statistical screen analysis[82] of the load data in the Test Period and other related information has influenced LADWP to use a 4 CP seasonal divisor, which is consistent with seasonal divisors used by utilities that are subject to FERC jurisdiction.[83]

Because the facts of the Test Period present a close case, LADWP will continue to monitor the operational realities of its system, which may, at some point in time, dictate a shift back to 12 CP rate divisor for future test periods. Indeed, as noted above and in LADWP's response to Data Request No. 27a, many of the operational realities of LADWP's system require LADWP to plan its system for contingencies and uses on a year-round basis, rather than peak basis. While native load service remains a focal point of LADWP's system planning and operations, there are numerous other considerations. For example, Attachment K of LADWP's

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[78] *Id.* at 12.

[79] *Id.*

[80] *Id.* at 13 (citing Exh. No. BWP/GWP-100 at 17-18).

[81] *Id.* at 14.

[82] As noted above, Glendale and Burbank misapplied Test 1. However, LADWP's actual Test 1 result of 25.2% also exceeds the 12 CP threshold of 19% that has been applied by FERC.

[83] *See, e.g., NV Energy, Inc.*, 149 FERC ¶ 63,012, at P 37 (2014) (calculating settlement rates based on 4 CP); *Troutman Sanders LLP*, 150 FERC ¶ 61,006, at P 8 (2015) (approving NV Energy settlement); *Ariz. Pub. Serv., Co.*, 124 FERC ¶ 61,088 (2008) (conditionally approving Arizona Public Service, Co. settlement); *Commonwealth Edison*, 15 FERC ¶ 63,048 at p. 65,195 (adopting 4 CP); *La. Power & Light Co.*, Opinion No. 110, 14 FERC ¶ 61,075, at p. 61,219 (adopting 4 CP), *reh'g denied*, Opinion No. 110-A 15 FERC ¶ 61,297 (1981). *See also* Arizona Public Service, Co., Docket No. ER07-1142-000, Attachment 1, Offer of Settlement and Settlement Agreement, Exh. A at Formula Rate, Attachment H-1, Original Sheet No. 162e *ll.* 156-57 (filed May 29, 2008) (utilizing 4 CP).

OATT now requires it to engage in open and transparent local, regional, and interregional planning based on the needs of third-party OATT customers and the needs of transmission customers in other systems throughout the Western Electric Coordinating Council ("WECC") footprint. LADWP could be required to construct network upgrades to support a generator interconnection or a request for firm point-to-point service, both of which would require the availability of transmission service on a static, year-round firm basis. Indeed, LADWP currently provides long-term firm point-to-point service under its OATT to third-party customers. Furthermore, as with other transmission-owning utilities in the Western United States, LADWP is also subject to NERC and WECC reliability standards, including Transmission Planning standards, which require that LADWP plan its system for all critical conditions, including peak and off-peak periods and varied dispatch patterns.

Moreover, certain policy goals that LADWP is subjected to under state law, such as meeting the California RPS, require LADWP to plan its system on a year-round basis to deliver and accommodate the integration of renewable energy. LADWP had close to 1,300 MW of owned or contracted for renewable resources during the Test Period,[84] and this number continues to rise dramatically in response to the mandatory procurement requirements California's RPS imposes on local publicly owned electric utilities and retail sellers.[85] Furthermore, the RPS imposes Portfolio Content Category ("PCC") requirements mandating that, for each compliance period after December 31, 2016, 75% of the renewable energy resource electricity products used to meet the RPS must directly interconnect with LADWP or be scheduled or dynamically transferred into LADWP.[86] Significant increases in the amount of renewable generation capacity scheduled into or directly interconnected with LADWP will require a transmission system that is available on a year-round basis to deliver renewables to load whenever such renewable generation is available, as well as dispatchable generation resources available year-round to provide ancillary services to integrate the renewables. These operating realities support the use of 12 CP and are expected to intensify the need for LADWP to plan its system on a year-round basis in the future.

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[84] Exh. No. DWP-503 at 20, tbl. 3 ("Consultant Report") (designated as Critical Energy Infrastructure Information ("CEII").

[85] Specifically, the RPS requires such utilities to procure a minimum quantity of electricity from eligible renewable energy resources as a specified percentage of total kilowatt hours sold to retail end-use customers for each of the following compliance periods: 25% by 2016; 33% by 2020; 40% by 2024; 45% by 2027; and 50% by 2030. Cal. Pub. Utils. Code § 399.15.

[86] *See* Cal. Pub. Util. Code § 399.16(c)(1); specifically, California Public Utilities Code § 399.16(b)(1) requires that

> Eligible renewable energy resource electricity products . . . that meet either of the following criteria: (A) Have a first point of interconnection with a California balancing authority, have a first point of interconnection with distribution facilities used to serve end users within a California balancing authority area, or are scheduled from the eligible renewable energy resource into a California balancing authority without substituting electricity from another source. . . . (B) Have an agreement to dynamically transfer electricity to a California balancing authority.

Cal. Pub. Utils. Code § 399.16(b)(1).

In light of the operating and planning realities of its system, LADWP finds that it is not appropriate to utilize 1 CP. LADWP does not operate and plan its system based on one peak month, but based on diverse system stresses throughout the year, as described above. The use of an annual peak rate divisor would not reflect these operational realities. To the extent that the screens indicate that LADWP experiences a peak summer season, this would support the use of a seasonal divisor rather than an annual divisor, *even if* LADWP's system planning was solely based on planning for peak load, rather than the totality of the operational factors identified above.

In support of their claim that LADWP should utilize 1 CP, Glendale and Burbank state only that "[b]ecause LADWP peaks once a year in the summer, it should use a 1 CP divisor for the calculation of all transmission and ancillary services rates."[87] This argument seems to imply that because LADWP has a peak in the summer, it must use 1 CP. However, as the Commission explained in *Entergy*, "every system peaks at one time or another during the course of a year, and that fact alone does not dictate the use of a particular allocation factor or mean that a 12 CP method is not appropriate."[88] Under Glendale and Burbank's logic, *every* utility would be required to use 1 CP, because, by definition, a utility can only have one annual peak. However, FERC precedent supports the idea that 1 CP is fitting only where the "system experiences a sharp 'needle peak' which is considerably higher than the rest of the year."[89] Contrary to Glendale and

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[87] Glendale and Burbank Brief at 14. Glendale and Burbank cite to one case in support of this proposition: *Am. Elec. Power Serv. Corp.*, 80 FERC ¶ 63,006 (1997), *affirming in part and reversing in part initial decision*, Opinion No. 440, 88 FERC ¶ 61,141 (1999) ("*AEP*"). However, *AEP* is easily distinguishable based on its procedural posture and does not support the use of 1 CP for LADWP. *AEP* is an initial decision in which the presiding judge found that 1 CP was appropriate based on the Commission's prior determination in 1993 in that same proceeding that 1 CP was required. *See Am. Elec. Power Serv. Corp.*, 64 FERC ¶ 61,279 (1993), *order on clarification*, 67 FERC ¶ 61,168 (1994). However, the Commission's decision in the 1993 case predated Order No. 888, which expressly revised the policy that the Commission relied upon in the 1993 case in imposing 1 CP. Specifically, in the 1993 *AEP* case, the Commission summarily rejected American Electric Power Service Corp.'s ("AEP") proposed use of 12 CP, citing to a policy it had announced in *Southern*, an earlier case. 64 FERC ¶ 61,279 at p. 62,976 (citing *S. Co. Servs. Inc.*, 61 FERC ¶ 61,339 (1992)). However, in Order No. 888, the Commission explicitly noted that it would "no longer summarily reject a firm point-to-point transmission rate developed using the average of the 12 monthly system peaks" (as it had done in *AEP*) and then proceeded to explain how the rationale announced in *Southern* had been overtaken by changed circumstances in the industry. Order No. 888 at p. 31,737. Indeed, in affirming the presiding judge's 1997 decision in *AEP* (the case cited by Glendale and Burbank), FERC expressly recognized that Order No. 888 had changed this policy, noting that "AEP correctly notes that in Order No. 888 we revised the policy we earlier had enunciated in *Southern* (and which we relied on in our earlier orders to dismiss AEP's 12 CP proposal)." *AEP*, 88 FERC ¶ 61,141 at p. 61,452. However, the Commission nonetheless affirmed the presiding judge's decision based on procedural grounds, finding that the Commission's summary disposition in the 1993 *AEP* case, although based on a superseded policy, had rendered the 12 CP issue beyond the scope of the proceeding and that AEP thus had to file a new section 205 case to revive the issue. *Id.* The *AEP* case was thus decided based on a procedural technicality, with explicit recognition that the policy on which it had been based was overtaken by Order No. 888. It thus lacks persuasive value and does not support use of 1 CP for LADWP.

[88] *La. Pub. Serv. Comm'n*, Opinion No. 480-A, 113 FERC ¶ 61,282 at P 92.

[89] *Ill. Power Co.*, 11 FERC ¶ 63,040, at p. 65,248 (1980), *aff'd in relevant part*, *Ill. Power Co.*, 15 FERC ¶ 61,050, at p. 61,093 ("[W]e also affirm the Initial Decision on the following determinations: that . . . demand cost allocation continue to be measured on the basis of the 12 monthly coincident peak method[.]"), *order on reh'g*, 19 FERC ¶ 61,073 (1981); *see also* 11 FERC ¶ 63,040 at p. 65,248 ("Furthermore, the Commission has rejected the argument that the 1 CP method is appropriate because a company plans capacity based on the system peak, reasoning that

Burbank's unfounded assertions, LADWP's load profile does not exhibit a "needle" or sharp peak, but rather a summer peak season, at most. Indeed, even the Glendale and Burbank April 14 Brief repeatedly states that the "summer" season is a peak time for LADWP, rather than just a single month.[90] Further, LADWP's annual system peak has, in recent years, occurred in September, as it did during the Test Period, but also during June and August. Accordingly, LADWP finds that 1 CP is inappropriate given LADWP's load profile and totality of operational realities. Glendale and Burbank proffered no persuasive arguments or evidence to the contrary.

B. Inclusion of Glendale and Burbank Load and Station Service in Native Load

1. LADWP Proposal

LADWP's rate divisor, as shown in Exhibit No. DWP-104, Statement BB, included LADWP's peak load plus long-term firm point-to-point transmission reserved under the OATT.[91] In response to Burbank and Glendale Data Request No. 122a, LADWP explained that "LADWP Native Load = Interchange in to the LA Native Load area – Interchange Out of the LA Native Load area + Generation in the LA Native Load area – Aux/Station Service in the LA Native Load area – IPP switchyard & Conv Station banks – Castaic Pumping Load."[92]

2. Comments Received

In their March 8 Presentation and April 14 Brief, Glendale and Burbank argued that they meet the definition of "Native Load Customers" in LADWP's OATT and their load is not included in the native load of any other control area, and thus should be included in the LADWP's native load for the purpose of calculating the divisor.[93] "Native Load Customers" are defined in LADWP's OATT as follows:

> The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.[94]

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facilities are installed for the purpose of meeting the demands season to season, month to month, and day to day and not just the maximum load on the system at any one given time or any one segment of the year.") (internal quotations omitted).

[90] Glendale and Burbank Brief at 13. Although Glendale and Burbank cite to LADWP's 2014 "Long-Term Transmission Assessment" ("2014 Assessment"), they point to no aspect of that assessment that would militate in favor of an annual divisor over a seasonal divisor. For instance, they cite to a quote from the 2014 Assessment that states that LADWP is a "summer-peaking utility" and avoids scheduling maintenance and outages "during the summer months." *Id.* (quoting 2014 Assessment at 2-4). However, this statement would support a seasonal divisor, such as the 4 CP being adopted by LADWP, rather than an annual divisor.

[91] Exh. No. DWP-104 at Statement BB.

[92] March 31 Response at 161-62 (LADWP Response to Burbank and Glendale Data Request No. 122a).

[93] Glendale and Burbank Brief at 18-21.

[94] LADWP OATT § 1.21.

Based on this definition, Glendale and Burbank claim that they are Native Load Customers because they are "wholesale" customers of LADWP and LADWP has bilateral contractual obligations to provide them with transmission and certain other limited construction and operational services.[95] Glendale and Burbank also assert that LADWP's reliability duties as the operator of the Balancing Authority Area and the fact that the cities are embedded in LADWP's balancing authority area render them Native Load Customers.[96]

Glendale and Burbank also contend that LADWP inappropriately excludes auxiliary/station service loads and pumping loads from its load divisor.[97]

3. General Manager's Decision

(a) Inclusion of Glendale and Burbank Load in Native Load

LADWP finds that Glendale and Burbank do not meet the definition of "Native Load Customers" in LADWP's OATT, which is the same definition as that included in the FERC *pro forma* OATT:

> The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.[98]

In making their claim that they meet the definition of "Native Load Customers," Glendale and Burbank ignore a core term in the definition—namely that the definition refers to the "wholesale and retail *power* customers" of LADWP.[99] This term "power customer" as used in the *pro forma* definition encompasses retail customers and wholesale requirements customers, of which Glendale and Burbank are neither. For instance, in *Re Entergy Services, Inc.*, the Commission required that

> Native load shall be defined as those customers on whose behalf the Entergy companies, by statute, franchise or contract, have undertaken the obligation to plan, construct and operate its system to provide reliable power supply services. ***This includes both retail native load customers and wholesale full and partial requirements customers*** to the extent Entergy must provide power supply service to those types of customers.[100]

Burbank and Glendale are not, and do not claim to be, retail or wholesale requirements *power* supply customers of LADWP. None of the agreements identified by Burbank and

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[95] Glendale and Burbank Brief at 18-20.

[96] *Id.* at 20-21.

[97] *Id.* at 21-23.

[98] LADWP OATT § 1.21.

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

[100] *Re Entergy Servs., Inc.*, 58 FERC ¶ 61,234, at p. 61,764 (1992) (footnote omitted) (emphasis added).

Glendale create any obligation by LADWP to serve the full or partial electric power supply requirements of Glendale or Burbank. Accordingly, because Burbank and Glendale are not retail or wholesale power requirements customers that LADWP is obligated to serve, they do not meet the definition of Native Load Customers.

FERC has previously rejected arguments raised by transmission dependent utilities like Glendale and Burbank to expand the definition of Native Load Customer to include customers with embedded loads for which the transmission provider is not also the full or partial power requirements supplier. For example, in Order No. 888-A, FERC rejected the arguments raised by several commenters, including transmission-dependent utilities ("TDUs"), requesting that the Commission remove the word "power" from the definition of Native Load Customer, so that TDUs could be considered native load. However, the Commission rejected these requests and refused to remove the word "power" from the definition, finding that:

> We reject Cooperative Power's suggestion to include transmission-only point-to-point customers in the definition of native load. We note that network customers are provided with rights comparable to native load customers because the transmission provider includes their network resources and loads in its long-term planning horizon. However, a point-to-point transmission service customer is not similarly situated to native load and Network Customers. The Network service formula rate requires the Network customer to pay a load-ratio share of the costs of the transmission provider's transmission system on an ongoing basis, while a point-to-point transmission service customer is only responsible for paying on a contract demand basis over the contract term. The network customer and the native load of the transmission provider pay all the residual costs of the transmission system and face greater risks of rate fluctuations due to facility additions and variations in load of both its and other customers. In contrast, the point-to-point transmission service customer may be more transitory in nature electing shorter terms of service and specific forms of service tailored for discrete services over specific time periods that do not necessarily enter into the transmission provider's planning horizon. To the extent a transmission customer desires similar rights and cost responsibilities to a native load customer, it can always elect to take network service.[101]

Unlike a Network or Native Load Customer, Glendale and Burbank do not pay the residual costs of a transmission system, and instead pay for their transmission services on a contract demand basis, and thus should not be considered Native Load Customers.

Similarly, in *Midwest Indep. Transmission Sys. Operator, Inc.*, a party asserted, much like Glendale and Burbank, that FERC should change the definition of "Native Load Customers" proposed by Midcontinent Independent System Operator ("MISO"), because it was "limited to wholesale and retail power customers of Transmission Owners . . . , and therefore exclude[ed] end users within the footprint of the Midwest ISO that are totally dependent on the transmission

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[101] Order No. 888-A at 30,306-07.

systems of the Transmission Owners . . . but do not purchase their power from these entities."[102] The party claimed that definition should be expanded to "cover all end users within the Midwest ISO footprint."[103] In response, the Commission noted that the definition was "identical to the Native Load definition in the currently effective Midwest ISO OATT" and that the commenter had "not offered any reasons to indicate the provisions have become unjust and unreasonable other than a general assertion of dependence" and denied the request.[104] Accordingly, the fact that Glendale and Burbank may be dependent on LADWP's transmission system to deliver some percentage of their power supply needs does not, in itself, render them to be Native Load Customers where they are not also wholesale full or partial requirements *power* customers on whose behalf LADWP has an obligation to construct and operate its transmission system to meet reliability needs.[105]

(b) Inclusion of Station Service and Pumping Loads in Native Load

LADWP finds that it is not appropriate to include station service or pumping loads in the load divisor. The majority of the cases cited by Glendale and Burbank—including Order No. 888-A—apply to the circumstance where the designated network load of a Network Customer is served in part by behind-the-meter generation. Specifically, FERC has found that a Network Customer cannot designate only part of a load at a discrete point of delivery, i.e., the customer cannot exclude the portion of the load served by generation behind the meter when it is taking network integration service for that load.[106] However, LADWP finds designated network load served by behind the meter generation to be a distinguishable situation from station service and pumping loads. Designated network load does not change when behind-the-meter generation is reduced or goes offline, and must be fully served by the transmission system if the behind-the-meter generation is unavailable. This contrasts with station service load, which is self-supplied when a generator is online, and is reduced significantly when a generator goes offline. Accordingly, LADWP does not find that the FERC decisions addressing the treatment of behind-the-meter generation in the context of designated network loads are controlling of the treatment of station service and pumping loads.

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[102] *Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,157, at P 405 (2004), *clarified*, 111 FERC ¶ 61,367 (2005).

[103] 109 FERC ¶ 61,157 at P 405.

[104] *Id.*

[105] Along similar lines, in *New England Power Pool*, 83 FERC ¶ 61,045 (1998), the New England Power Pool Tariff adopted the *pro forma* OATT definition of "Native Load Customers" and the Massachusetts Department of Public Utilities requested that this definition be revised to ensure that "once bundled retail customers and wholesale requirements customers are granted the right to choose and begin to exercise that right, such customers are no longer considered as the native load of their former utility provider." *Id.* at p. 61,253. In response, the Commission found that it was unnecessary to change the definition, because the definition "does not apply when retail customers seek alternative suppliers." *Id.* This also confirms the conclusion that an end-user within a utility's balancing area does not constitute native load if it obtains its power supplies from another source.

[106] *See* Order No. 888-A at p. 30,258.

In one of the cases cited by Glendale and Burbank—*MISO*—FERC did require certain behind-the-meter station service to be included in network load for the purposes of establishing the network customer's billing determinants.[107] However, LADWP finds the circumstances in *MISO* to be distinguishable from the circumstances at issue here. *MISO* involved the treatment of station service in an organized market with merchant generators, and this treatment was based on the particulars of MISO's market.[108] In contrast, LADWP is a vertically integrated utility that self-supplies its station power and is not part of an organized market. Glendale and Burbank point to no case in which FERC has extended its holding in *MISO* to a vertically integrated utility outside the context of an organized market, and LADWP is unaware of any cases in which FERC has required a vertically integrated utility to calculate the native load component of its rate divisor based on its gross generation, rather than net generation. Indeed, as the Commission stated in *CAISO*, "[b]ecause utilities ha[d] historically been vertically integrated, the treatment of station power was not previously an issue[.]"[109] The Commission further explained that

> [i]n response to the 'functional unbundling' directive of Order No. 888, many vertically-integrated utilities divested themselves of their generation facilities, often selling their generation facilities to merchant generators. The treatment of station power became an issue upon the entry of merchant generators into the market . . . .[110]

Accordingly, LADWP finds that *MISO* is not persuasive as to the treatment of station service and pumping loads in the rate divisor as they relate to a vertically integrated utility that is not part of an organized market and that has not divested its generation facilities.

Moreover, LADWP notes that FERC's holding with respect to transmission charges for station service in *MISO* has not been applied by FERC in most Regional Transmission Organization ("RTOs")—including PJM Interconnection, L.L.C. ("PJM"), the New York Independent System Operator, Inc. ("NYISO"), and the CAISO—and is no longer applied even in MISO. As noted in *MISO*, the Commission had allowed for monthly netting in determining transmission service charges for station service in PJM and the NYISO where the markets were structured differently.[111] Indeed, very shortly after *MISO* was decided, MISO filed to revise its station power rules to accommodate the operation of its new energy markets and changed the rules such that "if a facility self-supplies station power through on-site generation and net output

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[107] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,073 at P 26 (2004), *order on reh'g*, 110 FERC ¶ 61,383 (2005), *on reh'g*, 112 FERC ¶ 61,211 (2005) ("*MISO*").

[108] FERC found that its treatment of station service was appropriate based on the specific nature of MISO's proposal for delivery of station power and the particular features of MISO's organized market and noted that this treatment was a departure from the way station service had been treated in other markets. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 106 FERC ¶ 61,07 at PP 23, 25, *order on reh'g*, 110 FERC ¶ 61,383 at P 29 (2005) ("This is a departure from the NYISO and PJM station power provisions, which is justified by the different way in which Midwest ISO operated before the commencement of its Energy Markets.").

[109] *California Indep. Sys. Operator Corp.*, 125 FERC ¶ 61,072 at P 3 (2008), *vacated and remanded on other grounds*, *S. Cal. Edison Co. v. FERC*, 603 F.3d 996 (D.C. Cir. 2010).

[110] *Id.* at P 4.

[111] *See MISO*, 106 FERC ¶ 61,073 at P 25.

for the month is positive, the generator will not incur any charges for transmission service."[112] LADWP notes that CAISO also employs a monthly netting approach for station service similar to the other RTOs noted above, in addition to simultaneous netting at the time of the coincident peak.[113] In sum, the *MISO* precedent advocated by Glendale and Burbank for including station power in billing determinants has never been extended by FERC to the calculation of a vertically integrated utility's rate divisor, and is no longer followed even in organized markets for determining transmission access charges for the station power requirements of merchant generators.

The practices of other vertically integrated utilities that are not part of organized markets also appear to corroborate LADWP's treatment of station service and pumping load. Jurisdictional utilities typically utilize the load numbers reported on pages 400-401b of the FERC Form No. 1 in determining their load divisor. However, LADWP has not found any indication that the quantities reported on these Form 1 pages include station power load or pumped storage load.[114]

In light of the foregoing discussion and the limited and distinguishable nature of the precedent cited by Glendale and Burbank, as well as the absence of any cases extending the *MISO* precedent to vertically integrated utilities like LADWP, LADWP is not persuaded by Glendale and Burbank's arguments to include station service or pumping loads in the divisor.

C. Cost of Capital—Return On Equity

1. LADWP Proposal

In conjunction with LADWP's COSS, LADWP retained Dr. Habr of Habr Economics to develop an overall ROR to be utilized by LADWP.[115] LADWP's proposed ROE was determined

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[112] *Midwest Indep. Transmission Sys. Operator, Inc.*, 110 FERC ¶ 61,383 at PP 45, 82 (2005); *see also* MISO Tariff, Schedule 20, Version 33.0.0, Section III.

[113] *See* CAISO Tariff, Appendix I, Section 4; Appendix A (definition of "On-Site Self Supply").

[114] For example, Arizona Public Service's ("APS") formula rate pulls from the FERC Form No. 1 in a manner that appears to exclude station service and pumping loads from its load divisor. APS' 4 CP load divisor is shown on Attachment H, Line 155 of its formula rate, which is sourced from Line 47 of Worksheet 1 of its formula rate (titled "Network Transmission Peak Report"). As shown on Worksheet 1, the load divisor is the average of the "Total Network Adjusted Peaks" for June through September. The "Total Network Adjusted Peak" for each month includes APS' "Balancing Area Load" (Worksheet 1, Line 1) which appears to encompass APS' native load. These "Balancing Area Load" numbers for each month exactly match APS' monthly peak numbers reported on page 401b of APS' FERC Form No. 1. As shown on page 401a of the FERC Form No. 1, line 2 expressly excludes station use, while line 8 explicitly subtracts out energy for pumping. The total on page 401a ties to the total monthly energy reported on page 401b. In addition, the instructions on page 401b explain that the monthly peak for each month should be reported as the "system's monthly maximum megawatt load (60 minute integration) associated with the system." The "60 minute integration" metric generally refers to a system's net, rather than gross load. APS' formula rate thus appears to provide an example of a jurisdictional, vertically integrated utility that utilizes the approach taken by LADWP with regards to station service and pumped load.

[115] Direct Testimony in Support of Rate of Return ("Habr Testimony"), Exh. No. DWP-200 at 1-2.

based on a two-step DCF analysis[116] conducted by Dr. Habr, consistent with FERC's latest guidance in Opinion Nos. 531 and 551.[117] LADWP's study period for this analysis ran from September 2015 to February 2016.[118] Dr. Habr identified the Value Line utilities with the highest credit ratings to compose a proxy group, screened the utilities for mergers and acquisitions ("M&A") activity and outliers, and utilized the resulting proxy group to develop a range of reasonable returns.[119] Mr. Habr explained that it was necessary to include utilities rated more than one notch below LADWP's high Aa2/AA- credit rating in order to achieve a proxy group of sufficient size, because there were no utilities rated one notch below LADWP, and there would therefore be no utilities in the proxy group.[120] However, as Dr. Habr explains, he limited the proxy group to only Value Line utilities with the highest Standard & Poor's ("S&P") or Moody's ratings in order to obtain a proxy group of the most risk-comparable utilities to LADWP.[121]

Dr. Habr's DCF analysis produced a range of reasonableness of 7.04% to 9.65%, with a median of 8.57%. LADWP proposed to set its ROE at the median of the range of reasonableness, consistent with FERC precedent for a single-filer utility.[122] LADWP conservatively did not propose an upward adjustment from the median to account for anomalous market conditions despite FERC determinations in recently litigated cases that such anomalous market conditions continued to suppress the results of the DCF analysis.[123]

2. Comments Received

In their March 8 Presentation, representatives for Glendale and Burbank argued that LADWP's proxy group inappropriately did not include any municipal or publicly owned utilities, and that the utilities included in the proxy group had credit ratings that were lower than, and not comparable to, LADWP's credit rating. Glendale and Burbank contended that LADWP

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[116] *Id.* at 2. FERC has found that the DCF model is both appropriate and preferred for determining the ROE of non-jurisdictional entities, including municipalities. *City of Vernon, Cal.*, Opinion No. 479, 111 FERC ¶ 61,092, at P 96 (2005) ("We find that the DCF model for a non investor-owned entity such as Vernon is appropriate."), *order on reh'g*, Opinion No. 479-A, 112 FERC ¶ 61,207 (2005), *order on reh'g*, Opinion No. 479-B, 115 FERC ¶ 61,297 (2006), *vacated and remanded on other grounds sub nom.*, *Transmission Agency of N. Cal. v. FERC*, 495 F.3d 663 (D.C. Cir. 2007); *Sw. Power Pool, Inc.*, 153 FERC ¶ 61,281, at P 11 (2015) ("We are not persuaded by Basin Electric's arguments to deviate from our precedent requiring the use of the discounted cash flow methodology to determine a just and reasonable ROE.").

[117] Habr Testimony, Exh. No. DWP-200 at 3; *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234; *Midcontinent*, Opinion No. 551, 156 FERC ¶ 61,234. LADWP notes that Opinion No. 531 was recently vacated and remanded by the D.C. Circuit in *Emera Maine v. FERC*. However, it was not vacated on grounds that are at issue in this proceeding, and FERC guidance on remand will not be available for some time.

[118] Habr Testimony, Exh. No. DWP-200 at 3.

[119] *Id.* at 2-6.

[120] *Id.* at 3-4.

[121] *Id.* at 4.

[122] *See S. Cal. Edison Co. v. FERC*, 717 F.3d 177, 183 (D.C. Cir. 2013).

[123] *See Coakley*, Opinion No. 531, 147 FERC ¶ 61,234; *Midcontinent*, Opinion No. 551, 156 FERC ¶ 61,234.

should use a proxy group to develop its ROE that includes municipalities and/or publicly owned utilities and entities with comparable credit ratings. In the alternative, they contended that LADWP should develop a replacement methodology that reflects LADWP's risk profile. In their April 14 Brief, Glendale and Burbank renewed their contention that LADWP's proxy group is not risk-comparable due to LADWP's higher credit rating, and claimed that this risk differential justified setting LADWP's ROE at the bottom end of the zone of reasonableness of 7.04%, if the DCF method is used.[124]

Glendale and Burbank further commented that Dr. Habr's DCF analysis also contains various errors and is inconsistent with FERC precedent in certain respects. First, they argue that LADWP failed to utilize a six-month study period that reflects the most recent financial data available in accordance with Opinion No. 531.[125] Second, they argue that Dr. Habr's application of the M&A screen was flawed, and should have excluded Duke, NextEra, and Southern Company from the proxy group.[126] Specifically, they argue that *any* distortion to the stock price resulting from M&A activity, no matter how "minimal," requires a utility to be removed from the proxy group (and thus Duke should have been excluded), and that Dr. Habr did not adequately examine whether the NextEra's or Southern Company's DCF inputs had been distorted by their M&A activity.[127] Lastly, Glendale and Burbank object to the inclusion of a dividend for ALLETE, Inc. that was announced in the Test Period, but not paid until after the end of the Test Period, and claim that inclusion of this dividend violates Opinion No. 531.[128]

3. General Manager's Decision

LADWP adopts an ROE of 8.57%, as described in the January 17 Proposal. This ROE was derived by closely following FERC's preferred two-step DCF methodology, with necessary adaptations to account for LADWP's high credit rating. LADWP finds that it is appropriate and consistent with FERC precedent to utilize the two-step DCF methodology, rather than some unidentified and untested "replacement methodology," as advocated by Glendale and Burbank. LADWP further finds that the suggested changes to the proxy group are either inconsistent with the proper application of the DCF method, infeasible, or inappropriate.

First, LADWP finds that, under Commission precedent, it is appropriate to utilize the Commission's two-step DCF methodology, unless the application of that methodology is "simply not possible."[129] In *City of Vernon*, the Commission held that the DCF model is

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[124] Glendale and Burbank Brief at 25-28.

[125] *Id.* at 25 (citing *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 64).

[126] Testimony in Opposition to the Proposed Rates, Terms, and Conditions of LADWP's 2017 Electric Transmission Tariff Revisions ("Glendale and Burbank Testimony"), Exh. No. BWP/GWP-100 at 94-95.

[127] *Id.* at 94-96.

[128] *Id.* at 96-97.

[129] *Sw. Power Pool*, 153 FERC ¶ 61,281, at P 11 n.11 ("While the Commission prefers a discounted cash flow analysis to support an ROE, it may be appropriate to consider alternative approaches if a utility can demonstrate that a discounted cash flow analysis is simply not possible.").

appropriate for non-jurisdictional entities that are not investor owned.[130] Moreover, the Commission recently affirmed that it favors the use of the DCF model for such non-jurisdictional entities. In *Southwest Power Pool*, 153 FERC ¶ 61,281, a non-jurisdictional entity, Basin Electric Cooperative ("Basin"), sought use of a methodology other than the DCF methodology, arguing that the DCF methodology was not appropriate or possible for Basin. FERC rejected Basin's request, explaining that it was "not persuaded by Basin Electric's arguments to deviate from our precedent requiring the use of the discounted cash flow methodology to determine a just and reasonable ROE."[131] The Commission left a narrow window for utilities seeking to not use the DCF method, noting that "it may be appropriate to consider alternative approaches if a utility can demonstrate that a discounted cash flow analysis is *simply not possible*."[132] As demonstrated by Dr. Habr's testimony, it is possible to conduct a DCF analysis for LADWP. Accordingly, in light of this precedent demonstrating a clear preference for the use of the DCF method, LADWP finds that it is not appropriate to utilize an untested "replacement methodology" that is not supported by FERC precedent.

LADWP also finds that it is inappropriate to include municipal or publicly owned entities in the proxy group. LADWP is unaware of any FERC precedent to support the idea of including such entities in a DCF analysis. Indeed, this is likely because conducting a DCF analysis with such entities is, in fact, impossible, because they do not issue common stock or have dividends. Dividend yields are a core input to the DCF model, the underlying premise of which is that an investment in common stock is worth the present value of the infinite stream of dividends discounted at a market rate commensurate with the investment's risk.[133] The basic underlying formula for the DCF model is P=D/k-g, where "D" is the current dividend and "P" is the price of common stock; the Commission then solves for "k" (which is the discount rate and represents the ROR that investors require to invest in a company's common stock).[134] Because the "D" and "P" terms are unavailable for non-investor owned entities, it is impossible to conduct a DCF analysis using municipal or publicly owned entities, and it is thus inappropriate to include them in the proxy group.

LADWP further finds that it is not possible to include utilities with higher credit ratings in the proxy group, because it is already composed of the highest-rated, most-risk comparable

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[130] *City of Vernon*, Opinion No. 479, 111 FERC ¶ 61,092 at P 96 ("We find that the DCF model for a non investor-owned entity such as Vernon is appropriate.").

[131] *Sw. Power Pool*, 153 FERC ¶ 61,281 at P 11.

[132] *Id.* at P 11 n.11 (emphasis added) ("While the Commission prefers a discounted cash flow analysis to support an ROE, it may be appropriate to consider alternative approaches if a utility can demonstrate that a discounted cash flow analysis is simply not possible. *City of Vernon, California*, Opinion No. 479, 111 FERC ¶ 61,092, *order on reh'g*, Opinion No. 479-A, 112 FERC ¶ 61,207 (2005), *reh'g denied*, Opinion No. 479-B, 115 FERC ¶ 61,297 (2006). For example, some public power entities do not have bond ratings or even enter the market for debt, which might make it difficult to perform a discounted cash flow analysis. *See Sw. Power Pool, Inc.*, 152 FERC ¶ 61,248, at P 32 (2015); *Sw. Power Pool, Inc.*, 152 FERC ¶ 61,249, at P 32 (2015); *Sw. Power Pool, Inc.*, 152 FERC ¶ 61,251, at P 31 (2015).").

[133] *See Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 14.

[134] *Id.* at P 15.

utilities to LADWP.[135] As explained by Dr. Habr, the credit screen for the proxy group had to be slightly expanded to include utilities with an A3 or A- rating, because those were the two highest ratings for Value Line utilities, as reported by Moody's and S&P, respectively.[136] LADWP finds these utilities are risk comparable and provide an appropriate proxy group, and that this approach was a reasonable adaptation of this element of the DCF analysis.

LADWP also finds that the median ROE of 8.57% is very conservative and is appropriate for LADWP, even though LADWP has a marginally higher credit rating than the entities in the proxy group. Several factors counterbalance this rating differential. First, LADWP's capital structure of 40.2% equity is significantly riskier than the capital structures of the other utilities in the proxy group, which average 48% equity. As explained by Dr. Habr, "[g]iven the higher level of financial risk associated with the 40.2% net position ratio, the appropriate common equity return for [LADWP] would be *expected to exceed* the 8.57% median" for the proxy group.[137] As discussed below, LADWP has decided to utilize its actual capital structure of 40.2% equity-59.8% debt in lieu of the hypothetical capital structure of 48% equity-52% debt it proposed to utilize in its January 17 Proposal. The increased risk of LADWP's capital structure—as compared to the proxy group—thus provides a counterbalance to LADWP's slightly higher rating.

Second, LADWP conservatively did not request an upward adjustment from the median to account for anomalous market conditions, despite the likelihood that those conditions continued to exist. In Opinion Nos. 531 and 551, the Commission found that the central tendency ROE values of 9.39% and 9.29% resulting from the DCF analysis in those cases were insufficient to satisfy *Hope* and *Bluefield*[138] and merited an upward adjustment for anomalous conditions to 10.52% and 10.32%, respectively. These *inadequate* central tendency values of 9.39% and 9.29%, which the Commission deemed not to satisfy *Hope* and *Bluefield*, are substantially *higher* than the median value of 8.57% resulting from LADWP's DCF analysis. The very low result of the DCF method in this case indicates that anomalous conditions may continue to exist.

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[135] Glendale and Burbank assert that LADWP could have used utilities with "A3 and A-" ratings instead of "A3 or A-" ratings which would have yielded a proxy group of six utilities (Alliant, ConEd, OGE, Pinnacle West, WEC, and Xcel). *See* Glendale and Burbank Testimony at 92, Exh. No. BWP/GWP-100. LADWP notes that under this approach, it would have also been appropriate to include Vectren, which has a rating of A- with S&P and was not rated with Moody's, *see* Exh. DWP-202, because the Commission does not require a utility to be rated by both agencies for it to be included in the proxy group, if its rating with the one agency meets the screen criteria. With the seven company proxy group (composed of the six companies identified by Burbank and Glendale plus Vectren), the resulting median is 8.57% and the range of reasonableness would be 7.04% to 9.31%. Thus, LADWP notes that even if Mr. Habr had only used utilities with both an A- *and* an A3 rating (or an A- and a not-rated metric), rather than an A- *or* an A3 rating, the median value for this more restricted proxy group would still be 8.57%. This demonstrates the robustness of the proposed value for LADWP, and confirms its appropriateness.

[136] Habr Testimony, Exh. No. DWP-200 at 3-4.

[137] *Id.* at 7 (emphasis added).

[138] *See FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n of W. Va.*, 262 U.S. 679 (1923).

LADWP thus finds that any potential downward adjustment to LADWP's ROE that might have otherwise been appropriate to account for its slightly higher credit rating, is counterbalanced by the very low median produced by LADWP's DCF analysis (which may be influenced by anomalous conditions) and LADWP's decision to use its actual capital structure, as discussed below, which is riskier than the capital structures of the utilities in the proxy group. LADWP notes that the adopted ROE of 8.57% is on the very low end of ROEs authorized by FERC, and is *far* lower—approximately 200 basis points lower—than the ROEs determined to be just and reasonable in Opinion Nos. 531 and 551, which are the most recently litigated outcomes before the Commission.[139] This comparison provides additional confirmation as to the conservative nature of LADWP's proposal. Although Glendale and Burbank assert that LADWP should set its ROE at the very bottom of the range of reasonableness, they fail to identify precedent dictating this approach, and LADWP finds that this large downward adjustment is not appropriate for the reasons described above. Accordingly, LADWP will continue to use an ROE of 8.57% to calculate the overall ROR in Statement AV.

With respect to Glendale's and Burbank's allegations that certain errors were made in conducting the DCF analysis, LADWP finds that these arguments lack merit. First, Glendale and Burbank cite to Opinion No. 531 to assert that LADWP's study period is outdated.[140] However, the portion of Opinion No. 531 cited states that FERC's general policy is to "base the zone of reasonableness on the most recent financial data in the record."[141] The most recent data available in the record is that utilized by LADWP in conducting its DCF analysis. Glendale and Burbank could have chosen to provide an updated DCF analysis in their comments, but chose not to do so. Accordingly, LADWP finds that it is appropriate to adopt an ROE of 8.57% based on the data analyzed by Dr. Habr in his testimony.

Second, Glendale and Burbank object to the inclusion of Duke, NextEra, and Southern Company in the proxy group due to M&A activity. Glendale and Burbank claim that even the most "minimal" impact on stock price must trigger the merger screen.[142] However, FERC "practice is to eliminate from the proxy group any company engaged in M&A activity *significant enough* to *distort* the DCF inputs."[143] FERC explained in Opinion No. 551 that under this "distortion" test, FERC does

> not exclude a company simply because it has engaged in any M&A activity or that activity may cause changes in the DCF inputs. Rather, we exclude a company if the M&A activity may cause temporary changes in DCF inputs that

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[139] *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 142; Opinion No. 531-A at PP 1, 10 (finding that a just and reasonable base ROE for the New England transmission owners is 10.57%); *Midcontinent*, Opinion No. 551, 156 FERC ¶ 61,234 at PP 9, 67 (finding that the appropriate base ROE for the MISO transmission owners was 10.32%).

[140] Glendale and Burbank Brief at 25 (citing *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 64).

[141] *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 64. LADWP notes that using the most recent data in the record does not require the data to be updated when FERC makes its decision. For instance, Opinion No. 531 was decided in June 2014, yet the Commission utilized a study period from October 2012 through March 2013 because that was the most recent data available in the record. *Id.*

[142] Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 94-95.

[143] *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 114 (emphasis added).

are not sustainable or representative of longer-term investor expectations for the company.[144]

Accordingly, Dr. Habr concluded that Duke's 2% decrease in stock price associated with the announcement of Duke's acquisition of Piedmont had minimal impact on and did not "distort" its inputs.[145] He also concluded that NextEra's and Southern Company's price declines associated with their mergers would not have a noticeable impact on the DCF results or inputs during the study period.[146] LADWP is not persuaded that the M&A activity associated with these three utilities was significant enough to "distort" the DCF inputs in an unsustainable or non-representative manner, and Glendale and Burbank point to no evidence that suggests that inputs were distorted within the meaning of the FERC test.[147] In any event, as conceded by Glendale and Burbank, excluding these three utilities has no effect on the range of reasonableness,[148] and LADWP notes that the median of the proxy group would only change by one basis point from 8.57% to 8.56%.

Finally, Glendale and Burbank claim that the use of ALLETE, Inc.'s indicated dividend, which was declared in January 2016 (in the study period) but paid in March 2016 (after the study period) is contrary to FERC precedent.[149] However, Opinion No. 531 provides for the use of a company's indicated dividend and explains that FERC has "approved the use of the most recent dividend *declared* by the relevant company to determine the 'indicated annual dividend' for each of the six months."[150] Thus, LADWP finds that Dr. Habr properly utilized ALLETE, Inc.'s most recently declared dividend in his DCF analysis.[151]

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[144] *Midcontinent*, Opinion No. 551, 156 FERC ¶ 61,234 at P 37 (internal citation omitted).

[145] Habr Testimony, Exh. No. DWP-200 at 4; March 31 Response at 88-90 (LADWP Response to Burbank and Glendale Data Request No. 56-57).

[146] Habr Testimony, Exh. No. DWP-200 at 4-5; March 31 Response at 88-90 (LADWP Response to Burbank and Glendale Data Request No. 56-57).

[147] *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 114 ("No party presented evidence indicating that these companies' announcements at the end of the study period impacted the DCF results by distorting the companies' stock prices, dividends, or growth rates.").

[148] Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 97.

[149] *Id.* at 96-97.

[150] *Coakley*, Opinion No. 531, 147 FERC ¶ 61,234 at P 77 n.135 (emphasis added).

[151] In a footnote, Glendale and Burbank note that "DWP-200 states that the DCF analysis used the high and low intra-monthly share prices of the members of the proxy group. LADWP apparently erred in extracting data from *Yahoo Finance* for four utilities in five months. Table 5 in BWP/GWP-E-103 shows these errors, the correction of which does not change our conclusions here." Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 94 n.35. Correcting the five errors identified by Glendale and Burbank has no impact on the zone of reasonableness, median, or mean values shown on Exh. No. DWP-205.

D. Cost of Capital—Capital Structure

1. LADWP Proposal

LADWP proposed to adopt a hypothetical capital structure of 48% equity-52% debt, which was determined based on the average capital structure of the utilities in the DCF proxy group. As explained in LADWP's response to Burbank and Glendale Data Request No. 117, LADWP's proposal was consistent with FERC precedent, finding this approach to be appropriate for another non-jurisdictional municipal entity that, like LADWP, did not issue stock.[152] Specifically, in *City of Vernon*, the Commission accepted as just and reasonable the City of Vernon, California's ("Vernon") use of a proxy hypothetical capital structure based on the actual capital structure of a neighboring investor-owned utility Southern California Edison ("SCE") (which had previously been found by FERC to be a reasonable proxy).[153] The Administrative Law Judge ("ALJ") had determined that although the use of a utility's actual capital structure is typically preferred, "Vernon does not issue common stock and financed its transmission facilities with cash. Vernon lacks a parent entity whose capital structure could be used to decide a rate of return for Vernon. Accordingly, a hypothetical capital structure must be used in this proceeding."[154] In Opinion No. 479, the Commission "summarily affirm[ed] the presiding judge's findings with respect to the appropriate capital structure."[155] Based on this precedent, LADWP found it appropriate to adopt a hypothetical capital structure based on the average capital structure in the DCF proxy group.

LADWP's proposed hypothetical capital structure was also based on the recommendation of Dr. Habr.[156] As Dr. Habr explained in his direct testimony, LADWP's capital structure (comprised of its net position and debt)[157] contains significantly more risk than the capital structures of the other utilities in the proxy group, and this increased level of risk would be expected to justify an ROE exceeding the 8.57% ROE requested by LADWP based on the

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[152] March 31 Response at 157 (LADWP Response to Burbank and Glendale Data Request No. 117); *City of Vernon, Cal.*, 109 FERC ¶ 63,057, at P 111 (2004) (Initial Decision) ("Vernon does not issue common stock and financed its transmission facilities with cash. Vernon lacks a parent entity whose capital structure could be used to decide a rate of return for Vernon. Accordingly, a hypothetical capital structure must be used in this proceeding."), *aff'd in relevant part, City of Vernon*, Opinion No. 479, 111 FERC ¶ 61,092 at P 84 ("We will summarily affirm the presiding judge's findings with respect to the appropriate capital structure and debt cost.").

[153] The Initial Decision concluded that "The evidence clearly demonstrates that based on Commission direction, Vernon used SCE's capital structure for its second TRR filing proposal. . . . Since the Commission, in looking at Vernon's TRR filing, mandated use of SCE's capital structure, it is found appropriate in this proceeding to utilize this approach." *City of Vernon*, 109 FERC ¶ 63,057 at P 113 (internal citation omitted); *see also id.* at P 115 ("Accordingly, it is found that the Commission's approved SCE capital structure is the correct capitalization to use in this case to establish Vernon's overall weighted average ROR."); *id.* at P 119 ("The Commission in the first TRR review determined that Vernon should use SCE's capital structure . . . .").

[154] *City of Vernon*, 109 FERC ¶ 63,057 at P 111.

[155] *City of Vernon*, Opinion No. 479, 111 FERC ¶ 61,092 at P 84.

[156] *See* Habr Testimony, Exh. No. DWP-200 at 6-9.

[157] LADWP's actual capital structure is 40.2% equity-59.8% debt. LADWP's net position and long-term debt utilized in calculating its capital structure were $5,415,775,000 and $8,060,003,742, respectively.

median of the range of reasonableness established for the proxy group.[158] Dr. Habr stated that the reason for LADWP's high credit rating, despite its low net position ratio, was the fact that LADWP had competitive retail rates and strong flexibility as an unregulated utility providing essential service to native customers.[159] Dr. Habr explained that this meant that Native Load Customers were effectively assigned the risk of LADWP's low net position ratio, and that a potential solution would be to utilize the average capital structure of the proxy group (which Dr. Habr found to be reflective of the requested ROE of 8.57%) to ensure that LADWP would be adequately compensated for the risks born by Native Load Customers without requiring them to subsidize OATT customers' rates.[160]

Based on Dr. Habr's recommendation and FERC precedent supporting the hypothetical capital structure approach for municipal entities, LADWP utilized the average capital structure of the utilities in the DCF proxy group as the basis for its proposed capital structure of 48% equity-52% debt.

2. Comments Received

In their March 8 Presentation and April 14 Brief, Glendale and Burbank argued that LADWP should use its actual capital structure, rather than the proposed hypothetical capital structure. In support of their April 14 Brief, Glendale and Burbank cite to FERC precedent favoring the use of a regulated entity's actual capital structure provided that the entity (1) issues its own debt without guarantees; (2) has its own bond rating; and (3) has a capital structure within the range of capital structures approved by the Commission.[161] Glendale and Burbank also argue that the risk of LADWP's net position ratio relative to the proxy group does not justify a hypothetical capital structure, given the lower ratings of the entities in the proxy group and retail rate adjustment clauses that mitigate LADWP's risk.[162]

Lastly, Glendale and Burbank argue that the equity component of LADWP's actual capital structure is over-stated, based on their contention that LADWP's net position contains "restricted assets" and their belief that LADWP should have utilized a different long-term debt number, rather than the number utilized by LADWP in calculating its actual capital structure.[163] Based on their proposed adjustments, Glendale and Burbank calculate an actual capital structure of 66.42% debt-33.58% equity.[164]

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[158] Habr Testimony, Exh. No. DWP-200 at 7.

[159] *Id.* at 8.

[160] *Id.* at 8-9.

[161] Glendale and Burbank Brief at 28 (citing *Ass'n of Businesses Advocating Tariff Equity v. MISO*, 149 FERC ¶ 61,049, at P 190 (2014)).

[162] *Id.*

[163] *Id.*; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 106.

[164] Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 106.

3. General Manager's Decision

LADWP will use its capital structure of 40.2% equity-59.8% debt to calculate its overall ROR. There is limited precedent regarding the appropriate capital structure for non-jurisdictional entities. While FERC has stated that it favors the use of an actual capital structure if certain criteria are met (i.e., the utility issues its owner debt without guarantees, has its own bond rating, and has a capital structure within the range of structures approved by FERC), LADWP is unaware of cases in which FERC has applied this test to non-jurisdictional, municipal entities.[165] LADWP is also unaware of any precedent on how to determine an "actual" capital structure for a non-jurisdictional utility that does not issue stock, like LADWP. Indeed, what little precedent that does exist supports the approach proposed by LADWP in its January 17 Proposal: to adopt a hypothetical capital structure based on the capital structure of a proxy utility or utilities.

That said, LADWP does issue its own debt without guarantees, has its own bond rating, and has a capital structure with the range of capital structures approved by FERC, and thus nominally meets the test for the use of actual capital structures that has been utilized by FERC for jurisdictional utilities. Moreover, LADWP's proposed hypothetical capital structure of 48% equity-52% debt is not entirely dissimilar from its actual capital structure of 40.2% equity-59.8% debt.[166] Accordingly, in light of the facts presented by this Test Period, LADWP will use a capital structure of 40.2% equity-59.8% debt to calculate its overall ROR. This change has been reflected in Statement AV, which shows LADWP's cost of capital.

LADWP finds that Glendale and Burbank's claim that its capital structure is actually 66.42% debt-33.58% equity lacks merit and reflects a misunderstanding of the components of debt and equity that properly belong in the capital structure computation. With respect to the debt component, Glendale and Burbank cite to no FERC precedent and provide minimal justification for their approach, noting only that "KPMG reports a different amount for long-term debt, on the same page where 'net position' is reported. We have used KPMG's report of the amount of outstanding long-term debt, because it was audited, rather than the calculated amount in DWP-200."[167] The problem with this logic is that the "KPMG report"—i.e., LADWP's financial statements for June 30, 2014 and 2015, which were audited by KPMG—reports *both* the long-term debt number utilized by LADWP ($8,060,004 thousand) and the number proposed by Glendale and Burbank ($8,568,281 thousand) in the audited portion of the financial statements on page 52.[168]

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[165] Glendale and Burbank cite to *Valley Electric Ass'n, Inc.*, 141 FERC ¶ 61,238, at p. 62,279 (2012), but this case provides no support for the proposition that it is cited for as the Commission made no determinations as to capital structure and merely set a variety of issues for hearing and settlement judge procedures.

[166] The equity component of LADWP's actual capital structure is determined based on LADWP's net position (which is analogous to an investor owned utility's retained earnings), rather than issuance of common stock. *See* Habr Testimony, Exh. No. DWP-200 at 2 n.1.

[167] Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 106.

[168] LADWP, Power System, Financial Statements and Required Supplementary Information, at 52 (June 30, 2014 and 2015) (With Independent Auditors' Report Thereon).

Of these two numbers, FERC precedent clearly supports the use of the long-term debt number utilized by LADWP. FERC precedent distinguishes between the gross proceeds of debt, which is the total principal outstanding, and the net proceeds of debt, which is the gross proceeds less unamortized premium, discount, expenses, and losses.[169] FERC precedent has consistently rejected the use of the net proceeds of debt in the capital structure, and provides that "[i]t is the gross proceeds of a company's long-term debt, *i.e.*, the total principal outstanding, that belong in the capital structure because this reflects the company's total obligation with respect to long-term debt."[170] FERC has further explained that "[t]he principal amount outstanding is the face value of the debt, which is the amount used under the gross proceeds method."[171]

As shown on page 52 of LADWP's financial statements, $8,060,004 thousand is the "Total Principal Amount" and represents LADWP's gross proceeds of debt. The $8,568,281 thousand number proposed by Glendale and Burbank represents the net proceeds of debt, as it has been adjusted for unamortized premiums and discounts and the removal of current maturities from actual outstanding long-term debt.[172] Accordingly, LADWP utilized the correct measure of long-term debt, consistent with FERC precedent.

LADWP also finds unpersuasive arguments made by Glendale and Burbank that the equity component of LADWP's capital structure should be reduced to exclude assets identified as "restricted" in the KPMG-audited financial statements.[173] In their testimony, Glendale and Burbank argue with respect to the long-term debt component of LADWP's capital structure that "KPMG's report of the amount of outstanding long-term debt" should be used "because it was audited."[174] Yet with respect to LADWP's net position, they would deviate from this philosophy and apply adjustments to the KPMG-audited "Total net position" of $5.415 billion[175] by excluding $1.083 billion in assets identified as restricted – notwithstanding the fact that KPMG itself has not excluded these assets from LADWP's total net position. That the financial statement's reported total net position includes so-called restricted assets is consistent with generally accepted accounting principles. In GASB Concepts Statement No. 4 at paragraph 37, net position is said to be "measured by the difference between (a) assets and deferred outflows of resources and (b) liabilities and deferred inflows of resources." LADWP's KPMG-audited total net position of $5.415 billion was measured in a manner consistent with generally accepted accounting guidance.

LADWP also finds that it is appropriate to utilize LADWP's total net position as the equity component of LADWP's capital structure for ratemaking purposes. Total net position

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[169] *Sys. Energy Res., Inc.*, Opinion No. 446, 92 FERC ¶ 61,119, at pp. 61,448-49 (2000).

[170] *Id.* at p. 61,449.

[171] *Id.*

[172] In addition, the $200,000 thousand in revenue certificates included in Glendale's and Burbank's proposed debt number (shown on page 52) should not be included in the long-term debt because they back up to the commercial paper program and were not drawn on in the 2014/15 fiscal year.

[173] *See* Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 106.

[174] *Id.*

[175] *See* Attachment to Response to Information Request No. 89g1 at p. 16.

reflects the amount of internally generated funds used to support assets used in or caused by the provision of utility services. The fact that an asset may be restricted does not negate the source of the funds. The capital structure should include all long-term sources of capital without reduction for the type of assets being supported.[176]

E. Segmentation

1. LADWP Proposal

In its January 17 Proposal, LADWP provided testimony and analysis of its transmission system to provide its determination of the transmission facilities that are integrated into the LADWP transmission system for inclusion in the calculation of the proposed transmission rate. As supported by the testimony of Jennifer B. Tripp[177] and the findings and analyses conducted by nFront Consulting, LLC in the Transmission Consultant Report-LADWP Facility Determination,[178] LADWP evaluated its transmission system, including all owned and direct interest facilities at 34.5 kV and higher to identify integrated transmission facilities for which the associated costs are included in the transmission rate base for the COSS Model.

As further described in the Consultant Report, nFront, on behalf of LADWP, employed a functionalization approach to assess the general classifications of each of LADWP's facilities.[179] This review was completed using the evaluation tools that are also used in proceedings before FERC for identifying transmission facilities: the Seven-Factor Test and the *Mansfield* Five-Factor Test.[180] As explained in the Tripp Testimony, the conclusions in the Consultant Report provide the determinations for each facility to be included in LADWP's COSS and resulting transmission rates.[181]

2. LADWP Employed Two Standard Evaluation Tools to Complete Its Review of the Integrated Transmission Facilities.

(a) FERC'S Seven-Factor Test

As described in the Tripp Testimony, the first evaluation tool used to determine the classification of the LADWP transmission facilities was the Seven-Factor Test, established by

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[176] *See United Gas Pipe Line Co.*, 13 FERC ¶ 61,044 at p. 61,096 (1980), *reh'g denied*, 15 FERC ¶ 61,023 (1981) ("We take this position for the reason that the rate of return capitalization should, as nearly as possible, be representative of the types and relative amounts of capital invested in the company's rate base to which the rate of return is applied.").

[177] Direct Testimony in Support of Transmission Facility Determination ("Tripp Testimony"), Exh. No. DWP-500.

[178] Consultant Report, Exh. No. DWP-503.

[179] Consultant Report, Exh. No. DWP-503 at 2, 21-22.

[180] Consultant Report, Exh. No. DWP-503 at 2.

[181] Tripp Testimony, Exh. No. DWP-500 at 3-4; Consultant Report, Exh. No. DWP-503 at 2, 21.

FERC's Order No. 888.[182] In Order No. 888, FERC set out the seven factors, which include a combination of functional and technical tests, to separate local distribution facilities from FERC-jurisdictional transmission facilities.[183] The seven factors 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; it rarely, if ever, flows out;
4. When power enters a local distribution system, it is not reconsigned or transported on to 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 distribution interface to measure flows into the local distribution system; and
7. Local distribution systems will be of reduced voltage.[184]

As Ms. Tripp explained, these seven factors are intended to identify facilities that serve a local distribution function for purposes of unbundling services and rates as well as separation of state and federal regulatory jurisdiction.[185] Because these factors are intended to be indicators of local transmission, facilities that function as distribution "pass" the Seven-Factor Test, while facilities performing a transmission function "fail" the Seven-Factor Test.[186] Ms. Tripp explained that FERC has found that a facility can fail the Seven-Factor Test (i.e., be considered transmission) without failing to satisfy all of the seven factors.[187] FERC considers these factors in aggregate, and may consider "other factors" "under the totality of the circumstances."[188] In addition, FERC has noted that "failing" the Seven-Factor Test identifies individual facilities which are eligible to be considered transmission facilities for inclusion in the calculation of rate base for OATT

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[182] *See* Order No. 888.

[183] *Id.* at 31,771, 31,781-84.

[184] *Id.* at 31,771.

[185] Tripp Testimony, Exh. No. DWP-500 at 9:7-9; Order No. 888 at 31,771, 31,783.

[186] Order No. 888 at 31,771.

[187] Tripp Testimony, Exh. No. DWP-500 at 9:11-12 (citing *Alcoa Power Generating Inc.*, 143 FERC ¶ 61,161 at P 18 (2013)) (finding that facilities were properly classified as transmission based upon failing three of the seven factors, and not addressing the other four).

[188] *Id.* at 9:12-14 (citing *S. Cal. Edison Co.*, 153 FERC ¶ 61,384, at PP 33-37 (2015)) (finding that although the SCE facilities in question passed the Seven-Factor Test to be classified as distribution, the importance of several segments to regional reliability still required classifying those specific segments as "not used in local distribution").

purposes, and do not require automatic inclusion.[189] The Seven-Factor Test was performed for LADWP's facilities to evaluate the facilities to be integrated for purposes of the OATT COSS.[190]

(b) FERC's *Mansfield* Five-Factor Test

The Tripp Testimony also described a second tool used to evaluate LADWP's facilities. This evaluation employed a review of the five factors for determining classification provided by FERC in Opinion No. 454,[191] known as the *Mansfield* Test.[192] As explained by Ms. Tripp, the *Mansfield* Test involves five factors:

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.[193]

Each of the *Mansfield* Factors was evaluated for the LADWP Transmission Facilities and the results of this analysis were provided in the Consultant Report.[194]

3. Results of LADWP's Evaluation and Inclusion of Transmission Facilities in the OATT COSS.

According to the Tripp Testimony, the analysis of LADWP facilities identified the transmission facilities to be included in the transmission COSS rate base.[195] Because not all of the transmission facilities reviewed meet every factor within the Seven-Factor Test or the *Mansfield* factors, and simply failing one or more of the seven factors or being integrated under *Mansfield* does not alone indicate that transmission facilities should be included in the COSS, Ms. Tripp states that the analysis reviewed FERC precedent for similar facilities that had been

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[189] *Id.* at 9:14-17.

[190] *Id.* at 10:3-11; Consultant Report, Exh. No. DWP-503 at 23.

[191] *Mansfield*, Opinion No. 454, 97 FERC ¶ 61,134, *reh'g denied*, Opinion No. 454-A, 98 FERC ¶ 61,115.

[192] Tripp Testimony, Exh. No. DWP-500 at 14:3-6.

[193] Tripp Testimony, Exh. No. DWP-500 at 13:7-15; *Mansfield*, Opinion No. 454, 97 FERC ¶ 61,134 at pp. 61,613-14.

[194] Tripp Testimony, Exh. No. DWP-500 at 14:3-6; Consultant Report, Exh. No. DWP-503 at 34-39.

[195] Tripp Testimony, Exh. No. DWP-500 at 25:4-11.

classified as transmission.[196] As described in the Tripp Testimony, review of FERC precedent focused on the high voltage direct current ("HVDC") facilities, the Pacific DC Intertie ("PDCI") and purchased transmission/entitlements including the Intermountain Power Project–Southern Transmission System ("IPP-STS") and the Intermountain Power Project ("IPP")–Northern Transmission System ("IPP-NTS").[197] As shown in the Consultant Report and the Tripp Testimony, LADWP identified precedent further supporting the inclusion of these facilities in the transmission system rate base for the COSS.[198]

(a) Inclusion of the IPP-NTS and IPP-STS Transmission Facilities

In its January 17 Proposal, LADWP proposed to include the IPP-NTS and IPP-STS transmission facilities in the transmission rate base for the COSS because they are integrated facilities through findings that these facilities fail the Seven-Factor Test (classifying these facilities as transmission) and meet the *Mansfield* Test to be considered integrated.[199] Further, LADWP cited FERC case law to support this conclusion. As described in the Tripp Testimony, FERC has reviewed the rolled-in status of these facilities in the context of rates for the CAISO, and determined that the cost of the Anaheim and Riverside entitlements to the IPP-NTS and IPP-STS can be rolled in to the CAISO Transmission Access Charge ("TAC").[200] Specifically, FERC ruled that the IPP-NTS and IPP-STS facilities are networked transmission facilities that are integrated with the CAISO system,[201] which Ms. Tripp cites as further evidence that rolled-in treatment of these transmission facilities is appropriate here.

LADWP, therefore, proposed to include the cost of the IPP-NTS and IPP-STS facility entitlements in the transmission rate base for its proposed COSS.

(b) Inclusion of PDCI Transmission Facilities

LADWP also provided evidence to support the inclusion of the PDCI transmission facilities in the transmission rate base for its COSS. Under the analysis performed in the Consultant Report, Ms. Tripp found that this facility fails the Seven-Factor Test (classifying these facilities as transmission) and met the *Mansfield* Test, and should be considered integrated.[202] Further, Ms. Tripp noted that the PDCI facilities are included in the City of Pasadena, California's ("Pasadena") base revenue requirement for collection through the CAISO

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[196] Tripp Testimony, Exh. No. DWP-500 at 22:13-16; Consultant Report, Exh. No. DWP-503 at 39.

[197] Tripp Testimony, Exh. No. DWP-500 at 22-23.

[198] *Id.* at 23-24; Consultant Report, Exh. No. DWP-503 at 39-41.

[199] Tripp Testimony, Exh. No. DWP-500 at 22. A review specific to these facilities was performed under *Mansfield* Factors 4 and 5, which further confirmed the finding that these facilities were integrated into the LADWP transmission system. Tripp Testimony, Exh. No. DWP-500 at 17:18.

[200] Tripp Testimony, Exh. No. DWP-500 at 23. *See, e.g.*, *City of Anaheim, Cal.*, Opinion No. 483, 113 FERC ¶ 61,091, at P 48 (2005), *reh'g denied*, Opinion No. 483-A, 114 FERC ¶ 61,311 (2006).

[201] *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at PP 27, 47.

[202] Tripp Testimony, Exh. No. DWP-500 at 22.

TAC.[203] In addition, Ms. Tripp described the findings in Opinion No. 483, where FERC affirmed the findings of an ALJ cited precedent for permitting the transfer of operational control to the CAISO of facilities outside of the CAISO control area,[204] as further support that these facilities are fully integrated and therefore subject to inclusion in CAISO's (and other transmission providers') calculation of respective transmission owner's transmission rates.[205] Ms. Tripp also noted that FERC has been clear that costs attributable to entitlements on integrated transmission facilities subject to CAISO's operational control are recoverable under CAISO's transmission rates and charges.[206] Accordingly, LADWP proposed that the consideration of the PDCI costs in the LADWP rate should be reviewed in a similar manner, and included in the LADWP rate base as proposed.[207]

4. Comments Received

Burbank and Glendale challenge LADWP's analysis that rolls in the IPP-STS, IPP-NTS and PDCI transmission facilities, requesting that LADWP establish separate rate schedules for these transmission segments.[208] In support, Burbank and Glendale state that (1) the PDCI and IPP-STS/IPP-NTS facilities are not integrated into the LADWP control area; (2) the PDCI and IPP-STS/IPP-NTS facilities are segregated by LADWP when determining Real Power Losses; (3) the IPP-STS facilities were originally built to move only the IPP generation plant output to southern California;and (4) LADWP has not demonstrated that it has exercised rights to use the IPP-NTS facilities under the relevant agreement between IPP and LADWP. [209]

Burbank and Glendale request that the costs of the PDCI and the IPP-STS/IPP-NTS facilities be excluded from the transmission rate base and revenue requirement.[210] In accordance with this exclusion, Burbank and Glendale propose that LADWP should be required to establish

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[203] Tripp Testimony, Exh. No. DWP-500 at 23:12-18; *see City of Pasadena, Cal.*, 137 FERC ¶ 61,045 (2011). Ms. Tripp notes that Pasadena's rate filing was accepted by FERC, subject to settlement and hearing procedures and was ultimately settled, resulting in no precedent on the rate treatment of the PDCI facilities. Tripp Testimony, Exh. No. DWP-500 at 23:16-18.

[204] *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at P 21, n.45.

[205] Tripp Testimony, Exh. No. DWP-500 at 24:3-5.

[206] Tripp Testimony, Exh. No. DWP-500 at 24:10-13 (citing *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at PP 63-64).

[207] Tripp Testimony, Exh. No. DWP-500 at 24:13-16.

[208] Glendale and Burbank Brief at 43; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 75-80; *see also* March 8 Presentation at 10.

[209] Glendale and Burbank Brief at 43-44; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 79; *see also* March 8 Presentation at 10.

[210] Glendale and Burbank Brief at 44-45; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 79; *see also* March 8 Presentation at 11.

separate rate schedules for each of the three segments (PDCI, IPP-STS and IPP-NTS), with rate divisors for each segment established to comply with FERC precedent.[211]

5. General Manager's Decision

Based on the analysis provided by LADWP in its testimony and the Consultant Report, the General Manager finds that LADWP has supported the integrated nature of the IPP-STS, IPP-NTS and PDCI transmission facilities in its transmission rate base. Furthermore, LADWP's analysis shows that, in applying the standard tests for transmission classification and system integration, these facilities meet the necessary requirements to be considered integrated into the LADWP transmission system. Both the Seven-Factor Test and the *Mansfield* Test are standard mechanisms to determine whether facilities classified as transmission are integrated and therefore appropriately rolled in to transmission rates.[212]

As noted by LADWP, FERC has rolled in these facilities in similar contexts. Opinion No. 483, an order cited by LADWP, provided a detailed review of why the Riverside and Anaheim entitlements to the IPP-NTS/IPP-STS are CAISO network facilities, finding that "the NTS/STS entitlements perform transmission functions, are integrated with the CAISO grid, and are network facilities."[213] FERC, therefore, affirmed the finding of the ALJ that permitted the recovery of the cities' costs associated with these entitlements in the CAISO TAC.[214] The General Manger also finds persuasive LADWP's citations to the inclusion of the PDCI facilities within the revenue requirement for certain cities within the CAISO footprint.

Contrary to Burbank and Glendale's assertion, FERC precedent does not include the ability to schedule on an intra-hour basis in its standards for review for rolled-in treatment,[215] nor does it require the same interconnection agreement to be used for all facilities.[216] Further, while Burbank and Glendale rely heavily on language in an initial decision issued by a FERC ALJ to support their argument for segmentation, the General Manager finds this case to be inapplicable to the case at hand.[217] However, the *Puget ID* proceedings addressed the rate treatment, and segmentation, of a non-contiguous system under the control of Puget Sound Energy, Inc. ("Puget Sound"), in which Puget Sound did not have the right to use a certain number of these lines for

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[211] Glendale and Burbank Brief at 45; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 79; *see also* March 8 Presentation at 11.

[212] *See* Order No. 888 at 31,771; *see, e.g., San Diego Elec. & Gas Co.*, 139 FERC ¶ 61,006, at P 13 (2012) ("In *Mansfield*, the Commission discussed five factors, any one of which can be utilized to determine whether a facility is integrated with the rest of the network.").

[213] *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at P 49.

[214] *See id.* at P 47.

[215] Glendale and Burbank Brief at 43-44.

[216] *Id.* at 44. *See* Order No. 888 at 31,771 (listing the seven factors for consideration of transmission and distribution facilities) and *Mansfield*, Opinion No. 454, 97 FERC ¶ 61,134 at pp. 61,613-14 (listing the factors used for determining integrated facilities).

[217] Glendale and Burbank Brief at 43-44 (citing *Puget Sound Energy, Inc.*, 88 FERC ¶ 63,001 (1999) ("*Puget ID*")). This proceeding was ultimately settled. *See Puget Sound Energy, Inc.*, 97 FERC ¶ 61,309 (2001).

transmission-only purposes,[218] thus failing at least one of the *Mansfield* factors.[219] In fact, the ALJ makes note that if Puget Sound were to obtain the transmission-only use rights from Bonneville Power Authority ("BPA") at a future date, segmentation of the Puget Sound facilities would be contrary to the purpose and spirit of Order No. 888, which disfavors pancaking of rates over an integrated system.[220] In the ALJ's view, Order No. 888 contemplates availability of transmission-only service in a comparable manner to how the transmission provider uses the service, which would be accomplished by integrating facilities.[221] The General Manger also finds persuasive LADWP's citations to the inclusion of the PDCI facilities within the revenue requirement for certain cities within the CAISO footprint.

Therefore, the General Manager finds that rolling-in these transmission facilities in the transmission rate base in the COSS is supported by the record. Burbank and Glendale's request to exclude these facilities and require separate rate schedules is denied.

F. Revenue Crediting

1. LADWP Proposal

In its January 17 Proposal, LADWP proposed to include several items in Statement AU of the COSS as credits to the cost of service for determinations of the costs allocable to the services subject to the proposed rates.[222] As described in the accompanying testimony, the Revenue Credits reflected in Statement AU are the revenue LADWP receives from the use of its transmission system (including revenue that is imputed from LADWP's short-term firm or non-firm use of the transmission system for purposes other than serving native load).[223] These items are applied as a credit to LADWP's overall transmission revenue requirement, reducing the cost of service and related revenue requirements, and the resulting transmission and ancillary service rates.[224] As shown in the COSS, and as provided in the LADWP Testimony, the total amount of revenue credits included in Statement AU is $68.194 million.[225] In the January 17 Proposal, LADWP proposed to include the revenues from the following items in Statement AU: LADWP

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[218] *Puget ID*, 88 FERC ¶ 63,001 at 65,008.

[219] *Mansfield*, Opinion No. 454, 97 FERC ¶ 61,134 at pp. 61,613-14 (Factor 3 requires a consideration of whether the transmission provider is able to provide transmission service to itself or other transmission customers over the facilities in question).

[220] *Puget ID*, 88 FERC ¶ 63,001 at p. 65,009.

[221] *Id.*; *see also id.* at 65,010 ("To segment Puget's system now would not only thwart the objectives of Order 888, it would interfere with the regional transmission grid of which the company's entire system has been an integral part for years.").

[222] Exh. No. DWP-104 at Statement AU.

[223] Direct Testimony in Support of FY 2014-15 OATT Cost of Service Model and Rate Design ("LADWP Testimony"), Exh. No. DWP-100 at 129:9-13.

[224] *Id.* at 129:9-15.

[225] *Id.* at 129:6; Exh. No. DWP-104 at Statement AU, § A, Column P.

Wholesale Marketing (Short Term);[226] Grandfathered Service;[227] OATT Short-Term Service;[228] rent from electric property; other miscellaneous revenues from leases; and leased revenues for physical property and dark fiber.[229]

LADWP proposed to apply the revenue credits for the COSS to the following OATT services:

- Schedule 1: Scheduling, System Control, and Dispatch Service
- Schedule 2: Reactive Supply & Voltage Control from Generation Sources Service
- Schedule 5: Operating Reserve–Spinning Reserve Service
- Schedule 6: Operating Reserve–Supplemental Reserve Service
- Schedules 7 and 8: Short-Term Firm and Non-Firm Point-to-Point Transmission Service
- Schedule 10: Generator Regulation and Frequency Response Service[230]

Because LADWP did not provide service under Schedule 3–Regulation and Frequency Response Service during the Test Period, it has not proposed to include that service in Statement AU.[231]

LADWP has proposed to not include revenue credits associated with ancillary services (Schedules 3, 5, 6, and 10) to support LADWP Wholesale Marketing third party sales transactions. First, there are no revenue credits for Schedule 3 because LADWP Wholesale Marketing third party transactions involve off-system sales. As Schedule 3 is only applicable to the use of transmission to serve load in the LADWP balancing authority area, Schedule 3 would not apply to those transactions and therefore the revenue credits are zero.[232] Second, LADWP has not applied any revenues against Schedules 5, 6 and 10 for LADWP Wholesale Marketing third party sales transactions because LADWP Wholesale Marketing self-supplied these services during the test period.[233] LADWP provided documentation that the units supplying services

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[226] This item captures LADWP's use of its transmission system to make third-party sales. *See id.* at 130:22-23. For revenue credits associated with LADWP wholesale marketing use of the transmission system to support off-system sales during the test period, revenue credits were derived from data included in monthly transfer reports provided by LADWP. LADWP derived these credits based on the original transmission reservation amount, service type and increment, and the applicable rate. March 31 Response at 6-8 (LADWP Response to Burbank and Glendale Data Request No. 6a). Individual contracts were not used or reviewed to develop the revenue credit. March 31 Response at 8 (LADWP Response to Burbank and Glendale Data Request No. 6b).

[227] This item captures the revenue credits associated with transmission and certain ancillary services provided under agreements that LADWP entered into with third-party customers prior to the adoption of its OATT. LADWP Testimony, Exh. No. DWP-100 at 133:20–134:1.

[228] This item captures the revenue credits associated with short-term firm and non-firm transmission and ancillary services provided to third-party OATT customers, LADWP Testimony, Exh. No. DWP-100 at 132:3-5.

[229] *Id.* at 129:18-19 and 130:17-19; Exh. No. DWP-104 at Statement AU: 24-29.

[230] LADWP Testimony, Exh. No. DWP-100 at 130:3-14.

[231] *Id.* at 130:4-6.

[232] March 31 Response at 10-11 (LADWP Response to Burbank and Glendale Information Request No. 8c).

[233] March 31 Response at 10-11, 172-173 (LADWP Response to Burbank and Glendale Data Request Nos. 8c, 127a and 127b).

under these Schedules are owned or controlled by LADWP and are capable of providing those services.[234] Though LADWP Wholesale Marketing did not document its self-supply under the applicable LADWP Business Practice, LADWP states that LADWP Wholesale Marketing had been self-supplying ancillary services prior to the adoption of the business practice and continues to self-supply these services in compliance with the Tariff.[235]

In addition, LADWP has not proposed to include credits for revenues collected under operating agreements for jointly owned facilities, including an agency agreement between LADWP and the Southern California Public Power Authority ("SCPPA"), agreements for operations and maintenance ("O&M") services provided to PDCI owners, and an operating agreement with Intermountain Power Authority ("IPA") under which LADWP is the operating agent for IPP.[236] LADWP provided information in responses to Data Requests regarding its treatment of revenues and expenses under these agreements, which are recorded in a separate general ledger or are not cleared to any general ledger expense account.[237] LADWP has stated that, under these agreements, it is reimbursed for its actual expenses and therefore the agreements do not generate revenues for LADWP accounting purposes.[238] Therefore, LADWP asserted that there are no revenues to credit in Statement AU, and ultimately to the rates proposed in this proceeding.[239]

Specifically, LADWP provided an explanation in response to Information Request No. 31a regarding how it accounts for the revenues and costs associated with its agency arrangement with IPA under the Intermountain Power Project Construction Management and Operating Agreement ("IPP Agreement"). LADWP stated that all of the costs that LADWP incurs as operating agent of IPP are recorded outside of the LADWP General Ledger Power Revenue Fund in a separate IPP Fund labeled "Fund 91 IPP."[240] Costs for this agreement are billed to IPA on a monthly basis and an accounts receivable amount is established for the amount paid on behalf of "Fund 91."[241] According to LADWP's Response to Data Request No. 31a, the amounts are billed and a credit offset is recorded to the appropriate account.[242] These expenses and revenues do not appear in any of the General Ledger accounts of the Power Revenue Fund used to develop the cost of service.[243] LADWP explained that it reports a revenue neutral

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[234] March 31 Response at 172-173 (LADWP Response to Burbank and Glendale Data Request No. 127b (referencing Exh. No. DWP-104 at Statement Gen AS Matrix).

[235] March 31 Response at 173-174 (LADWP Response to Burbank and Glendale Data Request No. 127e).

[236] March 31 Response at 11-12, 48-50 (LADWP Responses to Burbank and Glendale Data Request Nos. 8g and 31a).

[237] *Id.*

[238] *Id.*

[239] *Id.*

[240] March 31 Response at 48-50 (LADWP Response to Burbank and Glendale Data Request No. 31a).

[241] *Id.*

[242] *Id.*

[243] *Id.*

accounting for services provided by LADWP as operating agent for IPA and therefore, it would be inappropriate to include revenues received under the IPP Agreement in Statement AU.[244] LADWP's share of costs under the operating agreement with IPA is reflected as a Purchased Power Expense in the OATT Annual Revenue Requirement.

Furthermore, LADWP provided detailed information to show its accounting for revenues and expenses associated with the agency agreement with SCPPA ("SCPPA Agency Agreement") under which LADWP provides support for activities on behalf of SCPPA.[245] As explained in its Response to Data Request No. 8g, LADWP bills costs it incurs through the SCPPA Agreement on a monthly basis and is reimbursed by SCPPA's participants.[246] LADWP accounts for these funds in the associated SCPPA work orders.[247]

The work orders associated with SCPPA projects are designated as "billable work orders" which clear to an Accounts Receivable asset account. These work orders do not clear to any LADWP general ledger expense account. The costs on these work orders are accumulated each month, billed to SCPPA, resulting in a zero net balance. The costs captured in these work orders are not included in the COSS Model or in the OATT Annual Revenue requirement.

Year-end balances within these SCPPA Work Orders have no impact on the COSS Model or OATT Revenue Requirement because none of these associated costs are captured within the COSS Model or are a part of the OATT Revenue Requirement.[248] As LADWP receives no funds in excess of the costs associated with its agency activities on behalf of SCPPA, LADWP asserted that this agency relationship results in a revenue neutral accounting position for LADWP and therefore there are no revenues to credit in Statement AU.[249]

Similarly, agreements for operations and maintenance activities provided by LADWP on behalf of PDCI owners, and services provided as operating agent of the PDCI, are not accounted for in the LADWP General Ledger.[250] Only LADWP's share of operating expenses associated with jointly owned facilities (such as PDCI) are included.[251] Just like SCPPA, costs are accumulated in "billable work orders," and the joint owners (Burbank, Glendale, Pasadena and Edison) are billed for their corresponding share on a monthly basis. Further, like the agreements described above, LADWP simply collects the costs expended on the O&M for these facilities.

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[244] *Id.*

[245] March 31 Response at 11-12 (LADWP Response to Burbank and Glendale Data Request No. 8g). LADWP notes that it is a member of SCPPA.

[246] *Id.* LADWP also notes that SCPPA maintains separate financial records for each of the SCPPA projects, meaning that SCPPA keeps separate records for this agreement which are separate from SCCPA's general ledger and other financial systems.

[247] *Id.* As a member of SCPPA, LADWP also pays a share of these costs.

[249] *Id.* LADWP is reimbursed for expenses incurred related to services provided to SCPPA, but such reimbursements do not exceed LADWP's costs, and never reside in a revenue account on LADWP's General Ledger. *See* March 31 Response at 129 (LADWP Response to Burbank and Glendale Data Request No. 89h).

[250] *See* March 31 Response at 20-22 (LADWP Response to Burbank and Glendale Data Request No. 18g).

[251] *Id.*

Because this relationship results in a revenue-neutral accounting position for LADWP, there are no revenues to credit within Statement AU.

LADWP, therefore, maintained that it has recorded the appropriate revenue credits to Statement AU and, because the agency agreements with SCPPA, IPA, and PDCI result in a revenue neutral accounting position for LADWP, there are no revenue credits included in Statement AU.

2. Comments Received

Burbank and Glendale protest certain of LADWP's proposed revenue credits for transmission and ancillary services.[252] First, Burbank and Glendale contend that LADWP's transmission revenue requirement in the 2017 OATT COSS fails to document fully and accurately account for the revenues, payments and cost offsets that LADWP receives under several identified agreements, including the SCPPA Agreement and certain PDCI Contracts for operations and maintenance activities and capital improvements provided by LADWP.[253] Second, Burbank and Glendale claim that LADWP's failure to reflect these revenue credits, payments and cost offsets in its COSS overstates the OATT rates by the amount of those credits, payments or cost offsets and results in the unlawful double recovery of transmission costs.[254] Third, Burbank and Glendale state that LADWP should be required to impute a revenue credit for LADWP Wholesale Marketing's use of Schedules 5, 6 and 10 because LADWP Wholesale Marketing did not comply with the LADWP Business Practice for self-supply and third-party supply of service under these Schedules.[255] Burbank and Glendale state that they calculate an imputed revenue credit for Schedules 5 and 6 of approximately $4.34 million in the test year.[256]

Burbank and Glendale specifically object to LADWP's explanation for the costs and revenues associated with the SCPPA and PDCI Agreements.[257] They state that LADWP has neither provided sufficient evidence to demonstrate that these costs and revenues are accounted for outside of the LADWP General Ledger, nor provided a basis to verify that all of the costs

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[252] Glendale and Burbank Brief at 45-48; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 80-83; *see also* March 8 Presentation at 12. While Glendale and Burbank also raise questions regarding the LADWP IPP Agreement, Glendale and Burbank note that responses from LADWP have indicated that these costs and revenues are accounted for in a separate ledger which "may be evidence" that answers their concerns relating to that agreement. Glendale and Burbank Brief at 45 (citing LADWP Response to Burbank and Glendale Data Request No. 31(a)).

[253] Glendale and Burbank Brief at 47, 48; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 80-81; *see also* March 8 Presentation at 12.

[254] Glendale and Burbank Brief at 47-48; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 81-83; *see also* March 8 Presentation at 12 (citing *Nev. Power Co.*, 153 FERC ¶ 61,306, at P 46 (2015) (rejecting a transmission provider's double recovery of transmission costs)); Order No. 888-B, 81 FERC ¶ 61,248 at 62,096 (directing transmission providers to design rates that will avoid double recovery of such transmission costs or ancillary costs)).

[255] Glendale and Burbank Brief at 48-50; Glendale and Burbank Testimony at 83-86.

[256] Glendale and Burbank Brief at 49; Glendale and Burbank Testimony at 85; Exh. No. BWP/GWP-E-10 at tbl. 3.

[257] Glendale and Burbank Brief at 47, 48; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 80-81.

associated with these Agreements are properly segregated from LADWP's OATT-related costs.[258] Because these costs and revenues are not recorded in a separate fund, as the IPA Agreement reimbursements are segregated into Fund 91, Burbank and Glendale are unable to conclude that the costs and revenues associated with these agreements are not assignable to the test year as credits.[259]

As a result, Burbank and Glendale propose that LADWP's COSS should be revised to document fully and accurately reflect the revenues, payments, and cost offsets that LADWP receives for the provision of services related to transmission and generation facilities included in the LADWP OATT, and to accurately account for LADWP Wholesale Marketing's use of ancillary services.[260]

3. General Manager's Decision

Based on the analysis provided by LADWP in its testimony and its Response to Data Requests in this proceeding, the General Manager finds that LADWP has supported the items included in Statement AU.

The General Manager rejects the request of Burbank and Glendale to estimate and apply revenue credits for ancillary services "purchases" by LADWP Wholesale Marketing under Schedules 5, 6 and 10. LADWP has shown that it clearly owns or controls generation capable of self-supplying ancillary services.[261] The General Manager does not agree that the lack of documentation under a LADWP business practice eliminates the ability of LADWP Wholesale Marketing to self-supply these services, or changes the reality that LADWP Wholesale Marketing did self-supply these ancillary services during the test period. Transmission service customers are clearly permitted to self-supply these services both under FERC's *pro forma* OATT[262] and LADWP's OATT.[263] Regardless of whether documentation exists for the self-supply arrangement, because LADWP owns or controls the generation providing these ancillary services and self-supplied during the test period, the General Manager finds no reason to impute a revenue credit for these services for ratemaking purposes.

Further, LADWP has supported the exclusion of revenue neutral agreements that have no effect on the LADWP OATT rates. As noted by LADWP, the costs associated with the IPP Agreement that reside in a fund completely outside of the LADWP General Ledger, and the year-end balance have no impact on the COSS Model or OATT Revenue Requirement.[264] In addition, LADWP has provided adequate information to show that the SCPPA Agreement and PDCI Agreements are accounted for in a similar manner, with costs offset completely by billings

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[258] *Id.*

[259] Glendale and Burbank Brief at 47-48; Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 83.

[260] Glendale and Burbank Brief at 45; *see also* March 8 Presentation at 13.

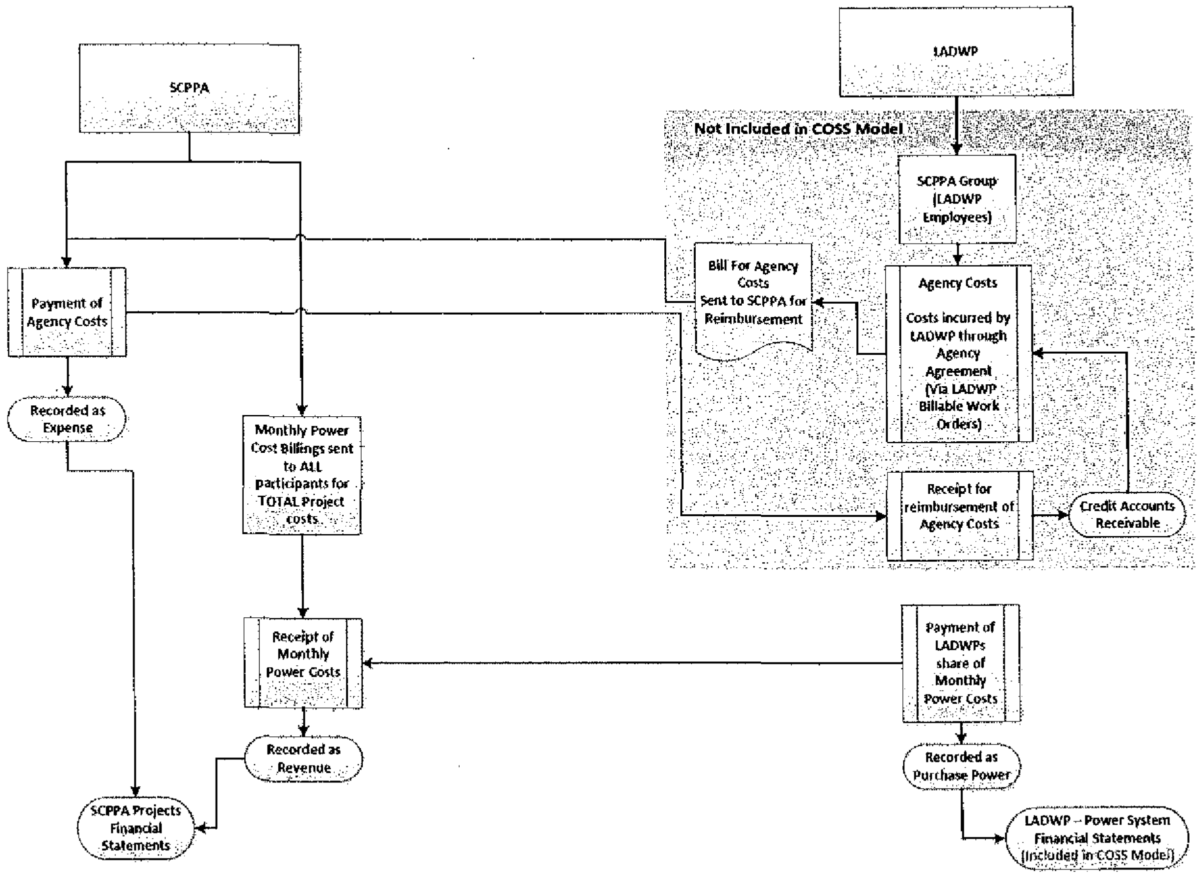
[261] *See* Exh. No. DWP-104 at Generator Ancillary Service Matrix tab.

[262] *See* Order No. 888 at 31,716.

[263] LADWP OATT § 3.

[264] March 31 Response at 11-12 (LADWP Response to Burbank and Glendale Data Request No. 8g).

to SCPPA and PDCI through an accounting mechanism within the LADWP General Ledger.[265] As shown in the flowchart provided by LADWP, the accounting for expenses and collection for the SCPPA Agreement is a process that has no impact on the COSS Model or OATT Revenue Requirement.[266] The SCPPA Agency Agreement is reflected properly in the COSS Model and OATT Revenue Requirement as a purchased power expense representing payments of LADWPs share of monthly power costs, as shown below:



There is no evidence to suggest that LADWP's administrative role under any of these Agreements generate expenses on LADWP's year-end general ledger, or revenues to credit within Statement AU. Therefore, the General Manager finds that LADWP's COSS Statement AU Revenue Credits should be accepted without further revisions. Burbank and Glendale's request to include additional items in this Statement is denied..

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[265] March 31 Response at 11-12, 20-22, 48-50 (LADWP Responses to Burbank and Glendale Data Request No. 8g, 18g and 31a).

[266] *Id.*; *see also* LADWP Response to Burbank and Glendale Data Request No. 8g, Attachment SCPPA and LADWP – Flow Diagram, http://www.oatioasis.com/LDWP/LDWPdocs/SCPPA_and_LADWP_Relationship_-_Flow_Diagram.pdf.

G. Classification and Functionalization

1. LADWP Proposal

In conjunction with LADWP's COSS concerning the Test Period, Ms. Tripp evaluated which LADWP facilities should be classified as integrated transmission facilities for which the associated costs should be included in transmission rate base.[267] Ms. Tripp considered all LADWP-owned and direct interest facilities rated at 34.5 kV and higher—which she referred to as the "LADWP Network"—and applied a series of analytical screens to determine which facilities should be considered integrated transmission for ratemaking purposes. As described by Ms. Tripp:

> First, nFront applied FERC's Seven Factor Test ("Seven Factor Test") to the LADWP Network facilities to identify the facilities to be classified as "transmission". Second, nFront applied FERC's *Mansfield* Five Factor Test ("*Mansfield* Test") to those classified as transmission facilities to determine which of those transmission facilities are "integrated" facilities. Third, nFront reviewed and opined on the methodology LADWP utilized to allocate Receiving Station ("RS") costs between LADWP's transmission, production and distribution functions. Fourth, nFront compared its conclusions against FERC precedent related to the same or similar facilities. Fifth, nFront applied the results of its aggregate analyses to classify the LADWP Network facilities that are transmission facilities and for which the costs should be recovered in transmission rates to all transmission customers rather than assigned to production, distribution or a single transmission customer.[268]

Ms. Tripp's analysis utilized a WECC power flow model, as modified by LADWP and nFront to approximate the system configuration for the Test Period. Ms. Tripp analyzed the base case and 15 scenarios to, for example, evaluate Factors 2 (distribution is primarily radial in character) and 3 (power flows into local distribution but rarely flows out) of FERC's Seven-Factor Test.[269] The results of Ms. Tripp's analysis were summarized in Tables 1-3 of her testimony,[270] and supported by her accompanying CEII report.[271] In particular, Ms. Tripp recommended the exclusion from the OATT COSS of 10.4% of LADWP's overhead 138 kV and 230 kV transmission line miles, and 31.9% of LADWP's underground 138 kV and 230 kV line miles.[272] The reclassification of facilities recommended by Ms. Tripp was reflected in the COSS Model in the tab labeled "7 Factor Summary," with such reclassifications flowing through to Statement AD, Plant in Service,

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[267] Tripp Testimony, Exh. No. DWP-500 at 3-4.

[268] *Id.* at 4-5.

[269] Consultant Report, Exh. No. DWP-503 at 1, 24-32; *see also* March 31 Response at 22 (LADWP Response to Data Request 18i).

[270] Tripp Testimony, Exh. No. DWP-500 at 26-29, tbls. 1-3.

[271] Consultant Report, Exh. No. DWP-503.

[272] Tripp Testimony, Exh. No. DWP-500 at 29, tbl. 3.

and other impacted COSS statements in the model.[273] As summarized in the "7 Factor Summary Tab," Ms. Tripp's recommendations resulted in a 7.1% reduction in transmission gross plant,[274] with appropriate reductions in accumulated depreciation, O&M, and other revenue requirement components also reflected.

As relevant here, Ms. Tripp noted that the Inyo to Cottonwood, Barren Ridge to Cottonwood, and Barren Ridge to Rinaldi 230 kV facilities remain classified as integrated transmission due to a phase shifting transformer[275] controlled tie at Inyo between LADWP and SCE that creates a non-radial configuration, causing these Inyo-Rinaldi 230 kV facilities to exhibit average modeled flow changes of 1.2, 1.2, and 1.1 MW, respectively.[276] Ms. Tripp also provided a table of LADWP's generator interconnection requests showing multiple requests for generation interconnection over these same facilities between Inyo and Rinaldi.[277] Finally, in response to Burbank and Glendale Data Request No. 73(a), Ms. Tripp provided a summary of metered flows over the Inyo phase shifting transformer during the Test Period which demonstrates both bi-directional flows and flows up to the rated limit of the path between LADWP and SCE.

2. Comments Received

In its March 8 Presentation during the second Public Information Forum, representatives for Burbank and Glendale argued that "LADWP inappropriately includes in the OATT revenue requirement the costs of facilities which do not qualify or function as transmission facilities but instead are either production facilities or distribution facilities" and that the "inclusion of these facilities violates FERC's precedent . . . "[278] Specifically, Burbank and Glendale argued that the "following facilities . . . should be excluded from the OATT revenue requirement because they provide only gen-tie functions for generators (Upper Gorge, Middle Gorge, and Control Gorge) used to serve LADWP's retail load:

a) Inyo Switching Station
b) Barren Ridge Switching Station
c) Haskell Switching Station
d) Inyo-Barren Ridge Line
e) Barren Ridge-Haskell Line
f) Haskell-Olive Line"[279]

Glendale and Burbank argued that "LADWP should revise its OATT revenue requirement to remove the costs of" these facilities.[280]

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[273] Exh. No. DWP-104.

[274] Exh. No. DWP-104, at Statement 7 Factor Summary, at cell E207.

[275] Consultant Report, Exh. No. DWP-503 at 28.

[276] Consultant Report, Exh. No. DWP-503 at A-1, tbl. A-2: LADWP Transmission Facility Power Flow Results.

[277] Consultant Report, Exh. No. DWP-503, at tbl. 8.

[278] March 8 Presentation at 14.

[279] *Id.*

Glendale and Burbank refined their objections in their April 14 Brief. Glendale and Burbank, presumably after learning that the Haskell substation and Barren Ridge to Olive facilities were not placed into service until after the Test Period,[281] now assert that "Inyo-Rinaldi Path" should be excluded from LADWP's OATT transmission rates "because they are not integrated transmission facilities."[282] Burbank and Glendale state that the Inyo-Rinaldi Path is:

> not integrated into the LADWP system because: 1) the facilities are radial and not looped; (2) energy flows in one direction on these facilities when they are operated as a gen-tie; however, when generation is insufficient to meet Owens Valley Electric System ("OVES") load, these facilities act as a distribution line to feed that load; (3) LADWP is only able to provide itself gen-tie service over these facilities and does not provide open-access transmission service over these facilities; (4) the radial configuration of the facilities prevents the applicant from providing support and added reliability to the other looped lines; and (5) an outage on these facilities would not have reliability or other effects on the LADWP transmission system.[283]

Burbank and Glendale argue that LADWP's finding of integration under the *Mansfield* Test is flawed because the modeled flow change on the Inyo-Rinaldi path facilities rely on changing the angle of the Inyo phase shifter owned by SCE to accomplish a transaction over the Inyo Tie.[284] Burbank and Glendale assert that this type of transaction across the Inyo Tie no longer occurs because LADWP no longer provides service to SCE "under a contract that terminated long ago and was not in effect during or after the test year."[285] Burbank and Glendale assert that modeling this type of transaction in Case 13 is "is bogus is [*sic*] tantamount to the manipulation of the power flow data."[286]

Burbank and Glendale also claim that LADWP or Ms. Tripp caused "a major shifting of power sources to produce a significantly exaggerated flow over the Adelanto-Toluca 500 kV transmission line which, in turn, was modeled as a line outage in Case 12."[287] They assert that this purported adjustment "overstated and thereby misrepresented the incidental flow changes on the Inyo-Rinaldi Path facilities to support LADWP's contention that Inyo-Rinaldi Path is looped and therefore, integrated with the LADWP system."[288] Lastly, Burbank and Glendale dispute

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[280] *Id.* at 15.

[281] March 31 Response at 22 (LADWP Response to Burbank and Glendale Data Request No. 18h).

[282] Glendale and Burbank Brief at 29.

[283] *Id.* at 33.

[284] *Id.* at 36.

[285] *Id.* at 34.

[286] *Id.* at 36.

[287] *Id.* at 35-36.

[288] *Id.* at 37.

LADWP's position that the Inyo-Rinaldi Path provides reliability benefits to the interconnected grid consistent with *Mansfield* Factor 4.[289]

3. General Manager's Decision

Absent special circumstances, "Commission precedent strongly favors use of the rolled-in method of transmission allocation."[290] The basis of the Commission's rolled-in policy is that:

> the integrated grid is a single interconnected system serving and benefitting all transmission customers; indeed, it is the grid's interconnected nature that makes for a reliable system. . . . Our rolled-in pricing policy recognizes the inherent benefit of the integrated grid to customers, by spreading the costs of the integrated grid among all customers.[291]

The test for determining whether such facilities are "network facilities" is whether there is "any degree of integration" of those facilities with the transmission network.[292] The "focus of the test is . . . whether a facility performs transmission functions."[293] However, such "transmission function[s] [are] not required to be exclusive or to outweigh other functions to justify a finding that a facility performs a transmission function and thus is an integrated, network facility."[294] Indeed, there is not always a clear-cut delineation between the transmission grid and a generation facility, and the Commission has found that generation-related facilities that also serve transmission functions and are part of the integrated grid should be rolled-in to transmission rates.[295]

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[289] *Id.*

[290] *N.Y. State Elec. & Gas Corp.*, Opinion No. 254, 37 FERC ¶ 61,151, at p. 61,365 (1986); *see Pac. Gas & Elec. Co.*, Opinion No. 466-A, 106 FERC ¶ 61,144, at P 22 (noting that with "limited exceptions" FERC has "consistently adhered" to its rolled-in policy), *reh'g denied*, Opinion No. 466-B, 108 FERC ¶ 61,297 (2004), *pet. for review denied*, *Cal. Dep't of Water Res. v. FERC*, 489 F.3d 1029 (9th Cir. 2007).

[291] *Pac. Gas*, Opinion No. 466-A, 106 FERC ¶ 61,144 at P 22; *see also id.* at P 12.

[292] *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at P 34 ("any degree of integration in the transmission network is sufficient to establish that a facility is a network facility and that its costs must be rolled into transmission rates and not directly assigned"), *aff'd on reh'g*, Opinion No. 483-A, 114 FERC ¶ 61,311 at P 13.

[293] *City of Anaheim*, Opinion No. 483-A, 114 FERC ¶ 61,311 at P 13.

[294] *Id.*; *Cf. Chehalis Power Generating, LP*, 123 FERC ¶ 61,038 (2008) (finding that facilities that are associated with a generator, but perform transmission functions—specifically, a 500kV switchyard and a substation—are transmission facilities whose costs should have been included in Account 353 and could *not* be included in ancillary services rates).

[295] *Pac. Gas*, Opinion No. 466-A, 106 FERC ¶ 61,144 at P 22. This includes facilities such as generator tie loop facilities that transmit power from local generation stations as well as "dual function" transformers that connect generation to the grid, but also transform power that passes through at various levels of voltage. *Id.* at P 24. Thus, the fact that assets are associated with generating facilities, does not mean that they do not also serve transmission functions that render them eligible for inclusion in transmission rates. In *California Department*, 489 F.3d at 1036-37, 1041, the United States Court of Appeals for the Ninth Circuit affirmed FERC's rolled-in treatment of such dual-use facilities, characterizing it as an "exclusive use" test in which only facilities used exclusively in connection with generation were classified as generation facilities for costing purposes.

In short, facilities that exhibit any degree of integration with the transmission system are likely eligible for inclusion in transmission rates, absent special circumstances. To determine whether such circumstances exist, the Commission has applied the *Mansfield* Five-Factor Test[296] that, all five factors taken *together*, indicates that a facility does not exhibit any degree of integration. A negative showing as to *all* five *Mansfield* factors "indicates that a facility is *not* integrated with the transmission network and that its costs should *not* be rolled into transmission rates."[297]

Here, Ms. Tripp's analysis has demonstrated that the Inyo-Rinaldi Path satisfies FERC's "any degree of integration" test. While a finding of integration requires a positive finding under just one of the *Mansfield* factors, the record in this proceeding conclusively demonstrates that the Inyo-Rinaldi Path likely satisfies at least the first three factors and should therefore be rolled in to LADWP's OATT transmission rates.

(a) <u>*Mansfield* Factor 1: The Inyo-Rinaldi Path is looped</u>

As Ms. Tripp explained in her report, *Mansfield* Factor 1 examines "whether the facilities are radial, or whether they loop back into the transmission system."[298] Ms. Tripp concluded that

> each LADWP Network facility which 'failed' Seven-Factor; Factor 2 and Factor 3 based on the power flow analyses and over which historical flows showed responsiveness to system changes other than just variations in load level (e.g., reversing flow, changing flow due to transmission line outages, responding to transactions through the LADWP Network) are integrated under the Mansfield Test, Factor 1.[299]

Radial facilities are not responsive to these types of system changes, and do not exhibit inadvertent flows.

As summarized in Table A-2 of Ms. Tripp's report, the Inyo-Rinaldi Facilities averaged 1.1–1.2 MW of modeled flow change in the 15 scenarios considered.[300] Burbank and Glendale voice unsupported allegations, using inflammatory language, concerning purported "data

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[296] The factors include: (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. *Mansfield*, Opinion No. 454, 97 FERC ¶ 61,134 at p. 61,613.

[297] *City of Anaheim*, Opinion No. 483, 113 FERC ¶ 61,091 at P 35. However, the Commission has emphasized that the *Mansfield* factors are *not* a test for determining whether a facility is a network facility. *Id.* Rather, the presence of all five confirms that a radial facility is not integrated with the transmission system. *Id.*

[298] Consultant Report, Exh. No. DWP-503 at 34.

[299] *Id.*

[300] Consultant Report, Exh. No. DWP-503 at A-1, tbl. A-2: LADWP Transmission Facility Power Flow Results.

manipulation" of Case 12 that "would not be tolerated at FERC," and assert that Case 13's simulated transaction across the Inyo phase shifter "is bogus [*sic*] is tantamount to the manipulation of the power flow data."[301] These allegations of "data manipulation" are not supported by any evidence in the record and are not compelling. Any changes made to the original WECC power flow base case were done to more closely mirror system conditions during the Test Period (i.e., by removing facilities that were not in service during the Test Period). There was no attempt to manipulate the data to inflate flows on the Inyo-Rinaldi Path.

In any event, Burbank and Glendale raise objections concerning just two of Ms. Tripp's modeled scenarios: Case 12 and Case 13. The Inyo-Rinaldi Path also exhibited flow changes above the 0.1 MW tolerance band in Cases 3, 4, 7, 8, 11, 14, and 15.[302] Burbank and Glendale's arguments that such modeled flow changes are "inadvertent, insignificant"[303] are not persuasive under the *Mansfield* Test and operate as a tacit admission that the Inyo-Rinaldi facilities are not radial. There is no *de minimis* threshold for demonstrating a looped facility—inadvertent loop flow simply does not occur on radial lines. Burbank and Glendale argue that the phase shifter, and the underlying contractual rights of LADWP and SCE, cause it to "operate the same as a normally open connection."[304] A phase shifter is not a normally open circuit, and LADWP and SCE have not opened the circuits at the Inyo Tie as they could have done if they truly intended an open configuration. In sum, the phase shifter at Inyo established a looped configuration for the Inyo-Rinaldi Path, which is confirmed by modeled flow changes in response to 10 of the 15 scenarios studied.

(b) *Mansfield* Factor 2: The Inyo-Rinaldi Path Exhibits Bi-Directional Flows

Ms. Tripp explained *Mansfield* Factor 2 as examining "whether energy flows in only one direction,"[305] which would tend to suggest a facility is not integrated. Integrated facilities, in contrast, exhibit bi-directional flows. In its Response to Burbank and Glendale Data Request No. 73a, LADWP provided a table for the Test Period "showing the average maximum import flows in megawatts and the minimum export flows in megawatts by month for the SCE to Inyo Tie as measured at LADWP's Inyo Substation. This information was used to look for bidirectional flows."[306] Exhibit No. 73(a) shows an average flow during the Test Period of a 4.60 MW import, but also shows exports as high as 55 MW and imports as high as 58.60 MW—i.e., up to the rated limit of Path 60.[307] While Burbank and Glendale discuss the contractual relationship between LADWP and SCE that, they claim, renders the phase shifter "much the same as a normally open connection," significant flows occurred in both directions across the Inyo Tie during the Test Period. Burbank and Glendale do not dispute the validity of the meter

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[301] Glendale and Burbank Brief at 36.

[302] March 31 Response (LADWP Response to Burbank and Glendale Data Request 18i).

[303] Glendale and Burbank Brief at 35.

[304] *Id.* at 34.

[305] Consultant Report, Exh. No. DWP-503 at 34.

[306] March 31 Response at 100-102 (LADWP Response to Burbank and Glendale Data Request No. 73a).

[307] LADWP Response to Burbank and Glendale Data Request No. 73a, Exh. No. 73(a) (designated as CEII).

data provided in Exhibit No. 73(a), which demonstrates conclusively under *Mansfield* Factor 2 that bi-directional flows occurred on the Inyo-Rinaldi Path during the Test Period.

(c) *Mansfield* Factor 3: Transmission Service Can Be Provided on the Inyo-Rinaldi Path

Mansfield Factor 3 "examines whether transmission service can be provided."[308] While the Inyo-Rinaldi Path is a path internal to LADWP's system and such paths are not individually posted for sale on OASIS, that does not mean that transmission cannot be provided on this path. Table 8 in Ms. Tripp's report indicates a number of active interconnection requests in the queue for Inyo-Rinaldi Path as of May 19, 2015 (during the Test Period).[309] As explained by Ms. Tripp, while interconnection service is not the same as transmission service, "[t]o the extent the queued generating resources are constructed, these resources will require transmission service and will contribute to flow on the integrated network."[310] Thus, the Inyo-Rinaldi Path is available to provide transmission service to interconnecting generators and satisfies *Mansfield* Factor 3.

H. Ancillary Services/Purchase Obligations

1. LADWP Proposal

An ancillary service purchase obligation reflects the percentage of a customer's transmission reservation, monthly network load, or nameplate generation capacity that must be purchased or self-supplied, and is used to establish charges under Schedules 3, 5, 6, and 10 of the LADWP OATT. LADWP proposed in its January 17 Proposal to change the purchase obligations for Regulation and Frequency Response Service provided under Schedules 3 and 10 of the OATT. Specifically, LADWP proposed a purchase obligation of 3.496% for Schedule 3, 9.278% for Schedule 10 (nondispatchable generation), and 3.496% for Schedule 10 (dispatchable generation).[311] LADWP indicated that the revised purchase obligations were calculated based on a study of the deviations between hour-ahead load and variable resource schedules and actual metered generation during the hour.[312] LADWP subsequently produced the supporting study, "Reserve Requirements for 2014 VER Integration," prepared by DNV GL–Energy Advisory Americas, in response to Burbank and Glendale Data Request No. 9a.[313] As explained in the Regulation Study, DNV GL:

[308] Consultant Report, Exh. No. DWP-503 at 35.

[309] *Id.* at 36.

[310] *Id*

[311] Exh. No. DWP-104 at Statement BL.

[312] LADWP Testimony, Exh. No. DWP-100 at 172-73.

[313] LADWP Response to Burbank and Glendale Data Request 9a, DNV, Reserve Requirements for 2014 VER Integration (February 9, 2017) ("Regulation Study").

(1) Determined hour-ahead ("HA") forecasts for load, wind, and solar (wind and solar referred to as "VER") based on hourly historical data for 2014;
(2) Subtracted the HA forecast wind and solar power output from the HA forecast load to obtain the HA forecast load-less-VER;
(3) Subtracted historical 1-minute in-hour wind and solar power output from historical 1-minute load data to obtain 1-minute historical load-less-VER;
(4) Statistically analyzed (2) and (3) to determine the regulation requirement for Load and VERs.[314]

LADWP explained that calculating regulation purchase obligations using the difference between hour-ahead load and generation forecasts and in-hour metered load and generation is consistent with FERC precedent established in *Westar Energy, Inc.*[315] LADWP explained that it used the 1st/99th percentile scheduling deviations shown in Table 5 of the Regulation Study[316] to establish the purchase obligations for Load and VERs under Schedules 3 and 10 of the OATT, respectively.[317] LADWP further explained that it proposed:

> to use the same 3.496% purchase obligation used in Schedule 3 when assessing Schedule 10 charges for dispatchable generation serving transmission customer load within or outside LADWP's balancing authority. While the study entitled "Reserve requirements for 2014 VER integration.pdf." evaluates the scheduling accuracy of load it does not evaluate the scheduling accuracy of dispatchable resources. That is, the study does not calculate the deviations between the forecast of hour ahead generation schedules and 1-minute actual metered generation. However, it is reasonable to assume the scheduling accuracy of dispatchable generation is the same as the scheduling accuracy of load because dispatchable generation is generally responsive to changes in load, and any deviation between the hour-ahead dispatchable generation schedule and the dispatchable generator's 1-minute output during the operating hour is likely the result of the unit's operator or automatic generation control device adjusting the level of output to track in-hour changes in load. Therefore, LADWP has proposed to use the same 3.496% purchase obligation for Schedule 3 and Schedule 10 as applied to dispatchable resources.[318]

2. Comments Received

In its March 8 Presentation at the second Public Information Forum, representatives for Burbank and Glendale argued that LADWP "inappropriately relies on a Variable Energy Resource (VER) study that occurred after the test-year to establish its rates for reliability and

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[314] Regulation Study at 1-2.

[315] 130 FERC ¶ 61,215 (2010), *order on reh'g*, 137 FERC ¶ 61,142 (2011); March 31 Response at 58-60 (LADWP Response to Burbank and Glendale Data Request No. 38c); Exh. No. DWP-104, Statement BL.

[316] Regulation Study at 12, tbl 5.

[317] March 31 Response at 58-60 (LADWP Response to Burbank and Glendale Data Request No. 38c).

[318] *Id.*

frequency response (RFR) service" and that LADWP "incorrectly uses a VER study to set the purchase obligation for RFR service under Schedule 3."[319] Burbank and Glendale also argued that LADWP has "apparently erred in Schedule 10 by setting the purchase obligation ("PO") for dispatchable resources higher than the PO for non-dispatchable resources." Lastly, Burbank and Glendale argued that LADWP should not use a 12 CP rate divisor to calculate its ancillary service rates, but rather a 1 CP rate divisor.[320]

Burbank and Glendale expanded on these arguments in their April 14 Brief and supporting testimony. Burbank and Glendale assert, principally, that (i) LADWP inappropriately used "a study conducted well after the test year to determine the capacity purchase obligations"[321] for Schedules 3 and 10, which they assert "violates LADWP's own restrictions against using data out of the test year";[322] (ii) provided no evidence in support of a regulating reserve requirement in excess of +/- 25 MW for load;[323] (iii) failed to support a confidence interval above the 21/79th percentile;[324] (iv) did not satisfy "the requirements of Order No. 764" for differentiating purchase obligations as between dispatchable resources and VERs;[325] and (v) LADWP failed to support its determination to use the same purchase obligation for dispatchable generators as load.[326]

3. General Manager's Decision

For the reasons discussed below, LADWP is reducing the purchase obligations for ancillary services proposed on January 17 as follows:

OATT Schedule	Purchase Obligation (Current)	Purchase Obligation (Jan. 17 Proposal)	Purchase Obligation (Final, May 14)
3	1.1%	3.496%	1.885%
5	6.4%	6.0%	4.874%
6	5.3%	6.0%	4.874%
10 (VER)	6.5%	9.278%	6.627%
10 (Dispatchabel)	1.1%	3.496%	1.885%

[319] March 8 Presentation at 16.

[320] *Id.* at 17.

[321] Glendale and Burbank Brief at 51.

[322] *Id.* at 53.

[323] *Id.* at 55-57.

[324] *Id.* at 62-64.

[325] *Id.* at 59-60.

[326] *Id.* at 56-57.

(a) Divisor

As a threshold matter, LADWP, consistent with the discussion in Section III.A.1, *supra*, now proposes to utilize a 4 CP rate divisor to recalculate the purchase obligations for ancillary service Schedules 3, 5, 6, and 10-dispatchable, and has also utilized a 4 CP rate divisor to recalculate the capacity charges for these rate schedules. The reduced rates are reflected in Statement BL of the revised COSS Model.[327]

(b) Arguments about the post-Test Period study are a red herring

Burbank and Glendale take issue with the fact that the Regulation Study was finalized in 2017, asserting that "LADWP appears to have cherry-picked test-year and post-test-year data with the objective of increasing OATT rates."[328] This argument is factually inaccurate. While the Regulation Study was finalized in 2017, it exclusively utilized calendar year 2014 data,[329] which overlaps but does not extend beyond the fiscal year 2014-15 Test Period. This makes the Regulation Study no different than any other component of LADWP's cost of service analysis: it is a recently performed study that uses historical data to assess LADWP's costs.

(c) The Regulation Study demonstrated that +/- 25 MW is insufficient to cover both the forecast error and in-hour variability of load with sufficient confidence

Burbank and Glendale express confusion that the regulating reserve requirement for load could be any higher than +/-25 MW, given the assumption that "hour-ahead load forecast errors are uniformly distributed between -25 MW and + 25 MW."[330] As explained in the Regulation Study, however, the regulating reserve requirements identified in Table 5 "compensate for both forecast error ***and sub-hourly variability***."[331] If the hour-ahead forecast were compared to hourly load data, Burbank and Glendale's point would be valid. However, the hour-ahead forecast—which is simulated using the normal distribution of +/-25 MW—is compared to actual 1-minute load data, with any resulting deviation capturing both the forecast error ***and*** in-hour variability of load. The Regulation Study thus identified +/-25 MW as sufficient to balance the $21^{st}/79^{th}$ percentile deviations between the 1-minute data and hour-ahead load forecasts, and +/-87 MW as sufficient to balance the $1^{st}/99^{th}$ percentile deviations.[332]

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[327] Exh. No. DWP-104 at Statement BL.

[328] Glendale and Burbank Brief at 53.

[329] Regulation Study at 12 ("This study quantified balancing reserve (load-following and regulation) requirements for LADWP for 2014 based on historical load and VER data for that year.").

[330] Glendale and Burbank Brief at 55.

[331] Regulation Study at 11(emphasis added).

[332] *Id.* at 12.

(d) LADWP will reduce the purchase obligation consistent with the 95th percentile confidence interval

Burbank and Glendale assert that LADWP's proposal to use the 99th/1st percentile deviations from hour-ahead schedules to establish its regulating reserve margin is inconsistent with the precedent established in *Westar* because "Westar proposed that the confidence interval used to establish the reserve requirement for VERs should be two standard deviations from the mean, or the 5th and 95th percentiles—sometimes referred to as a '95 percent confidence interval.'"[333] While LADWP is concerned that a lower confidence interval could lead to under-recovery of LADWP's fixed costs from OATT customers during instances of significant in-hour deviations from hour-ahead schedules —when regulation capacity is most needed—LADWP is persuaded to reduce the purchase obligations, at least on an interim basis, to reflect the 95th percentile regulation reserve requirements shown in Table 5 of the Regulation Study to be consistent with *Westar*.[334] If greater penetration of renewables or other system conditions warrant, a move to a higher confidence interval may be considered in future rate proceedings. Order No. 764 adopted a case-by-case approach to developing a generator regulation charge, and did not strictly require the implementation of any specific reforms before such a charge could be implemented.

(e) Order No. 764 endorsed a continued case-by-case review of generator regulation charges, and did not strictly require the implementation of any specific reforms before such a charge could be implemented

LADWP's proposal to use the Regulation Study to establish purchase obligations for Schedule 3 and Schedule 10, including a higher Schedule 10 purchase obligation for VERs than dispatchable generators, is not inconsistent with FERC's guidance to public utility transmission providers in Order No. 764. As FERC emphasized in Order No. 764-A, "the fact-intensive nature of public utility transmission provider proposals to implement a generator regulation charge with a differentiated rate justifies a case-by-case review of such proposals."[335] FERC specifically declined to adopt the Notice of Proposed Rulemaking's ("NOPR") proposed requirement that any such cost recovery proposal "show that the public utility transmission provider has fully implemented (or been granted waiver from) the intra-hourly scheduling requirement set forth and in the Proposed Rule and has developed and deployed power production forecasting for VERs."[336] The Commission also did not adopt the NOPR's proposed requirement that any such filing "be supported with actual data collected over a one-year period subsequent to the deployment of power production forecasting for VERs and the implementation of intra-hourly scheduling at 15-minute intervals."[337] As the Commission explained in Order No. 764-A,

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[333] Glendale and Burbank Brief at 59.

[334] Regulation Study at 12, tbl 5; *Westar Energy*, 130 FERC ¶ 61,215 at P 18, n.14.

[335] Order No. 764-A at P 47.

[336] Order No. 764 at P 280.

[337] *Id.* at P 281.

> [p]ublic utility transmission providers are entitled to an effective opportunity to recover the costs of providing service, and we will not foreclose their option to seek such cost-recovery for reasonably incurred reserve costs. However, in light of the potential for the reforms in Order No. 764 to result in additional cost savings over time, the Commission will be open to considering whether a public utility transmission provider should be required to update its rates to reflect the impact of these reforms over time to ensure that rates remain just and reasonable and not unduly discriminatory.[338]

Consistent with Order No. 764, LADWP has included provisions in it OATT related to intra-hour scheduling[339] and the collection of VER forecast data from interconnecting generators.[340] As such, LADWP has complied with Order No. 764's only two requirements. However, because FERC declined to adopt a *pro forma* generator regulation schedule and the proposed prerequisites for making such a cost-recovery filing in Order No. 764, FERC's review of proposed generator regulation rate schedules continues under the precedent established in cases like *Westar* and *Puget Sound*, which the Commission cites repeatedly in Order No. 764 and 764-A.[341]

LADWP's proposed purchase obligations for Schedule 3 and Schedule 10 are consistent with the precedent established in *Westar* and *Puget Sound*. Specifically, regulation and frequency response, whether provided to transmission customers serving load under Schedule 3 or delivering generation under Schedule 10, is the OATT mechanism by which a transmission provider recovers the fixed costs of generation capacity used to supply energy in response to scheduling imbalances and in-hour variability. In Order No. 764, the Commission explained that "[e]nergy imbalance service, offered under Schedule 4 of the *pro forma* OATT, accounts for ***hourly*** energy deviations between a transmission customer's scheduled delivery of energy and the actual energy used to serve load."[342] The Commission continued: "Regulation service and energy imbalance service . . . are complementary services through which public utility transmission providers maintain their systems' balance and recover both the capacity (regulation

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[338] Order No. 764-A at P 51 (internal citations omitted).

[339] OATT, §§ 13.8 and 14.6.

[340] LGIA, § 8.4.

[341] *See, e.g.*, Order No. 764-A at P 50 ("For these reasons, we will not make the determinations sought by PIOs on rehearing because the record in this proceeding leads us to believe that generator regulation services are best addressed on a case-by-case basis, where the specific facts and circumstances of a public utility transmission provider's system and its proposed generator regulation service can be explored.") (citing *Westar Energy*, 130 FERC ¶ 61,215, at P 36, *order on reh'g*, 137 FERC ¶ 61,142 (accepting a proposal by a public utility transmission provider to assess intermittent generators higher regulation costs in a manner consistent with cost causation principles)); *PacifiCorp*, 136 FERC ¶ 61,092 (2011) (setting a proposed generator regulation service rate schedule, among other things, for hearing and settlement procedures); *Puget Sound Energy, Inc.*, 137 FERC ¶ 61,063 (2011) (setting a proposed generator regulation service rate schedule that charges different rates for different customers for hearing and settlement procedures).

[342] Order No. 764at P 236 (emphasis added).

service) and energy (energy imbalance service) costs of doing so from transmission customers . . . ."[343]

Consistent with this explanation of the nature of regulation service, FERC has permitted transmission providers to establish purchase obligations for regulation service that reflect the amount of capacity needed to respond to deviations from hour-ahead schedules and the variability of resources and load during the operating hour.[344] Moreover, FERC has specifically directed transmission providers to use this same methodology to determine the purchase obligations for load under Schedule 3, as well as dispatchable and variable resources under Schedule 10.[345]

Accordingly, use of DNV GL's Regulation Study, which utilized data from calendar year 2014 to identify the quantity of reserves necessary to "compensate for both forecast error and sub-hourly variability,"[346] is consistent with "traditional principles, processes, and procedures of cost-of-service ratemaking," discussed in the FERC precedent above.

(f) LADWP's decision to adopt the same purchase obligation for load and dispatchable generation is reasonable

LADWP does not differentiate between the purchase obligations for load and dispatchable generation under its current OATT. As Burbank and Glendale note, the purchase obligations for both services are currently 1.059%.[347] Maintaining consistent purchase obligations for load and dispatchable generation is logical. As LADWP explained, "it is reasonable to assume the scheduling accuracy of dispatchable generation is the same as the scheduling accuracy of load because dispatchable generation is generally responsive to changes in load, and any deviation between the hour-ahead dispatchable generation schedule and the dispatchable generator's 1-minute output during the operating hour is likely the result of the unit's operator or automatic generation control device adjusting the level of output to track in-hour changes in load."[348] Therefore, LADWP's purchase obligation for Schedule 3 and Schedule 10 (dispatchable) should remain the same, as adjusted to reflect a 4 CP rate divisor and 95th percentile confidence interval.

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[343] *Id.* at P 237.

[344] *See, e.g., Puget Sound*, 137 FERC ¶ 61,063 at P 71.

[345] *Id.* at P 73 ("Therefore, we direct Puget to revise the purchase obligation for dispatchable generation exports under Schedule 13 and load under Schedule 3 using the same portfolio-wide methodology it uses to calculate the purchase obligation for intermittent/non-dispatchable generation exports.").

[346] Regulation Study at 11.

[347] Glendale and Burbank Brief at 52.

[348] March 31 Response at 58-60 (LADWP Response to Burbank and Glendale Data Request No. 38c).

I. <u>Generators Used to Supply Ancillary Services</u>

1. LADWP Proposal

LADWP proposed capacity charges for ancillary service rate schedules 2, 3, 5, 6, and 10 by identifying the revenue requirement associated with the facilities used to supply those services. LADWP's operating personnel identified the units capable of providing each of the above mentioned ancillary services during the test period.[349] The units capable of supplying each service were identified by LADWP in Exhibit No. DWP-104, Tab "Gen AS Matrix."[350]

2. Stakeholder Comments

Burbank and Glendale take issue with LADWP's characterization of certain units as being capable of supplying ancillary services during the Test Period. Namely, they assert that the Owens Gorge Units are not capable of supplying Schedule 2 Reactive Power and Voltage Support because the "capacitive reactance of the lines between Control Gorge and Rinaldi exceeds the ability of the units to compensate."[351] They also assert that these units "are 'block loaded' to a 'water schedule' created to move water down the Los Angeles Aqueduct" and thus cannot provide spinning and supplemental reserves under Schedules 5 and 6.[352] Glendale and Burbank claim that the San Francisquito hydro units "cannot provide reactive and voltage control" because the 115 kV lines in the area "create more capacitive reactance than the power plants can absorb."[353] They further claim that Scattergood Unit 3 "was not available during the test year to provide ancillary services" because "'[o]n September 29, 2013 LADWP broke ground on the Scattergood Unit 3 Repowering Project."[354] Lastly, Glendale and Burbank assert that IPP is unable to "provide Schedule 2 Service because it's almost 500 miles from the LA Basin, and is connected through an HVDC transmission system, with reactors, filters, and power factor capacitors at both ends to supply the reactive needs of the converter stations."[355] They assert that IPP is unable to supply Schedule 5 spinning reserves because IPP is LADWP's most severe single contingency ("MSSC"), and because "LADWP does not offer intra-hour scheduling on the NTS or STS."[356]

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[349] March 31 Response at 2 (LADWP Response to Burbank and Glendale Data Request No. 2); Exh. No. DWP-104, Statement Gen AS Matrix.

[350] Exh. No. DWP-104 Statement Gen AS Matrix.

[351] Glendale and Burbank Brief at 39.

[352] *Id.* at 39-40.

[353] *Id.* at 40 (citing Exh. No. BWP/GWP-100 at 72).

[354] *Id.* (citing LADWP, 2015 Power Integrated Resource Plan (Dec. 31, 2015).

[355] *Id.* at 41.

[356] *Id.* at 41-42.

3. General Manager's Decision

The arguments of Burbank and Glendale concerning the Owens Gorge, San Francisquito, Scattergood Unit 3, and IPP facilities are unpersuasive. As discussed below, each of these facilities can provide the ancillary services indicated in Exhibit No. DWP-104, Gen AS Matrix, and the facilities' costs should be included in the revenue requirements for those services.

(a) Owens Gorge Units

The Owens Gorge Units are capable of providing reactive power to the Inyo-Rinaldi Path which, as described above, is part of LADWP's integrated transmission network. The facilities each provide 20 Mega Volt*Amps Reactive ("MVAR") of reactive power which, in combination with a shunt reactor located at the Cottonwood switching station, affords over 90 MVAR of reactive capability - 15 MVAR more than the reactive capacitance of the Inyo-Rinaldi 230 kV line. Accordingly, the arguments of Glendale and Burbank that the "capacitive reactance of the lines between Control Gorge and Rinaldi exceeds the ability of the units to compensate"[357] is unpersuasive. Additionally, the argument that the "impact of their range of control does not reach the LADWP grid"[358] is inapposite: as discussed above, the LADWP integrated grid extends northward to Inyo.

The arguments of Glendale and Burbank that the Owens Gorge Units "cannot provide spinning and supplemental reserves"[359] are also unpersuasive. The Owens Gorge Units are now, and were during the Test Period, reported to Peak Reliability (the reliability coordinator for the Western Interconnection) as spinning and supplemental reserves during certain operating conditions. When offline, they are capable of responding within 10 minutes as supplemental reserves when water levels allow. The units are also, at times, online but not fully loaded, and any headroom allowed by water conditions can be and often is reported to Peak Reliability as available for spinning reserves.

(b) San Francisquito Units

Burbank and Glendale argue that the San Francisquito units "cannot provide reactive and voltage control" to "the larger LADWP grid beyond the Olive Switching Station."[360] The San Francisquito units each provide 10 MVAR of reactive power. Even if one were to assume, *arguendo*, that such reactive power capability does not extend beyond the Olive Switching Station, the Olive Switching station is, in fact, part of LADWP's integrated network as determined in Ms. Tripp's analysis. Accordingly, Burbank and Glendale's arguments concerning the geographical range of the reactive power supplied by these units in fact support the idea that the units are capable of supplying reactive power to the integrated LADWP

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[357] *Id.* at 39.

[358] *Id.*

[359] *Id.* at 40.

[360] *Id.*.

transmission system. Accordingly, LADWP is not persuaded to remove these units from the Schedule 2 rates.

(c) Scattergood Unit 3

Burbank and Glendale misunderstand the nature of the Scattergood Unit 3 Repowering Project as described in LADWP's "2015 Power Integrated Resource Plan" (December 31, 2015). After the groundbreaking of the repowering project in September of 2013, Scattergood Unit 3 remained online and operational through late 2015 as LADWP "repowered" Unit 3 by constructing its eventual replacements: Units 4-7. Those units were not placed into service, and Scattergood Unit 3 was not retired, until after the Test Period. Thus, the "repowering" of Scattergood Unit 3 during the Test Period did not result in the unit being taken out of service such that it was unable to provide ancillary services during the Test Period.

(d) IPP

Burbank and Glendale's claims concerning the ability of IPP to supply Schedule 2 reactive power rest on their assertion that the STS/NTS transmission facilities are not integrated and thus the "reactive capacity of IPP should be assigned to the STS/NTS segment as a segment-specific ancillary service, with a separate revenue requirement and rate schedule."[361] As discussed above, Ms. Tripp's analysis provides persuasive evidence that the STS/NTS facilities are part of LADWP's integrated transmission network and should not be segmented. Therefore, the reactive capacity of IPP should be included in LADWP's generally applicable Schedule 2 rate.

LADWP is also not persuaded by the argument that IPP, which LADWP frequently identifies as its MSSC, cannot also provide spinning reserves. As a preliminary matter, the MSSC is not a static concept and varies as system conditions change. In some cases, the activities of third-party transmission customers could also impact the identification of the MSSC. Even in scenarios where IPP is identified as the MSSC, LADWP can and does report IPP as a source of Schedule 5 spinning reserves to Peak Reliability. If only one IPP unit were to trip, the other IPP unit could supply reserves in response to the contingency. Accordingly, because the resource is available to supply Schedule 5 spinning reserves, and does in fact supply such spinning reserves, it is appropriate for LADWP to include the costs of IPP in its Schedule 5 rates.

J. Self-Identified Corrections

1. Pre-Paid Energy and Transmission Costs

(a) LADWP Proposal

In its January 17 Proposal, LADWP included prepayments related to Purchased Power (MWh) energy in its calculation of Working Capital costs in Statement AL of the COSS.[362] As

[361] *Id.* at 41.

[362] Exh. No. DWP-104 at Statement AL, columns AD-AN.

proposed by LADWP in Statement AL, the amounts calculated for this item were determined through a specific general ledger query to obtain the total purchased MWh energy dollars. However, because the General Ledger does not breakdown the purchased energy into production, transmission and distribution or non-OATT functions, LADWP derived the portions of purchased energy that are related to production and transmission and included an estimate in its work papers that was validated by LADWP's consultant.[363]

As described in LADWP's testimony, Section A of Statement AL shows the Description of General Ledger Material & Supplies (M&S), Fuel Stock, and Prepayments.[364] Prepayments were calculated using a 13-month balance, as shown in columns AD through AN of Statement AL, and are made up of the following components:

- Corporate
- Miscellaneous
- Prepaid insurance excess liability
- Prepaid medical premiums non-Nevada Health Plan
- Prepaid medical premiums Nevada Health Plan
- Prepaid insurance–excess boiler and turbine explosion (Other than Navajo, Mohave, and Nuclear)
- Option natural gas hedging activities
- Prepaid energy purchased–(Overbillings by IPP and SCPPA)
- SCPPA Stabilization Fund–Renewable
- Prepaid insurance Mohave Steam Plant
- Prepaid insurance Navajo Steam Plant
- Prepaid insurance Nuclear Power Plant[365]

For each of these categories, LADWP determined the General Ledger amounts for direct assignment or, where these categories were not specifically tracked in the General Ledger, LADWP allocated prepayments using either a labor or plant allocator.[366] LADWP provides the detail for the allocation process in its COSS Model.[367]

LADWP proposes a specific prepayment category for prepayments associated with IPP that includes prepayments of Purchased Energy (excluding fuel) relating to LADWP's

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[363] LADWP Testimony, Exh. No. DWP-100 at 29:21–30:8. As described in this testimony, the estimate is based on an IPP Generation Station report.

[364] LADWP Testimony, Exh. No. DWP-100 at 119:10-11; *see also* Exh. No. DWP-104 at Statement AL, columns AD-AN.

[365] LADWP Testimony, Exh. No. DWP-100 at 123:14–124:7.

[366] LADWP Testimony, Exh. No. DWP-100 at 124:9-15.

[367] Exh. No. DWP-104 at Statement AL, Section B "Allocation of Prepayments to the Reclassified Generation and Transmission Functions"; *see also* LADWP Testimony, Exh. No. DWP-100 at 124:16–126:8.

entitlement portion of the IPP power.[368] LADWP has clarified in Responses to Data Requests that the total amount used to calculate this prepayment is $35.5 million for energy supplied, transmission services and fuel (natural gas) related to IPP-IGS (energy supplied), IPP-NTS (transmission services), SCPPA (transmission services) and a Wyoming Natural gas project (fuel).[369] LADWP noted that the costs relating to energy supplied are total amounts from its General Ledger and are not based on specific contracts.[370] LADWP also provided clarification on which portions of these services it considered to be outside the OATT, stating that prepaid energy is non-OATT if the prepayment is not related to providing ancillary services, prepaid transmission services are non-OATT if they are not considered integrated with the transmission network, and prepaid fuel (natural gas) is not a component of the annual revenue requirement since fuel expense is not a fixed cost of the generating capacity used to provide ancillary services under the OATT.[371] LADWP also clarified that only the prepaid energy costs and prepaid transmission services that are included in the prepayments category are overbillings relating to the provision of ancillary services.[372]

Following LADWP's January 17 proposal, LADWP provided revised information regarding certain amounts calculated for the prepayments within Statement AL, Section B.5. Specifically, LADWP revised certain prepayments between OATT and non-OATT components to reflect 13-month average balances rather than fiscal year-end balances.[373] LADWP proposed to revise the amounts as follows:

- For the item "IPP-Production (non-fuel)," the amount shown in cells D138 and AG138 in tab AL of Exhibit No. 104 should be revised from $13.03 million to $9.63 million.
- For the item "IPP (NTS)," the amount shown in cells D139 and AD139 of tab AL in Exhibit 104 should be revised from $0.109 million to negative $0.0821 million (reduction to rate base).[374]

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[368] Exh. No. DWP-104 at Statement AL, Section B.5; LADWP Testimony, Exh. No. DWP-100 at 125:8-14. LADWP clarifies in this testimony that a portion of this prepayment is related to fuel and is not included in the COSS Model. *Id.* at 125:11-13.

[369] LADWP Response to Burbank and Glendale Data Request No. 5d; March 31 Response at 53-54 (LADWP Response to Burbank and Glendale Data Request No. 35a).

[370] March 31 Response at 53-54 (LADWP Response to Burbank and Glendale Data Request No. 35a). LADWP provided a summary of the IPP power sale and the IPP true-up statements in LADWP Response to Burbank and Glendale Data Request No. 5a and provided the relevant contracts Response to Burbank and Glendale Data Request No. 35a, Attachments 35a.1 through 35a.8. Further detail of the $35.5 million was provided by LADWP in Response to Burbank and Glendale Data Request No. 96a.

[371] March 31 Response at 54 (LADWP Response to Burbank and Glendale Data Request No. 35b).

[372] March 31 Response at 54-55 (LADWP Response to Burbank and Glendale Data Request No. 35d); March 31 at 55 (LADWP Response to Burbank and Glendale Data Request No. 35e).

[373] March 31 Response at 141-42 (LADWP Response to Burbank and Glendale Data Request No. 97a). LADWP also provided with this response an excel spreadsheet to show the revised prepayment calculations, Attachment_96a.1_35_M_Prepayment at Statement OATT-NonOATT Explanation.

[374] March 31 Response at 141-42 (LADWP Response to Burbank and Glendale Data Request No. 97a).

Further, LADWP identified a further error. In its response to Burbank and Glendale Data Request 97a, LADWP stated that it erroneously had not included certain SCPPA-related transmission prepayments.[375] LADWP proposed to correct this error by including a $1.35 million prepayment amount in Statement AL, Section B.5 to reflect this prepayment.[376]

(b) General Manager's Decision

Based on the analysis provided by LADWP in its Testimony and its Response to Data Requests in this proceeding, the General Manager finds that LADWP has supported the items included in its Working Capital calculations. LADWP has provided information to support the conclusion that allocated portions of these costs are directly used for the benefit of the OATT customers and are used to support OATT services.

However, given the adjustments provided by LADWP in subsequent Responses to Request for Information, the General Manager will require that an updated COSS be posted reflecting the corrected amounts from LADWP Response to Burbank and Glendale Data Request No. 96a. With this correction, LADWP's revenue requirement will reflect the most up to date information available for the calculation of accurate rates.

Therefore, the General Manager finds that LADWP should adjust its proposed prepayment amounts to account for the updated information provided in its Response to Burbank and Glendale Data Request No. 97a. With these adjustments, the General Manager finds that the prepayment amounts in the OATT COSS should be accepted.

2. Adjustment to Receiving Station Allocation Percentages

As discussed in LADWP's Response to Data Request No. 72b, an error was found in the recommendation of a 50%-50% split of the three 230/138 kV Valley transformer cost between Distribution and Production. The revised recommendation is reflected in Table 2 - Receiving Station Reclassification Percentages.[377] This revised allocation impacts the calculation of the Receiving Station Study Reclassification percentages that are used as inputs to the COSS Model (see the Control Sheet tab in Exhibit No. DWP-104).[378]

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[375] *Id.*

[376] *Id.*

[377] March 31 Response at 99-100 (LADWP Response to Data Request 72b ("Refer to Table S-1 of Exhibit DWP-503, Ref#'s 14 to 16, Table S-2, footnote 5 and Table A-2. nFront found an error with its recommendation of a 50/50% split of the three 230/138 kV Valley transformer cost between Distribution and Production. The allocation should have only considered the generation and load requiring use of the 230/138 kV Valley transformers and errantly considered the entire generation connected at both 230 kV and 138 kV (over 550 MVA). The power flow case as provided in response to IR18(i) shows that only 47 MVA of Valley generation (unit 5G) relies on the 230/138 kV Valley transformers compared with 313 peak load served via Valley 138 kV (based on actual metered data) during the FY14/15 Test year. nFront's revised recommendation is a 87/13% split to distribution/production.").

[378] Revised Receiving Station Study will be posted on OASIS once it has been signed.

Table 2: Receiving Station Reclassification Percentages		
	RS % Used in	
	Jan 17 COSS Model	Revised RS %
Distribution Allocation	52.53%	54.08%
Production Allocation	3.48%	1.93%
Transmission Allocation	43.99%	43.99%
Total	100.00%	100.00%

The General Manager accepts the recommended adjustments. With these adjustments, the General Manager finds that the receiving station allocation percentages in the OATT COSS should be accepted.

3. Scattergood Sales Tax

In responding to Burbank and Glendale Data Request No. 133b, LADWP determined that $19.4 million of Unit 4-7 construction work was incorrectly recorded as Scattergood plant in service during June 2015—the last month of the test period—when such amount should have been recorded as Unit 4-7 CWIP. The impact on Scattergood gross plant in service would be a reduction of approximately $1.5 million based on the 13-month average of $19.4 million, with a corresponding increase in the Scattergood CWIP balance included in rate base. The adjustments to the COSS Model related to this correction are as follows:

- Tab AD: Line 94 removes $1.49 M of Scattergood U4-7 costs.
- Tab AE: Line 45 removes $0.38 M of Scattergood U4-7 ending balance accumulated depreciation. Line 78 removes $0.03 M of Scattergood U4-7 13-month average accumulated depreciation.
- Tab AJ New Rates: Scattergood U4-7 depreciation expense was removed from cell AN37.
- Tab AJ: Scattergood U4-7 depreciation expense was removed in cell AL37. Depreciation expense for FY 14-15 was assumed to be the same value as the June 2015 accumulated depreciation balance since this plant cost was put into service (for accounting purposes) in June 2015.
- Tab Source Investment Data: The Scattergood U4-7 plant costs were removed from cell H21.
- Tab AG: Line 44 was added to include the $19.4 million ($1.49 M 13-month average) of Scattergood U4-7 CWIP.

PART IV: DECISION ON NON-RATE TERMS AND CONDITIONS ISSUES RAISED IN STAKEHOLDER COMMENTS

This section discusses the non-rate terms and conditions of LADWP's Proposed Tariff that are disputed by stakeholders, as well as the General Manager's determination on each disputed item. The undisputed portions of LADWP's proposal are deemed accepted and supported by LADWP.

A. Attachment C—ATC Calculation

1. Initial Proposal:

In FERC's Order No. 890, the Commission created a new *pro forma* Attachment C to achieve industry-wide consistency in all ATC components and certain definitions, data and modeling assumptions.[379] LADWP's existing OATT contains Attachment C but directs the user to the ATC Information folder posted on LADWP's OASIS for its ATC information.[380] Attachment C did not set forth LADWP's methodology for calculating ATC. The January 17 Proposal incorporated without change LADWP's Available Transfer Capability Implementation Document ("ATCID") (11.25.2011) with additional details noted in redline. The additional details included a statement that LADWP's ATC process flow diagram is shown in the ATC Information folder on OASIS.

2. Comments Received

Glendale and Burbank assert that LADWP's Proposed Tariff fails to "fully explain and justify LADWP's calculation of ATC.[381] Glendale and Burbank desire a "clear explanation of how LADWP calculates ATC generally and how specific MW amounts are used in calculating ATC for each posted path."[382]

3. General Manager's Decision

In response to Glendale and Burbank's comments, LADWP reconsidered its Attachment C. After reconsidering FERC's instructions for the preparation of Attachment C, as set forth in the FERC *pro forma* OATT, LADWP made number of changes to its Attachment C. First, LADWP removed the ATCID (11.25.2011) from Attachment C. That document will remain posted on OASIS. Second, Attachment C was reorganized to follow the organization anticipated by FERC's *pro forma* Attachment C. Third, the details expected by FERC to be included in

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[379] Order No. 890 at P 323. FERC's requirements are summarized in Order No. 890-B, App. B at Attachment C.

[380] Attachment C, Methodology to Assess Available Transfer Capability (Sept. 1, 2014) https://www.oasis.oati.com/LDWP/LDWPdocs/Attachment_C.pdf

[381] Glendale and Burbank Brief at 3:3-6 and 67:4-13.

[382] *Id.* at 67:11–13.

incorporated directly into the OATT.[388] Thus, to become consistent with FERC's *pro forma* OATT, LADWP's January 17 Proposal moved the existing Real Power Loss factors from its transmission business practice manual to Section 15.7 of its OATT.[389] Additionally, LADWP's February 21 Proposal incorporated the existing Real Power Loss factors into Section 28.5 of its OATT.[390] These Proposals made no changes to LADWP's existing Real Power Loss factors.

2. Comments Received

LADWP received no stakeholder objections to moving its Real Power Loss factors into its OATT. However, Burbank and Glendale commented on the Real Power Loss factors themselves. Specifically, Burbank and Glendale stated, among other things, that these Real Power Loss factors are overstated and have not been adequately justified.[391] In their data request, Burbank and Glendale asserted that Real Power Losses must be justified by a transmission losses study that uses available hourly metered data, or power flow simulations, for all hours of the test year for each of the facilities at issue.[392] Burbank and Glendale also requested that LADWP provide stakeholders with the power flow models LADWP used in its power loss study, as well as the base cases for each, and the variables and assumptions utilized.[393] Burbank and Glendale further requested that LADWP explain the data and methodologies employed in the power loss study.

In their April 14 Brief and Testimony, Burbank and Glendale further argue that the current Real Power Loss factors are outdated because they were developed outside of the test year, and presumably do not reflect efficiencies gained through improvements to LADWP's transmission system.[394] Burbank and Glendale also state that while they cannot determine the actual basis for the LADWP's current Real Power Loss factors because they do not have access to the studies used to develop them, LADWP should conduct a new transmission loss study, and revise the Real Power Loss factors according.[395] Burbank and Glendale also offer several recommendations on how a new power loss study should be conducted.[396]

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[388] Order No. 890-B, App. B §§ 15.7 and 28.5.

[389] LADWP OATT § 15.7; LADWP Real Power Loss Factors (Sept. 1, 2014), http://www.oasis.oati.com/LDWP/LDWPdocs/Real_Power_Loss_Factors.pdf.

[390] LADWP OATT Proposed Draft (Feb. 21, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/COMPARISON_OATT_2_-_Orig_2014_to_change_(02.21.2017).pdf § 28.5.

[391] March 8 Presentation at 22, 25.

[392] *Id.* at 25.

[393] *Id.*

[394] Glendale and Burbank Brief at 65.

[395] Glendale and Burbank Testimony, Exh. No. BWP/GWP-100 at 50.

[396] *Id.* at 51-53.

3. General Manager's Decision

The General Manager accepts the proposal to move LADWP's Real Power Loss factors from its business practices manual to its OATT, in compliance with FERC's *pro forma* OATT requirements. The General Manager agrees with Glendale and Burbank that LADWP should perform an updated Real Power Losses study as LADWP most recently conducted a loss study in 2011. Accordingly, LADWP has contracted with nFront Consulting to prepare an updated Real Power Losses study. The updated Real Power Losses study will serve as a basis for LADWP's evaluation of a possible future amendment of the Real Power Loss factors to be set forth in its OATT.

C. Interest on Deposits

1. LADWP Proposal

LADWP's existing 2014 OATT generally does not provide for interest payments on refunded deposits for Transmission Service Applications or System Impact Study Agreements.[397] In other places, LADWP's OATT is silent about the payment of interest altogether. Thus, LADWP's January 17 and February 21 Proposals continued the existing practice of not paying interest, and added language to Sections 17.3, 17.4, 17.6, 19.1, 19.4, and 20.3 to specify that fact.

2. Comments Received

In their data requests, Glendale and Burbank asked that LADWP provide a rationale for requiring customers to pay interest on delinquent amounts, while not paying interest on customers' refunded deposits.[398] LADWP responded that it does not pay interest on refunded deposits because LADWP does not invest those funds, and thus derives no revenue from which to pay this interest. Additionally, LADWP indicated that charging interest on late payments helps incent customers to make timely payments.[399] In their April 14 Brief, Glendale and Burbank responded that FERC requires interest payments on deposits and that LADWP should follow suit.[400]

3. General Manager Decision

The General Manager agrees to pay interest to conform with FERC's *pro forma* OATT. As such, LADWP will adopt the FERC *pro forma* provisions related to interest payments on deposits and has modified the OATT attached to this General Manager's certificate accordingly.

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[397] LADWP OATT §§ 17.3 & 19.1.

[398] Burbank and Glendale Data Request No. 43.

[399] March 31 Response at 72-73 (LADWP Response to Burbank and Glendale Data Request No. 43).

[400] Glendale and Burbank Brief at 67-68.

D. Intra-Hour Scheduling and Redirects

1. LADWP Proposal

Powerex provided comments generally supporting LADWP's stakeholder process and Proposed Tariff.[401] It also recommends that LADWP make additional changes to its business practices and operating protocols. Specifically, Powerex indicated that, as a long-time customer of LADWP, LADWP's Proposed Tariff, which more closely resemble FERC's *pro forma* OATT, provides customers a high degree of confidence in the durability and fairness of LADWP's transmission service. Additionally, Powerex supports the stakeholder process used to update LADWP's OATT, and states that this process has allowed customers to participate in an open and transparent manner.

2. Comments Received

Powerex states that several aspects of LADWP's Proposed Tariff remedy issues previously identified by Powerex, and thus are beneficial. These changes include LADWP's proposed changes to Sections 13.8 and 14.6 of its OATT to allow for 15-minute scheduling of Firm and Non-firm Point-to-Point Transmission Service. Powerex states it supports these changes as conforming to the *pro forma* OATT and aligning LADWP's service with other western transmission providers. Powerex also indicates support for the revisions to Section 2.1 of LADWP's OATT, which allows for automatic renewal of Transmission Service Agreements.

In addition to supporting LADWP's effort to update its OATT, Powerex urges LADWP to undertake a similar review of its business practices and operational protocols. According to Powerex, business practices or operational protocols that do not align with LADWP's Proposed Tariff can nullify these beneficial OATT changes. For example, Powerex states that LADWP must ensure that its business practices governing intra-hour scheduling must be made consistent with the revisions to Sections 13.8 and 14.6 of the OATT. Moreover, Powerex states that LADWP's operating protocols must allow for the scheduling of 15-minute increments on all transmission facilities physically capable of supporting such scheduling, including the Pacific DC Intertie. In this regard, Powerex notes that while both LADWP and BPA must agree to allow 15-minute scheduling on the PDCI, it hopes LADWP will indicate its support for such 15-minute scheduling and that LADWP will work with BPA to achieve this outcome. Powerex also requests that LADWP ensure its operational practices align with the provisions of Section 22.2 of its OATT, which permits firm redirect service on all paths with firm ATC.

3. General Manager's Decision

Powerex correctly points out that Sections 13.8 and 14.6 of LADWP OATT, and its business practices, allow for 15-minute scheduling.[402] However, as Powerex acknowledges,

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[401] *See* Powerex Comments on LADWP January 17, 2017 OATT Revisions (Mar. 3, 2017), https://www.oasis.oati.com/LDWP/LDWPdocs/Powerex_LADWP_Jan_17_OATT_Revisions_Comments.pdf.

[402] *See* LADWP Intra-Hour Transmission Service and Scheduling (Effective Sept. 27, 2016), http://www.oatioasis.com/LDWP/LDWPdocs/Intra-Hour_Transmission_Service_Business_Practice.pdf.

LADWP cannot unilaterally change the operating protocols of the PCDI. This requires the agreement of BPA. However, as Powerex requests, LADWP supports 15-minute scheduling on the PCDI and will work with BPA to achieve this end.

Additionally, Powerex is correct that LADWP has not revised its OATT regarding firm redirect requests. And while LADWP seeks to implement firm redirect requests in line with its OATT and business practices,[403] LADWP is limited with regard to the PCDI because LADWP cannot unilaterally change the operating protocols of this line. However, if there are specific instances where LADWP has not implemented firm redirect requests in accordance with its OATT and business practices, please bring such instances to the attention of LADWP staff, who will work to remedy these errors. LADWP's contacts are set forth on OASIS.[404]

E. Municipal Tax Exempt Bonds and Private Use Restrictions

1. LADWP Proposal

LADWP has proposed revisions to OATT sections 2, 5, 13.1, 23.1, and 28.1A, and the addition of Attachment A-2, in order to satisfy private use restrictions imposed by the Internal Revenue Service ("IRS") on LADWP's outstanding municipal bonds. The Proposed Tariff seeks to ensure that transmission service is not offered in an unduly discriminatory or preferential manner while satisfying the safe harbor provisions, that avoid private business use problems, specified by the IRS. To meet this standard, the Proposed Tariff would allow LADWP to provide Transmission Service to an Eligible Customer for a term greater than three years if the Eligible Customer, in the exclusive judgment of LADWP, meets the criteria established in LADWP's modified section 5.2.

2. Comments Received

Six Cities provided comments in which they state they does not oppose LADWP's above-referenced Tariff modifications. However, Six Cities requests certain additional OATT revisions to facilitate the transfer of transmission entitlements from Six Cities to the operational control of the CAISO, or other RTOs or Independent System Operators ("ISOs"). Specifically, Six Cities requests the addition of a new tariff section 5.2.6 to explicitly provide for such transfers. Similar conforming revisions to OATT sections 5.2.5, 23.1 and Attachment A-2 are also proposed.

In addition, Six Cities' also seeks to remove the word "unqualified" from LADWP's proposed section 5.2.3 allowing for Eligible Customers to provide documentary support, such as an IRS letter ruling or unqualified opinion of a nationally recognized bond counsel, in support of Certification as required under section 5.2.1. Six Cities also seeks to require LADWP to exercise reasonable rather than exclusive judgment in determining whether a customer satisfies the requirements of section 5.2 of the OATT. Finally, Six Cities' proposes additional revisions to

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[403] LADWP Business Pratices: Redirect Service (Feb.25, 2014), https://www.oasis.oati.com/LDWP/LDWPdocs/Redirect_Service_Business_Practices.pdf.

[404] LADWP Contacts (Aug. 11, 2014), https://www.oasis.oati.com/LDWP/LDWPdocs/contacts.pdf.

sections 2.1, 2.2 and 15.6 to allow the terms of existing service agreements that would otherwise expire, terminate, or be subject to the renewal procedures set forth in section 2 of the Tariff to govern the renewal or extension of service upon the agreement's expiration.

3. General Manager's Decision

The General Manager accepts several of Six Cities' proposed changes to LADWP's OATT, but rejects others as explained below. FERC has consistently recognized the challenge faced by pubic power entities with certain tax-exempt financial instruments in conforming to the Commission's specific open access requirements.[405] In establishing its open access policies, the Commission acknowledged that its purpose is not to disturb the IRS's regulatory authority and discretion with respect to tax-exempt financing. In its Proposed Tariff, LADWP has attempted to incorporate the IRS' safe harbor requirements into the tariff while ensuring its non-rate terms and conditions of service are "comparable to those under which [it] provides transmission service to itself and that are not unduly discriminatory or preferential," consistent with section 211A of the FPA.[406]

LADWP agrees with Six Cities that LADWP's Proposed Tariff incorporating the IRS' safe harbor requirements into the OATT should also provide for, and facilitate, an Eligible Customer's transfer of transmission entitlements to the operational control of an RTO/ISO, and that such provisions were absent from LADWP's proposal. As a result, LADWP has modified its OATT to address Six Cities' requests as detailed below.

LADWP accepts Six Cities' proposed OATT section 5.2.6, and conforming revisions to sections 5.2.5, 23.1 and Attachment A-2, with additional clarification. Namely, LADWP will condition a customer's transfer of transmission service provided by LADWP to the operational control of an RTO or ISO on (i) the customer's provision of an unqualified opinion of a nationally-recognized bond counsel and (ii) LADWP's reasonable but exclusive determination that such a transfer will not impair the tax-exempt status of LADWP's outstanding municipal bonds. Relatedly, LADWP maintains the requirement in section 5.2.3 that such opinions be "unqualified." Allowance of an opinion that is less than unqualified is inconsistent with the level of opinion provided by LADWP to bondholders in the initial bond offering, and is inconsistent with the bonds themselves. As a result, LADWP cannot risk weakening the opinion given to bondholders by allowing for anything less than an unqualified opinion with regard to this issue. Additionally, as indicated above, LADWP amends its "exclusive" determination on the impact of transfers on its municipal bond status to incorporate the requirement that LADWP's determination shall also be reasonable. However, LADWP maintains its exclusive authority to make such determinations.

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[405] Order No. 888 at pp. 31,760-63; *Regional Transmission Organizations*, Order No. 2000, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,089, at pp. 31,197-98 (1999), *order on reh'g*, Order No. 2000-A, 1996–2000 FERC Stats. & Regs., Regs. Preambles ¶ 31,092 (2000), *pets. for review dismissed sub nom. Pub. Util. Dist. No. 1 v. FERC*, 272 F.3d 607 (D.C. Cir. 2001); *see also* Order No. 890-B at p. 62,104.

[406] 16. U.S.C. § 824j-1.

LADWP also accepts Six Cities' requested revisions to sections 2.1, 2.2 and 15.6 of the tariff, with additional modification. LADWP agrees with Six Cities that, when possible, a prior agreement's provisions governing continuation, renewal, or extension of agreement should be determinative, and its existing tariff does not require prior service agreements to comply with the requirements of section 5.2 until the contract expires, rolls over or is renewed. However, LADWP is concerned that service agreements entered into prior to this Tariff may not satisfy the IRS safe harbor requirements necessary to protect its municipal bond status, especially as the safe harbor rules have been modified by the IRS over time and interpretations of those rules may also have evolved. Therefore, as stated in Part V.A below, General Manager finds that existing contracts with a rollover right at the time of effectiveness of the Tariff Revisions may exercise their next rollover based on the existing notice rules. It is only a rollover contract entered into or renewed after the effectiveness of the Tariff Revisions that must comply with the new rollover provisions, including the one-year notice requirement.[407] However, to ensure compliance with the IRS safe harbor provisions, that avoid private business use problems, the transmission customer must meet the same requirements that apply to a new service agreement. On balance, LADWP believes this amendment provides adequate protection for existing service customers while ensuring its municipal bonds are not jeopardized.

F. Attachment L—Creditworthiness Procedures

1. LADWP Proposal

In FERC Order No. 890, the Commission added a new Attachment L, creditworthiness procedures to the *pro forma* OATT. In doing so, the Commission requires that Attachment L contain "the qualitative and quantitative criteria that the transmission provider uses to determine the level of secured and unsecured credit required."[408] LADWP's existing OATT contains Attachment L but links to additional credit worthiness procedures posted on LADWP's OASIS. Attachment L did not contain LADWP's procedures. The January 17 Proposal incorporated LADWP's existing Creditworthiness Procedure (09.01.2014) into Attachment L with minor changes, along with LADWP's Transmission Credit Policy (08.18.2014).

2. Comments Received

Stakeholders submitted no comments on Attachment L. However, during the regular course of business LADWP reviewed its transmission credit practices with its general credit practices. During that review LADWP discovered revisions are warranted to Attachment L to better align Attachment L with the Commission's expectations. LADWP therefore revised Attachment L to clarify: That an investment grade credit rating is required from its lowest rating, if there are multiple ratings; the criteria applied to calculating an equivalent rating for unrated utilities; the factors considered when establishing the actual quantity of unsecured credit that may be extended to a utility up to the maximum quantity of unsecured credit; the forms of

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[407] Order No. 890 at P 1267; Order No. 890-A at PP 694-96.

[408] Order No. 890 at P 1657.

security that may be provided when a counterparty must post security; and the ability of a counterparty to request an explanation of a credit determination, and made other clarifying edits.

3. General Manager's Decision

The General Manager accepts the incorporation of LADWP's creditworthiness procedures and transmission credit policy into Attachment L along with the additional edits resulting from LADWP review of its existing practices with FERC's *pro forma* OATT. As such, the General Manager has modified Attachment L of the OATT attached to this General Manager's Certificate.

G. Attachment M—Large Generator Interconnection Procedures

1. LADWP Proposal

The January 17 Proposal incorporated an updated Attachment M, Large Generator Interconnection Procedures, which includes LADWP's form of Large Generator Interconnection Agreement. On February 21, 2017, LADWP posted a revised version of the Large Generator Interconnection Procedures in which LADWP amended certain provisions of the form of Large Generator Interconnection Agreement to provide non-synchronous generation with options related to power factor design criteria and cost responsibility related to operating and maintaining voltage regulation. LADWP also made minor editorial changes to the form of Large Generator Interconnection Agreement to replace the term "Balancing Authority" with "Control Operator," and remove references to FERC orders and submitting filings to FERC.

2. Comments Received

No comments were received from stakeholders on Attachment M. However, LADWP has determined that further changes to the form of Large Generator Interconnection Agreement and the Large Generator Interconnection Procedures are warranted to include provisions for the reimbursement of certain expenses incurred by an Interconnection Customer in the event of third-party use certain Interconnection Facilities, and made implementing revisions. LADWP also revised the form of agreements appended to the Large Generator Interconnection Procedures to conform to LADWP's interconnection study processes.

3. General Manager's Decision

The General Manager accepts the incorporation of the proposed changes to Attachment M. The proposed changes incorporate, generally, the currently effective FERC *pro forma* Large Generator Interconnection Procedures, as of December 2016, including the currently effective Large Generator Interconnection Agreement. Where LADWP has deviated from the FERC *pro forma* to accommodate LADWP's system, LADWP's business practices and the fact that LADWP is not a FERC jurisdictional entity, and to benefit interconnection customers, those deviations are either consistent with or superior to the FERC pro forma. As such, the General Manager has modified Attachment M of the OATT attached to this General Manager's Certificate.

H. Ministerial Changes

Attachment K of the February 21 Proposal included in section VII.B.9 a mistaken reference to VII.C.6, which does not exist. The appropriate reference is VII.B.6, which has been corrected in the Proposed Tariff attached to this General Manager's Certificate.

I. Stakeholder Process

1. Comments Received

Glendale and Burbank assert: "Stakeholders were provided only approximately 60 working days to review and comment on the materials. This is an unreasonably limited amount of time to conduct discovery and prepare of testimony. LADWP compounded this issue by asserting claims of privilege over necessary information, responding late or not responding at all to discovery requests, and drafting several responses in a manner that required follow-up to achieve clarity and receive requested documentation. LADWP's use of its consultants to shield it from answering certain information requests is of particular concern."[409]

2. General Manager's Decision

Glendale and Burbank's complaints about the process are without merit. Consultants were used to develop cost-based rates with objective independence, using FERC precedent as a guidepost. LADWP adhered to its business practice that was developed with full stakeholder input. LADWP extended the schedule by a week to accommodate Burbank and Glendale scheduling requirements. LADWP further accommodated Glendale and Burbank by re-scheduling the final public comment forum and flying consultants to LADWP for an additional, unscheduled technical conference in February. LADWP responded to all 135 data requests (with multiple subparts for a total of 372 data requests) made by Burbank and Glendale within the period specified in the LADWP's business practices. While initially only data reviewed by consultants was provided, LADWP has provided additional, clarifying information. LADWP did

[409] Glendale and Burbank Brief at 2:8-14.

not provide data that was unduly burdensome or had no relevance to the issues under consideration.

PART V: EFFECTIVE DATES

This section describes the effective date for the changes to rates, terms and conditions of LADWP's OATT.

A. Rates, Terms and Conditions (excluding Part III Network Integration Transmission Service); Rollover Rights

The rate changes and changes to the terms and conditions reflected in the Tariff Revisions, except for (a) Part III Network Integration Transmission Service and the associated definitions and Attachments, and (b) Attachment M, set forth in this General Manager's Certificate, if approved by the Board and City Council, shall: (1) become effective on the first day of the month, two months following the date of City Council approval (the "Effective Date"), and (2) be incorporated into all current and future transmission service agreements as of the Effective Date.[410] The proposed terms and conditions set forth in Attachment M, the Large Generator Interconnection Procedures, shall: (1) become effective on the Effective Date, and (2) be incorporated into all agreements associated with Attachment M entered into on or after the Effective Date.[411]

The General Manager recognizes that Transmission Customers with rollover rights may not be able to comply with notice provisions set forth in the Tariff Revisions as the Tariff Revisions requires notice be provided father in advance that is required in the existing OATT. Accordingly, the General Manager finds that existing contracts with a rollover right at the time of effectiveness of the Tariff Revisions may exercise their next rollover based on the existing notice rules. It is only a rollover contract entered into or renewed after the effectiveness of the Tariff Revisions must comply with the new rollover provisions, including the one-year notice requirement.[412] However, to ensure compliance with the IRS safe harbor provisions, that avoid private business use problems, the transmission customer must meet the same requirements that apply to a new service agreement.

B. Rates, Terms and Conditions—Network Integration Transmission Service

The rate changes and changes to the terms and conditions set forth in Part III "Network Integration Transmission Service" of the tariff and the associated definitions and Attachments

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[410] *Midwest Indep. Transmission Sys.Operator, Inc.*, 142 FERC ¶ 61,215, at PP 176-78 (2013) ("where the terms of an agreement would, if approved, be incorporated into the service agreements of all present and future customers, those terms are properly classified as tariff rates and the Mobile-Sierra presumption would not apply."), *order on reh'g*, 147 FERC ¶ 61,127 (2014), *order on reh'g*, 150 FERC ¶ 61,037 (2015).

[411] *Midcontinent Indep. Sys. Operator, Inc.*, 152 FERC ¶ 61,145, at P 13 (2015) ("The Commission reasoned that it has consistently held that the governing Tariff provisions are those in effect at the time an LGIA is executed or filed unexecuted."), *order on reh'g*, 154 FERC ¶ 61,072 (2016).

[412] Order No. 890 at P 1267; Order No. 890-A at PP 694-96.

(collectively referred to as "NITS") set forth in this General Manager's Certificate become effective, if approved by the Board and City Council, by February 1, 2019 following the date of City Council approval. Since LADWP does not currently offer NITS, a delayed effective date is necessary to allow LADWP sufficient time to procure and implement software upgrades, adopt transmission business practices, train personal, and retain, as necessary, additional personnel, and to allow eligible customers sufficient time to plan for the request and implementation of NITS and to participate in the development of transmission business practices. To provide transparency of implementation, if NITS is approved by the Board and City Council, within 30 days following the date of City Council approval, the Senior Assistant General Manager–Power System Engineering, Planning, and Technical Services shall: (1) cause LADWP to post on OASIS the key milestones associated with NITS implementation; and (2) at the end of each calendar quarter until implementation is complete, provide the General Manager and stakeholders with implementation progress reports.

PART VI: ATTACHMENTS

Attachment A: Sets forth all the documents that are part of the administrative record upon which the General Manager based his decision.

Attachment B: Clean May 4, 2017 OATT.

Attachment C: Redline of the May 4, 2017 OATT against the current, 2014 OATT.

Attachment D: Redline of the May 4, 2017 OATT against the February 21, 2017 OATT that was posted for stakeholder comment.

Attachment E: May 4, 2017 Cost of Service Model.

Attachment F: Mathematical Algorithms for Calculation of Firm and Non-Firm ATC

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PART VII: General Manager's Findings, Certification, and Recommendation

Based upon the analysis and decisions set forth above, the General Manager finds that final Tariff Revisions establish rates, and terms and conditions of service that are comparable to those under which LADWP provides transmission services and ancillary services to itself and that are not unduly discriminatory or preferential. Accordingly, the General Manager certifies that the final Tariff Revisions were developed using traditional principles, processes and procedures of cost-of-service rate making, and recommends that the Board and City Council approve the final Tariff Revisions. This General Manager's Certificate shall accompany the final Tariff Revisions, along with the suite of supporting data, studies and documents, for consideration by the Board and City Council.[413]

Dated this 4th day of May 2017.

By David H. Wright

David Wright
General Manager
Los Angeles Department of Power and Water

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[413] Public Participation Business Practices § 12(b).