124 FERC ¶ 63,015
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Southwestern Public Service Company Docket No. ER06-274-007

INITIAL DECISION

(Issued August 29, 2008)

APPEARANCES

Clark Evans Downs, Esq., *Carolyn Y. Thompson, Esq., and Brooke M. Proto, Esq.* on behalf of Southwestern Public Service Company

Robert A. O'Neil, Esq., Craig W. Silverstein, Esq., and Bethany Pribila, Esq. on behalf of Golden Spread Electric Cooperative, Inc.

James W. Bushee, Esq. on behalf of Occidental Permian, Ltd.

Robert Weinberg, Esq., Eli D. Eilbott, Esq., and Kathleen L. Mazure, Esq. on behalf of Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc. (collectively, New Mexico Cooperatives).

Jeffrey M. Jakubiak, Esq. on behalf of Public Service Company of New Mexico

David S. Berman, Esq. on behalf of Cap Rock Energy Corporation

Joel M. Cockrell, Esq. and Renee Terry, Esq. on behalf of Commission Trial Staff

CHARLOTTE J. HARDNETT, Presiding Administrative Law Judge

I. PROCEDURAL HISTORY

The Rate Case

1. Southwestern Public Service Company (SPS) filed revisions to wholesale full and partial requirements customers' rates and rate design on December 1, 2005, pursuant to section 205 of the Federal Power Act, 16 U.S.C. § 824d (section 205). The Commission, by its order of January 31, 2006, conditionally accepted SPS' proposed revisions for filing, suspended the rates to become effective, subject to refund, on July 1, 2006, and set the matter for hearing in Docket No. ER06-274-000 (Rate Case).[1] The Commission held the hearing in abeyance pending the outcome of settlement judge procedures.

2. A settlement judge was appointed in the Rate Case by order of the Chief Administrative Law Judge (Chief Judge) issued February 6, 2006. Settlement negotiations were conducted throughout the first half of 2006 and ultimately yielded: (1) a partial settlement between SPS and its Full Requirements Customers – New Mexico Cooperatives (NMC)[2] and Cap Rock Energy Corporation (Cap Rock) (Full Requirements Settlement Agreement); and (2) a separate settlement between SPS and the Public Service Company of New Mexico (PNM) (PNM Settlement Agreement). The Full Requirements Settlement Agreement was filed before the Commission on September 7, 2006 and was approved by Commission order issued September 20, 2007.[3] The PNM Settlement was filed before the Commission on September 19, 2006 and remains pending before the Commission.

3. SPS was unable, however, to reach a negotiated settlement with one of its partial requirements customers, Golden Spread Electric Cooperative, Inc. (Golden Spread), and one of its retail customers, Occidental Permian, Ltd. (Occidental). Accordingly, the Chief Judge, in an August 2, 2006 order, severed Golden Spread

---

[1] *Southwestern Pub. Serv. Co.*, 114 FERC ¶ 61,091 (2006).

[2] The utilities comprising the NMC are: Farmers Electric Cooperative, Inc.; Lea County Electric Cooperative, Inc.; Central Valley Electric Cooperative, Inc.; and, Roosevelt County Electric Cooperative, Inc.

[3] *Southwestern Pub. Serv. Co.*, 120 FERC ¶ 61,243 (2007).

and Occidental from the settlement proceeding in Docket No. ER06-274-000, and initiated hearing procedures and appointed a presiding Administrative Law Judge (presiding ALJ) in Docket No. ER06-274-003. By order of the presiding ALJ, a procedural schedule was established. The participants submitted testimony in the proceeding; however, the Chief ALJ again suspended hearing procedures on March 29, 2007 to allow the participants to resume settlement negotiations. This round of settlement negotiations resulted in a settlement between SPS, Golden Spread, and Occidental on all issues raised in the Rate Case save the appropriate demand cost allocator methodology to be applied to the SPS System (System) from July 1, 2006 through June 30, 2008 (Locked-In Period). Accordingly, by order of February 5, 2008, the Chief Judge re-initiated hearing procedures in Docket No. ER06-274-007 to determine the appropriate demand cost allocator methodology to be applied to the System during the Locked-In Period.

4. The presiding ALJ convened a pre-hearing conference on February 14, 2008. In her February 19, 2008 Order Establishing Procedural Schedule (February 19, 2008 Order), the presiding ALJ noted that participants had stated in the December 3, 2007 offer of settlement filed in ER06-274-000 that the case was postured such on the issue of the appropriate demand cost allocator methodology that it could be promptly litigated after acceptance of the offer of settlement. The offer of settlement stipulated that discovery had ended, and initial, answering, and rebuttal testimony had been filed on the issue of the proper demand cost allocator methodology prior to the suspension of the procedural schedule in that proceeding. Therefore, the presiding ALJ ordered the participants to resubmit the testimony proffered in ER06-274-003, with testimony not dealing with the demand cost allocator methodology issue redacted. No participant sought reconsideration of the February 19, 2008 Order. SPS filed on June 6, 2008 an unopposed motion to supplement the record with rebuttal testimony of David T. Hudson. Mr. Hudson's testimony was responsive to the testimony of Golden Spread witness Stephen Page Daniel. The presiding ALJ granted SPS' motion on June 18, 2008.

The Complaint and FCAC Proceedings

5. On November 2, 2004, SPS requirements service customers Golden Spread, Lyntegar Electric Cooperative, Inc. (Lyntegar), and NMC, (Wholesale Cooperative Customers) filed a complaint in Docket No. EL05-19-000 in which it was alleged that SPS was violating the fuel cost adjustment clause (FCAC) provisions of its wholesale customers' rate schedules and Commission FCAC regulations (Complaint Proceeding). Concurrent with the Wholesale Cooperative Customers' complaint, SPS filed in Docket No. ER05-168-000, pursuant to section 205, proposed revisions to its FCAC and power supply contracts, contending that such revisions were necessary to conform to the Commission's current fuel cost and purchased economic power adjustment clause regulations

(FCAC Proceeding). The Complaint Proceeding and FCAC Proceeding were subsequently consolidated[4] and set for hearing.

6. A hearing was conducted in Docket Nos. EL05-19-002 and ER05-168-001 at which SPS argued that a 12 Coincident Peak demand cost allocator methodology (12 CP Methodology) was more appropriate on the System despite the fact that it had historically used a 3 Coincident Peak demand cost allocator methodology (3 CP Methodology). The presiding ALJ issued an initial decision in the above-referenced dockets on May 24, 2006, in which he ordered SPS to continue to use a 3 CP Methodology.[5] Between July and November of 2007 the parties filed three motions requesting that the Commission withhold action on the initial decision pending the outcome of settlement discussions. The Commission granted the motions.

7. SPS filed a settlement agreement on behalf of itself, Golden Spread, Lyntegar and Occidental on December 3, 2007 in Docket Nos. EL05-19-000, ER05-168-000, and ER06-274-000 (December 3, 2007 Settlement Agreement). The December 3, 2007 Settlement Agreement resolved all issues except the appropriate demand cost allocator methodology for use on the System. The December 3, 2007 Settlement Agreement was certified to the Commission as unopposed on January 18, 2008, and was approved by the Commission, subject to modification, on April 21, 2008.[6]

8. Also on April 21, 2008, the Commission issued its order on the May 24, 2006 initial decision – Opinion No. 501[7] – in which it overruled the ALJ on the issue of the appropriate demand allocator methodology, finding that SPS had demonstrated that a 12 CP Methodology was appropriate for the System. On March 30, 2008, SPS filed changes to its wholesale full requirement customers' rates and rate design, pursuant to section 205. By its order of May 30, 2008, the Commission conditionally accepted SPS' proposed rates for filing, suspended them for a nominal period, to be come effective June 1, 2008, subject to refund,

---

[4] *Golden Spread Elec. Coop., Inc.*, 109 FERC ¶ 61,373 (2004) (order accepting and suspending proposed fuel adjustment clause changes, establishing hearing and settlement judge procedures, and consolidating proceedings).

[5] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.*, 115 FERC ¶ 63,043 at 65,174 (2006).

[6] Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co., 123 FERC ¶ 61,054 (2008).

[7] *Golden Spread Elec. Coop. v. Southwestern Pub. Serv. Co.* ,Opinion No. 501, 123 FERC ¶ 61,047 at 61,249 (2008).

and established hearing and settlement judge procedures in Docket No. ER08-749-000 (May 30, 2008 Order). Although SPS, out of an abundance of caution because the demand allocator issue was pending before the Commission, had filed using a 3 CP Methodology, the Commission ordered SPS to use a 12 CP Methodology.[8]

9. On June 12, 2008, SPS filed a motion for summary disposition in this proceeding, on the sole issue to be resolved, to wit, the appropriate demand cost allocator methodology for the Locked-In Period (SPS Motion). The SPS Motion was denied because it was erroneously construed as a motion to dismiss. SPS filed a motion requesting that the presiding ALJ reconsider the decision to deny its previous motion for summary disposition on June 17, 2008. The presiding ALJ granted SPS' motion for reconsideration on June 18, 2008. Cap Rock, NMC, and Commission Trial Staff all filed answers supporting SPS' motion for summary disposition.

10. Golden Spread submitted an answer opposing SPS' motion for summary disposition on July 3, 2008. Golden Spread's July 3, 2008 answer also included a cross-motion to hold the hearing in abeyance pending the outcome of rehearing requests on Opinion No. 501. SPS and Cap Rock filed answers opposing Golden Spread's motion to hold the case in abeyance on July 9, 2008 and July 18, 2008, respectively. The Chief Judge suspended the procedural schedule by order of July 11, 2008 in order to accommodate the presiding ALJ's schedule.

II. WITNESS TESTIMONY

11. Five witnesses presented testimony in this proceeding: David T. Hudson and Alan C. Heintz on behalf of SPS; Stephen Daniel Page and Joseph N. Linxwiler on behalf of Golden Spread; and Fred R. Saffer on behalf of NMC.

12. David T. Hudson testified on behalf of SPS. Mr. Hudson is a director of regulatory administration for Xcel Energy Services, Inc., a subsidiary of Xcel Energy, Inc., of which SPS is a subsidiary public utility. In this position Mr. Hudson is responsible for directing and supervising SPS' state and federal regulatory activities, including tariffs, compliance reporting and complaint response. Mr. Hudson has over 22 years of regulatory experience in matters including cost-of-service work, rate design studies, resource planning, and facilities approval. Mr. Hudson has testified numerous times before the Commission and various state regulatory agencies. He is a Texas-licensed engineer. He holds a Bachelor of Science degree in industrial engineering from

[8] *Id.*

Texas Tech University and a Master of Business Administration degree from West Texas State University.[9]

13. Mr. Hudson testified that SPS is filing for an unbundled production-related rate change to recover SPS' increasing production-related cost of service for 2006 and beyond. Pursuant to a rate complaint filed in 2005 in Docket No. EL05-19-002, *et. al.* (Complaint Proceeding), SPS' unbundled wholesale production-related rates are subject to refund for some of its full and partial-requirements wholesale customers. Because the Complaint Proceeding does not reflect a projected test year, Mr. Hudson testified that SPS is concerned that the rates resulting from the Complaint Proceeding will not be adequate to recover SPS' current and future production costs. This deficiency, combined with the loss of a large wholesale customer, Lyntegar, will negatively impact SPS' wholesale loads and rates. The instant rate change was filed, Mr. Hudson testified, to set compensatory production-related base rates applicable to wholesale customers SPS will serve in 2006 and beyond.[10]

14. Mr. Hudson testified that Golden Spread is a partial-requirements customers; its contract with SPS terminates in April 2012. Cap Rock and NMC are full requirements customers of SPS.[11]

15. Mr. Hudson testified that the majority of the participants in the Complaint Proceeding, including Cap Rock, NMC and Trial Staff support the use of a 12 CP Methodology on the System and have testified accordingly. This position is premised on data taken from calendar years 2000 through 2006. Mr. Hudson testified that this data establishes that SPS' demand curve is, and will continue to be, relatively flat and, as such, a 12 CP Methodology is appropriate on the System.[12]

16. Mr. Hudson testified that there are three load ratio tests used by the Commission to determine the flatness of a utility's demand curve for purposes of establishing whether a 12 CP Methodology would be appropriate for the utility. The first test, which compares the average of utility peaks during the peak months as a percentage of the annual peak to the average of the peaks during non-peak months as a percentage of the annual peak (On & Off Peak Test) shows an average

---

[9] Ex. SPS-1 at 4-5.

[10] *Id.* at 7.

[11] *Id.*

[12] *Id.* at 18.

19 percent difference between off-peak and on-peak levels on the System, hardly a substantial difference, according to Mr. Hudson.[13]

17. Mr. Hudson testified that the second measure used by the Commission to determine demand curve flatness, which calculates the lowest monthly peak as a percentage of the annual peak (Low to Annual Peak Test), also indicates a relatively flat demand curve for the System. The lowest monthly peak is, on average, 68 percent of the annual peak level for the System, sufficiently above, in Mr. Hudson's opinion, the 66 percent load ratio threshold which the Commission has found supports a 12 CP Methodology.[14]

18. Mr. Hudson testified that the third test used by the Commission, which determines the average of the 12 monthly peaks as a percentage of annual peak demand (Average to Annual Peak Test), indicates that the monthly peaks are, on average, 82.5 percent of peak demand, above the 81 percent load ratio threshold which the Commission has found supports a 12 CP Methodology. In sum, Mr. Hudson, asserts, all tests used by the Commission to determine whether a 12 CP Methodology is appropriate for a utility indicate such a methodology is appropriate for the System. [15]

19. Mr. Hudson testified that Mr. Daniel's assertion that the firm power sales SPS made to El Paso Electric Company (EPE) and the Public Service Company of New Mexico (PNM) in 2006 are opportunity sales properly attributed to incremental fuel costs is an erroneous position premised on a illusory semantic distinction. Mr. Hudson testified that opportunity sale are properly construed as short-term non-firm sales which the buyer enters into to lower its short-run energy costs; the EPE and PNM sales do not match this description. Mr. Hudson testified that the EPE and PNM sales are firm sales of the same nature and character of "traditional requirements service sales," as defined by Mr. Daniel. The EPE and PNM sales represent firm wholesale service obligations which SPS takes into account in its power supply planning with a curtailment priority only second to SPS' own retail customers, Mr. Hudson testified.[16]

20. Mr. Hudson also takes issue with Mr. Daniel's definitions of traditional requirements sales and opportunity sales. Mr. Daniel distinguishes the two on the basis of where the sales are made – either within or outside of the supplier's

---

13 *Id.*

14 *Id.*

15 *Id.*

16 Ex. SPS-47 at 7-8.

control area. Mr. Hudson testified that he is not aware of the Commission making such distinction and, in fact, believes it to be inconsistent with the Commission's policy of broadening wholesale markets, as well as being both anti-competitive and geographically discriminatory. Distinguishing purchaser's load on the basis of location would also be a violation of the Federal Power Act's prohibition on unreasonable differences in rates between localities or service classes. The EPE and PNM sales at issue in the proceeding represent only one of the more recent transactions in a relationship between SPS and EPE and PNM that stretches for decades. Both EPE and PNM are longstanding partial requirements customers of SPS that have relied on power purchased from SPS to meet peak load responsibilities for their own retail customers. According to Mr. Hudson, because SPS delivers power to both customers on the SPS side of the Eddy County tie that connects the System to Western Electric Coordinating Council's transmission network, both customers are, as a matter of "electrical fact," in the SPS control area even if they are not so geographically.[17]

21. Mr. Hudson testified that, in order to carry out its contractual obligations to EPE and PNM, SPS must, at all times, have available generating capacity sufficient to supply the amounts of capacity it has contracted to provide to EPE and PNM. As such, Mr. Hudson testified, these sales are properly classified as "firm" sales, which are not subject to interruption by the supplying utility absent circumstances beyond its control. They are not "inter-system" sales, which are short term in nature, have lower priority and are subject to interruption on a purely economic basis. Mr. Hudson testified that opportunity sales are properly considered inter-system sales because they are made only when the seller has sufficient capacity and electricity available. Given the fulfillment requirements SPS has with the EPE and PNM sales, it is categorically inappropriate to identify the transactions as opportunity sales, according to Mr. Hudson.[18]

22. Mr. Hudson testified that the language in the EPE and PNM firm capacity sales contracts that gives priority to SPS' native load customers does not render the EPE and PNM sales opportunity sales. While the Commission requires that native load and firm service customers be accorded similar curtailment priorities, Mr. Hudson testified that it is standard practice in the industry to give curtailment priority to native load obligations over off-system firm sales, such as those made to EPE and PNM. Practically speaking, however, Mr. Hudson testified, SPS maintains reserves for all its firm loads, including those firm sales – like those with EPE and PNM-- subject to a native load curtailment priority. Perhaps more importantly, SPS has never invoked such curtailment priorities, Mr. Hudson

[17] *Id.* at 8, 10, 16.

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

testified. In light of this evidence, Mr. Hudson testified, the EPE and PNM sales are categorically firm system capacity sales and not, as Mr. Daniel contends, opportunity sales as defined in the industry and by the Commission.[19]

23. Mr. Hudson testified that he disagrees with Mr. Daniel's recommendation that the revenues associated with the EPE and PNM sales should be revenue credited. Mr. Hudson testified that mischaracterizing the EPE and PNM sales as "opportunity sales" as Mr. Daniel's does, would result in a substantial revenue credit at SPS' expense. The EPE and PNM sales are firm contract capacity sales and, as such, should be treated exactly as the sales to Golden Spread, with proportionate demand-related costs allocated in the cost-of-service study.[20]

24. Mr. Hudson testified that the EPE and PNM sales were made under SPS' market-based rate tariff at rates designed to recover SPS' embedded costs. SPS' market rates include a negotiated demand charge comparable to the demand charge assessed to Golden Spread in its contract. As such, Mr. Daniel's assertion that that the EPE and PNM sales contracts are at a rate higher than SPS' current average system-production-related capacity costs is erroneous and merely another attempt, in Mr. Hudson's opinion, to justify a windfall revenue credit at SPS' expense.[21]

25. Mr. Hudson testified that he also rejects Mr. Daniel's assertion that the EPE and PNM sales result in an improper "cross-subsidy." Any new sale, whether cost or market-based, will change utility running costs, according to Mr. Hudson. The suggestion of a cross-subsidy intimates that one customer class is inappropriately subsidizing another customer class. There is no such impropriety on the System, contends Mr. Hudson. EPE, just like Golden Spread, can purchase a block of capacity from SPS for whatever use it desires. Both are firm capacity sales backed by the full resources of SPS' power supply portfolio over a multi-year period requiring capacity planning additions by SPS in order to meet its obligations, Mr. Hudson testified.[22]

26. Mr. Hudson concluded that there is no valid basis upon which to distinguish SPS' firm power sales to EPE and PNM from those it makes to Golden Spread. All are multi-year obligations which require capacity planning by SPS to ensure that the respective load requirements are fulfilled. It is inappropriate to

[19] *Id.* at 13.

[20] *Id.* at 14.

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

[22] *Id.* at 15.

distinguish the sales on the basis of whether the sale is made pursuant to a market-based tariff or a cost-based contract. All three sales place a capacity demand on the System and as such the costs associated with those capacity requirements should be factored in to the cost-of-service study.[23]

27. Alan C. Heintz testified on behalf of SPS. Mr. Heintz is a vice president with Brown, Williams, Moorhead & Quinn, Inc. where he provides consulting services on matters relating to power sales, transmission and ancillary service issues associated with Commission Order Nos. 888, 889, 890 and 2000. Mr. Heintz has over twenty years of experience in the utilities field, both as a consultant and with the Commission, where he served as Public Utilities Specialist in the Rate Filing branch and Section Chief for the Division of Applications. Mr. Heintz has testified in numerous proceedings before the Commission and various state and international regulatory agencies. He has been particularly involved in proceedings involving ISOs and RTOs including MISO, NY ISO, ISO New England and California ISO. Mr. Heintz holds a Bachelor of Science in Business and Bachelor of Arts in Economics from the University of Colorado, Boulder, and a Masters of Business Administration from the George Washington University.[24]

28. Mr. Heintz testified that demand cost allocators are used to distribute among customer classes those costs the utility incurs as a function of the capacity required to generate electricity. The amount and type of capacity required is a function of the load pattern that the utility expects to experience in a calendar year. A demand cost allocator is a fractional ratio representing the ratio of a particular customer class's load to the utility's aggregate load. Mr. Heintz testified that the utility uses the demand cost allocator to determine the revenue requirement associated with each customer class; this is done by multiplying the demand cost allocator by the utility's demand related costs.[25]

29. Mr. Heintz testified that the Coincident Peak method (CP Method) of demand cost allocation allocates to each customer class a share of the test year costs of generating capacity based upon that class's proportionate use of capacity at peak system demand times. The Commission uses this methodology because it ensures that the cost of generating capacity is proportionally born by those customers who require the utility's generated capacity.[26]

---

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

[24] Ex. SPS-61 at 4-5.

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

[26] *Id.* at 7.

30. Mr. Heintz testified that the "threshold issue" in determining which CP Method is appropriate for a utility is which peak periods contribute the most to the utility's capacity costs. The Commission looks to factors such as the utility's load pattern, maintenance schedule, unscheduled outages, reserve requirements and short-time firm power sales to determine a utility's peak period(s).[27]

31. Mr. Heintz testified that which demand cost allocator is applied to a utility is important because it determined what proportion of demand-related costs each customer class will have to pay. Mr. Heintz testified that the Commission supported the use of a 12 CP Methodology in Order Nos. 888 and 888-A because it believes most utilities plan to meet twelve monthly peak times. The Commission did not, however, foreclose the possibility of utilities using other demand cost allocator methodologies, Mr. Heintz testified. Mr. Heintz testified that a 12 CP Methodology is appropriate because a utility is required to ensure its generational resources will meet it firm load requirements at all times, not just at one, or a few, maximum load times in a given calendar year.[28]

32. Mr. Heintz reiterated that Commission precedent supports the use of a 12 CP Methodology where a utility's demand curve is relatively flat. In addition to the three principal tests for determining demand curve flatness – On & Off Peak Test, Average to Annual Peak Test, and Low to Annual Peak Test – the Commission uses two ancillary tests to determine a utility's demand curve shape. The first test determines whether any off-peak months in a year exceed the lowest monthly demand in a peak period in the same year (Peak Month Identifier Test). If the monthly peak in an off-demand month is higher than the monthly peak in a month identified as a peak month, then it may be assumed that the peak months are not, in fact, months with highest monthly-peaks and the utility's demand curve is relatively flat, according to Mr. Heintz. The other test, determines whether off-peak months in a year exceed the lowest monthly peak in a preceding year's peak season. (Preceding Peak Year Test). This test, according to Mr. Heintz, identifies if winter peaks are higher than prior summer peaks, which would indicate a relatively flat demand curve. Mr. Hudson testified that all five of these tests indicate that SPS has a relatively flat demand curve such that a 12 CP Methodology could appropriately be applied to the System.[29]

33. Mr. Heintz testified that the results he arrived at for the On & Off Peak Test, Average to Annual Peak Test, and Low to Annual Peak Test differ from the

[27] *Id.*

[28] *Id.* at 8.

[29] *Id.* at 9-12.

results of Mr. Linxwiler (which indicate a 12 CP Methodology is not appropriate) because Mr. Linxwiler erroneously decided not to take into account SPS' firm sales to other utilities. This omission resulted in a computation which yielded lower peak load values; it is also inconsistent with Commission policy that all firm sales should be accounted for to establish the full picture of a utility's operational obligations. Because a utility commits to firm sales at a contract demand level that is to be made available for delivery in any hour in a calendar year, including such demand levels in peak load values effectively flattens the utility's demand curve, Mr. Heintz testified. Mr. Heintz asserts that Mr. Linxwiler did not consider this information in his analysis specifically because it would yield a flattened demand curve for the System.[30]

34. Mr. Heintz testified that, contrary to Mr. Linxwiler's assertion, the fact that SPS is not "maintenance saturated" does not mean that a 12 CP Methodology is in appropriate for the System. The Commission has previously adopted a 12 CP Methodology for utilities which, like SPS, schedule their planned maintenance in non-summer months; a policy which enables SPS to insure adequate capacity at a lower cost by taking advantage of the greater capacity reserves available in off-peak months.[31]

35. Mr. Heintz testified that his analysis indicates SPS is no longer a 3 CP Methodology utility; a 12 CP Methodology is more appropriate. Mr. Heintz testified that Mr. Linxwiler's assertion that a 3 CP Methodology must continue to be applied to the System because SPS has not demonstrated changed circumstances warranting a change in demand cost allocator methodology is meritless. Mr. Heintz testified that the purpose of the changed circumstances requirement is to avoid relitigation of decided issues. When, as here, the issue of the appropriate demand cost allocator methodology was litigated more that 20 years ago, it is appropriate, if not necessary as a matter of public policy, to look at recent operating trends of the utility to establish which demand cost allocator methodology is appropriate.[32]

36. Stephen Page Daniel testified on behalf of Golden Spread. Mr. Daniel is a founding principal of GDS Associates (GDS), an engineering and consulting firm. As a principal with GDS, Mr. Daniel is primarily responsible for providing consulting services relating to power industry regulation and ratemaking, power supply planning, and transmission access. Mr. Daniel has over 36 years of

---

[30] *Id*. at 12- 13.

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

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

consulting experience in the power industry, 20 of which are with GDS. He has testified extensively before the Commission and numerous state regulatory bodies during his career. Mr. Daniel holds a Bachelor of Industrial Engineering degree from Georgia Institute of Technology and a Master of Business administration degree from Georgia State University, with an emphasis in finance.[33]

37. Mr. Daniel had also testified on behalf of Golden Spread in the proceeding in ER05-168-000, which addressed issues associated with the complaint proceeding submitted in the Complaint Proceeding. Mr. Daniel testified that he believes the Complaint Proceeding encompasses several issues relevant to the present rate litigation, specifically: (1) whether SPS cost based rate are excessive; and (2) whether SPS has violated the terms and conditions of the fuel adjustment clause set forth in its filed rates.[34]

38. Mr. Daniel testified that Golden Spread is a tax-exempt, consumer-owned public utility, organized to provide reliable, low-cost electric service to rural distribution cooperative members. Golden Spread is comprised of 16 member systems serving approximately 187,000 retail customers throughout the Oklahoma panhandle and Texas. Golden Spread operates in the Southwest Power Pool and the Electric Reliability Council of Texas. The Commission identified Golden Spread as a public utility subject to its jurisdiction on June 18, 1987, at which time it accepted Golden Spread's initial rates for wholesale full requirements service.[35]

39. Mr. Daniel testified regarding the relationship between Golden Spread and SPS. With the formation of Golden Spread in the early 1980s, the cost-based requirements contracts of its distribution cooperative members located in the SPS control area, members who were previously direct SPS customers, came under Golden Spread's control. In 1998 an agreement was filed before, and subsequently accepted by, the Commission which merged the individual contracts of the cooperative members located in the SPS control area into a single agreement (PR Agreement). The PR agreement is the cost-based agreement under which SPS seeks to increase its rates in the present proceeding. The PR Agreement is an 'evergreen" contract which can only be cancelled upon ten (10) years' prior written notice by either SPS or Golden Spread; SPS provided such notice to Golden Spread in April 2002.[36]

---

[33] Ex. GSE-1 at 1-5.

[34] *Id*. at 7.

[35] *Id*. at 8.

[36] *Id*.

40. Mr. Daniel testified that the projected loads and energy sales in 2006 include off-system, market-based sales to EPE and PNM totaling 133MW and 67 MW, respectively. SPS also provides interruptible sales service to PNM, which was addressed in an unrelated settlement proceeding. Mr. Daniel testified that SPS incorporates the associated loads and energy sales to EPE and PNM in its monthly total system loads and total annual system energy values to develop the demand cost allocator used to allocate costs to Golden Spread. Mr. Daniel testified that this methodology is inappropriate; to correctly incorporate the EPE and PNM contracts into the demand and allocators, Mr. Daniel testified that SPS should calculate an appropriate revenue credit and remove the corresponding loads and energy values from the demand cost allocator.[37]

41. Mr. Daniel described SPS' 2006 sale to PNM as a block sale of 67 MW of capacity and associated energy scheduled by PNW for us. The sale concluded on December 31, 2006. Mr. Daniel testified that it was his understanding that the sale was a market-based sale made in accordance with SPS' market-based rate authority over non-SPS control area purchasers. According to Mr. Daniel, the PNM sale was not subject to the same Commission regulations as the Golden Spread partial requirements sale because Golden spread is a SPS "native load" customer.[38]

42. Mr. Daniel described "traditional requirements load" as the retail or wholesale load which a supplying entity is obligated to plan for and serve on a long-term basis. The obligation may be statutory or contractual. A requirements load sale is distinct from an "opportunity sale" because the latter is a voluntary transaction that generally does not carry the same long-term planning commitment of a requirements load sale, and as such may be less firm than a requirements load sale or carry different terms and conditions of service. Mr. Daniel testified that the PNM and EPE sales are not requirements load sales.[39]

43. Mr. Daniel testified that traditional requirements load sales are wholesale and retail sales of capacity and energy to native load customers that are made in response to a regulatory, or long-term contractual responsibility to serve of the supplier. This statutory or regulatory obligation requires the supplier to either construct new generation facilities or make firm purchase to meet its requirements load obligations, including adequate planning reserves, on a firm basis. Requirements loads are virtually indistinguishable from native loads in that both

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

[38] *Id.* at 19.

[39] *Id.* at 21.

share an equivalent service reliability expectation; requirements load customers can expect to be treated no differently than native loads customers during system emergencies in which service may be curtailed or interrupted. Requirements load customers are generally located in the suppliers control area.[40]

44. Mr. Daniel testified that "opportunity" sales are sales made by energy suppliers in the ordinary course of business for primarily economic reasons. Opportunity sales are generally transacted to improve operational efficiency on the system or to market surplus energy and/or capacity. Opportunity sales do not generally place long-term planning and requirements obligations on the supplier.[41]

45. Mr. Daniel testified that both the PNM and EPE sales were opportunity sales. The PNM sale was transacted at a time when SPS had surplus capacity available for sale; it was concluded at the end of 2006.[42]

46. Mr. Daniel testified that he believes the sales to PNM and EPE in the instant proceeding should be treated the same way as the opportunity sales that were the subject of the Complaint Proceeding. There the presiding ALJ determined that the revenues associated with opportunity sales should be counted as credited revenue, as opposed to load and associated energy quantities included in the development of demand and energy allocators for the test year, respectively. Mr. Daniel believes the PNM and EPE sales should be treated in this manner because there is no factual distinction between those sales and the sales at issue in the Complaint Proceeding that warrants different treatment. The only difference between the PNM and EPE sales and those at issue in the Complaint Proceeding is size; the PNM and EPE sales are several hundred MW smaller than those that were at issue in the Complaint Proceeding.[43]

47. Mr. Daniel testified that the PNM and EPE sales should not be included in demand and energy allocators because it would result in an over-recovery of costs by SPS. SPS would realize profits equal to the difference between the average embedded costs allocated to the PNM and EPE sales and the actual rates it charged PNM and EPE for the capacity and associated energy. This profit would accrue directly to SPS' bottom-line profits. Further, Mr. Daniel testified, it would be inappropriate for SPS to include the EPE sale in its allocators because SPS had to purchase additional capacity to meet its load obligation by virtue of its acceptance

---

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

[41] *Id.* at 22.

[42] *Id.* at 22-23.

[43] *Id*. at 23-24.

of the EPE sale. Including the EPE sale in SPS' allocators will effectively force SPS' requirements customers, like Golden Spread, to bear the burden of an allocated share of additional capacity resources which SPS had to purchase to meet its load requirements, while allowing SPS to pocket the profits realized from the opportunity sale to EPE (and PNM).[44] Mr. Daniel testified that the associated capacity and non-fuel energy revenues for revenue crediting for 2006 are as follows:[45]

	EPE	PNM	Total
Capacity	$8,937,600	$5,346,000	$14,284,200
Non-Fuel Energy	$1,731,600	$525,381	$2,256,981
Total	$10,669,200	$5,871,981	$16,541,181

48. Mr. Daniel testified that he calculated the above capacity and non-fuel energy credits by estimating on-peak and off-peak energy schedules for 2006 from the ratios of 2005 on-peak and off-peak sales made to PNM under contract, and the combining those figures with the estimated annual charges incurred by EPE and PNM for day-ahead-schedule changes.[46]

49. Mr. Daniel testified that although SPS proposes a 12 CP Methodology, a 3 CP Methodology, such as the one proposed by Mr. Linxwiler, is appropriate for the System. Mr. Daniel testified that he developed revised demand cost allocators reflecting a 3 CP Methodology that does not include the loads associated with the sales to EPE and PNM because, as he previously testified, the costs associated with those sales should be realized as revenue credits.[47]

50. Mr. Daniel testified that the EPE and PNM sales are unregulated market-based sales. As such, they are opportunity sales which earn higher rates of return at the expense of traditional requirements customers. Mr. Daniels testified that by virtue of the fact that the EPE and PNM sales are both made at average system energy costs rather than incremental energy costs and are contracted at rates higher than SPS current average system production related capacity costs, including the loads associated with the EPE and PNM sales in the divisor of the demand cost allocator allows SPS to realize as profit 100 percent of the difference between the

[44] *Id.* at 24-25.

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

[46] *Id.* at 26.

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

lower average system capacity costs and the higher capacity charges for the EPE and PNM sales.[48]

51. Joseph N. Linxwiler testified on behalf of Golden Spread. Mr. Linxwiler is the owner and chief executive of Linxwiler Consulting Services, through which he provides utility business analysis and rate consultation services. Mr. Linxwiler has 25 years of electric utility industry consulting experience with a concentration in the areas of rates, contracts, strategic planning and inter-utility bulk-power and transmission arrangements. Mr. Linxwiler has testified on numerous occasions before the Commission, as well as various state regulatory bodies and courts. Mr. Linxwiler holds a Bachelor of Electric Engineering Degree with high honors from the Georgia Institute of Technology and has completed significant graduate level course work in electrical and systems engineering and mathematical systems theory. He is a member of the Institute of Electrical and Electronics Engineers.[49]

52. Mr. Linxwiler testified that it is his conclusion that the 12 CP Methodology proposed by SPS is not reasonable and does not provide sufficient justification for deviation from the 3 CP Methodology that has been the basis of SPS' wholesale rates for several decades. Mr. Linxwiler testified that the Commission has twice already ordered a 3 CP Methodology be applied to SPS' wholesale rates.[50]

53. Mr. Linxwiler testified that an allocator is a percentage value that represents a customer class' (i.e. those customers taking service under a particular rate schedule) proportionate contribution to the costs incurred on its behalf relative to costs incurred by all customer classes in aggregate. Allocators are required for each category of costs incurred by customers; costs are categorized on a general causation basis. Demand-related costs are those costs that relate to the serving utility's readiness to serve its customers' highest rates of use. Mr. Linxwiler testified that these costs are also known as capacity-related costs. Mr. Linxwiler testified that the demand cost allocator methodology defines what types of monthly demands are included in the numerator and denominator of the demand cost allocator.[51]

54. Mr. Linxwiler testified that the 12 CP Methodology proposed by SPS is represented as each customer class' average monthly contribution to monthly peak

---

[48] Ex. GSE-64 at 5.

[49] Ex. GSE-40 at 2-3.

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

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

demands over the average of aggregate monthly system peak demands for all customer classes for each month of the test year.[52]

55. Mr. Linxwiler testified that the 3 CP Methodology he proposes differs from SPS' 12 CP Methodology in that the denominator represent the average of total system peak demands during the three months most likely to have the highest demands in a given year; in the case of SPS, June, July and August. Mr. Linxwiler testified that there are other CP methodologies for determining demand cost allocators, namely 1 CP and 4 CP methodologies, and that a company's choice of methodology, or the decision to change methodologies can significantly affect customer rates, as is the case in the instant proceeding.[53]

56. Mr. Linxwiler testified that the Commission, in Opinion Nos. 162 and 337 required SPS to apply a 3 CP Methodology to its wholesale rates. Those decisions were issued in 1983 and 1989, respectively. Mr. Linxwiler testified that more recently, in the Complaint Proceeding, the presiding ALJ ruled that a 3 CP Methodology remained appropriate for the System.[54] In that proceeding, Mr. Linxwiler testified, Trial Staff initially supported a 12 CP Methodology but later withdrew such support, choosing instead to accept the presiding ALJ's determination on the use of a 3 CP Methodology.[55]

57. Mr. Linxwiler testified that he disagrees with SPS Witness David T. Hudson's conclusion that the monthly peak demands of the System have been, and will continue to be, relatively flat. Mr. Linxwiler testified that SPS' peak loads vary substantially by season, with predominant summer peaking. Mr. Linxwiler believes that some of the data Mr. Hudson uses to determine that peak demand on the System is relatively flat is inaccurate and non-representative of demand requirements on the System, and that Mr. Hudson neither accurately nor completely explains the results of his analysis.[56]

---

[52] *Id*. at 5.

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

[54] The Presiding ALJ's decision in the Complaint Proceeding was overturned by the Commission in Opinion No. 501; this testimony was prepared before the issuance of Opinion No. 501, as was all other testimony submitted in this proceeding.

[55] Ex. GSE-40 at 7-8.

[56] *Id.* at 9-10.

58. Mr. Linxwiler testified that Mr. Hudson is erroneous in concluding that the three tests most relied upon by the Commission to determine a utility's appropriate CP method support the use of a 12 CP Methodology on the System. Mr. Hudson completely ignores Commission precedent that supports the use of a 3 CP Methodology on the System, namely Opinion Nos. 162 and 337, according to Mr. Linxwiler. Mr. Hudson fails to point out, according to Mr. Linxwiler, that the three tests the Commission uses to determine if a 12 CP Methodology is appropriate indicate that SPS is very close to the threshold levels at which point the Commission has previously found a 12 CP Methodology is not acceptable. They are, in Mr. Linxwiler opinion, barely indicative of the use of a 12 CP Methodology. These borderline results, Mr. Linxwiler testified, are not sufficiently indicative of a change in peak demand requirements on the system to warrant a shift from a 3 CP Methodology to a 12 CP Methodology.[57]

59. Mr. Linxwiler testified that when results of the tests used by the Commission to determine an appropriate demand cost allocator methodology only slightly weigh in favor of one methodology over the other, other factors and metrics should be considered in determining which is the proper allocation method for the utility.[58] One factor that should be considered, according to Mr. Linxwiler, is proportionality. That is to say, changing a utility's demand cost allocator methodology should be avoided in those situations where a large discontinuity in customer class cost responsibilities would result from a change in the demand cost allocator methodology which is only minimally supported by those tests relied upon by the Commission to determine an appropriate allocation methodology, according to Mr. Linxwiler.[59]

60. Mr. Linxwiler testified that the significance of the cost shift resulting from a change to demand cost allocator methodologies should also be considered in "borderline" cases. Large costs shifts should be avoided or at least mitigated in the absence of strong evidence indicating a correspondingly strong change in cost characteristics.[60]

61. Mr. Linxwiler also believes rate stability and predictability must be weighed in determining an appropriate demand cost allocator. According to Mr. Linxwiler, rate stability and predictability are well-established objectives in determining utility rates, premised on the assertion that frequent and/or significant

---

[57] *Id.* at 10-12.

[58] *Id.* at 12-13.

[59] *Id.* at 34-35.

[60] *Id.* at 35.

rate changes are disruptive. Customers need consistent price signals to operate efficiently themselves; frequent rate changes nullify consistency in price signals, according to Mr. Linxwiler.[61]

62. Mr. Linxwiler testified that it is important to consider more than just the basic statistics of a utility's load pattern in borderline cases. One important factor that needs to be considered, according to Mr. Linxwiler, is the fact that SPS has only one peak period, during the summer, whereas many other utilities have two peak periods in a given year.[62]

63. Finally, Mr. Linxwiler believes it is also important to consider which loads are included in the analysis. Mr. Linxwiler testified that, in the instant proceeding, non-requirement sales to off-system customers should not be considered in determining the appropriate demand cost allocator for on-system customers. Mr. Linxwiler testified that the fact that SPS' off-system sales are sold on a take-or-pay basis ensures that off-system purchasers will take more power in off-peak months than they would under other off-system sales arrangements. Including the capacities sold to off-system customers in the monthly demand cost allocators for on-system customers will artificially distort those allocators, Mr. Linxwiler testified.[63]

64. Mr. Linxwiler testified that the first step he took in determining whether a 12 or 3 CP Methodology should be used on the System was to examine SPS' monthly load pattern for the years 2000 through 2006.[64] This data clearly shows that peak demand is at its highest on the System for the months of June, July and August. In each of the those seven years, Mr. Linxwiler testified, July and August were the months with greatest peak demand while for six of the seven years examined, June was one of the four highest demand months of the year.[65] The only year in which June was not one of the four highest peak demand months, 2000, is anomalous, according to Mr. Linxwiler because of very unusual weather during 2000. Mr. Linxwiler testified that because the data from 2000 is anomalous and the oldest data set used in the demand allocation analysis performed by SPS and Golden Spread, it would be appropriate to exclude that year from the results.

---

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

[62] *Id.* at 36-37.

[63] *Id.* at 37.

[64] *Id.* at 13.

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

Mr. Linxwiler testified that when the year 2000 data is excluded from his analysis there is even less justification for adopting a 12 CP Methodology. [66]

65. Additionally, Mr. Linxwiler testified that data from the 2000-2006 period indicates that there is a substantial difference between peak demand in summer (i.e. June-August) and non-summer months. On average, non-summer month peak demand was 75 percent less than summer month peak demand over the 2000-2006 period, according to Mr. Linxwiler.[67]

66. Mr. Linxwiler testified that the next step in his analysis was to conduct a Low to Annual Peak Test. Mr. Linxwiler testified that his calculations, found on page 5 of Exhibit GSE-42, indicate that the average current minimum ratio is only 1.5 percent higher than the average minimum ratio on the System when the Commission issued Opinion No. 162, which required the use of a 3 CP demand allocation methodology.[68]

67. Mr. Linxwiler testified that he next performed the Average to Annual Peak Test. This test was relied upon by the Commission in their decision in Opinion No. 162 to determine that a 3 CP Methodology was appropriate on the System at the time. Mr. Linxwiler testified that his analysis indicated that the mean Average to Annual Peak ratio for the 2000-2006 period was less than two percent greater than the mean Average to Annual Peak ratio for the System at the time Opinion No. 162 was issued.[69]

68. Mr. Linxwiler testified that the results of these tests do not warrant a change to a 12 CP Methodology. Only minimal differences were found in the ratios for the 2000-2006 period compared against the ratios when the Commission ordered a 3 CP Methodology in Opinion No. 162. These differences are, in Mr. Linxwiler's opinion, too slight to warrant a shift in the demand cost allocator methodology used by SPS.[70]

69. Mr. Linxwiler testified that the unadjusted statistical information SPS provided indicates a negligible flattening of SPS' monthly load pattern when compared against the data considered by the Commission in Opinion No. 162.

---

66 *Id.* at 24.

67 *Id.* at 16-17.

68 *Id.* at 17.

69 *Id.*

70 *Id.* at 18.

The variations are, in Mr. Linxwiler's opinion, the result of minor seasonal temperature fluctuations that do not occur with sufficient regularity to warrant shifting to a 12 CP Methodology. Mr. Linxwiler testified that the data clearly indicates that SPS remains a summer-peaking utility and, as such, deviation from a 3 CP Methodology is neither necessary or warranted.[71]

70. Mr. Linxwiler testified that the data relied upon by Mr. Hudson is unrepresentative and inaccurate in three principle ways: (1) it does not reflect the fact that Golden Spread went from a full-requirements customer to a partial requirements customer of SPS in 2000; (2) it does not reflect the fact that the West Texas Municipal Power Agency changed from a contract-demand service customer to a quasi-cooperative wholesale service customer in 2004; and (3) it does not reflect actual 2005 demand value figures which became available in late September 2006. Mr. Linxwiler conducted further analysis using data from the 2000-2006 period correcting for these alleged errors. The analysis again indicates only slight variations in the System ratios since the 3 CP Methodology was ordered for the System in Opinion No. 162. [72]

71. Mr. Linxwiler testified that he used actual 2006 demand load data as opposed to projected demand load data, which SPS witness Mr. Hudson used. Mr. Linxwiler testified that it is reasonable, and indeed preferable, to use actual data when such data does not reflect non-recurring anomalies.[73]

72. Mr. Linxwiler testified that he believes that non-native off-system sales should be excluded from loads for the purpose of determining the appropriate demand cost allocator methodology to use on the System. Removal of these sales is necessary, according to Mr. Linxwiler, to better evaluate the demand cost allocator methodology that best suits native load customers, particularly Golden Spread. It is also appropriate, Mr. Linxwiler testified, because off-system sales have a lower level of priority of service than firm, native-load sales.[74]

73. Mr. Linxwiler testified that to justify a 12 CP Methodology, a utility must have either a highly flattened demand curve (i.e. average monthly peaks of 90% or more of annual peak), or very pronounced summer and winter peak periods. SPS has none of these characteristics. Mr. Linxwiler testified a 12 CP Methodology is not appropriate when the ratio of average monthly demand to annual peak demand

---

[71] *Id.* at 20.

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

[73] *Id.* at 23.

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

is slightly elevated for non-peak months when the highest non-peak months bookend the high peak season, as is the case on the System.[75]

74. Mr. Linxwiler testified that maintenance saturation should also be considered in determining whether a 12 CP Methodology is valid. Maintenance saturation occurs, Mr. Linxwiler testified, when a utility's valley load periods are neither low or long enough to accommodate schedules maintenance of generating units without driving capacity reserves too low or requiring maintenance to be performed during a peak period. If maintenance requirements and demand necessitate peak-time maintenance or result in an unacceptable capacity reserve level, a 12 CP Methodology should be applied. SPS is not confronted with either situation and thus, according to Mr. Linxwiler, should not operate under a 12 CP Methodology. Mr. Linxwiler confirmed from three independent sources that the System is not in a maintenance saturation situation.[76]

75. Mr. Linxwiler testified that developments in SPS' loads have not led to a flattening of SPS' load pattern, as established in the Complaint Proceeding. As such, a 12 CP allocation methodology is not appropriate. Although Golden Spread went from a full requirements customer to a partial requirements customer, that shift has not lead to a flattening of the demand curve; under its partial requirements contract, Golden Spread can only increase its demand as a result of projected increases in its native load served by the System. Golden Spread is a summer-peaking utility and, as such, Golden Spread has an increased load demand in SPS' summer peaking months, negating any purported flattening effect.[77]

76. Mr. Linxwiler also testified that Golden Spread's decision to install generation in an attempt to reduce the peak load obligation it placed on the System resulted in a negligible impact on the overall summer peak demands SPS services.[78] As such, Mr. Linxwiler believes that it would be inconsistent with sound regulatory policy to switch to a 12 CP Methodology to deal with what are, in essence, statistically insignificant variations in seasonal usage ratios.[79]

77. Mr. Linxwiler testified that SPS' load management efforts have had a negligible impact on the predominance of its summer peak demand obligations.

---

[75] *Id.* at 27-28.

[76] *Id.* at 28-30.

[77] *Id*. at 31.

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

[79] *Id.* at 32.

Mr. Linxwiler testified that SPS' reliance on demand-side efforts to reduce summer peak demands lends credence to the continued use of a 3 CP Methodology because it highlights the fact that its service loads in the summer peak months are more important than service loads in other months. Changing to a 12 CP Methodology would have the deleterious effect, in Mr. Linxwiler's opinion, of encouraging new growth in summer peak loads or reductions in off-peak month demand.[80]

78. Mr. Linxwiler testified that NMC witness Fred Saffer's analysis in support of a 12 CP Methodology is incomplete and inaccurate. Mr. Linxwiler criticizes Mr. Saffer for "cherry-picking" data to establish that there has been a substantial change in the ratios established in the tests used by the Commission to determine whether it is appropriate to use a 12 CP Methodology. Specifically, Mr. Saffer includes the market based sales and demand data that NMC explicitly advocated against in the proceeding in the Complaint Proceeding to inflate the differences in the various demand ratios used to determine whether a 12 CP Methodology is appropriate.[81]

79. Mr. Linxwiler testified that Mr. Saffer's testimony inappropriately inflates the amount of SPS' generating capacity that operates more than 50 percent of the time. Mr. Linxwiler testified that this assertion is not supported by any data.[82]

80. Mr. Linxwiler testified that Mr. Saffer inappropriately categorizes SPS' generating facilities for the purposes of determining capacity factor. Mr. Saffer does not distinguish between facilities with individual generating units and larger plants which consist of two or more generating units. The larger plants, Mr. Linxwiler testified, have generating units of different ages, efficiencies and operating characteristics. Aggregating them, as Mr. Saffer does, yields a capacity factor that overstates the output of the larger plants; the result of this over-calculation is the erroneous conclusion that SPS' generating capacity operates more than 50 percent of the time. [83]

81. Mr. Linxwiler testified that Mr. Saffer goes "too far" in his characterization of facilities having capacity factors that exceed 50 percent. Even if one accepts the premise that SPS generating capacity is operating more than 50 percent of the time, an assertion which Mr. Linxwiler contends is incorrect by virtue of the

[80] *Id.* at 32-34.

[81] Ex. GSE-75 at 20-22.

[82] *Id.* at 23.

[83] *Id.* at 24-25.

inappropriate aggregation of generating facilities on Mr. Saffer's part, that is a far cry from being able to assert that all of SPS' generating facilities can be said to have "most likely" been operating at the time of monthly peak demands.[84]

82. Mr. Linxwiler testified that it would not be possible for Mr. Saffer to discern from the data he analyzed, the extent to which any of SPS' generating resources were used the 2000-2006 period to meet on-system loads as opposed to off-system sales. Mr. Saffer's capacity factor analysis is, in Mr. Linxwiler's opinion, flawed at every level and not demonstrative of the reasonableness of applying a 12 CP Methodology to the System.[85]

83. Fred R. Saffer testified on behalf of NMC. Mr. Saffer is a principal with Fred Saffer and Associates, Inc., a consulting firm providing financial, engineering and management services to rural electric cooperatives, municipalities, and other agencies and government entities that own, operate or regulate utility systems. Mr. Saffer has over thirty years of experience in public utility management, operations, and regulation and has testified numerous times before the Commission and various state regulatory agencies. Mr. Saffer holds Bachelor of Arts degrees in mathematics, physics and English literature from Emporia State University.[86]

84. Mr. Saffer testified that it is the Commission's general policy to adopt the use of a coincident peak demand methodology to allocate demand-related production costs to a utility's various customer classes; the subject costs are fixed costs incurred in the generation of electricity. The CP methodology adopted by the Commission depends on the system peak load characteristics and load profiles of the subject utility.[87]

85. Mr. Saffer testified that the Commission has found a 12 CP Methodology appropriate in situations where peak demand in each month of the year is important to the subject utility's planning and operation of system resources. Mr. Saffer testified that a 12 CP Methodology has the benefit of assigning customer class responsibility for the capacity costs customers impose on the system, consistent with Commission cost-causation policies.[88]

---

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

[85] *Id.* at 26-27.

[86] Ex. NMC-1 at 2-3.

[87] *Id.* at 6.

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

86. Mr. Saffer testified that a 12 CP methodology helps the subject utility to more accurately determine when and to what extent generation capacity may be taken offline for maintenance, whether scheduled or not, throughout the year. Mr. Saffer testified that a 12 CP Methodology is superior to a 3 CP Methodology because it presumes that customer demands will exist on the system throughout the year, whereas a 3 CP Methodology operates on the assumption that customer demands will reach peak levels for only 3 months of the year.[89]

87. Mr. Saffer testified that although the Commission has not endorsed a single methodology for a demand cost allocator, the 12 CP Methodology is predominantly approved by the Commission. Mr. Saffer testified that the Commission's decision in Order No. 888 reinforced the importance of utilities considering twelve monthly peak demands in their system planning and operations.[90]

88. Mr. Saffer testified that he did not find any evidence indicating that the Commission explicitly gives greater weight to load ratio tests, or that such tests were the principle determinant of a utility's demand cost allocator methodology though the amount of discussion dedicated to such tests in Commission decisions indicates that the Commission may place greater weight on the results of load ratio tests in determining an appropriate demand cost allocator methodology, as opposed to other tests or metrics.[91]

89. Mr. Saffer testified that it is his opinion that the Commission should give greater accord to load ratio tests than any other indicators of an appropriate demand cost allocator methodology because such tests accurately reflect the demands customer classes impose on a utility and also comport with cost causation principles and, as such, should be more likely to result in just and reasonable rates and charges.[92]

90. Mr. Saffer testified that while Commission precedent acknowledges that the majority of utilities incur seasonal peak loads, these seasonal disparities do not, of themselves, rule out the use of a 12 CP Methodology. The threshold issue in determining whether a 12 CP Methodology is appropriate for a utility is, in Mr. Saffer's opinion, whether a season peak – June-August for a summer peaking

---

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

[90] *Id*. at 8.

[91] *Id*. at 9.

[92] *Id*.

utility, December-November for a winter peaking utility – is so pronounced as to render non-peak period usage requirements irrelevant. If this query can be answered in the negative, a 12 CP Methodology may be appropriate for the utility.[93] Mr. Saffer testified that SPS is a summer peaking system.[94]

91. Mr. Saffer testified that the Commission has traditionally found that a 12 CP Methodology is warranted where the On & Off Peak Test load ratio is 19 percent or less, Low to Annual Peak Test loads ratio is 66 percent or greater, and the Average to Annual Peak Test load ratio is 81 percent or greater. These ratios are used by the Commission to determine the flatness of a utility's demand curve/load shape, Mr. Saffer testified.[95] Mr. Saffer testified that his analysis demonstrates that the average load ratios derived from these three tests establish that SPS' load requirements warrant the application of a 12 CP Methodology to the System; indeed in the last four years the load ratios have only moved more squarely into the 12 CP range.[96]

92. Mr. Saffer testified that the Commission has not issued a decision regarding the appropriate demand cost allocator methodology for SPS based on a fully-litigated proceeding since 1989, when the Commission issued Opinion No. 337 which applied a 3 CP Methodology to the System. Mr. Saffer testified that, given the substantial amount of time that has passed since that decision, it is appropriate to examine more recent data to determine whether it supports the use of a different demand cost allocator methodology. Mr. Saffer, although not an attorney, opined that twenty-year old precedent need not be deemed controlling, or even persuasive authority.[97]

93. Mr. Saffer testified that he was able to determine that 67 percent of SPS' generational facilities were utilized to serve loads during more than 50 percent of the hours during a recent year. Mr. Saffer testified that where a generating facility load is greater than 50 percent, that generating facility is meeting load during most, if not all of the 12 month system peaks. Mr. Saffer testified that this fact warrants a change to a 12 CP Methodology on the System.

---

[93] *Id*. at 10-11.

[94] *Id*. at 21.

[95] *Id*. at 13.

[96] *Id*. at 19.

[97] *Id*. at 14-16.

94. Mr. Saffer testified that Mr. Linxwiler is incorrect in his assertion that the load ratios calculated by SPS Witness David T. Hudson do not warrant a change to a 12 CP Methodology. The load ratios calculated by Mr. Hudson fall within the 12 CP Methodology range determined by the Commission. Mr. Saffer testified that the load ratios calculations indicate that the System's load curve has been flattening every year since at least 2000.[98]

95. Mr. Saffer testified that Mr. Linxwiler's assertion that SPS must overcome a heightened burden of proof to justify moving from the 3 CP Methodology ordered by the Commission over 25 years ago is warrantless and unsupported by Commission precedent. Commission policy indicates only that a demand allocation should not be changed but for the occurrence of changed circumstances or policy. Mr. Saffer asserts that the load ratio calculations performed by he and Mr. Hudson clearly indicate sufficiently changed circumstances to warrant changing to a 12 CP methodology on the System. Data indicates that the System load curve is flattening and all 12 monthly peak loads are important considerations for planning and operational purposes, according to Mr. Saffer. This, combined with the potential for SPS' scheduled maintenance program to result in constant reserve level ratios during all 12 months of the year warrant changing to a 12 CP Methodology, Mr. Saffer asserts. Mr. Saffer testified that the load data used in the early 1980s to demonstrate that a 3 CP Methodology was appropriate for the System bears no relationship to the 2000-2006 period load data, and consequently, the demand requirements placed on the System at present; the most recent data weighs heavily in favor of the application of a 12 CP Methodology to the System.[99]

96. While he does not object to Mr. Linxwiler's substitution of projected load data for 2005 and 2006 with actual load data and updated forecasted load data for the purpose of calculating load ratios on the System, Mr. Saffer testified that he objected to the other adjustments Mr. Linxwiler made to the data – such as omitting year 2000 data from his calculations – to establish that SPS does not fall within the 12 CP Methodology threshold established by the Commission. Mr. Saffer testified that, despite the modifications that Mr. Linxwiler made to the 2000-2006 period data set, two of the three load ratios calculated by Mr. Linxwiler, the Average to Annual Peak Test ratio and the Low to Annual Peak Test ratio, still fall within the 12 CP Methodology range established by the Commission.[100]

---

[98] Ex. NMC-6 at 18-19.

[99] *Id.* at 19-20.

[100] *Id.* at 22-24.

97. Mr. Saffer testified that it is his opinion that Mr. Linxwiler's assertion that a significant change is required to warrant changing to a 12 CP Methodology on the System, when coupled with his augmentation of the 2000-2006 data set to establish less severe load ratio variations, represents an unfettered attempt on Mr. Linxwiler's behalf to "bootstrap" Golden Spread's support for a 3 CP Methodology over the great weight of facts supporting the use of a 12 CP Methodology.[101]

98. Mr. Saffer testified that Mr. Linxwiler mischaracterized the load ratios calculated by Mr. Hudson by labeling them "very borderline." Mr. Saffer contends that Mr. Linxwiler is quibbling about semantics; there is no requirement of a major change to warrant a change to a 12 CP Methodology. Mr. Saffer testified that the load ratios derived from the data set used by both he and Mr. Hudson fall clearly within the 12 CP Methodology range established by the Commission.[102]

99. Mr. Saffer testified that Mr. Linxwiler is erroneous in his assertion that certain loads should be excluded from the calculation of the System's load ratios. There is a distinction between the cost-of-service procedure known as revenue crediting, where it is assumed that revenue associated with loads are equal to the costs associated with those loads, and load ratio calculation. In order to establish an accurate picture of a utility's load curve, all loads must be included in load ratio calculations. Mr. Saffer testified that Commission precedent supports the inclusion of all utility load obligations in the calculation of its load ratios.[103]

III. PARTICIPANT POSITIONS

100. Cap Rock, NMC, and Trial Staff support the June 12, 2008, motion of SPS for summary disposition. Golden Spread opposes it and seeks, as well, to have the presiding ALJ hold this proceeding in abeyance until the Commission fully addresses the Opinion No. 501 rehearing motions filed by Cap Rock and other participants in the Complaint Proceeding. SPS and Cap Rock oppose Golden Spread's request for a delay.

101. SPS asserts that summary disposition is appropriate in light of: (1) the Commission's finding in Opinion No. 501 that demand-related costs should be

---

[101] *Id.* at 26.

[102] *Id.* at 27.

[103] *Id.* at 28-29.

allocated using a 12 CP methodology for the purpose of setting wholesale power supply rates on the SPS System from January 1, 2005 through June 30, 2006; [104] (2) the Commission's determination in the proceeding in Docket No. ER08-749-000 that rates based on a 12 CP methodology should take effect on June 1, 2008, after a nominal, one-day suspension;[105] (3) the Commission's finding that the analytical criterion used to determine that SPS was a 3 CP Methodology utility in 1983[106] and 1989[107] most recently demonstrates that SPS is a 12 CP Methodology utility;[108] and (4) an extrapolation of the statistics used by the Commission in Opinion No. 501 to determine a 12 CP Methodology is appropriate on the System for previous periods indicates that it is also appropriate for the Locked-In Period.[109]

102. SPS argues in support of its motion for summary disposition that the fact that the Commission recently twice found that SPS is a 12 CP Methodology utility clearly supports its position that the 12 CP Methodology is the appropriate methodology for setting rates for its power supply service to Golden Spread. SPS argues that the Commission fully considered in Opinion No. 501, whether usage patterns on the SPS system supported use of the 12 CP demand allocation methodology and concluded that it did.[110]

103. SPS points out that Opinion No. 501 covered the period January 1, 2005 through June 30, 2006. On May 30, 2008, in Docket No. ER08-749-000, the Commission again found that the 12 CP Methodology was appropriate on the System. Docket No. ER08-749-000 was a proceeding instituted to consider the reasonableness of rates SPS filed to supersede the rates for full-requirements service established by settlement in this proceeding. The Commission found that use of the 12 CP Methodology was just and reasonable and ordered that rates based on that methodology were to take effect on June 1, 2008, following a one-

---

[104] Opinion No. 501 at 61,249.

[105] *Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,225 (2008).

[106] Opinion No. 162.

[107] Opinion No. 337.

[108] Opinion No. 501 at 61,249-250.

[109] Motion of Southwestern Public Service Company for Summary Disposition of Demand Cost Allocation Issue, Docket No. ER06-274-007 (June 12, 2008) (SPS Motion).

[110] SPS Motion at 1-3.

day suspension.[111] Thus, SPS points out, the Commission has found the12 CP Methodology appropriate for the period immediately before and immediately after the Locked-In Period.[112]

104. SPS maintains that Opinion No. 501 is the law of the case.[113] In response to Golden Spread's claim that the demand cost allocator methodology for the SPS system was still undecided because Golden Spread had sought rehearing of Opinion No. 501, SPS points out that the Commission has explicitly responded to Golden Spread's argument. In setting this case for hearing, the Commission wrote that Opinion No. 501 is precedent while rehearing is pending.[114] Therefore, SPS states, the presiding ALJ should find that Opinion No. 501 may be used to resolve the issue in this case, without prejudice to the possibility that the Commission might grant Golden Spread's pending request for rehearing.[115]

105. SPS argues that statistics continue to support SPS' use of the 12 CP Methodology. Expanding the chart the Commission included in Opinion No. 501 to explain its adoption of the 12 CP Methodology shows data filed by witnesses for SPS, NMC and even Golden Spread in this docket proves that SPS was a 12 CP Methodology utility during the period at issue here.[116] SPS notes that the Linxwiler-developed data presented for Golden Spread shown in the expanded table[117] does not reflect the results of two studies Linxwiler performed. Linxwiler

---

[111] *Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,225 at 62,378 (2008) (Hearing Order).

[112] SPS Motion at 3-5.

[113] *Id.* at 1-3, 5, 7 & n.12-13.

[114] *Id.* at 3-5; See Hearing Order at P 13 & n.8, *citing* 18 C.F.R. § 385.713(e) and *Midwest Hydraulics, Inc.*, 120 FERC ¶ 61,247 at P 8 (2007).

[115] SPS Motion at 5.

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

[117] See chart below

Opinion No. 501 Chart	Lowest-To-Peak	On-Peak-Off-Peak	Average-To-Peak
Historical Commission Range for 12 CP	66% or higher	19% or less	81% or higher
Heintz, SPS-37 at 16	68%	19%	82%
Saffer FRC-2 Pro Forma	70%	18%	84%
Linxwiler, GSL – 1 at 9-1-10	67.55%	19%	82.05%
Diller, CRE-1 at 18	70%	18%	84%

incorrectly excluded from SPS' system loads SPS capacity commitments associated with sales to other utilities. SPS maintains that exclusion is not consistent with Commission precedent; it does not follow the analysis that underlies the Commission's decision in Opinion No. 501. Secondly, according to SPS, Linxwiler's more egregious and incorrect adjustment was to include all of Golden Spread's load in the SPS system load even though SPS is only responsible for servicing about 40 percent of Golden Spread's total load under the fixed-contract demand partial-requirements sales agreement at issue here. SPS maintains that by including all of Golden Spread's load, Linxwiler was trying to present a false picture of SPS' load profile.[118]

106. NMC filed an answer supporting SPS' motion for summary disposition.[119] NMC argues that in Opinion 501 the Commission found that the three load ratio test percentages calculated by witnesses in the Complaint Proceeding showed that SPS was a 12 CP Methodology utility for the period January 1, 2005 through June 30, 2006.[120] NMC stated that the Commission found that even the three load ratio test percentages as calculated by Mr. Linxwiler met the acceptable range for use of the 12 CP Methodology.[121]

107. NMC maintains that changes have occurred on the System since the demand allocation issue was last addressed in 1989. One change is that Golden Spread changed from a full-requirement, high-peaking customer on the System to a partial requirements customer with a year-round fixed contract.[122] That change,

---

Expanded Chart			
Hudson, SPS-4	68%	19%	83%
Heintz, SPS-63	69%	19%	83%
Saffer, NMC-2	70%	18%	84%
Linxwiler, GSE-50	68% - 69%	19% - 20%	82-83%

118 *Id*. at fn. 10, 11.

119 Answer of Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc. and Roosevelt County Electric Cooperative, Inc. in Support of Motion of Southwestern Public Service Company for Summary Disposition of Demand Cost Allocation Issue, Docket No ER06-274-007 (June 24, 2008) (NMC Answer).

120 NMC Answer at 2, *citing* Opinion No. 501 at 61, 249.

121 *Id*.

122 *Id*.

taken with other factors, helped flatten SPS' load profile to the point that a 3 CP Methodology was no longer appropriate for SPS.[123]

108. NMC maintains that SPS is correct in its assertion that the load ratio test percentages presented here by SPS Witnesses Hudson and Heintz, New Mexico Cooperative witness Saffer, and Golden Spread witness Linxwiler are essentially unchanged from evidence the Commission considered in Opinion No. 501. SPS' table accurately shows that the three load ratio test percentages calculated by those four witnesses fall within the acceptable range for a 12 CP Methodology utility, as the Commission determined in Opinion No. 501. Moreover, NMC asserts, the Hearing Order also supports SPS. Therefore, there is no genuine issue of material fact. No issue of fact exists respecting the load ratio test percentages in the witnesses testimonies.[124]

109. Anticipating Golden Spread's argument, NMC says Golden Spread will likely claim there is a genuine issue because there are factors other than the three load ratio test percentages that have to be considered. Those factors include: maintenance saturation, variability of the capacity of thermal generating units with temperature, the allegedly 'anomalous' nature of the weather in year 2000, purportedly 'incorrect price signals' that would result from use of the 12 CP Methodology, SPS' load-management efforts, and 'proportionality,' which all allegedly support use of the 3 CP Methodology.[125]

110. NMC points out that Mr. Linxwiler gave virtually identical testimony on each of the Commission's non-load ratio test percentage factors in Docket No. EL05-19-000.[126] The Commission considered that evidence in Opinion No. 501, but concluded that it did not support a 3 CP methodology.[127]

111. Trial Staff filed an answer to SPS' motion for summary disposition on the demand cost allocator methodology issue.[128] Staff points out that under the terms of the Commission-approved December 3, 2007 Settlement Agreement, the parties

---

[123] Opinion No. 501 at 61,249.

[124] NMC Answer at 2-6.

[125] *Id.* at 4-5

[126] *Id.* at 5-6 & fn. 13, 14.

[127] *Id.* at 6.

[128] Answer of Commission Trial Staff to Motion of Southwestern Public Service Company for Summary Disposition of Demand Cost Allocation Issue, Docket No. ER06-274-007 (July 1, 2008) (Trial Staff Answer).

are explicitly permitted to litigate the reserved issue of demand cost allocator methodology. The chart used in Opinion No. 501 and used here expanded to encompass the testimony filed by witnesses for SPS, Golden Spread and NMC in this proceeding both rely on evidence that is virtually identical.[129]

112. Staff notes that it had recognized in its December 20, 2007 Initial Comments in support of the December 3, 2007 Settlement Agreement, that failure of the parties to resolve the demand cost allocator methodology issue would result in the Commission examining the issue several times over a short period of time. Staff pointed out that leaving the demand cost allocator methodology issue unresolved could lead to two different findings – one in the Opinion No. 501 proceedings and another in this proceeding. Staff's opinion is that new circumstances have not developed such as to warrant two different findings in the case that led to Opinion No. 501.[130]

113. Staff also observes, as does NMC, that the Commission set forth three tests it would apply in determining the demand cost allocator methodology issue and applied those three tests to the evidence in the Opinion No. 501 case. In its motion for summary disposition, SPS has taken the same evidence and by expanding the Opinion No. 501 chart, SPS has shown that the facts are "virtually" identical. Staff, like NMC, also observes that the May 30, 2008 Order directed SPS to use the 12 CP Methodology in its compliance filing and that the rates involved take effect after June 1, 2008. Thus, the Commission has found that SPS was a 12 CP Methodology utility in the periods immediately before and after the Locked-In Period at issue in this proceeding.[131]

114. Staff argues that in this situation holding an evidentiary hearing does no more than cause an unnecessary expenditure of financial and personnel resources. Staff points out that any summary disposition decision would be subject to Commission review on exceptions. Summary disposition would be without prejudice to the rights of the participants to take whatever action Golden Spread deems appropriate if the Commission grants rehearing of Opinion No. 501 on the demand cost allocator methodology issue or should a reviewing court reverse or remand Commission's orders.[132]

---

[129] Trial Staff Answer at 6-7.

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

[131] *Id.*

[132] *Id*. at 9-10.

115. Golden Spread contends that SPS does not meet its burden for summary disposition and thus the presiding ALJ should not grant it. Specifically, Golden Spread contends that summary disposition is inappropriate because: (1) Opinion No. 501 is non-dispositive on the issue of the appropriate demand cost allocator methodology for the Locked-In Period because (a) it is subject to reversal on rehearing, (b) it does not explicitly dictate that a 12 CP methodology is appropriate for any time period beyond the January 1, 2005 through June 30, 2006 period, and (c) it does not take into account new evidence regarding recent variations on the SPS system, information which will greatly impact the determination of an appropriate demand cost allocator methodology; and (2) a grant of summary disposition will prejudice Golden Spread, leaving it without a sufficient mechanism for recourse in the event the Commission reverses itself on rehearing for Opinion No. 501.[133]

116. Further, Golden Spread contends that it is administratively inefficient to conduct a hearing on the appropriate demand cost allocator methodology for the Locked-In Period while Opinion No. 501 is still awaiting rehearing determination. Golden Spread asserts that to conduct a hearing at this point would only result in disorder and unnecessary expenses for the participants, and be in contravention of the Chief Judge's "expressed . . . preference for administrative efficiency and conservation of resources with respect to the contemporaneous litigation of similar issues in separate proceedings."[134]

117. Golden Spread says Rule 217(b)[135] puts the burden on the summary disposition moving party and all inferences have to be drawn in favor of the non-moving party. The facts have to be so one-sided as to entitle movants to judgment as a matter of law.[136] Golden Spread argues that the law and facts do not support SPS.[137]

---

[133] Answer of Golden Spread Electric Cooperative, Inc. to Southern Public Service Company's Motion for Summary Disposition on Demand Allocation issue and Cross-Motion to Hold Case in Abeyance Pending Rehearing Requests, Docket No. ER06-274-007, at 3-5, 8-9 (July 3, 2008) (Golden Spread Answer and Cross-Motion).

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

[135] 18 C.F.R. § 385.217 (b) (2008).

[136] *Id.* at 2 *citing Phillips Pipe Line Co.*, 67 FERC ¶ 63,002 at 65,002-003 (1994).

[137] Golden Spread Answer and Cross-Motion at 2.

118. Golden Spread argues that SPS' reliance on Opinion No. 501 and the May 30, 2008 Order is misplaced. Those Commission pronouncements should not govern the outcome of the demand cost allocator methodology issue in this proceeding. First of all, Golden Spread argues, the Commission has granted participant requests for rehearing on various issues in Opinion No. 501.[138] Second, Opinion No. 501, according to Golden Spread, is not the product of reasoned decision-making. Golden Spread contends that, notwithstanding the Commission's findings in Opinion No. 501, SPS retains the characteristics of a 3 CP Methodology system.[139]

119. Golden Spread argues that Opinion No. 501 ignores data presenting other Commission-applied indicative tests, misreports the SPS case-specific precedent from Opinion Nos. 162 and 337, and is internally inconsistent.[140] Golden Spread states that the Commission rejected SPS' argument that off-system, market-based opportunity sales were not sales for which SPS had to plan as part of the System.[141] Golden Spread states that the Commission, however, found that SPS did not plan, construct, or maintain its system for those sales unlike it did for requirements sales to entities like Golden Spread. Further the Commission held that the two contracts that expired during the test period had to be revenue credited as well.[142]

120. Golden Spread argues that there is nothing in Opinion No. 501 that would indicate the Commission was definitively holding that a 12 CP Methodology was appropriate for SPS in periods beyond the Locked-in Period at issue in this proceeding. Rather, such determinations have to be made on case-by-case basis. Opinion No. 501 is based on 2004 historical test year data.[143] Golden Spread notes that the Commission denied summary disposition in a similar case, *Illinois Power Co.*[144][145] Different facts could warrant different determinations. One fact

---

[138] Order Granting Rehearing for Further Reconsideration, Docket Nos. ER05-168-003 and EL05-19-004 (June 18, 2008) (Rehearing Order).

[139] Golden Spread Answer and Cross-Motion at 2-3.

[140] *Id*. at 4.

[141] Opinion No. 501 at 61,251.

[142] *Id*. at 4-5 *citing* Opinion No. 501 at 61,254.

[143] *Id*. at 6.

[144] *Illinois Power Co.*, 11 FERC ¶ 63,040 (1980), *aff'd in relevant part,* 15 FERC ¶ 61,050 (1981).

[145] Golden Spread Answer and Cross-Motion at 6.

in *Illinois Power* was the different test periods: 1974 in one decision, and a period ending on September 30, 1978 in the second. Golden Spread observed that there are different time periods at issue here, 2004 actual in Opinion No. 501 and 2006 projected.[146]

121. Golden Spread also argues that there have been changes to the System. One change is a significant reduction in the flat, market-based opportunity sales across all months of the year. That change will have a significant effect on the demand curve. Golden Spread wants to be allowed to come forward in the hearing scheduled here with other evidence that would show that SPS remains a 3 CP Methodology system, including evidence of system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments. Golden Spread claims it would be prejudiced if summary disposition were granted. According to Golden Spread, it would have no appropriate recourse if the Commission were to reverse itself on rehearing of Opinion No. 501.[147]

122. Golden Spread further argues that summary disposition based on the May 30, 2008 Order is not availing to SPS because it is a non-final order and reflects the commitment of SPS to bear the economic consequence of a different determination on the demand cost allocator methodology issue; SPS did not take on the economic risk of reversal of Opinion No. 501 as to Golden Spread, thereby leaving Golden Spread without a remedy. [148]

123. Moreover, the May 30, 2008 Order is also “misguided.” Again, there is the difference in the test periods. ER08-749 relies on actual and projected data submitted in SPS’ rate change application for calendar years 2007, 2008, and 2009. That data was not available for consideration in the Opinion No. 501 case. Nor was that data available when the ER06-274 rate application was prepared and submitted to the Commission. If the loads have changed in the years after the 2006 test year at issue here, then future rate cases will reflect that data.[149]

124. Golden Spread also maintains that there is a dispute of record facts when evidence of Golden Spread is viewed in the light most favorable to Golden Spread, contrary to what SPS claims. Moreover, SPS’ chart is a “gross oversimplification” of the record leaving only part of the record for consideration here. SPS’

---

[146] *Id*. at 7.

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

[148] *Id*. at 9-11.

[149] *Id*. at 9.

characterization of Linxwiler's results in Ex. GSE-50 is incorrect as it excludes the results of certain of Linxwiler's analyses, including the pivotal analysis that he ultimately recommended. Linxwiler's Ex. GSE-49 reports for 3 metrics: Lowest-to-peak" test 68.11%, not 68-69; On-peak off-peak, 21.22, not 19-20%; average-to-peak, 81.23", not 82-83. SPS has distorted Ex. GSE-50 results to exclude Linxwiler's expert opinion. [150]

125. Golden Spread also says that in relying on *Carolina Power & Light,*[151] SPS does not mention that market-based sales did not exist in 1978 and that all sales involved here are market-based sales. Nor does SPS indicate whether off-system sales in that case were revenue-credited or demand-allocated. [152]

126. SPS disputed Golden Spread's arguments in its answer to Golden Spread's cross-motion to hold a case in abeyance pending decision on the rehearing requests in Opinion No. 501. SPS derides Golden Spread's arguments that (1) the Chief Judge has a preference for holding related proceedings in abeyance pending Commission determination of common issues; (2) summary disposition is not appropriate because there are factual disputes; (3) if the Commission were to determine that off-system firm capacity sales should be excluded from system load data used in selecting a demand cost allocator methodology, granting SPS' motion would result in duplicative and inefficient litigation; and (4) that Golden Spread would be prejudiced if the presiding ALJ were to grant SPS's motion for summary disposition. [153]

127. Regarding Golden Spread's claim that the Chief Judge's preference for holding related proceedings in abeyance pending Commission determination of common issues, SPS points out that Golden Spread is relying on a June 22, 2006, unpublished Chief Judge's order issued in Docket No. EL05-151-001, *et al*.[154] The order in EL05-151-001 was issued in a proceeding instituted to consider a complaint brought by Public Service Company of New Mexico (PNM) against SPS in which PNM claimed that SPS had misapplied its fuel clause. That claim of

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

[151] *Carolina Power & Light Co.*, 4 FER ¶ 61,107 (1978).

[152] Golden Spread Answer and Cross-Motion at 12-13.

[153] Answer of Southwestern Public Service Company to Cross Motion of Golden Spread Electric Cooperative, Inc. to Hold Case in Abeyance Pending the Outcome of Pending Rehearing Request, Docket No. ER06-274-007, at 2, 3, 6 (July 9, 2008) (SPS Answer).

[154] Attached to Golden Spread's Answer and Cross-Motion as Exhibit A.

misapplication of use of the fuel clause had been made earlier by other SPS customers in Docket No. EL05-19-000, had been adjudicated by the Presiding ALJ, and was on appeal to the Commission. SPS and PNM agreed, with support or non-objection of all, that it would be appropriate to hold in abeyance. SPS points out that there is no agreement of parties here.[155]

128. SPS also notes that the *PJM Interconnection* cases cited by Golden Spread[156] [157]do not support holding this proceeding in abeyance. Those cases did involve related proceedings with a common issue, but the Commission had not acted on merits in either. SPS points out that the Commission has already decided the sole issue to be decided here in Opinion No. 501. [158]

129. The Commission clearly identified in Opinion No. 501 the tests to apply in determining the appropriate demand cost allocator methodology. SPS maintains that when those tests are applied to similar but more current SPS system load data, it is evident that SPS is a 12 CP utility. [159]

130. Regarding Golden Spread's claim that there are factual disputes that defeat a claim for summary disposition, SPS maintains that there are no "material" differences. SPS addresses the *Illinois Power* case relied on by Golden Spread for the proposition that although a case has recently been decided on the same issue, the fact of there being different test periods may block summary disposition.[160] [161] However, SPS points out, that in *Illinois Power*, the Commission stated that a recent decision would be controlling absent a showing of changed circumstance.[162] Also, SPS maintains that, unlike in *Illinois Power*, Golden Spread has had opportunity to present more recent data. That data, and other evidence presented in this case, prove that SPS is a 12 CP Methodology utility.[163]

---

[155] SPS Answer at 2.

[156] *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,112 (2008) and *PJM Interconnection, L.L.C.*, 118 FERC ¶ 61,154 (2007).

[157] Golden Spread Answer and Cross-Motion at 15.

[158] SPS Answer at 2 & fn. 3.

[159] *Id*. at 3.

[160] *Illinois Power Co.*, 59 FPC 2240 (1977).

[161] SPS Answer at 4-5.

[162] *Id*. at 4 *citing Illinois Power Co.*, 59 FPC at 2247.

[163] *Id*. at fn. 7.

131. SPS explains that the chart it included in its motion does not include the data Linxwiler presented in Ex. GSE-75, page 18, line 10 through page 19, line 22 and in GSE-76, because the adjustments made by Linxwiler are properly not included on the chart. First, excluding off-system firm capacity sales does not comport with the Opinion No. 501 analysis. Mr. Linxwiler's second inappropriate adjustment, according to SPS, was to include in the SPS system load all of Golden Spread's load even though SPS is responsible for serving only about 40 percent of Golden Spread's total load under the fixed contract demand partial-requirements sales agreement at issue here.[164]

132. SPS states that, although Golden Spread claims that the data used to apply the three tests the Commission used in Opinion No. 501 should exclude loads associated with SPS' firm capacity sales to other utilities, the Commission choose not to consider the data proffered by Golden Spread in the Complaint proceeding that excluded such sales. SPS argues that there has been no change in circumstances such as to make the 12 CP Methodology not appropriate for SPS during the period at issue in this case. Further, it is relevant that in Docket No. ER08-749-000 the Commission found the 12 CP Methodology valid for use in setting SPS' rates for full-requirements service that will supersede the rate agreed to in settlement of this case. [165]

133. As to Golden Spread's complaint about duplicative litigation if summary disposition is granted and the Commission later reverses its holding on the demand cost allocator methodology issue, SPS states that an evidentiary hearing could then be scheduled. Golden Spread would not be prejudiced. It would then be eligible for return, with interest, of amounts exceeding that that would have been collected under rates based on the 3 CP Methodology.[166]

134. Cap Rock Energy Corporation filed an answer on July 18, 2008 supporting SPS' motion for summary disposition.[167] [168] Cap Rock also answered Golden

[164] *Id.* at 4, fn. 9.

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

[166] *Id*. at 6.

[167] Answer of Cap Rock Energy Corporation To Motion of Southwestern Public Service Company, Docket No. ER06-274-007, at 1 (July 2, 2008).

[168] Cap Rock acknowledged that Rule 213 limits the filing of an answer to an answer, and by Order of August 22, 2008, I declined to accept Cap Rock's answer.

Spread's cross-motion to hold the case in abeyance agreeing with SPS that the case should not be held in abeyance.[169]

IV. DECISION

135. Rule 217 provides that a decisional authority may grant summary disposition if she determines that there is no "genuine issue of fact material to the decision of a proceeding or part of a proceeding."[170] The burden in summary disposition is on the moving party. There is no genuine issue of fact if the record taken as a whole could lead a reasonable trier of fact to find for the moving party.[171] There is no genuine issue of fact here, and SPS' Motion will be granted.

136. Based on the record as a whole in this case, it is reasonable to conclude that 12 CP is the appropriate demand cost allocator methodology to be applied to the System during the Locked-In Period. The fact that the Commission recently twice found, on essentially the same evidence as that submitted in this case, that SPS was a 12 CP Methodology utility is pertinent to the determination of the appropriate demand cost allocator methodology during the Locked-In Period. Opinion No. 501 covered the period January 1, 2005 through June 30, 2006 and on May 30, 2008, in Docket No. ER08-749-000, the Commission again found that the 12 CP Methodology was the correct demand cost allocator methodology on the System. In ER08-749-000, the Commission concluded that use of the 12 CP Methodology was just and reasonable and ordered that rates based on that methodology were to take effect on June 1, 2008, following a one-day suspension.[172] The Locked-in Period, the period under consideration in this proceeding, is July 1, 2006 through June 30, 2008. The Commission has, thus, found the12 CP Methodology appropriate for the period immediately before, and through the last month of the Locked-in Period.

137. The doctrine of the law of the case applies where issues have been decided either explicitly or by necessary implication. The doctrine serves to preclude a lower decisional authority from reconsidering an issue already decided by an

---

[169] Answer of Cap Rock Energy Corporation, Docket No. ER06-274-007, at 4 (July 18, 2008).

[170] 18 C.F.R. § 385.217 (2008).

[171] *Investigation of Certain Enron-Affiliated QFs*, 108 FERC ¶ 63,101 at P25 (2004) (citing *Matsushita Electric Industrial Co. v. Zenith Radio Corp.*, 475 U.S. 574, 586 (1986)), *aff'd* 111 FERC ¶ 61,013 (2005).

[172] *Southwestern Pub. Serv. Co.*, 123 FERC ¶ 61,225 at 62,378 (2008).

appellate or higher decisional authority.[173] In Opinion No. 501, the Commission reversed the Presiding ALJ's finding that SPS was a 3 CP Methodology utility during January 1, 2005 through June 30, 2006, concluding instead that SPS was a 12 CP Methodology utility during that period. The Commission explained that the determination of the appropriate demand allocator methodology is made on a case-by-case basis and takes into account "in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system sales commitments."[174] Thus, in addition to evidence Golden Spread presented on system demand to the Commission in the Complaint Proceeding that led to Opinion No. 501, the Commission also had before it Golden Spread evidence on the other considerations that Golden Spread argues in its answer in this case. The doctrine of law of the case applies here and the Commission has already found, on essentially the same evidence presented in this case, that SPS is a 12 CP Methodology utility.

138. The SPS-expanded version of the chart the Commission compiled and included in Opinion No. 501 using its articulated three load ratio tests to be employed in determining whether a utility's system is 3 CP or 12 CP Methodology utility, is an especially important piece of evidence in this case. The Commission used the same analytical criteria in compiling the chart in Opinion No. 501 that it used in Opinion Nos. 162 and 337, cases in which SPS was found to be a 3 CP Methodology utility. SPS conducted the same analysis in compiling the chart included in its Motion,[175] using evidence submitted in this case. The SPS chart shows that SPS has continued, since the Complaint period covered in Opinion No. 501, to be a 12 CP Methodology utility system. Opinion No. 501 does not have to explicitly state, as Golden Spread seems to think it does, that a 12 CP Methodology is appropriate for the time period immediately following the January 1, 2005 through June 30, 2006 Complaint Proceeding period, especially taken with the Commission's conclusion that the 12 CP Methodology was appropriate for the last month of the Locked-in Period.

139. Golden Spread's argument that Opinion No. 501's relevance is less because it does not take into account new evidence of recent variations on the System, is also unavailing. More recent evidence was submitted in this case. To the extent

---

[173] *Electric Utilities – FPL Energy Marcus Hook, L.P. v. PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,289 at P 23 & fn. 37 (2008), *citing Maggard v. O'Connell*, 703 F.2d 1284, 1289 (D.C. Cir. 1983), and *Cleveland Ohio v. FPC*, 561 F.2d 344, 348 (D.C. Cir. 1977).

[174] Opinion No. 501 at 61,249 (citations omitted).

[175] SPS Motion at 6. .

that Golden Spread is talking about evidence more recent than the written filings submitted in this case, Golden Spread was a signatory to the Offer of Settlement in Docket No. ER06-274-003. Golden Spread, along with the other participants in that docket, agreed that discovery had ended and that initial, answering, and rebuttal testimony had been filed covering the issue of demand cost allocator methodology before the suspension of the procedural schedule in that proceeding. The ER06-274-003 testimony was re-filed in this case. That testimony was reviewed and included nothing that lessened the relevance of Opinion No. 501.

140. Nor is Golden Spread's argument that the difference in time periods between the Complaint Proceeding and the Locked-In Period could defeat a motion for summary disposition availing.[176] In the *Illinois Power* case Golden Spread cites, the test period was 1974 in one case and a period ending on September 30, 1978, in the other. Here the comparative test periods are closer in time -- 2004 actual in Opinion No. 501 and 2006 projected in this case. In addition, Golden Spread has had the opportunity to submit more recent data in this case than that submitted in the Complaint case. The newly submitted data does not show that anything extraordinary happened during the Locked-In Period, such as would render Opinion No. 501 less controlling. Therefore, there is no genuine issue of material fact, and the record taken as a whole leads to the reasonable conclusion that SPS was a 12 CP Methodology utility during the Locked-In Period.

V. FURTHER FINDINGS AND CONCLUSIONS

141. Findings and conclusions stated in the body of this Initial Decision are to be considered incorporated in this list of findings and conclusions The omission from this Initial Decision of any argument or portion of the record raised by the participants in their motions and answers does not mean that it has not been considered. All arguments have been evaluated and found to either lack merit or significance such that their inclusion would only tend to lengthen this Initial Decision without altering its substance or effect.

142. The Commission's Rules 385.217 (a) and (b) provide that any proceeding set for hearing, or part of one, may be subject to summary disposition if the decisional authority determines there is no genuine issue of material fact. Rule 385.217(d) provides that if the decisional authority is not the Commission, and summarily disposes of an entire proceeding, that decisional authority will issue an Initial Decision for the entire proceeding.

---

[176] Golden Spread Answer and Cross-Motion at 6-7, *citing Illinois Power Co.*, 59 FPC 2245 (1977), *reh'g denied*, 1 FERC ¶ 61,174 (1977) (different test periods was a factor warranting denial of a motion for summary disposition).

143. There is no genuine issue of material fact in this case. Load ratio test percentages presented in this case place SPS within the 12 CP Methodology range during the Locked-In Period using the analysis used by the Commission in Opinion No. 501. Therefore, summary disposition is appropriate for this case and is hereby granted.

144. IT IS SO ORDERED, subject to review by the Commission on exceptions or on its own motion or on its own motion, as provided by the Commission's Rules of Practice and Procedure, that within thirty (30) days from the issuance of the Final Order of the Commission in this proceeding, SPS shall conform its rate filing to the rulings made in this Initial Decision.

Charlotte J. Hardnett
Presiding Administrative Law Judge

Document Content(s)