UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

101 FERC ¶ 63,031

Nevada Power Company and Sierra Pacific Power Company v. Enron Power Marketing, Inc. El Paso Merchant Energy American Electric Power Services, Corp.	**Docket Nos. EL02-28-000 EL02-33-000 EL02-38-000**
Nevada Power Company v. Morgan Stanley Capital Group Calpine Energy Services Mirant Americas Energy Marketing, L.P. Reliant Energy Services BP Energy Company Allegheny Energy Supply Company, L.L.C.	**Docket Nos. EL02-29-000 EL02-30-000 EL02-31-000 EL02-32-000 EL02-34-000 EL02-39-000**
Southern California Water Company v. Mirant Americas Energy Marketing, L.P.	**Docket No. EL02-43-000**
Public Utility District No. 1 Snohomish County, Washington v. Morgan Stanley Capital Group, Inc.	**Docket No. EL02-56-000**

(Consolidated)

INITIAL DECISION

(Issued December 19, 2002)

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CARMEN A. CINTRON, Presiding Administrative Law Judge

INTRODUCTION

1. The Commission designated this case for hearing to determine whether the dysfunctional Cal ISO and PX spot markets adversely affected the long-term bilateral markets, and if so, whether the effect was of a magnitude warranting modification of contracts entered into in the bilateral markets in California, Nevada and Washington. As discussed below, it is found that the *Mobile-Sierra* public interest standard of review applies to these contracts. Furthermore, it is concluded that under the public interest standard, Complainants failed to establish that the dysfunctions of the Cal ISO and PX spot markets adversely affected the long-term bilateral markets.

PROCEDURAL HISTORY

2. Nevada Power Company and Sierra Pacific Power Company (collectively, "Nevada Companies") filed separate complaints against Duke Energy Trading and Marketing, L.L.C. ("Duke"), Morgan Stanley Capital Group, Inc. ("Morgan Stanley"), Calpine Energy Services, L.P. ("Calpine"), Mirant Americas Energy Marketing, L.P. ("Mirant"), Reliant Energy Services, Inc. ("Reliant"), El Paso Merchant Energy, L.P. ("El Paso"), BP Energy Company ("BP"), American Electric Power Services Corporation ("AEP"), Enron Power Marketing, Inc. ("Enron"), and Allegheny Energy Supply Company, L.L.C. ("Allegheny") (collectively, "Respondents"). Southern California Water Company ("SCWC") filed a complaint against Mirant. Public Utility District No. 1 Snohomish County, Washington ("Snohomish") filed a complaint against Morgan Stanley.[1] The Nevada Companies and SCWC argued that the dysfunctions in the Cal ISO and PX spot markets caused long-term contracts negotiated in California, Washington,

[1] In this order, the Nevada Companies, SCWC and Snohomish will be collectively referred as ("Complainants").

and Nevada to be unjust and unreasonable. Snohomish argued that the terms of its contract and the collateral annex are unjust and unreasonable. Complainants seek modification of their contracts.

3. On April 11, 2002, the Commission consolidated the above complaint proceedings and set the matter for hearing.[2] On April 17, 2002, the Chief Administrative Law Judge designated a presiding judge in this proceeding.[3] At a May 1, 2002, prehearing conference the parties agreed to a procedural schedule. Discovery commenced on May 29, 2002. Numerous discovery motions were filed and numerous discovery conferences were held in this proceeding.

4. On September 17, 2002, the Commission issued an Order Addressing Requests for Rehearing and Clarification of the hearing order.[4] In this order, *inter alia*, the Commission corrected the list of contracts set for hearing.

5. On June 28, 2002, the parties filed their direct testimony. Staff filed direct testimony and answering testimony on August 6, 2002. Respondents' answering testimony was filed on August 27, 2002. On September 17, 2002, Complainants filed rebuttal testimony. The hearing was held from October 7-24, 2002. Initial briefs were submitted on November 8, 2002 and Reply Briefs on November 22, 2002. Initial Briefs were filed by the Nevada Companies; SCWC and Snohomish (jointly); Snohomish; Allegheny on one issue (real party in interest); the Public Utilities Commission of Nevada ("PUCN") joined by the Office of the Attorney General for the State of Nevada, Bureau of Consumer Protection ("BCP"); Morgan Stanley Capital Group; Commission Staff ("Staff") and Respondents (all including Morgan Stanley). All of these entities also filed reply briefs.

ISSUES

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[2] *Nevada Power Company v. Duke Energy Trading and Marketing, LLC, et al.*, 99 FERC ¶ 61,047 (2002) ("Hearing Order").

[3] Settlement procedures were initiated. The Nevada Companies and Duke reached a settlement agreement. On June 26, 2002, the Nevada Companies' withdrew their complaint against Duke. On September 30, 2002, Duke's motion requesting removal of their name and case docket number from the caption of future orders in the proceeding was granted. Consequently, the caption is now *Nevada Power Company v. Enron Power Marketing, Inc., et al.*

[4] *Nevada Power Company v. Enron Power Marketing, Inc.*, 100 FERC ¶ 61,273 (2002).

Issue I. Whether Nevada Power Company, Sierra Pacific Power Company and Southern California Water Authority must bear the burden of showing that the challenged contracts are not just and reasonable under the Federal Power Act or that the contracts are contrary to the public interest under the *Mobile-Sierra* doctrine?

A. Parties Contentions:

6. The Nevada Companies assert that *Mobile-Sierra* applies only to long-term contracts filed with and approved by the Commission. The Confirmation Agreements (which contain the terms of the transactions- price, duration and delivery point) in this proceeding were not filed with or approved by the Commission.[5] As a result, these companies argue, *Mobile-Sierra* does not apply since the Commission must be granted an opportunity in every case to judge the "reasonableness" of the rate. The Nevada Companies distinguish their contracts from those in *Mobile-Sierra* since the contracts at issue in this case are for supply from three months to one year, not ten and fifteen year contracts like in *Mobile-Sierra*.[6]

7. According to the Nevada Companies, the Commission has found that there is a "potential for the exercise of market power" and "a dysfunctional market place both in California and the remainder of the West." Moreover, the Nevada Companies contend that the Commission previously stated that any party that "believes any of its contracts are unjust and unreasonable… [t]o file a complaint under FPA Section 206 to seek modification of such contracts." These companies maintain the Commission has not applied the *Mobile-Sierra* public interest standard to contracts entered into in a dysfunctional market.[7] Thus, the Commission should follow precedent and examine the contracts here under the just and reasonable standard, the Nevada Companies argue.

8. In addition, the Nevada Companies contend that in a proposed policy statement the Commission made clear that, unless an agreement specifically states that the public interest standard applies, market-based rates will be reviewed under the just and reasonable standard.[8] In this case, the Confirmation Agreements do not include language adopting the public interest standard of review nor do they mention the "just and reasonable" standard. The Nevada Companies argue that their witnesses testified that they had no intention of waiving their right to challenge the agreements as "unjust and unreasonable," nor would they have recommended waiver of this right had the issue been raised. As a result, the Nevada Companies argue that the Confirmation Agreements

[5] The Nevada Companies Initial Brief ("IB") at 4.
[6] Id. at 5.
[7] Id.
[8] Id. at 6.

should be construed as "demonstrating the intent of the parties to allow a just and reasonable standard of review."[9] Any other interpretation would be contrary to the Commission's proposed policy statement clarifying its own precedent, which provides that silence on what standard applies is to be read not against the buyer, but in the buyer's favor.

9. Further the Nevada Companies assert that *Mobile-Sierra* does not apply because the Western Systems Power Pool Agreement (WSPPA) is an umbrella agreement which does not contain the fundamental terms - price, duration and delivery point - for transactions under the "Service Schedules." The Confirmation Agreements are expressly distinct from the WSPP itself and Section 32.3 of the WSPP states that, in the event of a conflict between a binding and effective Confirmation Agreement and [the WSPP], the Confirmation Agreement shall govern.[10]

10. Additionally, the Nevada Companies argue that Section 6.1 of the WSPP limits the parties' rights to unilaterally amend the WSPP by providing it can only be amended by joint application to FERC.[11] If the parties had intended to limit their Section 206 rights, they could have done so, the Nevada Companies argue and indeed have done so with regard to some contracts.[12] The fact that the Confirmation Agreements do not include language on Section 206 rights is substantial evidence that the parties did not intend to limit the Nevada Companies' rights under Section 206 or to be bound to a public interest standard of review.[13]

11. In addition, the Nevada Companies maintain that the Commission has modified "uneconomical" contracts under the just and reasonable standard even when the contract expressly mandates application of the *Mobile-Sierra* doctrine. Moreover, case law does not indicate a "completely consistent pattern" as to whether the doctrine of *Mobile-Sierra* applies where the contract is silent in this respect.[14] In this case, because of the effect of market dysfunction, prices for power were unjust and unreasonable, and thus, Section 206 obligates the Commission to fix a just and reasonable price, the Nevada Companies argue.

[9] Id. at 7.

[10] Id. at 8.

[11] Id. at 9.

[12] For instance, Snohomish's contracts with AEPSC, Calpine and BP, Mirant and California Department of Water Resources ("DWR").

[13] The Nevada Companies IB at 10.

[14] Id. at 8.

12. SCWC and Snohomish aver that nothing in Section 6.1 suggests that it was meant to preserve (or restrict) the rights of an individual party to seek changes to the rates, terms or conditions of a Confirmation Agreement for a specific transaction.[15] The Confirmation Agreements are not part of the WSPP Agreement, by virtue of the fact that Section 4.1, in defining "Agreement" excludes the Confirmation Agreements.[16] In executing its contract with Mirant, SCWC argues that it relied on the Commission's December 15 Order which mentioned the just and reasonable standard.[17] In addition, Mirant's conduct, by not adding a *Mobile-Sierra* clause to its contract with SCWC, indicates that it was relying on the just and reasonable standard, SCWC argues.[18]

13. The PUCN[19] avers that the just and reasonable standard is applicable to the challenged contracts at issue for several reasons.[20] First, the *Mobile-Sierra* public interest standard, developed under an entirely different set of facts, is inapplicable to the situation at hand, involving wholesale transactions based on market-rate authority, subject to a dysfunctional market, which was incapable of restraining prices at just and reasonable levels.[21] Moreover, these contracts were not subject to review by the Commission.[22] The market dysfunction negated the presumption that the market rates were just and reasonable, thereby invoking the Commission's independent duty to establish a just and reasonable rate, unconstrained by the *Mobile-Sierra* doctrine.[23]

14. Another reason supporting use of the just and reasonable standard in lieu of the *Mobile-Sierra* doctrine is that the Commission and entities representing third parties, that are non-signatories to the challenged contracts, such as the PUCN, are not necessarily bound by the doctrine.[24] In addition, the Commission, pursuant to the Federal Power Act, ("FPA") is under a duty to "make an independent assessment of the reasonableness of wholesale rates, regardless of the terms of the agreement between the parties."[25] Moreover, the PUCN, as representative of Nevada in utility matters, has standing to challenge wholesale power rates as unjust and unreasonable as applied to the Nevada

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[15] SCWC IB at 5.

[16] Id. at 6.

[17] Id. at 7.

[18] Id. at 10.

[19] The PUCN and a number of other entities were allowed to intervene in this proceeding.

[20] PUCN IB at 3.

[21] Id. at 4.

[22] Id.

[23] Id. at 4- 6.

[24] Id. at 6.

[25] Id. at 7.

utilities and their retail customers, and thus, the PUCN is not bound by the *Mobile-Sierra* public interest standard.[26] Further, the PUCN also avers that the parties retained the right to pursue unilateral contractual changes, pursuant to the just and reasonable standard of section 206 of the Federal Power Act, by not expressly waiving the right to do so under section 6.1 of the WSPPA, and thus, the parties are not bound by the *Mobile-Sierra* doctrine.[27]

15. The PUCN also contends that, even if the *Mobile-Sierra* public interest standard applies, "where contract relief is sought to safeguard the interest of third parties, the Commission is entitled to apply a *more flexible standard* in evaluating whether contract modification is in the public interest," and in this evaluation, the Commission should assign "great weight to the possibility that Nevada customers could be harmed by the indisputably high prices in the challenged contracts."[28] Moreover, a heavier than usual burden should not be applied.[29]

16. Respondents argue that this is the first time the Commission has ordered a hearing under Section 206 of the FPA of a complaint against a market-based rate resulting from freely-negotiated, bilateral contracts.[30] The record supports a finding that the Nevada Companies and SCWC agreed that contract modifications of the rates, terms and conditions would not be sought unilaterally, but jointly under Section 205 of the FPA pursuant to Section 6.1 of the WSPP. The parties did not agree to any other mechanism for contract modification and did not agree that either party could seek future rate changes pursuant to Section 206. The fact that parties did not agree to permit unilateral changes means that the Nevada Companies' and SCWC's unilateral proposals to change the contracts through the regulatory process are impermissible unless the Complainants can demonstrate that contract abrogation or modification is required by the public interest.[31] Accordingly, Respondents argue that the *Mobile-Sierra* doctrine applies to the voluntarily-negotiated contracts at issue in this proceeding.[32] Respondents argue that precedent supports their allegations.[33] Parole evidence of the parties' intent may not be introduced, Respondents argue. Moreover, even if extrinsic evidence is allowed,

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[26] Id.
[27] Id. at 8-9.
[28] Id. at 12, 14.
[29] Id. at 14-15.
[30] Respondent's IB at 1.
[31] Respondents IB at 9.
[32] Id. at 10.
[33] Id. at 9.

Complainants have not submitted affirmative evidence that the parties intended to allow application for unilateral changes to the contracts.[34]

17. The reason Respondents did not specifically raise the issue of unilateral rate filings or other special *Mobile-Sierra* provisions is easily explained: contracting parties need not include language explicitly restricting the rights of a party to file a complaint because "anyone bargaining in the shadow of the [*Mobile-Sierra*] doctrine would assume that a contract unconditionally setting a fixed rated, or a fixed rate of return, would be governed by *Mobile-Sierra*. In addition, the Commission has stated that the public-interest standard governs where a fixed-rate contract did not provide the moving party with the right to make a unilateral rate change under Section 206 and the evidence showed that the parties "did not even discuss" either Section 206 or the standard that would apply if a complaint were filed. These are the facts here, Respondents argue.[35] Additionally, contracts not at issue here have no bearing on the clear intent of the parties as expressed in Section 6.1 of the WSPP.

18. In this proceeding, Staff asserts that the appropriate burden of proof applicable to these contracts (except for the collateral annex in the contract between Morgan Stanley and Snohomish) is the public interest standard. According to Staff, this is gleaned from the terms of the WSPP and is confirmed by the testimony of those who actually made the deals. The participants in the WSPP intended to limit the possibility for contract modification to very narrow circumstances, otherwise a "deal is a deal."[36]

B. Discussion/Findings:

19. The Commission in this case set for hearing the following issue: whether complainants must bear the burden of showing that the challenged contracts are contrary to the public interest, or whether they will bear the burden of showing that the contracts are not just and reasonable. The Commission stated that even under a "just and reasonable" standard, parties who seek to overturn market-based contracts into which they voluntarily entered will bear a heavy burden.[37] On rehearing, the Commission stated that the evidentiary hearing was established to interpret Section 6.1 of the WSPPA and ascertain the parties' intent at the time the contracts were signed.[38] A short description of the transactions is relevant to this discussion.

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[34] Id. at 13.
[35] Id. at 14.
[36] Staff IB at 3.
[37] *The Nevada Companies v. Enron Power Marketing, Inc.*, 99 FERC ¶ 61,047 at 61,190 (2002).
[38] Id. at 100 FERC ¶ 61, 273 at 62,047 (2002).

20. The Nevada Companies contracts are fixed rate, over the counter, "brokered transactions," for "standard on-peak (6 x 16 blocks of power in 25 MW increments for delivery hubs in the West, such as Palo Verde or Mead) products."[39] Many are "locational basis swaps," and others are "sleeve transactions." Only two contracts with AEP are for more than one year.[40] Most of the contracts are quarterly contracts entered into for the third quarter of years 2002, 2003 or 2004, plus several one-year transactions. The prices of these contracts are varied, but all were at or below prevailing market levels.[41]

21. Snohomish issued a Request for Proposals (RFP) on December 22, 2000. Morgan Stanley was one of 17 suppliers who received the RFP.[42] Morgan Stanley was one of five suppliers who responded to the Snohomish RFP. Snohomish executed three separate contracts with three different sellers, including Morgan Stanley. On January 26, 2001, Snohomish and Morgan Stanley entered into a power sales agreement (PSA) comprised of the WSPPA, a Confirmation Agreement, Attachment A (modifying the WSPPA) and a collateral annex. Morgan Stanley agreed to sell Snohomish 25 MW of around-the-clock energy for delivery at Mid-C for a period of 105 months (8.75 years) at a price of $105/MWh.

22. SCWC also issued an RFP sent to Mirant and five other companies.[43] Mirant and SCWC executed a long-term power sale contract on March 19, 2001. This consisted of two separate transaction confirmations covering on-peak and off-peak hours for a single, long-term sale of 15 MW of round-the-clock firm energy ("7 x 24 energy"). The delivery point being the Victorville substation in the South-of-Path 15 ("SP 15") zone in Southern California, with delivery to occur from April 1, 2001 through December 31, 2006, at a fixed $95/MWh.[44] After execution of the SCWC contract, on March 30, 2001, Mirant and SCWC agreed to a one-month transaction for April 2001, in which Mirant would buy back the 15 MW of power from SCWC at the spot price of energy at SP15 (using the Dow Jones Index) minus $20 per MWh ("SCWC Buyback Contract").[45] These contracts were entered into pursuant to the WSPPA.

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[39] Three 25 MW off-peak contracts with El Paso (2 transactions) and Enron (1 transaction) are not standard products.

[40] The two-year contracts were filed with the Commission. Ex. NEV-3 at 93 and 100.

[41] Tr. at 2645:14-17; 2656:16-20; 2709:9-15; 2288:3-12.

[42] Ex. SNO-4 at 5:6-8; Ex. SNO-5.

[43] Tr. at 2897:19-2899:9.

[44] Ex. MAEM-2 at 4:9-13.

[45] Ex. MAEM-2 at 4:13-17.

23. The record supports the finding that the contracts at issue in this proceeding are contracts under the WSPPA. Moreover, the record supports the finding that the Confirmation Agreements[46] are part of the WSPPA. Complainants' contentions that the Confirmation Agreements are not part of the WSPPA are meritless. Each contract consists of a Confirmation Agreement, the WSPPA and any amendments, which together form a single, integrated document.[47] Section 26 of the WSPPA states that amendments and confirmations constitute the full and complete agreement.[48] Section 2.2 of the WSPPA states that the WSPPA together with any applicable Confirmation Agreement, sets forth the terms and conditions to implement these services, within any applicable rate ceilings set forth in the Service Schedules, in conformance with FERC orders, where applicable. Additionally, Section 35 of the WSPPA states: "The Parties acknowledge and agree that all of their transactions, together with this Agreement and the related Confirmation Agreement(s) form a single, integrated agreement, and agreements and transactions are entered into in reliance on the fact that the agreements and each transaction form a single agreement between the Parties.[49]

24. The record is clear that Section 6.1 of the WSPPA allows parties to jointly seek modification of the rates, terms and conditions of the contracts under Section 205 of the FPA. However, the cited section does not have any language regarding the parties' rights *vis-å-vis* Section 206 of the Federal Power Act. None of the confirmation agreements, except the Morgan Stanley-Snohomish contract, address the parties' rights under section 206 of the FPA.

25. A summary of applicable law may be helpful in this regard. In the "*Mobile*" case a supplier of natural gas sought to unilaterally increase the rate of a contract filed with the Commission. In *Mobile*[50] the Supreme Court held that the Natural Gas Act does not empower natural gas companies unilaterally to change their contracts. This Court went on to say that by "preserving the integrity of contracts, it permits the stability of supply arrangements which all agree is essential to the health of the natural gas industry. . . The

[46] These agreements are *pro forma*, the parties simply fill in the blanks to add their names, rate, length of service, and quantities. The WSPPA contains draft Confirmation Agreements. (Sample Form for Confirmation, Exhibit C to WSPPA). Ex. NPC-14.

[47] Ex. NPC-14, Section 26.

[48] Ex. NPC-14, Section 26.

[49] Contrary to Complainants' contentions, Section 38 of the WSPPA governs changes to the WSPPA and its service schedules. Ex. NPC-14 at 56. Likewise, SCWC's contentions that Section 6.1 applies only to changes to the WSPPA is disingenuous.

[50] *United Gas Pipeline Co. v. Mobile Gas Service Corp*, 350 U.S. 332 (1956).

contracts remain fully subject to the paramount power of the Commission to modify them when necessary in the public interest."

26. In *"Sierra,"* [51] a supplier of electric power (a public utility) tried to unilaterally increase the rate of a contract filed with the Commission. The Supreme Court stated:

> But, while it may be that the Commission may not normally impose upon a public utility a rate which would produce less than a fair return, it does not follow that the public utility may not itself agree by contract to a rate affording less than a fair return or that, if it does so, it is entitled to be relieved of its improvident bargain. . . . In such circumstances the sole concern of the Commission would seem to be whether the rate is so low as to adversely affect the public interest – as where it might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory."

Id. at 355.

27. Staff recites applicable law in its brief. Staff's arguments and review of the case law is persuasive. The law is clear: absent contractual language susceptible to the construction that the rate may be altered while the contract subsists, the *Mobile-Sierra* doctrine applies.[52] In the absence of clear contractual language allowing unilateral contract modifications under Section 206, the party seeking change must meet the public interest standard. In *Texaco,* the Court held that *Mobile-Sierra* applies: "Because nothing in the agreements suggests that the contracting parties intended to grant Mojave unilateral authority to modify shipment rates." Moreover, in *Boston-Edison,*[53] the Court held that "the specification of a rate or formula by itself implicates *Mobile-Sierra* (unless the parties negate the implication). The Commission has interpreted silence in contracts concerning section 206 rights as an implicit waiver of the buyer's rights to unilaterally modify contracts.[54]

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[51] *Federal Power Commission v. Sierra Pacific Power Co*., 350 U.S. 348 (1956).

[52] *Texaco Inc. v. FERC,* 148 F. 3d 1091, 1096 (D.C. Cir. 1998). The language of the contract in *Texaco,* was similar to the language of the contracts in this case, and the Court held *Mobile-Sierra* applicable.

[53] *Boston Edison Company v. FERC,* 233 F.3d 60 (1st Cir. 2000).

[54] *San Diego Gas & Electric Company v. Public Service Company of New Mexico,* 91 FERC ¶ 61,233 at 61,851 (2000). *See also, Metropolitan Co. v. FERC,* 595 F.2d 851, 855 (D.C. Cir. 1979) (silence regarding FPA rights invokes public interest standard). In their reply brief the Nevada Companies cite *Alabama Power Co. v. FERC,* 993 F. 2d 1557, 1559 (D.C. Cir. 1993). This and other cases cited by Complainants are inapposite.

28. Accordingly, it is found that Section 6.1 of the WSPPA does not negate *Mobile-Sierra*; therefore, the public interest standard applies. Nothing in Section 6.1 of the WSPPA, nor in the underlying confirmation agreements, suggests that the contracting parties intended to give unilateral authority to modify the contracts under Section 206 of the FPA. As a matter of fact, this conclusion is bolstered by the fact that the WSPPA does indeed address the parties' rights. Thus, Section 6.1 specifically provides that, under Section 205, the parties may "*jointly*" seek rate modifications. The inference to be made from the wording of the contract is that by agreeing to jointly apply for modifications, they excluded the possibility of unilaterally seeking modifications under Section 206 of the FPA. There is no language in the WSPPA or Confirmation Agreements allowing unilateral rate changes. In this case, the parties expressed their intent that the contracts could only be changed if jointly requested under Section 205. When parties agree to a specific, fixed rate in a contract, the *Mobile-Sierra*[55] doctrine applies.[56] The contracts in this case contain a fixed rate, thus *Mobile-Sierra* applies. As here, where the contract has not preserved the rights of a party to seek unilateral modifications, *Mobile-Sierra* applies in order to preserve the contractual expectations of parties by limiting modification only if the public interest so requires. This furthers the policy goals of ensuring that parties'

As a matter of fact, the Nevada Companies' briefs exhibited a disregard towards proper citation of the applicable case law. The Alabama case is inapposite because the facts are totally different, dealing with a "formula rate" which required Commission "agreed to" review every three years. Moreover, the cited case is silent on the applicable standard of proof and precedes the Texaco case cited above. In addition, Complainants reliance on a recent Commission policy statement is not persuasive since *inter alia*, it would not apply to the contracts at issue in this case. *See in general, Pacific Gas and Electric*, 506 F. 2d 33, 38 (D.C. Cir. 1974) (a policy statement announces the agency's tentative intentions for the future). Moreover, the Nevada Companies mischaracterize the policy statement. To wit, in the policy statement the Commission stated that it was proposing to hold parties bound to a public interest standard only when both parties agreed to bind themselves in this fashion, stating that this is a departure from past precedent. *Standard of Review for Proposed Changes to Market-Based Rate Contracts for Wholesale Sales of Electric Energy by Public Utilities*, FERC Stats & Regs ¶ 32,563 at 34,272 (2002).

[55] *United Gas Pipe Line Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) ("*Mobile*"); *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956) ("*Sierra*").

[56] *Richmond Power and Light v. FPC*, 481 F.2d 490 (D.C. Cir. 1973); *Boston Edison Co. v. FERC*, 233 F.3d 60 (1st. Cir. 2000) ("*Boston-Edison*")

expectations are respected and promoting stability of contract and supply arrangements. *Mobile-Sierra* applies unless the contract states otherwise.[57]

29. Staff witness Forman testified that the WSPPA itself or the rates, terms, and conditions of specific transactions can be changed in two separate ways. First, through Section 6.1 or through Section 34 which requires that the parties enter into Dispute Resolution before any other form of litigation may proceed.[58] Additionally, this witness testified that the drafters of the WSPPA could easily have added language to allow other ways of making changes to the WSPPA or the rates, terms and conditions.[59] This witness opines that the language of Section 6.1 of the WSPPA makes clear that the parties intended that transactions could only be modified as stated in the agreement (jointly under Section 205 or dispute resolution). Thus, the parties intended that the rates, terms and conditions of a transaction would be final, and not easily changed, once memorialized in a confirmation agreement.

30. The unrebutted testimony of Dr. Perillo is entitled to substantial weight.[60] Dr. Perillo testified that contracts formed by the Transaction Confirmations and the WSPPA do not permit either party to make unilateral applications to FERC to modify the rates, terms or conditions of service. He states that under the maxim "*expressio unius est exclusio alterius,*" (the expression of one thing is the exclusion of the other), the only interpretation of Section 6.1 of the WSPPA is that the parties thought about, contemplated, and provided for applications to FERC, excluding all applications not specifically provided for in the contracts. In other words, the parties agreed that unilateral applications to FERC would not be permitted under the contracts.[61] According to Dr. Perillo, due to the fact that the parties chose not to modify or supplement Section 6.1 (which only allows joint application to FERC) it is clear, as a matter of contract law, that there was no intent on the part of the parties to the Transaction Confirmations to allow unilateral applications for contract modification.[62]

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[57] *Texaco Inc. v. FERC*, 148 F.3d 1091, 1095 (D.C. Cir. 1998). *See also Town of Norwood v. FERC*, 202 F.3d 392, 400 (1st Cir. 2000); *Papago Tribal Util. Auth. v. FERC,* 723 F.2d 950, 953 (D.C. Cir. 1983).

[58] The Commission recognizing this in the hearing order, required the parties to submit to mediation before the hearing could proceed. *Nevada Power Company v. Enron Power Marketing, Inc.*, 99 FERC at 61,193. Duke Energy Trading and Marketing reached a settlement in this case as a result of this process.

[59] Tr. at 4513-16; Ex. S-1.

[60] Ex. MAEM-1 at 7:8-10.

[61] Ex. MAEM-1 at 10:8-12.

[62] Ex. MAEM-1 at 13:5-9.

31. The WSPPA contains no contractual language which may be construed as permitting parties to alter the fixed-rate contracts by means of a unilateral filing. Consequently, the contracts are governed by the public interest standard. The Commission has held that it will not read into the parties' agreements provisions that the parties did not include and courts have held that fixed-rate contracts fall under the *Mobile-Sierra* public interest standard if they omit express language granting a party the right to unilaterally seek contractual modifications.[63]

32. Complainants argue that other contracts have specific reference to Section 206. Complainants' arguments are not persuasive. These contracts are not part of this proceeding. The contract is clear, it contains specific language concerning the rights of the parties to seek contract modifications. Therefore, the only rationale interpretation of Section 6.1 of the WSPPA is that it precluded unilateral contract modification. Moreover, Dr. Perillo's testimony concerning parole evidence is persuasive. When parties "have foreseen an event or action, such as application to FERC to change the rates, terms or conditions of service under transactions pursuant to the WSPPA, and have made some provision for it," as was done in the WSPPA with regard to applications to the Commission for contract modification, parole evidence may not be introduced regarding the parties intent as to unilateral application for contract modifications.[64]

33. Even though the above resolves this issue, the Commission in its Rehearing Order stated that it wanted a record developed "to interpret section 6.1 of the WSPP Agreement and to ascertain the intent of the parties at the time the contracts were signed.[65] Consequently, intent will be considered. The evidence in this case does not support Complainants' allegations concerning intent. Complainants' witnesses' testimony in this regard is not credible. Substantial evidence supports Respondents' arguments concerning this issue. To wit, Calpine witness Posoli, stated that there is an understanding among traders in the electricity business that once agreed to, prices and other terms are fixed and not subject to later modification.[66] In particular, in brokered transactions, involving standard products, the discussions are limited to the basic economic terms such as

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[63] *City of Lebanon Ohio v. Cincinnati Gas and Elec. Co.*, 64 FERC ¶ 61,341 at 63,445 (1993); *Power Authority of New York v. Long Island Lightning Co.*, 60 FERC ¶ 61,069 at 61,234 (1992). See *Boston-Edison*, *supra* at 65;*Union Pac. Fuels, Inc. v. FERC*, 129 F.3d 157 (D.C. Cir. 1997). See also *San Diego*, 91 FERC at 61,851-53.

[64] Ex. MAEM-1 at 12:15-20. In their reply brief, the Nevada Companies concede the point that since there is no ambiguity in the contracts, resort to extrinsic evidence of intent is not necessary. Nevada Companies RB at 10, n.6.

[65] *Nevada Power Company v. Enron Power Marketing, Inc.*, 100 FERC at 62,047 (2002) (Rehearing Order).

[66] CES-1 at 9-10.

product, quantity, price, delivery period and delivery point.[67] This is corroborated by a number of trader telephone conversations played at the hearing.[68] Further, corroboration appears in the testimony of AEP witness William Reed, who testified that discussions regarding standards of review for future changes to the contract would have been highly irregular for traders or brokers.[69] Even Nevada Companies' trader Perry stated that he never considered section 206 and it never came up during negotiations.[70]

34. Furthermore, the arguments that *Mobile-Sierra* does not apply to the Nevada Companies contracts because they were shorter-term forward contracts[71] or SCWC's argument that *Mobile-Sierra* applies only to a "low rate" case, are not persuasive. *Mobile-Sierra* does not distinguish the length of the contracts, whether the rates are low or high or whether the complaint is filed by the buyer or the seller. The PUCN's, SCWC's and the Nevada Companies' arguments that *Mobile-Sierra* does not apply because the Confirmation Agreements were not filed with the Commission are not persuasive.[72] The Commission has held that, in the case of market-based rates, the Section 205 requirements are satisfied by the Commission's determination, prior to the effectiveness of those rates, that the utility (and its affiliates) lacks market power or has taken sufficient steps to mitigate market power.[73] In this case, an initial review has already occurred under Section 205 when the Commission approved the WSPPA and found that all Respondents are authorized to sell power at market-based rates and that Respondents did not possess the ability to exercise market power in the WSPP.[74] Thus,

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[67] Tr. 3171-72.

[68] Exs. MSC 11; 135;136; 178 .

[69] Ex. AEP-1 at 4-5. See also, Tr. 2734-39; 3166; 3181-82; 3260-62; 3334; 3500; 4155-56; Ex. MSC-21 at 10-12.

[70] Tr. 2337.

[71] The delivery terms of the Nevada Companies' contracts, in many cases were for a three-month period. However, the majority of the contracts would be in force for much longer periods, several months to several years. Under the terms of the WSPP, only agreements of one year or longer need be filed. Several of the challenged contracts had terms longer than one year and were filed with and accepted by the Commission. Respondents' IB at 5, n.12.

[72] The Nevada Companies cite *Florida Power and Light Company*, 67 FERC ¶ 61, 141 (1994). This case is inapposite since it applies to initial Commission review under Section 205. This is not the case here.

[73] See, *e.g. San Diego Gas and Electric Company*, 91 FERC at 61,853 (applied the public interest standard to a "high rate" case where the buyer was seeking to decrease the rate). ("California Refund Proceeding")

[74] The WSPPA and *pro forma* Confirmation Agreements set guidelines for the development of contract prices, setting market based rates or rates under established price

the rates under the WSPPA are presumed just and reasonable.[75] Finally, the Nevada Companies' and PUCN's argument that *Mobile-Sierra* should not apply because the market was dysfunctional is without merit. This is indeed the issue in this case, whether the dysfunctions in the Cal PX and ISO spot markets adversely affected the forward markets.

35. SCWC argued that the Commission in the California Refund Proceeding asserted that the just and reasonable standard would apply to long-term contracts. This contention is specious. The Commission did not make a public interest finding that *Mobile-Sierra* would not apply (as it did for instance, in Order 888).[76] Moreover, this hearing would be superfluous if the Commission had made the finding that SCWC contends. Nor is there a basis for applying a "more flexible" standard as the PUCN argues. The cases cited in support of the PUCN's arguments are inapposite, referring to initial evaluations of contracts under Section 205 and not to cases like the ones here where the parties to the contracts are seeking to change the rates.[77] Moreover, the hearing order in this case specifically referred to *Mobile-Sierra* and the just and reasonable standard. These pronouncements are binding in this case. Furthermore, the Commission has applied the public interest standard to challenges brought by non-contractual parties.[78]

36. Accordingly, it is found that the *Mobile-Sierra* public interest standard applies to the contracts in this case. In addition, it is found that the record supports a finding that the parties did not intend to retain for Complainants the right to unilaterally seek changes to their contracts.

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caps. As Staff appropriately points out, as long as the contract prices at issue fall within these guidelines, which they did, they are entitled to a presumption of justness and reasonableness. Staff RB at 4.

[75] *California v. British Columbia Power Exch. Corp.*, 99 FERC ¶ 61,247 at 62,063 (2002).

[76] See Transmission Access Policy Study Group v. FERC, 225 F.3d 667, 709-12 (D.C. Cir. 2000).

[77] *Southern Company Services*, 67 FERC ¶ 61,080 (1994) (Commission not bound, absent its consent, to a public interest standard of review when the Commission reviews an agreement initially). *PJM Interconnection, LLC*, 96 FERC ¶ 61,206 (2001) (a third party non-signatory to an agreement was significantly impacted if the agreement were to remain unchanged).

[78] See, *e.g. Public Utility Commission v. Sellers of Long Term Contracts*, 100 FERC ¶ 61,098, 61,396 (2002).

Issue II. Whether the dysfunctional California Independent System Operator (ISO) and Power Exchange (PX) spot markets adversely affected the Western long-term bilateral markets?

A. Parties Contentions:

37. The Nevada Companies assert that its witnesses established that prices in the Cal ISO and PX spot markets drove prices in spot markets throughout the Western System Coordinating Council ("WSCC"). According to the Nevada Companies, forward market prices are based upon expected future spot market prices. [79] The forward price will be equal to the expected spot price for the delivered power adjusted for the risk associated with uncertainty in the spot price, the Nevada Companies maintain. The dysfunctional spot markets strongly influenced forward prices in the West.[80] Additionally, the Nevada Companies assert that the dysfunctional Cal ISO and PX spot markets adversely affected forward market prices for energy to be delivered in years 2002 and 2003, to the extent that the dysfunction in the Cal ISO and PX spot markets was expected to persist.[81]

38. In addition, the Nevada Companies argue that the forward price curves provide proof that at the time the contracts were executed, market participants expected dysfunction to continue at least through 2002 and possibly into 2003.[82] These forward price curves show that forward market prices remained high until the Commission acted in the spring and summer of 2001 to mitigate the impact of spot market dysfunction through the imposition of price caps, when market prices declined dramatically, the Nevada Companies assert.[83] The actions taken by the Commission in November and December 2000 did not convince market participants that the Commission would eliminate the dysfunction in the spot market.[84] According to the Nevada Companies, statistical analysis shows that forward market prices had lots of movement when spot market prices were static, because the forward price changes anticipating future mitigation began to happen before the spot price changes took place. Thus, despite the obvious linkage, a low correlation could show, the Nevada Companies argue.[85] The Commission found that the April 2001 Order reduced prices in the California spot

[79] The Nevada Companies' IB at 16.
[80] Id. at 18.
[81] Id.
[82] Id.
[83] Id. at 21.
[84] Id. at 22.
[85] Nevada Companies RB at 13.

markets and, in turn, in the Western long-term bilateral markets, confirming the actual interdependence of prices in the two markets.[86]

39. Both SCWC and Snohomish assert that the spot market dysfunctions created hugely inflated expectations of future prices, plus administered a fatal blow to the liquidity of the forward markets.[87] Moreover, these companies maintain that FERC's attempts to correct the spot market dysfunctions by moving the loads of California's Investor Owned Utilities (Cal IOUs) to the forward markets and a federal order requiring power to be sold to the Cal ISO during the crisis, led to even higher demand, less supply, and higher prices in the forward markets.[88] The forward price for a one-year contract (peak MidC) increased and by January 26, 2001, had increased by over 900 percent.[89] Both SCWC and Snohomish assert that prices available for long-term contracts during the crisis were two to three times over the long run marginal costs ("LRMC") and the forward price curves during the crisis projected that prices would remain far above LRMC for many years.[90] Even in periods of shortages, long-term prices should approach LRMC within the period necessary to construct new plants, two to three years. Indeed, in functionally competitive markets, most of the backwardation (*i.e.* the excess of spot prices over the LRMC) disappears within the first twelve to eighteen months of the forward price curve. However, both SCWC and Snohomish maintain that none of this happened in the Western markets during the crisis.[91]

40. The Western forward markets, during the crisis, also suffered from a severe lack of liquidity (an adequate number of sellers willing to conduct business), SCWC and Snohomish maintain.[92] The CalPX Block Forward and NYMEX forward markets collapsed as a result of the California crisis and very few sellers were willing to trade in the forward bilateral markets, according to SCWC and Snohomish,[93] thus eliminating the available choices to both companies. The volatility of the forward markets during the crisis period is further evidence of the pervasive dysfunction of those markets, according to SCWC and Snohomish. This volatility led to untenable deals for Snohomish and SCWC, because any delays in considering the contract terms would result in price increases, both companies aver.[94]

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[86] Id. at 20.
[87] SCWC/Snohomish IB at 10.
[88] Id. at 10.
[89] Id. at 11.
[90] Id. at 12.
[91] Id. at 12.
[92] Id. at 13.
[93] Id. at 13.
[94] Id. at 14.

41. Additionally, these companies argue that price discovery in the Western forward markets was limited and subject to manipulation. For instance, these companies argue that California markets operated under secrecy, so that data was not readily available from these markets. Similarly, forward gas and electricity markets in other parts of the West were characterized by a lack of adequate market information. In addition, SCWC and Snohomish argue that the reported prices for both natural gas and electricity were purposefully manipulated and that sham trading artificially inflated forward market prices in the Northwest by as much as twenty-five percent. These companies further argue that the lack of reliable market data made it difficult or impossible for buyers to obtain reasonable prices.[95] Both SCWC and Snohomish conclude that the Enron manipulations reached beyond the California borders and influenced directly the prices that Snohomish faced in the long-term market.[96]

42. SCWC and Snohomish argue that the Commission has repeatedly confirmed the relationship between spot and forward prices.[97] In addition, they maintain that there is a direct and well-understood economic relationship between spot market prices and forward market prices. Spot market prices represent the opportunity cost of selling power in the forward markets, SCWC and Snohomish argue. As such, the inflated prices charged in the dysfunctional California spot market had a direct adverse effect on the prices at which sellers offered to sell power in the forward market. As a matter of fact, SCWC and Snohomish argue, the relationship between spot and forward market prices tightened during the crisis because the breakdown of ordinary market functions made it extremely difficult to predict the movement of forward markets based on anything other than the then current spot market prices.[98] SCWC and Snohomish maintain that the inflated spot prices inflated sellers' opportunity costs, pursuant to sales under long-term forward contracts, and that during the first three months of 2001, this caused sellers to offer inflated prices under long-term contracts.[99] A seller would not forego the inflated prices available in the spot market unless compensated by its prices for sales in the long-term forward market.[100]

43. These companies additionally maintain that the forward prices, during the crisis period, were also artificially inflated by the volatility and uncertainty in spot markets due

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[95] Id. at 14.
[96] Id. at 15.
[97] Id. at 16.
[98] Id. at 18.
[99] Id.
[100] Id.

to market dysfunction and market power.[101] Thus, the dysfunctions in the spot markets translated into dysfunctions in the forward markets.[102] SCWC and Snohomish maintain that the volatility in spot market prices effectively eliminated the spot market, including shorter-term forward contracts (as options to the long-term contracts at issue) because the prices were not only beyond the means of buyers to pay, but carried the risk of financial ruin for buyers who tried to remain on the spot market.[103]

44. According to SCWC and Snohomish, the empirical evidence demonstrates that spot market prices affect forward markets. These companies maintain that the forward price curves underlying the SCWC and Snohomish contracts demonstrate that they were in fact a product of spot and short-term prices, and thus, Respondents' witnesses in effect conceded that prices in the dysfunctional California spot markets adversely affected the California long-term market.[104]

45. In a properly functioning market, current spot market prices will have a very strong influence on expected spot market prices in the near term, which declines over time, so that large swings in current spot market prices produce modest swings in the long-term forward markets, SCWC and Snohomish assert. However, according to these companies, the dysfunction of the Western power markets caused the relationship between spot market fluctuations and long-term forward prices to become unexpectedly strong. Since these markets were no longer responding to fundamentals, and because the liquidity of the forward markets had collapsed, reported spot market prices were the only reliable market indicator that market participants could rely upon, SCWC and Snohomish maintain.[105] As a result, these companies conclude that spot and forward prices were highly correlated. SCWC and Snohomish maintain that the principal cause of the dysfunction in the forward markets, namely, the expectation that no effective measures would be taken to control spot market dysfunctions, remained until FERC finally acted in mid-2001 to constrain spot market dysfunctions.[106] Additionally, these companies contend that given the government indications at the time that no price caps would be forthcoming anytime soon, there was no reason to expect the high prices would decrease soon.[107]

46. SCWC and Snohomish contend that evidence submitted by Respondents indicates that they also were of the view that the dysfunctions in California adversely affected

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[101] Id.
[102] Id. at 19.
[103] Id.
[104] Id. at 21.
[105] Id. at 22.
[106] Id.
[107] Id.

forward markets throughout the West and as a result their litigation position lacks credibility.[108] The dysfunctions in the California spot markets adversely affected the availability of power supplies in markets throughout the West, among others, by causing resources to be drained from other regions in the West, including hydropower from dams operated by BPA.[109] Moreover, SCWC and Snohomish aver that the dysfunctions in the California spot markets caused demand to increase in the Western forward markets as well.

47. Market fundamentals cannot explain the western market crisis, SCWC and Snohomish maintain. According to witness McCullough, market fundamentals accounted for only roughly half the increase in prices (on-peak spot prices in California were $90.93 − nearly fifty percent above competitive levels; off-peak prices were $45.52 − more than thirty percent above competitive levels). These results have been replicated in other studies, which conclude that market dysfunction and the exercise of market power were major contributors to the extreme prices observed in the California spot markets.[110] According to these entities, the only logical explanation for the persistent dysfunction of the forward markets in the WSCC is that market participants expected the spot market dysfunction in California to continue indefinitely, which artificially inflated forward prices far above LRMC.[111]

48. Concerning Respondents' witnesses, SCWC and Snohomish argue that the Hogan/Harvey analysis is fatally flawed because it includes dummy variables which artificially mask price variations during a period in which observed prices exhibited the “most extraordinary price change in the industry’s history.” Additionally, the study consists of “data dredging” that fails to provide any logical explanation for the obvious fact that spot and forward prices rose and fell in close parallel during the crisis period, selectively discussing only regressions which support their claims. Further, according to these entities, Kalt used bizarre assumptions, and thus produced bizarre results. For instance, Kalt compares the Cal ISO’s mitigated market clearing price (“MMCP”) from the California refund proceedings (using now discredited spot gas prices), with prices at Palo Verde; ascribes a value of zero to calculations for which there is no ISO data; and assigns a negative value to the MMCP minus market price calculations, with the implication that producers sold power at less than marginal costs.[112]

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[108] Id. at 24.
[109] Id. at 26.
[110] SCWC/Snohomish RB at 7-8.
[111] Id. at 13.
[112] SCWC/Snohomish RB at 19.

49. The PUCN argues that although, in order to prevail, the Complainants are not required to prove that market manipulation occurred, the record provides evidence that market manipulation in the West, in fact, helped create the dysfunction in the western forward markets and is therefore, highly relevant to the issues in this proceeding.[113] Moreover, the PUCN argues that, for purposes of a complete record, the Commission should not make a decision in this proceeding until the investigation of market manipulation in the Western markets in Docket No. PA02-2-000 has concluded.[114]

50. Respondents, on the other hand, argue that Complainants failed to meet their burden and provided no evidence that the Cal ISO and Cal PX spot markets adversely affected the western long-term bilateral markets or the challenged contracts.[115] However, Respondents demonstrated that there was no nexus between the high prices in the Cal ISO/Cal PX spot markets during May 2000 to June 2001 and that the elevated prices were also observed (during the same period) in the forward markets of California, Nevada and Washington. Respondents maintain that the evidence in this case fails to demonstrate that dysfunctions in the Cal ISO/Cal PX spot markets adversely affected the WECC bilateral forward markets.

51. According to well-settled principles of law and economics, spot prices do not determine forward prices, Respondents argue. Rather, both spot and forward prices are affected by market fundamentals, namely, spot-market prices by current fundamentals and forward prices by expected future fundamentals.[116] According to Respondents, to the extent that any relationship or statistical correlation exists between spot and forward prices, such relationship or correlation is only reflective of the fact that these market fundamentals may coincidently be moving in the same direction at various points in time. Forward market prices are driven by expectations of future market fundamentals, not current or past dysfunctions in the spot markets, Respondents argue.[117] The record demonstrates that both spot and forward market fundamentals changed dramatically between early and mid-2001, leading to large declines in both then-current spot prices and forward prices by mid-2001 which were not related to the dysfunctions in the California spot markets or to Commission actions addressing those dysfunctions, Respondents maintain. Respondents state that forward prices during years 2000 and 2001 are entirely consistent with then expected market fundamentals.[118]

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[113] PUCN IB at 15-16.
[114] Id. at 17-18.
[115] Respondents IB at 15.
[116] Id. at 17.
[117] Id.
[118] Id.

52. The elevated prices experienced in the forward markets were the product of market fundamentals, Respondents aver. They argue that following years of low wholesale electricity prices and little system disruption in the western U.S. electricity markets, beginning in mid-2000, the region suddenly experienced major changes in demand and supply fundamentals. There was a shortage for much of the period between mid-2000 and mid-2001, *i.e.*, reserve margins were well below both forecast and historical reserve margins and were accompanied by significantly elevated hourly and daily electricity prices. This resulting crisis, Respondents argue, was simply booming demand running into limited and aging supply sources exacerbated by counterproductive regulatory policies (particularly in California).[119]

53. Morgan Stanley also alleges that the purchasing activities of the DWR brought a creditworthy buyer to the California spot markets and probably worked to abate spot market prices in California beginning in the late winter/early spring of 2001.[120] In addition, Morgan Stanley alleges that DWR's decision to hedge a large portion of California's demand in the forward market likely increased forward prices relative to expected future spot prices.[121] Additionally, Respondents aver that while Complainants argue market power and market manipulation, their generalized allegations fail to meet their burden and they are not relevant or probative to the core issue set for hearing.

54. Staff avers that the Commission found the dysfunctions in California to be the result of three factors. One, the "central cause," was an over-reliance on the day-ahead spot market. Two was the impact of competitive market forces or market fundamentals. Third, a potential cause, about which it could not be sure, was the exercise of market manipulation and market power. The Commission recognized that competitive market forces would continue to impact prices. Staff asserts that Complainants contend that something other than market fundamentals must have caused the high prices of forward contracts. However, Staff maintains that Complainants have failed to substantiate their claims, that their claims offer unsupported opinions of witnesses, and that their cases are distinguished more by the information they lack than by what they show. According to Staff, Complainants failed to analyze how competitive market factors affected forward prices and they did not conduct studies on the effects of the dysfunction on prices. Complainants offered flawed studies that even if accurate, show only a rough correlation between spot and forward prices, not a cause-and-effect relationship, Staff maintains. Thus, Staff asserts that Complainants have not demonstrated that the spot market dysfunction had any adverse impact on forward prices, or if it did, what that impact was.

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[119] Id. at 18.
[120] Ex. MSC-65 at 54:10-16.
[121] Ex. MSC-65 at 53:11-54:2.

B. Discussion/Findings:

55. Staff presents a chronology of events worth repeating as an aid to understanding the issues in this case. On July 26, 2000, the Commission issued an order initiating an investigation of the conditions of bulk power markets in various regions of the country.[122] On August 2, 2000, San Diego Gas & Electric Company filed a complaint, requesting that the Commission impose a $250 price cap for sales into the Cal ISO and Cal PX spot markets. The Commission denied the request in an order issued August 23, 2000.[123] The Commission instituted hearing procedures to investigate the justness and reasonableness of the rates of public utility sellers into the ISO and PX markets. The hearing was held in abeyance pending completion of the Staff fact-finding investigation of the conditions of bulk power markets.[124]

56. The fact-finding investigation of California markets was completed in October.[125] The Staff Report identified three factors that contributed to high electricity prices in the summer of 2000. First, market forces in the form of significantly increased power production costs combined with increased demand, due to unusually high temperatures and a scarcity of available generation resources, played a major role. Second, existing market rules exacerbated the situation by exposing the three investor-owned utilities in California to the volatility of the spot market without providing the opportunity to mitigate the price volatility. These market rules promoted underscheduling in the PX, thereby increasing the amount of demand and supply that appeared in the ISO's real-time market. Third, the Staff Report noted evidence suggesting that sellers had the potential to exercise market power, although there was insufficient data to make determinations about the exercise of market power by individual sellers.[126]

57. The Commission issued an order on November 1, 2000, proposing measures to address the dysfunctions in the California market and remedy the problems identified in the Staff Report.[127] The Commission specifically identified the following rules and regulatory policies as flawed: the CPUC's requirement that the three California IOUs buy and sell all their energy needs through the PX; the CPUC restrictions on the IOUs' ability

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[122] *Order Directing Staff Investigation*, 92 FERC ¶ 61,160 (2000).

[123] *San Diego Gas & Electric Co.*, 92 FERC ¶ 61,172, at 61,606 (2000).

[124] Staff IB at 10.

[125] Staff Report on Western Markets and the Causes of the Summer 2000 Price Abnormalities – Part I, (November 1, 2000).

[126] Staff IB at 11-12.

[127] *San Diego Gas & Electric Co.*, 93 FERC ¶ 61,121 at 61,349 (2000) ("November 1 Order").

to contract forward; the lack of retail demand responsiveness; underscheduling due to the ISO's replacement reserves policies.[128]

58. The November 1 Order distinguished between market dysfunctions and supply and demand variables, such as increased power production costs, scarcity of available generation resources, and increased demand due to unusually high temperatures.[129] Relying on the Staff Report, the Commission noted that the following competitive market forces affected energy prices in California: the increased cost of fuel, emission credits, and O&M expenses; sustained higher demand resulting in the use of higher cost generating resources and reduced hydro power supply due to drought.[130] The Commission concluded that competitive market forces played a major role in the increase in energy prices in California.[131]

59. The Commission noted that the dysfunctional market structure and rules provided the opportunity for sellers to exercise market power when supply was tight.[132] However, based on the information available to it at that time, the Commission was not able to determine whether individual sellers actually had exercised market power.[133] Furthermore, the Commission stated:

> This summer's wholesale markets exhibited certain market fundamentals that would be expected to cause prices to rise. Input costs increased as the cost of fuel, emission credits and O&M expenses increased. Sustained demand increased, requiring increased reliance on generating resources that would have been more expensive to operate even if input prices had not increased. Conditions in the Northwest decreased amounts of hydropower supply usually available to the market which, combined with a failure to bring new generation into service over the last decade, resulted in a true scarcity of generation. In circumstances like this, prices are expected to rise- and indeed they must rise to induce the investment in new capacity that is needed to serve customers adequately. [134]

60. The Commission further stated:

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[128] Id. at 61,354-5.
[129] Id. at 61,353-4.
[130] Id. at 61,358-9.
[131] Id. at 61,354; Staff IB at 12.
[132] November 1 Order at 61,350.
[133] Id. at 61,355; Staff IB at 12.
[134] November 1 Order at 61,358-9.

> We conclude that certain market rules do interfere with the functioning of the market and, taken together, may permit sellers to exercise market power. Accordingly, these market rules must be revised. Many of the market dysfunctions in California and the exposure of California consumers to high prices can be traced directly to an over reliance on spot markets. Industries that are either capital intensive or that have a lack of demand response do not rely solely on spot markets where volatility is to be expected. Because the price risks inherent in spot markets are too great for both suppliers and consumers, these market sectors will prefer to manage their risk profiles through forward contracts. However, in California certain market rules imposed by AB 1890 and its implementation by the California Commission (e.g. mandatory buy-sell through the PX) prevented the IOUs from engaging in forward contracts to any significant degree. And other retail suppliers who would have been free to implement appropriate risk management strategies could not be induced to participate in California's market because the low retail rate, frozen at 10 percent below historical levels, thwarted competitive opportunities for new participants to enter the market. Even so, until the market was stressed this summer by extreme events, pricing volatility was isolated and short-lived and wholesale prices were so low that stranded costs were paid off more quickly than expected. The significant failings of this market design became apparent only as peak demand outstripped supply.[135]

61. Having found that the existing market structure and market rules, in conjunction with an imbalance of supply and demand in California, caused and would continue to have the potential to cause, unjust and unreasonable rates for short-term energy during certain time periods, the Commission proposed the following measures to "fix" what it described as the "market design problems:"[136] elimination of the requirement that the California IOUs sell all their generation into and buy all their requirements from the PX (the buy/sell requirement); establishment of a penalty charge for underscheduling (this penalty was later eliminated without being implemented); [137] replacement of the existing ISO and PX stakeholder boards with independent boards; requirement that the ISO file standard procedures to facilitate the interconnection of new generators or existing generators to increase their rated capacity.[138]

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[135] Id. at 61, 359.

[136] Id. at 61,366-67.

[137] Id. at 97 FERC ¶ 61,275 at 61,227; Staff IB at 13.

[138] November 1 Order at 61,360-5.

62. On December 15, 2000, the Commission issued an order adopting these remedies. The Commission stated that it was necessary to change some of the market rules "that arose from the original state restructuring." [139] Summarizing the November 1 Order, the Commission stated that "the central cause of the exposure of California to high prices can be traced directly to a mandated over reliance on ...spot markets. As we stated, between 1996 and 1999, California added about 700 MW of generation while its peak load grew by some 5, 500 MW. This coupled with reduced availability of generation from out-of-state and little demand responsiveness to price, leaves California's spot markets vulnerable to price spikes…".[140] The December 15 Order adopted:

- a benchmark price to provide guidance for assessing the prices of long-term electric supply contracts;
- market monitoring and price mitigation for ISO and PX spot markets, including a $150 per MW price breakpoint.[141]

63. To put the contracts at issue in this case in context, the Nevada Companies' contracts were executed between November 2000 to June 2001; the Snohomish contract was executed on January 26, 2001; and the SCWC contract was executed on March 19, 2001.

64. From reading the cited Commission orders, it can be concluded that the Commission identified specific dysfunctions in the Cal ISO and Cal PX to be the result of over reliance on the spot market. To wit: (a) the California-mandated requirement that the three major investor-owned utilities ("IOUs") in California sell into and buy form the

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[139] *San Diego Gas and Electric v. Sellers of Energy*, 93 FERC ¶ 61,294 (2000) ("December 15 Order").

[140] Id. at 61,992; Staff IB at 13.

[141] *Id*. at 61,982-3. The benchmark for five year contracts for supply around –the-clock was $74/MWh. Id at 61,994. Subsequent orders were issued on April 26, 2001, *San Diego Gas & Electric Co.*, 95 FERC ¶ 61,115 ("April 26 Order") and June 19, 2001, Id. 95 FERC ¶ 61,418. The April 26, 2001 Order adopted further market monitoring and mitigation measures for the California markets, and proposed to extend those measures, to all Western markets. The June 19 Order recognized the success of earlier orders and noted that additional load needed to move from the spot to the forward market and that there was still inadequate supply in the West. To allow time for the conditions to be corrected, the price mitigation was expanded to all hours. The Commission took these measures to protect consumers and the economies of the Western states, with the caveat that "even though we view prices above the marginal cost of generation in these hours as a necessary reflection of the supply shortage at hand." 95 FERC ¶ 61,418 at 62,547 ("June 19 Order").

PX spot market; (b) a chronic pattern of underscheduling load and generation in the PX's day-ahead and day-of markets; (c) problems with the governance of the Cal ISO and Cal PX; and (d) the lack of standardized generator interconnection procedures.[142] These orders also state that high prices in both the Cal ISO and Cal PX spot markets were caused in large part by "market fundamentals" and "competitive market conditions" and that forward prices would be based "on analysis and expectations" of these factors with respect to the future.[143]

65. For instance, in the November 1 Order, the Commission stated that there was significantly increased power production costs combined with increased demand, due to the unusually high temperature and a scarcity of generation resources throughout the West, and California in particular.[144] The December 15 Order notes with respect to forward contract prices that projections or estimates of future market fundamentals in California, in particular, natural gas and NOx emission allowance prices, "will heavily influence forward prices more than anything else."[145] These Commission pronouncements are directly in contradiction with SCWC's and Snohomish's assertions that prior Commission orders had already determined that the Cal ISO and PX spot market dysfunctions adversely affected forward prices. Moreover, the Commission specifically stated that it had not determined that the forward markets had been rendered unreasonable or dysfunctional due to impacts of dysfunction on the Cal ISO and PX spot markets in its December 19, 2001 order.[146]

66. The evidence in this record reflects that changes in market fundamentals and competitive conditions drove spot and forward markets.[147] The following changes

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[142] *San Diego Gas & Electric Co. v. Sellers of Energy*, 93 FERC ¶ 61,121 at 61,359 (2000) ("November 1, 2000 Order"); *San Diego Gas & Electric Co. v. Sellers of Energy,* 93 FERC ¶ 61,294 at 61,992-93 (2000) ("December 15, 2000 Order").

[143] November 1 Order at 61, 354; 61,358-59; December 15 Order at 61,994.

[144] November 1 Order at 61,254 and 61,358-59.

[145] 93 FERC at 61,994.

[146] December 19, 2001 Order, 97 FERC ¶ 61,275 at 62,222 (2001) ("the spot markets were the only markets in which the Commission determined that rates may be unjust and unreasonable." The Commission denied requests to extend price mitigation measures to forward markets).

[147] The testimonies of Drs. Hogan and Harvey and Professor Kalt are given substantial weight. These witnesses testified, among other things, to the effects that supply and demand market fundamentals had on the spot and forward electricity prices in the 2000-2001 period. SCWC and Snohomish in their reply brief attack the analyses done by Drs. Hogan and Harvey. It is noted that Complainants raised issues concerning the analysis performed by Drs. Hogan and Harvey and Professor Kalt for the first time in

affected demand and supply in the WECC including California during the 2000-2001 period: (a) significant increases in peak demand for electricity in the WECC, in particular in California in 2000 and early 2001; however, as a result of conservation, retail rate increases and reduced economic activity, peak demand decreased beginning in the winter of 2001;[148] (b) increased demand for natural gas, due to increased demand for electricity which resulted in increased spot and forward prices for natural gas in the WECC and in California in 2000 and early 2001; however, spot and forward prices for natural gas declined beginning in the spring of 2001;[149] (c) increases in emission allowance costs in 2000 and early 2001 in California's South Coast Air Quality Management District ("SCAQMD"); however, these leveled off and declined in late spring 2001;[150] (d) environmental restrictions on gas-fired generation in California in 2000 and early 2001, followed by government-mandated lessening of these restrictions in the late winter of 2001;[151] (e) reductions in output from hydro, nuclear, and Qualifying Facilities ("QF")

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their reply brief. The timing is suspect, nevertheless it is found that their arguments are meritless. Drs. Hogan and Harvey did extensive analyses inclusive of many different variables to test the arguments of the complainants and to show that complainants have not proven that the dysfunctional California spot markets adversely affected the western long-term bilateral contract or the challenged contracts.

Complainants' arguments are based on the testimony of McCullough, which as discussed below is entitled to very little weight. McCullough's main criticism of Drs. Hogan and Harvey's studies is that it is too complex and his more simplistic analysis is better. Ex. SNO-63 at 105. His critique is based on his own bias that the long term prices "tagged" along behind spot prices throughout the period of the market failure." *Id*. For instance, McCullough presented only one set of results for his statistical model while Drs. Hogan and Harvey presented eight sets of results for their statistical model. McCullough presented two sets of price correlations for COB. Dr. Hogan and Harvey presented sixty-three sets of sensitivity cases for the price correlation results for COB. Tr. at 1449, 1478, 1476-78. Complainants did not prove that Drs. Hogan and Harvey were "data dredging." It is noted that in answering testimony, Drs. Hogan and Harvey critiqued McCullough's testimony. Afterwards in rebuttal testimony, McCullough criticized Drs. Hogan and Harvey and Kalt. Complainants cite Ex. EPME-31 for support of their allegations against Kalts' studies. However, this exhibit proves a totally contrary proposition, since it is Professor's Kalt's corrections to error in McCullough's testimony. It is found that the studies done by Drs. Hogan and Harvey and Professor Kalt are sound and statistically valid and thus, are more persuasive and entitled to substantial weight.

[148] Ex. MSC-65 at 5-13.

[149] Ex. MSC-65 at 19-28.

[150] Ex. MSC-65 at 28-36.

[151] Ex. MSC-65 at 36-37.

resources in late 2000-early spring 2001 with a return of QF generation output in early spring of 2001, and return of nuclear generation output in late spring of 2001;[152] (f) entry of new generation in California specifically and the WECC generally beginning in the spring of 2001;[153] (g) entry of the California Department of Water Resources ("DWR") into spot and forward markets beginning in early 2001, and DWR's purchase of thousands of MWs of electricity by the early spring of 2001.[154] All of these factors impacted spot and forward prices during the period at issue in this proceeding. Supply and demand imbalances, exacerbated by California's power market design had a significant impact on prices during the period at issue in this proceeding. Forward prices reflect underlying supply and demand conditions. Perceptions of continued tight supply and continued consistent demand increased forward prices in 2000 and 2001. Moreover, the abatement of demand and the appearance of additional supply put downward pressure on forward prices.[155]

67. Evidence in this case demonstrates that, in the spring of 2000, certain areas of the WECC experienced strong economic growth, unusually high temperatures and an increase in electricity demand.[156] In addition, demand levels in California in June and July 2000 were higher than in previous years. Demand levels in the California-Mexico portion of the WECC in the latter part of 2000 and the first half of 2001 were above the prior years' levels, leading to capacity shortages which contributed to elevated prices during those months.[157] Demand levels in the California-Mexico region of the WECC stabilized during the second half of 2000. However, demand and energy consumption in the rest of the WECC exceeded peak demand in prior years during 2000 until February 2001.[158] The decrease in demand in late winter of 2000/early spring of 2001, reflected the slowing of the California economy, higher retail electricity prices and significant load reduction efforts.[159] The decline in energy consumption was reflected in forward prices.[160]

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[152] Ex. MSC-65 at 13-19, 37-40 and 43-46.

[153] Ex. MSC-65 at 50-53.

[154] Ex. MSC-65 at 53-54.

[155] Ex. EPME-11A and EPME-11B.

[156] Ex. MSC-65 at 6:19-7:2. Clark County, Nevada was the fastest growing region in the US during this period.

[157] Ex. MSC-65 at 5:5-6:17.

[158] Id. at 7:9-10; 9:1-10:12.

[159] Id. at 7:2-5; 8:12-16; 9:12-12:4. Bonneville Power Administration had load reduction efforts in the first half of 2001.

[160] Id. at 12:6-18.

68. Generation supply during the period at issue in this proceeding was also affected by changes in market fundamentals. Supply levels in mid-2000 to mid-2001 were reduced as compared to previous years. There is evidence in this proceeding which is given substantial weight, that hydroelectric generation in California and the rest of the WECC began to fall in the summer of 2000, continued falling through the late summer of 2000, and fell below historical levels throughout 2001.[161] Starting in February-March 2001, WECC peak loads began to fall to levels below prior year levels, and energy consumption began to decline.[162] As a result of diminished Canadian and Pacific Northwest hydro supplies, imports of electricity into California diminished beginning in June 2000.[163] In addition, record evidence shows that nuclear generation in California was subjected to significant outages during October 2000 and May 2001.[164] Additionally, the evidence presented in this case shows that QF output was lower in the first half of 2001, due among other things, to the policy decisions of the State of California which prevented Pacific Gas and Electric Company from paying their QF suppliers and discouraged QF's from operating.[165] Evidence in this case also indicates that many fossil fuel power plants in and around California, ran considerably more often than they had in previous years.[166] This increased operation of these aging plants led to their increased unavailability which increased imbalances between supply and demand.[167] Moreover, this increased activity also increased demand for natural gas, with the result that natural gas prices also increased.[168] During this period of shortage, spot prices increased.[169] Spot prices continued to increase in the summer of 2000, with additional increases beginning in December 2000 as hydroelectric shortages significantly impacted the Pacific Northwest when the first cold spell hit. High spot prices continued until the spring of 2001.[170]

69. One of the factors which influenced spot and forward electricity prices in the WECC during the period at issue in this proceeding is the price of natural gas and the

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[161] Exs. MSC-65 at 13:7-16:4; EPME-5, EPME-6 and EPME-8.

[162] Id. at 8:12-16; 9:12-10:12.

[163] Ex. MSC-65 at 16:8-17:4; 40:10-43:6.

[164] Exs. MSC-65 at 37:12-38:7; EPME-36.

[165] Ex. MSC-65 at 43:10-46:2.

[166] Exs. EPME-6; EPME-7; EPME-35; EPME-36; MSC-65, Tables 18 & 40.

[167] Ex. EPME-1 at 38:16-41:8.

[168] Ex. MSC-65 at 17:13-18:7 and 38:8-12.

[169] EPME-9.

[170] EPME-1 at 41:10-16. Evidence in this record suggest that as generation in Southern California was within or at the margin for meeting load in California, when power could be wheeled into California, the cost of generation in Southern California served as a floor on prices of electricity throughout the WECC. Ex. MSC-65 at 35:13-36:2.

underlying supply and demand conditions in the gas markets in and around California.[171] Gas-fired electricity plants in California were being run at high levels, pushing up demand for gas. This was being influenced also by the strong California economy and adverse weather. Tight pipeline capacity and upward pressure on prices in the gas supply basins in Texas, New Mexico and elsewhere, also affected natural gas prices for inputs to California gas-fired power plants. Prices for inputs to California increased gradually in the summer of 2000 and dramatically at the end of 2000 (above historical levels).[172] The evidence in this case reflects that the impact of gas prices on the level of electricity prices was large in the spring of 2001. This was due to the fact that California gas-fired thermal generation was operating at unprecedented levels and was at or below the margin for meeting load. In previous years, during spring, gas-fired generation in the West was likely to be running to manage local transmission constraints and was less likely to be on the margin setting regional electricity prices.[173] During the spring of 2001, forward gas prices were above historical levels and fell during late spring and early summer.[174]

70. Another factor which warrants consideration in the analysis of market fundamentals are emissions allowance costs and other environmental restrictions which limited the ability of gas-fired generation in California to respond to the reduction of generation output from hydro, nuclear and QF resources.[175] The increased reliance on these units escalated the price for NOx emissions allowances ($40-$200/MWH) until June 2001.[176] Environmentally-related operating limitations on gas-fired generation in California, such as annual run time limits and water outlet temperature restrictions, constrained the supply response of gas-fired generation to increases in demand and reductions in output from other generation resources.[177]

71. The evidence establishes that market fundamentals changed in the spring of 2001, causing demand to decrease and generation supply to increase. These market fundamentals contributed to the decrease in spot and forward prices, beginning in the spring of 2001. Therefore, Complainants' arguments that the Commission's mitigation orders drove spot prices down in California and the WECC are not supported by the record in this proceeding, especially in light of the fact that the Commission's mitigation

[171] Ex. MSC-65 at 20:14.
[172] Ex. MSC 65 at 20:11.
[173] Ex. MSC-65 at 21:1-9.
[174] Ex. MSC-65 at 21:19-23:8.
[175] Ex. MSC-65 at 29:1-7.
[176] Ex. MSC-65 at 32:1-35:2.
[177] Ex. MSC-65 at 36:4-37:8.

order for the West was issued on June 19, 2001. Starting in April 2001, steadily declining forward prices indicated an expected decrease in future spot prices.[178]

72. The abatement of demand due to concerted demand reduction efforts and slowing economic growth in California brought forward prices down.[179] The reduction in demand[180] and the costs of gas-fired generation, affected both spot and forward markets. Forward prices for natural gas began to fall during the late spring and early summer of 2001.[181] The State of California ensured payment to the QF and capped emission costs, which reduced the demand and costs of gas-fired generation.[182] New efficient gas-fired generation began to come on line in and around California beginning in mid-2001, resulting in 2,688 MW of additional, lower-cost generating capacity by the end of 2001.[183] The added capacity helped relieve supply shortages, and pushed out the supply curve so that demand could be served with more efficient, cheaper gas fired units.[184] Forward prices fell with the expectation of new generation supply.[185]

73. Staff's and Respondents arguments that dysfunctions in the ISO and PX spot markets were caused by factors not influencing forward prices are entitled to substantial weight. The regulatory policies for the ISO and PX contributed to the conditions prevailing in the spot markets in 2000 and 2001. The restrictions placed on utilities procurement strategies limited their abilities to forward contract for their wholesale power needs. This created an over reliance on the spot markets and was the central source of many of the dysfunctions in the California market. Respondents' arguments that the California regulations left a substantial amount of retail load exposed to spot-market volatility, the IOU's bore substantial price risk, demand was concentrated in California's

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[178] Ex. EPME-11A; EPME-11B.

[179] Exs. MSC-65 at 63:18-23; EPME-1 at 51:15-18; EPME-11A and EPME-11B.

[180] Due to State actions securing payments for the QFs and capping emissions costs. Id. at 63:23-64:2.

[181] Ex. MSC-65 at 21:19-23:8.

[182] Ex. MSC-65 at 63:23-64:2.

[183] Ex. MSC-65 at 50:12-52:2

[184] Ex. MSC-65 at 52:6-11.

[185] Exs. MSC-65 at 50:9-53:5; EPME-13A; EPME-14 and EPME-15; EPME-23 at 20. DWR negotiated 59 power purchase agreements by the spring of 2001 (after 2/1/01). This totaled 14,000 MW of capacity for power to be delivered in various amounts from 2001 through 2010. Ex. EPME-1 at 50:11-15. This evidence tends to show that a significant portion of the IOU's load entered into the forward power markets during this time period. The purchasing activities of DWR brought a creditworthy buyer to the California spot markets, which probably helped abate spot market prices in California in late winter/early spring 2001. Ex. MSC-65 at 54:10-16.

spot markets, demand was held off from the forward markets in the WECC and this meant that there were fewer *buyer-side* competitors in forward markets, are entitled to substantial weight. The Commission mandated correction of the distortion in its December 15, 2000 order.[186]

74. Complainants failed to establish that dysfunctions in California spot markets materially affected forward markets in the WECC, especially for longer-term contracts, *i.e.* at least one year or more. In addition, Complainants failed to provide any evidence that the Cal ISO and PX spot market prices drove forward prices throughout the WECC. Their argument that there is a critical interdependence between spot and forward markets does not establish that the effects of the dysfunction on spot markets drove or affected forward prices. Moreover, Staff's argument that Complainant's failed to identify and segregate that portion of the forward contracts' rates at issue, which is due to the effect of competitive factors from the portion due to other effects such as dysfunction caused by over-reliance on the spot market, is persuasive.

75. On the other hand, Respondents established that forward markets summarize future expected supply and demand conditions, current market fundamentals drive spot prices and expected future market fundamentals drive forward prices. Forward and spot prices can be expected to be linked only to the extent that spot markets summarize information from current supply and demand conditions which provide useful information on future supply and demand conditions. Forward prices are determined by expected future spot prices, which themselves are determined by expected future market fundamentals. The forward price curves at the time the contracts were executed only reflect that Respondents expected future spot prices to remain high.[187] As Staff points out, to the extent that current supply and demand conditions are expected to continue into the near and/or long-term future, there will be an interdependence between those fundamentals and forward market prices.[188] To the extent that future fundamentals change or are expected to change from the current situation, there will be less and less interdependence.

76. The Commission itself has recognized this. In the December 15 Order the Commission states:

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[186] 93 FERC at 61,992.

[187] Forward prices reflect the market's expectation of forward prices, at a particular moment in time. Forward prices are determined by market fundamentals, including: the capital costs of new gas-fired generation, long-term interest rates, credit spreads, taxes and labor costs, the forward price of natural gas and other fuels, as well as the market's perception of long-term economic growth and demand-side management efforts. Exs. MSC-7 at 6:16-18; MSC-65 at 109:9-10.

[188] Staff IB at 22.

> However suppliers also benefit from the stable revenue stream of forward markets and have every bit as much incentive to avoid the volatility of the spot markets as do purchasers. Moreover, suppliers will bargain knowing that the spot market's size will be greatly reduced and that next summer's spot prices will therefore not be fueled by frenzied buyers whose over-reliance on last minute purchases have forced them to bid up the prices to obtain needed supply. Suppliers, of course, will be influenced by their best projection of next summer's gas and NOx prices. The cost of these vital imputs has risen steadily from about $2 MMBtu and $6/lb in 1999 to well over $50 MMBtu and nearly $50/lb now. Estimates of the cost of these inputs will heavily influence forward prices more than anything else. The rise in the cost of these critical elements will inevitably affect forward prices, but this will be based on *analysis and expectations for next summer, and not last summer*."[189]

77. As Staff points out in its brief, all the facts in this case point to the same conclusion: the rise and fall in spot and forward prices was in large part the result of market fundamentals or factors, other than "dysfunction."

78. Staff's witness, Dr. Ogur, testified that the effect of competitive market forces on prices is neither a dysfunction nor an adverse effect, but rather an effect that is *supposed* to be reflected in forward contracts. The parties that negotiate forward contracts rely on their expectations of competitive market forces throughout the term of the contract. This witness further testified that if high prices in 2001 were expected to continue due to the interaction of competitive market forces, it is efficient that these prices be reflected in the forward contracts.[190] The Commission said as much in its November 1 Order, wherein it described certain recent market fundamentals (i.e., competitive market forces) and explained that, "In circumstances like this, prices are expected to rise – and indeed they must rise to induce the investment in new capacity that is needed to serve customers adequately."[191] SCWC witness Taylor agreed, that to the extent market fundamentals affect forward prices, there is no adverse effect.[192] Complainants' witnesses admitted that they did not disagree with Dr. Ogur's testimony.[193]

79. Staff persuasively points out that after December 15, prices in the spot market were becoming less and less reflective of the dysfunctional market design identified by

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[189] *San Diego Gas and Electric Company*, 93 FERC at 61,994.
[190] Ex. S-4 at 8.
[191] November 1 Order at 61,358-9, 61,366.
[192] Tr. 2987.
[193] Tr. 2830-33; 2985-87.

the Commission, and thus, more reflective of competitive market conditions. When the Commission issued its June 19, 2001 Order, the dysfunction of over reliance on the spot market had been greatly reduced, and fundamentals affecting the competitive market had begun to significantly improve. This is confirmed by the Commission's Order of June 19, 2001. In this Order, the Commission said:

> Specifically, the elimination of the mandatory buy-sell requirement and the elimination of the PX rate schedule have helped to turn the tide in eliminating California investor-owned utilities' chronic reliance on spot markets. The effects of the price mitigation directed by our December 15 Order and the actions of the State of California in moving to longer-term contracts and conservation efforts have had a significant dampening effect on prices. As a result, California investor-owned utilities no longer rely on spot markets for meeting the entirety of the needs of the electric customers they serve. California now forecasts that it will only rely on the spot markets this summer for about 20% of its on-peak energy requirements, as compared to 100% prior to the December 15 Order.[194]

This order also noted a dramatic reduction in gas prices and fewer generation outages in California as factors which had the effect of lowering energy prices in the West, and that prices for Western forward contracts decreased dramatically.

80. The evidence in this case demonstrates that forward markets, during the period in question in this proceeding, were competitive and not dysfunctional. Staff's and Respondents' arguments on this issue are found persuasive. In a competitive market spot and forward prices can be above LRMC under conditions of scarcity, just as they can be below LRMC during conditions of surplus.[195] In this case, where market conditions were tight, input costs were in excess of LRMC and sellers of power had opportunity costs that far exceeded LRMC.[196]

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[194] *San Diego Gas & Electric Co.*, 95 FERC ¶ 61,418 at 62,546 ("June 19 Order"). El Paso witness Kalt testified that the Commission's efforts to shift demand from the spot to the forward markets had the effect of reducing buyer's exposure to the volatility of the spot markets, reducing opportunities and incentives to underschedule loads and generation, and improving financial incentives for generators to undertake the development of new capacity. Ex. EPMI-1 at 9-10.

[195] Ex. MAEM-16 at 14:1-13. When supply is tight, prices in excess of LRMC can signal the market the need for new supply, or be a signal to the demand side to reduce consumption in the short to medium term. Ex. MAEM-15 at 13:18-14:6.

[196] Ex. MAEM-16 at 14:6-9.

81. Respondent's assertion that the forward market is, in its economic essentials, not a market for power; but a market for insurance is credible. The forward market provides a contractual means by which buyers and sellers can lock in prices over an extended period, hedging and allocating risk to specialists willing and able to take on that risk. This statement warrants substantial weight. The evidence shows also that there were no meaningful barriers to competition among sellers in forward markets, with generators and marketers willing to sell power contracts forward, during the relevant time period in this proceeding. The evidence in this case establishes that the forward market was a well functioning market (functioning competitively and efficiently) during the period in question.[197] There were numerous buyers and sellers, the WSPP has 241 members. The record does not support SCWC's alllegation that there was a lack of adequate market information. Complainants and Respondents had access to similar and transparent sources of forward price information. Complainants could call market participants for forward price quotes, and monitor on a daily basis forward price sources such as Platt's and Enerfax.[198] The evidence shows that the forward market had parties with industry knowledge and that they had access to this knowledge. The evidence in this case further established that, during this period, the market reflected backwardation, *i.e*. prices in the short-term were higher than prices in the long-term. Respondents correctly point out that this case should not be analyzed with the LRMC since this ignores the fact that input prices and opportunity costs in the near term far exceeded the cost-based benchmark and the LRMC of new generation.[199]

82. The evidence in this case shows that the Nevada Companies made wholesale purchases of firm power from thirty-nine separate providers in 2000 and 2001.[200] In fact, Sierra Pacific reported purchases from forty-five to forty-seven separate providers in the same time frame.[201] Considering the number of sellers available, the preponderance of the evidence shows that Complainants had choices,[202] *i.e.*, they were free to reject offers and turn to other suppliers. Evidence in this case shows that in 2001, the Nevada Companies doubled their wholesale power purchases from the previous year, buying in

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[197] Ex. EPME-1 at 62:8-16.

[198] Tr. at 2875:8-16; Ex. MAEM-68 at 82-83.

[199] Ex. MAEM-16 at 14:6-9. The SCWC contract has a levelized price of $95 over five-years and nine-months, reflecting the fact that Mirant could hedge the transaction at lower prices in the out years and had higher hedging costs in the near term (in excess of $95). Ex. MAEM-16 at 27:8-17; 33;13-19. The record does not support SCWC's and Snohomish's contentions that the LRMC in the West is $30-35/MWh. See MAEM-50 at 25.

[200] EPME-1 at 16.

[201] Id.

[202] Ex. RES-12 at 2.

excess of their own sales to retail customers. It also sold more than four times as much wholesale power as it did in 2000.[203] As a result, it may be concluded that the Nevada Companies were net marketers of power. Official notice has been taken of the decision of the Public Utilities Commission of Nevada (PUCN) which found that The Nevada Companies had acted imprudently with regards to some of these purchases.[204]

83. The record shows that there was consensus among the witnesses for both sides that competitive fundamentals affected spot and forward prices during the period in question in this proceeding. However, as Staff correctly points out, Complainants did not isolate that impact from other factors they claim affected prices. Complainants' witnesses did not measure any impact of dysfunction in the Cal ISO and PX spot markets, and they also failed to isolate the impact of spot market dysfunction on forward contract prices as compared to the impact of market fundamentals.[205]

84. The main witnesses for the Nevada Companies were Drs. Shepherd and Goldberg. These witnesses' testimonies are not entitled to substantial weight. Respondents' and Staff's arguments concerning these witnesses' testimonies are persuasive. To wit, Dr. Shepherd, who talks about market dysfunctions, does not offer a definition of "dysfunctions," yet he agrees it is not a clear technical term. Moreover, he states that he used it in the same manner as the Commission, while admitting that he does not understand exactly what the Commission had in mind.[206] Most significantly, these witnesses did not analyze whether market fundamentals contributed to price increases in the California spot markets and the forward markets in the WECC. Their conclusions are restatements of their second and third assumptions.[207] Additionally, these witnesses

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[203] Ex. EPME-18.

[204] The Nevada Companies, Public Utilities Commission of Nevada, Docket No. 01-11029 (Order dated March 29, 2002).

[205] The central cause of the exposure of California to high prices can be traced directly to a mandated over reliance on spot markets. December 15 Order, above. Staff persuasively points out that by June 2001, reliance on the spot market for on-peak energy requirements had dropped from 100% to 20%, so that dysfunction should not have been perceived as a problem in later years. Staff RB at 14.

[206] Tr. at 2770:16-2771:2.

[207] Shepherd and Goldberg assume that: (a) spot prices, reflected on their charts for May 2000 to June 2001, represent long-run marginal costs; (b) their charting of what prices should have been for May 2000 – June 2001 based on increased gas prices represents long-run marginal costs; (c) any portion of an actual price charged that is above their assumed long-run marginal costs represents dysfunction; (d) dysfunction accounts for significant changes in both spot and forward prices during May 2000-June 2001. Tr. at 2811:4-2813:11; Exs. NPC-40 at 26:8-28:2; NPC-40 at 31:8-32:9.

cannot state whether the shortage of power in California during the relevant time frame was caused by market fundamentals or dysfunction.[208] Dr. Shepherd could not meaningfully limit the scope of factors that might be considered market fundamentals rather than "dysfunction."[209] These witnesses argue that spot markets drove forward prices because of market participants' expectation that the dysfunctions would continue into the future. However, they offer no evidence of the actual expectations of market participants to support this theory.[210] Furthermore, their rebuttal testimony is not determinative, since the bid-ask spread reflects, rather than explains the underlying market conditions.[211]

85. Shepherd and Goldberg rely on the argument that any time a price is above long-run marginal costs, the portion above long-run marginal costs is the product of dysfunction, market power or market manipulation.[212] These witnesses assume that $40 to $60 represents the long-run marginal cost of power during the relevant time period. However, these witnesses did not perform cost/revenue studies to assess the long-run marginal costs of producing power in California during the time frame in question. Moreover, they did not examine the marginal costs of any Respondent in this proceeding. This and other omissions were considered in determining the weight to be given to this testimony.

86. In light of the fact that there is unrebutted evidence in this record that the forward prices represented the seller's marginal costs, Shepherd's and Goldberg's testimonies are not entitled to substantial weight. The evidence in this case shows that the sellers were buying power to cover their obligations in the same market.[213] As a matter of fact, Professor Shepherd agreed that prices in excess of his assumed marginal costs do not necessarily indicate dysfunction and could be a reflection of supply shortages.[214]

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[208] Tr. at 2776:9-2776:15, 2787:19-2788:13.

[209] Tr. at 2771:3-2771:8.

[210] Tr. at 2775:7-2775:20; 2801:13-21. The Nevada Companies' experts did not perform any formal surveys or studies on the expectations market participants had with regard to the continuation of dysfunctions into the forward markets. Tr. at 2801:23-2802:7.

[211] Tr. at 2766:23-2767:7.

[212] Tr. 2981:10-15.

[213] Tr. 2055, 2074, 2109, 2232-33; 4302.

[214] Tr. at 2769, 2824. Prices prior to the dysfunction rose above $60 and are currently below $40. (Tr. at 2823-24; 2828). Staff IB at 26. Competitive prices at any point in time can be above the LRMC because of scarcity or below the LRMC because of surplus, as long as, on average over the long run, they are equal to the LRMC. Ex. MAEM-16 at 14:1-13.

Likewise, Dr. Goldberg[215] did not perform any studies to support his claim that there is a link between the spot market dysfunction and forward prices. In addition, he did not perform any study of what caused the spot market dysfunction.[216]

87. As Staff points out, Shepherd and Goldberg admitted: they did not study the causes of the decline of forward prices in the spring of 2001, they did not study the fundamentals outlined by Hogan and Harvey, and they did not analyze capacity shortages to determine if supply and demand factors were real or induced.[217] As Staff points out, Professor Shepherd presented unpersuasive economic analysis. The charts prepared by this witness try to depict a correspondence between spot and forward prices while the bid-ask spreads do not reveal results caused by dysfunction, but merely "reflect" dysfunction, in general.[218]

88. Professor Shepherd only studied one factor - the changes in gas prices, although he admitted that a number of competitive factors likely affected prices in the forward markets.[219] However, this witness did not study the market conditions in the California gas market during 2000-01, nor did he study gas market transportation infrastructure dynamics during the relevant time frame or analyze the impact of constraints (lack of pipeline take-away capacity in California).[220] Another flaw in Professor Shepherd's study was the lack of a supply factor in the study, even though he acknowledged that there was a shortage in the capacity of facilities available to produce electricity in California in 2000-01.[221] This witness did not analyze supply and demand variables.[222] Both witnesses testified that they believe that by adjusting the $40-$60 LRMC estimate by a factor for increased gas prices, they had done everything necessary to capture the impact on prices of all market fundamentals.[223] As Respondents correctly point out, these

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[215] This witness supplied statistical support for Professor Shepherd.

[216] Staff IB at 27. Tr. at 2801-02.

[217] Staff IB at 21, Tr. 2784-88. In their reply brief, the Nevada Companies agree that these witnesses did not attempt to measure the individual effect of each fundamental on forward price movements. The Nevada Companies' RB at 16-17.

[218] Staff IB at 25; Tr. at 2765-67.

[219] Tr. 2830-33.

[220] Tr. at 2765; Staff IB at 25.

[221] Tr. at 2775-76.

[222] Tr. at 2784-88. Further, Shepherd and Goldberg's analysis is flawed since they failed to analyze whether the lack of demand response due to retail price freeze exacerbated the actual and expected supply-demand imbalance and thus, increased the scarcity rents in the wholesale spot and forward market. Respondents' RB at 34.

[223] Ex. NPC-40 at 26:8-28:2; Tr. at 2776:9-15; Tr. at 2787:19-2788:13.

witnesses merely assumed what they sought to prove, namely, without basis, that all impacts of market fundamentals are captured within their adjusted gas price.

89. Professor Shepherd did not conduct any study to prove his claim that the forward markets were subject to manipulation, because of the number of suppliers. He did not study the number of active participants in the market at the time and he did not analyze whether any of the Respondents controlled or owned generation facilities.[224]

90. The main witnesses for Snohomish were McCullough and Mount. These witnesses' testimonies will not be given substantial weight. In so holding, Staff's and Respondents' arguments are found persuasive. McCullough concluded that spot prices drove forward prices based on simple regressions. McCullough testified to a certain correlation between certain bilateral spot and forward markets in the WECC during June 2000 through June 2001. The major flaw in this testimony is his failure to establish any casual link between the ISO and PX spot market prices and forward prices. Staff's and Respondents' arguments that correlation does not establish causation is persuasive.[225]

91. McCullough analyzed the bilateral spot markets at the California Oregon Border (COB) and Palo Verde, Arizona (Palo Verde) with data from Energy Market Report ("EMR"). He failed to analyze the ISO and PX markets or the forward market at Mid-C or SP-15 (the markets relevant to this proceeding).[226] The differences in the markets are important because the Cal ISO and PX spot markets were subject to price caps and breakpoints from December 2000 to June 2001 and the bilateral spot markets were not subject to these same bid caps. McCullough's analysis of the correlation between the bilateral spot markets at Palo Verde and COB to the forward markets at these same delivery points fails to analyze or prove that the centralized, dysfunctional Cal ISO and PX spot markets adversely affected forward prices, for instance at Mid-C. As Respondents' witnesses testified, a correlation does not mean casuality, and the statement that "spot prices rose, contract prices rose; spot prices fell, contract prices fell" does not prove anything by itself.[227]

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[224] Tr. at 2753-54; 2755; 2771; 2778; 2767-68; 2788; 2789.

[225] The prices will move together if they are impacted by common market fundamentals, but move differently if the fundamentals are moving differently. Ex. MSC-65 at 111.

[226] The appropriate data related to spot market prices would have been the Cal ISO and PX.

[227] Ex. MAEM-50 at 18:19-22. For instance, Dr. Hieronymus explained that covariance of market fundamentals (gas spot and forward prices for example) likely does, explain that forward prices were high when spot prices were high, and that they fell at roughly the same time. Ex. MAEM-50 at 20:14-20.

92. Another flaw in McCullough's regression analyses is its failure to account for market fundamentals affecting spot and forward prices. This reveals its bias in his study on the estimated impact of spot prices on forward prices by creating a correlation that may not exist if market fundamentals had been included. As Respondents state, McCullough's correlation studies fail to show any correlation. McCullough did not test for serially correlated residuals, and his model uses a flat average annual forward price that would not be influenced by seasonal factors to predict daily spot prices (which would be expected to be influenced by seasonality).[228]

93. Drs. Hogan and Harvey analyzed McCullough's study and re-estimated his correlation model to adjust for serial correlation. Drs. Hogan and Harvey conclude that no significant correlation was found.[229] Additionally, witness Kalt testified that McCullough's model not only fails to establish that spot prices drove forward prices, but rather, it tests whether forward prices drove and explained spot prices.[230] This witness also testified that when McCullough's analysis is corrected for several statistical errors, the result shows no discernible impact of spot prices on the forward market.[231] Moreover, it is impossible to discern to what extent dysfunction may have impacted forward prices as opposed to competitive market forces.[232] McCullough's testimony is discredited by his own memo written to the California Attorney General on June 13, 2001.[233] In this salient piece of evidence, McCullough refers to the "NYMEX" prices (which he uses in his analysis) as "mysterious" and "questionable."[234] In addition, he writes: "with a fall in spot prices, we would expect to see some, but not a great deal, of impact on future prices."[235]

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[228] Exs. MSC-65 at 115:1-116:2; 115:8-116:2. His failure to test for serial correlation is so significant that the other Complainants' witnesses (Drs. Mount and Bidwell) admitted that they would not have run the analysis in a similar fashion. Tr. at 2200:2-2201:22.

[229] Exs. MSC-65 at 116:19-122:12; MSC-65 at 122:17-141:2. McCullough discounts a $3300/Mwh spot price cited by Snohomish as an outlier (statistical aberration) hen it would contradict his findings. However, when analyzing the volatility in the market, he includes this outlier. Respondents correctly point out that this is not valid use of the data.

[230] Ex. EPME-23 at 22-33.

[231] Id. at 26-33.

[232] Id. at 36-47.

[233] This memo's "publicity" was a discovery issue in this proceeding. McCullough inadvertently disclosed it, notwithstanding the fact that it was confidential.

[234] Tr. at 1452; Ex. MSC -108 at 2.

[235] Tr. at 1452; Ex. MSC-108 at 3.

94. Snohomish's and SCWC's witness, Dr. Mount, contends that the spot price at Palo Verde was a statistically significant determinant of the forward price and thus, concludes that high forward prices for electricity can be largely attributed to the high spot prices during the period when the spot market was dysfunctional.[236] The major flaw in his study is that it fails to analyze the statistical relationship between the Cal ISO or Cal PX spot prices and forward bilateral prices at Palo Verde or in the WECC.[237] This witness acknowledged that there were no econometric studies in this proceeding demonstrating an econometric relationship between the Cal ISO spot market and bilateral spot or forward markets anywhere in the West.[238] Moreover, Dr. Mount admitted that he never included Cal ISO prices in his model of the relationship among Western spot markets and that his analysis did not show that bilateral Western spot prices could be predicted by changes in Cal ISO or PX spot prices.[239]

95. There are other flaws in Dr. Mount's analysis. Staff's and Respondents' arguments in this regard are persuasive. For instance, they point out that Dr. Mount fails to account for changes in market fundamentals, even though he acknowledged that market fundamentals provide at least "partial explanation" for increased spot and forward prices during 2000 and 2001. [240] Dr. Mount treated anything that deviated from "the normal seasonal pattern of prices" as a "surprise in the market."[241] Furthermore, Dr. Mount fails to specify a key variable: the expected price for natural gas (by using forward prices for natural gas deliverable at Henry Hub trading in Southern Louisiana) instead of forward prices for natural gas deliverable in California or elsewhere in the West.[242] Dr. Mount's

[236] Ex. SNO-58 at 17.

[237] Tr. at 2208:11; 2209:24-2210:5; 2230:8-2231:5.

[238] This witness stated he did not analyze the Cal ISO spot market because these prices were subject to a soft price cap and actual data on market clearing prices is not publicly available. Tr. at 2242:25-2243:16. However, this directly contradicts the fact that he provides an econometric analysis of spot prices which includes "structural shift" variables to account for the unique characteristics of the soft price cap in the Cal ISO spot market. Ex. SNO-58 at 16:13-17:2.

[239] Tr. at 2230:15-22; SNO-17 at 74:13-77:9.

[240] Tr. at 2197:16-2199:5. The inconsistent accounting of fundamental factors that impacted spot markets in the West renders Dr. Mount's modeling unreliable for four Western spot markets.

[241] Tr. at 2245:13-17; 2216:17-2217:2.

[242] Dr. Mount claims that he did this relying on Staff's report in PA02-2-000. However, in this report, Staff rejected the use of Henry Hub spot price data as a substitute for California delivery point spot prices because natural gas from Henry Hub is not delivered to California. In addition, in this report, Staff acknowledged that some sellers in the Cal ISO and PX spot markets may have incurred actual natural gas costs higher

testimony acknowledges that generators in California (i) may have paid actual prices for natural gas much higher than those reported at Henry Hub (ii) reported forward prices for natural gas for delivery points in California "significantly higher" than reported forward prices at Henry Hub and (iii) "it is extremely unlikely" that suppliers in California could have purchased natural gas on a forward basis at prices equal to reported forward prices at Henry Hub.[243] As a matter of fact, California generators did not purchase their natural gas at Henry Hub.[244] Respondents' and Staff's arguments are persuasive. They argue that Dr. Mount's acknowledgement of the realities present in the forward natural gas markets in California undermines the validity of using forward natural gas prices at Henry Hub as an explanatory variable, in a model, to explain forward electricity prices in and around California. Accordingly, Dr. Mount's testimony will not be entitled to substantial weight.

96. SCWC's witness, Dr. Taylor, did not conduct econometric or statistical studies. This witness agreed that prices in the long-term markets were affected by market fundamentals. However, he did not conduct any studies to determine how these factors may have impacted long-term contract prices.[245] He relies solely on his interpretation of prior Commission orders[246] and MIRANT's forward price curve.[247] This testimony will not be given substantial weight. Dr. Taylor's interpretation of prior Commission orders is incorrect.[248] Additionally, Dr. Taylor's conclusions regarding Mirant's forward price curves are unfounded. For instance, Dr. Taylor does not explain how the "expectation of

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than Staff's recommended substitute natural gas price indices. Moreover, Staff's Report does not conclude that reliance on reported forward prices for natural gas at delivery points in California is inappropriate with respect to forward sales of electricity; it also expressly states that Staff makes no conclusion as to whether reported natural gas prices for delivery points in California "are inappropriate for structuring contractual provisions between two sophisticated parties bargaining at arms-length." *Initial Report in Docket No. PA02-2-000*, August 2002 at p. 58.

[243] Tr. at 2179:3-2180:6.

[244] Tr. at 2179, 2197. Ex. MAEM-61.

[245] Tr. at 2962-63.

[246] Dr. Taylor asserted that prior Commission orders established that the dysfunctions in the California spot markets adversely affected forward market prices. Ex. SCWC-20 at 28:20-21.

[247] Tr. at 2961:1-5; 2961:24-2962:4; 2962:16-2963-12; 2967:28-2968:2.

[248] Respondents' IB at 41-42, Staff's IB at 23. Factually, the Commission made clear that it did recognize interdependence between spot and forward markets, but it has never decided that the dysfunctions in the spot market rendered forward contract prices unjust and unreasonable. *Pub. Utilities Com'n of the State of California, et al. v. Sellers of Long-Term Contracts to the California Dep't of Water Resources, et al.*, 100 FERC ¶ 61,098 at 61,396 (2002).

high prices in the future can be attributed to dysfunctions in the Cal ISO/Cal PX spot markets, nor does he show that Mirant's forward price curve was, in fact, the expectation of continued dysfunctions in these spot markets.[249] Dr. Taylor admitted that Mirant's expectations about prices in the long-term market was affected by market fundamentals and factors other than dysfunctions in the Cal ISO/CalPX spot markets.[250] Dr. Taylor conceded that one cannot tell by looking at price curves what expectations they include, or whether they reflect expectations about future dysfunctions or future market fundamentals.[251]

97. Snohomish also presented testimony from Mr. Bidwell. This witness did not conduct any empirical studies to demonstrate to what extent the drop in long-term prices in mid-2001 resulted from FERC's mitigation of the spot market versus changes in market fundamentals.[252] Additionally, this witness did not conduct any studies of the marginal cost of power during May 2000- June 2001.[253] Furthermore, the studies of marginal costs he accepted were studies of the spot market, not the long-term market.[254] This witness did not do any studies to demonstrate that the forward markets during the relevant time period were not in competitive equilibrium.[255]

98. The Nevada Companies' witness Schiffel did not provide any evidence concerning the impact of fundamentals. Schiffel admitted he had not done any studies quantifying the effect of market factors, such as generation capacity or weather conditions. This witness did no analysis to determine the scope of the impact of dysfunctions on prices.[256] In addition, Schiffel did not perform any economic analysis regarding whether the forward markets were competitive during the period at issue in this proceeding.[257]

99. Witness Adams is a commodities expert. This witness did not know how Morgan Stanley derived its forward price curves[258] and he did not conduct any studies. However,

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[249] Tr. at 2968:10-2970.

[250] Tr. at 2962:16-2963:12.

[251] Tr. at 2967-72.

[252] Tr. 1294.

[253] Tr. 1300.

[254] Tr. 1347-48.

[255] Tr. 1328.

[256] Tr. 2488, 2524.

[257] Tr. 2595.

[258] The evidence shows that Morgan Stanley relies on a variety of information sources when developing its forward price curve, including (1) bids and offers from existing electronic exchanges (*e.g.* Intercontinental Exchange, Bloomberg); (2) bids and offers from over-the-counter brokers (*e.g.* Pebron, Natsource); (3) daily mark sheets from

this witness did admit that the marginal cost for a power marketer such as Morgan Stanley is the price at which it buys power.[259]

100. The preponderance of the evidence shows that the relationship between price determination in spot and forward markets, especially long-term bilateral markets, is attenuated. Therefore, it is not credible that dysfunctions in the California spot markets would have significantly affected the rates, terms, or conditions of the forward, fixed price contracts at issue in this proceeding. Notably, the dysfunctions affecting the Cal ISO and PX spot markets were not present in bilateral markets (short -term or long- term) in and around California.[260]

101. Complainants argued that sellers withheld production, that they exercised market power, and that there was a possibility of market manipulation. They did not offer any evidence in support of this. Moreover, the Commission in designating this matter for hearing stated that, in a separate proceeding, it was ordering an investigation of potential manipulation of electric and gas prices in the west.[261] Specifically, the Commission stated that this investigation would include whether there was improper behavior by sellers that may have caused prices not to be reasonable.[262] Consequently, evidence of potential market manipulation or the behavior of individual sellers was not developed in this proceeding.[263] This Initial Decision focuses on the issues mandated by the

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Tradition Financial Services; (4) price levels gleaned from Morgan Stanley's trade activity that day and (5) price levels gleaned from reported trade of other market participants that day. Ex. MSC-21 at 15:16-16:5; Tr. at 4184:3-8.

[259] Tr. at 2082-83; 2104; 2109.

[260] Snohomish argued that Respondents' witnesses conceded that current spot prices determined forward prices. Snohomish's contention is meritless. Respondents' witnesses did not so testify. For instance, Mirant's witness Schaefer testified that Mirant's forward curves did not reflect then current spot prices. This witness explained that expected market conditions were the basis of Mirants' offer prices. Ex. MAEM-38 at 6:17-18; 7:3-4. Dr. Hieronymus testified that forward prices relate to expected future spot prices. Ex. MAEM-500 at 14:22-24; 4:16-22; see also Tr. at 4234:9-13; 4235:3-5 (Funk); Tr at 4265:10-12 (Greenshields). Exs. MSC-65 at 109:9-10; MSC-65 at 111:1-112:12.

[261] See *Nevada Power Company v. Enron Power Marketing, Inc.,* 99 FERC ¶ 61,047 at 61,191 n. 12 ("Hearing Order").

[262] Id.

[263] McCullough, for instance, testified that there was market power. However, on cross-examination, this witness stated that he had provided no documents, analysis or other evidence empirically showing that the forward markets were subject to market power or that the Enron trading strategies affected market prices in the forward markets

Commission. To wit: whether the dysfunctional spot markets in California had an adverse effect on the long-term, bilateral markets in California, Nevada and Washington. Thus, these allegations were construed as collateral attacks of the hearing order and not considered.[264]

102. However, it bears noting that these witnesses did not present any evidence of specific manipulation by any Respondents which impacted the forward markets generally or any contract at issue in this case specifically.[265] The allegations that the impacts of Enron's trading strategies, withholding and exercise of market power in the ISO and PX spot markets, inflated prices in the forward markets, were refuted by Drs. Hogan and Harvey,[266] Dr. Hieronymus[267] and Mr. Baird.[268] The allegations of withholding in the ISO and PX markets[269] did not contain any specific studies proving withholding by any Respondent in any market, spot or forward.[270] Moreover, no evidence was presented that any sellers actually engaged in discriminatory pricing regarding the contracts at issue in this proceeding. Finally, there is no evidence of the exercise of market power by any Respondent in this proceeding.[271]

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in the WECC. Tr. at 1423:18-1424:8. Additionally, witness Adams testified that he had no evidence that Morgan Stanely or Mirant inflated prices by either controlling supplies or withholding power. Tr. at 2113-14.

[264] SCWC and Snohomish open their brief with numerous references which they claim prove market power and market manipulation during the California energy crisis supported by extra record citations (*e.g.* Oil Daily regarding Avista; newspaper articles regarding reports on gas prices; recent initial decision in docket RP00-241-006). These unsupported allegations were not considered in this proceeding in accordance with the mandates of the Hearing Order.

[265] <u>See</u>, *e.g.*, Tr. at 2762:16-20; 2768:8-18.

[266] Exs. MSC-65 at 54:18-61:19; MSC-65 at 68:7-106:15.

[267] Ex. MAEM-50 at 3:11-4:2; 6:12-11:20; 31:14-36:19.

[268] Ex. MSC-98 at 9:9-10:16; 12:16-14:22.

[269] Ex. SNO-60 at 29-41.

[270] Witness McCullough testified generators were physically withholding from November 2000-June 2001. However, his analysis was flawed and will not be entitled to substantial weight. To wit, McCullough acknowledged that many of the plants were old and did not run efficiently. He also acknowledged that environmental constraints could have affected their operational capacity. Tr. at 1402. Furthermore, he did not consider vintage in his calculations. Moreover, he did not look at NOx prices. Tr. at 1409; Ex. MSC-103. Finally, his analysis of plant availability relies on a study of "comparable" plants, instead of a study of actual plants. Tr. at 1414.

[271] It is noted that two Respondents (El Paso and Enron) are involved in separate proceedings to determine whether they have violated Commission rules. <u>See</u>, *Public*

103. The record in this proceeding establishes that Complainants did not perform any analysis regarding the impact of market fundamentals on the forward prices. Complainants' witnesses who tried to do analyses only measured one factor, and they did not account for all of the changing market fundamentals which impacted forward prices. Furthermore, Complainants did not provide any evidence that the Cal ISO and PX spot market prices drove the spot prices throughout the WECC. As a matter of fact, Complainants did not analyze the Cal ISO or PX markets. Instead, they analyzed the bilateral spot markets at COB and Palo Verde. This evidence only shows that the prices at theses two points were high.[272] Additionally, Complainants offered a model of bilateral spot prices at four locations in the WECC. This evidence establishes only that the spot markets at COB, Palo Verde, Mid-C and Mead were correlated, and that the spot and forward markets at Palo Verde were also correlated. However, this evidence is not related to the Cal ISO or PX spot prices. Complainants did not perform any survey or study to determine the market participants' expectations (concerning the continuation of spot market dysfunction).[273] Complainants did not prove what role any factors (including market fundamentals) had in the development of any forward price curves. As a result, Complainants failed to demonstrate that prices in the Cal ISO and PX drove the expected future spot and forward prices throughout the WECC.

Utilities Commission of the State of California v. El Pas Natural Gas Company, 100 FERC ¶ 63,041 (2002); *Enron Power Marketing, Inc., El Paso Electric Company*, Docket No. EL02-113-000 (Order Establishing Hearing Procedures). Commission findings on these two cases may require further examination of the contracts in this case. Staff points out that "with regard to the investigation in PA02-2, if it reveals that a seller or its affiliate clearly engaged in the exercise of market power and/or market manipulation that significantly affected the forward markets at the time the contracts were negotiated, the public interest standard has been met and that seller's contracts should be reformed." Staff RB at 17. Pertinent to this also would be the fact that the Enron contracts with the Nevada Companies purportedly have been terminated.

[272] Respondents assert that the centralized Cal ISO and PX spot markets were subject to price caps and breakpoints at the time when the Nevada Companies' contracts were executed which did not apply to the bilateral spot markets in California or the West. They state that the assumption is that dysfunction in the Cal ISO and PX spot markets would not have affected prices in spot markets elsewhere in the WECC that were not subject to any price cap or mitigation. Based on the evidence presented in this case, this assertion is very persuasive.

[273] Staff persuasively argued that Complainants cannot prove their case by arguing that market participants expected alleged "dysfunctions" to continue. Staff correctly states that after December 15, 2000, prices in the spot market were becoming less and less reflective of the dysfunctional market design identified by the Commission, and thus more reflective of competitive market forces. Staff RB at 18.

104. Staff and Respondents are correct in that the prices in the forward markets, during the time the contracts at issue in this case were negotiated, were the direct result of competitive market forces at work in the marketplace. Reduced supply and increased demand conditions produced high spot prices. These supply and demand fundamentals, coupled with the expectations of market participants produced high forward prices. Moreover, there is no record evidence to support Complainants' arguments or any quantification of the effects of spot market dysfunctions on forward markets. Accordingly, it is found that Complainants have failed to prove that the dysfunctional Cal ISO or PX spot markets adversely affected the Western long-term bilateral markets.[274]

Issue III. Whether the adverse effect of the dysfunctional Cal ISO and PX spot markets on Western long-term bilateral markets was of a magnitude warranting modification of contracts entered into in the bilateral markets?

A. Parties Contentions:

105. The Nevada Companies assert that its witnesses estimated the impact of the dysfunctional California spot markets on forward market prices. The witnesses calculated the forward prices for energy that would have been charged absent dysfunction in the California spot markets. These witnesses used the forward gas prices during the crisis period and the implied heat rates for the marginal generation units that market participants expected, during the pre-and post-crisis periods, to be dispatched for delivery of energy at Palo Verde during the third quarter of 2002 (Q3 2002).[275] The expected forward market prices for power were significantly less than the actual forward prices during the crisis period, the Nevada Companies conclude.[276] This approach is the same as

[274] Staff is correct that, in accordance with the hearing order in this case, Complainants had a heavy burden of proof which could not be met by artificially creating a presumption that high [current] spot market prices affected [future] forward prices and making Respondents overcome this presumption. Staff's argument criticizing SCWC's "theoretical" basis that current spot prices present the opportunity costs of selling power in the forward markets as fundamentally flawed is persuasive. Staff correctly asserts that the output of a generator is continual, and cannot be stored. Today's output can be sold in the current spot market, and tomorrow's output can be sold in the forward market for delivery later. According to Staff, an opportunity cost relationship exists between future spot sales and current forward contracts, *i.e.* both sales relate to tomorrow's output. However, there is no such relationship between current spot sales (today's output) and current forward sales (tomorrow's output), *i.e.* it is not the same electricity. Staff RB at 12.

[275] Id. at 28.

[276] Id.; NPC-40 at 24:10-29:7.

that adopted by the Commission to establish benchmark prices for use in determining refunds in the Cal ISO and PX proceedings, except that it relies on heat rates estimated from forward market prices in the absence of dysfunction rather than upon historical rates for the units that actually cleared the spot market during the crisis period.[277]

106. Nevertheless, the Nevada Companies contend, in each case, the magnitude of the impact of dysfunction is measured against the marginal cost of the generation unit that was or would be dispatched absent dysfunction in the spot markets. According to the Nevada Companies, the estimates show that the difference between the forward prices and the actual prices ranged from $50 to $100/MWh for much of the crisis period or from 14% to 168% of the expected prices absent dysfunction in the California spot markets.[278] The impact of spot market dysfunction ranged from approximately $2,000,000 to approximately $7,000,000 per contract for a representative sample of the Nevada Companies.[279] As a result, the Nevada Companies aver that this significant difference confirms that the contract prices are unjust and unreasonable and warrant contract modification. Additionally, the Nevada Companies contend that if gas prices (as FERC Staff believes) were also inflated during this period the differential between the expected forward market prices absent dysfunction and the actual forward prices would be even greater.[280]

107. The Nevada Companies assert that Professor Shepherd's and Goldberg's analysis takes into account all of the market fundamentals and, while market fundamentals unaffected by dysfunction may explain some of the forward price changes observed during the crisis, they do not explain all of the price changes.[281] According to the Nevada Companies, the prices in the contracts at issue in this case were unjust and unreasonable because they exceeded the prices that would have prevailed in a functionally competitive market. Competitive rates, the Nevada Companies maintain, in a properly functioning market, would be roughly equivalent to the marginal cost of the least efficient, *i.e.* highest cost, generating unit actually dispatched to meet load.[282] Before and after the California energy crisis, the marginal costs of production in the forward market in the WSCC were approximately $40 to $60. During the energy crisis, increased gas prices may have caused the marginal cost of production to rise to a degree, the Nevada Companies assert. However, the prices in the Nevada contracts at issue in this proceeding

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[277] The Nevada Companies IB at 30; NPC-40 at 29:6.
[278] Id. at 31.
[279] Id.
[280] Id.
[281] Id. at 32.
[282] Id. at 33.

are several multiples of any measure of the marginal costs of production, sometimes as high as $290 per MWh.[283]

108. The Nevada Companies contend that it is inappropriate to regard these high prices as reflecting scarcity rents because the system does not really permit a consumer response to these prices. These prices do not reflect a willingness to pay because there has been no demand side discipline in the market.[284] Additionally, the Nevada Companies argue that there is no evidence that expected physical scarcity caused all of the forward market price increases for power to be delivered in 2002 and 2003.

109. SCWC and Snohomish, in addition to making similar assertions to the Nevada Companies, further argue that forward market prices converge around the long-run marginal cost of production (in this case around $34 per MWh), and that forward prices will vary over time in a band within about twenty percent of the LRMC.[285] Accordingly, the zone of reasonableness for long-term forward contracts in the West would be from $28 to $40, SCWC and Snohomish contend.[286] These companies claim that one would never expect to see the prices contained in the long-term contracts signed by Snohomish ($105 per MWh for nine years) and by SCWC ($95 per MWh for 69 months) in a fully competitive market, because these prices are at least twice the LRMC of a gas-fired turbine. Additionally, SCWC and Snohomish argue that the price paid by SCWC is twenty-eight percent higher than the competitive-level benchmark established by the Commission in its December 15 Order, and this difference is attributable to the California spot market dysfunction, thus warranting modification of SCWC's contracts.[287] This is also applicable to the Snohomish contract, these parties aver.

110. Changes in the seasonally adjusted average monthly spot price of electricity during the California electricity crisis (May 2000 through Spring 2001) explained approximately eighty to ninety percent, of the variation in forward electricity prices as a ratio of forward gas prices for the delivery months of August 2001 and August 2002. As a result, SCWC and Snohomish argue that the high forward prices for electricity that occurred when the spot market was dysfunctional can be largely attributed to the high spot prices.[288]

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[283] Id. at 34.
[284] Id.
[285] SCWC IB at 28.
[286] Id.
[287] Id. at 28.
[288] Id at 29.

111. Evidence in this case demonstrates[289] that more than half the increase in spot market prices during the crisis period was attributable to market power, defined as the excess of market prices over marginal costs. According to SCWC, this is corroborated by other academics and the Commission. As a result, these complainants argue that the contract prices in this case far exceed any relevant measure of costs plus reasonable risk premium.[290] Respondents have not demonstrated that they incurred costs to serve Snohomish or SCWC that are near the prices they have received under the long-term contracts, therefore, the Commission should remedy the unreasonable effect on Complainants' ratepayers. Commission inaction would encourage continued market abuse, SCWC and Snohomish argue.[291] Morgan Stanley would not suffer a real loss but a paper loss amounting to about 0.12% of its net cash flow for 2001, which will be incurred anyway due to accounting rule changes. Moreover, these companies argue that, in any event if such stranded costs occur, FERC has taken steps to protect market participants.

112. As stated above, Respondents argue that Complainants failed to demonstrate that the dysfunctional spot markets in California affected the forward markets. In addition, they argue that as a result, Complainants failed to adduce evidence of a magnitude warranting modification of fixed rate bilateral forward contracts entered into in the Western markets. Thus, Respondents argue that the Commission's long standing policy is to promote the stability of contracts and Complainants have not established any reasons for abandoning this policy. Respondents further aver, that the record overwhelmingly establishes that factors other than the dysfunctions in the ISO and PX spot markets explain the bilateral forward contract market prices at issue. Additionally, Respondents maintain that enforcement of wholesale power contracts is an absolutely essential element to attract investment by market participants. Potential market participants cannot effectively develop and finance new merchant generation projects absent certainty that their contracts will be honored, Respondents argue. Accordingly, Respondents contend that modification of the contracts is contrary to the public interest. Finally, Respondents aver that Complainants have not described the dysfunctions that allegedly adversely affected the forward markets, nor quantified the effects of any purported dysfunction in the forward markets on the contracts at issue. Since they failed to establish any impact, they have failed to establish an impact sufficient to warrant contract modification, Respondents maintain.

113. Staff points out that the rates, terms and conditions of the contracts in question are a reflection of the choices Complainants made regarding the risks they wanted to accept and the purchasing strategies they employed. Snohomish and SCWC elected to avoid

[289] Id.
[290] Id. at 30.
[291] Id.

price volatility and lock in below-market prices by entering into long-term, fixed price contracts, even though other options were available to them. The Nevada Companies chose to pursue an aggressive purchasing strategy which was inconsistent with its own resource plan, by concentrating on buying relatively short-term contracts at any price, without considering the risk of future price decreases. Moreover, Respondents hedged the contracts by purchasing power concurrently with the sale. Thus, Respondents incurred or locked in high-priced purchases to meet their obligations. As a result, Staff argues it would be unfair to abrogate the contracts. In a competitive marketplace, each participant makes its own determinations regarding the manner and the extent to which current and forecasted changes in competitive market forces, as well as current and forecasted changes in regulatory policies, will affect price. In a highly volatile market, buyers use this information to determine how to manage risks (and how much of the risk to pass on to sellers). This ability to choose is, in fact, fundamental to any market-based rate scheme, Staff argues. To now go back and adjust, or make up for, choices and risk decisions that the buyers made in 2000-01 defeats the underlying purpose of competitive ratemaking. According to Staff, buyers and sellers in competitive markets should be required to live with the consequences of their choices, good or bad.

B. Discussion/Findings:

114. In the Hearing Order, the Commission directed record evidence on "the totality of purchases and sales and the conditions present at the time the contracts were entered into;" Complainants' overall portfolio, as well as their own sales, (pattern, duration, price); whether complainants' transactions were physical or financial in nature and designed to serve complainants' load; the terms, conditions and rate over the entire duration of each contract (*e.g.* whether the contract is front-end loaded); what other alternatives were available to buyers and sellers; whether, at the time, it was a reasonable decision to enter into these contracts (e.g. duration, scope and time period, and the participants' expectations as to the duration of dysfunctions in the Cal ISO and PX markets); the terms and conditions of any request for proposals, and the process and procedures the Complainants used to evaluate the contracts, including any changes in offered rates, terms and conditions mandated or negotiated by the Complainants; and the relation of the contract rates to the Commission's previously identified benchmark for long-term contracts.[292]

115. In addition, the Commission indicated that the parties could present evidence on: the effect of the contracts on the financial health of Complainants; the effect of the contracts on wholesale and retail customers; the impacts contract modification may have

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[292] *Nevada Power Company v. Enron Power Marketing, Inc.*, 99 FERC at 61,191 (2002).

on the nation's energy markets, including, but not limited to, impacts on investment in new generation and transmission infrastructure, and the effect on confidence in competitive markets; the willingness of market participants to enter into long-term contracts in the future and the prices and terms and conditions of such contracts; and the potential modification of other existing energy contracts.[293]

116. The Commission stated: "[t]he Commission's long-standing policy, consistent with a substantial body of Supreme Court and other judicial precedent, has been to recognize the sanctity of contracts. Rarely has the Commission deviated from that policy, and then only in extreme circumstances, such as the fundamental industry-wide restructuring under Order No. 888 and the reorganization of a bankrupt utility. Preservation of contracts has, if anything, become even more critical since the policy was first adopted. Competitive power markets simply cannot attract the capital needed to build adequate generating infrastructure without regulatory certainty, including certainty that the Commission will not modify market-based contracts unless there are extraordinary circumstances."[294]

117. Review of the "totality of purchases and sales" and the "conditions present at the time the contracts were entered into"[295] supports the finding that the contracts should not be modified. Complainants allege that they expected the market dysfunctions would last at least "indefinitely."[296] This testimony is not credible. In November 2000, the Commission issued an order proposing remedies for the California market. The Commission found there were a number of factors that contributed to the high prices experienced in California that summer: competitive market forces played a major role in the run-up of prices through significantly increased power production costs combined with increased demand due to unusually high temperatures and a scarcity of available generation resources throughout the West. In addition, market rules and flawed retail regulatory policies exacerbated the situation.[297] Specifically, the November 1, 2000 Order identified the following problems: (i) the CPUC's requirement that the California IOUs buy and sell all of their energy needs through the CalPX, (ii) CPUC restrictions on the IOUs' ability to enter into forward contracts, (iii) the lack of a retail demand response program, and (iv) underscheduling due to the ISO's replacement reserves policies.[298] In the December 2000 Order, the Commission adopted remedies to fix the rules in the California spot markets.[299] Therefore, the evidence shows that there should have been no

[293] Id.
[294] *Nevada Power Co. v. Duke Energy*, 99 FERC at 61,190 (2002).
[295] 99 FERC at 61,191.
[296] Exs. NPC-1 at 11;1-6; SNO-1 at 12:14-13:5.
[297] 93 FERC at 61,349-50.
[298] Id. at 61,354-55; See also S-4 at 3:5-12.
[299] 93 FERC at 61,982-83.

expectation that dysfunctions in those spot markets would affect forward bilateral markets after December 2000. As the Commission explained in the December 15, 2000 Order:

> Some parties in this proceeding argue that the prices in the forward markets will be affected by last summer's spiraling spot prices and should therefore be deemed unreasonable. We do not agree. Sellers will certainly be aware that supplies of power are tight and that the IOUs are now aggressively seeking to avoid the exposure of the spot markets. Under these circumstances . . . we will be vigilant in monitoring the possible exercise of market power. However, suppliers also benefit from the stable revenue stream of forward markets and have every bit as much incentive to avoid the volatility of the spot markets as do purchasers. Moreover, suppliers will bargain knowing that the spot market's size will be greatly reduced and that next summer's spot prices will therefore not be fueled by frenzied buyers whose over-reliance on last minute purchases have forced them to bid up the prices to obtain needed supply.[300]

118. Staff witness Ogur testified that the "effect of these two Orders (the November 1, 2000 and December 15, 2000 Orders) was to provide a strong signal to market participants that the Commission was acting vigorously to eliminate this spot market dysfunction."[301] Although all spot purchases would not be expected to move immediately to the forward market after December 15, market participants were (or should have been) aware that this critical dysfunction was going to be less and less of a factor affecting prices.[302]

119. Moreover, the Commission, in an April 26, 2001 Order adopted further market monitoring and mitigation measures for the California markets, and proposed to extend those measures to all Western spot markets.[303] The Commission included in its Western-wide proposal a must-offer rule for all non-hydroelectric generators and marketers and a condition on the market-based rate authority of all public utility sellers selling in the WECC to ensure that they do not engage in anti-competitive behavior.[304] In subsequent orders, the Commission adopted a Western-wide mitigation plan.

120. As a result of these Commission orders, Complainants were aware of the possibility of market mitigation and the risks they faced. Additionally, it must be found

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[300] 93 FERC at 61,994.
[301] S-4 at 6:8-10; <u>See</u> <u>also</u> S-1 at 28:20-23.
[302] Tr. 4447-8.
[303] 95 FERC ¶ 61,115.
[304] <u>Id.</u> at 61,365-66.

that it was not reasonable for Complainants to expect spot market prices to remain high indefinitely based on the fact that the Commission had given clear signals that it was going to act to remedy problems in the California and Western spot markets.

The Nevada Companies.

121. Record evidence shows that the Nevada Companies' procurement strategies, and the manner in which the strategies were implemented, were choices voluntarily made by these companies. To the extent they left themselves open to unnecessary risks, that was their choice also. As a result, as will be described below, substantial evidence in this case demonstrates that the contracts should not be modified or abrogated.

122. In March 2000, a Risk Management Committee ("RMC") was formed by the Nevada Companies. The RMC was set up to establish guidelines for procurement and risk management strategies. The evidence, in this case, shows that the Nevada Companies' contracts at issue in this case were entered into pursuant to an "Accelerated Procurement Strategy" ("APS") adopted in November 2000.[305] The APS was a "radical proposal." The record evidence in this case shows that there was a lack of rigorous analysis or quantitative studies supporting the APS.[306] The APS was adopted in an executive session, at the end of a regular RMC meeting. The APS was adopted without the benefit of any calculation concerning the Companies' exposure, should prices fall.[307] The Chairman of the RMC cited concerns about the creditworthiness of the Companies as the basis for the adoption of the APS. Under the APS, the Nevada Companies entered into short-term forward contracts much further in advance of the delivery period. This was totally different from their previous purchasing strategy, which had used a monthly RFP process to procure power.[308] Under the APS, they bought standardized, fixed-price products for the 2001 summer season and for 2002-2005.

123. The evidence indicates that APS was undertaken due to the Nevada Companies' perceived need to secure "reliability at any price,"[309] a desire to beat California before it "hit that market,"[310] and a desire to buy as much power as they could before their

[305] Ex. CES-2 at 18:12-13; Tr. at 2655:22-2656:2.

[306] Ex. CES-2 at 19:4-5, 19:17-20:1; Tr. at 2482:4-9; 2586:25-2587:6.

[307] Tr. at 2583-86; 2596-97.

[308] Exs. ECS-2 at 18; CES-8; NPC-12; Ex. CES-39; S-6 at 16-17; Tr. 2328; 2581-83; 2614-15.

[309] Ex. CES-2 at 15:8.

[310] Tr. at 2629:24-2630:1.

counterparties discovered their already "precarious financial position."[311] As the Companies' risk management consultant, Mr. Joyce, explained, the Companies sought to lock in power purchases early because: "t*here was a fear that very soon the market would get wind of the credit situation of the companies* … And it was felt, and I probably recommended, that they acquire power before any kind of news hits the streets, because once it does hit the streets, the number of counterparties that would be willing to deal with them, since they couldn't post collateral, would dwindle to close to zero."[312]

124. The Nevada Companies contend that state regulatory policies drove the APS and witness Smart references a PUCN order.[313] This testimony is not supported by record evidence and is thus not credible. The order cited by Mr. Smart was issued after the Nevada Companies had conceived of and adopted the APS.[314] In an order dated November 22, 2000, the PUCN concluded that "NPC's purchase power acquisition strategy is inadequate since it does not consider long-term [*i.e.*, greater than three years] agreements."[315] Moreover, the minutes of the Risk Management Committee meetings at which the APS was considered and adopted, do not mention that the APS was being driven by a concern for state regulatory policies.[316]

125. The Nevada Companies did not pursue a mix of products. This is particularly troubling since their Comprehensive Energy Plan ("CEP"), submitted to the PUCN in January 2001, recomended a diverse portfolio.[317] The CEP specifically recommended a "[m]ixture" of short, intermediate and long-term resources; a "[b]lend of spot, indexed and fixed prices," and "[f]lexibility" to take advantage of future lower prices.[318]

126. The APS focused only on standardized products available in the broker markets. Even though the Nevada Companies had authority to enter into forward contracts of up to three years duration without additional regulatory approval, virtually all of their contracts at issue in this proceeding are for terms of one year or less.[319] Many of the contracts are

[311] Exs. CES-2 at 22:16-24:3; CES-14b at 154; Tr. at 2273:10-2274:16. The declining financial condition was due to the fact that they had incurred costs greater than they were allowed to recover in rates. Tr. at 2657.

[312] Ex. CES-14b at 154 (emphasis added).

[313] See Ex. CES-2 at 3:9-4:5, 10:13-11:9.

[314] Tr. at 2614:4-2615:19.

[315] Ex. NPC-7 at 9, ¶ 73.

[316] See Ex. CES-7; Ex. CES-8.

[317] Ex. CES-2 at 20:18-21:7.

[318] Ex. CES-9 at 17.

[319] Ex. NPC-12; Tr. at 2337:14-18.

for terms of only 90 days.[320] All of the contracts are fixed-price contracts.[321] The evidence also shows that there were long-term, structured transactions offered, but not accepted by the Nevada Companies.[322] The record supports the finding that since the forward curve at the time reflects backwardation, lower average prices could have been obtained by entering into longer-term contracts.[323] The evidence demonstrates that the Nevada Companies undertook a strategy of purchasing solely short-term, fixed-price products well in advance of when they were actually needed, even though they knew that it would be prudent to have a mix of short-term, mid-term and long-term contracts.[324]

127. Moreover, the evidence supports a finding that the Nevada Companies overestimated their ability to resell their excess power.[325] The record evidence shows that the Nevada Companies sold excess power in 2000 and realized a margin of $100 million.[326] NPC's revenues from resale increased eight-fold from 1999 to 2000, and 6.7 times from 2000 to 2001.[327] SPPC's revenues from resale increased five-fold from 1999 to 2000, and more than doubled from 2000 to 2001.[328] The Nevada Companies sold power in 2000 and 2001 in the ISO and PX organized spot markets, as well as to DWR.[329] The Nevada Companies realized prices in the $400 to $750/MWh range for their excess power sales to those California entities.[330] At one point, the Companies' portfolio was "in the money" by $1.8 billion.[331] This course of action was risky and the Companies' own CFO, Mark Ruelle acknowledged this,[332] yet the Companies failed to purchase any of the other risk-hedging products offered in the market.[333] The Companies did not hedge the risk of a drop in market prices. The evidence supports a finding that it would be a reasonable inference that the Nevada Companies expected to return a profit again in

[320] Ex. NPC-12.

[321] Ex. NPC-12; Tr. at 2336:23-2337:1.

[322] Ex. CES-35. The Calpine offer was a five-year deal for a 6x16, must-take sale at $67/MWh.

[323] Tr. at 2338:20-24; Ex. RES-10 at 5:17-18, 5:21-22.

[324] Exs. CES-36 at 54-55; NPC-12; CES-34.

[325] CES-4 at ¶ 291.

[326] Ex. CES-2 at 26:18-28:3. Professor Kalt graphically depicted the amount of excess power purchased by the Nevada Companies for September 2002 and compared those purchases to previous years. Ex. EPME-38b.

[327] Ex. S-10 at 3 and 5.

[328] Ex. S-12 at 3 and 5.

[329] Ex. MSC-137; Tr. at 2267:1-5, 2335:25-2336:10.

[330] Ex. MSC-137.

[331] Tr. at 2681:3-7.

[332] Ex. CES-10.

[333] Exs. RES-1 at 7:5-18; RES-10 at 4:13-6:3; Tr. at 3440:5-3444:18.

2001.[334] This is supported by the following: on a Nevada Companies' investors' conference call on May 11, 2001, then-CFO Mark Ruelle stated: "[W]e have great opportunities in liquidating our long position…. But if for example there will be regional price caps put [in, they] would limit our ability to liquidate our long position at favorable prices." [335] This shows that their purchases were not just to serve their load. As Staff witness Tingle-Stewart testified, "by choosing to contract for significantly more power than they needed to reliably serve their loads, [the Nevada Companies] exacerbated the situation in which they now find themselves. It does not appear to have been necessary for them to purchase these amounts of excess energy. However, inasmuch as [the Nevada Companies] freely chose to do so, that certainly mitigates against relieving them of their contracts."[336] This testimony is given substantial weight.

128. Furthermore, the record shows that the Companies did not adjust their purchasing strategy even after deferred energy accounting was reinstituted as a result of AB 369, effective on April 18, 2001.[337] Deferred energy accounting allowed the Companies to take a more orderly approach to acquiring their needed power supplies. Nevertheless, the Nevada Companies continued to purchase fixed priced contracts during April, May, and June 2001.

129. The Nevada Companies purchased more power than necessary to cover their load requirements, effectively hedging against increases in the price of power. However, they ignored the prospect that power prices could decrease – even though forward curves

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[334] This is consistent with the PUCN's findings regarding purchases in 2000 for the summer of 2001. The PUCN found in the deferred energy orders that the Nevada Companies had purchased more than they needed, which was indicative of some speculation in the power markets, had focused on reliability at any price without conducting a thorough analysis of the options available, had failed to undertake appropriate quantitative and qualitative analyses in changing their procurement practices in 2000 and 2001, and had failed to develop a balanced portfolio. Ex. CES-2 at 7:12-8:19 (these PUCN Orders were in 2002). While these power purchases were for the summer 2001 delivery (unlike the contracts at issue in this case, which are for delivery in 2002 and beyond), they were undertaken "pursuant to the same directives from the RMC and management" as the contracts at issue in this case. Ex. CES-2 at 9:12-14. The PUCN argued that the reasonableness of their purchases should not be considered in this case. However, suffice to say, the hearing designation order mandated such consideration.

[335] Ex. CES-10.

[336] Ex. S-6 at 28:15-29:2.

[337] Ex. CES-2 at 6:14-15.

from the time of contract execution showed that the market reflected backwardation.[338] This concerted effort was undertaken even though the Risk Management Committee was aware of the risk management tools available to assess the Companies' exposure to price decreases. However, they did not utilize them.[339]

130. The record shows that the Nevada Companies relied on prices reflected in broker sheets,[340] checking price quotes and reading a few trade publications to guide their expectations about the future of energy prices.[341] Moreover, these Companies did not analyze the impact of new generation on forward prices, or the supply situation for 2002 and 2003.[342] Instead, they relied on public reports to assess the supply and market prices as an indicator of expected supply.[343] The Nevada Companies' head trader was aware that there was new generation capacity scheduled to come on-line in California, Arizona and Nevada in 2001 and 2002.[344] However, the evidence developed in this case shows that, at the time they were entering into the contracts, the Nevada Companies did not do any quantitative analysis concerning how the entry of new generation capacity would impact supplies or prices in 2002 and 2003.[345] The Nevada Companies' risk manager also did not do any analysis or review any reports on new generation when the companies were determining their APS strategy.[346] This evidence belies any claims that the purchasing strategy was for reliability purposes.[347]

131. The Commission directed the parties to present evidence on "what other alternatives were available to buyers and sellers."[348] The Nevada Companies claim there were no feasible alternatives. The record evidence shows that there were alternatives available to the Nevada Companies during the period at issue. Accordingly, it is found that the Nevada Companies' contentions in this regard are meritless. First, the Nevada Companies knew what types of products were available to them. They traded through

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[338] Ex. CES-2 at 14:1-14. Prices in the short term were higher than prices in the long term.

[339] Ex. CES-2 at 15:13-16:14.

[340] Tr. at 3108:10-18.

[341] Tr. at 3113;15-3114:3; 2597:15-22; 2488:8-10.

[342] Tr. at 2597:15-22; 2669:8-10.

[343] Tr. at 2669:5-7; 2597:15-25.

[344] Tr. at 2264:6-13 (Perry).

[345] Tr. at 2264:14-18; 2669:8-11.

[346] Tr. at 2668:23-2669:11.

[347] For instance, the Nevada Companies' cite a NERC report to support shortages in 2002, but this report applied only to 2001. Tr. at 2667-69.

[348] 99 FERC at 61,191.

five brokers and purchased forward power from more than thirty companies.[349] They had access to "RFP's, bulletin boards, trade press, broker sheets, multiple broker quotes and direct supplier solicitation."[350] The Risk Management Committee was aware of physically-and financially-settled risk management tools, such as indexed products, shaped products, unit contingent products, derivatives, swaps, collars, caps, floors, put and call options, and blended contracts.[351] In fact, the Companies entered into at least one type of option.[352] The Companies simply concluded that they could not purchase options because "they would have a hard time coming up with the cash" to pay the option premiums.[353] However, they could have chosen options that could have avoided at least some of the higher priced contracts they are now locked into."[354]

132. The record establishes that the Nevada Companies had long-term deals presented to them, but they declined to enter into those deals.[355] These companies undertook this course even though their own recommended course of action was to enter into long-term deals.[356] For example, ten different entities offered the Nevada Power Companies long-term contracts for peak power for delivery starting in 2002.[357] The Nevada Companies considered but rejected a five year contract for $67/MWh and a fifteen year deal at $47/MWh.[358]

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[349] Exs EPME-16; CES-2 at 13:12-13; Tr. at 2253:2-12; Exs. RES-10 at 3:17-18, 3:22-4:2; CES-14b at 121; EPME-16; CES-2 at 13:12-13; Tr. at 2253:2-12; Exs. RES-10 at 3:17-18, 3:22-4:2; CES-14b at 121.

[350] Ex. CES-2 at 13:13-15.

[351] Exs. CES-2 at 14:4-6; RES-1 at 7:10-18; RES-10 at 3:11-18, 4:13-6:3; Tr. at 3440:5-3444:18.

[352] Tr. at 2611:21-2612:7.

[353] Tr. at 2342:8-14.

[354] Ex. S-6 at 19:7-10.

[355] Ex.CES-35; Tr. 2572-76.

[356] See Exs. CES-9 at 17; CES-35.

[357] The evidence establishes that the Nevada Power Companies considered two Calpine proposals: one a 200-MW, five-year, 6x16 must-take proposal with a composite price of $67.00/MWh; and a second proposal combining a 150-MW, fifteen-year, 7x24 must-take proposal with a 150-MW day-ahead call option with a composite price of $42.14/MWh. Ex. CES-35. NPC also concurrently considered a ten-year proposal from Duke, which apparently was a 100-MW, 6x16 must-take proposal with a composite cost of $102.00. Exs. CES-34; CES-35; Tr. at 2573:10; 2576:13-15. At least two such deals were offered by merchant power plant developers, which mean that the long-term sales would have been backed by generation. The Nevada Companies did not pursue these options.

[358] Ex. CES-35; Tr. 2572-76.

133. Another option would have been transmission procurement strategies conducive to obtaining transmission resources which could have aided in the procurement of alternative sources of power. The Nevada Companies failed to do this. For instance these companies failed to develop the resources needed to compete effectively for and use transmission capacity.[359] The Companies lacked the technology to compete effectively for transmission capacity when it became available.[360] Furthermore, on at least one occasion when the Companies acquired transmission capacity, they sold the capacity before it could be used.[361]

134. Contrary to the assertions of the Nevada Companies, the markets in the West, including Mead, were liquid trading points. Unrebutted evidence in this case establishes that the Western markets were liquid. According to Reliant's witness, Flowers, the forward markets in the West were "liquid" during the period at issue in this case.[362] Flowers testified that "more than twenty-five entities were actively trading at the Palo Verde and Mead hubs."[363]

135. The Hearing Order directed the parties to present evidence on "the process and procedures the complainants used to evaluate the contracts" at issue.[364] The evidence in this case demonstrates that each of the transactions with the Nevada Companies was a "brokered" transaction, *i.e.*, it was entered into by the parties using an independent, third-party broker without knowledge of the counterparty's identity.[365]

136. The evidence supports a finding that the Respondents were price takers.[366] They did not set the price, but instead were subject to the prevailing market prices. Indeed, the Nevada Companies admit that the contract prices were at or below prevailing market prices.[367]

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[359] Ex. CES-2 at 16:15-17:2.

[360] Tr. at 2609:12-2610:6.

[361] Ex. CES-34.

[362] Tr. at 3442:13-3443:6.

[363] Exs. RES-10 at 3:17-18; see also MAEM-78. Mr. Perry stated that Mead was a liquid point to deliver power into California. Tr. at 2796:8-2797:8; Ex. EPME-40.

[364] 99 FERC at 61,191.

[365] Ex. NPC-10 at 3: 1-11; Tr. at 2252:12-17; Exs. CES-1 at 3:15-27; AEP-1 at 3:21-4:16; EPME-22 at 18:6-14; MSC-21 at 8:19-9:8; RES-1 at 4:14-17.

[366] See Exs. S-1 at 28:14-16; CES-1 at 4:2-15; EPME-22 at 19:7-8.

[367] See Nevada Power Companies/Calpine Complaint at 19; Nevada Power Companies/MSCG Complaint at 19; Nevada Power Companies/Reliant Complaint at 18.

137. The evidence shows that the Nevada Companies were not forced to enter into any of the contracts. Tapes of the conversations between Jonathan Perry, the Nevada Companies' principal trader for forward power, and the independent brokers for several of the transactions that are the subject of the Nevada Companies' complaints substantiate the terms of the contracts. In addition, these tape conversations show the context and tone of the negotiations. Thus, the record evidence demonstrates: that the transactions often occur in a matter of seconds, there is no direct communication between the counterparties, and Mr. Perry is relaxed and congenial. The evidence does not show any pressure, uncertainty, hesitancy, or a lack of understanding about what Mr. Perry was purchasing. Instead, the transactions are routine and unremarkable broker trades.[368]

Snohomish:

138. The evidence in this case proves that Snohomish profited from reselling power that it had purchased in the wholesale market during 2000 and early 2001.[369] Snohomish benefited in another way: by entering into the contract with Morgan Stanley (it hedged against fluctuations in the spot market) it protected its ratepayers from additional rate increases.[370] The record also shows that Snohomish's decision to enter into the MSCG contract was reasonable given the circumstances at the time. Finally, the record also shows that Snohomish had other "alternatives" available to it.[371]

139. The evidence presented in this case establishes the chronological sequence of events to the transaction between Morgan Stanley and Snohomish. Several months before negotiating the contract, Snohomish recognized the need to secure additional wholesale power. In October of 2000, the Snohomish's Board authorized Snohomish to enter into contracts to purchase up to 107 MW of power for periods as long as ten years.[372]

140. On December 13, 2000, Snohomish's Board resolved to raise retail rates an average of thirty-five percent. This allowed Snohomish to purchase up to 100 MW of power at a melded cost of up to $125/MWh.[373] The rate increase took effect on January

[368] Ex. MSC-136.

[369] Ex. MSC-132 at 31.

[370] Tr. at 1776: 5-15 (Bulova); *see also* Ex. SNO-4 at 7:15-18; Ex. MSC 81-3.

[371] See id.

[372] Exs. MSC-113; MSC-114; Tr. at 1606:11-1609:23.

[373] Snohomish's 35 percent rate increase occurred prior to Snohomish's negotiating its contract with MSCG, and prior to issuing an RFP for the purchase of power. Exs. MSC-116 at 9-10; SNO-1 at 4:19-5:2. Thus, the $125 is a place holder to cover the costs of the subsequent RFP. Any price paid for power in excess of $125 would not have fit within the new rate structure. Tr. at 1720-23; 1724.

1, 2001.[374] Snohomish issued on December 22, 2000, a Request for Proposal ("RFP") containing three bid "[o]ptions." The RFP's "[o]ptions" reflected just some of the products from which Snohomish could choose.[375] Option A was for the purchase of 50 to 100 MW for one, two, or three years (without a price). Option C had benchmark prices of \$50, \$75, \$100, \$150 and \$200; bidders were to specify the length of contract term necessary to obtain those prices.[376] Snohomish issued this RFP to a total of seventeen entities based on their credit ratings, performance, payment history and a general trading relationship with Snohomish.[377] Five entities responded to the RFP.[378] The RFP specified that Snohomish was not required to select any of the bids submitted in response to the RFP. Snohomish reserved the right to reject any and all bids, and to terminate negotiations at any time. Snohomish could terminate the RFP if the price of power offered by counterparties was too high, a collateral annex term proposed was "onerous or unfair" or the proposed term was too long.[379] Snohomish amended the RFP to permit refreshing of bids.[380]

141. Snohomish received Morgan Stanleys' bid under Option "A" of the RFP for power for periods of one, two or three years with gradually decreasing prices respectively.[381] Snohomish rejected this bid and requested Morgan Stanley to bid under Option "C" for an unspecified term, at a rate of \$100/MWh.[382] Snohomish specifically requested Morgan Stanley to bid "for however many months" to permit Snohomish to purchase power for approximately \$100/MWh. Morgan Stanley complied with Snohomish's request, and submitted a bid for 50 MW for an approximately ten-year term, at a price of

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[374] Ex. SNO-1 at 4; Tr. at 1625, 1719.

[375] Ex. SNO-5.

[376] Ex. MSC-8 at 3-4; Tr. 1735, 1737.

[377] Ex. SNO-4 at 5:6-8; Tr. at 1796:1-15.

[378] Id. Snohomish cites *Teco Power Service Corp*, 53 FERC ¶ 61,202 at 61,810 (1990) to support its allegations of market power. However, this case is inapposite. In the cited case, the Commission stated that it did not intend to apply a rigid numerical sparseness test, nor did it consider that a rigid numerical test is appropriate in determining whether a bidding program is sufficiently subscribed to allay concerns about market dominance in generation.

[379] Exs. SNO-5; Tr. at 1730:15-22; Tr. at 1730:23-1731:1; Tr. at 1731:21-1732:23.

[380] Ex. SNO 10 at 2 ¶ 6; Tr. at 1747:22-23. The amendment allowed bids of 25 MWs. Id. at 1. MSCG and other offerors refreshed their prices due to changing market conditions. Ex. MSC-80.

[381] Exs. MSC-10; MSC-8 at 10; Tr. 1745.

[382] Tr. at 1743:20-1744:5; 1752-53; 3984-85; Ex. MSC-8 at 10.

$100/MWh.[383] In response to a bid from a competitor, Snohomish next requested Morgan Stanley to shorten its offer term by one year, and to extend the delivery commencement date.[384] Snohomish informed Morgan Stanley that a price "slightly over" $100/MWh, might be acceptable for the year shorter term.[385] Morgan Stanley complied with Snohomish's request, and submitted an approximately nine-year bid at a price of $105/MWh for 25 MW.

142. Snohomish and Morgan Stanley then engaged in the process of negotiating the terms of the contract. Throughout the negotiations, Snohomish's goal was to keep the price of the contract to under the $125 "placeholder" established by the Snohomish Board in December 2000, long before the RFP was announced. Shorter terms at market rates were available to Snohomish, but rejected. Morgan Stanley offered to enter into an alternative arrangement of two separate deals, one for five years (at above market prices) and another for five-seven years (at below market prices).[386] This too was rejected. The record conclusively shows that it was Snohomish's choice to pass the risk of price volatility to the seller and pay a below market rate of $105 for the first five years, even if the contract had to be for a longer term.[387] Moreover, Snohomish had the choice of a shorter contract at higher prices, but rejected that choice.[388] Witness Herrling for Snohomish testified that, in January 2001 (when the contract was being negotiated) Snohomish expected spot prices to remain high for no more than a year or two.[389] This was corroborated by witness Adam who testified that it was reasonable to conclude that spot prices would decline to $25/MWh by 2003, once supply and demand fundamentals were corrected.[390] The inference to be made from this testimony is that the primary goal was to get a below market rate at any cost. Thus, the evidence shows that Snohomish voluntarily chose the term of its contract.

143. The negotiations (which included amendments to the WSPP Agreement, the form of confirmation and a collateral annex to manage the parties' credit risks)[391] took place by telephone calls and electronic mail. Snohomish was represented by counsel during the

[383] Tr. at 1749:10-13. Morgan Stanley informed Snohomish that the proposed $100/MWh, ten-year deal was probably "more length" and "more volume" than Morgan Stanley wanted to sell. Ex. MSC-11, Vol II at 51:19-21.

[384] Tr. at 1752:6-11; 1751:18-25.

[385] Exs. MSC-11, Vol. III at 18:19-22; MSC-16, KH 1/25/01 08:07.

[386] Tr. 3992-93.

[387] Tr. at 1586-87, 1592; 1758; 3993-94.

[388] Tr. at 1776.

[389] Tr. at 1866.

[390] Tr. at 2120-21.

[391] Ex. MSC-8 at 8:1-7.

negotiations of the contract.[392] Snohomish dictated the deadlines to complete negotiations and several of the contract terms.[393] Snohomish submitted to MSCG a proposed margining agreement when it learned that Morgan Stanley was concerned about Snohomish's credit.[394] Morgan Stanley witness Hamdan testified that Morgan Stanley valued its business relationship with Snohomish, and thus felt it was under significant pressure to enter into the deal with Snohomish by Snohomish's deadline of midnight on January 26, 2001.[395] This testimony is credible. The evidence demonstrates that, shortly after Snohomish entered into the contract, it touted to its customers that the Morgan Stanley and other long-term contracts "give us a lot of security against the uncertainty of market fluctuations," and that the contracts insulate the ratepayers from market volatility.[396] Snohomish expected, based on its forward curve (April 2001), that its contract with Morgan Stanley would provide Snohomish with power at a price far below market for at least two years.[397]

144. The evidence establishes that Snohomish had several other available alternatives as well, including: (1) continuing to purchase power in the spot market; (2) executing a forward contract for a term shorter than the term of the Morgan Stanley contract; (3) contracting for a share of a new generation plant or building its own generation; (4) purchasing a put option contract,[398] and/or (5) entering into two separate agreements with a total term of nine years with one or two counterparties.[399]

<u>SCWC:</u>

145. The record in this case establishes that in 1996, SCWC ended its status as a full requirements customer and began purchasing energy from the deregulated market. In early 1999, SCWC retained a consulting firm, Complete Energy Services ("CEServices"), for advice on power purchasing and market monitoring.[400] In consultation with CEServices, SCWC began to purchase minimum load capacity needs through block forward contracts of one year duration, while purchasing from the PX spot market to meet

[392] Ex. MSC-55 at 7:21-23.
[393] Tr. at 1762:15-17; 1762:18-22.
[394] Exs. MSC- 19; MSC-8 at 15:1; MSC-177 at 26.
[395] Tr. at 3938:3-3938:6, 3942:12-16, 3945:15-24.
[396] Ex. MSC-83 at 6; Ex. MSC-78 at 7:10-12.
[397] Ex. MSC-37 at 22:22-23:3, Ex. MSC-50. If Snohomish had purchased a short-term contract for 25 MW for the remainder of 2001, it would have needed to raise its rates an additional 11 percent to cover this exposure. Tr. at 1776:5-15; Ex. SNO-4 at 7:15-18.
[398] Ex. MSC-98 at 38:2-39:8.
[399] MSC-11, Vol. III at 22:19-24:17; Ex. MSC-16, KH 1/25/01.
[400] Ex. SCW-1 at 8:11-17.

peak load.[401] SCWC testified that this strategy was successful, permitting it to avoid market volatility and achieve savings – approximately $13.26 million from 1999 through April 2001 – as compared to the costs SCWC would have incurred had it purchased exclusively from the centralized spot markets.[402]

146. SCWC was an active participant in the competitive power markets. SCWC transacted as a buyer and seller, in both the spot and forward wholesale markets.[403] SCWC actively monitored electricity markets through CEServices, and had full access to forward price information through daily monitoring of sources such as Platt's, Enerfax, NYMEX, the Intercontinental Exchange, and EnronOnline and, if needed, by calling suppliers for price quotes.[404] Mirant relied on similar sources.[405]

147. The evidence establishes that in the spring of 2000, the baseload contract with Illinova finished and SCWC had to replace it. SCWC considered, but rejected, entering into a block forward contract for a term greater than one year. SCWC was aware that spot market prices had risen substantially above historical levels, and well above the $35.50/MWh one-year contract with Dynegy that it had executed for service beginning May 1, 2000.[406]

148. Notwithstanding the high prices that SCWC was observing and the increased market volatility, SCWC made a decision to wait until early March 2001 to issue an RFP to replace the one-year contract it knew would expire on May 1, 2001.[407] SCWC testified that it had to issue an RFP at the "peak" of the energy crisis – seemingly through no fault of its own.[408] The evidence does not support this contention. It is apparent that SCWC made its own choices based on the information available to it at the time and thus made informed decisions. SCWC followed a consistent procurement strategy that relied upon one-year contracts from third-party suppliers.[409] SCWC's existing one-year baseload contract was due to expire in May 2001 and by March 2001, SCWC had made little progress in securing a replacement source of firm energy. SCWC has not proffered any evidence of why it waited until March 2001- to cover a position it knew was impending. There is a lack of evidence of any reasons that prevented SCWC from seriously pursuing

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[401] Ex. SCW-1 at 11:1-12:10.
[402] Ex. SCW-1 at 11:3-14.
[403] Tr. at 2878:23 to 2879:16; Ex. SCW-1 at 16:5-7.
[404] Tr. at 2875:8-16 (Dickson); Ex. MAEM-68 at 82-83.
[405] Ex. MAEM-2 at 7:14-18.
[406] Tr. at 2884:6-24.
[407] Ex. MAEM-68 at 99:10-20; Tr. at 2889:10 to 2891:11.
[408] Ex. SCW-1 at 12:5-10.
[409] Ex. SCW-1 at 24:14-16.

other options well before March 2001. Thus, the record supports the finding that SCWC simply chose to wait until that time before it was willing to issue an RFP and negotiate a new contract.

149. On March 7, 2001, SCWC issued an RFP, prepared largely by its consultant David Kolk at CEServices, to initiate a competitive bidding process.[410] Prior to issuing the RFP, Dr. Kolk and an SCWC manager contacted suppliers and narrowed down the list of RFP recipients to six, including Mirant.[411] The RFP restricted bidders to terms ranging from one to seven years,[412] indicated a preference for fixed price offers,[413] and a price in the range of $90.[414] Three different responses were received with varying options, permitting SCWC to choose the most favorable offer.[415] SCWC made no subsequent effort to seek out other offers, consult a broker, or reissue the RFP to get other proposals.[416]

150. The evidence reflects that Mirant knew it had to compete for the sale.[417] Mirant offered a price quote of $89/MWh for a five-year contract, starting April 1, 2001, (SCWC's RFP had asked for a contract to begin "as soon as possible").[418] Mirant's indicated price quote was based on its forward price curve. Mirant subsequently refreshed its offer(s) based on its forward prices curves, over the following two days of negotiations.[419] Mirant's practice is to price forward sales from its own forward price curves, as explained by witness Schaefer.[420] The forward curves reflected Mirant's best

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[410] Tr. at 2893:4-18.

[411] Tr. at 2893:19-2894:20; Ex. SCW-1 at 17:1-8.

[412] Tr. at 2900-02.

[413] Tr. at 2903.

[414] Exs. MAEM-2 at 13; MAEM-9; Tr. 2904-5. Tr. at 2901:1-4; 2903:3-7; Exs. SCW-4 at 12; SCWC-1 at 12:5-10; 24:10-12.

[415] Tr. at 2894:21-24; 2944:10-17. SCWC's fifty percent response rate to its RFP in 2001 was actually a better response rate than SCWC received when it issued a similar RFP for a baseload contract in early 2000 – before the California energy crisis began. At that time, SCWC received just two responses. Tr. at 2897:19-2899:9.

[416] Tr. at 2897:8-18.

[417] Exs. MAEM-2 at 19; MAEM-2 at 10:6-9. Mirant transacted with twenty-seven different entities at SP15 in the month of March 2001. Ex. MAEM-39. SCWC states that it was aware there were more than fifteen or sixteen different entities supplying wholesale power at SP15 – a sufficient number "to ensure that we were getting a competitive bid." Tr. at 2894:9-14 (Dickson).

[418] Ex. MAEM-2 at 13:1-12 & 14:5-7.

[419] Ex. MAEM-2 at 14:5-7.

[420] Ex. MAEM-2 at 7:12-26.

estimate of expected future spot prices,[421] and are driven by expectations of future market fundamentals.[422]

151. According to unrebutted evidence submitted in this case, Mirant relied on forward curves specifically developed to price power for delivery at SP15.[423] At the time, Mirant and SCWC were discussing the contract, forward prices were increasing. As a result, when Mirant repriced its offer on March 16, 2002 in response to SCWC's $92/MWh counter-offer, the refreshed price was $95/MWh.[424] Mirant's initial and subsequent price offers remained close to the price range of $90/MWh or less that SCWC's consultant testified he was expecting to receive in response to the RFP.[425]

152. SCWC's lead executive in charge of executing the contract, Mr. Joel Dickson, was a seasoned negotiator.[426] There is a lack of evidence that anyone from SCWC, including Mr. Dickson, attempted to negotiate non-price terms during the parties' discussions from March 14 to March 16, 2001, including any specific modifications to the WSPPA, to permit SCWC to seek unilateral modifications to the contract.[427]

153. The $95/MWh price was substantially below the then-prevailing expected future spot market prices for the remainder of 2001 through the summer of 2002.[428] The evidence in this case shows that SCWC expected prices to drop in the fall of 2001. [429] Notwithstanding this fact, it chose to enter into this contract. As a result, Mirant took on the market risk, when it agreed to sell to SCWC at $95/MWh. The savings to SCWC were front-end loaded and provided stability and price protection from volatility for SCWC. Conversely, Mirant agreed to take an up-front loss in the early years of the contract, with the expectation that the losses would be made up in later years.[430]

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[421] Ex. MAEM-38 at 7:7-9.

[422] Ex. MAEM-2 at 8:8-16.

[423] Offers at any other trading hubs in California or Palo Verde would have involved the risk of transmission congestion costs. Tr. at 2900:13-17; Ex. MAEM-68 at 65:4-21.

[424] MAEM-2 at 14:13-15 & 15:8-16.

[425] Exs. MAEM-68 at 111:10-13; MAEM-2 at 13:16-18; MAEM-9.

[426] Tr. at 2876:22-2877:5.

[427] Ex. MAEM-2 at 20:23-21:4.

[428] Exs. MAEM-2 at 13:24-28 & 20:8-9; SCWC-4 at 4.

[429] Tr. at 2927:11-2928:1.

[430] Ex. MAEM-2 at 20:12-18.

154. Mirant's business practice is to hedge forward delivery obligations with transactions at the same delivery point.[431] The record reflects that Mirant entered into various transactions at SP15 over the next month, which could be used to hedge its sale to SCWC.[432] In some of the indicated hedge transactions, Mirant ended up paying approximately $232/MWh in 2001, substantially more than the $95 in its contract with SCWC.[433] Mirant expected it would recoup initial losses during the "out years," where Mirant's hedge transactions are less than $95/MWh.[434] Mirant witness, Dr. Stephen Henderson, performed a net present value analysis of these various near-term and far-term hedge transactions, and concluded that Mirant stands to earn a profit margin (if any) only if the SCWC contract price is honored throughout the entire term of the contract.[435]

155. Additionally, Dr. Henderson testified that any margin Mirant may earn would not be excessive, "especially in light of the high price volatility that characterized the forward markets during this period."[436] SCWC's consultant agreed that Mirant would likely hedge its SCWC contract immediately.[437] Accordingly, the record in this case substantiates the finding that modification of the price of the SCWC contract would provide a windfall to SCWC, since, in effect, SCWC will have bought power from Mirant during 2001 at a significant discount to market prices," and Mirant will loose its ability to earn a return on its risk in later years.[438]

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[431] Tr. at 3349:6-16.

[432] Exs. MAEM-2 at 9:5-10:2; MAEM-7.

[433] Ex. MAEM-2 at 25:1-5.

[434] Ex. MAEM-2 at 9:8-10:2; 24:22-25:9. SCWC questions Mirant's inclusion of certain indicative hedge transactions with Enron. The hedge transactions with Enron were terminated before they had gone to delivery. These hedge transactions represent costs incurred and risk for Mirant associated to the SCWC Contract. According to Mirant, when it entered into its hedges it essentially locked in its margin (if any) on the SCWC contract. Mirant's position with respect to the SCWC transaction did not change due to the early termination of four of the hedge transactions. Mirant's arguments are persuasive, *e.g.*, Mirant's liquidated damages expenses (the mark-to-market exposure on the contract for terminating the contracts early) in this case, are approximately $19 million associated with the terminated Enron contracts. Tr. at 3342:8-20.

[435] Dr. Henderson stated "it seems clear that [Mirant] lost a substantial amount of money under the SCWC contract during the period from April 1, 2001 to December 31, 2001." Exs. MAEM-16 at 32:14-16; MAEM-16 at 28:5-15; 33:13-34:3.

[436] Ex. MAEM-16 at 33:6-8.

[437] MAEM-68 at 128:5-13. Staff also recognized Mirant's risks. Ex. S-1 at 28.

[438] Ex. MAEM-16 at 34:15-19.

156. SCWC's witness Dickson's testimony is contradictory and thus, not credible. For instance, in his rebuttal testimony, Mr. Dickson's claims that SCWC thought in mid-March 2001, that "FERC would do very little" to remedy spot market dysfunctions.[439] However, Mr. Dickson admitted that "FERC was being pressured from many quarters to provide relief for California consumers,"[440] and he asserted that Mirant should have anticipated the possibility of Commission action to modify its contract.[441] SCWC's consultant, Dr. Kolk, testified more candidly. He admitted that future prices were simply difficult to predict with certainty.[442] Moreover, Mirant's witness testified that Mirant was aware that "FERC was under pressure" to adopt more severe price limitations, but ultimately "it was impossible for Mirant to predict with any degree of certainty what mitigation measures would be in place for [California and nearby] spot markets."[443] Both parties testified that they did not expect the high prices to last indefinitely.[444]

157. SCWC also had available to it and actively explored a variety of resource options. The record shows, for instance, in October 2000 (after a summer of high prices) Dynegy offered to extend its contract with SCWC, based on a "blend and extend" rate of between

[439] Ex. SCW-11 at 9:2-4.

[440] Ex. SCW-11 at 13:10-13.

[441] Mr. Dickson also testified, that based on his discussions with CEServices, he thought the dysfunctions would last until the summer of 2003, when he expected sufficient new generation would come on line. (Ex. SCW-1 at 22:11-14). However, this is not credible since it is not supported by his actions of agreeing to a contract with duration through 2006. SCWC could have accepted a shorter contract of sufficient duration to hedge against volatility through the summer of 2003 (Tr. at 2944:10-17) but did not. SCWC's consultant at CEServices confirmed that analysis of the spot market dysfunctions was not a driving factor in SCWC's procurement strategy and, indeed, that his own analysis of those dysfunctions was "irrelevant" to what SCWC was looking at. Ex. MAEM-68 at 147:3-11.

[442] Ex. MAEM-68 at 86:2-4.

[443] Ex. MAEM-2 at 12:3 & 12:10-12.

[444] Tr. at 2925:23 to 2928:1; Ex. MAEM-2 at 11:4-6. SCWC asserts that any reasonable seller should have expected SCWC to file a complaint if FERC did not take "broader based" action for price relief in Docket No. EL00-95-000. Ex. SCW-11 at 13:8-10. SCWC based this statement on the existence of the $74/MWh advisory benchmark price as of mid-December 2000. SCWC's arguments are meritless. There is no record evidence to support its allegations. The RFP never specified a target price of $74/MWh and there is no record evidence that any representative from SCWC told Mirant that it sought a price of $74/MWh. Moreover, SCWC's assertion could call into question its intentions at the time it signed this contract.

$46.50/MWh to $54.50/MWh, depending on the term of the extension.[445] Moreover, SCWC and Enron discussed in November 2000, a contract for differences by which SCWC could hedge costs at $55.73/MWh.[446] Also, SCWC could have chosen to rely on the spot market. Additionally, SCWC could have entered into a shorter term block forward contract for the Summer of 2001. SCWC had a variety of responses to its RFP, from which it could have chosen a proposal other than Mirant's, including contracts for less than five years. The record also shows that, beginning in 1999, CEServices prepared and continually updated a Strategic Energy Plan (SEP)[447] making recommendations on numerous supply options available to SCWC.[448] SCWC's SEP specifically discusses using a "call" arrangement (SCWC would pay a monthly capacity charge for the right to purchase energy at a price tied to natural gas costs, rather than committing to a long-term purchase).[449]

158. Staff witness Tingle-Stewart testified that the structure of SCWC's RFP limited the options available to it – "by ruling out, up front, contracts of less than one year, variable price contracts, and contracts with prices higher than the $90 range, SCWC made a conscious decision to take the risk that its price projections would hold true."[450] The record supports a finding that if there were "limitations" on resource options available to SCWC, then these were the result of SCWC's calculated decisions.

159. Like Snohomish, SCWC in order to obtain a certain price upfront, imposed conditions on the bidders which locked in a contract of several years. In fact the record shows that SCWC believed it would have to agree to a contract of at least five years to be able to get the price it wanted.[451] The record evidence establishes that SCWC agreed to the contract in spite of the fact that it did not expect high prices to persist for long due to a number of things: California streamlining authorizations for new generation; demand shifts from spot to forward markets; the effect of FERC decisions.[452] Thus, SCWC chose to avoid price volatility by shifting the risks on to Mirant. Under these circumstances, contract modification is not warranted.

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[445] Exs. MAEM-16 at 21:6-22:2; MAEM-24; MAEM-25.

[446] Exs. MAEM-16 at 20:11-21:3; MAEM-22; MAEM-23; Tr. at 2888:10-19 (Dickson).

[447] Exs. MAEM-17; MAEM-18 at 6:6-20.

[448] Ex. MAEM-17 at 14-15. Alternatives included contracts for options, swaps and contracts for differences. Exs. MAEM-16 at 10-11; S-14.

[449] Ex S-14.

[450] Ex. S-6 at 36:13-16.

[451] Tr. at 2927.

[452] Tr. at 2924-26; 2965; 2926;.

160. The evidence in this case also demonstrates that contract modification would destroy investor confidence and threaten the viability of bilateral forward markets. An investment banker with thirty years experience (including credit risk management) testified that performance of the competitive wholesale market "has mirrored the performance of companies in other deregulated industries," with price volatility, among others, causing deterioration of the "overall credit quality of the industry participants."[453] If an industry has "weakened capital structures and volatile industry dynamics, predictability of cash flow becomes important in assessing risk… [and use] of financial hedging instruments and fixed-rate forward contract[s] are important tools in building predictability of cash flow."[454] Energy merchants rely on forward contracts, in an industry with volatile markets, to provide "stable and predictable cash flows" that "bolster their substantial credit requirements and support ongoing trading and marketing operations."[455] This testimony is entitled to substantial weight. The testimony was not contradicted by any other testimony in this case and the testimony is from a financial expert with years of experience in investments.[456]

161. The evidence in this case indicates that abrogation or modification of these contracts will harm credit and investor confidence by altering the perception of a formerly stable cash flow into an undependable, risky cash flow.[457] Moreover, the evidence in this case demonstrates that modification of the contracts would cause market participants to suffer adverse credit and financial consequences, which could lead to hesitancy to enter into forward contracts, because of the uncertainty of the enforceability of such contracts.[458]

162. As witness Boland testified, if there is a perception of unstable cash flow triggered by contract modification, this would result in a "domino effect." This could

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[453] Ex. EPME-20 at 6:14-17.

[454] Id.

[455] Exs. EPME-20 at 3:1 n.2; EPME-20 at 7:10-13.

[456] Dennis Schiffel, an employee of the Nevada Companies, asserts that modification of contracts will not have an impact on investor confidence in the market. Ex. NEV-4. This testimony does not rebut the testimony cited above. Snohomish witness McCullough also asserts that contract modification will provide notice to the market that the Commission will act to protect markets from the exercise of market power and market manipulation. This unsubstantiated testimony does not rebut the testimony cited above. Therefore, it is found that Complainants' arguments in this regard are not persuasive.

[457] Ex. EPME-20 at 8:9-13.

[458] Suppliers may be reluctant to enter into forward contracts and take on the regulatory risk and uncertainty that the Commission could modify contracts in the future. Exs. RES-10 at 6:19-23; BP-1 at 10:16-21, 11:18-12:18; MSC-7 at 9:9-10.

cause the following: (1) some investors may view the regulatory risk for the energy merchant sector to be too unpredictable and avoid committing capital to this sector in the future;[459] (2) abrogation or modification of the contracts could be a signal that FERC would be willing to do the same for any other buyer or seller, which would cause an industry-wide impact; (3) energy merchants with generation assets financed, directly or indirectly, with project finance debt, could find themselves in a payment default on debt obligations or a covenant default relating to project or financing agreements, or both; (4) the creditworthiness of energy merchants could be adversely impacted; (5) an energy merchant's financial flexibility and liquidity could deteriorate if the contracts modified or abrogated constitute a sizeable portion of the merchant's expected revenue base; (6) an energy merchant could suffer credit deterioration that forces it to incur additional costs to comply with requirements to post additional cash collateral or letters of credit to back up trading positions.[460]

163. Respondents argue that the fact that the Commission set these cases for hearing has itself increased uncertainty in the power markets. In support, they cite reports discussing rating downgrades in the U.S. power and energy sector, which exceed ratings upgrades by a ratio of 5:1.[461] Another factor mentioned by Respondents is that suppliers would be discouraged from entering into contracts, especially at times of short supply when suppliers are most needed. This, in turn, would raise prices by removing the disciplining effect of the threat of entry on forward prices."[462] Furthermore, Respondents maintain that modifying the contracts at issue in this case may require energy merchants to unwind "a hedged position vis-à-vis forward fuel or power purchases made to fill forward power sales."[463] This will leave the energy merchant "with an out-of-market gas or power purchase contract, a stranded investment in generation assets, or both.[464] Drs. Hogan and Harvey also explain that permitting regulatory reform of contracts "could have worse effects on forward markets than permitting abrogation if sellers that entered into forward contracts risked being required to provide price hedges that would be uneconomic based on the 'reformed contracts.'"[465] These statements are supported by record evidence and are persuasive.

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[459] Given the significant on-going capital requirements of industry participants, such a reduction in available capital could hamper the growth of energy merchants and restrict their ability to meet future energy needs.

[460] Ex. EPME-20 at 4:5-10.

[461] Exs. EPME-41 at 9; MAEM-77.

[462] Ex. MSC-65 at 147:14-18.

[463] Ex. EPME-20 at 5:5-.

[464] Ex. EPME-20 at 5:7-9.

[465] Ex. MSC-1 at 30:20-31:2.

164. These are serious consequences which could erode investor confidence and willingness to invest in merchant energy projects. This, in turn, could have an adverse effect on infrastructure development, especially at a time when Western markets need new generation and transmission. Additionally, this could have detrimental effects on Commission efforts to promote and develop competitive wholesale power markets. Furthermore, contract modification in this case could result in increased prices to compensate for increased risks.[466] Respondents' witness, Professor Kalt, states that abrogation of contracts would increase the price thresholds at which generators would choose to invest, raising the overall level of competitive prices to consumers. He further states that competitive prices rise when there are greater risks, because competitive prices must compensate generators for the risks they undertake when investing in new plant(s).[467] This testimony is entitled to substantial weight.

165. Additionally, modification of these long-term contracts may preclude sellers from ever making a profit on the transaction. Staff's arguments in this regard are persuasive. Resetting a contract rate now, based upon today's forecasts, raises the possibility that the contract may have to be revisited again in the future, based upon future events. Either result would interfere with competitive markets. Many of the sellers in this case did not own generation or have generation assets that serve the market in question.[468] Under these circumstances, the sellers must purchase power in the open market at prevailing market rates. The record in this case establishes that Respondents covered their forward contracts by purchasing hedges, or forward contracts of their own.[469] The record establishes that Respondents entered into hedging arrangements when the overall balance of their portfolios demanded it, based on their own internal risk parameters.[470] As a

[466] Exs. MAEM-2 at 26:17-21; MSC-7 at 8:20-22.

[467] Ex. EPME-1 at 73:8-13.

[468] Morgan Stanley Power Development Corp, a wholly-owned subsidiary of Morgan Stanley, has an ownership interest in Naniwa Energy LLC, which owns a 360 MW peaking plant in McCarren, Nevada. This plant did not commence commercial operation until the end of June 2001 (after the relevant period in this case). Ex. MSC-7 at 4:10-13. El Paso owns or controls under 80 MWS of generation and does not own or control any transmission or distribution facilities in the WECC and has no retail load obligations in the WECC. Ex. EPME-22 at 3:21-4:14.

[469] Exs. MAEM-2 at 25; MSC-7 at 3 and 10; EPME-22 at 22; Tr. 3014-15; 3030, 3433-35; 3445; 4208; MSC-21 at 18:4-5. Morgan Stanley hedges its entire position in the WSCC power market and adjusts its overall power portfolio on a daily basis. The practical effect of the Snohomish/Morgan Stanley contract is that, Mogan Stanley essentially lent Snohomish money at the front end for expected value at the back end. Ex. MSC-21 at 18:22-19:4.

[470] Tr. 3194, 3198.

result, it is difficult to determine the costs of the hedging contracts with the contracts at issue in this case.[471] It is a reasonable inference, supported by the record, to find that Respondents were paying prices in the same price range as those reflected in the contracts in dispute, due to the fact that they were buying the hedges in the same market as they were selling to the Complainants in this case. Additionally, to the extent a seller was hedging a long term contract, such as Snohomish's or SCWC's, which have prices below market upfront, the seller likely hedged the contract with high-cost power upfront for which it will not be reimbursed until later years.[472] Consequently, reformation of the contracts is not warranted in this case.[473] To conclude otherwise would deprive Respondents of the benefits of their bargains, since they have already incurred costs associated with these contracts, either through hedging the contracts or delivery of the power.[474] As Staff witness Forman testified, "it would cast a pall over any future negotiations, and possibly increase the sellers' risk-related costs, if a seller always had to be concerned that the market in which it was participating at the moment might later be found to be "dysfunctional" and contracts entered into during the period of dysfunction made subject to retroactive adjustment."[475] The record supports the finding that Complainants have failed to prevail on this issue and therefore, these contracts should not be modified.

166. The findings and conclusions above demonstrate that Complainants failed to show adverse effects warranting contract modification. As a matter of fact, the evidence shows that it would be contrary to the public interest to modify the contracts at issue in this case.

Issue IV. Whether the term of the contract and the collateral annex between the Public Utility District No. 1 of Snohomish County, Washington and Morgan Stanley Capital Group Inc. are contrary to the public interest?

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[471] Respondents argue that the Commission's advisory benchmark is not relevant to the contracts at issue in this proceeding. The Nevada Companies' contracts do not fall within the parameters of the advisory benchmark (they had shorter terms and were standardized contracts, for either on-peak or off-peak delivery, not round-the-clock). Moreover, the advisory benchmark was based on rates of return approved for the California IOUs. These arguments are persuasive. Additionally, it is found that the issue is moot based on the resolution of Issue number II, above.

[472] Tr. at 3022-23.

[473] Morgan Stanley would incur losses if the contracts are modified. Tr. at 4302:18-20; Tr. at 4302:20-22.

[474] Mirant suggested that it has incurred an average price of over $232/MWh to cover the cost of power delivered to SCWC in 2001 at a contract price of $95/MWh. Ex. MAEM-2 at 25.

[475] Ex. S-1 at 31.

A. Parties Contentions:

167. Snohomish requests that the Commission either immediately terminate or substantially reform the collateral annex ("collateral annex").[476] As a threshold matter, Snohomish argues that the just and reasonable standard, rather than the public interest standard applies to the evaluation of the annex.[477] The Commission did not address the applicable standard for the annex.[478] Snohomish avers that the dysfunctional market lead to the implementation of the annex.[479] Snohomish argues that, due to the high electricity prices in the spot market, it sought to fill between 75 and 100 megawatts in the long-term market.[480] Only three firms offered to supply 25 megawatts each, with Morgan Stanley offering this amount at $105 per megawatt hour, for a nine-year term and subject to a collateral annex.[481] Snohomish considered these terms too long in duration, and the prices unjust, unreasonable, and contrary to the public interest.[482]

168. Snohomish contends that the annex is unreasonable on its face.[483] Morgan Stanley required acceptance of the annex as a condition to the underlying contract for power.[484] Snohomish's past experience with creditworthiness agreements, namely, with the Bonneville Power Administration and the WSPP agreement, are less onerous than the terms and conditions of Morgan Stanley's annex.[485] In addition, Snohomish contends that, at the time of negotiations, they did not understand how the annex "works in practice."[486] Further, Snohomish argues that Morgan Stanley knew that the annex was unreasonable and that such a requirement was not even a typical part of Morgan Stanley's past transactions.[487]

169. Snohomish also alleges that since it poses minimal risk, the collateral annex is not even necessary, since several independent rating agencies have given Snohomish high

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[476] Snohomish IB at 1.
[477] Id. at 1.
[478] Id. at 1-2.
[479] Id. at 2.
[480] Id. at 2-3.
[481] Id. at 3.
[482] Id.
[483] Id. at 3.
[484] Id. at 3-4.
[485] Id. at 4.
[486] Id.
[487] Id. at 5.

credit ratings.[488] Further, Snohomish's structure minimizes credit risk, since their governing Board of Commissioners can independently set rates, and by statute, Snohomish is required to set rates and maintain revenue sufficient to recover the cost of power.[489] In fact, a month prior to execution of the Morgan Stanley contract, Snohomish implemented a rate increase sufficient to pay for the contract.[490] In addition, Snohomish is also less risky than others entities for the following reasons: Snohomish's revenues are derived directly from the final customers, Snohomish hedges its contract position with Morgan Stanley, Snohomish is required to maintain a minimum debt coverage, Snohomish's bond covenants prioritize payments to creditors (such as Morgan Stanley), Snohomish's internal risk management policies prohibit risky purchase commitments, and Morgan Stanley was aware that Snohomish posed a low credit risk.[491]

170. Snohomish accepted the collateral annex because Morgan Stanley Capital Group refused to hold its prices firm.[492] In addition, the collateral annex poses a threat to the Commission's fundamental policy of achieving robust wholesale electric markets, for the following reasons.[493] First, as applied to a load-serving entity like Snohomish, the annex produces a perverse result, whereby the collateral requirement moves in the opposite direction of the credit risk.[494] Second, in other commodity markets, including electricity, collateral requirements are not favored as credit risk management tools in over-the-counter bilateral contracts, and thus, are not widely used in the industry.[495] Third, should such use become prevalent, the industry's recent credit problems could increase.[496] Fourth, terms such as those in the annex, significantly increase barriers to entry, increase financing costs, transaction costs, administrative costs/burdens, and total power-supply costs.[497]

171. The collateral annex includes various onerous terms and thus, should be immediately terminated.[498] These terms include Morgan Stanley's role as valuation agent, whereby it exclusively can select the applicable forward price curves and discount rate, upon which the collateral demands are based, and this provision is not typical in the

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[488] Id. at 5- 6.
[489] Id. at 6.
[490] Id.
[491] Id. at 6-8.
[492] Id. at 9.
[493] Id. at 10.
[494] Id.
[495] Id. at 10-11.
[496] Id. at 11.
[497] Id.
[498] Snohomish IB at 12.

industry.[499] In addition, Snohomish maintains that Morgan Stanley's forward price curves are miscalculated, lack factual support and/or are based on sheer speculation.[500] Moreover, Morgan Stanley's discretion over selection of the discount rate allows them to arbitrarily raise the level of collateral, they have frequently abused their authority in administering the collateral annex and their setting of a low threshold amount is unduly discriminatory toward Snohomish.[501] The collateral annex does not allow: adequate time to post collateral, the earning of interest on cash collateral, adequate protections for posted funds, nor are the conditions governing the dispute resolution provisions fair.[502]

172. Under the collateral annex, Snohomish has incurred unnecessary costs. This includes $101 million in posted funds, $419,000 in related costs and the encumbrance of assets used to support credit lines opened to provide the collateral. This could increase interest costs, which, in turn, could lead to higher rates.[503] Moreover, Morgan Stanley is protected from risk even in the absence of the annex, since Morgan Stanley could seek liquidated damages equaling the mark-to-market value of the contract if Snohomish terminates the contract.[504] Snohomish avers that Morgan Stanley's true motive for seeking the collateral annex is for increased leverage for future negotiations.[505] Finally, Snohomish argues that Morgan Stanley's rejection of Snohomish's suggested alternatives to the collateral annex, such as a surety bond, are not justifiable.[506]

173. Morgan Stanley asserts that The MSCG/Snohomish Contract and the collateral annex cannot be modified without proving they are contrary to the public interest. The Commission stated that parties such as Snohomish who seek contractual modification carry a heavy burden requiring a showing of extraordinary circumstances.[507] Further, the *Mobile-Sierra* doctrine is the applicable standard for the Snohomish contract and collateral annex, which requires proving that the rate could adversely affect the public interest.[508]

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[499] Id. at 13.
[500] Id.
[501] Id. at 14-15.
[502] Id. at 15-16.
[503] Id. at 17.
[504] Id. at 18.
[505] Id.
[506] Id. at 18-19.
[507] Morgan Stanley IB at 4.
[508] Id. at 4.

174. In addition, Morgan Stanley avers that there are two standards, one stricter than the other.[509] Snohomish's claims must be reviewed under the stricter public interest standard of review, because the case meets the necessary criteria, the contract meets the just and reasonable standard, and there has been a unilateral challenge to a contractual term.[510] Snohomish's claim is similar to its claims in another case, which the court dismissed, after applying the stricter public interest standard, and so, its claims in this proceeding should suffer the same fate.[511]

175. Snohomish failed to prove that the term of the contract impairs its financial ability to continue to serve its ratepayers. According to Morgan Stanley, Snohomish failed to prove that the term of the contract is excessively burdensome on wholesale and retail customers, since Snohomish's evidence consisted of only the conclusory opinions of six ratepayers.[512] Snohomish failed to establish that the term of the contract is unduly discriminatory, since the existence of contracts with shorter terms does not prove discrimination, in the absence of other evidence.[513]

176. Snohomish did not prove that the collateral annex violates the public interest. Morgan Stanley argues that it did not act unreasonably in administering the collateral annex, the terms of the annex are fair, and the *Mobile-Sierra* public interest standard of review applies to the collateral annex since the Commission already decided that the public interest standard applies to the contract.[514]

177. Snohomish's challenges to the collateral annex are unfounded and contradicted by its own records and witnesses. Specifically, Morgan Stanley contends that its role as the valuation agent does not give it an undue advantage over Snohomish, in that Snohomish is at liberty to conduct its own mark-to market and exposure calculations.[515] Second, Snohomish's contention that Morgan Stanley's forward price curves are speculative or fabricated based on duration, lacks merit, since Snohomish's files contain forward price curves (predating their complaint) extending to the year 2008 and Snohomish's expert lacked knowledge of how Morgan Stanley derived its curve.[516] Third, Morgan Stanley has acted in a commercially reasonable manner in administering the collateral annex. Fourth, Snohomish cannot complain about the dispute resolution provision, since it

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[509] Id. at 6-7.
[510] Id.
[511] Id. at 7-8.
[512] Id. at 9.
[513] Id. at 11.
[514] Id. at 12.
[515] Id. at 13.
[516] Id. at 13.

understood and accepted the provision.[517] Fifth, Snohomish cannot complain about the lack of provision in the Annex for interest payment(s) on cash collateral since it applies to both parties equally and Snohomish has never posted any such cash collateral.[518]

178. Moreover, Snohomish's contention that Morgan Stanley refused to reduce Snohomish's posted collateral is incorrect because Snohomish delayed for several months to demand a collateral reduction and when requested, Morgan Stanley agreed to it.[519] Morgan Stanley also avers that the opinion of Snohomish's witnesses should be accorded little weight because neither witness was qualified in credit risk management nor did either witness analyze the annex with the requisite care, diligence, and objectivity.[520] In addition, Staff's witness, Mr. Shriver, failed to understand that Morgan Stanley's discretionary role as the Valuation Agent is constrained by the provision requiring good faith and a commercially reasonable performance, with the term defined under both the Uniform Commercial Code and Commission application in past contract disputes.[521] Finally, the annex does not impair Snohomish from providing continued service, nor does it impose an excessive burden or unduly discriminate against third parties, but is just and reasonable and a sound credit risk management tool consistent with the public interest.[522]

179. Morgan Stanley alleges that utilities may have a strong public credit rating one month and may not be a creditworthy entity a few month(s) later. It asked that judicial notice be taken of the fact that from 1997 to 2002, Standard and Poor ("S&P") decreased public ratings of at least forty-four load-serving entities below investment grade and submitted an exhibit attached to its reply brief.[523] Modification of the collateral annex will have a chilling effect on the wholesale power market, Morgan Stanley maintains. Additionally, the Commission should not substitute its judgment for the business judgment of market participants who must analyze and manage credit risk on a daily basis, according to Morgan Stanley.

180. Staff argues that the appropriate standard of review for the collateral annex is "just and reasonable." According to Staff, the collateral annex is unjust, unreasonable and unduly discriminatory because it gives Morgan Stanley advantages *vis-ả-vis* a "monopolistic load-serving entity posing little risk of default in light of less onerous provisions that MSG could have used to mitigate its risk adequately, and in light of the

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[517] Id. at 14.
[518] Id.
[519] Id.
[520] Id. at 15.
[521] Id. at 16-17.
[522] Id. at 17-18.
[523] Morgan Stanley RB at 12.

circumstances under which the parties executed the contract." Staff argues that the contract did not waive the parties § 206 rights with respect to the terms and conditions (as opposed to the rates) and that the Commission has never reviewed this collateral annex. Morgan Stanley and Snohomish limited the *Mobil- Sierra* clause to "rates," thus, allowing for the just and reasonable standard to apply to provisions not imbedded within the common definition of rate. Staff concludes that the collateral annex is unjust and unreasonable because: it designates Morgan Stanley as the sole valuation agent (determines the amount of collateral either party must post); Morgan Stanley as sole valuation agent determines the "Mark-to- Market Value" (the amount that the non-defaulting party would have to pay to a third-party to fulfill the defaulting party's obligations, minus a threshold amount based on the party's credit rating); the Valuation Agent can set the discount rate (Morgan Stanley's estimate of its own internal cost of borrowing) and the forward price curves.

181. According to Staff, the discount estimate lacks transparency since it is not a public rate, and verification would be difficult. There is a possibility this discount rate may be low because Morgan Stanley would provide itself a low and economical interest rate. A low discount rate would require more collateral. The estimation of the forward price curves nine years into the future is highly speculative. The Valuation Agent may select four reference market-makers and take the arithmetic average of the quotes obtained, in instances of dispute. Staff maintains that other standardized collateral annexes do not appoint one of the two parties as the sole Valuation Agent or to select the market makers. For instance, the Edison Electric Institute Master Power Purchase and Sale Agreement (EEI) allows each party to calculate its own exposure to the other party.[524] The WSPP Agreement and the International Swaps and Derivatives Association, Inc. Master Agreement (IsDA Agreement) provide that the demanding party may calculate the amount of collateral. The cost of the collateral is $419,000 per year to maintain a $92 million Letter of Credit or an increase of $1.89 in the cost of power per MWh per year. Staff acknowledges two issues: that even if the collateral annex is modified, the collateral required from Snohomish would still be substantial; that the Commission should consider whether load serving entities, should have to deal with these types of contractual provisions.

182. Additionally, Staff argues that the following conditions make the collateral annex contrary to the public interest. First, it was Morgan Stanley who first proposed the collateral annex. Second, Morgan Stanley told Snohomish the collateral annex was

[524] Staff IB at 46.

standard. Third, the Morgan Stanley credit department emphasized that due to the contract price, the collateral annex included "every bell and whistle."[525]

C. Discussion/Findings:

183. In Issues II and III above, it was found that the term of the contract between these two parties is not contrary to the public interest and thus, the contract does not require modification. Therefore, this discussion is limited to the collateral annex. In addition to the facts set out above under Issue III, concerning Snohomish's negotiations of the transaction at issue in this proceeding, the evidence shows that Morgan Stanley and Snohomish discussed the terms of the collateral annex during the negotiations, including the mark-to-market collateralization provisions, and their potential effect on Snohomish.[526] It appeared that Snohomish was familiar with financial credit requirements.[527] Snohomish and Morgan Stanley exchanged written comments concerning the form of collateral annex, and several telephone conversations concerning the terms of the collateral annex. Snohomish not only understood, but did preliminary calculations of its exposure depending on different pricing scenarios.[528] Morgan Stanley's in-house attorney and Snohomish personnel and counsel reviewed step-by-step, the collateral annex and other provisions of the contract.[529]

184. At the outset, it must be pointed out that the Snohomish/Morgan Stanley Confirmation Agreement specifically states "Terms used but not defined herein shall have the meaning ascribed to them in the WSPP Agreement as amended by Attachment "A."[530] Attachment "A" (Additional Special Provisions, Amendment to WSPP Agreement) states in its very first paragraph:

> By this Attachment to the Confirmation Agreement, Morgan Stanley Capital Group Inc. ("MSCG") and Public Utility District #1 of Snohomish

[525] Staff IB at 51, including recommendations for modifying the collateral annex (both parties calculate the Mark to Market; objective standards for the discount rate, cash should earn interest, both parties should be valuation agents, failure to return collateral should incur default).

[526] Exs. MSC-11, Vol. IV at 102:11-104:21; 107:1-108:9; MSC-16 (KH 1/25/01, 18:18 Side B); MSC-8 at 15:18-16:4; MSC-127; MSC-130; MSC-131.

[527] Exs. MSC-55 at 7:4-7; MSC-55 at 7:12-13.

[528] Exs. MSC-55 at 2:1-6; MSC-158; MSC-171-173; Tr. at 4144:17-4148:10; MSC- 55 at 2:1-22; MSC-122; Tr. at 1761:14-1762:10.

[529] Exs. MSC- 11, Vol. VIII at 31:3-52:14; MSC-16 (KH 1/26/01, 19:26:01, side A); MSC- 11, Vol. IX at 12:13-36:4; MSC-16 (KH 1/26/01 21:35 side A).

[530] Ex. SNO-6.

> County (“Snohomish”) (individually a “Party” and collectively the “Parties”) agree to amend certain sections of the WSPP Agreement, . . . in accordance with the guidelines of the Western System Power Pool guidelines and procedures (the “WSPP Agreement”). All references in the WSPP Agreement to “this Agreement” shall be deemed to include this Attachment “A.” In the event of any conflict between the terms of this Attachment “A” and the terms of the WSPP Agreement, the terms of this Attachment “A” shall prevail. In the event of any conflict between the terms of any Confirmation Agreement and the terms of this Attachment “A,” the Confirmation Agreements shall prevail.

185. The collateral annex, in its very first paragraph, states:

> [t]his collateral annex supplements, forms a part of, and is subject to, the Western Systems Power Pool (“WSPP”) Agreement . . . and the Attachment “A” Additional Special Provisions Amendment to the WSPP Agreement, dated January 26, 2001 (collectively, the “Master Agreement”) between Public Utility District #1 of Snohomish County (“Counterparty”) and Morgan Stanley Capital Group Inc. (“MSCG”). The obligations of Counterparty under the Master Agreement shall be secured in accordance with the provisions of this collateral annex, which sets forth the conditions under which a Party will be required to deliver cash, securities and other property, as well as the conditions under which a Party will release such Collateral.

186. Section 35 of the WSPPA provides in pertinent part: “. . . that all transactions, together with this Agreement and the related Confirmation Agreement(s) form a single, integrated agreement, and agreements and transactions are entered into in reliance on the fact that the agreements and each transaction form a single agreement between the Parties.”

187. By virtue of this language, the collateral annex has been made a part of the WSPPA. Attachment “A” to the Confirmation Agreement specifically states: "The rates for service specified in this Agreement shall remain in effect for the terms of this Agreement and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act."[531]

188. Staff’s arguments that the collateral annex should be reviewed under the just and reasonable standard are found not persuasive for three reasons. Number one, the

[531] SNO-6, Attachment A (§ 39B “Fixed Rates”).

language of the collateral annex makes it part of the WSPPA. Under Issue I, above, it was ruled that the standard to be applied under the WSPPA to determine whether the contracts should be modified, is the public interest standard. Moreover, on reconsideration, the Commission held that the Snohomish Morgan Stanley contract would be reviewed under the public interest standard. The collateral annex is part of the contract. Therefore, review of the terms of the collateral annex has to be under the public interest standard. As discussed above, under the public interest standard, it was found that Snohomish has not met its burden for modification of the contracts at issue in this case.[532] Number two, the Commission specified that the issue in this proceeding was whether the dysfunctional California spot markets had an adverse effect on the long term bilateral markets in California, Nevada and Washington. Under Issue II above, it was found that Complainants had not established that the dysfunctional California spot markets adversely affected the Western long-term bilateral markets. Therefore, Snohomish has not proved that the collateral annex should be modified. Number three, Staff's own arguments make clear that the collateral annex is part of the "rate" of this contract, and therefore, subject to the public interest standard of review. This should conclude the analysis of this issue. However, in order to establish a clear record, further analysis is provided.[533]

189. The terms of the Morgan Stanley/Snohomish contract (the Confirmation Agreement, Attachment A and the collateral annex) support the conclusions reached above. Attachment A to the Morgan Stanley/Snohomish "Master Agreement" purports to amend the WSPPA. Attachment A amends Section 4; 9.1; 12.2; 22.1; 24; 27; 28; 37 and adds new sections 12A, B and C; 24A; 39A, B and C. New Section 39B (added in Attachment A, to modify the end of the WSPPA) is titled "Fixed Rates" and states: "The rates for service specified in this Agreement shall remain in effect for the terms of this Agreement and shall not be subject to change through application to FERC pursuant to the provisions of Section 205 or 206 of the Federal Power Act." It is significant that new Section 39B makes no mention of Section 6.1.[534] Therefore, reading the WSPPA and the

[532] Staff recommends that the Commission should determine whether load-serving entities should be held to these kinds of requirements. This is a policy determination for the Commission.

[533] Staff argues that the collateral annex is unjust and unreasonable and contrary to the public interest because it discriminates against Snohomish. Under *Mobile-Sierra*, discrimination does not cover discrimination to a party to the challenged contract. The standard of undue discrimination would be applicable to the detriment of purchasers who are not parties to the contract. *Papago Tribal Authority v. FERC*, 723 F.2d 950, 953 n. 4 (D.C. Cir. 1983).

[534] Section 6.1 of the WSPPA, titled "Service Schedules and WSPP Default Transmission Tariff," provides in pertinent part:

Morgan Stanley/Snohomish contract together, it is concluded that Section 6.1 of the WSPPA applies to the "classification, service, terms or conditions affecting WSPP transactions." This is due to the fact that the parties in drafting Section 39B did not refer or modify Section 6.1 of the WSPPA. Therefore, Section 6.1 of the WSPPA applies to the collateral annex which is part of the contract, *e.g.* "the terms, conditions, etc."[535]

190. The evidence in this case does not establish that the collateral annex is contrary to the public interest. For instance, Snohomish can make its own mark-to-market calculations. Snohomish has made such calculations and used them to challenge Morgan Stanley's calculations.[536] In 2001, Snohomish itself had forward curves which extended to 2008.[537] This belies the allegation that such forward curves are speculative. Moreover, the collateral annex requires Morgan Stanley to administer it in a commercially reasonable manner.[538] The discount factor used by Morgan Stanley has ranged between 4.5 to 6.5%.[539] Morgan Stanley has not terminated the contract, even though Snohomish has not posted collateral on a timely basis.[540] The parties have resolved their differences amicably without resort to the formal dispute resolution procedures. The collateral annex requires that Morgan Stanley act in "good faith," in the selection of four dealers in the relevant market, and to provide quotes in the case of formal dispute resolution.[541] The

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> The Parties contemplate that they may, from time to time, add or remove Service Schedules under this Agreement. The attached Service Schedules A through C for Economy Energy Service, Unit Commitment Service, and Firm System Capacity/Energy Sale or Exchange Service are hereby approved and made a part of this Agreement. Nothing contained herein shall be construed as affecting in any way the right of the Parties to jointly make application to FERC for a change in the rates and charges, classification, service, terms or conditions affecting WSPP transactions under Section 205 of the Federal Power Act and pursuant to FERC rules and regulations promulgated thereunder. Id.

[535] See discussion under issues I, II and III, *supra.* Moreover, this rationale would apply to Snohomish's argument that the "nine year term of the contract" is not subject to the changes effected by the parties to the WSPPA at Section 39 B, since the evidence in this case, specifically the evidence cited concerning contract negotiation, proves that the rates are intertwined with the contract length. Moreover, the same would be applicable to the collateral annex since, arguably, it also affects the "rates."

[536] Ex. MSC-94 at 2:17-19; Tr. at 1872:23-1873:7; MSC-128; MSC-169; Tr. at 4391:7-11; Tr. at 1878:1-6;

[537] Tr. at 1857:6-18. Exs. MSC-119 at 6; MSC-124 at 12; MSC-117; MSC- 166.

[538] Exs. MSC-21; MSC-96; MSC-94.

[539] Ex. MSC-94 at 9:17-19.

[540] Tr. at 1880; Ex. MSC-89 at 4:11-5:12; MSC-87 at 5:1-6; MSC-169.

[541] Tr. at 1878:1-6; Tr. at 1873:133-21; Exs MSC-128; MSC-94 at 3:10-15.

lack of an interest provision for cash collateral applies to both parties. Snohomish has never posted cash collateral.[542]

191. Snohomish's witnesses, Kemp and Adams, testified as to the unreasonableness of the collateral annex. This testimony will not be given substantial weight. Mr. Kemp is not qualified to testify on credit risk. This witness has never negotiated bilateral commodity contracts with credit support terms or managed credit risk in his employment history.[543] Additionally, Mr. Adams did not review materials or study relevant documents or information to support his opinions.[544] Conversely, Morgan Stanley's witness testified that the credit department of Morgan Stanley was concerned about Snohomish's ability and willingness to comply with its contractual obligations. Morgan Stanley conducted its own internal and independent credit review of Snohomish and Morgan Stanley's potential exposure under the proposed transaction. Morgan Stanley did not rely solely on the public credit rating of Snohomish's debt in making its credit risk assessment.[545] This testimony is given substantial weight.

192. The language of the collateral annex requires Morgan Stanley to act in a commercially reasonable manner. This is a term of art which is used in other forums and this Commission has recognized it.[546] The WSPPA, the NYISO, NEPOOL and PJM

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[542] Ex. MSC-177 at 84; MSC-60 at 3; MSC-60 at 4 ¶ 5(a); MSC-94 at 2:8-5:6; Tr. at 1872:4-7; 1871:12-18.

[543] Tr. at 2413:4-7; Tr at 2413:13-2414:10.

[544] For instance, he testified that he did not know how Morgan Stanley derives its forward curves; he was not aware that a Snohomish Senior Manager reported that Morgan Stanley's forward curves are consistent with independent forward curves; he did not review Snohomish's forward curves; he did not review the entire contract; he was not familiar with the negotiations underlying the contract, and he did not perform any studies of spot and forward markets. Tr. at 2082:3-9; Tr. at 2083:9-21; Tr. at 2084:24-2085:11; Tr. at 2084:11-14; Tr. at 2089:3-14; Tr. at 2089:3-14; Tr. at 2092:19-24; Tr. at 2095:15-22; Tr. at 2099:13-21; Tr. at 2108:8-12.

[545] Tr. at 3908. Mr. Lupiano testified that the collateral annex should include "every bell and whistle because these are the ones they try to figure out how to walk on." *Id.* Snohomish admitted that but for the collateral annex it would not have performed its contractual obligations to Morgan Stanley. Tr. at 3504:3-3509:17. Morgan Stanley's request in its reply brief that judicial notice be taken of S&P ratings will be denied as untimely. MSC RB at 13. The record in this proceeding was closed at the end of the hearing on October 24, 2002.

[546] *Entergy Louisiana, Inc.*, 99 FERC ¶ 61,199 at 61,827 (2002); *In re NE Hub Partners, L.P.*, 90 FERC ¶ 61,142 at 61,431 (2000). *See also, Coca-Cola Bottling Co. v. Coca-Cola Co.*, 4 F.3d 930 at 936 (10th Cir. 1993).

tariffs all contain the term “commercially reasonable manner.”[547] The EEI collateral annex and the WSPP collateral annex require the parties to act in good faith and in a "commercially reasonable" manner.[548] The Uniform Commercial Code uses the term “commercially reasonable.” The WSPPA requires non-defaulting parties to calculate in a reasonable manner the gains, losses and costs resulting from a terminated transaction.[549] The EEI Master Agreement requires the non-defaulting party to “calculate, in a commercially reasonable manner, a Settlement Amount for each . . . Terminated Transaction.”[550] The EEI collateral annex requires the secured party to calculate the “current mark-to-market value” of the contract in a commercially reasonable manner.[551] The NEPOOL tariff financial assurance policy requires NEPOOL to use commercially reasonable credit review procedures to assess the financial ability of applicants for membership, and can require generator owners to post a letter of credit as security.[552]

193. The evidence in this case shows that the collateral annex does not impair Snohomish’s ability to continue its service, does not impose an excessive burden, nor does it unduly discriminate. The per-ratepayer cost of providing collateral (based upon current net exposure under the collateral annex) is seventy-five cents per year. Staff’s assertion that the cost of the letter of credit is burdensome is inconsistent with Staff's previous arguments under issues II and III, above, namely that the contract does not impose an excessive burden because it only has a five percent effect on rates. Moreover, as discussed under issues II and III and V, the nine-year term of the contract is not contrary to the public interest. In light of the above, it is found that the Snohomish/Morgan Stanley contract should not be modified. The evidence in this case shows that the parties negotiated at arms-length. Accordingly, it is found that the public interest standard applies to the collateral annex. It is also found that the collateral annex is not contrary to the public interest. Accordingly it is found that contract modification is not warranted, thereby allowing the contracts which set forth the business judgment of the parties concerning their credit risks to remain as negotiated.[553]

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[547] Exs. MSC-174; 175; 176 (official notice taken).

[548] Exs. MSC 61; 64; 57 at 27:2-5; 33:9-10; 34:1-2.

[549] Ex. NPC-14 at § 22.3.

[550] Ex. MSC-120, Sec. 5.2.

[551] Ex. MSC-61.

[552] Ex. MSC-174.

[553] In its reply brief, Snohomish cites *New York ISO v. Morgan Stanley Capital Group, Inc*., 98 FERC ¶ 61077, at 61,232-33 (2002) for the proposition that FERC has terminated or modified collateral requirements to protect consumers. Snohomish RB at 9. This case is totally inapposite, since it deals with compliance filings of the NYISO for a tariff to implement a new market mechanism. It does not deal with two power marketers entering into a bona-fide arms length transaction. Moreover, the Commission approved

Issue V. Whether the complainants have satisfied their burden under the applicable just and reasonable or public interest standard?

A. Parties Contentions:

194. The Nevada Companies maintain that the appropriate standard for judging the contract prices at issue in this case is the just and reasonable standard. Alternatively, assuming the standard was the public interest, consumers would be served by reducing the prices in the contracts to the level that would have been set had there been no market dysfunction.[554] According to the Nevada Companies, the contract prices in this case are the product of dysfunctional markets, and are significantly higher than the marginal cost of production. Therefore, the Commission should determine and fix the just and reasonable prices.

195. The Nevada Companies contend that the Commission is obligated to protect the public interest, which includes the interest of consumers in having access to an adequate supply of power at a reasonable rate.[555] According to the Nevada Companies, Respondents' shareholders have no statutory right or expectation to collect the specific prices in the contracts. If the prices are not mitigated, the Nevada Companies assert, all the cost burden of the market dysfunction and exorbitant prices will be placed entirely on the Nevada Companies, load serving entities, and their customers.[556]

196. The Nevada Companies contend that they purchased the energy at issue in this proceeding to serve their load obligations and avoid risks of shortages. They maintain that, in April 2001, when the State reversed its course concerning restructuring of energy markets, it was faced with having to purchase power for later years.[557] The Nevada Companies maintain that they did not purchase significant amounts of power to resell it, and seventy percent of their $100 million revenues are location basis swaps made to substitute for transmission rights.[558] Remaining sales were made solely because the Nevada Companies' load did not perfectly match the standard 6x16 product, and selling off power in the shoulder hours is an appropriate way to reduce power costs for the

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credit policies which required collateral, removing only the minimum collateral requirements.

[554] Nevada Companies IB at 35.
[555] Id. at 37.
[556] Id. at 38.
[557] Nevada Companies RB at 36.
[558] Id. at 37.

consumer.[559] The power supply contracts at issue in this case have had a devastating effect on the Nevada Companies' financial position, *e.g.*, credit downgrades, no credit facilities for much of 2002, and difficulty securing supply.[560]

197. Additionally, the Nevada Companies aver that contract modification serves the public interest because such action would ensure the integrity of the nation's energy markets, a benefit to both consumers and investors.[561] The Commission cannot rely on market prices to ensure just and reasonable rates because such an approach retains the false illusion that a government agency is keeping watch over rates, when it is in fact doing no such thing, the Nevada Companies allege. In circumstances such as these, the Commission is fulfilling its statutory duty by intervening to assure that market-based prices are just and reasonable, due to the fact that government regulators urged the Nevada Companies to "increase their reliance upon the forward markets." The Nevada Companies argue that it would be egregious and unfair for the Commission to refuse to modify unjust and unreasonable forward contract prices.[562] In addition, the Nevada Companies argue that pushing load-serving entities into the forward markets and then providing relief only to those who stay in the spot markets is likely to lead to vertical integration and a return to cost-of-service regulation.[563]

198. The Nevada Companies assert that parties should be more willing to enter into short- and long-term power supply contracts if the Commission modifies the contracts at issue in this case. This is so because demonstrating that the market will be disciplined and fair should appeal to all parties and reduce the need for the Commission to intervene in the future. Suppliers had no reasonable expectation that the contract prices they charged could never be found to be unjust and unreasonable, since this is part of regulatory risks. The greater market certainty and enforcement of just and reasonable rates will provide incentives to invest in the market. In addition, the Nevada Companies assert that there should be no effect (or a positive effect) on energy investments from clear and effective rules requiring just and reasonable prices, and from the regulators who enforce those rules to ensure an effective and functioning competitive market.[564]

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[559] Id. at 38.
[560] Id. at 39.
[561] The Nevada Companies argue that dysfunctional forward market prices provide wrong signals to market participants, for example, in the development of new generation capacity. Id. at 41.
[562] Id. at 41.
[563] Id. at 42.
[564] Id. at 44

199. It is the Nevada Companies' contention that the action with the most severe impact on investments would be to deny relief to the Nevada Companies, due to the fact that their ability to invest in generation and transmission facilities has been hampered. Concerning the contract termination issue, the Nevada Companies assert that the issue was not designated in this case and that it is incumbent on Respondents to seek an order from the Commission setting the termination issue for hearing.[565]

200. According to SCWC and Snohomish, the contracts are unjust and unreasonable because: (a) the language of the WSPPA and the underlying facts demonstrate that the parties intended the just and reasonable standard to apply; (b) the Mirant/SCWC contract has never been reviewed by the Commission; (c) the public interest standard cannot be applied in a "high-rate" case such as the one here.[566] Enumerating their arguments: (1) the $95/MWh rate greatly exceeds the $74/MWh; (2) competitive market forces did not ensure just and reasonable rates because too few sellers were competing for SCWC's business, spot market conditions made sellers reluctant to sell excess power, and other sellers focused on sales to DWR;[567] (3) wholesale sellers such as Mirant and Morgan Stanley had no incentive to enter into long-term contracts with buyers like SCWC and Snohomish at just and reasonable rates until FERC mitigated the dysfunctional spot markets beginning in April 2001.[568]

201. It was not until after the Commission's April 26, 2001 Order, that the spot market mitigation efforts impacted forward prices. However, these mitigation efforts, according to SCWC did not provide it with any relief. Only three sellers responded to SCWC's RFP and none offered a just and reasonable price, SCWC argues.[569] These circumstances compelled SCWC to enter into a contract with Mirant to secure the least "unjust and unreasonable" rate. SCWC states that it met its burden of proving that the contracts are contrary to the public interest. To wit, it argues that the contract price was the product of the dysfunctional California market, and the lack of liquidity and volatility in the forward markets left SCWC without alternatives. In addition, this company argues that the record shows that the dysfunctional spot markets were directly reflected in the prices charged in forward contracts during the first half of 2001, a possibility the Commission acknowledged in its November 1 Order and has repeatedly acknowledged since then. Further, the contract imposes undue burdens on third parties.

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[565] Nevada Companies RB at 26.
[566] SCWC and Snohomish IB at 48.
[567] Id. at 49.
[568] Id.
[569] Id. at 52.

202. SCWC asserts that the purchase from Mirant is a baseload around-the-clock contract which accounts for a substantial majority of the MWhs purchased by SCWC. It maintains it purchased this power only to serve its load. The contract has a huge financial impact on SCWC and its ratepayers.[570] Ratepayers have seen a thirty-eight percent increase in their electric rate(s) due to a dysfunctional California marketplace. However, this estimate is small, due to the fact that SCWC has taken proactive mitigation efforts to lower its overall purchased power costs and the fact that it entered into a rate settlement approved by the CPUC on July 17, 2002, whereby SCWC's shareholders agreed to bear a portion of SCWC's purchased power costs (anything above $77/MWh).[571] Further, SCWC asserts that prior to entering into the Mirant contract, SCWC's average purchased power rate was $24.37/MWh. The Mirant contract represents more than a $70/MWh increase over SCWC's pre-Mirant contract rates. Compared to the $74 Commission imposed benchmark, the $21 dollar difference imposed upon SCWC and its ratepayers amounts to an additional $2.8 million per year. Reformation of the contracts arising out of the gross dysfunction of the California market, according to SCWC and Snohomish, would promote the Commission's policies of encouraging market-based reform of the electric markets by restoring faith in the markets and in FERC's willingness to police market abuses.[572]

203. Snohomish and SCWC maintain that the Morgan Stanley contract imposes an undue burden on Snohomish's consumers. The Morgan Stanley contract, according to these entities, will cost $2 million per month for Snohomish consumers. The Snohomish ratepayers have had rate increases of nearly sixty percent since the start of the Western wholesale energy crisis, mostly from the cost of electricity, SCWC and Snohomish argue.[573] The contract at issue in this case, Snohomish argues, is approximately five percent of overall rates (including transmission costs, local distribution, debt service, and other overheads, as well as power and are attributable to the Morgan Stanley contract), even though providing less than three percent of the Snohomish power supply portfolio. Indeed, Snohomish argues, over its term, the contract is $102 million above current market prices, or nearly twenty-eight percent of Snohomish's purchased power costs in 2001.[574] Snohomish maintains that these costs will be borne by Snohomish's ratepayers,

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[570] Id. at 53.

[571] Id.

[572] Id. at 54.

[573] Id. at 42.

[574] Id. at 43. Snohomish argues the costs of serving the contract are lower than the contract price since Morgan Stanley buys power from Snohomish in the short-term market at lower prices. Moreover, as a result of new accounting rules, Morgan Stanley would not have losses if the contract is abrogated.

since it is a government-owned utility which operates on a non-profit basis and has no shareholders to absorb the costs, and must pass-through all of its costs to consumers.[575]

204. The PUCN and the Nevada AG contend that the prudence of the Nevada Companies' purchasing decision is not before the Commission in this proceeding, since such an inquiry is within the sole authority of the PUCN.[576] In addition, the PUCN avers that the effects of granting the requested relief would be positive, rather than negative, as predicted by the Respondents.[577] In support, the PUCN asserts witness, Dr. William G. Shepherd, testified that reforming the contracts would "restore confidence in power markets and, ultimately, in the integrity of deregulation itself."[578] The PUCN contends that it supports Mr. Greenshield's admission that the market price already incorporates costs for increased regulatory and legal risks, so the relief in this proceeding could not cause "significantly higher prices," based on such risks.[579] Moreover, the PUCN argues that past accounting practices, excessive debt loads and fundamentally-flawed business models are also factors causing the problems in power markets, and thus, granting relief will not significantly increase such problems.[580] Finally, the PUCN, argues, that, even if, contractual modification does adversely affect investor confidence, this effect is far outweighed by the Commission's statutory duty of ensuring just and reasonable rates.[581]

205. Respondents aver Complainants failed to satisfy their burden under either the public interest or the just and reasonable standard. Complainants have not shown that the challenged contracts are unduly discriminatory, impose an excessive burden, threaten the Companies' ability to serve their customers, and the Complainants failed to meet their burden of proof under the public interest standard. The Complainants have not demonstrated that the locational basis swap challenged in this case is unjust or unreasonable. Moreover, Respondents argue that the economic effect of the locational basis swaps should be gauged by focusing on the price differential of the transactions. In addition, Respondents argue Complainants have not shown that the fee received by certain Respondents for assisting the Nevada Companies to secure power when others were unwilling to sell directly to them is not reasonable. It would be patently unfair and arbitrary to impose a refund on a Respondent for a sleeve transaction when the corresponding upstream purchase is not subject to refund.

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[575] Id. at 43.
[576] PUCN IB at 19-21.
[577] Id. at 21.
[578] Id. at 22.
[579] Id. at 23.
[580] Id. at 23-24.
[581] Id. at 24.

206. In addition, Respondents argue that the Nevada Companies failed to meet their burden with respect to their contracts with MSCG, Reliant, El Paso and Enron. This is so because the contracts have been terminated and no longer involve the physical delivery of power. According to Respondents, the Commission cannot retain jurisdiction over contracts that have been terminated and as such, do not result in the physical delivery of power. Therefore, Respondents aver that as a matter of law, the Commission cannot grant the relief sought by the Nevada Companies.

207. Staff argues that under the only prong of the public interest test applicable in this case, whether the contracts have caused severe financial distress on the utility or excessive burden on consumers, the Complainants have failed to meet their burden of proof. The contracts at issue do not amount to a significant percentage of Complainants' load or costs. Additionally, Staff points out that none of the Complainants addressed the impact of the contracts on their rates, or the rates of their ratepayers. In its reply brief, Staff asserts that Respondents have not shown that the Commission lacks jurisdiction over the contracts which were terminated during the course of this proceeding.

C. Discussion/Findings:

208. The *Mobile-Sierra* public-interest standard applies to the challenged contracts. The public-interest standard has been characterized as "practically insurmountable,"[582] and can be overcome only in extreme circumstances, such as when the existing terms of the contract "might impair the financial ability of the public utility to continue its service, cast upon other consumers an excessive burden, or be unduly discriminatory."[583] Commission and court precedent clearly establish that "the fact that a contract has become uneconomic to one of the parties does not necessarily render the contract contrary to the public interest."[584] Allegations that contracts may be uneconomic by the passage of time, does not render them unjust and unreasonable nor contrary to the public-interest under the FPA.[585] As Staff points out, there has to be a nexus between the contract and

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[582] *Papago*, 723 F.2d at 954.

[583] Id. at 953 (citing 350 U.S. at 355).

[584] *Potomac Elec. Power Co. v. FERC*, 210 F.3d 403, 409 (D.C. Cir. 2000) (citing *Soyland Power Coop. Inc. v. Central Illinois Pub. Serv. Co.*, 51 FERC ¶ 61,004, at 61,013 (1990). See also *Sierra*, 350 U.S. at 354-355; *Pontook Operating Ltd. P'ship v. Public Serv. Co. of New Hampshire*, 94 FERC ¶ 61,144 at 61,552 (2001); *Public Serv. Co. of New Mexico*, 43 FERC ¶ 61,469 at 62,152 (1988); *Gulf States Utils. Co. v. Southern Co. Servs., Inc.*, 43 FERC ¶ 61,003 at 61,014 (1988).

[585] *Gulf States Utils. Co.*, 43 FERC ¶ 61,003, at 61,016 (1988) (footnote omitted). *See also San Diego Gas & Elec. Co. v. FERC*, 904 F.2d 727 (D.C. Cir. 1990).

the claimed financial difficulty, burden or discrimination.[586] The Complainants have not offered any evidence to overcome their high burden under the public-interest standard.

The Nevada Companies:

209. The Nevada Companies concede that the prices were at or below prevailing market prices, *i.e.*, the prices were available to all participants in the market.[587] The contracts were all standard products arranged through independent third-party brokers. This evidence does not show any discrimination.

210. The evidence in this case does not show there is an "excessive burden" on consumers. On the contrary, the evidence presented in this case shows that the Nevada Companies' projections assume that they will file for a rate decrease in excess of 20 percent in November 2002 in their base tariff energy rate ("BTER") cases. This is based on their cash flow projections. The Nevada Companies' cash-flow projections further assume that full payment will be made to all Respondents (other than Enron).[588] Even if they are required to pay Enron, any rate increase would be on the order of five percent.[589]

211. Witness Schiffel, testified that the Companies' cash flow projections assume one hundred percent recovery of the power purchase costs (including approximately $60 million of Nevada Power's remaining deferred energy balance and $10-$20 million of SPPC's remaining deferred energy balance). The Companies project rate *decreases* for both NPC and SPPC of approximately 20 percent (from $52/MWh to $40/MWh for NPC retail electric service effective June 1, 2003; from $51/MWh to $40/MWh for SPPC retail electric service effective August 15, 2003).[590] The Companies' cash-flow projections show *positive cash balances* for each of the next several years, even assuming dividend payments and scheduled debt repayments.[591] Respondents' assertion that the fact that

[586] Staff IB at 53-54, citing *Metropolitan Edison Co. v. FERC*, 595 F.2d 851, 855 (D.C. Cir. 1979) (financial difficulties could not be traced to the revenue deficit associated with the contract at issue).

[587] Tr. at 2645:14-17; 2656:16-20, 2709:9-15; 2288:3-17; NPC/Calpine Complaint at 19; NPC/MSCG Complaint at 19; NPC/AEP Complaint at 19.

[588] Ex. CES-20.

[589] Tr. at 2545:15-16.

[590] Ex. CES-20 at ¶¶ 5, 9-10.

[591] Ex. CES-18, CES-19, CES-20. In an editorial board meeting with a local newspaper, the *Las Vegas Review-Journal*, the Nevada Companies publicized their plans to seek a rate decrease. Ex. CES-17 at 1. As the Nevada Companies' Chairman and Chief Executive Officer is quoted as saying, "We believe that we will be able to lower the

these Companies project dividend payments indicates a healthy company with a sufficient equity ratio to make such payments is persuasive.[592] The Companies' cash flow projections also indicate that they continue to have adequate access to capital markets. NPC expected to finalize high-yield secured debt totaling $250 in October 2002.[593] NPC expects to issue another $150 million in fully-secured long-term debt in September 2003.[594] The assumptions to the cash flow projections also show that SPPC is expected to issue debt in October 2002 ($100 million).[595] Moreover, the Companies have obtained the requisite regulatory approvals for these debt issuances.[596]

212. Further, there is no evidence that Complainants' ability to serve their customers is threatened.[597] The Nevada Companies made general allegations about financial consequences. However, their allegations are not supported by record evidence.[598] Without factual support, these allegations are not credible and are not entitled to any weight. The Nevada Companies failed to adduce any evidence of specific financial

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price of electricity very soon." Ex. CES-17 at 1. "Do I need rate relief, I hope not, I think not," he is quoted as predicting. Ex. CES-17 at 2.

[592] The Nevada Companies' allegations concerning state restructuring issues are not credible. Nevada Companies RB at 36. The restructuring order they cite in the reply brief occurred in April 2001, just two months before the end of the period in question in this case.

[593] Tr. at 2494:1-5 (Schiffel); Ex. CES-20 ¶¶ 32-33.

[594] Ex. CES-20 at ¶ 42.

[595] Ex. CES-20 at ¶ 36.

[596] Ex. CES-20 at ¶ 33.

[597] For instance, a contract for 25 MWS for peak power at Palo Verde, beginning April 1, 2002 through June 30, 2002, represents .009% of NPC's April 2002 net peak load, .007% of NPC's May 2002 net peak load and .006% of NPC's June 2002 net peak load.

[598] For example, witness Schiffel, the Nevada Companies' CFO, testified that the Companies "cannot absorb further losses and remain financially viable." Ex. NPC-8 at 11:16-17. There are no facts supporting this allegation. He also testified that either the Companies' retail customers or their investors and bondholders will bear financial distress without contract modification. Ex. NPC-47 at 22:23-25. Again, he backs up that assertion with no facts. The Nevada Companies witness, Oldham, similarly offers unsupported assertions regarding the consequences of not modifying the contracts. Mr. Oldham testifies that the Companies "likely will go into bankruptcy" if they are unable to recover the costs of the contracts, and that if the contract prices are not modified, it will have a negative impact on the Companies' ability to provide reliable service. Ex. NPC-48 at 16:14-18, 18:3-6 (*citing* Ex. NPC-8 at 10-18). No facts are provided to support these assertions.

distress for the companies or their ratepayers as a result of the contracts at issue in this case. The evidence does show that the Nevada Companies had financial difficulties, even before the contracts at issue in this case were signed. The Nevada Companies' financial condition was *not* caused by the contracts at issue in this case.[599] The Nevada Companies' own officers explain that they were in a "precarious" financial position by November 2000, well before the bulk of the challenged contracts were executed.[600] Any additional financial distress suffered by the Nevada Companies stems from the decision of the PUCN in March 2002 to disallow recovery of costs associated with contracts *not* at issue in this proceeding.[601] The drop in their credit rating to below investment grade occurred only after issuance of the PUCN's order.[602] Thus, their financial distress is not the result of the contracts at issue in this proceeding, especially in light of the fact that they were in dire financial conditions by November 2000. Staff points out that it is plausible that the PUCN may make similar findings with regard to some of the contracts at issue in this case. A further disallowance of imprudence would not meet the *Mobile-Sierra* public interest standard. However, if the PUCN allows recovery of the costs of these contracts, there would be no financial distress associated with these contracts. Staff's argument is persuasive. The PUCN/BCP argues that its findings should not be considered by this Commission and views it as tantamount to usurping its authority. However, the PUCN's findings are pertinent to the matter at issue as evidenced by the fact that the Commission took official notice of the decision.[603]

SCWC

213. SCWC did not adduce any evidence of financial hardships either for itself or its ratepayers. SCWC was able to avoid the risk of price volatility and achieve rate certainty

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[599] Ex. S-1 at 22:1-3.

[600] Ex. NPC-8 at 3:18.

[601] The PUCN found that a significant portion of the Nevada Companies' purchase under the APS (specifically those scheduled for delivery through September 2001) were excessive and based, at least in part on the hope of speculative profits. In 2000-01 these companies realized about $100 million by making off-system sales of excess power, charging $400-500/MWh. Ex. CES-2 at 26-27; Tr. at 2336, 2676. The PUCN found the purchases imprudent and disallowed recovery through the retail rates of the Nevada Power Company and Sierra Pacific of $437 and $55 million purchased power costs. The PUCN criticized the Companies' failure to enter into long-term contacts to meet their load-serving obligations. Exs. CES-4 at 63 (¶ 268); Id. at 66 (¶ 279)'; CES-5 at 214 (¶ 840).

[602] Ex. CES-2 at 23:7-8.

[603] 100 FERC ¶ 61,273 at 62,047 (2002).

as a result of its contracts with Mirant.[604] There is a lack of evidence that SCWC customers will suffer an excessive burden if the SCWC Contract is upheld. In July 2002, SCWC reached a retail rate settlement at the CPUC. The settlement provided for purchased power costs of $77/MWh, so it will be able to pass through to its customers most of the costs of this contract. Under the terms of the settlement, there is *no rate increase at all* for ratepayers who are permanent residents of SCWC's service territory and use within 130% of a baseline energy allowance established by the CPUC.[605] The other group of residential ratepayers are people with second homes around the two ski areas in SCWC's service territory, and under the terms of the CPUC settlement, this ratepayer class will face an average monthly electric bill of $35.13.[606]

214. The record does not establish that SCWC's ability to continue doing business is, in any way, threatened if the contract is not reformed or that the contract had a negative impact on its financial health or the financial health of its shareholders.[607] The evidence indicates that SCWC's contract with Mirant has not damaged it at all. The contract commenced in April, but SCWC did not need it until May. SCWC bought the power from Mirant at $95/MWh, and sold it back to Mirant at $173/MWh, thus realizing a healthy profit.[608]

215. The price of the SCWC contract seems reasonable, especially in light of the fact that Mirant is a power marketer that had to purchase power in the market in order to resell it to SCWC.[609] Moreover, the Commission recognized that buyers could choose to negotiate rates above the $74/MWh benchmark "to the extent they believe the particular contract or supplier brings value which suits their needs."[610] The record in this case shows that the SCWC Contracts provide significant benefits, including the following benefit that SCWC emphasized before the CPUC; that energy is typically traded in 25-MW blocks, and Mirant took on the risk of supplying SCWC with a 15-MW "odd lot" sale. SCWC recognized in its CPUC testimony that a 15 MW block of energy should carry "a slight pricing premium."[611] A reliable supply of firm energy was particularly important to SCWC since it had no resources of its own. Mirant's contract offered

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[604] Tr. at 2943-44.

[605] Tr. at 2934:8:16.

[606] Tr. at 2933:22-2934:1; Ex. MAEM-69.

[607] Tr. at 2937:13-2938:4. *See*, *e.g.*, Exs. MAEM-70; MAEM-71; MAEM-72; MAEM-74; MAEM-76.

[608] Tr. 2907-08.

[609] Ex. MAEM-16 at 35:1-4.

[610] December 15 Order at 61,995.

[611] Ex. MAEM-30 at JAD-10-11.

greater capacity-like reliability benefits than a unit-specific contract. A unit-specific contract would have resulted in too much system unreliability for such a small system.[612]

216. Even if the just and reasonable standard is applied to SCWC's complaint, SCWC still failed to meet its burden and thus, the preponderance of the evidence favors Respondents. The evidence shows that the price of the contract was based on the market at the time. Dr. Henderson showed that the contract's $95/MWh price compares favorably with forward prices available at the time the contract was entered into. For instance: (i) hedges identified by Mirant; (ii) Mirant's own forward price curves from March 2001; (iii) forward price quotes from TFS Energy; and (iv) NYMEX futures available at the time.[613] Dr. Henderson's finding echoes statements made by SCWC's Mr. Dickson, before the CPUC, where he testified that "based on the market information that existed at the time [SCWC] negotiated the [Mirant] contract . . . the [Mirant] contract terms are reasonable."[614]

217. Additionally, the evidence shows that SCWC received benefits from the April "buy-back" arrangement that was negotiated between the parties.[615] SCWC concedes that the buy-back *benefitted* SCWC's ratepayers to the tune of over $600,000.[616] These savings, totaled with SCWC's prior savings of $13.26 million in recent years show that SCWC is a market participant that has largely *benefitted* from over $14.5 million in savings from 1999 through April 2001, as a result of its forward contracting and marketing strategy.[617] Thus, the preponderance of the evidence weighs in favor of finding that the SCWC contract is just and reasonable.

218. Conversely, record evidence shows that Mirant will be directly harmed if the SCWC Contract is modified. Dr. Henderson testified that Mirant lost a "substantial amount of money" on the SCWC Contract from April 1, 2001 to December 31, 2001.[618] Mirant stands to earn any profit margin at all on the SCWC Contract "only if the [c]ontract price is honored through the term."[619] Moreover, Moody's recently downgraded Mirant's credit rating a second time, specifically citing in its report the

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[612] Ex. MAEM-30 at JAD-10-11.

[613] Ex. MAEM-16 at 25:18-21; MAEM-16 at 27:6-28:15; 28:16-29:9; 29:10-30:11; 30:12-32:9.

[614] Ex. MAEM-30 at 11:10-11.

[615] Exs. MAEM-2 at 15:17-16:20; SCW-11 at 6:18-22; MAEM-14.

[616] The buy-back was needed due to a change in the contract start date. Ex. SCW-4 at 12.

[617] Ex. SCW-1 at 11:1-14.

[618] Ex. MAEM-16 at 32:14-16.

[619] Ex. MAEM-16 at 33:19-20; MAEM-16 at 27:6-17.

"uncertainty as to potential liabilities arising from ongoing government investigations *and lawsuits related to California's power markets*."[620] Mirant's downgrade: (i) increases its financing costs (ii) hinders its access to capital markets, (iii) forces it to post additional collateral to support its trading and marketing business, and (iv) generally has hampered its' business.[621]

Snohomish

219. Snohomish seeks redress for the length of its contract. Snohomish submitted testimony from six ratepayers who described how rate increases impacted them. However, the rate increase preceded the contract at issue. Under these circumstances, the testimony of the ratepayers is not pertinent to the issue designated in this case (the effects of the Cal ISO and PX spot market prices on forward bilateral markets). The record does not have any evidence regarding the impact of the contract upon ratepayers. Therefore, Snohomish failed to meet its burden of proof.[622] As Staff correctly points out, it is significant that this Commission does not have jurisdiction over retail rates and thus, an examination of the impact of the contracts on retail rates may be exceedingly complicated.

220. In the past, Courts ruled that the individual parties' bargaining power is not significant. What is required under *Mobile-Sierra* is whether the complaining utility can demonstrate that revising the contract is in the public interest.[623] Thus, Snohomish's claims in this regard are without merit. Additionally Snohomish failed to present any evidence of discrimination. Snohomish alleges that the contract is discriminatory because other parties who contracted with Morgan Stanley have other terms. This is not the type of discrimination contemplated by the *Mobile-Sierra* doctrine. Other terms in other contracts are not relevant to the determination that the contract at issue in this case is discriminatory. In the past, the *Mobile-Sierra* doctrine has been applied to allegations of discriminatory or preferential treatment to the detriment of other purchasers who are not parties to the contract.[624]

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[620] Ex. MAEM-77.

[621] Tr. at 3336:20-3337:1.

[622] See *Potomac Elec. Power Co*., 210 F. 3d 403 at 409 (D.C. Cir 2000) (PEPCO failed to provide any evidence of undue discrimination or excessive burden, other than the disparity in rates and a bald claim that its ratepayers would derive benefit from a rate modification).

[623] Id.

[624] *Papago Tribal Util. Auth. v. FERC*, 723 F. 2d 950 at 953, n.4 (D.C. Cir 1983) (regarding unduly discriminatory or preferential treatment to the detriment of purchasers who are not parties to the contract).

221. Snohomish sold more than one million megawatts- hours in 2001, at an average price of $134/MWh.[625] This produced a net profit of over $17 million in the first five months of 2001.[626] This occurred at the same time it was purchasing power from Morgan Stanley at $105/MWh. Its revenue exceeded expenses by more than $21 million in the year ended December 31, 2001.[627] In 2001, Snohomish resold 1,066,183 MWhs of power that it had purchased in the wholesale market at an average price of $137 per MWh (an 86.4% increase in the volume of resales over the prior year. Snohomish's revenues on power sales in 2001 were $146,285,000 (a 252.1% increase in revenues over the prior year).[628] The contract at issue in this proceeding is no more than five percent of Snohomish's current portfolio costs,[629] with a small impact on rates. The Morgan Stanley/Snohomish contract is only three percent of Snohomish's load and an eight percent increase over existing rates in 2001, while other contracts accounted for an increase of fifty-one percent over existing rates.[630] The record reflects that Snohomish's new power contract with BPA had the most impact on its rates (a forty-six percent increase). Staff argues persuasively, that since the Morgan Stanley deal was less than the $125 placeholder (which was the result of a rate increase) it actually resulted in rate relief.[631]

222. The record demonstrates that the contract prices were consistent with market prices at the time each contract was executed.[632] The record also shows that these transactions were bona fide arm's-length transactions between knowledgeable companies. In the past, the Commission has enforced the parties' bargains in similar circumstances.[633] Accordingly, it is found that Complainants failed to meet their burden of proof under the

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[625] Tr. at 2405:1-2410:5.

[626] Tr. 2408-09.

[627] Ex. MSC-132 at 18 (page 4 of 17). An October 1, 2001 rate increase of eighteen percent was attributable to a forty-five percent increase in power costs for power from BPA. Tr. at 1587:20-1588:6; Ex. MSC-111. In April 2002, Snohomish reduced its rates by 5.1 percent. Ex. MSC-160.

[628] Ex. MSC-132 at 31; SNO-27 at 12:19-21; Tr. at 1767:25-1768:11; Tr. at 2406:1-2408:18. Alleged losses in SNO-38 are based on an assumption that any excess power sold came from the long-term contracts. Ex. SNO-4 at 15:7-8; Tr. at 1769:10-15.

[629] Tr. at 1661.

[630] Staff IB at 55; Tr. 1661-62, 1770.

[631] Staff IB at 55; Tr. 1793.

[632] Ex. MSC-85 at 2:1-3; Tr. at 2645:14-17; Tr. at 2656:16-20, 2709:9-15; Tr. at 2288:3-1; Tr. at 4504-05.

[633] 51 FERC at 61,014-15, *citing Gulf States Utils. Co. v. Southern Co. Servs., Inc*., 43 FERC ¶ 61,003 (1998).

Mobile-Sierra doctrine. Even under the just and reasonable standard, the Complainants failed to meet their burden of proof.

223. Some of the transactions at issue in this proceeding were locational swaps or paired transactions. The record shows the Nevada Companies failed to establish that the locational basis swap transactions, *i.e.*, the "paired" transactions, were not just and reasonable. Indeed, the record reflects that this was a practice undertaken by the Nevada Companies to move power to delivery points on the Nevada Companies' system.[634] As explained by Calpine witness Posoli, for example, these locational basis swaps involved simultaneous transactions in which NPC, which apparently had purchased power at Palo Verde, then purchased power from a seller for delivery at Mead, and simultaneously sold the same amount of power to the same counterparty for delivery at Palo Verde.[635] The purpose of entering into these swap transactions is to effectively move power to a desired delivery point without having to secure transmission capacity.[636] NPC could buy power at the liquid Palo Verde hub and, through the use of a locational basis swap, effectively transfer to Mead (where it has load-serving obligations) the power it had to sell at Palo Verde.[637] The Nevada Companies presented no evidence that these arrangements were unjust, unreasonable or otherwise improper in any way. Indeed, the record shows that the Nevada Companies' regularly participated in locational basis swaps.[638]

224. Respondents contend that the economic effect of these locational basis swaps should be gauged by focusing on the price differential between the two transactions, rather than on the price of an individual transaction in the pair. This coincides with how the parties enter into the transactions. In arranging each pair of transactions, the parties first would agree upon the "spread," or price differential, between the two delivery points, and then enter each of the two "legs," or individual transactions, that constitute the pair of transactions.[639] As explained by Mr. Posoli, "[a]lthough each pair of the transactions was executed as two separate agreements, in fact each pair is more properly viewed as one overall transaction in which the item being traded is the locational price differential."[640] Thus, rather than focusing on the price for an individual leg of a paired set of

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[634] Ex. CES-38.
[635] Ex. CES-1 at 7:3-5.
[636] Ex. CES-1 at 8:10; Ex. CES-1 at 8:8-14.
[637] Ex. CES-1 at 8:16-25.
[638] Tr. at 2376:22-2377:10.
[639] Ex. CES-1 at 7:8-13.
[640] Ex. CES-1 at 7:13-15.

transactions, the economic effect to each party to the transactions is reflected in the price differential. Respondents' arguments are persuasive on this point.[641]

225. NPC is challenging contracts in which Mirant, Reliant and MSCG agreed to sleeve the transaction. A sleeve transaction is a transaction in which a third party enters into contracts with two other parties in order to facilitate a transaction between the two parties.[642] Sleeve transactions are often at a price that was already agreed upon by the original two parties.[643] A sleeve transaction is arranged by a broker, when either of the parties to a transaction decide that it cannot transact with its counter-party.[644] In return for this sleeving service, Mirant, Reliant and MSCG received no or minimal fees per

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[641] In Calpine's case, for example, transactions 2a and 2b have individual prices of $135/MWh for NPC's sale at Palo Verde and $110/MWh for NPC's purchase at Mead. Ex. CES-1 at 4:24-25; Ex. NPC.-13 at 14-17. The differential is $25/MWh. CES-1 at 7:19. The other paired Calpine-NPC transactions are similar. While the individual transaction prices range from $54/MWh to $250/MWh, the spreads range only from $20/MWh to $45/MWh. Ex. NPC-13 at 9-25; Ex. CES-1 at 7:19-8:5. MSCG's May 22, 2001 transaction is comparable. Exs. MSC-21 at 7; MSC-26; NEV-3 at 49-53. El Paso's basis swap also had a markup of a $2 spread on February 13, 2001. In this set of transactions, SPPC sold to El Paso 50 MW of power at $223/MWh for delivery at Palo Verde for the period July 1, 2002 through September 30, 2002 while on the same day El Paso sold to SPPC 50 MW at $225/MWh for delivery at COB for the same period. Ex. EPME-22 at 20:3-21. These transactions were set for hearing. Mirant's transactions with the Nevada Companies were a package deal. Ex. MAEM-38 at 7:10-8:16. On November 10, 2000, Mirant entered into two 25-MW sales with NPC, one for delivery in the third quarter of 2001, and one for delivery in the third quarter 2002. The Nevada Companies only challenge the latter transaction. Both transactions were priced at $126.50/MWh, the average of both prices [the price for power for delivery in the third quarter of 2001 ($109/MWh) and the price for power for delivery in the third quarter of 2002 ($142/MWh). Ex. MAEM-38 at 8:18-9:16. The two transactions were sold to the Nevada Companies as a package and recorded in two separate confirms at NPC's request. Ex. MAEM-38 at 11:1-16. The Nevada Companies received the benefit of the 2001 transaction. Ex. MAEM-38 at 11:1-16.

[642] Ex. MSC-21 at 5:2-3.

[643] Ex. MAEM-38 at 12:6-11.

[644] For example, a transaction may be "sleeved" if a party's portfolio has a large number of pre-existing obligations with the counter-party, and it is concerned about a lack of sufficient diversification. Ex. MSC-21 at 4:16-19. The third party usually receives a modest fee for acting as an intermediary or "sleeve." Ex. MSC-21 at 5:3-4.

megawatt traded.[645] Witness Schaefer testified that it is ironic that NPC is attempting to modify the price in a sleeve transaction. This is so because NPC already had negotiated the transaction price with another third-party seller, and the sleeving Respondents facilitated the transactions by taking on NPC's credit risk.[646] This unrebutted testimony is supported by the record and entitled to substantial weight.

226. This record establishes that sleeves increase market liquidity by facilitating transactions between counterparties that cannot deal directly with each other. Respondents argue that market participants will no longer provide this service if they are subject to contract modification and refunds, particularly if any resulting price adjustment exceeds the sleeving fee (*e.g.*, a $1.00/MWh for the MSCG transactions). It also would be arbitrary and contrary to the FPA to require any Respondent who sleeved on behalf of the Nevada Companies to pay refunds or receive a downward price adjustment for transactions that were a service to the Nevada Companies, particularly when the Respondents cannot seek recovery from the third-party market participant who sold the Respondent power. Respondents' contention that it would be unjust and unreasonable to permit the Nevada Companies to break the second part of the "package transaction" has merit.

227. Pursuant to these findings and based on the findings and discussions in Issues I, II and III above, applicable to these transactions, it is found that Complainants failed to establish that the contracts are contrary to the public interest. Moreover, even under the just and reasonable standard, Complainants failed to meet their burden of proof. Accordingly, the contracts should not be modified.

228. Morgan Stanley, Reliant, El Paso and Enron terminated their contracts with the Nevada Companies, arguing that the Nevada Companies failed to satisfy the credit requirements of the WSPPA. As stated above, the Nevada Companies' credit problems arose in part, as a result of two decisions by the PUCN disallowing the recovery by the Nevada Companies of certain costs for power purchases prior to 2001. The March 29, 2002 PUCN Order did not allow the Nevada Companies full cost recovery because it found that it engaged in certain imprudent behavior.[647] As a result of these and other

[645] Ex. MAEM-42; Ex. MAEM-65; Ex. MSC-136; Tr. at 2281:20-2282:4 (Perry); Ex. MSC-21 at 5:6-16, 9:10-20; Ex. MSC-22 at 1; Ex. MSC-35; Ex. MSC-36; Ex. NEV-3 at 29-32; Ex. RES-13; Tr. at 3454:5-9 (Flowers).

[646] Ex. MAEM-38 at 12:19-22.

[647] CES-2 at 7:3-9:8. The May 29, 2002 Order addressed similar issues with regards to *Sierra Pacific*.

events, on March 28, 2002, Standard & Poor's downgraded certain debt security of the Nevada Companies to a non-investment grade rating.[648]

229. Respondents argue the downgrade triggered the right of counterparties to demand additional credit assurances (*e.g.*, a Letter of Credit, cash, Guarantee Agreement) under Section 27 of the WSPPA. The WSPPA requires the party to provide the requested collateral within three business days of receiving a counterparty's performance request.[649] According to Respondents, the Nevada Companies failed to provide adequate assurance of performance to counterparties requesting such assurance within the contractually-mandated period. The failure to provide additional credit assurances constitutes a default under Section 22.1(d) of the WSPPA, triggering a right of termination by the affected counterparty, pursuant to Section 22.2 of the WSPPA. Thus, Morgan Stanley, Enron, Reliant and El Paso terminated their power sales contracts with the Nevada Companies.[650]

230. Staff's arguments are persuasive that the Commission has jurisdiction over the contracts which have been set for hearing and subsequently (apparently) terminated. The cases cited by Respondents are inapposite. Respondents claim that since the physical delivery of energy is no longer contemplated, the contracts are "futures" contracts. However, the contracts at issue in this case do not fit within the Commission's definition of futures contracts, since the contracts were not transacted on an organized exchange and, thus, they are not subject to the terms and conditions of the exchange.[651] Additionally, unlike the cited case, Respondents have not alleged that their contracts were made subject to the jurisdiction of the CFTC. Further, pursuant to Commission precedent, FERC retains jurisdiction over these contracts. For instance, FERC retains jurisdiction over plants in which construction has been cancelled before completion, or the cancellation of deliveries occurred.[652] In so holding, this finding is not contrary to the

[648] As the Nevada Companies admit, the credit downgrade did not refer to and was not the result of the contracts that are the subject of the present proceeding. Ex. MSC-144.

[649] WSPPA at § 27. Ex. NPC-14 at 84-88.

[650] Tr. at 2525:23-2526:11 (Schiffel); Tr. at 4306:13-16 (Price); Ex. EPMI-9 at 6:22-8:9; Ex. MSC-7 at 8:12-15; Tr. at 2484:11-19 (Schiffel); Tr. at 2293:5-9 (Perry); Tr. at 4298:22-4299:16 (Greenshields); Ex. RES-4, RES-5.

[651] *New York Mercantile Exchange*, 74 FERC ¶ 61,311 at 61, 984 n.7. (1996). Additionally, claimants have not claimed that the transactions are "risk management transactions," accordingly, 87 FERC ¶ 61, 074 (1999) does not apply.

[652] *New England Power Company*, 8 FERC ¶ 61, 054 (1979) *reh'g denied*, 10 FERC ¶ 61,279 (1980); *aff'd sub nom. NEPCO Municipal Rate Committee v. FERC*, 668 F. 2d 1327 (D.C. Cir. 1981), *cert. denied*, 457 U.S. 117 (1982), through Opinion No. 295, New England Power Company, 42 FERC ¶ 61,016 (1988), *reh'g denied in relevant part*,

Nevada Companies' contention that the termination issue has not been set for hearing. Moreover, it appears this issue would be more pertinent to remedies if it had been deemed the contracts should be modified.

231. As stated above, Complainants have not met their burden of proof under either the public interest or just and reasonable standards.

Issue VI. Whether Merrill Lynch Capital Services or Allegheny Energy Supply Company, LLC (Allegheny) was a real party in interest in the transactions identified in the Nevada Power Company's complaint against Allegheny?

A. Parties Contentions:

232. Citing Section 14 of the WSPPA, the Nevada Companies argue that Allegheny became the successor in operation to Merrill Lynch since it acquired the wholesale electricity trading business of Merrill Lynch, not merely some contracts or assets.[653] The Nevada Companies argue that various provisions of the purchase agreement prove this. To wit, the definitions of "Business," and "Energy Commodities;" the third whereas clause and the listing of assets in Section 2.01 of the Asset Contribution and Purchase Agreement ("Purchase Agreement," "Asset Agreement," or "APA"). In addition, the Nevada Companies contend that further evidence of the acquisition is the following: (a) Allegheny purchased all rights under all sales and purchase orders and under all bids and offers solely related to the Business; (b) Merrill Lynch was required to use "reasonable efforts to obtain the consent of the New York Mercantile Exchange to transfer Seats No. 285 and 733 on the Exchange . . . to Purchasers; (c) Allegheny agreed to offer employment and indeed, hired a number of personnel from Merrill Lynch.[654] Allegheny has repeatedly acknowledged its acquisition in various forums, the Nevada Companies contend.

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43 FERC ¶ 61,285 (1988). *Town of Norwood v. FERC*, 80 F.3d 526 at 530 (D.C. Cir. 1996) (owners could recover 100 percent of its unamortized investment, construction-work-in-progress, decommissioning costs, and the operating expenses of a nuclear power plant which shut down before the plant's license expired). *Jersey Central Power & Light Co. v. FERC*, 810 F.2d 1168 at 1170 (1987) (FERC to hold hearing on treatment of $397 million investment in a nuclear generating station which was never completed); *Connecticut Yankee Atomic Power Company*, 95 FERC ¶ 61,269 (2000) (Commission asserts jurisdiction over charges for a plant which has not been operational since 1996).

[653] Nevada Companies IB at 48-49.

[654] Id. at 50.

233. Additionally, the Nevada Companies argue that the transfer to Allegheny pursuant to Section 14 of the WSPPA was to a successor in operation with comparable or higher creditworthiness.[655] Moreover, the Nevada Companies maintain that since they never objected to the transfer of their contracts and proceeded to do business with Allegheny, instead of Merrill, it *de facto*, consented to the agreement. However, even if consent were deemed to be required, the Nevada Companies argue that they waived such consent.[656] Additionally, the Purchase Agreement along with the Bill of Sale and Assignment constituted an actual assignment of the NPC contract.[657] The Nevada Companies argue that, in one and a half years since entering into the Purchase Agreement, neither Merrill Lynch nor Allegheny made any attempts to obtain consent from the Nevada Companies. This fact, according to the Nevada Companies, evidences that The Nevada Companies' written consent was not necessary. Section 5.05(b) of the Purchase Agreement evidences the fact that all of Merrill's rights under the Nevada Companies' contracts were sold, assigned, transferred, conveyed and delivered to Allegheny and under Section 5.05(c), Allegheny shall fully perform all the obligations under the Nevada Companies contracts.[658]

234. Additionally, the Nevada Companies point out that there are numerous material inconsistencies between Allegheny's position and assertions in this proceeding *vis-å-vis* prior representations to the Commission.[659] For instance, in the Section 203 application, it was represented that Merrill Lynch would be transferring "all of its rights, title and interest" in the relevant contracts. Yet Allegheny now claims it can reject assignment of any contracts, if it is not in its interest, the Nevada Companies aver.[660] Moreover, Allegheny never informed FERC that it would not be seeking assignment of the NPC contracts.[661] Therefore, the Nevada Companies plead that Allegheny is estopped from making directly contrary representations to the detriment of the Nevada Companies.

235. By virtue of the fact that it has the benefits and obligations under the contracts, pursuant to the Purchase Agreement, the Intermediation Services Agreement, Electric Power Master Agreement and Confirmation Agreement, Allegheny is the real party in interest in this proceeding, the Nevada Companies contend.[662] For instance, payment under the Nevada Companies' contracts flow directly to Allegheny under Section 5.05(b)

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[655] Id. at 52.
[656] Id. at 53.
[657] Id. at 55.
[658] Id. at 56.
[659] Id. at 58.
[660] Id. at 58.
[661] Id. at 59.
[662] Id. at 60.

of the Purchase Agreement. In addition, Section 5.05(b) provides that if an agreement is not assigned, Merrill Lynch shall keep it in effect through "Seller Maintained Agreements" and give Allegheny the benefit of the Seller Maintained agreement to the same extent as if it had been assigned. The Nevada Companies argue that, under Section 2.1.1 of the Intermediation Services Agreement, the parties enter into confirmations under the Electric Power Master Agreement, evidencing hedge transactions concerning any seller maintained agreements that are Structured Contracts and Hedge Contracts.[663] Allegheny's status as a party in interest is further evidence of its obligation to perform under the contracts and because it controls the jurisdictional sale of energy, whereas Merrill merely acts as Allegheny's agent, the Nevada Companies argue.[664]

236. Allegheny contends that the Nevada Companies failed to sue the seller of power as required under section 206 of the Federal Power Act. The Asset Agreement and Intermediation Services Agreement, in conjunction with the parties' actions when implementing these agreements, provide clear evidence that there was neither an assignment of the Nevada Companies contracts nor did Allegheny become the successor-in-operation, pursuant to these agreements.[665] Nevada did not provide evidence that the Nevada Companies contracts at issue were assigned from Merrill Lynch to Allegheny, because they were not so assigned.[666] Further, the "Transfer of Interest in Agreement" clause of the WSPP states that assignments require written consent.[667] Therefore, since no written consent from the Nevada Companies exists and since the Nevada Companies never requested assignment, no assignment ever occurred.[668] According to Allegheny, the Intermediation Agreement governs all contracts that were not assigned to Allegheny, and by virtue of this agreement, Allegheny is merely an agent of Merrill Lynch. Moreover, according to Allegheny there are dozens of contracts with twenty counterparties that remain with Merrill Lynch. Additionally, Allegheny asserts that NPC's arguments violate the customary course of dealing in the power industry and if NPC's position prevails, it would lead to a collapse of credit obligations between parties.[669]

237. In addition, pursuant to the Asset Agreement, the Merrill Lynch contract could not be transferred or assigned without counterparty consent.[670] Allegheny avers that their witness Locke McMurray's testimony provides evidence that the parties to the Asset

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[663] Id. at 60.
[664] Id. at 63.
[665] Allegheny IB at 4.
[666] Id. at 4.
[667] Id. at 5.
[668] Id. at 5.
[669] Allegheny RB at 5.
[670] Id.

Agreement understood that counterparty consent was a prerequisite to transfer or assignment, that only one contract was actually transferred at closing, and that according to McMurray and witness Kenneth Blasko, attempts at contractual transfers began either May or June of 2001.[671] Further, McMurray testified that prior to any assignment, Merrill Lynch retains responsibility for invoicing, position monitoring, creating collateral calls, in addition to retaining its status as the counterparty-obligor, responsible for operational risks incident to the contracts.[672] McMurray also testified that in addition to an actual assignment executed by a tri-party transfer, an assumption agreement, needed to exist, with a termination and release agreement between Merrill Lynch and Allegheny.[673] Moreover, McMurray testified that section 5.05(b) allows Allegheny the option of rejecting any assignment of a contract or transaction if certain terms are deemed unreasonable, while continuing with the intermediated hedge agreement.[674] In addition, under section 5.05(b), McMurray testified that Merrill Lynch was not acting either as an agent or a trustee for Allegheny because the contracts at issue were not Seller-Maintained agreements.[675]

238. The interactions between Merrill Lynch and Allegheny after closing the Asset Agreement were consistent with the conclusion that no assignment occurred.[676] Allegheny avers that the course of performance and the acts and conduct between the parties should be accorded great weight in the interpretation of an agreement.[677] In addition, Allegheny contends that witnesses for Merrill Lynch and Allegheny concurred as to their interpretation of the necessary requirements for contractual assignment, that these requirements were not met in regard to the Nevada Companies contracts, and that Merrill Lynch's inclusion of the Nevada Companies contracts on their books is evidence of conduct inconsistent with contractual assignment.[678] Allegheny's witnesses, McMurray and Blasko, also testified that the contracts were not transferred to Allegheny when the parties closed on the Asset Agreement, that such transfers required consent, and that the contracts have not been transferred to date.[679] Allegheny witness, Yair Yaish, explained the logistics of transfers involving counterparties, concluding that since no transfer and assumption agreement had ever been executed, that no assignment took

[671] Id. at 5-6.
[672] Id.
[673] Allegheny IB at 6-7.
[674] Id. at 7.
[675] Id. at 8.
[676] Id. at 9.
[677] Id. at 9.
[678] Id. at 10.
[679] Id. at 11.

place.[680] Further, Allegheny alleges that after the sale of assets, Merrill Lynch retained its status as seller with respect to the contracts at issue while this entity entered into the hedge contracts with Allegheny, whereby Allegheny would financially benefit from these aforementioned contracts via back-to-back hedge agreements.[681]

239. The parties' course of dealing after closing of the asset agreement is consistent with the conclusion that, pursuant to the WSPP agreement, Allegheny is not the successor in operation to Merrill Lynch.[682] In addition, Nevada has conducted business as though Merrill Lynch were the counterparty, as evidenced by Merrill Lynch's sending invoices to Nevada, who then made payments directly to Merrill Lynch.[683]

240. Allegheny avers that three letters, sent five to six months after filing of the complaint, provide further evidence of such conduct, namely one letter written by the Nevada Companies to Merrill Lynch confirming "to all power suppliers" Sierra Pacific Resources' short-term liquidity plan; a second letter from the Nevada Companies to Merrill Lynch confirming understanding of Merrill Lynch's extension of its right to terminate the WSPP agreement for a short duration; a third letter from Merrill Lynch to the Nevada Companies requesting additional collateral for the swap portfolio between the entities.[684] Allegheny asserts that Nevada did not argue that the former succeeded Merrill Lynch's operations either in their answer to Allegheny's answer to the complaint, in the Nevada Companies' direct case, or in their opposition to Allegheny's motion for summary disposition because the Nevada Companies did not regard Allegheny as the successor-in-operation.[685] Moreover, the recent clarification of the definition of "successor in operation" in the WSPP confirms Allegheny's status is not that of a successor.[686] Further, Allegheny contends that it did not acquire the Nevada Companies through restructuring, Merrill Lynch retained certain contracts, Merrill Lynch remained a power marketer pursuant to the Federal Power Act, and this was an asset sale only.[687]

241. Contrary to the Nevada Companies' allegations, Merrill Lynch's representations in their FERC section 203 application for authorization of transfer of jurisdictional assets does not contradict Allegheny's position that there has been no assignment.[688] In fact,

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[680] Id. at 11.
[681] Id. at 12.
[682] Id.
[683] Id.
[684] Id. at 13-14.
[685] Id. at 15.
[686] Id. at 15.
[687] Id. at 16.
[688] Id. at 17.

Allegheny avers that their witness, Blasko, explained that, although Merrill Lynch and Allegheny once intended to assign the Nevada contracts after closing on the Asset Agreement, this intention was abandoned when Nevada refused to sign a collateral agreement with Allegheny. Further, Allegheny argues that Nevada's argument that the section 203 application estops Allegheny from denying assignment lacks merit since the Nevada Companies' witness Pierce, agreed that a transfer of assets required consent(s) and approval(s). Further, the application stated that without assignment, Merrill Lynch would remain the counterparty, entering into intermediated trades with Allegheny; the application acted as notice to FERC that none of contracts might be transferred; the application did not state the prerequisites for obtaining counterparty consent for the asset transfers; section 203 does not place any time limit on disposition of assets and finally, a section 203 order allows, but does not mandate disposition of assets.[689]

A. Discussion/Findings:

242. As a consequence of the rulings under the previous issues in this decision, it may be argued that this issue is a moot issue. However, in order to develop the record, a determination under this issue will be made. The mystery of why the Nevada Companies did not sue Merrill Lynch will never be resolved in this case. There is lack of evidence in this regard. However, the evidence does establish that this is a unique case and not one of just "hedges" as Allegheny contends. As a matter of fact, by virtue of the Asset Contribution and Purchase Agreement ("APA") Merrill Lynch and Allegheny created a very distinct relationship. This distinct relationship does in fact, make Allegheny the "owner" of the contracts in this case and thus, the correct Respondent in this case.

243. Article II of the APA sets forth the purchase and sale of assets as follows:

> <u>Section 2.01 Purchase and Sale of Assets</u>. (a) On the terms and subject to the conditions of this Agreement, MLCS shall, and ML & Co. shall cause MLCS to, sell, assign, transfer, convey and deliver to Rule 58 Company, and Rule 58 Company shall, and Allegheny and Supply shall cause Rule 58 Company to, purchase from MLCS, the following assets and properties of MLCS (such assets being referred to as the "<u>Purchased Assets</u>"):
>
> (i) the Business as a going concern;
>
> (ii) the furniture, fixtures, computers, equipment, machinery and other tangible personal property

[689] <u>Id.</u> at 18-19.

used by the Transferred Employees in the conduct of the Business and listed on Schedule 2.01(a)(ii) and owned or held by MLCS at the Closing Date; provided that if Sellers cannot deliver any of such assets, Sellers shall pay Purchasers' costs of acquiring such assets as are not delivered, up to an aggregate amount of (XXX);

(iii) the goodwill of MLCS relating solely to the Business;

(iv) rights to the Intellectual Property to the extent provided in the Intellectual Property License;

(v) subject to Section 5.05 and to the extent provided in Section 5.17, (x) all Structured Contracts, Hedge Contracts, Master Agreements, transactions (whether governed by the Master Agreements or not), contracts and other agreements which expire on or after March 1, 2001 relating to Energy Commodities to be transferred by MLCS to Supply pursuant to this Agreement and listed on Schedule 2.01(a)(v), and any similar transactions or contracts entered into after the date hereof and prior to the Closing and prior to March 1, 2001, and identified in a written notice provided to the Purchasers by the Sellers immediately prior to or on the Closing Date) together with all rights, including the right to receive payment of accounts receivable, arising under such Structured Contracts and existing on the Closing Date, less those transactions or contracts that, prior to the Closing Date, have expired or have been fully performed or duly terminated in accordance with their respective terms (and in accordance with the terms of this Agreement) and (y) all rights of MLCS under all other contracts, licenses, sublicenses, agreements, leases, commitments listed on Schedule 2.01(a)(v) (the terms set forth in clauses (x) and (y) of this Section 2.01(a) (v) being the "Transferred Contracts") together with all rights, including the right to receive payment of accounts receivable, arising under such Transferred Contracts and existing on the Closing Date;

(vi) subject to Section 5.05, all rights of MLCS under all sales and purchase orders and under all bids and offers solely

> related to the Business and all accounts receivable related to the assets set forth in this clause (vi);
>
> (vii) the memberships in exchanges or clearinghouses or other rights (whether by contract, equity ownership or otherwise) to trade or clear transactions on or through exchanges, clearinghouses, facilities, systems, platforms or other entities (including, but not limited to, electronic trading facilities) that are listed on Schedule 2.01 (a)(vii);
>
> (viii) originals or copies of all books, records, ledgers, files, reports, accounts, data, plans and operating records, whether in hard copy, electronic format, magnetic or other media, which are related to the Business (it being understood that any operating records or accounts that are related to the Business which are included in MLCS's operating records or accounts shall not constitute a Purchased Asset); and
>
> (ix) all claims, causes of action, choses in action, rights of recovery and rights of setoff of any kind (including rights to insurance proceeds and rights under and pursuant to all warranties, representations and guarantees made by suppliers of products, materials, or equipment, or components thereof) related to any of the Purchased Assets described in clauses (i)-(viii) above.

Ex. NPC-57 at 14-16.

244. A simple reading of Section 2 of the APA shows that the going concern, the goodwill, assets, employees, computer software, seats in the New York Mercantile Exchange, power contracts, etc. were transferred by virtue of this agreement. The conclusion to be reached from reading this section is that it was the intent of the parties at the time of closing to transfer to Allegheny power contracts belonging to Merrill Lynch. This is the relationship between these two parties. Thus, as to Merrill Lynch and Allegheny, the contracts were, in fact, transferred. However, the APA also recognized that third party consents would be necessary for the transfer of some contracts. Allegheny witnesses testified that only one contract was, in fact, transferred at the time of closing. For those contracts requiring third party consents, Section 5.05 of the APA is applicable.

245. Section 5.05 of the APA establishes that if the consent necessary for "Transferred Contracts" is not obtained prior to closing, the Sellers will, subsequent to the closing

cooperate with the Purchasers in attempting to obtain such consent. Thus, this section is very significant since it establishes that there are "Transferred Contracts" (as between Merrill Lynch and Allegheny) for which there is missing third party consent. It is for these contracts that Section 5.05(b) was established.

246. Section 5.05(b) of the APA, establishes that after the closing Allegheny could not object to consents with unreasonable terms and the Sellers would use commercially reasonable efforts to obtain consent. If any Transferred Contract cannot be transferred without consent or waiver, then the APA would not constitute an assignment or transfer of such contracts. Moreover, if any consents for any agreement were not obtained prior to closing (and thus, the agreement has not been assigned) the Seller shall keep such agreements in effect ("Seller-Maintained Agreements") and give Purchaser the benefit of such agreements as if they had been assigned. The specific language provides:

> If any consent for any agreement is not obtained and such agreement shall not be assigned, transferred, leased, subleased, licensed or sublicensed, the Sellers shall, to the extent possible without incurring any liability to any third party for which the Purchasers have not agreed to reimburse the Sellers, keep the agreement in effect (such agreements kept in effect are referred to herein as the "<u>Seller Maintained Agreements</u>") and to the extent reasonably possible give the Purchasers the benefit without limitation: (i) cooperating with the Purchasers in holding any rights under agreements for which no consent to assign rights to Purchaser is obtained ("<u>Non-Assignable Rights</u>") in trust for the Purchasers or acting as agent for the Purchasers; (ii) enforcing any rights of the Sellers arising from such Non-Assignable Rights against the issuers thereof or the other party or parties thereto; (iii) taking all such actions and doing, or causing to be done, all such things at the request of the Purchasers as shall be reasonably necessary and proper in order that the value of any Non-Assignable Rights shall be preserved and shall inure to the benefit of Purchasers; and (iv) paying over to the Purchase[r]s all monies or other assets collected by or paid to the Sellers in respect of such Non-Assignable Rights.

Ex. NPC-57 at 40.

247. Pursuant to the APA, the rights to the non-transferred contracts passed from Merrill Lynch to Allegheny, and it is these rights that govern the contracts at issue. Thus, Allegheny is correct, that third party consents have not been obtained for some Transferred Contracts. However, Allegheny is not correct in contending that Section 5.05(b) does not apply to these contracts. Expressed in other terms, the finding in this

case is that for those Transferred Contracts which did not have third party consents, and thus, the transfers have not been consummated *de facto*, section 5.05(b) applies. The express language of Section 5.05(b) states that Merrill Lynch became a trustee of Allegheny, who took on the role of beneficiary of the non-transferred contracts. This caveat makes the relationship between the parties unique, without which the ruling would have been different. Therefore, Allegheny is the principal in this relationship. Consequently, Allegheny is the correct Respondent in this case.

248. Nothing in the Intermediation Services Agreement ("ISA") contradicts this finding. As a matter of fact, the ISA supports this finding. Allegheny's assertions will be given substantial weight in that the ISA is applicable to this situation. The ISA provides that the service is for ". . . hedge transactions ("Pass-Through Transactions") in respect of (a) Seller-Maintained Agreements that are Structured Contracts and Hedge Contracts (each an "Existing Intermediation Transaction") and (b) Future Intermediation Transactions."[690] Additionally, under the ISA, Allegheny held Merrill Lynch harmless in connection with Existing Intermediation Transactions.[691] This agreement provides that Sellers (Merrill Lynch) shall not have liabilities to Allegheny unless and to the extent that, Merrill Lynch actually receives corresponding and equal payment or delivery from Client. Finally, this agreement also provides that Merrill Lynch's relationship to the Purchasers is that of an "[i]ndependent contractor only."[692] Therefore, Allegheny's argument that, under this agreement, it is merely an agent of Merrill Lynch is meritless. The relationship as described, is more than Allegheny merely acting as an agent of Merrill Lynch.

249. Witness White testified that by the terms of the Asset Agreement, specifically section 5.05(b) of the Asset Agreement, Merrill Lynch became an agent of Allegheny, who took on the role of principal in regard to the non-transferred contracts.[693] This testimony is entitled to substantial weight. Allegheny contends that Section 5.05(b) does not apply since the contracts at issue are not Seller-Maintained Agreements, while conceding that "the term 'Seller-Maintained Agreement may have been *used differently* in the Intermediation Services Agreement[.]"[694] (emphasis added). However, as witness White points out, the term is not merely used differently in the Intermediation Services Agreement, but is, in fact, used to cover "[s]tructured contracts and [h]edge contracts," and not simply "licensing agreements or software or equipment contracts." Ex. NPC-55 at 12:23-13-6. Moreover, the evidence does not support Allegheny's conclusory allegations that the contracts at issue are not Seller-Maintained Agreements. In the

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[690] Ex. NPC- 57 ISA, Section 2.1.
[691] Ex. NPC- 57 ISA, Section 6.1.
[692] Ex. NPC-57 ISA, Section 8.3.
[693] Ex. NPC-55 at 12: 4-10.
[694] See Allegheny RB at 3, fn 2.

absence of other evidence, reliance upon the plain language of the Asset Agreement and related documents is appropriate.

250. Although interesting, the argument that a successor-in-operation relationship existed between Merrill Lynch and Allegheny is unpersuasive. Section 14 of the Western Systems Power Pool covering a "Transfer of Interest in Agreement states:

> No party shall voluntarily transfer its membership under this Agreement without the written consent and approval of all other Parties except to a successor in operation of the applicable properties of such Party. With regard to the transfer of the rights and obligations of any Party associated with transactions under the Service Schedules, neither Party may assign such rights or obligations unless a) the other Party provides its prior written consent which shall not be unreasonably withheld; or b) the assignment is to a successor in operation whose creditworthiness is comparable to or higher than that of the assigning Party.[695]

251. Witness White testified that pursuant to the Western Systems Power Pool Agreement, the term "successor-in-operation" is currently defined as:

> The successor entity which takes over the trading operations of the first entity either through a *merger* or *restructuring*. A Successor in Operation shall not include an entity which merely acquires power sales contracts from the first entity either through a purchase or by other means without taking over the wholesale electric trading operations of the first entity. NPC-55 at 16:2-9 (emphasis added).

252. However unique the relationship between Merrill Lynch and Allegheny may be, the terms and conditions, as set forth in the Asset Contribution and Purchase Agreement, the Intermediation Services Agreement, Electric Power Master Agreement, ISDA Master Agreement do not support the finding that there was a merger or restructuring. Therefore, Allegheny is not the successor-in-operation to Merrill Lynch. Allegheny established that Merrill Lynch continued its trading operations on a reduced basis.

253. Nevada Power's contention that written consent was not a prerequisite to assignment because the Purchase Agreement in conjunction with the Bill of Sale and

[695] Ex. NPC-14 at 51-52.

Assignment *effectively* created an assignment of the contracts at issue is not persuasive, as to third parties. As discussed above, under Section 14 of the WSPPA, consent from third parties is required before an assignment of a transaction can take place. However, it bears mention that Section 5.05(b) of the APA allows waiver of consent. To wit, the section states "without the consent or waiver of . . . third party." Nevada Power alleges it waived the consent requirement. By virtue of the findings above, the waiver or the Section 14 consent issue need not be reached.

254. Witness White persuasively testified that the Bill of Sale and APA effectively created an assignment of the contracts at issue. This testimony is found persuasive as to the relationship between Merrill Lynch and Allegheny. Furthermore, the following testimony from this witness is found persuasive: "my understanding is, I assume if I were Merrill Lynch I would like to be released from my liability under these [contracts] by the counterparties. If I assign the contract to a third party to Allegheny, I'm not released, I still have liability, as I answered you before."[696]

255. Additionally, witness White testified that "they [Allegheny] could have decided not to pursue negotiations with the counterparties *that would have the effect of releasing Merrill Lynch from liability* in effect as a guarantor of Allegheny's performance."[697] The wording of the Transfer and Assumption Agreement in conjunction with the APA supports this, finding that the reason behind the requirement is to release Merrill Lynch from liability.

256. Nevada Power also contends[698] that, pursuant to Commission precedent, a party with a financial stake in the outcome of a case suffices to make it a real party in interest. However, Allegheny maintains that the cases cited by Nevada Power are distinguisable from the facts in this proceeding, and are therefore, inapplicable. The cases cited[699] are

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[696] Tr. at 3068:3-12.

[697] Tr. at 3068: 23-29 and Tr. at 3069:1 (emphasis added).

[698] Nevada Power Company also alleges that Allegheny made inconsistent representations to FERC, and as a result, is now estopped from arguing that the contracts at issue have not been assigned. NPC IB at 59 citing *New Hampshire v. Maine*, 532 U.S. 742 (2001). It is found that Allegheny did not make inconsistent representations to FERC, thus the estoppel doctrine is not applicable.

[699] *United Gas Pipe Line Company,* 20 FERC ¶ 63,050 (1982); *El Paso Natural Gas Company,* 40 FERC ¶ 63,047 (1987); *Tennessee Gas Pipeline Company, et al.,* 22 FERC ¶ 61,146 (1983); *Texas Eastern Transmission Corporation,* 50 FPC ¶ 1419 (1973); *Pan American Petroleum Corporation, et al.,* 29 FPC ¶ 1216 (1963); *Philco Corporation v. FCC,* 257 F.2d 656 at 658 (D.C. Cir. 1958); *In re Michael O'Dell and Linda O'Dell,* 268 BR 607 at 615 (N.D. Ala. 2001).

persuasive in terms of supporting arguments for intervention *ab initio*. However, this issue is not the issue in this case. Since the issue in this case is whether Allegheny is the appropriate respondent in this proceeding, the cases are inapposite. Accordingly, the findings under this issue are based on the actual terms and conditions of the Asset Agreement itself which defines the relationship created between Nevada Power and Allegheny, as discussed above. Interpretation of this and the other agreements between these entities leads to the finding that Allegheny is the correct Respondent in this proceeding.

CONCLUSION

257. As stated above, it is concluded that the *Mobile-Sierra* public interest standard is the applicable standard for use in this case. It is further concluded that under the public interest standard, Complainants failed to prove that the Cal ISO and PX spot markets adversely affected the long-term bilateral markets. As a result, it is concluded that the contracts at issue in this case should not be modified. Therefore, it is concluded that the complaints should be dismissed. Additionally, it is concluded that Allegheny was the proper Respondent in the Nevada Power proceeding.

258. **WHEREFORE, IT IS ORDERED**, subject to review by the Commission on appeal or on its own motion as provided in the Commission's Rules of Practice and Procedure, that the complaints filed by the Nevada Companies, Sierra Pacific, Southern California Water Company and Snohomish be dismissed.

Carmen A. Cintron
Presiding Administrative Law Judge