UNITED STATES OF AMERICA 115 FERC ¶63,044
FEDERAL ENERGY REGULATORY COMMISSION

The United Illuminating Company Docket No. EL05-76-001

v.

Dominion Energy Marketing, Inc.

INITIAL DECISION

(Issued May 24, 2006)

APPEARANCES

James Beh, Jennifer A. Kerkhoff, Mark. E. Nagle, and *Duane Duclax* on behalf of Dominion Energy Marketing, Inc.

C. Fairley Spillman, Charles Franklin, and *Phil Nowak* on behalf of The United Illuminating Company.

Charlotte J. Hardnett, Presiding Administrative Law Judge

BACKGROUND

1. The dispute between the Parties arises from a December 28, 2001, Wholesale Power Supply Agreement ("PSA") between Virginia Electric and Power Company ("VEPCO"), a subsidiary of Dominion Resources, Inc. ("Dominion") and the United Illuminating Company ("UI"). In December 2001, UI and VEPCO negotiated the PSA, exchanging term sheets and draft agreements and engaging in discussions about various issues. The PSA was first executed on December 28, 2001, and was subsequently amended and restated on January 28, 2002, with changes not at issue in this case. Later in 2002, VEPCO assigned the PSA to Dominion Energy Marketing, Inc., ("DEMI"), another subsidiary of Dominion. At issue in this proceeding is whether the PSA allocates responsibility for the reliability cost tracker charges, which are charges arising under reliability must run ("RMR") agreements, to UI or to DEMI.[1]

PROCEDURAL HISTORY

2. On March 14, 2005, UI filed a complaint with the Federal Energy Regulatory

[1] DEMI Initial Brief ("DEMI IB") at 1-2 and 5; United Illuminating Initial Brief ("UI IB") at 4.

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Commission ("Commission" or "FERC").[2] The Commission assumed original jurisdiction[3] and on May 13, 2005, issued an order finding that the PSA allocated responsibility for the reliability cost tracker charges to DEMI.[4] The Commission found that section 2.1(c) of the PSA assigned all costs, including transmission congestion costs, associated with delivery of energy to DEMI.[5]

3. On June 13, 2005, DEMI filed a request for rehearing of the May 13 Order.[6] On September 15, 2005, the Commission issued an order granting rehearing and instituting hearing procedures. The Commission directed that the designated Presiding Administrative Law Judge, after evidentiary hearing, determine which Party is responsible for the reliability cost tracker charges at issue.[7]

4. On September 19, 2005, the Chief Administrative Law Judge designated Administrative Law Judge Charlotte J. Hardnett as Presiding Judge to hear the matter. A prehearing conference was held on October 13, 2005. The hearing was held on February 28 and March 1, 2006.

ISSUE

5. ISSUE -- Whether the PSA allocates responsibility for the reliability cost tracker charges to UI or to DEMI? Sub-issues to be resolved are: 1) whether "reliability cost tracker" charges are "transmission congestion costs" within the meaning of section 1.9 of the PSA[8]; 2) whether "reliability cost tracker" charges are "associated with the delivery of Energy" within the meaning of section 2.1(c) of the PSA; and, 3) what is the proper allocation of reliability cost tracker charges between DEMI and UI if

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[2] *UI Co. v. DEMI Energy Mktg. Inc.*, *Complaint of The UI Company for Order Directing DEMI Energy Marketing, Inc. to Comply With the Terms of Its Filed Rate Schedule*, filed Mar. 14, 2005, Docket No. EL05-76-000 ("Complaint").

[3] On April 13, 2005, DEMI filed a lawsuit against UI in the United States District Court for the District of Connecticut in *UI Co. v. DEMI Energy Mktg. Inc.*, *Motion to Dismiss and Answer of DEMI Energy Marketing, Inc.*, filed April 13, 2005 ("Answer").

[4] *UI Co. v. DEMI Energy Mktg., Inc.*, 111 FERC ¶ 61,224 at 62,023-24, ("May 13 Order"), *reh'g granted*, 112 FERC ¶ 61,279 (2005) ("September 15 Order").

[5] *Id.*

[6] *UI Co. v. DEMI Energy Mktg., Inc.*, *Request for Rehearing of DEMI Energy Mktg., Inc.*, filed June 13, 2005, Docket No. EL05-76-000 ("DEMI's Request for Rehearing").

[7] September 15 Order, 112 FERC ¶ 61,279 at 62,279 (2005).

[8] Ex. UI-4 at 18.

reliability cost tracker charges are found to be associated with the delivery of energy pursuant to section 2.1(c) of the PSA.

POSITIONS

TRANSMISSION CONGESTION COSTS

6. UI - - The position of UI is that the PSA assigns responsibility for reliability cost tracker charges, a form of RMR charge imposed by ISO-NE, to DEMI as evidenced by, the express language of the PSA itself, the intent of the Parties at the time of execution of the PSA, and implementation or course of performance of the PSA.[9]

7. Article I of the PSA contains the definitions of specific words and terms used in the PSA. Section 1.90 of the PSA defines "transmission congestion costs" as "all costs resulting from insufficient transmission capacity, without regard to the cause of such congestion or how such costs are allocated or assessed including … . "[10] UI argues for a broad reading of section 1.90 claiming that what follows the word, "[i]ncluding," in section 1.90 are just examples, and does not constitute an exclusive list of what could be considered transmission congestion costs. Therefore, it is not determinative that the "reliability cost tracker charges" at issue are not listed as an example of a transmission congestion cost.[11] In support of its position, UI points to Article XIX of the PSA, which addresses contract interpretation. Article XIX provides that the words "[i]ncludes" or "including" means "including, without limitation."[12]

8. It is UI's position that the PSA cost allocation provisions were broadly drafted intentionally because transmission congestion was a recognized market issue at the time the PSA was executed.[13] The PSA, according to UI, is an "all-in" fixed-price requirements contract which UI bargained for in order to secure a predictable, fixed price for wholesale energy throughout the life of the PSA to accommodate the risk associated with the volatility of the delivery costs of energy during the transition to a competitive market. DEMI agreed to provide at a fixed price the electricity necessary to

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[9] UI Initial Brief ("UI IB") at 1-2, and UI Reply Brief at 1.

[10] Ex. UI-4 at 18.

[11] UI IB at 13-18 and UI RB at 6-7.

[12] *Id*. at 13.

[13] *Id*. at 12-13, *citing* Ex. UI-1 at 14, Ex. UI-2 at 6, Ex. UI-3 at 6, Ex.UI-73, Ex. DOM-4 at 18-19, Ex. DOM-18 at 13; Tr. 235-36, Tr. 323, Tr. 320, Tr. 326; and, *United Illuminating Co. v. Dominion Energy Mktg., Inc., Joint Stipulation Regarding the Admissibility of Certain Exhibits and Taking of Testimony*, Dkt. No. EL05-76-001 at ¶ 10.

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serve UI's load.[14]

9. Robert T. Gagliardi, a UI witness, is Director of Strategic Policy at UI. Mr. Gagliardi testified about UI's intent in carrying out the initial bidding solicitation and negotiating the PSA. Mr. Gagliardi testified that UI began receiving unsolicited expressions of interest from wholesale suppliers in 2001 because there was industry expectation that Enron would default. When it became evident Enron would default, UI took steps to find an alternative supplier and in late 2001 sent e-mail messages to companies, outlining UI's bid requirements and specifications.[15]

10. Mr. Gagliardi testified that the bid requirements specifically stated that bids should be based on the bidder taking responsibility for settlement uplift, transmission congestion, and ISO-NE Tariff Schedule II and III costs. He testified that the term, "transmission congestion costs," was highlighted in the bid solicitation. The agreement with Enron had allocated those costs to Enron and UI believed that allocation provision was important and should be in any replacement agreement. Some bidders complained; DEMI was one of them. DEMI expressed concern about uncertainty of the future magnitude of future transmission congestion costs. DEMI was encouraged to contact ISO-NE for whatever information it could provide about future costs. Mr. Gagliardi testified that he was not sure whether DEMI followed that advice or not. Mr. Gagliardi testified that DEMI did not raise the issue again during negotiations, nor did DEMI propose language for inclusion in the PSA that would have limited its responsibility for transmission congestion costs.[16]

11. Dennis E. Hrabchak, a UI witness, is Vice President of Corporate Affairs for UI. Mr. Hrabchak testified that he had been involved in the PSA negotiations. Mr. Hrabchak testified that at the time the PSA was being negotiated, the wholesale power market in New England was transitioning from cost-based, market-regulated rates, to an open-access, competitive market. He testified that the PSA was originally executed on December 28, 2001 and became effective on January 1, 2002. It was amended, in ways not relevant here, and restated on January 28, 2002. UI's strategy and goal in entering into the PSA was to minimize its risk occasioned by the changing nature of the regional market.[17]

12. Mr. Hrabchak testified that in order to minimize its risk, UI had suppliers incorporate various categories of costs into their fixed rates. Mr. Hrabchak testified that

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[14] *Id*. at 39-40, *citing* Ex. UI-1 at 7-9 and 10, Ex. UI-3 at 7, Ex. UI-37 at 5.

[15] Ex. UI-2 at 2-5.

[16] *Id*. at 5-9.

[17] Ex. UI-3 at 5-6.

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UI understood that some suppliers would be concerned about taking on the risks associated with uncertainties surrounding future wholesale power costs, including transmission congestion costs associated with the delivery of energy, but UI was willing to pay a premium for shifting the risks. He testified that UI intentionally kept the terms of the agreement very broad in order to allocate the risks of the wholesale market to the supplier which, in this case, which turned out to be DEMI.[18]

13. Cliff W. Hamal, a UI witness, is an economist with experience in electric industry contracts. Mr. Hamal provided testimony supporting UI's claim that RMR fixed-price type agreements were known to be a distinct possibility due to industry conditions existing around the time of execution of the PSA. Mr. Hamal testified that by May 1997 it was clear to New England market participants that the fixed costs of generators needed for reliability in load pockets would have to be paid and on May 1, 1997, NEPOOL submitted proposed Market Power Mitigation Principles and a Market Power Mitigation Procedure to the Commission. Mr. Hamal testified that the Principles and Procedures filed on May 1, are quite explicit in allowing the recovery of those fixed costs. Market Power Mitigation Principle 5 provided that payments would cover all costs necessary to keep the RMR units in operation and fixed costs are specifically referenced. Market Rule 17 explicitly recognized that units that are seldom run except for load pocket conditions, must be allowed to recover their fixed costs. Therefore, according to Mr. Hamal, even as early as 1997, there was indication that fixed-price contracts would be used in New England.[19]

14. The May 1999 "State of the Market Report, 1998" recognized that a standard response to local market power was to regulate RMR units. The market in Ontario also had provisions for RMR contracts in place before the PSA was executed. Even ISO-NE had specific rules accepting the potential for RMR contracts to cover revenue insufficiency that might result from the bid caps. Additionally, in May through June of 2000 the problems associated with the need to compensate RMR units to maintain system reliability were well-recognized as evidenced by an article in *American Scientist Online* discussing the issue. According to Mr. Hamal, VEPCO was aware of the need to fully compensate a RMR unit for all costs three years before the execution of the PSA.[20]

15. Therefore, according to Mr. Hamal, at the time of execution of the PSA, the potential for RMR generators to need additional revenue to cover fixed costs in order to stay in operation and ensure reliable service was widely recognized. He testified that the California market had relied on RMR contracts since its inception. New York was, at that time, addressing the load pocket problem through locational capacity

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

[19] Ex. UI-43 at 13-16.

[20] *Id.* at 41-44.

requirements. In PJM, although fixed cost recovery was not explicitly recovered by RMR contracts, generators constrained for local reliability reasons were allowed to recover a moderate premium over their fixed costs. In addition, in Pennsylvania-New Jersey-Maryland Interconnection ("PJM"), there were provisions for separately negotiated contract prices.[21]

16. Michael A. Coretto, a UI witness, is the Director of Regulatory Strategy and Retail Access at UI. Mr. Coretto testified that UI would have to buy on the spot markets if it did not use wholesale power agreements to meet its load demands. Mr. Coretto testified that UI had not relied on spot markets since the divestiture of its generation and the advent of industry restructuring in Connecticut because the prices in those short-term markets fluctuate significantly. Long-term power supply agreements allow UI to place more of the risks and uncertainties of the wholesale market on the supplier. According to Mr. Coretto, UI considers economic and industry trends before drafting agreements that allocate costs among the parties.[22]

17. Mr. Coretto testified that he had been a member of the UI management team established to address the issue of possible insolvency of Enron. He testified that the team developed a strategy for obtaining a replacement wholesale power source, which had as a goal entering into a wholesale power supply agreement in which the supplier was responsible for the costs associated with delivery of energy and market products to UI, including the costs resulting from insufficient transmission capacity in the region. Mr. Coretto testified that this condition was so important to UI because UI was very concerned about the impact that the growing problem of congestion would have on the price of wholesale energy during the term of the contract. By asking bidders to build estimates of future transmission congestion and other costs into the fixed rates they bid, UI intended to shift the burden and risk of evaluating, anticipating, and quantifying risks associated with future costs.[23]

18. Mr. Coretto testified that UI sent DEMI and other bidders, the text of the UI-Enron agreement. The bidders had the opportunity to comment on the UI-suggested agreement terms and to suggest others. The language, "the material economic terms of the Agreement have been subject to individual negotiation by the Parties" was included in the PSA at DEMI's insistence. DEMI did not object to the proposed PSA language affording no presumption against the party drafting the agreement in the event of ambiguity in the PSA. Nor did DEMI object to the language defining the terms "includes" and "including," according to Mr. Coretto. DEMI submitted the best bid.[24]

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[21] *Id.*

[22] Ex. UI-1 at 2-7.

[23] *Id*. at 14-15.

[24] UI IB 16-18*; see* Section 1.9 and Article XIX.

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19. Mr. Coretto testified that UI and DEMI mutually agreed to the broad definition of "transmission congestion costs" because both Parties were aware that transmission congestion would be a material consideration in pricing future energy delivery costs even though reliability cost tracker charges were not established at the time the PSA was negotiated. Therefore, UI and DEMI thought it reasonable to have categorical cost allocation language in the PSA instead of enumeration of specific charges.[25]

20. Mr. Coretto testified that UI and DEMI had explored the possibility of an extension of the PSA, because of the legislative and regulatory discussion occurring in Connecticut in the spring of 2003. However, UI concluded that it would better suit their interests to conduct a competitive bidding process to find a future supplier for transitional standard offer ("TSO") service. Mr. Coretto explained that TSO refers to the standard offer terms that Connecticut law required UI to offer retail customers beginning January 1, 2004. The TSO replaced the Standard Offer Service ("SOS"). Mr. Coretto related that UI used a request for proposal ("RFP") to seek bids from wholesale suppliers to provide energy and market products needed to meet UI's obligations to its TSO customers.[26]

21. Mr. Coretto testified that in preparing the terms for the RFP, UI used the PSA as a starting point. UI did update some PSA terms to reflect various legal and other changes in the market since the PSA was originally executed. For example, Connecticut had passed a law that allowed federally mandated congestion costs ("FMCC"), such as locational market pricing ("LMP") and RMR agreements, to be passed through to retail customers. UI also agreed to accept responsibility for costs associated with RMR agreement allocated and charged to UI *pro rata* portion or share of the network load within the affected Reliability Region.[27]

22. Mr. Coretto testified that UI eliminated the definition of "transmission congestion cost," following the logic of the PSA in that the supplier would be responsible for most costs other than those specifically identified up to the delivery points. UI would be responsible for costs from those points on. Mr. Coretto testified that UI was comfortable with that approach because it knew it could pass costs associated with RMR agreements on to retail customers. In addition, after discussions with DEMI and other possible suppliers, UI had come to the conclusion that requiring bidders to build the costs of RMR agreements into their energy rates was likely to inflate the rate proposals received from bidders, or to discourage possible bids. That

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[25] Ex. UI-1 at 37-38.

[26] *Id*. at 50-51.

[27] *Id*. at 50-53, Ex. UI-15 and 2005 Ct. ALS 1; 2005 Cr. P.A. 1; 2005 Ct. HB 7501.

approach was thought to encourage competitive bids. Also, Mr. Coretto testified that UI was comfortable with this approach because it was confident that if it retained responsibility for costs associated with RMR agreements, DPUC would allow UI to pass the FMCC costs on to retail customers.[28]

23. UI maintains that the present dispute is not covered by section 17.2 of the PSA, contrary to DEMI's argument in its request for rehearing that the Commission erred by not considering the effect of section 17.2. Section 17.2 is the regulatory changes provision of the PSA. As such, section 17.02 provides that, if during the term of the PSA, changes occur with the Restated NEPOOL Agreement in a manner that would materially adversely affect the rights or responsibilities of a party to the Agreement, the parties were to negotiate to amend the Agreement to incorporate the changes. UI points out that DEMI witness, Mr. Armstrong, admitted that DEMI did not invoke or even consider invoking section 17.2 before filing suit in federal court. UI argues that it is obvious that DEMI did not invoke section 17.2 for the reason that it had no expectation that it applied.[29]

24. According to UI, the Restated NEPOOL Agreement has to be terminated or amended in a manner that would eliminate or materially change a NEPOOL rule and the termination or amendment would have to be expected to have an adverse effect on the rights or responsibilities of either of the parties to the PSA. DEMI did not identify any termination or amendment that would trigger section 17.2. The reliability cost tracker charges did not result from a material alteration of any NEPOOL rule. ISO-NE first entered into a fixed-payment RMR agreement in December 2001 under the authority of Market Rule 17. UI maintains that even the switch to Standard Market Design ("SMD"), which occurred after ISO-NE began using fixed-payment RMR agreements, did not have a material impact on the rights and responsibilities of the Parties under the PSA as they relate to the costs associated with RMR units because DEMI was responsible for those costs before SMD.[30]

25. DEMI - - The position of DEMI is that the PSA allocates responsibility for the reliability cost tracker charges to UI. According to DEMI, those charges are not within the PSA's definition of "transmission congestion costs" because: 1) at the time of negotiation of the PSA such charges did not exist; 2) applicable market rules defined "transmission congestion costs" as costs resulting from out-of-merit dispatch; 3) no RMR agreements with fixed monthly payments existed in the New England market at the time of execution of the PSA; 4) and, both FERC and ISO-NE requires that material

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[28] *Id.* at 53-54.

[29] UI-IB at 45-46, *citing* Ex. UI-4 at 63-64, Ex. UI-37 at 11, Ex. DOM-18 at 18-19.

[30] UI IB at 46-47, *citing* Ex. UI-4 at 65, Ex. UI-37 at 10-11 and 18, Ex. DOM-19 at 6; and, Tr. 252-53.

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changes to the governing market rules are required in order for RMR agreements with fixed monthly payments, including the agreements giving rise to the reliability cost tracker charges at issue here, to become effective. [31]

26. DEMI claims that UI is not correct in its conclusion that the PSA's definition of "transmission congestion costs" is unique. DEMI argues that the term "transmission congestion costs" should be interpreted consistent with the market rules in place at the time of execution of the contract. DEMI maintains that the market rules at place when the PSA was executed only referred to the costs resulting from out-of-merit dispatch, and not to fixed costs. At that time, 2001, ISO-NE managed transmission congestion through the out-of-merit order generation dispatch. The amount by which the out-of-merit order generator bids exceeded the market-clearing price was termed by ISO-NE "transmission congestion costs" and was billed to all load-serving entities ("LSEs") based on their respective load shares. Market Rule 1, the definitional section of the governing market rules, defined "transmission congestion costs" as costs incurred in dispatching generators in out-of-merit order, and ISO-NE contemporaneous reports indicated the same. DEMI also claims that in 2001 the term "reliability must-run," had essentially the same definition. According to DEMI, those market rules are evidence of the intent of the Parties.[32]

27. DEMI states that section 1.90 should be interpreted using *ejusdem generis* which requires that a general term in a listing embodied in a contract be given a meaning that is consistent with the more specific terms in that list. According to DEMI, applying this principle would limit "transmission congestion costs" to out-of-merit dispatch costs. DEMI further argues that since the charges were billed separately from transmission congestion costs by ISO-NE, they cannot fall under Section 1.90.[33]

28. Ronald E. Armstrong, a DEMI witness, is Manager of Electric Market Origination at DEMI. His duties at DEMI include negotiating and managing contracts. He was directly involved in the PSA negotiations with UI, and in DEMI internal deliberations occurring during the negotiations. He was also involved in regulatory proceedings and interactions with UI about the reliability cost tracker charges (also

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[31] DEMI IB at 5-6 and 313-32, *citing May 13 Order* at ¶ 62,023-02.

[32] *Id*. at 14-16, *citing* Ex. DOM-1 at 8, 10, 11, 14, and 16, Ex.4 at 13 and 15, Ex. DOM-5 at 30, Ex. DOM-10 at15-16, Ex. DOM-19 at 9, 11 and 14, Ex. DOM-42, Ex. DOM-46, and Tr. 110-111, 122, 184-187; *New England Power Pool*, 95 FERC ¶ 61,123 (2001).

[33] *Id.* at 24-25, *citing* Ex. UI at 18; *New PJM Companies*, 107 FERC ¶ 61,271 at 62,220, *reh'g denied* 100 FERC ¶ 61,009 (2005); *Cities of Batavia and St. Charles, Illinois v. Commonwealth Edison Co.*, 95 FERC ¶ 61,163 at 61,526 (2001), *reh'g denied* 95 FERC ¶61,480 (2001).

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variously referred to as "reliability cost of service" or "CT reliability COS" charges by the Parties). Mr. Armstrong addressed the issue of DEMI's intent with respect to particular terms and sections of the PSA, and how DEMI performed its obligations under it.[34]

29. Mr. Armstrong testified that both Parties proposed changes during the negotiation process. He explained that the factors DEMI considered in evaluating the terms and conditions of the proposed agreement with UI included: basic economic drivers; congestion costs relating to the delivery of energy, which were particularly important in light of the transmission constraints in the New England market; and, regulatory charges that were tariff-based.[35]

30. Mr. Armstrong testified that the Parties did not specifically agree that DEMI would bear responsibility for the RMR agreement charges and the reliability cost tracker charges; the charges did not exist and were not contemplated by the Parties when the PSA was negotiated and executed. Nor did DEMI, under the terms of the PSA or in communications, agree to assume responsibility for future regulatory changes which might create and allocate such costs to UI. DEMI even raised concerns about the charges within the time period prescribed by the PSA.[36]

31. Mr. Armstrong testified that in November 2001 DEMI notified UI of its interest in being considered as a potential replacement for Enron as a supplier of wholesale power to UI. During the first week of December 2001, UI contacted DEMI, advising DEMI that UI was then seeking bids for a new wholesale power supply contract. DEMI sent a team of senior management officials to meet with UI officials in early December 2001. UI provided DEMI with a list of its bid requirements and historical hourly load data, and DEMI submitted proposed rates to UI. Contract negotiations began and UI presented a draft agreement, which was similar to UI's prior agreement with Enron, and contained essentially the same terms and conditions. That draft was used as the starting point for negotiations.[37]

32. Mr. Armstrong disagreed with the "broad definition" UI would give to the PSA term, "transmission congestion costs," in order to shift to DEMI all risk associated with all costs resulting from insufficient transmission capacity. According to Mr. Armstrong, the definition must be given reasonable limits. When the PSA was drafted, transmission congestion costs were assumed to be variable in nature. Mr. Armstrong explained that it

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[34] Ex. DOM-18 at 1-3.

[35] *Id.* at 6-7.

[36] *Id.* at 14-20.

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

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was DEMI's understanding and intent, based on the state and development of the New England market at the time, that the definition of "transmission congestion costs" was designed to cover the different ways in which the existing variable congestion costs associated with the delivery of energy could be recovered; it was not intended to cover new or additional cost categories not associated with the delivery of energy.[38]

33. Mr. Armstrong did admit that in 2001 DEMI was aware that transmission constraints made it difficult to get power into parts of New England, including Connecticut. At this time DEMI understood that the ISO-NE was considering ways to handle the transmission constraints in the region. RMR agreements did not exist in the ISO-NE at the time the PSA was negotiated, Mr. Armstrong testified.[39]

34. Mr. Armstrong testified that in the fall of 2003 DEMI received a draft power supply agreement from UI as part of a request for a transitional standard offer contract. The draft stated that the seller would be responsible for variable costs attributable to unit-specific RMR agreements and that UI would be solely responsible for fixed costs associated with such agreements. Other power supply agreements Mr. Armstrong drafted on DEMI's behalf with several New England utilities during 2004 distinguished fixed and variable RMR agreement costs, allocating fixed costs (such as the CT Reliability COS Charges) to the load-serving entity and variable costs to the seller.[40]

35. Howard W. Pifer, III, Ph.D., a DEMI witness, is a Senior Advisor to CRA International, Inc. Dr. Pifer has provided consulting services to electric utilities and governmental entities as well as expert witness testimony on industry issues. Dr. Pifer's testimony addressed the nature of the costs at issue. He opined that those costs are not transmission congestion costs as defined in the PSA.[41]

36. Dr. Pifer testified that when the PSA was negotiated, ISO-NE relieved transmission congestion by dispatching generation units out-of-merit. The market clearing energy price was based on in-merit generation, so the additional costs of dispatching out-of-merit generation were recovered through uplift or transmission congestion charges. He explained that merit order refers to the ranking of all generator bids from lowest to highest cost and out-of-merit generation is generation that is called on when a generation unit in merit order could not be dispatched due to transmission constraints so a higher cost unit must be dispatched instead. According to Dr. Pifer, the term "congestion cost," usually refers to variable costs associated with generation

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[38] *Id.* at 14-15.

[39] *Id.* at 13-14.

[40] *Id*. at 24.

[41] Ex. DOM-19 at 1-4.

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dispatched in out-of-merit order.[42]

37. Dr. Pifer indicated that revenues from out-of-merit dispatch as well as other market revenues may not have fully compensated all generators for fixed costs. However, none of the ISO-NE rules at that time contemplated the need for fixed-cost recovery by generation units that might not be able to cover all fixed and variable operating costs through the energy, installed capacity, and ancillary services markets. Dr. Pifer testified that the PSA is consistent with the rules in place at the time it was signed.[43]

38. Philip Hanser, a DEMI witness, is a principal of The Brattle Group. Mr. Hanser has 25 years of experience in the electric power industry. He has testified previously before FERC as an expert witness on market power and market design issues, among other topics. Mr. Hanser provided testimony on the market structure and rules in place in the New England wholesale market as of December 2001 and the subsequent evolution in the market rules, including the introduction of cost-based RMR agreements in 2002. He addressed transmission congestion costs as that term generally is understood in the electric power industry and as defined by ISO-NE's tariff and market rules and the mechanisms in place in late 2001 for addressing transmission congestion.[44]

39. Mr. Hanser concluded that: (1) at the time the PSA was negotiated and executed, although ISO-NE had the authority to dispatch generation units out-of-merit order for reliability purposes, there was no ISO-NE charge or mechanism then in place to pay generators for costs that were not recovered through market-based energy and capacity sales; (2) the costs recovered under RMR agreements are not "transmission congestion costs" as that term generally is understood in the electric power industry, or defined by the applicable ISO-NE market rules, in effect at the time the PSA was negotiated or in effect today; and (3) in every instance in which responsibility for the costs that are the subject of this proceeding have been addressed by state and federal regulators since these costs arose in 2002, the determination has been that such costs should be borne by the load-serving entity. (As to Mr. Hanser's third point, Connecticut regulators only determined to allocate reliability cost tracker charges to load until after ISO-NE established charges for fixed RMR costs. Also, FERC concluded only concluded after *Sithe New Boston* that reliability cost tracker charges should be allocated to load.)[45]

40. Mr. Hanser defined "transmission congestion costs" as being associated with

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[42] *Id.* at 14-15.

[43] *Id.* at 17-18.

[44] Ex. DOM-1 at 1-3.

[45] *Id.* at 3-4 and 41-42.

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dispatching generators out-of-merit order. According to Mr. Hanser, congestion costs are inherently and fundamentally a variable cost because congestion costs are the incremental production costs incurred when transmission constraints force the system operator to dispatch more expensive generation in place of lower-cost generation. Those costs are reflected in market prices in various ways. He testified that ISO-NE recovered congestion costs through a region-wide surcharge or uplift charge assessed on a *pro rata* basis to all LSEs or transmission customers prior to its implementation of a LMP system in March 2003. He said that while there were certain exceptions, congestion costs, in general, were allocated to all New England transmission customers on a *pro rata* basis.[46]

41. Mr. Hanser testified that in late 2001, there was a common understanding of the types of costs that constituted transmission congestion costs. The understanding was that congestion costs are energy-related costs that occur when units are dispatched out-of-merit order because of transmission constraints. ISO-NE in its August 2002 *Annual Market Report* stated that "[t]ransmission congestion uplift arises when generating resources are dispatched out-of-economic merit order to alleviate transmission constraints." Further, the ISO-NE used the same terminology to describe transmission congestion costs in its *Annual Market Report*, which addressed the period May 2001 through April 2002.[47]

42. Mr. Hanser testified that, in addition to the common or usual understanding of the meaning of "transmission congestion costs," the term was explicitly defined in the tariffs and rules governing the New England market in December 2001. He indicated that the NEPOOL tariff defined "[c]ongestion" as "[a] condition of the NEPOOL Transmission System in which transmission limitations prevent unconstrained regional economic dispatch of the power system." He noted that "congestion" was also defined in section 24 of the NEPOOL tariff as the difference between the market-clearing price in the hourly energy market and the price that ISO-NE pays to a unit dispatched out-of-economic merit order multiplied by the number of megawatt hours dispatched. Mr. Hanser testified that the NEPOOL tariff language makes it clear that transmission congestion cost is the incremental energy cost associated with dispatching certain generating units out-of-merit order.[48]

43. Mr. Hanser testified that the term "congestion" did not have a meaning in the market that was different from the definition based on the tariff and market rules. He explained that all ISO-NE charges are carefully specified and defined and charges are subject to FERC jurisdiction and review, meaning that those charges can only include

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[46] *Id.* at 11-12.

[47] *Id.* at 14.

[48] *Id.* at 15-16.

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those costs specified in ISO-NE's tariff and market rules. Therefore, market participants would have recognized that ISO-NE did not have broad discretion to include any type of generation-related costs in its congestion charges. Mr. Hanser's opinion was that it would be unusual for parties to a bilateral agreement to use a term that is defined by the governing tariff and market rules, but intend for that term to have a different meaning.[49]

44. Mr. Hanser testified that neither the costs recovered under the pro forma cost of service agreement, nor the ISO-NE tracker charge are properly viewed as congestion costs because those are payments made to certain generators to ensure that such generators are able to recover their fixed costs which are not affected by transmission constraints or congestion. In contrast, congestion costs are not fixed, they are the incremental energy costs associated with dispatching units out-of-merit order because of transmission constraints. While the out-of-merit dispatch of RMR units, or any generating unit, will result in congestion costs, the fixed costs of such units and the costs incurred to maintain such units and to keep them in service are not congestion costs. [50]

45. Mr. Hanser disagreed with Mr. Coretto's assertion that costs associated with RMR agreements are costs resulting from insufficient transmission capacity. He argues that Mr. Coretto is mistaken for two reasons: 1) the fixed maintenance costs associated with generating units under RMR agreements, or any generating unit's fixed costs, are not costs that result from insufficient transmission capacity because fixed generation maintenance costs do not vary with the level of transmission congestion or the insufficiency of transmission capacity; and, 2) RMR agreements are not required solely to address transmission constraints. RMR agreements are designed to ensure that generation units needed for the reliable operation of the transmission grid remain available and are not retired or otherwise removed from service due to the inability to earn sufficient revenues.[51]

46. Mr. Hanser testified that Mr. Coretto overreaches when he asserts that FERC orders conclude that fixed RMR costs represent costs of relieving transmission congestion in specific regions. According to Mr. Hanser, taken to its logical conclusion, Mr. Coretto's view would make DEMI fully responsible for very expensive transmission upgrades and other investments made to mitigate transmission constraints. Mr. Hanser testified that it would be unreasonable to believe that DEMI intended to make itself potentially liable for any cost incurred to relieve transmission congestion in Southwest Connecticut.[52]

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[49] *Id.*

[50] *Id.* at 32-33.

[51] *Id.* at 7-8.

[52] *Id.* at 35.

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47. Mr. Hanser contested Mr. Hrabchak's claims that at the time the PSA was executed, the New England wholesale power market was transitioning from market-regulated, cost based rates, to an open-access competitive market. Mr. Hanser claimed that New England's wholesale market structure did not change significantly between May 1999 and December 2001. Although the ISO-NE was in the process of redesigning its market as of December 2001 and a large scale market redesign was proposed in early 2000 and was conditionally approved by the Commission in June 2000, it was not implemented for several years[53]

48. Mr. Hanser testified that at the time DEMI signed the PSA, there were no out-of-merit units recovering their fixed costs through an ISO-NE congestion charge or other mechanism. Mr. Hanser testified that this aspect of the New England market changed on December 28, 2001, the same day that DEMI and UI signed the PSA. The Sithe[54] filing was the first instance where a generation owner sought to recover all or a portion of its fixed costs from ISO-NE. He explained that in these filings both ISO-NE and NEPOOL explained that the fixed-cost charge component of the agreements was unprecedented in the New England market and that the costs to be paid to the generator through the fixed- cost charge were fundamentally different from congestion costs recovered through existing market mechanisms.[55]

49. Mr. Hanser explained that the ISO-NE entered into the agreement with Sithe to keep Sithe from retiring the plant. After the Sithe agreement, ISO-NE and NEPOOL filed tariff changes to implement SMD. Generating units located in Connecticut began seeking recovery of their fixed costs through RMR agreements with ISO-NE. ISO-NE proposed a new Market Rule 1 that would replace Market Rule 17 and several other ISO-NE market rules that had been effect. Market Rule 1 allows ISO-NE annually (or more often if necessary) to designate units needed for reliability as RMR resources. The rule also established a pro forma RMR cost-of-service agreement which is available to all generating units that would otherwise cease operation and which ISO-NE determined were required for system reliability. Market Rule 1 did not become fully effective until March 1, 2003. The ISO-NE modified the existing market rules in response to the Sithe agreement. ISO-NE filed proposed changes to Market Rule 17 to provide a method for allocation of fixed-monthly costs paid by ISO-NE under

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[53] *Id.* at 7-8.

[54] *Sithe New Boston, LLC*, 98 FERC ¶61,164 at 61,609 (2002). (This filing served as the first public announcement of the negotiations and resulting agreement between Sithe and ISO-NE. It was the first RMR agreement with a fixed monthly payment in the New England market.)

[55] DOM-1 at 23-24.

mitigation agreements with generators.[56]

50. Mr. Armstrong testified that section 17.2(b) was included in the original draft agreement. DEMI proposed significant edits to this section during negotiation. He testified that it is DEMI's routine business practice to include this kind of language in its wholesale power supply agreements as DEMI operates in a highly-regulated environment that is constantly changing. The agreements entered into by DEMI are based on its analysis and understanding of the regulatory environment as it exists when the contract is negotiated and signed. As a matter of routine business practice, DEMI does not attempt in its agreements to allocate or accept the risk for unknown future regulatory changes. Section 17.2(b) is included to provide a mechanism for the Parties to address future regulatory changes that were not and/or could not have been accounted for when drafting the contract. According to Mr. Armstrong, UI did not seek to alter in a material way or object to DEMI's proposed changes to section 17.2(b). To the extent that the Parties intended that DEMI be responsible for the risk of future regulatory changes, they expressly stated that intent. For example in section 6.2, DEMI specifically accepts the risk for certain bidding if required by NEPOOL market rule change, while section 2.1(c) does not contain any such express statement to allocate the risk of future regulatory changes not reflected in that section.[57]

Charges Related to Delivery of Energy at, and from the Delivery Point(s)

51. UI - - UI acknowledges that section 1.90 does not allocate transmission congestion costs, but argues that even if section 1.90 is found not to include reliability cost tracker charges within the definition of "transmission congestion costs," such costs are clearly associated with the delivery of energy. UI argues that these charges are DEMI's responsibility because the purpose of the agreement creating the charges is to ensure reliable energy delivery. Section 2.1(c) of the PSA provides that the seller or supplier (i.e., DEMI) is responsible for all charges related to the delivery of energy "at and from the Delivery Point(s)."[58]

52. UI points out that the Commission has already recognized that the language of section 2.1(c) is broad enough to include reliability tracker cost charges.[59] UI argues that even if reliability cost tracker charges were neither transmission congestion costs nor costs associated with the delivery of energy, those charges would still be DEMI's responsibility under the PSA because they are costs imposed by ISO-NE on the delivery

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[56] *Id.* at 25-28.

[57] DOM-18 at 18-20.

[58] UI IB at 32, *citing* Ex. UI-43 at 34 and Ex. UI-57 at 25; *see* Ex. 4 at 20.

[59] UI RB at 16, *citing* May 13 Order, 111 FERC at 62,023.

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of energy.[60]

53. UI argues that under the plain language of Section 2.1(c), cost tracker charges are to be paid by DEMI. Section 2.1(c) clearly specifies the rules for allocating all costs or charges imposed on, or associated with the delivery of energy. Section 2.1(c) allocates costs according to whether they arise upstream or downstream from the delivery points. If the cost is imposed on, or associated with delivery of energy from the market to UI's system, the seller is responsible. If the cost is imposed on, or associated with delivery of energy and market products from UI's system to its retail customers, it is UI's responsibility.[61]

54. UI claims DEMI is incorrect in arguing that it is responsible for transmission congestion costs only to the extent that they are associated with DEMI's performance of its obligations under the PSA, which DEMI defines as the delivery of a specific quantity of energy to UI at the applicable delivery point. UI claims that Mr. Armstrong cites to no PSA provision to support this contention. UI claims its interpretation is supported by the text which refers to "all costs." [62]

55. Mr. Coretto, testifying for UI, stated that the initial draft of the PSA established the general rule that, with respect to "any costs" imposed on or associated with the delivery of energy up to the "Delivery Point(s)," such costs would, with limited specific exceptions, be borne by DEMI. Mr. Coretto stated that UI accepted responsibility for costs imposed on, or associated with the delivery of energy at, and from the "Delivery Point(s)," with the exception that UI was responsible for all stranded costs and DEMI was responsible for ISO-NE Tariff charges at the customer meter. Mr. Coretto averred that DEMI was aware of the cost allocation provisions, and did provide a number of specific edits to add words or revise punctuation in the Section 2.1(c) cost allocation statement, but suggested no substantive changes. Mr. Coretto testified that DEMI offered no language which would have indicated that the section 2.1(c) categories were intended to be exclusive or limiting. He testified that the examples were intended to indicate the types of costs included, but were not intended to be exclusive or exhaustive.[63]

56. Mr. Hrabchak, testifying for UI, has oversight responsibilities regarding the signatories' performance under the PSA. Mr. Hrabchak also participated in communications with representatives of DEMI throughout the life of the PSA. Mr.

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[60] UI IB at 38, *citing* Tr. 218.

[61] *Id*. at 28.

[62] *Id.* at 31-32.

[63] Ex. UI-1 at 18-23.

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Hrabchak testified that DEMI agreed to the basic terms of the PSA, which included a fixed price for energy and market products with a broad categorical approach to the allocation of related costs. DEMI is responsible, under the PSA which had been modeled on the Enron agreement, for all costs or charges imposed on or associated with the delivery of energy and market products delivered, or caused to be delivered by DEMI to UI's delivery points. Those costs included: transmission congestion costs; settlement uplift charges; control area services; inadvertent energy flows; and losses and loss charges. Mr. Hrabchak testified that, with a few specified exceptions, DEMI is responsible, under the PSA, for the costs associated with delivery of wholesale power and market products to UI; UI is responsible for the costs associated with delivering the power to its retail customers.[64]

57. DEMI -- DEMI maintains that reliability cost tracker charges are not "associated with the delivery of energy" as that term is used in the PSA, specifically section 2.1 because the costs do not arise from DEMI's delivery of energy to UI; the costs are, rather, fixed payments intended to keep financially distressed generators in service in order to maintain system reliability. DEMI states that a review of how it meets its obligations under the PSA is evidence that the reliability cost tracker charges at issue are not associated with the delivery of energy. DEMI explains that the PSA requires it to deliver energy and associated ancillary service in quantity sufficient to meet UI's load under its SOS and special contracts obligations. Instead of linking the output of particular generating facilities to individual wholesale power supply agreements, DEMI buys power from the ISO-NE Connecticut pool. Before adoption of SMD, DEMI bought power directly from ISO-NE. ISO-NE still directly manages ancillary service. Actual delivery of energy is made to specified delivery points, which are the points where ISO-NE's transmission system and UI's distribution system meet.[65]

58. DEMI asserts that the purchase and delivery of energy, as outlined above, gives rise to three categories of costs, none of which are associated with the delivery of energy. Those costs are: 1) the cost of the energy itself; 2) congestion costs (*i.e.*, out-of-merit dispatch charges; and 3) ancillary services costs (Schedule 2 and 3 administrative costs, day-ahead operating reserve charges, and real-time operating reserve charges). According to DEMI, transmission congestion affects the costs associated with the delivery of energy to the extent that congestion requires DEMI to pay higher prices for the energy delivered to UI, including charges for out-of-merit dispatch. DEMI maintains that each of the three charges or costs is separate and distinct from fixed monthly payments under RMR agreements and reliability cost tracker charges.[66]

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[64] Ex. UI-3 at 8.

[65] DEMI IB at 31, *citing* Ex. DOM-18 at 8, 9, and 11.

[66] *Id.* at 31-32, *citing* Ex. DOM-18 at 11.

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59. DEMI asserts that there is no nexus between DEMI's delivery of energy to UI and the RMR agreements. The costs reflected in the RMR agreements are fixed payments intended to keep financially-distressed generators in service in order to maintain system reliability. RMR agreements are revenue sufficiency agreements. State and federal agencies have distinguished those costs from costs associated with the delivery of energy. State and federal agencies have found that the fixed monthly payments under RMR agreements should be allocated to load.[67]

60. Mr. Armstrong, testifying for DEMI, explained that DEMI does not separately contract for, or arrange for transmission services to deliver energy to UI's delivery points; the ISO-NE provides this service when DEMI purchases power from its pool for delivery to UI to meet its load. UI remains responsible, under the PSA, for regional and local network services, which are transmission services that distribute power throughout the Connecticut zone to certain end users. Mr. Armstrong related that there are three categories of costs associated with the purchase and transmission of energy from the ISO-NE generation pool to UI's delivery points: the cost of energy; congestion costs; and ancillary services costs.[68]

61. Mr. Hanser, testifying for DEMI, stated that at the time the PSA was executed, neither FERC nor the DPUC had addressed the issue of who was responsible for paying fixed RMR costs, because those costs did not exist as of December 2001. According to Mr. Hanser, FERC and the DPUC have consistently held that such costs should be allocated to load. (As noted previously, however, FERC and DPUC made those pronouncements after the PSA was executed.)[69]

62. Mr. Hanser testified that UI's claim that the reliability cost tracker charge is associated with the delivery of energy by DEMI to UI, is not correct since fixed RMR costs are entirely independent of the amount of energy that DEMI delivers under the PSA and is not affected by DEMI's performance under the contract. There is no nexus between DEMI's performance and the amount of reliability cost tracker charges or other similar costs assessed to UI.[70]

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[67] *Id*. at 32, *citing* Ex. DOM-1 at 32, 36, and 40, 41 (*citing Sithe New Boston, LLC*, 98 FERC ¶ 61,164 at 61,610), Ex. DOM-19 at 27; and, Tr. 76. 39 (*citing Establishment of the United Illuminating Company's Transitional Standard Offer* [Draft Decision], Connecticut Dep't of Public Utility Control, Docket No. 03-07-15 (Dec. 18, 2003) and *New England Power Pool*, 100 FERC ¶ 61,287 at 62,270-71; DOM-16 at 4-5; *Devon Power LLC*, 102 FERC ¶ 61,314 at 61,056, *reh'g denied* 104 FERC ¶ 61,123 (2003);

[68] Ex. DOM-18 at 11.

[69] Ex. DOM-1 at 38.

[70] *Id.* at 36.

63. Mr. Hanser testified that the DPUC order approving UI's current SOS characterized RMR contract costs as a type of federally-mandated congestion charge, not as a congestion cost or an energy-related cost. According to Mr. Hanser, this shows that once ISO-NE established charges for fixed RMR costs, Connecticut policymakers and regulators determined that it was appropriate to allocate those costs to load. Mr. Hanser testified that the nature of those costs have not changed since they first arose in 2002, the only difference is that they have been examined in the context of the entire market structure.[71]

64. Finally, Mr. Hanser testified that his opinion was that having suppliers bear fixed RMR costs is inconsistent with FERC policy. He argues that FERC has consistently ruled that load should bear the costs of RMR agreements. FERC has found that having load bear those costs would send the appropriate locational price signals. In general FERC supports LMP in energy markets, because it gives market participants an accurate and dynamic measure of the cost of congestion as indicated by differences in energy prices between locations. FERC seeks locational pricing in regional markets so that areas that currently are constrained receive price signals that will encourage economical investments in new generation and transmission capacity. Mr. Hanser indicated that the decision to allocate fixed RMR costs to load is consistent with the ratemaking concept of causality. Additionally, requiring power suppliers to bear fixed RMR costs is entirely at odds with the Commission's goal of reflecting those costs in the cost of energy and giving customers appropriate price signals. Mr. Hanser explained that DEMI has no control over the fixed RMR costs because those charges recover the fixed costs of keeping certain generating plants in service, plants that are not owned or operated by DEMI.[72]

65. Dr. Pifer, testifying for DEMI, stated that the RMR agreement costs are not transmission congestion costs, nor are they "imposed on or associated with the delivery of energy" or "relating to the transmission of energy" by DEMI to UI. According to Dr. Pifer, those costs are costs relating to the variable cost of production, specifically the costs that arise from dispatching generation in out-of-merit order. The costs recovered through RMR agreements to ensure revenue sufficiency are costs relating to the fixed expenses of keeping units available so that they can provide system reliability. Costs reflected in the RMR agreements are not directly necessary for the delivery of energy or the transmission of energy; they are fixed costs relating to keeping generation in service and preventing retirement of plants needed for system reliability.[73]

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[71] *Id.* at 39.

[72] *Id.* at 40-44.

[73] Ex. DOM-19 at 27-28.

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Course of Performance

66. The position of UI is that the Parties' implementation of, or course of performance under the PSA makes clear that there was a meeting of the minds that DEMI was responsible for reliability cost tracker charges. UI states that from the time ISO-NE began billing for payments made under the Sithe agreement,[74] UI passed the charges on to DEMI and DEMI did not protest the pass-through. When the Parties contemplated extending the PSA, DEMI's conduct indicated that it felt it was responsible for those charges as it indicated the payment of these charges would be something they would seek to modify from its current treatment.[75]

67. UI states that in late 2002 and early 2003, UI participated in a Commission-sponsored mediation about the proposed RMR agreements among NRG affiliates and ISO-NE ("NRG fleet mediation"). UI states that the NRG fleet mediation gave rise to the reliability cost tracker charge. After UI notification to DEMI of the proceedings, DEMI became a participant in the NGR fleet mediation. According to UI, DEMI gave every indication during the NRG fleet mediation that it was responsible for the reliability cost tracker charges. For example, DEMI participated in the "load group" which, according to UI, is significant because DEMI could have participated in the "generation group." The generation group included market participants that generate energy and that might ultimately need to request an RMR agreement with ISO-NE. Load group participants were participants that would be subject to RMR agreement charges based on their obligation to supply energy to load.[76] Mr. Hrabchak, testifying for UI, stated that DEMI representatives stated at mediation sessions that DEMI was responsible for a variety of transmission congestion costs, including costs associated with RMR agreements.[77]

68. In addition to DEMI's actions in connection with the NRG fleet mediation, UI notes that for nearly three years after ISO-NE first began imposing charges for fixed-payment RMR agreements and for almost two years after ISO-NE began imposing the cost tracker charges, UI and DEMI both consistently interpreted the PSA as assigning responsibility for those costs to DEMI. According to UI, since DEMI cannot explain

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[74] *Sithe New Boston, LLC*, 98 FERC at 61,164.

[75] UI IB at 53-56.

[76] *Id*. at 52-56, *citing* Ex. DOM-36, Ex. DOM-34 at 2, Ex. UI-1 at 28, 29, and 44, Ex. UI-2 at 10, 11-16, Ex. UI-3 at 10, Ex. UI-10, Ex. UI-25, Ex. UI-29, Ex. UI-30 at 6, Ex. UI-31 at 3, Ex. UI-32 at 2, Ex. UI-34 at 4, Ex. UI-40, Ex. UI-42 at 2, Ex. UI-78 at 5, Ex. UI-79 at 5, Ex. UI-88 at 4; and, Tr. 26, 46-47, 233.

[77] Ex. UI-3 at 11.

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that conduct away, it ignores it.[78] UI identified the charges as a separate line-item on billing statements to DEMI and DEMI accepted the invoices without question or objection from April 2003 through December 2004. UI points out that DEMI's own internal documents show that DEMI was aware that it was being billed. For example, beginning in October 2002, a DEMI employee prepared spreadsheets estimating future reliability cost tracker charges, which is proof of DEMI's understanding that it was responsible for the charges. An internal DEMI e-mail dated April 10, 2003, with the subject line "Potential RMR cost for UI deal," contained an estimate of DEMI's exposure for maintenance funding and RMR agreements.[79] UI further points out that DEMI acknowledged many times to the Commission and to the United States Court of Appeals for the D.C. Circuit that it was responsible under the PSA for transmission congestion costs, including costs associated with RMR agreements, in various pleadings by the same counsel representing DEMI in these proceedings.[80]

69. DEMI's suggestion that the fact that the ISO-NE bills UI, rather than DEMI, for these charges is of no consequence. UI asserts that section 1.90 of the PSA clearly provides that all costs resulting from insufficient transmission capacity are transmission congestion costs "regardless of how such costs are allocated or assessed." Further, UI indicated that DEMI has offered a variety of shifting and often contradictory interpretations of the PSA, arguing that: the issues do not involve a determination of whether RMR charges result from insufficient transmission capacity; DEMI's mistaken belief that it was responsible for all RMR charges under the PSA originated with UI; and, DEMI's previous statements of responsibility only indicated responsibility for variable transmission congestion costs associated with the delivery of energy, not all charges under the RMR agreements. DEMI had consistently made public statements of responsibility for these costs, and despite questions that Mr. Armstrong may have had in the second half of 2003, DEMI continued to make statements of responsibility at least through mid-2004.[81]

70. UI argues that DEMI misused the audit provision of the PSA. Article XVI provides that the Parties to the PSA have a two-year period (or such longer period as NEPOOL rules allow) for account settlement within which to "verify the accuracy of

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[78] UI RB at 23.

[79] UI IB at 51-56, *citing* Ex. DOM-34, Ex. UI-1 at 29 and 42, Ex. UI-2 at 11-6, Ex. Ex. UI-3 at 10-11, Ex. UI-11, Ex. UI-13, Ex. UI-14, Ex. UI-25, Ex. UI-29, Ex. UI-40, Ex. UI- 61 at 1, Ex. UI-66, Ex. UI-67, Ex. UI-68 at 1-4, Ex. UI-71 at 1-2, Ex. UI-82 at 2-3, Ex. UI-84; Tr. 234, 311-312, 319, 323-25, 340, 360 and 362-63; and, UI RB at 22-23 *citing* Ex. UI-30 at 7, Ex. UI-31 at 3, Ex. UI-32 at 3, Ex. UI-33 at 3, Ex. UI-78 at 6, Ex. UI-79 at 4, Ex. UI-80 at 3, Ex. UI-81 at 3, Ex. UI-88 at 4-5.

[80] UI RB at 22-23.

[81] *Id.* at 25-28.

any statement, charge or computation" made under the PSA.[82] According to UI, Article XVI does not give DEMI the right to challenge the "nature" of a charge, as opposed to the "accuracy." DEMI decided to use the audit provision after deciding it would challenge the reliability cost tracker charges.[83]

71. DEMI - - The position of DEMI is that its course of performance of the PSA does not support a claim that it accepted responsibility under the PSA for the RMR charges. Mr. Armstrong, testifying for DEMI, talked about what happened at the NGR mediation. He stated that statements made by DEMI during subsequent proceedings involving the NRG facilities were premised on DEMI's understanding that the charges it was being assessed by UI from those unit-specific RMR agreements were variable transmission congestion costs associated with the delivery of energy. DEMI's statement did not purport to assume responsibility for all charges under the RMR agreements, but rather reflected its understanding that, to the extent the RMR agreements allocated the variable costs of congestion associated with DEMI's delivery to UI, DEMI would be responsible for such costs. According to Mr. Armstrong, this statement does not assume responsibility for fixed charges or an entirely new type of cost. Mr. Armstrong explained that at the time that UI notified DEMI of the situation regarding the NRG facilities and during the referenced mediation sessions no one at DEMI challenged UI's assumption that the PSA allocated to DEMI the responsibility for all RMR requirements, because DEMI's statements referring to its responsibility for RMR costs, referred to the traditional RMR costs which existed in 2001 at the time the PSA was negotiated and signed.[84]

72. Mr. Armstrong testified that he had not been involved in the day-to-day administration of the PSA, and was not aware of how UI was allocating charges under the unit specific RMR agreements to DEMI. He said he did not become aware of how such charges were being allocated until he became involved in agreement extension negotiations. Once he became aware, Mr. Armstrong testified that he reviewed the PSA and invoices and determined that DEMI was not responsible for the fixed costs assessed under the PSA or for the fixed costs assessed under the unit-specific RMR agreements, including the CT Reliability COS Charges. He believes that DEMI was not responsible for the CT Reliability COS Charges because: 1) the PSA does not make any mention of any fixed costs relating to RMR requirements; 2) all the costs for which DEMI is responsible under the PSA relate to its performance under the PSA; and 3) neither the CT Reliability COS Charges, nor other costs under the unit specific RMR agreements are associated with DEMI's performance under PSA. He indicated that he discussed the results of the analysis with colleagues at DEMI and pursued the matter with UI through

[82] Ex. UI-4 at 64.
[83] UI RB at 25-26.
[84] Ex. DOM-18 at 23.

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a letter dated November 12, 2004, requesting an audit as provided for under Article XVI of the PSA.[85]

73. Mr. Armstrong explained that ISO-NE bills DEMI directly for the energy and associated ancillary services purchased from the ISO-NE pool to meet UI's load. For purposes of billing, within two business days after energy is delivered to the UI's system, UI submits a report to DEMI and to the ISO-NE identifying UI's consumption of load for each hour based on reports from its system meters. In addition, there is a 45-day reconciliation process when information from UI's customer meters is compared with UI's consumption reports based on its system meters. The report is submitted to DEMI and the ISO-NE, which then bills DEMI directly for the actual amount of energy and associated ancillary services purchased from the pool and delivered to UI to meet its load.[86]

74. Mr. Armstrong testified that UI began to apply costs related to RMR agreements as offsets to the amounts to be paid by DEMI in early 2002. He said that UI described the charges as being charges associated with the FERC decision involving Sithe New Boston. Later, according to Mr. Armstrong, UI described the RMR charges as costs associated with both the *Sithe* and *Devon* decisions.[87]

75. Mr. Armstrong testified that transmission constraints can prevent the use of the most economical generation, requiring the use of higher cost generation. An inefficient dispatch increases costs which are then passed through to all market participants and are effectively socialized and assessed system-wide. Prior to the implementation of SMD these increased costs were recovered by the ISO-NE through uplift charges, which were billed to UI. UI then passed them to DEMI pursuant to the PSA. After implementation of the SMD those increased costs were recovered by the ISO-NE through redispatch charges, and the ISO-NE directly billed DEMI for these charges based on the amount of energy purchased by DEMI and delivered to UI's system. According to Mr. Armstrong, the charges disputed in this proceeding are an entirely separate charge.[88]

76. Mr. Armstrong defined "CT Reliability COS charges" as charges related to the FERC order in Docket No. ER03-663, which provided for the maintenance of NRG plant in Connecticut for the summer 2003 peak season. According to Mr. Armstrong, the ISO-NE tariff allocates those costs to load serving entities such as UI, and ISO-NE bills UI for the costs in accordance with the applicable tariff. UI then offset those costs against the amount properly owed to DEMI even though DEMI did not intend to assume

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[85] *Id.* at 24.

[86] *Id.* at 24-26.

[87] *Id.* at 20-21, *see Sithe New Boston, LLC.*, 98 FERC ¶ 61,164 and *Devon Power, LLC*, 103 FERC ¶ 61,314, *order on reh'g*, 104 FERC ¶61,123 (2003) ("Devon").

[88] *Id*. at 12-17.

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responsibility for those costs when it negotiated and executed the PSA. Mr. Armstrong testified that DEMI could not have known that, slightly more than one year after the PSA was signed, the following would occur: 1) unit specific RMR Agreement and CT Reliability COS charges could be created; 2) charges under the new RMR Agreements and the CT Reliability COS charges would be billed to UI by the ISO-NE; or 3) UI would attempt to pass those charges on to DEMI under the PSA.[89]

77. Mr. Armstrong testified that DEMI's resort to Article XVI of the PSA was timely as Article XVI allows for an audit within two years following the end of the calendar year in which the charge, statement or computation was made. According to Mr. Armstrong, Article XVI was put in the PSA to deal with future regulatory changes that could impact the agreement even though the effect of the changes would not be evident for some time after the actual implementation of the change. DEMI requested a refund of all CT Reliability COS charges and requested additional information about the RMR agreement charges allocated to DEMI by UI for the period January 2002 through March 2003.[90]

78. Edward Anderson, a DEMI witness, is a power market analyst for Dominion Energy Clearinghouse. Mr. Anderson is directly involved in DEMI's billing interactions with UI. He receives and reviews the monthly invoices related to the PSA and serves as liaison to UI's billing department when there are accounting questions. His duties also include review of the monthly invoices to DEMI from ISO-NE. Mr. Anderson presented testimony about the invoices that DEMI received from UI for the period from January 2002 to October 2005.[91]

79. Anderson testified that UI produced the invoices for the energy that DEMI delivered. UI uses information provided by ISO-NE to create an invoice to report what it owes DEMI. Mr. Anderson explained that the invoice is primarily focused on the amount of energy provided by DEMI as measured by ISO-NE and the price per kilowatt hour associated with the deliveries. The invoices detail the amount of energy purchased from DEMI from each of the classes of services included in the PSA, along with the prices for those deliveries and the total amount due to DEMI. The invoice also includes itemized deductions or off-sets for certain charges. He testified that UI deducted four categories of charges from its payment to DEMI: 1) congestion charges; 2) RMR agreement charges; 3) CT reliability COS charges; 4) NOATT Schedule 2 charges; and 5) other incidental non-material charges that are not the subject of the dispute in this

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[89] *Id.* at 21-22.

[90] *Id.* at 25-26.

[91] Ex. DOM-33 at 2-3.

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case.[92]

80. Mr. Anderson testified that the invoices do not include a definition of "congestion costs," but do include spreadsheet computations of congestion based on the amount of energy that DEMI delivered to UI. He said that RMR charges have been defined using brief descriptions that have changed over time. For example in June 2003, the RMR line item was described as "are associated with FERC ruling on Sithe, Boston units." For April 2004, the RMR line item was described as "associated with FERC ruling on Sithe, Boston units and Devon 7, 8." In September 2005 the description was "Per FERC ruling on NRG Devon 7, 8 units." He explained that CT Reliability COS Charges were described as being for the maintenance of NRG plants in Connecticut for the summer 2003 peak season.[93]

81. Mr. Anderson testified that UI did not separate those charges on all of its invoices to DEMI. The invoices from May 2004 through August 2004 consolidated the charges under the RMR heading, but from June 2004 through September 2004 included a note beside the CT Reliability COS line item that stated "included in RMR" and there is nothing charged on this line during this period. Mr. Anderson described NEPOOL Open Access Transmission Tariff ("NOATT") Schedule 2 Charges as relating to bills from ISO-NE to UI for costs incurred under Schedule 2 in the NOATT. These costs have been on the invoices since February 2002.[94]

Allocation of Reliability Cost Tracker Charges

82. UI - The position of UI is that consideration of the PSA as a whole strongly supports the conclusion that DEMI is responsible for the reliability cost tracker charges. Taking into account that the entire agreement provides strong support for UI's position as the PSA included a fixed price for energy and market products with a broad categorical approach to the allocation of related costs. The all-in-fixed-price aspect of the PSA was very important to UI, because its purpose in entering into the agreement was to secure a predictable fixed price for energy through the life of the PSA in order to minimize the risk associated with volatility of the delivery costs of energy during the transition to a competitive market. If the PSA were interpreted as DEMI wishes, the all-in PSA would be incomplete, since the Cost Tracker charges would not be allocated to either party, yielding an outcome totally at odds with the fundamental purpose and structure of the PSA.[95]

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

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

[94] *Id.* at 5-6.

[95] UI IB at 38-40.

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83. UI further argues that allocation of the reliability cost tracker charges under the PSA should consider how the PSA allocates responsibilities to the Parties; DEMI has an absolute and unconditional obligation to supply wholesale energy and market products to serve UI's load as addressed in the PSA. Those Cost Tracker charges clearly do not fall within the limited categories of costs for which UI is responsible under the PSA, as UI is not responsible for any generation costs. Finally, Section 17.2 of the PSA does not relieve DEMI of responsibility for the Cost Tracker chargers; DEMI has never invoked the provisions of Section 17.2 nor does the present dispute fall under this section.[96]

84. UI argues that allocation of the Reliability cost tracker charges to DEMI is consistent with the intent of the Parties, as it was an all-in-requirements contract to which DEMI agreed to provide the electricity necessary to serve UI's load at a fixed price. During negotiations, UI confirmed DEMI's understanding that DEMI would be responsible for transmission congestion costs under the PSA and DEMI did not seek to narrow its responsibility for those costs as some other bidders had. DEMI's argument that the Parties could not have intended to assign Cost Tracker charges because those specific charges did not exist at the time the PSA was executed is also incorrect, according to UI.[97]

85. UI asserts that Parties to an agreement can use broad categorical language to address future developments. The wholesale power market was already in transition at the time the Parties entered into the PSA and the broad language was used precisely because of the uncertainty. Also, while the charges may have been a new recovery mechanism, the need to compensate critically needed generators to keep them in operation was well-established at the time the PSA was executed, and the mechanisms then in use to recover these costs were clearly DEMI's responsibility.[98]

86. DEMI - - DEMI argues that UI's claim that DEMI bears responsibility for these charges is unsupported by the evidence, since the PSA defines the Parties' risks and obligations in relation to the market rules in effect at the time it was executed. DEMI argues that the Parties included Section 17.2 with this situation in mind. DEMI argues that these charges arose out of a change in market rules.[99] DEMI argues that allowing UI's interpretation of the PSA would render Section 17.2 meaningless, in contravention of contract law.[100]

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[96] *Id.* at 41-42 and 45-46.

[97] *Id.* at 47- 49.

[98] *Id.* at 50.

[99] DEMI IB at 42-43.

[100] *Id.* at 44, *citing Net2Globe,* 273 F. Supp. 2d 436 at 445 (quoting *Pearce,*

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87. Second, according to DEMI, RMR agreements are between the ISO-NE and specific generators, and the costs of those agreements, initially borne by ISO, are then recovered from load serving entities like UI. The payments made under RMR agreements do not change with the plant's use, or the ISO-NE's system dispatch. Rather, the payments are designed to allow a generator to recover such costs as operating and maintenance expenses, taxes (property, income, and others), debt service, and investment costs for plant and capital equipment. For reliability cost tracker charges, a subset of costs under RMR agreements, the Sithe Agreement allows such as demand charges paid to natural gas pipeline companies, material supplies, building and grounds maintenance, safety equipment, health and business insurance, and taxes. The amount of the costs are not related to how much a generator runs.[101]

88. DEMI also argues that although 17.2 protected the interests of the Parties, the Parties failure to invoke the section is irrelevant. DEMI also argues that it was not its obligation alone to invoke Section 17.2, and in fact, UI should have invoked the section since the charges were billed to UI. Further, the section is not invalidated simply because no party invoked it, and failure to do so does not waive any rights held by DEMI to challenge the allocation and payment of the charges in dispute as the PSA allows it to pay for the charges then dispute its responsibility for the charges at a later date.[102]

89. DEMI claims that UI's "plain language" argument must fail because the Commission rejected that in its finding on rehearing that the PSA was ambiguous on the issue of which Party bore responsibility under the PSA for reliability cost tracker charges.[103] According to DEMI, when the PSA was being negotiated in 2001, reliability cost tracker charges did not exist and the market rules and structures in place at the time did not provide for the types of agreements between ISO-NE and specific generators that ultimately led to the reliability cost tracker charges. The disputed costs resulting from RMR agreements, including the reliability cost tracker charges, came about as a result of changes to market rules that were implemented in 2002, which was after the PSA was negotiated. Because the charges did not exist, they could not have been contemplated in the drafting of the PSA.[104]

Urstadt, Mayer & Greer Realty Corp. v. Atrium Dev. Assoc., 77 N.Y.2d 490).

[101] *Id*. at 32-36, *citing* Ex. DOM-1 at 30, 32, 36, 40 at 205(internal citation omitted), 39, Ex. DOM-19 at 11, 22, 29 and 33; and, Tr. 78, 151, and 156;).

[102] *Id.* at 44-46.

[103] DEMI RB at 27-28, *see* September Order, 112 FERC ¶ 61,279.

[104] DEMI IB at 12-13, *citing VTech Holdings*, 172 F. Supp. 2d 435 at 441 (2001) and *Eastman Kodak Co. v. STWB, Inc.*, 232 F. Supp. 2d 74 at 91 (2002), for the proposition that market rules in effect at the time of negotiation of the PSA is reasonably

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DISCUSSION

90. In *Devon Power LLC*, 103 FERC ¶ 61,082 ("Devon"), *order on reh'g*, 104 FERC ¶ 61,123 (2003), the Commission accepted, in part, four RMR agreements for generation units in Southwest Connecticut. The Commission, thereby, accepted the reliability cost tracker provisions of the RMR agreements. The reliability cost tracker provisions provide a mechanism for compensating generation units identified by ISO-NE as needed for reliability, for maintaining the units so that they remain available to be called on by the ISO.[105] ISO-NE had imposed its first charge for fixed payments under an RMR agreement in early 2002, in connection with an RMR agreement between ISO-NE and Sithe New Boston.[106] UI began invoicing DEMI for fixed-payment RMR charges the second month of implementation of the PSA.[107] After *Devon* ISO-NE began billing UI for a share of ISO-NE's payments to the NRG units. UI, in turn, identified these RMR agreement "CT Reliability COS" charges, as deductions from amounts it owed DEMI on invoices it prepared under the PSA.[108]

91. Between January 2002 and December 2003, UI deducted all of the "CT Reliability COS" charges imposed by ISO-NE on UI's load.[109] Beginning January 2004, UI began deducting only a portion of the charge because DEMI had ceased being UI's sole special contracts supplier.[110] It was not until December 16, 2004, that DEMI contested the pass-through of the reliability cost tracker charges by UI to it, and requested refund of amounts UI had withheld from its payments to DEMI under the PSA.[111] DEMI filed a lawsuit against UI in state court to recover from UI the withheld amounts and UI brought the instant case before FERC against DEMI.[112] DEMI claims, as discussed in paragraphs above, that the PSA does not assign responsibility for payment of the reliability cost tracker charges to DEMI.

92. The Commission, noting that reliability cost tracker charges are not mentioned in the PSA, determined that the PSA is ambiguous as to which party is responsible for

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considered in attempting to determine intent).

[105] *Devon Power LLC*, 103 FERC ¶ 61,082 at 61,272, *order on reh'g*, 104 FERC ¶ 61,123 (2003)("Devon").

[106] *Sithe New Boston, LLC*, 98 FERC ¶ 61,164.

[107] Ex. DOM-36; Ex. DOM-34; Ex. UI-1 at 15-33; Tr. 46.

[108] Ex. UI-1 at 28; Ex. DOM-34.

[109] Ex. DOM-34 at 17-25.

[110] Ex. UI-37 at 6.

[111] Ex. UI-1 at 42; Ex.UI-3 at 12; Ex. UI-36 at 1; Ex. DOM-18 at 25.

[112] Tr. 340; *United Illuminating Co. v. Dominion Energy Mktg., Inc. Complaint of the United Illuminating Co. for Order Direction Dominion Energy Mktg., Inc. to Comply with the Terms of Its Filed Rate Schedule*, EL05-76-000 at Ex. 2, filed Mar. 14, 2005.

those charges.[113] In contract interpretation, the Commission looks to the law that would apply if the subject matter of the contract were unregulated, absent a significant conflict between federal interests and the application of state law.[114] No such extraordinary circumstances are present in this case and the Parties here chose the law of New York as governing law.[115] Under New York law, a contract is to be interpreted as a whole, and the intention of parties determined by looking at the entire instrument. Particular words, phrases, clauses, or detached or isolated portions of the contract does not guide the meaning. The meaning should be determined from a reading of the contract as a whole.[116] Each clause is to be given its intended purpose, the intention of the parties is determined from the language use, and in order to understand the language, "we may put ourselves in their place and discern if possible the objects they had in view and the motives which dictated their choice of words."[117]

93. A contract has to be enforced according to the expectations of the parties, taking into account the circumstances at the time of the formation of the contract. Determining intent requires the fact finder to look at reasonable expectation, purpose, and common speech of the ordinary business person in the relevant circumstance. In addition, the level of business savvy and sophistication of the parties may be considered.[118] When the terms of a contract are ambiguous, extrinsic evidence, including evidence of industry custom or practice, may be considered to determine the intent of the parties.[119] Course of performance under the contract is considered the most persuasive evidence of the parties' agreed intent. How the parties practically interpreted the contract, for any considerable period of time before a dispute arose, is "deemed of great, if not controlling influence."[120] When a contract is ambiguous, the parole evidence rule does not prohibit the admission of extrinsic evidence to aid in interpreting evidence.[121]

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[113] *UI Co. v. DEMI Energy Mktg.*, 112 FERC at 62,279.

[114] *Golden Spread Electric Cooperative, Inc.*, 40 FERC ¶ 61,348 at 62,047 (1987) (citations omitted).

[115] Ex. UI-4 at 69.

[116] *Sunoco Overseas, Inc. v. Texaco Int'l Trader, Inc.*, 69 F. Supp. 2d 502 at 509 (1999).

[117] *Williams Press, Inc. v. State*, 37 N.Y. 2d 434 at 440 (N.Y. 1975) (citations omitted).

[118] *Eastman Kodak Co., v. STWB, Inc.*, 232 F. Supp. 2d at 74 at 91 (S.D.N.Y. 2002) (citations omitted).

[119] *Garza v. Marine Transp. Lines, Inc.*, 861 F/2d 23 (2d Cir. 1988) (citations omitted).

[120] *Federal Ins. Co. v. Americas Ins. Co.*, 691 N.Y.S. 2d 508 at 44 (1999) (citations omitted); *see Ocean Transp. Line, Inc. v. America Philippine Fiber Industry, Inc.*, 743 F.2d 85 at 91 (2d Cir. 1984).

[121] *Garza v. Marine Transp. Lines, Inc.*, 861 F.2d 23 (2d Cir. 1988) (citations omitted.)

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94. The Commission concluded in its September 15 Order common industry usage did not apply to the fixed costs, such as the reliability cost tracker charges at issue in this case, but noted its concern that the PSA definition went beyond that of common industry usage.[122] The Undersigned concludes that in the "context of the PSA in its entirety,"[123] reliability cost tracker charges are within the PSA definition of "transmission congestion costs" as stated in section 1.90 of the PSA.[124] The Undersigned has also concluded that section 2.1(c) assigns responsibility for those costs to DEMI up to UI's system. UI acknowledges that if the cost is imposed on, or associated with delivery of energy and market products from UI's system to its retail customers, it is UI's responsibility[125] and there appears to be no allegation that UI is charging DEMI for any costs from UI's system.

95. The evidence supports a conclusion that the expectation of the Parties at the time of the negotiation and execution of the PSA was that the entity providing electric capacity, energy, and ancillary services to UI, an electric distribution company, would assume all costs associated with providing that capacity, energy, and services. The PSA was written broadly to include such costs as the reliability cost tracker charges.[126]

96. Because of the uncertainty about the impact the growing problem congestion would have on the price of wholesale energy, UI intended to shift the burden and risk of evaluating, anticipating, and quantifying future costs. UI proposed an "all-in," fixed-price, requirements contract for which it would pay a premium price. UI's bid requirements statement specifically stated that bids should be based on the bidder taking responsibility for settlement uplift and transmission congestion costs, among other costs. UI required that estimates of congestion costs be included in its bids. UI's intention to shift the burden of specified future congestion costs in an uncertain market did not go unnoticed. DEMI was among the bidding wholesalers expressing concern about the requirement. Yet, DEMI made the business decision to submit a bid and enter into the PSA with terms in it that DEMI knew passed costs associated with congestion on to it during the term of the PSA.[127]

97. Also, DEMI, an energy industry business, could reasonably be expected to know that RMR-type agreements were a distinct possibility. In May 1997, NEPOOL

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[122] September 15 Order, 112 FERC at 62,279.

[123] September 15 Order, 112 FERC at 62,279.

[124] Ex. UI-4 at 18 ("Transmission Congestion Costs" means all costs resulting from insufficient transmission capacity, without regard to the cause of such congestion or how such costs are allocated assessed … .")

[125] UI RB at 28.

[126] Initial Decision ¶ 31, *see also* Initial Decision ¶13.

[127] *Id*. ¶¶ 8, 10, 12, 17, 18 and 26.

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submitted proposed Market Power Mitigation Principles and Market Power Mitigation Procedures to the Commission. The Principles and Procedures allow for recovery of RMR fixed costs. There was also the May 1999 "State of the Market Report, 1998," which spoke of regulating RMR units. There were other articles in the industry literature about regulation and other possible ways to address congestion issues. Some markets (i.e., New York, Ontario, California) were using RMR-type contracts as early as 1998. Even ISO-NE had rules addressing the potential for RMR contracts to cover revenue insufficiency resulting from bid caps.[128]

98. DEMI's witnesses acknowledged being aware of industry changes. Mr. Armstrong admitted that in 2001 DEMI was aware that transmission constraints made it difficult to get power into parts of New England, including Connecticut. He testified that although RMR agreements did not exist in New England at that time (although we note that the Sithe Agreement was imminent and do not believe DEMI was clueless), DEMI knew that that ISO-NE was considering ways to handle the transmission constraints in the region. Mr. Hanser, while claiming that the New England wholesale market structure did not change significantly between May 1999 and December 2001, also testified that the ISO-NE was in the process of redesigning its market as of December 2001 and a large scale market redesign was proposed in early 2000 and was conditionally approved by the Commission in June 2000.[129]

99. In light of the circumstances associated with the negotiation and execution of the PSA, DEMI's claim now that the contemporaneous industry definition of congestion costs should be controlling rings hollow and is not credible. In addition to knowing that it was entering into an agreement in which it undertook the risks associated with congestion costs, DEMI also knew that the industry was changing and that what those costs would be was uncertain. It is noted also that UI offered and paid a premium in order to shift the costs at issue to the seller (in this case, DEMI).[130]

100. DEMI's course of performance also belies any claim that DEMI did not know that it was liable for the reliability cost tracker charges. For example, DEMI participated at the NRG mediation in the load group. The load group participants were participants who would be subject to the RMR charges based on their obligation to supply energy to load. The NRG mediation was in late 2002 and early 2003. Mr. Armstrong, testifying for DEMI, stated that UI had begun to apply RMR costs to DEMI in early 2002. Mr. Armstrong is not, then, credible in claiming that statements and behavior of DEMI agents at the NRG mediation was based on a belief that DEMI was only liable for the RMR costs that existed at the time the PSA was negotiated and

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[128] *Id.* ¶¶ 13-15.
[129] *Id.* ¶¶ 33 and 47.
[130] *Id.* ¶ 12.

executed.[131] It is difficult to believe that DEMI was as unknowing about its business dealings as it claims here to be.

101. DEMI accepted invoices showing UI deducting the cost of the reliability cost tracker charges from amounts it owed DEMI for months before complaining. DEMI cannot reasonably claim ignorance, although it tries to, when its employee, beginning in October 2002, prepared spreadsheets estimating future reliability cost tracker charges. Also, an internal DEMI e-mail dated April 10, 2003, with the subject line stating "Potential RMR cost for UI deal" contained an estimate of DEMI's exposure for costs resulting from UI's RMR agreements. Even if we could accept Mr. Armstrong's apparently contention that until the reliability cost tracker charges came to his specific attention DEMI should not be held responsible sitting on any rights it had to complain, Mr. Armstrong testified that he became aware when PSA negotiation extension talks began. Those talks began in Spring 2003, yet DEMI did not act until November 2004.[132] And, DEMI, in considering whether to bid in the PSA extension proceedings, indicated it knew it was liable for the reliability cost tracker charges under the then current PSA. On being asked by Mr. Coretto of UI if DEMI was interested in extending, Mr. Armstrong answering for DEMI answered in the affirmative if certain "modifications" could be made, including that "seller is not responsible for RMR charges," among other things.[133]

FINDINGS AND CONCLUSIONS

102. On December 28, 2001, UI and VEPCO entered into a PSA. On January 28, 2002, UI and VEPCO executed an amended and restated version of the PSA. VEPCO later in 2002 assigned the PSA to DEMI. VEPCO and DEMI are both subsidiaries of Dominion.

103. The PSA established DEMI as the sole supplier of electricity to UI's SOS load between January 1, 2002, and December 31, 2003, and to UI's Special Contract Customer load between January 1, 2002, and December 31, 2008.

104. The PSA is an "all-in," fixed-price requirements agreement. The PSA established fixed prices that UI was required to pay based on the amount of energy DEMI delivered. The PSA included specific a provision addressing how to allocate all costs imposed on, or associated with the delivery of energy and market products to UI's delivery points, and from such delivery points to UI's retail customers.

105. At the time the PSA was negotiated and executed, Market Rule 17 of the

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[131] *Id*. ¶¶ 67, 71, 74 and 76.
[132] *Id*. ¶ 68 and 72.
[133] Ex. UI-12, Ex. UI-13, and Ex. UI-14.

NEPOOL Agreement recognized that units that were seldom run except for load pocket conditions were to be paid sufficient revenues to recover fixed costs so that they could stay in operation.

106. At the time the PSA was negotiated and executed, RMR agreements providing payments to critically-needed generation sources were well-established in New England as a tool to manage transmission congestion and to ensure system reliability.

107. While no special contractual arrangements under Market Rule 17 used fixed-payment structure before the PSA was executed, other arrangements for providing support to designated units were being used.

108. On the same day the PSA was executed, Sithe New Boston filed a fixed-payment RMR agreement with the Commission that Sithe New Boston had negotiated with ISO-NE under the provisions of Market Rule 17.

109. In March 2003, New England implemented SMD and replaced Market Rule 17 with Market Rule 1. Market Rule 1 contained provisions similar to the earlier Market Rule 17 provisions that gave ISO-NE the ability to enter into RMR agreements. Market Rule 1 allowed special contractual arrangements that included fixed-payment structures.

110. Connecticut where UI's load is located, has been designed by ISO-NE as a geographic area in which units are required to be run to relieve transmission congestion.

111. "Cost tracker" charges are a form of fixed-payment RMR charge imposed by ISO-NE and approved by the Commission to cover deferred and going-forward maintenance costs of some units operated by subsidiaries of NRG Energy, Inc.

112. At the time the PSA was executed, costs of some RMR units were being recovered through energy bids, which included both the variable and fixed costs of generators.

113. ISO-NE first imposed a charge for fixed payments under a RMR agreement in early 2002, in connection with a RMR agreement between ISO-NE and Sithe New Boston, LLC.

114. UI invoiced DEMI for fixed-payment RMR charges beginning the second month of the implementation of the PSA. After the Commission accepted "cost tracker" in April 2003, UI began receiving invoices from ISO-NE for a share of ISO-NE's payments to the NRG units. UI, in turn, began identifying those charges identified as "CT Reliability COS" charges, as deductions on invoices it prepared under the PSA.

115. At all times during which UI passed charges associated with RMR agreements through to DEMI, UI identified the charges as RMR or CT Reliability COS charges on

invoices it prepared under the PSA.

116. ISO-NE allocates CT Reliability COS charges to market participants according to network load. Between January 2002 and December 2003, DEMI supplied all of UI's load requirement. Between January 2002 and December 2003, UI deducted all of the CT Reliability COS charges imposed by ISO-NE on UI's load. Since 2004, DEMI has only supplied the portion of UI's load associated with special contracts, and since January 2004, UI has deducted from its payments to DEMI only the portion of the reliability cost tracker charges relative to DEMI's proportion of UI's load.

117. DEMI did not dispute the accuracy of any statement or invoice prepared by UI assigning the reliability cost tracker charges to DEMI, until it sent a letter dated December 16, 2004, to UI disputing the charges and asking UI to refund to it over $8 million dollars plus interest.

118. Article XIX of the PSA provides that the word "including" when used in the PSA means "including, without limitation." The definition of "Transmission Congestion Costs" at section 1.90 of the PSA is broader than the contemporaneous, customary or usual industry definition of such costs. Section 2.1(c) of the PSA assigns the transmission congestion costs at issue to DEMI as they are all incurred before the PSA-defined point of delivery and as the listed costs are only examples and are not exclusive.

119. The Parties had a meeting of the minds about which Party would bear the reliability cost tracker charges costs at issue even though those specific charges were not in existence at the time of execution of the PSA. UI intended the seller to be responsible for those type of charges or costs, and DEMI agreed, for a premium price, to be responsible.

120. Findings and conclusions contained in the body of this Initial Decision but not restated here are incorporated in this "Findings and Conclusions" section.

121. Issues raised but not discussed, were considered and found to be without merit.

122. UI has met its burden of proof and DEMI is responsible for the reliability cost tracker charges.

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ORDER

123. IT IS ORDERED, subject to review by the Commission on exceptions or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that

A. UI's complaint is hereby granted, as discussed in the body of this Initial Decision;

B. Dominion's motion to dismiss is hereby denied, as discussed in the body of this Initial Decision.

Charlotte J. Hardnett
Presiding Administrative Law Judge