UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Golden Spread Electric Cooperative, Inc., Lyntegar Electric Cooperative, Inc., Farmers' Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc., and Roosevelt County Electric Cooperative, Inc., v. Southwestern Public Service Company,	Docket No. EL05-19-002
Southwestern Public Service Company	Docket No. ER05-168-001

INITIAL DECISION

(Issued May 24, 2006)

APPEARANCES

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

Robert Weinberg, Esq., and Eli D. Eilbott, Esq. on behalf of Farmers Electric Cooperative, Inc., Lea County Electric Cooperative, Inc., Central Valley Electric Cooperative, Inc, and Roosevelt County Electric Cooperative, Inc.

Clark EvansDowns, Esq., Shelby L. Provencher, Esq., James P. Johnson, Esq. and Kenneth B. Driver, Esq., on behalf of Southwestern Public Service Company

John W. Griggs, Esq. and Ray Schwertner, Esq., on behalf of Cap Rock Energy Corporation

John T. Stough, Jr., Esq., Kevin M. Downey, Esq., and Charles V. Garcia, Esq., on behalf of Public Service Company of New Mexico

James M. Bushee, Esq., Matthew J. Binette, Esq., Keith R. McCrea, Esq., Richard P. Noland, Esq., and Andrew K. Soto, Esq., on behalf of the Occidental Permian, Ltd. and

Occidental Power Marketing, L.P.

William W. Bennett, Esq., Irene E. Szopo, Esq., Lea A. Ekman, Esq., and Marcia A. Lurensky, Esq., on behalf of the Trial Staff of the Federal Energy Regulatory Commission

WILLIAM J. COWAN, Presiding Administrative Law Judge

PROCEDURAL HISTORY

A. Complainants' Section 206 Filing

1. On November 2, 2004, six electric cooperatives – Golden Spread Electric Cooperative, Inc. (Golden Spread), Lyntegar Electric Cooperative, Inc. (Lyntegar), Farmers' Electric Cooperative, Inc. (Farmers), Lea County Electric Cooperatives, Inc. (Lea County), Central Valley Electric Cooperative, Inc. (Central Valley), and Roosevelt County Electric Cooperative, Inc. (Roosevelt County) (collectively, the Cooperative Customer Group, CCG, or Complainants) – jointly filed a complaint pursuant to Section 206 of the Federal Power Act (FPA), 16 U.S.C. § 824e (2000), against Southwestern Public Service Company (SPS or the Company) in Docket no. EL05-19-000. The complaint claimed that SPS' cost-based rates for full and partial requirements service are excessive, unjust and unreasonable, and unduly discriminatory or preferential.

2. The complaint also alleged that SPS has historically violated, and continued to violate, the fuel cost adjustment clause (FCAC) provisions for its wholesale customers' rate schedules and the Commission's FCAC regulations. Complainants asserted that SPS may be flowing through its FCAC virtually all energy-related purchased power costs, and that some of the costs are not permissible under the filed rate or the Commission's regulations. Complainants also expressed concern that SPS was not appropriately crediting the FCAC (and as a result, its requirements customers) when it makes off-system sales. Complainants stated that higher cost energy purchases have been allocated to the requirements customers through the FCAC while lower cost energy purchases have been allocated to off-system sales, resulting in requirements customers' subsidizing SPS' marketing function. Complainants asked the Commission to investigate FCAC charges dating back to the last Commission audit of SPS under section 205(f) of the FPA, 16 U.S.C. § 824d(f) (2000), or at least from 1994.

3. Timely motions to intervene were filed by Public Service Company of New Mexico (PNM) and Cap Rock Energy Corporation (Cap Rock). SPS answered the complaint on December 2, 2004. On December 10, 2004, Complainants filed a reply to SPS' answer. On December 21, 2004, the Commission issued its Order establishing

hearing and settlement judge procedures to address the CCG's complaint against SPS.[1]

B. SPS' Section 205 FCAC Filing

4. Also on November 2, 2004, SPS filed changes to its FCAC in Docket no. ER05-168-000, pursuant to Section 205 of the FPA, 16 U.S.C. § 824d (2000), requesting an effective date of January 1, 2005 (New FCAC). The changes included: (1) changes in the FCAC applicable to the following wholesale full requirements customers: Cap Rock, Central valley, Farmers, Lea County, Lyntegar, and Roosevelt County; (2) changes in the FCAC applicable to SPS' wholesale partial requirements customer, Golden Spread; (3) changes in the FCAC applicable to SPS' interruptible contract customers, PNM; and (4) corresponding revised pages from SPS' power supply contract with each of the foregoing customers.

5. SPS made the filing to revise its FCAC to conform to the Commission's Order No. 352[2] fuel cost and purchased economic power adjustment clause regulations, 18 C.F.R. § 35.14 (2005). In addition, SPS made the filing to revise its FCAC to account for expenses and revenues associated with SPS' participation in the Southwest Power Pool (SPP) Regional Open Access Transmission Tariff (OATT). Under the revised FCAC, SPS proposed to collect the net difference between amounts SPS pays to the SPP for transmission losses and amounts that the SPP distributes to SPS to compensate it for supplying energy to cover transmission losses.

6. On November 23, 2004, Motions to Intervene and Protest were filed by PNM and by the CCG members. On December 3, 2004, Cap Rock filed a Motion to Intervene Out-of-Time and Protest. On December 8, 2004, SPS filed an answer to the protests.

C. The Consolidated Proceeding

7. On December 29, 2004, the Commission issued an "Order Accepting and Suspending Proposed Fuel Adjustment Clause Changes, Establishing Hearing and Settlement Judge Procedures, and Consolidating Proceedings,"[3] in which it set SPS' FCAC filing in Docket No. ER05-168-000 for hearing and settlement judge procedures, and consolidated it with the complaint proceeding in Docket No. EL05-19-000. In an

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[1] *Golden Spread Elec. Coop., Inc., et al. v. Southwester Public Serv. Co.*, 109 FERC ¶ 61,321 (2004) (EL05-19 Hearing Order).

[2] *Treatment of Purchase Power in the Fuel Cost Adjustment Clause of Electric Utilities*, Order No. 352, 1982-1985 FERC Stats. & Regs. [Regs. Preambles] ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984).

[3] *Southwestern Pub. Serv. Co.*, 109 FERC ¶ 61,373 (2004) (December 29 Order).

order issued on December 27, 2004, the Chief Administrative Law Judge (Chief Judge) designated Judge Lawrence Brenner to serve as the settlement judge in the complaint proceeding in Docket No. EL05-19-000. By order issued December 30, 2004, the Chief Judge applied his December 27 order to the consolidated proceeding.

8. On March 15, 2005, Occidental Permian Ltd. and Occidental Power Marketing, L.P. (collectively, Occidental or OCC) filed a Motion to Intervene Out-of-Time in the consolidated proceeding. The motion was denied, but the Chief Judge stated that the matter would be reconsidered if settlement negotiations were unsuccessful. On April 22, 2005, Occidental filed a Renewed Motion to Intervene, which was granted by letter order dated May 10, 2005.

9. After being advised by Judge Brenner that the parties' settlement negotiations had reached an impasse, the Chief Judge issued an order on April 26, 2005, terminating the settlement judge procedures and designating Judge William J. Cowan to preside over the hearing previously ordered by the Commission. The hearing date was modified by order of the Chief Judge issued December 2, 2005, to account for the unavailability of one of SPS' key witnesses on the originally scheduled hearing date due to an accident. The hearing was held from February 24, 2006 through March 15, 2006, exclusive of March 10, 2006. On February 23, 2006, the participants to the proceeding submitted a Joint Trial Stipulation that resolves many cost-of-service issues and reduced substantially the number of issues in controversy to be resolved through hearing. The Joint Trial Stipulation was executed the morning of February 24, 2006, and admitted as Exhibit J-1.[4]

FINDINGS AND CONCLUSIONS

I. Cost of Service Issues

A. Whether demand-related production costs should be allocated to customer classes using a 3-CP or a 12-CP allocator.

10. The demand allocation method to be used in this proceeding is contested. Demand allocation determines the charge to each class of customers based upon the class' contribution to the company's capacity costs. Capacity costs are driven by peak demand. A company that has a relatively flat demand curve would typically allocate demand on a 12 Coincident Peak (12 CP) basis, which assumes that a utility's fixed costs are related to the demand throughout all twelve months of a year. On the other hand, a summer (or winter) peaking company would more typically allocate demand on a 3 CP basis, which relates demand to the three peak usage months.

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[4] Tr. at 235-236.

11. Since the early 1980's, SPS has allocated demand-related costs to its various customer classes using the 3 CP method. The Commission has determined in the last two SPS rate cases, that a 3CP allocation method was appropriate for SPS, given that it is a summer peaking utility. *Southwestern Public Service Company*, Opinion No. 162, 22 FERC ¶ 61,341 (1983), *Southwestern Public Service Company*, Opinion No. 337, 49 FERC ¶ 61,296 (1989).

12. CCG witness Daniel used the 3 CP method to allocate production-related fixed costs to all of the full and partial requirements customers of SPS, deeming it appropriate to follow the above-cited Commission precedent. SPS witness Heintz, however, contends that the Company's 2000-2005 load data support the use of a 12 CP demand allocator. Exh. SPS-37 at 15. Although SPS has traditionally been viewed as a 3 CP system, the Company argues that circumstances have changed and the data now point in the direction of a relatively flat system demand curve. This, SPS argues, supports a shift to a 12 CP allocator. More specifically, SPS looked at a number of tests which it contends the Commission has used historically to decide this issue. While the tests are indicative of the result, SPS points out that the Commission has looked to the "full range of a company's operating realities, including, in addition to system demand, scheduled maintenance, unscheduled outages, diversity, reserve requirements, and off-system commitments." *Carolina Power and Light Company*, 4 FERC ¶ 61,107 at 61,230 (1978).

13. Turning attention to the tests that the Commission has employed, SPS compared the average of system peaks during the purported peak period, as a percentage of annual peak, to the average of the system peaks during the off-peak months, as a percentage of the annual peak – the so called On and Off Peak test. The Company's data show that the percentage differences in the studied period range from 14 percent to 22 percent, with a 19 percent average. From this, SPS concludes that SPS loads are consistent with 12 CP, since the Commission has found averages under 26 percent to be suggestive of a 12 CP system. Exh. SPS-40 at 1.

14. Calculating the lowest monthly peak as a percentage of the annual peak (the so-called Low to Annual Peak test), the results ranged from 66 percent to 70 percent, which are above the 66 percent observed threshold for 12 CP, according to SPS. *Id.* The third test employed by Mr. Heintz, computing the average of twelve monthly peaks as a percentage of annual peak (Average to Annual Peak test), yielded a similar result. *Id.* Mr. Heintz' analysis is supported by Company witnesses Hudson and Blair.[5]

15. The New Mexico Cooperatives (NM) witness Mr. Fred Saffer also offered testimony and exhibits supporting an analysis which concludes that a 12 CP allocator

[5] See Exhs. SPS-2 at 36-41; SPS-13; SPS-17-24; SPS-76 at 39-40; and SPS-108; SPS-102; and SPS-106 at 17.

would be appropriate for SPS. He performed several of the load ratio tests employed by the Commission in deciding which allocator to use. Exh. FRC-2. Load Ratio test 1 is the ratio of the minimum annual monthly system peak demand divided by the maximum annual monthly system peak demand. On both an adjusted basis (to adjust for the planned Lyntegar shift to Golden Spread, and a 6/1/2005 25 MW demand increase in Golden Spread's contract demand), and on a pro forma basis, Mr. Saffer found the ratios to be 69 – 70 percent. This, he concluded, was within the 66 to 89 percent load ratio range which the Commission has found supports use of 12 CP. The second load ratio test undertaken by Mr. Saffer measures the difference between the average of the three highest peaks divided by the annual peak and the average of the other nine monthly peaks divided by the annual peak. He found the 19-20 percent results within the range that the Commission has historically found to be consistent with 12 CP, albeit near the high end of the range. A third test measured the average of the twelve monthly system peaks and the annual system peak. Here, the 83 and 84 percent ratios are also above the 81 percent threshold which the Commission has determined to be indicative of a relatively flat load curve. A fourth test performed was to determine the ratio of the three summer peaks to the other nine monthly peaks. He found the 42 and 41 percent ratios close enough to 33 percent to demonstrate relative flatness. Exh. FRC-1 at 15.

16. Mr. Saffer also considered operating reserves and determined that during nine of the twelve months of 2004, the level of capacity reserves indicate that at least those nine months were critical load months, which suggests the propriety of 12 CP. Mr. Saffer also noted that base load generation represented 87.5 percent of the total available capacity and 84.7 percent of energy sold by SPS during 2004. Peaking generation represented less than 5 percent of the total available capacity and provided only 0.64 percent of the total energy sold last year. This suggests to Mr. Saffer that a 12 CP allocation would provide a more equitable allocation of demand-related production costs than 3 CP.

17. Golden Spread/Lyntegar and PNM argue that continued use of a 3 CP allocator is appropriate in the current circumstances. Golden Spread/Lyntegar witness Linxwiler testified that there was not sufficient justification for changing the 3 CP method traditionally used in SPS cases. He stated that the Company's load pattern had not changed enough in recent years to warrant a departure from the settled 3 CP method adopted by the Commission for SPS. Using Company data, [6] Mr. Linxwiler discovered that for all six years studied (2000-2005), July and August were the months of greatest demand, and the months of June and September were the third highest. Exh. GSL-1 at 8. According to Mr. Linxwiler, a graph demonstrating relative monthly peaks as a percentage of annual peaks shows how much lower the non-summer months are compared to the summer months. Except for 2000, no winter month ever exceeded 80

[6] Mr. Linxwiler also tested his conclusions using data employed by CCG witness Daniel, but concluded that no change in his conclusion was warranted on that account. Exh. GSL-1 at 16-17.

percent of the annual peak, and most often, these months were 75 percent or less than the annual peak. Exh. GSL-3 at 4. Looking at the minimum ratio[7] and the average ratio[8] tests, Mr. Linxwiler found that the six year average in the former test was only slightly higher (0.66 percent) than it was in Opinion No. 162, and the average ratios for the six years were slightly higher (1.86 percent) than they were in the years considered in Opinion 162. Exh. GSL-1 at 9.[9] He stated that these slight increases "can hardly be described as significant." *Id.* at 10. Other tests he conducted confirmed his conclusion that SPS remains a summer peaking utility. He noted that some of the data the Commission considers in deciding this issue are close to or at the break point or thresholds the Commission has used, but that no changes should be made to the 3 CP method preferred by the Commission historically for SPS. Exh. GSL-3.

18. Mr. Linxwiler further noted that factors necessary to justify a 12 CP allocator are not present here. The system does not have very flat monthly demands, nor does it have high winter and summer demands, both of which would suggest the propriety of 12 CP. Exh- GSL-1 at 11. Neither does the condition of maintenance saturation exist, according to Mr. Linxwiler. That is when valley load periods are not low enough or long enough to accommodate scheduled maintenance of generating units, forcing maintenance into peak periods. The witness pointed to a report by the independent market monitor, Boston Pacific Company, for the Southwest Power Pool in 2004, which observed only small amounts of generating capacity out of service for maintenance during the three peak months. Exh. GSL-1 at 14. A similar fact is noted in the affidavit of Company witness Dr. William Hieronymous in FERC Docket No. ER01-205, submitted as Exhibit WHH-5 in that proceeding, and in an exhibit of Company witness Heintz in the instant case (Exh-SPS-41). *Id.*

19. Mr. Linxwiler rebutted the testimony of Cap Rock witness Diller, who had concluded that certain changes in the SPS load pattern warranted a switch to 12 CP. Mr Diller concluded that Golden Spread's change to a partial requirements customer, load management efforts to flatten load, and increases in off-system sales have contributed to a flattening of SPS's load curve. Mr. Diller's analysis concluded that the SPS system had changed significantly over the time since the Commission last examined this allocation method. Exh. CRE-1 at 17, CRE-2-CRE-8. However, Mr. Linxwiler concluded that the actions of Golden Spread to reduce load and install generation "barely dented the relative impact of the summer peak on SPS." Exh. GSL-1 at 20. He found the statistically insignificant changes in seasonal usage ratios, even in the face of removal of 400 MW of

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[7] The ratio of the lowest monthly peak demand to the annual peak demand as a measure of the significance of off-peak loads.

[8] The ratio of the average of all twelve monthly peak demands in each year to the annual peak demand.

[9] If the year 2000, considered to be anomalous by the witness, is excluded, the difference is even less. Exh. GSL-1 at 9, and 16.

summer peak load (assumed by Golden Spread), demonstrates that SPS remains a summer peaking company. *Id.* Mr. Linxwiler went on to argue that a change to a 12 CP methodology would not be consistent with sound regulatory policy, would represent a departure from established Commission precedent and would send the incorrect price signal to SPS's wholesale customers. *Id.*

20. PNM witness Judah Rose agreed that the 3 CP method was superior in this case, because June, July and August are the only months in which SPS's annual coincident peak occurs. He testified that nearly all of the positive marginal costs associated with obtaining capacity needed to ensure reliability occur in these months. Proper price signals require rates that recognize this cost causality, according to Dr. Rose. Exh. PNM-6 at 3. He further noted that the concentration of maintenance in the non-summer months provides support for the conclusion that marginal capacity cost is higher in the summer months. No interruptions in PNM's partially interruptible contract with SPS occurred during coincident peaks in other than the summer and in January and February, Dr. Rose observed, providing further support for his theory.

21. He also found that the historical evidence did not support a change to 12 CP, pointing out that the average of the ratio of 3 CP to the annual peak was 97 percent between 1994 and 2004, and also between 2000 and 2004. The average of the ratio of 12 CP to annual peak was 81 percent between 1994 and 2004, and increased only 1 percent to 82 percent, looking at the more recent 2000- 2004 data. Exhs. PNM-6 at 5; PNM-7. [10]

Discussion and conclusion

22. We begin with the fact that Commission precedent supports use of 3 CP. In the Company's last two litigated rate cases, the Commission reached the result that SPS was a summer peaking system, and 3 CP was the appropriate demand allocator. The Commission has expressed the view that the demand allocation method used for a particular utility should not be changed except where there are changed circumstances or a change in policy. *Louisiana Power & Light Co.*, 14 FERC ¶ 61,075 at 61,128, *reh'g denied*, 15 FERC ¶ 61,297 (1981).

23. The question presented here is whether the Company's load profile has changed sufficiently to move to a 12 CP allocator. The expert testimony is divided on this issue, as suggested above. The ratio tests performed by Mr. Heintz and Saffer suggest the propriety of a shift to 12 CP in order to recognize a flattening of the Company's load over the 12 months of the year. This is supported by Mr. Diller and Staff witness Sammon;

[10] On cross-examination, it was disclosed that there was an error in the data set employed by Mr. Rose, and that the data he used did not match similar data offered by Mr. Heintz. Dr. Rose stated that the revised data would not alter his conclusions that SPS was a summer peaking company. Tr. at 2024-2026.

however, Mr. Sammon was unaware of and did not review the testimony of witnesses Linxwiler and Dr. Rose, who testified that the data have not moved all that much, and that it is important to set proper price signals for what remains essentially a summer peaking utility.

24. I am persuaded that 3 CP remains the correct allocator here. I am influenced by the record evidence that there should be a strong reason for changing allocation methodologies, given the impact on customers' expectations and the shifting price signal effects associated with a change in methodology. Tr. at 2472-2473; Exh. PNM-6. Here, the data are not suggestive of major shifts in the load curve in the direction away from summer peak, but reflect more modest changes. These changes lead one closer to the edges of the various ratios relied on historically by the Commission, and some of them carry over in the direction of a flatter demand curve, but there is no smoking gun pointing to 12 CP. Staff's witness Sammon, although arguing for a shift to 12 CP, saw this as a "close call". *Id.* at 2473. Moreover, as argued by a number of parties, one of the factors that may have caused the movement in the direction of a flatter demand curve, to wit, the increase in off-system sales caused by the availability of excess power due to the shift of Golden Spread to a partial requirements customer, has run its course. Exh. SPS-76 at 11; see also Exh. SPS-77. Accordingly, one cannot assume that whatever modest flattening of the demand curve that occurred on that account will continue. In order to justify a departure from Commission precedent, even a 20 year old precedent, more is needed than a mere step or two in the direction of a flatter curve, particularly in light of the decline in excess capacity, and the need to set proper price signals.

B. Whether revenues from SPS' market-based long-term capacity sales to purchasers located outside the SPS Control Area should be credited against the cost of serving requirements customers whose rates are at issue in the proceeding or whether the loads associated with such sales should be included in the "Other Customers" category when allocating cost of service?

25. Off-system sales are reflected in wholesale rates either through a revenue credit or an allocation in the cost of service. Under the allocation methodology, off-system sales customers are treated as if they were a separate customer group in a cost of service study by including their monthly demands in the energy and demand cost allocator denominators. Exh. S-8 at 56. Off-system customers thus are allocated a share of the total system fixed and variable costs as if they were requirements customers. *Id.*

26. Under the revenue credit methodology, all the costs associated with off-system sales are allocated to requirements customers, and each requirements customer group is credited with its share of the off-system demand revenues via the demand allocator and its share of off-system energy revenues via the energy allocator. *Id.* at 55.

27. SPS contends that the sales in question here are all long-term capacity sales from

system resources which have historically been considered in developing demand and energy allocators. In *Commonwealth Edison Company*, 21 FERC ¶ 61,096 at 61,294 (1982), the Commission reflected these sales in the fully allocated cost basis on which rates for firm service are set. SPS argues that revenue credit treatment has been limited to short-term [opportunity] sales of less than one year, where the sales do not implicate a company's system planning.

28. SPS argues that a threshold issue arises as to how to deal with certain sales that expired in 2004 and were not replaced or continued. CCG witness Daniel applied revenue credits to such sales because he believed that they would be effectively replaced by retail and wholesale requirements load growth. SPS witness Heintz, on the other hand, excluded these sales from the test year altogether, since the sales (100 MW to Manitoba Hydro and 25 MW to Midwest Energy, Exh. SPS-77) terminated in 2004 and rates set here will not become effective until later. Exh. SPS-37 at 14. SPS argues that the remaining firm capacity sales should be recognized in the derivation of the demand and energy cost allocation factors because such sales continued into 2005, the first year that rates set here could affect complainants.

29. Staff agrees with SPS that the allocation method should be used here, because it sees the off-system sales as long-term sales, which should be treated just like requirements sales for cost-of-service purposes. Exh. S-8 at 58. Staff contends that SPS considers the off-system sales to be firm, interruptible only under emergency conditions, and second only to SPS' native load. Staff essentially sees all of SPS' long-term firm customers as having an equal right to SPS' generation assets, whether served under cost-based or market-based rates, and should be treated the same for ratemaking purposes. *Id.* at 26-27.

30. CCG identified nine sales in the 2004 test year that it believed were different from traditional requirements sales, and which it excluded from system load in developing the demand and energy allocation factors. It treated the associated revenues as allocated revenue credits. Exh. CCG-1 at 42. CCG argues that the sales at issue were voluntary, market-based sales of limited duration, and only available for as long as SPS had a surplus of capacity to justify the sales. The Company's surplus capacity is dwindling, notes CCG, which will require it to cease making these kinds of sales. It sees these sales as similar to those sales found to be opportunity sales by the Commission in *Florida Power& Light Co.*, 33 FERC ¶ 61,116 at 61,248 (1985). CCG see these as sales for which SPS does not plan, construct or maintain capacity, as it does for its native load.

31. PNM believes that revenues associated with all of SPS' market-based long term capacity sales should be credited against non-fuel production costs. PNM sees these sales as fundamentally different from long-term sales to SPS' cost of service customers, making allocation inappropriate. PNM witness Rose depicts cost-of-service customers as participants in the regulatory compact, where they have accepted the risks and rewards

associated with the construction of base load generation in a closely regulated environment, in contrast to customers served in a competitive marketplace. Exh. PNM-2 at 18-19.

32. Cap Rock contends that the loads associated with SPS' market-based long-term capacity sales to purchasers located outside of the SPS control area should be included in the "Other Customers" category when allocating cost of service.

Discussion and conclusion

33. I agree with CCG that the sales it identified, excluding the expired sales to Manitoba Hydro and Midwest Energy, should be revenue credited. These sales are fundamentally different from long-term sales to SPS' cost of service customers, making allocation inappropriate. Exhs. CCG-9 and CCG-1 at 38-41. They are more in line with the type of sales found by the Commission to be opportunity sales in *Florida Power & Light,* than they are the type of requirements sales for which SPS is required to plan, construct and maintain capacity. Exh. PNM-2 at 18-19. While Staff argued that these sales were second only to native load, they do in fact have a lesser status, and one that the record discloses is closer to the opportunity sales category. With respect to the expired contracts to serve Manitoba Hydro and Midwest Energy, they should be excluded altogether, since they have expired and whether similar sales will recur is speculative, particularly in light of evidence that suggests a reduction in excess capacity. Exh. SPS-37 at 14 and 77.

C. Should there be an adjustment to the production component of the cost of service allocated to Golden Spread to reflect Golden Spread's resource on the system to recognize generation-related ancillary services that could be provided from Golden Spread's generating resource operated in SPS control area?

34. Section 4.2 of the Service Agreement for Network Integration Transmission Service (NITSA) between Golden Spread and SPS dated June 8, 2000 states that "No ancillary services are provided under this Service Schedule. All ancillary transmission services shall be the responsibility of Golden Spread to arrange." Exh. SPS-120 at Section 4.2. Section 6.0 of the NITSA states that "certain arrangements" in the Commitment and Dispatch Agreement (C&D) between SPS and Golden Spread will "result in the self supply of these Ancillary Services that are required under the Tariff." Exh. CCG-81 at Section 6.0.

35. CCG witness Daniels explains that the demand-based-generation-related ancillary services (ancillary services) that are necessary to support transmission service are: (1) Schedule 2 – Reactive Supply and Voltage Control From Generation Sources Service; (2) Schedule 3 – Regulation and Frequency Response Service; (3) Schedule 5 – Operating

Reserves Spinning Reserve Service; and (4) Schedule 6 – Operating Reserves Supplemental Reserve Service. Exh. CCG-1 at 46. He argues that SPS supplies these four ancillary services to the Cooperative FR Customers, as part of its retail requirements load, and to other power customers. *Id.* at 46-48. He maintains that these costs are allocated without any distinction as to the elements of the costs that are associated with providing these four ancillary services. *Id.* at 48.

36. Golden Spread/Lyntegar is asking for a credit based on the rates for ancillary services that were in existence during the calendar year 2004 test year, as recommended by Staff. Golden Spread/Lyntegar argues that since both the full and partial requirements rates reflect an allocation of the ancillary services, Golden Spread should be granted a credit to the partial requirements cost of service. Golden Spread/Lyntegar contends that language in the Xcel OATT allows for SPS to require Golden Spread to purchase these ancillary services under the tariff in the event that Golden Spread did not provide evidence to SPS that it was self supplying these services. Golden Spread/Lyntegar witness Mr. Daniels argues that Golden Spread is allocated a share of the production costs associated with SPS providing these ancillary services which causes Golden Spread to be double charged, through the rate base and again in the ancillary services charges. Exh. CCG-1 at 49. Mr. Daniels indicates that the FR Customers' are directly assigned a demand-related revenue credit which prevents the FR Customers from being double charged for ancillary services. *Id.*

37. Mr. Daniels explains that Mustang station is operated for the purpose of serving SPS and Golden Spread's combined load requirement. Tr. at 511. Mr. Daniels maintains that through the Mustang station, Golden Spread is providing SPS a resource which in terms of service obligation requirements is more than Golden Spread would have to purchase from SPS. *Id.* at 370. Mustang station is available to SPS, and SPS can call upon it to provide reactive power, spinning reserves, supplemental reserves, etc. *Id.* at 366-367. Mustang station is a fully dispatchable resource for SPS, and it can be operated just like any other SPS system generator. *Id.* at 511. Mr. Daniels argues that the Mustang Station could be operating with spinning reserve capability, supplemental reserve capability, could be used to provide regulation on the system, and can produce or absorb VARs. *Id.* at 512.

38. SPS argues that it, not Golden Spread, incurs the cost of providing the ancillary services associated with its firm capacity commitment to Golden Spread. SPS witness Mr. Heintz argues that the fact that Golden Spread self supplies ancillary services, does not provide for a reduction in the cost of power sold by SPS to Golden Spread. Exh. SPS-37 at 21-22. Mr. Heintz contends that Golden Spread is paying for its contract demand and Golden Spread would only be entitled to a credit if the contract provided that Golden Spread was to self supply these ancillary services and SPS was not required to regulate or back up its power sale. *Id.* at 22. Mr. Heintz maintains that Golden Spread is exempt from paying for generation based ancillary services but Golden Spread does not

provide regulation service or required operating reserves so there is not a basis upon which to base a revenue credit. Exh. SPS-87 at 21. Mr. Heintz argues that the ancillary services Golden Spread pays for are inherent in the partial requirements service it takes from SPS. *Id.* Unlike Golden Spread, the FR Customers pay for ancillary services under their network service agreements and pay for SPS' provision of those services in the SPS control area as part of the full requirements service payment. *Id.* If a revenue credit was not made for the FR Customers they would pay twice; Golden Spread however is not entitled to a credit. *Id.*

39. SPS argues that Golden Spread is attempting to obtain a capacity payment for the Mustang plant, something that was foregone in the negotiation of the C&D. SPS indicates that the C&D does not entitle SPS to count Mustang's capacity as its own, nor does SPS count on using Mustang capacity.

40. Staff argues that Golden Spread should receive a credit for the ancillary service costs that are charged to Golden Spread through the partial requirements service. Staff indicates that the NITSA unambiguously states that self supply of the ancillary services are required under the tariff, a scheduling dispatch charge of $0.019/kW of monthly Network load per month was included, and local distribution facilities charges to be calculated at $2.43 times the maximum metered kW per distribution delivery point, adjusted for losses per month were also included. Exh. CCG-81. Further, Staff points out that the NOA specifies that the Network Customers will meet, through self-supply, its proportional share of Regulating Margin. *Id.*

41. Staff witness Mr. Sammon argues that unless there is an adjustment that removes the ancillary service costs from the cost of service, the costs will be included because these ancillary service costs are inherent in the costs of generation. Exh. S-8 at p. 68. Mr. Sammon contends that regardless of whether SPS is actually providing these services to Golden Spread, it needs to adjust the production component of its cost of service because the contract states that ancillary services are not part of what SPS is providing to Golden Spread. *Id.* at 67-68. Mr. Sammon explains that the ancillary service credit should be developed using SPS' revised rates which were in effect during the 2004 test period and will be effective on the day that any rate change resulting from this proceeding can become effective. *Id.*

42. Cap Rock opposes a credit to Golden Spread, because Golden Spread did not prove that the credit was justified. Cap Rock contends that in future years such a credit would cause an unjust and unreasonable shift of cost responsibility from Golden Spread to the full requirements customers.

Discussion and conclusion

43. I find that Golden Spread should receive a credit for ancillary services that it self

supplies. The contract provisions are clear, and provide that SPS and Golden Spread agreed that Golden Spread would self supply these ancillary services. SPS does not dispute that when it allocates a portion of its generation fleet to Golden Spread, production costs required in providing ancillary services are allocated to Golden Spread. Tr. at 1786. SPS is simply arguing that the ancillary services Golden Spread is paying for have to be provided in order for SPS to meet its obligations to Golden Spread. However, both the NITSA and the NOA clearly establish that Golden Spread is to self supply ancillary services. Further, the Xcel OATT indicates that if Golden Spread's ancillary service capacity is inadequate, SPS is entitled to seek payment for those ancillary services and modification of Section 6.0. The credit should be based on the rates for ancillary services that were in existence during the calendar year 2004 test year, as recommended by Staff.

D. What is the appropriate cash working capital allowance to be included in the cost of service?

44. A cash working capital allowance (CWCA) is an amount included in rate base to allow a company to pay "out-of-pocket" expenses that are incurred in daily operations before the expenses are recovered through customer revenues. The Commission has used two methods to calculate CWCA, the 45 day rule, also known as the 1/8 rule, and a fully developed and reliable lead-lag study. The Commission has stated that the 45 day rule has many benefits as "it avoids imposing on utilities, and ultimately, on their consumers, the cost of regularly performing a thorough and detailed lead-lag study … the method has been found to produce reasonable results over the years without the expense of prolonged litigation … [and] it affords substantial advantages from the standpoints of administrative convenience and as an aid to the Commission in managing its large and increasing case load." *Carolina Power & Light Co.*, 6 FERC ¶61,154 at 61,295 (1979). However, the Commission allows parties to submit fully developed and reliable lead-lag studies to develop a proper working capital allowance, in lieu of the 45 day rule.

45. A fully developed and reliable lead-lag study's revenue lag calculation must be based on, or confirmed by, a study of the wholesale customers' actual bill paying practices. Absent this, the lead-lag study cannot be found to reflect the actual cash needs of the company. *Pennsylvania Power Co,* 12 FERC ¶ 61,049 at 61,080 (1980), *aff'd, Boroughs of Ellwood City, et. al v. FERC,* 731 F.2d 959 (1984) (*Boroughs of Ellwood*). Further, a lead-lag study that is fully developed and reliable "must include a calculation of the lag in paying other operating and maintenance expenses based on an audit which is in turn based on an appropriate sampling methodology." *Louisiana Power & Light,* 14 FERC ¶61,075 at 61,122-123. However, the United States Court of Appeals for the District of Columbia has also added that, where a study is conducted based on assumptions that payments were received on time, rather than on actual bill paying practices, and those assumptions are verified by checking the data against actual payment practices, the lead-lag study is given the same credibility as if it had been based on data

derived from actual payments. *Cities of Aitken, et. al.*, 704 F2d. 1254 at 1258 (1982). In another decision the District Court found that a lead-lag study was not fully developed and reliable where the study's revenue lag assumption was expressly contradicted by actual practice, since such a flaw was enough to undermine confidence in the study's reliability, despite the fact that another inaccuracy tended to negate the effect of the revenue lag error. *Boroughs of Ellwood*, 731 F2d. 959 at 965.

46. CCG contends that SPS is not entitled to a CWCA based on a lead-lag study CCG produced. CCG witness Ms. Humphrey argues that there is no need for a CWCA because SPS is receiving payments from its wholesale customers 35.17 days after the date the services are rendered and payment of these expenses is occurring 38.49 days after the expenses are incurred. Exh. CCG-73 at 4. Ms. Humphrey indicates that she "reviewed and analyzed 93 percent of wholesale revenues, 100 percent of coal purchases, 72 percent of gas purchases, 83 percent of purchased power, 99.75 percent of property taxes, 77 percent of cash A&G expenses, 85 percent of other cash O&M expenses, in addition to a review and analysis of other items." *Id.* at 17.

47. Ms. Humphrey indicates that she relied upon 2004 data which included: (1) billings and cash receipts related to wholesale customers; (2) purchases and payment dates for all coal purchases; (3) all purchases and payment for natural gas; (4) all purchases and payment dates related to purchased power; (5) property taxes and payment dates; (6) payroll and withholding records; (7) information about A&G expenses. Exh. CCG-56 at 4. Ms. Humphrey's analysis consisted of performing, for each specific category of expenses, either an analysis of 100 percent of the underlying transactions, or a specific analysis based on selected transactions to determine the average time between incurrence of the expense and payment. *Id.* at 5. Ms. Humphrey explains that the significant categories of expenses she identified included fuel expense, for both coal and gas, non-fuel and purchased power O&M, which consists of payroll cost, employee benefits, charges from affiliates, and "other", purchased power, payroll taxes, property or ad-valorem taxes, and Federal and State income taxes. *Id.* Ms. Humphrey states that she analyzed all of the 2004 transactions for SPS' 13 largest wholesale customers representing 93 percent of all wholesale revenues for the 2004 test year, to determine the average revenue lag. *Id.*

48. Ms. Humphrey indicates that she used an estimate for the portion of expenses for which SPS had not provided information, which consisted of less than 10 percent of the wholesale cost of service. Exh. CCG-73 at 5. According to Ms. Humphrey, she had access to the service periods for 100 percent of the wholesale revenues and more than 90 percent of the cash cost of service items, which included fuel, purchased power, payroll, taxes other than income taxes, and income taxes. *Id.* at 6. Ms. Humphrey explains that she did not have service period information for the non-fuel and purchased power portion of O&M costs, which includes payroll costs, employee benefits, A&G costs, charges from affiliates and "other" types of costs. *Id.* at 15. Ms. Humphrey argues, however, that

her inability to analyze these expenses is inconsequential, as the nature of the types of expenses is such that there is a long period between when the expenses are incurred and when they are paid. *Id.* at 15. She argues that if she had obtained and analyzed the data, it would have only further reduced SPS' CWCA. *Id.* at 16. Ms. Humphrey indicates that wherever there was a reason to estimate, she always used assumptions that were advantageous to SPS. *Id.* at 17. Ms. Humphrey indicates that if SPS actually believed itself to be entitled to anything near what the 1/8 rule provides, it would have performed its own lead-lag study to rebut her testimony. *Id.* at 16.

49. CCG counters Staff's and SPS's arguments that the lead-lag study was not fully developed, arguing that the reason the study relied on estimated not actual service periods was because the Company did not agree to provide CCG a listing of actual service periods. CCG argues that SPS opposed CCG's attempts to obtain the data, only to then use the lack of an analysis of the data that was withheld by SPS to argue that the lead-lag study was not fully developed. Finally, CCG indicates that SPS' and Staff's arguments indicating that if anything less that 100 percent of actual expenses and invoices are used a lead-lag study is not fully developed and reliable are not supported by Commission precedent and relies on *Cities of Aitken* to argue that where the assumptions are verified by actual payment practices, the lead-lag study can be fully developed and reliable. *Cities of Aitken, et. al.*, 704 F2d. 1254, at 1258.

50. SPS argues that there should be a CWCA based on the Commission's 45-day rule included in the rate base, for a total of $2,667,963 for the wholesale customers at issue in this case. Exh. SPS 114 at 13. SPS contends that Ms. Humphrey's lead-lag study was not fully developed and should not be used since the study relied on contract terms and not the actual billing and payment of revenues and expenses. SPS maintains that if Ms. Humphrey had visited SPS parent, Xcel Energy's (Xcel) offices she could have determined the actual service periods. SPS' witness Ms. Blair argues that Ms. Humphrey estimated actual service periods in many instances and particularly did so in regards to O&M expenses other than fuel and purchased power. *Id.* at 5. Because of Ms. Humphrey's estimates, Ms. Blair argues that the study is not fully developed and is not indicative of the Company's actual cash needs. *Id.* at 6. Ms. Blair indicates that Ms. Humphrey did not do a detailed audit of actual service periods and payment dates and this would have been essential to a fully developed and reliable lead-lag study. *Id.* Ms. Blair argues that even Ms. Humphrey's revised testimony was based on guesses at expense leads based on contract terms and Ms. Humphrey's understanding of SPS payment practices. *Id.* at 7.

51. Ms. Blair explains that SPS did not provide CCG a list of actual service periods, because the information is not stored in SPS' computer systems; instead SPS agreed to allow Ms. Humphrey to come to Xcel's Denver office so that Ms. Humphrey could physically inspect copies of each invoice in order to determine the actual service periods, however Ms. Humphrey never did so. *Id.* at 5. Finally, Ms. Blair contends that even if

Ms. Humphrey's study is validated, SPS should be allowed a CWCA related to O&M expenses other than fuel and purchased power, giving SPS a net lag of 11.57 days, which would give SPS a CWCA of $677,000. *Id.* at 13.

52. Staff argues the 45 day rule should be applied to determine SPS' CWCA because Ms. Humphrey's lead-lag study was not fully developed and lacks details in the billing of O&M expenses and that the study relied on contract terms instead of physically reviewing each expense bill. Staff witness Ms. Radel testifies that Ms. Humphrey's study was not fully developed because each expense bill was not reviewed, and the study relied on contract terms instead of actual billing and payment of revenues and expenses. Exh. S-4 at 13.

Discussion and conclusion

53. I find that 45-day rule should be applied to determine SPS' cash working capital allowance because CCG's lead-lag study is not fully developed and reliable.

54. CCG's lead-lag study is based on too many assumptions. Ms. Humphrey testified, when cross examined regarding gas purchases, that she assumed that the invoice date was an indication of when the service or good had been provided. Tr. at 744. Also, where the data did not provide an invoice date, Ms. Humphrey indicated that based on the payment date and the nature of the type of items, she made an assumption as to the service period. *Id.* at 747. Additionally, when asked about repetitive data items, Ms. Humphrey indicated that she did not actually look at invoices so she could not rule out the possibility that identical charges were erroneously entered. *Id.* at 817-819. While Ms. Humphrey testifies that, in many instances, SPS provided the service period,[11] SPS refutes this, indicating that it did not agree to provide, nor did it provide service periods in the data it gave to CCG.[12]

55. When asked about the sampling methodology used to determine which invoices were selected for testing, Ms. Humphrey indicated that since it was not required, she did not use statistical sampling. *Id.* at 750. When asked about her methodology, Ms. Humphrey indicated that her general rule was to include all transactions over a certain amount, but she scanned the rest of the transactions to ensure that she had a representative sample. *Id.* at 813. Ms. Humphrey could not articulate her sampling methodology at the hearing and she did not provide an explanation of her sampling methodology in her testimony.

56. Finally, CCG's reliance on *Cities of Aitken* is unfounded, as the District Court

[11] Tr. at 799.

[12] Exh. SPS-114 at 5.

found that because the study's assumptions had been validated against actual payment practices, the lead-lag study was fully developed and reliable. However, in this proceeding, Ms. Humphrey did not review the actual payment practices, as she did not look at the invoices that were made available for her inspection. Further, CCG's attempt to provide that verification by asking Ms. Humphrey questions concerning a 1997 SPS lead-lag study is irrelevant as are Ms. Humphrey's assertions that payment practices rarely vary. *Id.* 826-827. The verification required to validate the assumptions in the lead-lag study is not provided by either Ms. Humphrey's assertions of her knowledge of SPS' payment practices, nor by the review of a lead-lag study that is nearly 10 years old.

E. Is Pollution Control Construction Work in Progress properly included in rate base?

57. In Order No. 555, the Commission permitted an allowance of pollution control work in progress (CWIP) in rate base where the facilities being constructed are used for pollution control and indicated that the intent was to encourage the building of facilities designed to reduce the amount of pollution produced by the underlying power facility.[13] 18 C.F.R. § 35.25 (c) (2005) states that :

> "[f]or purposes of any initial rate schedule or any rate schedule change filed under § 35.12 or § 35.13 of this part, a public utility may include in its rate base any costs of construction work in progress (CWIP), including allowance for funds used during construction (AFUDC), as provided in the section."

In 18 C.F.R. § 35.25(c)(1)(i), "[a]ny CWIP for pollution control facilities allocable to electric power sales for resale may be included in the rate base of the public utility."

58. CCG argues that SPS has not complied with Commission requirements for inclusion of pollution control CWIP in is rate base because SPS has not provided any of the data required in Section 35.25(c)(1)(ii). CCG argues that to allow SPS to include pollution control CWIP in rate base without demonstrating that the treatment complies with 18 C.F.R. § 35.25 would lead to utility's being able to include in rate base substantial sums of money until the time it becomes the target of a Section 206 complaint, instead of making a filing under Section 205. CCG also contends that SPS did not use forward looking allocation ratios to allocate its requested CWIP to its customers; SPS instead provided an allocation ratio that was the product of 2004 test year data.

59. SPS argues that $3,835,043 of pollution control CWIP is properly included in its

[13] *Amendments to Uniform System of Accounts for Public Utilities to Provide for Inclusion of Construction Work in Progress in Rate Base*, Order No. 555, 56 FPC 2939, 2943-44 (1976), *reh'g denied*, Order No. 555-A, 57 FPC 6 (1977).

2004 rate base as the evidence it provided explained the nature and scope of its pollution control CWIP projects. SPS indicates that it has assured CCG that SPS would not charge customers for both pollution control CWIP and AFUDC in rate base. SPS indicates that Commission policy requires that current customers be responsible for the costs of construction of pollution control equipment. SPS refutes CCG's assertion that SPS did not fully comply with the Commission's filing regulations, arguing that it does not have to, as CWIP regulations do not apply in this proceeding because it is a complaint case, but instead apply when a utility files a Section 205 case to initiate or change its CWIP.

60. Staff argues that pollution control CWIP is properly included in rate base, indicating that Commission regulations allow an electric utility to include pollution control CWIP in the rate base and earn a return. Staff argues that SPS has complied with FERC regulations and the amount at issue is related to pollution control and explains that CWIP regulations apply when a utility seeks to initiate or change its CWIP in a Section 205 rate case.

Discussion and conclusion

61. Pollution control CWIP is properly included in SPS' rate base. The Commission's regulations clearly permit the recovery of pollution control CWIP. SPS has submitted a list in Exhibit SPS-52 indicating the pollution control facilities it is including in rate base, and has provided testimony indicating that the facilities are all pollution control facilities, associated with existing facilities that SPS owns. Tr. at 2225. CCG's arguments regarding 18 C.F.R. § 35.25 (c)(1)(ii) are unpersuasive, as 35.25(c)(1)(ii) simply indicates what the Commission will consider in determining what is a pollution control facility, but does not specifically state that this documentation must be filed. Additionally, 35.25 (c)(1)(ii)(C) states that the Commission will consider "[o]ther evidence showing that such facilities are for pollution control." As for CCG's AFUDC concerns, SPS has testified that the pollution control costs will be included in customers' rate base only as long as they are taking service from the Company and the Company has submitted evidence, Exhibits SPS-158 and SPS-159, supporting its assertion. Tr. at 2226.

F. What is the proper treatment of undistributed subsidiary earnings from former subsidiaries in determining SPS' equity capital balance?

62. In *United Gas Pipeline Co.*, 13 FERC ¶ 61,044 at 61,096 (1980), the Commission has held that, for rate of return purposes, undistributed subsidiary earnings are not to be included in capitalization, because they are not available to the company to invest in rate base; however, distributed subsidiary earnings are includable, as they are available for rate base investment.[14]

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[14] *See Ohio Edison,* 24 FERC ¶ 63,068 at 65,090 (1983) (Settlement agreement superceding initial decision accepted by the Commission, 26 FERC ¶ 61,359 (1984)) and

63. Account 216 Unappropriated Retained Earnings should include:

> [T]he balances, either debit or credit, of unappropriated retained earnings arising from earnings of the utility. This account shall not include any amounts representing the undistributed earnings of subsidiary companies. 18 C.F.R. Pt. 101 (2005).

Account 216.1 Unappropriated undistributed subsidiary earnings should include:

> [T]he balances, either debit or credit, of undistributed retained earnings of subsidiary companies since their acquisitions. When dividends are received from subsidiary companies relating to amounts included in this account, this account shall be debited and account 216 ... credited. 18 C.F.R. Pt. 101

64. CCG argues that that $22,855,828 in Undistributed Subsidiary Earnings should be excluded from SPS' common equity. CCG's witness Mr. Cook explains that those earnings are from former SPS subsidiaries Utility Engineering Corporation (UEC) and Quixx Corporation (Quixx), which were sold by SPS in 1997 and are not affiliated with SPS' electric operations. Exh. CCG-55 at 22. On brief CCG argues that SPS' contention that a subsidiary's retained earnings are transferred to SPS is flawed for a number of reasons: (1) SPS had for seven years after the sale, treated these earnings as subsidiary earnings; (2) even if SPS had shown that for accounting purposes, this transfer was proper, it has not shown that it is proper for ratemaking purposes; (3) the inclusion of the amount in its common equity is inconsistent with its exclusion of the amount in SPS' transmission rate filing on October 13, 2004; (4) inclusion of the amount would provide an unjust windfall to SPS as ratepayers would be forced to pay a return on dollars that are already a return from an investment in a subsidiary; and (5) since neither Quixx nor UEC were involved in the provision of electric service while they were SPS subsidiaries, they should not be considered in SPS' cost of capital as part of the common equity component.

65. SPS maintains that the standard ratemaking practice is to use the test year-end capital structure to determine a utility's test year revenue requirement. *ARCO Pipe Line Co.*, 43 FERC ¶ 63,033 at 65,379 (1988), *reh'g*, 52 F.E.R.C. P61,055 (1990). SPS witness Ms. Blair explains that SPS no longer has a financial interest in the subsidiaries and SPS' practice when a subsidiary is no longer on the operating company's books, is that accumulated retained earnings associated with the subsidiary are transferred to retained earnings of the operating company and are not identified separately on the books. Exh. SPS-49 at 40-41. The retained earnings are then part of the common equity

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Carolina Power & Light, Co., 17 FERC ¶ 63,040 at fn. 103 (1981) (Settlement agreement superceding initial decision accepted by the Commission, 19 FERC ¶ 62,602 (1982)).

balance. *Id.* at 41. Ms. Blair explained that in 2004, SPS made a journal entry to move the amounts of the undistributed subsidiary earnings out of FERC account 216.1 and into FERC account 216.0, making the balance at the end of 2004 zero. Tr. at 2203. SPS argues that the amounts in dispute represent an additional amount of retained earnings, which SPS has invested in its utility business, and although the funds were from profits earned by non-utility subsidiaries, the amount has been used to fund utility activities, which makes the amount properly included in the common equity balance.

66. SPS refutes CCG's assertion that SPS has treated the amount inconsistently in another transmission rate case, arguing that the Commission generally takes the position that undistributed subsidiary earnings, when determining the overall rate of return, must be excluded from capitalization. *United Gas Pipe Line Co.*, 13 FERC ¶ 61,044 at 61,096. SPS argues that since the rate case referred to by CCG was based on 2003 data, and the amount at that point was carried under Account 216.1, which would not have made it available for rate base, it had to be excluded.

67. On brief Staff agrees with CCG's arguments and further argues that the fact that it took SPS seven years to transfer the amounts from accounts 216.1 to account 216.0 indicates that these amounts should not be included in rate base.

Discussion and conclusion

68. The $22,855,828 in retained earnings from former subsidiaries of SPS should be included in the capital structure used to determine SPS' overall rate of return in this case. The issue is not whether undistributed subsidiary earnings should be included in rate base as Commission precedent clearly does not allow it. Rather the issue is whether the amount in fact represents undistributed subsidiary earnings. CCG and Staff rely on the amount of time that has passed between the sale of the subsidiaries and the transfer to account 216.0 to indicate that these are still undistributed subsidiary earnings. However, SPS no longer owns the subsidiaries, as its share in Quixx and UECC were sold to NC Enterprises in 1997. Exh. SPS-127. To explain the length of time, SPS indicated that there was note payable from NC Enterprises to SPS, that was paid back over a five-year term to SPS and held on the books until the note was paid. Tr. at 2198. The amounts were properly moved to account 216.0 in 2004, which is includable in capitalization for rate base purposes, and Ms. Blair has indicated that SPS had contacted FERC's Chief Accountant's Office who informed SPS that that would be a proper treatment for FERC Form 1 reporting purposes. *Id.* at 2197.

69. Staff and CCG indicate that not all amounts includable for accounting purposes are includable for rate making purposes; they have no specific precedent indicating why in this instance, the amounts should not be included. SPS does not dispute that the subsidiaries operations did not involve the provision of utility service. *Id.* at 2197-2198. However, the funds are now available for use by SPS to invest in is electric utility

operations, and, under *United Gas Pipeline*, includable in SPS' equity balance.

G. Should the costs of Demand Side Management programs be allocated to wholesale customers?

70. SPS argues that since Demand Side Management (DSM) programs benefit all customers by reducing SPS' system production costs for capacity and/or energy, wholesale customers should be allocated some of the costs. SPS counters Staff's argument that in order to be allowed to allocate the DSM program costs to wholesale customers, SPS must show that a certain percentage of SPS' peak load would have to be displaced by a DSM program, asserting that neither Commission precedent nor logic supports that assertion. SPS contends that in *Cities of Greenwood and Seneca, South Carolina v. Duke Power Co.* ("*Cities of Greenwood*"), 77 FERC ¶ 63,017 at 65,065 (1996), it was held that simply the fact that a utility did not have to spend money for capacity as a result of DSM programs was enough justification for allocating those costs to wholesale customers.[15] Additionally, in *Cities of Greenwood* Staff supported the allocation of DSM program costs in the utility's cost of service, and Staff has offered no explanation of its contrary position in this proceeding.

71. Staff argues that SPS' request to include the DSM programs in its rate base should be rejected. Staff contends that SPS has not provided any hard data showing that wholesale customers have benefited from the DSM programs, and there is no support for SPS' request that these programs be rolled into rate base for wholesale customers. Staff argues that before SPS is allowed to include these costs in rates, it should at least perform a study to show that the programs have allowed SPS to reduce the load on its system enough to allow SPS to delay the installation of new generation capacity. Staff also argues that its position in the previous proceeding is irrelevant.

Discussion and conclusion

72. The costs of DSM programs are properly allocated to wholesale customers. SPS has shown that in the past four years the DSM programs have allowed SPS to reduce its peak generation needs by approximately 38 MW and reduced SPS' energy needs by approximately 323,000 MWh. Exh. SPS-88 at 6. Staff offers no support for its assertion that SPS is required to at least perform a study to show that the programs have reduced load enough to delay the installation of new generation capacity. SPS has clearly shown the DSM programs are reducing SPS' peak generation needs and energy needs. In *Cities of Greenwood*, the ALJ found that, "paying certain customers ... not to use the system is an appropriate alternative to building or acquiring excess capacity," and while the decision is not precedential, it is persuasive. 77 FERC ¶ 63,017 at 65,066. The programs

[15] The case was later resolved through settlement.

are providing SPS an alternative to building additional capacity and are properly allocated to the wholesale customers.

H. What is the appropriate treatment of Renewable Energy Credits, base rate revenue credit or flow-through in the FCAC?

73. Renewable Energy Credits (REC) come from state programs and are obtained from owned resources or from purchases in an amount that corresponds to renewable generation. *American Ref-Fuel Co., et al.*, 105 FERC ¶ 61,004 at 61,005 (2003), *reh'g denied*, 107 FERC ¶ 61,016 (2004). Commission regulations provide that:

> [*t*]*otal cost of the purchase* is all charges incurred in buying economic power and having such power delivered to the buyer's system. The total cost includes, but is not limited to, capacity of reservation charges, energy charges, adders, and any transmission or wheeling charges associated with the purchase. 18 C.F.R. § 35.14 (a)(2)(iii) (2005).

74. CCG argues that it, along with Staff and PNM, support fuel adjustment clause treatment of the REC, indicating that the REC should be offset against the costs of the wind resource purchases; this net cost should be used in quantifying the portion of the energy costs for the wind resource purchase that is less than SPS' total avoided variable costs. CCG explains that SPS' wind energy contracts include REC. CCG explains that SPS has acquired more REC than it needed to satisfy its state obligations and so was able to sell the excess and reduce its net cost of wind purchases. CCG witness Mr. Daniels indicates that during 2002-2004, SPS sold 386,377 REC for $2,125,074. Exh. CCG-8 at 35 and CCG-39 at 6. Mr. Daniels testified that allowing SPS to include the REC as a base rate revenue credit, instead of off-setting it against the costs of wind purchases, would allow SPS to pocket REC as revenue, if it holds on to the REC until they were beyond the test year so that the REC would not be recognized for purposes of ratemaking. Tr. at 513-515. Further, SPS anticipates increasing their wind generation, so the potential for increased revenue from REC exists. *Id.* at 515. CCG argues that SPS should be required to accurately reflect the cost of its fuel in its FCAC and failure to include the revenues to SPS from the sale of REC would result in a windfall to SPS.

75. CCG argues that there should be a historical and prospective FCAC treatment of revenues from REC. CCG indicates that not offsetting the credits from the charges will overstate the cost of the purchase. CCG maintains that REC are akin to emission allowances, which can be obtained, marketed and transferred separately. CCG indicates that, in *Cincinnati Gas & Electric*, the Commission allowed emission allowances to be flowed through a FCAC and the REC should be similarly treated 71 FERC ¶ 61,083 at 61,294 (1995).

76. SPS argues that no unfairness results from treating the $382,248 in REC proceeds

as a base rate revenue credit. SPS indicates that the Commission fuel clause regulations do not allow REC proceeds to be captured through the fuel clause. SPS witness Mr. Hudson argues that standard ratemaking practice is to include the REC proceeds under account 456, which will be included in the test year revenue credits when setting base rates. Exh. SPS-108 at 29. Mr. Hudson argues that it is improper to ascribe a value to REC since the contracts that provide the REC indicate that they are delivered to SPS at no additional compensation. *Id.* at 34. Mr. Hudson explains that customers have already received the benefit of having low cost renewable energy and proceeds from the sale of excess REC should be included in base rate and not credited to fuel and purchased energy costs in the FCAC calculation. *Id.* at 42-43. SPS indicates that there is no evidence of any 2005 or 2006 REC sales so there is not evidence in the record that including REC sales revenues in fuel clause calculation would make a difference. SPS also indicates that this issue has been raised in Docket No. ER06-276-000 and should not be given further consideration in this proceeding.

77. Staff argues that the Commission's regulations do not permit RECs to flow through to the New FCAC and Staff does not advocate violating the Commission's regulations. Staff contends that it is fair to offset the credits with the costs, but that this issue is more properly addressed in Docket No. ER06-274-000.

78. PNM agrees with CCG's position that the proceeds from the sales of REC should not be dissociated from the costs of wind energy purchases. PMN witness Mr. Rose argues that wind resources' purchase price clearly includes the REC, and the value realized from the REC should be shared with those who paid for the purchase. Exh. PNM-2 at 30-31.

Discussion and conclusion

79. I find that REC should be flowed through in the FCAC. While the Commission's regulations do not contemplate the capture of the sale of REC through the FCAC, it is just and reasonable to off-set the REC proceeds from the costs of the wind energy purchases which are being included in the FCAC. During 2002-2004, SPS sold 386,377 REC for $2,125,074, and SPS still has unused credits that it could sell. I am persuaded by CCG's, and PNM's arguments that not allowing the REC to be offset against the wind energy purchase price overstates the cost of the purchase and could provide a windfall to SPS. SPS does not argue that its method would be equitable but simply relies on the fact that the regulations do not contemplate this treatment of REC and that the issue may be addressed in Docket No. ER06-274-000.

I. What is the proper rate of return on common equity to be allowed SPS in the development of its current cost-based wholesale rates?

80. The determination of a just and reasonable rate of return on common equity (ROE)

is governed by two standards: (1) the rate must be sufficient to allow the regulatory entity to maintain its financial integrity and to allow the utility to maintain its credit and attract investment capital; (2) must be commensurate with returns on investments in enterprises that have a corresponding risk.[16] The discounted cash flow (DCF) methodology has been favored by the Commission, and the Commission has expressed a preference for using current market data to develop an electric utility's ROE.[17]

81. SPS does not have publicly traded stock, as its common stock is wholly owned by Xcel, so a DCF analysis cannot be performed using SPS data. Exh. S-1 at 6. All three return on common equity witnesses also contend that a DCF analysis of Xcel to determine ROE would not be acceptable, because Xcel cut its dividend payment during the fourth quarter of 2002, making the results of a DCF analysis unreliable at this time. *Id.* at 6-7, Exh. CCG-25 at 11-12. Therefore, all three witnesses in this proceeding have selected proxy groups and developed the DCF methodology using data from these proxy groups. Exhs. S-1, SPS-42, CCG-25. All three witnesses also recommend a 0.07 percent flotation adjustment, calculated using the Commission's formula developed in Order No. 420.[18]

82. SPS' witness Mr. Cassidy recommends a ROE of 10.5 percent, based on the midpoint of the range and including a flotation adjustment of 0.07 percent. Exh. SPS-82 at 17.

83. Mr. Cassidy's proxy group included four utilities: (1) Constellation Energy Group (Constellation); (2) SCANA Corp.; (3) Sempra Energy (Sempra); and (4) Wisconsin Energy Group. SPS-42 at 13. Mr. Cassidy selected these companies based on the following criteria: (1) they have estimated five year growth rates, based on at least four estimates, published by *Zacks Investment Research* (*Zacks*); (2) they have bonds rated by *Standard & Poor's* (*S&P*) from BBB to A-; (3) they have common stock rated B by *S&P*;

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[16] *Bluefield Water Works and Improvement Co. v. Public Service Commission*, 262 U.S. 679, 693 (1923); *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

[17] *Southern California Edison, Co.*, 92 FERC ¶ 61,070, 61-267 (2000) ("SCE"); *See Midwest Independent Transmission System Operator, Inc.*, 100 FERC ¶ 61,292 (2002) ("*MISO*") and 106 FERC ¶ 61,302 (2004) ("*MISO Remand*"), *aff'd*, *PSC of Ky v. FERC*, 397 F.3d 1004 (2005).

[18] *Generic Determination of Rate of Return on Common Equity for Public Utilities*, Order No. 420, 50 Fed. Reg. 21802 (May 29, 1985), FERC Stats & Regs., Reg. Preambles 1982-85, ¶ 30,644 (1985); Order No. 442-A, 51 Fed. Reg. 22505 (June 20, 1986) FERC Stats. & Regs., Reg. Preambles 1982-1985 ¶ 30,702 (1986); Order no. 489, 53 Fed. Reg. 3342 (February 5, 1988), FERC Stats. & Regs., Reg Preambles 1986-90 ¶ 30,795 (1988).

(4) they have *Value Line* published Safety Ranks of 2; (5) they have common equity ratios between 40 percent and 50 percent. *Id.* Mr. Cassidy explains that since Xcel Energy and the proxy companies all pay quarterly dividends, he used a quarterly payment mode, and he developed an adjustment factor to the current dividend yield for the quarterly payment of dividends equal to 1 plus one half of the growth rate. *Id.* at 16.

84. Mr. Cassidy derived the constant growth rates of the proxy companies using estimates of future book values, earnings and dividends per share published by *Value Line* to estimate, for the proxy companies, future earned rates of return and earnings retention rations. Exh. SPS-42 at 17. Mr. Cassidy computed an estimated book value per share for 2008 for the proxy companies by dividing the book value for 2009 by one plus the growth rate of book value per share. *Id.* Mr. Cassidy's internal growth rate is the product of the expected return and retention ratio. *Id.*

85. Mr. Cassidy used the midpoint of the proxy group as his measure of central tendency. Exh. SPS-82 at 19. Mr. Cassidy argues that the midpoint is a better measure of central tendency because the median will not be representative of a small group of companies in many cases. *Id.* Mr. Cassidy argues that it does not seem reasonable to exclude some of the proxy companies from the sample, by the use of the median rather than the average, and he suggests that the Commission rely on an average range, as the methodology would lessen the effect of skewed distributions of returns and consider all of the proxy group companies. *Id.* at 20.

86. Mr. Cassidy argues that CCG's witness Mr. Solomon's proxy group is not appropriate because the companies included in Mr. Solomon's proxy group are considerably less risky than SPS. *Id.* at 8. Mr. Cassidy argues that Mr. Solomon placed special importance on the Financial Strength Rating, and de-emphasized the Index of Price Stability, because Mr. Solomon used both *Value Line's* Safety Ranks and Financial Strength Ranks. *Id.* at 8-9. Mr. Cassidy further contends that Mr. Solomon's proxy companies are considerably less risky than Xcel with respect to the Index of Price Stability. *Id.* at 9. Finally, Mr. Cassidy argues that Mr. Solomon should not have excluded WPS Resources Corp. from his proxy group, although including it would not have significantly altered Mr. Solomon's proposed ROE, and Mr. Solomon should have used a common stock ranking of B. *Id.* at 10.

87. Mr. Cassidy also argues that Staff's witness Mr. Green created a downward bias in his analysis because Mr. Green has eliminated companies that should have been included in the proxy group. Exh. SPS-82 at 5. Mr. Cassidy indicates that Mr. Green's requirement that the DCF model growth rate cannot be higher than the proxy group's median low estimate of investors' ROE is not valid. *Id.* at 6. Mr. Cassidy argues that while a basic and logical assumption of the DCF model is that a company's growth rate has to be lower than the company's own required return, this theory cannot be extended to require that one company's growth rate must be lower than the required return for

another company or group of companies. *Id.*

88. At the hearing Mr. Cassidy testified that as of mid-December, Constellation had announced a merger. Tr. at 871. Mr. Cassidy indicated that if the merger activity had been public at the time his testimony had been prepared, it would probably have not been appropriate to include Constellation in the proxy group. *Id.* at 871. Mr. Cassidy also explained that Constellation and Sempra had retention-of-earning ratios well in excess of 50 percent, which makes them unusual among the electric companies that *Value Line* reports on, and that there is a correlation between high retention rates and high growth rates for electric companies. *Id.* at 899–900. Mr. Cassidy also agreed that, when just those two factors are considered, investors will perceive a regulated monopoly electric company as less risky than an unregulated competitive holding company. *Id.* at 901.

89. CCG's witness Mr. Solomon recommends a ROE of 9.2 percent based on the median of the range including a flotation adjustment of 0.07 percent. Exh. CCG-51 at 13.

90. Mr. Solomon selected his proxy group using the following criteria: (1) utilities classified by *Value Line* as electric utilities; (2) revenue is mainly from regulated electric operations, with no current or recent merger or acquisition activity; (3) utilities that had *Value Line* Safety rank of 2 and Financial Strength ranking of B++; and (4) utilities that had *S&P* corporate credit ratings of BBB or BBB+ and common stock rankings of B or B+. *Id.* at 8. Mr. Solomon's resulting proxy group consisted of Dominion Resources, Inc., Energy East Corporation (Energy East), Progress Energy, and Wisconsin Energy Corporation. *Id.* at 9.

91. Mr. Solomon applied the DCF methodology to this proxy group, by first developing the average high and low dividend yields for the most recent six month period. Exh. CCG-25 at 9. He then developed a range by using two different growth rates for each proxy group company. *Id.* For the first growth rate he used *Institutional Broker's Estimate System's* (*I/B/E/S*) average of the analysts' consensus five-year growth rate projections for each proxy group company. *Id.* Mr. Solomon calculated the second growth rate using the sustainable growth formula g = br + sv, applying the average of the Value Line projections for 2005, 2006, and the period 2008-2010. *Id.*

92. Mr. Solomon argues that the median should be used instead of the midpoint, for determining ROE because the Commission, in *Northwest Pipeline Corporation,* 99 FERC ¶ 61,305 at 62,276 (2002), has determined that the median, not the midpoint, is the better representation of central tendency where there is a skewed distribution. *Id.* at 10. Further, Mr. Solomon indicates that the Commission, in *MISO Remand,* 106 FERC ¶ 61,302 at 62,192, found that the median should be used in cases were the ROE is set for one electric utility.

93. Mr. Solomon also explains that he applied the DCF methodology to SPS' parent

Xcel, although he does not rely heavily on these results and indicates that the range for Xcel was below the proxy company calculations. *Id.* at 12. Mr. Solomon found that all of the proxy group utilities display similar risk, and while Xcel's risk is slightly greater than the proxy group, SPS' risk is less than Xcel and therefore equal to the proxy group average. *Id.*

94. Mr. Solomon offers some criticisms of Mr. Cassidy's analysis, indicating that he agrees with Staff's witness Mr. Green's criticisms and finds that Mr. Cassidy's ROE is too high and not justified in this case. CCG-51 at 4. Mr. Solomon argues that Constellation and Sempra are not appropriate proxy group companies because their business and related risks are too different from SPS'. *Id.* Mr. Cassidy maintains that only 16 percent of Constellation's revenues are from regulated electric utility operations. *Id.* Also Mr. Solomon argues that Sempra only has 1.3 million electric customers, but has 6.3 million gas customers and various non-utility subsidiaries which accounted for 52 percent of Sempra's 2004 earnings. *Id.* at 5.

95. At the hearing Mr. Solomon indicated that Energy East Corporation, one of the proxy group companies, was primarily a transmission and distribution utility. Tr. at 846. Mr. Solomon explained that he believed that investment analysts and investors would generally regard a company which does not own generation, such as East Energy, as less risky than a company that is engaged in vertically integrated electric operations such as SPS. *Id.* at 847.

96. Staff's witness Mr. Green proposes a ROE range of 7.81 percent to 11.12 percent for the proxy group and an ROE of 9.27 percent based on the median of the range including a flotation adjustment of 0.07 percent. Tr. at 926.

97. Mr. Green included Allete Inc. (Allete), OGE Energy Corp, Progress Energy Inc, and Wisconsin Energy Corporation in his proxy group. The criteria he used to select these companies included that the companies: (1) operated in the continental US, and are reported on by both *Value Line* and *I/B/E/S* in their respective industry sections; (2) had a *Value Line* safety rank of 2; (3) had a *S&P* utility business profile of 4 to 6; (4) currently are paying a dividend, have not, within the past three years cut their dividend level, and *Value Line*, in future dividend estimates, does not expect a dividend cut; (5) had no announced or pending merger activity during the 6 month DCF analysis period; (6) either DCF model growth rate cannot be higher than the proxy group's median low estimate of investor's required ROE and; (7) the low end DCF result, must, by at least 100 basis points, exceed *Moody's* six-month average yield on Baa Public Utility bonds. Exh. S-1 at 10.

98. Mr. Green calculated the internal growth rates, by multiplying each company's average retention ratio by its average return on common equity. *Id.* at 23. Mr. Green calculated the external growth rates using *Value Line* estimates of common shares

outstanding and multiplied that figure by the company's recent average price-to-book ratio. *Id.*

99. Mr. Green maintains that his proxy group is indicative of SPS' overall risk profile and satisfies the *Hope* and *Bluefield* standards, is sufficiently large to eliminate or significantly reduce measurement error and provides ROE estimates that reflect SPS' true cost. *Id.* at 19. Mr. Green used *I/B/E/S* five year growth estimates in earnings per share and computed estimates of sustainable growth using the company specific, implicit components of growth that *S&P* and *Value Line* publish. *Id.* at 20. Mr. Green indicates that he has exclusively used short term growth rates because Commission precedent indicates that this is the proper approach.[19] *Id.* at 21.

100. Mr. Green argues that the median should be used in this case, because it involves the selection of an ROE for a single entity rather than one that would apply to the entire proxy group of companies. *Id.* at 27. Mr. Green contends that the Commission model for electric utilities includes two dividend yields, two growth rates, and two ROEs. It is appropriate to average the two in order to obtain a single ROE for each company. *Id.* Mr. Green indicates that since the proxy group has an average business profile rating of 5.5, an average CCR of BBB+, and each of the proxy companies has a *Value Line* safety rank of 2, the proxy group is equal in risk to SPS and its median DCF result is a reliable estimate of the common equity of SPS. *Id.* at 28. Mr. Green also argues that while investors would consider an overall risk measure for Xcel in their evaluation of SPS' business profile, it is inappropriate to develop a proxy group for SPS which focuses all business risk factors on Xcel, and gives no weight to *S&P's* business profile rating published for SPS. *Id.* at 35.

101. Mr. Green indicates that two of Mr. Cassidy's proxy companies have a business profile of 7, two points greater than the S&P risk profile for SPS which is 5. *Id.* at 36. Mr. Green argues that the Commission has relied on a one rating difference in business profile to offset a considerable difference in financial risk, and two of Mr. Cassidy's proxy companies are two ratings higher than SPS. *Id.* at 36-37. Further, Mr. Green indicates that in this case it is not proper to emphasize the Index of Price Stability for several reasons: first, SPS' rates are at issue not Xcel's; second, using the Index of Price Stability separately as a risk comparison for gauging risk difference between SPS and a set of proxy companies overstates the risk of Xcel's regulated business operations. *Id.* at 37. Mr. Green explains that the overstating occurs because of steep stock price declines

[19] *See SoCal*, 92 FERC ¶ 61,070 (2000), *System Energy Resources, Inc.*, 92 FERC ¶ 61,119 (2000); *New York State Electric & Gas Corporation*, 92 FERC ¶ 61,169 (2000); *MISO*, 100 FERC ¶ 61,292 (2002), *Northern Indiana Public Service Company, Inc.*, 101 FERC ¶ 61,394 (2002); *Allegheny Power*, 106 FERC ¶ 61,241, *reh'g denied*, 108 FERC P61,151 (2004); *City of Vernon, California*, 111 FERC ¶ 61,092 (2005).

experienced by Xcel in 2002 due to losses of a non-regulated independent power subsidiary of Xcel, and the fact that the Index of Price Stability incorporates the 2002 time period. *Id.* at 38. Mr. Green indicates that if the Index of Price Stability were emphasized, it would force SPS' ratepayers to subsidize Xcel's poor investment results in non-regulated business activities. *Id.* Mr. Green indicates that the Commission has found that financial distress caused by unregulated business enterprise losses should not be allowed to impact the ROE for electric utility companies. *Id.* at 39.

102. Mr. Green also argues that Mr. Cassidy's application of the DCF model is inconsistent with Commission precedent, because Mr. Cassidy: used *Zacks* growth rates instead of *I/B/E/S*; used six months of growth rates to calculate the dividend yields used in his analysis, instead of the most recent growth rate available at the time he filed his testimony; and he calculated his own returns on average common equity by dividing earnings per share by the average book value for each year. *Id.* at 39-40. Mr. Green contends that two of Mr. Cassidy's proxy companies, Constellation and Sempra, produce aberrational results. *Id.* at 40. Mr. Green explains that the growth rates for these two companies are greater than the entire median low DCF result for the proxy companies, and so violate the DCF model requirement that g must be less than k. *Id.* Further, the high growth rates for Constellation and Sempra are roughly twice the median growth rate for the electric utility industry, and they are nearly twice the expected growth rate in GDP, as calculated by the Commission for gas and oil pipelines. *Id.* Mr. Green argues that growth rates that are so high in relation to both the median for electric utility industry and GDP cannot be sustained over the long term horizon assumed by the DCF model. *Id.*

103. At the hearing, Mr. Green testified that Allete had a subsidiary, Adessa, which was spun off in 2004. Tr. at 929. Mr. Green indicated that while he agreed that in 2004 the spin off may have affected Allete's performance, no financial impact occurred because of the spin-off. *Id.* at 930. Further, Mr. Green indicated that since the spin off had occurred approximately 10 months to a year prior to his data period, investors have had time to develop expectations for Allete as an ongoing entity without Adessa. *Id.* at 934.

Discussion and conclusion

104. An ROE of 9.64 percent is a just and reasonable rate of return for SPS. The 9.64 percent ROE (including the 0.07 percent flotation adjustment) was obtained using the median of the ROE range of Staff's proxy group, updated to reflect the most recent interest rates on ten-year constant maturity Treasury bonds. Commission precedent establishes that the Commission will update the return on equity, because capital market conditions often change substantially between the time a utility files its case-in-chief and the date the Commission issues a final decision. *Northeast Utilities Service Company,* 83 FERC ¶61,184 at 61,765, *reh'g denied,* 84 FERC ¶ 61,159 (1998).[20] The update was

[20] *See, New York State Electric and Gas Corp.*, 37 FERC ¶ 61,151 (1986); *Pacific*

calculated using the methodology the Commission has used when updating return on equity.[21] Mr. Green's 9.2 percent ROE was calculated based upon the DCF methodology, using data from the six month period ending on January 1, 2006. During this period, the average yield on ten-year constant maturity Treasury bonds was 4.40%.[22] Since January, the interest rates on ten-year constant maturity bonds has been steadily increasing, and the average from January 2006 to May 2006 is now 4.77 percent. There is no indication at the time of this writing that this trend is likely to reverse. It is a factor that cannot simply be ignored. This update to reflect rising interest rates implies an additional equity risk of 0.37 percent. Adding the 0.37 percent update to the 9.27 percent, yields an ROE of 9.64 percent. I note that the 9.64 percent ROE is within the zone of reasonableness that Mr. Green had established in his analysis. It is a return that is well supported by the testimony and evidence in this record.[23]

105. Staff's proxy group includes companies with similar risk profiles to SPS. On this record, Staff's proxy selections fit the risk profile we are attempting to emulate. Mr. Green's inclusion of Allete is proper, he explained reasonably, because no financial impact had occurred due to the spin-off, and sufficient time had passed so that investors have had time to develop expectations for Allete as an ongoing entity without Adessa. Tr. at 934. Moreover, Mr. Green's analysis does not overly account for Xcel's risks due to non-regulated activities, which is a problem with the SPS approach, as Staff convincingly argues. Staff's analysis also does not include aberrational growth results, such as those in Mr. Cassidy's analysis.

106. SPS' proxy group and ROE are rejected for several reasons. First, the inclusion of Constellation in the proxy group is undesirable, due to that company's recent merger activity. The Company's ROE, moreover, is derived from use of the midpoint, whereas Commission precedent clearly establishes the median as the more appropriate point to be

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Gas & Electric Co., 53 FERC ¶ 61,100 (1991); *Appalachian Power Co.*, 55 FERC ¶ 61,509 (1991), *reh'g*, 57 FERC ¶ 61,100 (1991), *reh'g* 58 FERC ¶ 61,193 (1992). *See also*, *Boston Edison Company v. FERC*, 885 F2d. 962, at 966-968 (1989); *Union Electric Co. v. FERC*, 281 U.S. App. D.C. 388 at 1202 (1989), *distinguished by*, *Town of Norwood v. FERC*, 80 F.3d 526 at 535 (1996).

[21] *See eg*, *Northeast Utilities Service Company*, 83 FERC ¶61,184 at 61,766, *reh'g denied*, 84 FERC ¶ 61,159 (1998), *New York State Electric and Gas Corp.*, 37 FERC ¶ 61,151 at 61,377-378 (1986); *Pacific Gas & Electric Co.*, 53 FERC ¶ 61,146, at 61,538-539 (1991).

[22] *Federal Reserve Statistics Releases and Data*, http://www.federalreserve.gov/releases, (accessed on 5/16/2006).

[23] It is worth remembering that this decision must be grounded upon the record, and this record provided a rather limited range of reasonable outcomes. The decision is driven by a proxy group analysis that also provided a limited range of choices.

used for establishing the ROE. SPS' arguments to the contrary are not persuasive; clearly in *MISO Remand* the Commission stated that the setting of the midpoint was due to the unusual circumstance of setting an ROE for an entire group of electric utilities. 106 FERC ¶ 61,302 at 62,192-193. The Commission indicated that, since it was not selecting an ROE for a single utility, the median was not appropriate. *Id.* Also, SPS' Mr. Cassidy used *Zack's* growth rates, instead of the *I/B/E/S* growth rates, which the Commission indicated it preferred in *SFPP, L.P.*, 86 FERC ¶ 61,022 at 61,100, *aff'd in part & vacated in part, BP West Coast Products, L.L.C.*, 374 F.3d 1263 (2004). I agree with Staff and CCG's assertions that Mr. Cassidy's proxy group selection criteria focus too much on financial risk relative to business risk, are overly concentrated on parent company Xcel's business risk profile instead of SPS', and include companies with business and related risks that are significantly different from SPS' regulated utility business and wholesale electric service.

107. Finally, CCG's proxy group, while yielding the same ROE as Staff, is rejected because of the inclusion of Energy East. Mr. Solomon's testimony indicates that this company may not accurately reflect the risks of SPS. If Energy East is removed from CCG's proxy group, it is left with three companies, Dominion Resources, Inc., Progress Energy, and Wisconsin Energy Corporation, which do not form a sufficiently reliable universe upon which to judge return in a DCF analysis.

J. In deriving the demand cost allocation factors, should wholesale and retail interruptible loads be deducted from system and customer demand for each month of the test year, and if so what credits should be made?

108. CCG indicates that this issue has been resolved by the Joint Trial Stipulation, Exh. J-1, at stipulated issue I.J.(i) through (iii).

109. SPS argues that full revenue credit has been given to the cost of serving the customers at issue here for all interruptible services in the Joint Trail Stipulation, and since full credit has been given in the manner that the Commission's regulations provide for, this should no longer be an issue. SPS indicates that Cap Rock's witness Mr. Diller has acknowledged that making this revenue credit will offset any inequity that may be caused by removing interruptible demands from the denominator used to develop demand allocation factors but not giving credit in the cost of service for the revenues SPS receives for interruptible service. SPS suggests that Cap Rock may pursue the matter in the rate proceeding under Docket No. ER06-274-000.

110. Staff agrees with SPS' position and argues that unless and until the Commission changes its regulations regarding the deductions of these wholesale and retail interruptible loads, these deductions should be found appropriate.

111. Cap Rock argues that revenue credits should be made for any capacity charges

associated with properly deducted interruptible loads. Cap Rock argues that Commission precedent indicates that interruptible loads should be removed when calculating demand cost responsibility, but partially interruptible loads can be included for the portion that is not interruptible. *Louisianna Public Service Commission v. Entergy Corporation*, 106 FERC ¶ 61,228 *aff'd*, 111 FERC ¶ 61,080 (2005) & *Kentucky Utilities Co.*, 15 FERC ¶ 61,002, *reh'g denied*, 15 FERC ¶ 61,222 (1981). Cap Rock indicates that the intent behind the interruptible load policy is that these loads impose no obligation on the utility to build generation or purchase additional power supply and so they should not be allocated capacity costs.

112. Cap Rock explains that while the parties have stipulated as to what the total revenue credits should be if all of the interruptible loads are deducted, the evidence shows that not all of the loads are interruptible. Cap Rock indicates that if all interruptible loads are removed from the monthly demands used for cost allocation purposes, then the revenue credits should be made in the amounts indicated in the Joint Stipulation. Cap Rock however believes that the interruptible portions of wholesale customer loads should be deducted from the individual wholesale customer' billing demand when calculating their demand cost responsibility and the non interruptible portions of the retail interruptible loads should not be deducted from system demands.

Discussion and conclusion

113. This issue has been resolved by the Joint Trial Stipulation as SPS has agreed to deduct from system demands all wholesale and retail interruptible loads, for each month of the test year to credit interruptible revenues against the revenue requirement of the customers at issue as required by Commission regulations. Cap Rock can pursue this matter further in the Docket No. ER06-274-000 rate proceeding.

K. In deriving the demand cost allocation factors, should any post test year adjustments be made to account for known and measurable changes in system loads or demands during the time that the rates are to be in effect?

114. The Commission has held that it has discretion to allow post test-year adjustments for known and measurable changes. *National Fuel Gas Supply Corp.*, 51 FERC ¶ 61,122 at 61,334 (1990); *accord*, *Trunkline Gas Co.*, 55 FERC ¶ 63,005 (1991), *order on Initial Decision*, 62 FERC ¶61,198 (1993). The Commission has further indicated it would allow post test year adjustments if the test year estimates were unreasonable when made or if subsequent events indicate that where those estimates would produce results that are unreasonable. *American Electric Power Co.*, 89 FERC ¶ 63,007 at 65,039 (1999), *order on Initial Decision*, 90 FERC ¶61,242, *reh'g*, 91 FERC ¶61,129 (2000). 18 C.F.R. § 35.13 (d)(ii) (2005) indicates that Period I data submitted in support of a change in rates, has to be "data adjusted to reflect revenues and costs prior to the proposed effective date of the rate schedule change."

115. Cap Rock argues that usually a utility seeking a rate change will file a historic Period I actual data and a Period II test year that uses projected data. The Period II data is used to set the rates. If a single historic year, instead of a projected year, is used for rate setting, it is appropriate to make adjustments to the test year to take into account known and measurable changes that occur or will occur after the end of the test year, Cap Rock contends. To account for changes that occurred, Cap Rock proposes that two adjustments be made in this case. First, the Golden Spread demand should be changed from 330 kW to 355 kW, and second, the Lyntegar loads should be removed. The normalized data is then used to derive allocation factors for the FR customer class, as well as the partial requirements customer class, and produces two complete sets of allocation factors based on two sets of assumptions. Cap Rock maintains that since SPS has filed a new rate case, and it has become apparent that the rates set here will be in effect for a locked in period of 18 months, from January 1, 2005 to June 30, 2006, two sets of rates should be designed in this case, and the two post-test year adjustment recommended by Mr. Diller be made effective only from January 1, 2006 through June 30, 2006. Tr. at 1061-1062.

116. CCG argues that the out of period adjustments proposed by Cap Rock are improper and should be rejected, and the proper place to address these changes is in a new rate case, and SPS has already made such a filing with a projected 2006 Period II test year. CCG indicates that both adjustments are inappropriate because Lyntegar received service from SPS for 12 months after the established refund effective date in this proceedings and Golden Spread PR demand from June 2004 until six months after the refund effective date established in this proceeding was 330 MW.

117. Staff argues that SPS should be found to have properly included the post test-year loads that Cap Rock proposed to remove. Staff argues that Cap Rock's proposal to remove Lyntegar's loads served by SPS for all of 2005 and to ignore the increase in Golden Spread's partial requirements contract reservation should not be adopted. Staff indicates that the Commission's regulations indicate that when Period I is the test year, the cost of service date can be adjusted in order to reflect changes affecting revenues and costs, which are known and measurable with reasonable accuracy, prior to the proposed effective date.

118. SPS argues that the adjustments proposed by Cap Rock should not be made, and agrees with CCG's arguments.

Discussion and conclusion

119. Cap Rock's proposed adjustments are inappropriate as the Lyntegar load was served by SPS as a full requirements customer for all of 2005 and Golden Spread's partial requirements increase occurred on June 1, 2004. Therefore, no post test year adjustments should be made to the Period I test data in this proceeding. Further, SPS has

filed a new rate case, in Docket No. ER06-274-000, in which these adjustments are more properly considered.

II. Fuel Cost Adjustment Clause ("FCAC") Issues

A. Old Fuel Clause (Order No. 517)

1. What is the appropriate time period to be covered by the investigation concerning SPS' historical FCAC charges in this docket?

120. CCG witness Daniel testified that SPS has misapplied the FCAC at least since 1999, through and including December, 2004. Exh. CCG-1 at 89. Mr. Daniel further argued that the Commission should order SPS to make available to Staff and the parties all of the information required to evaluate FCAC implementation practices going back to January 1, 1994, and to establish a second phase of this proceeding for the purpose of a retrospective inquiry into such practices for the earlier period. *Id.*

121. Occidental argues that SPS' FCAC practices have been inappropriate since 1999, and agrees with CCG that the Commission should authorize a further inquiry back into the period 1994-1998, requiring SPS to provide full information as to its FCAC practices to determine if similar problems occurred in these earlier years.

122. SPS contends that the complaining customers were dilatory in raising the FCAC issues and the appropriate time period begins no earlier than 1999. Company witness Hudson testified that SPS had a longstanding practice of pricing energy sales associated with firm capacity sales on the basis of system average costs. Exhs. SPS-12 at 14; SPS-76 at 8-9, 11-13. He further stated that none of the CCG members has ever protested or otherwise directly challenged the pricing of SPS's firm capacity contracts on the basis of system average fuel costs. *Id.* He further contended that the Commission's regulations permit the recovery of Qualified Facility (QF) purchase costs at avoided cost rates through the FCAC, and that such recovery was provided for in the Docket No. EL89-50-000 settlement. CCG cannot be heard now to question this recovery and escape responsibility for the cost of QF energy at rates at or below avoided cost, according to Mr. Hudson. *Id* at 43-44.

123. On brief, SPS argues that the scope of the investigation of FCAC claims should be limited to those specifically alleged in the complaint, which it says contains no specific allegation of any misapplication of the FCAC prior to 2003. SPS I.B. at 41-43. Because the complaint alleged overcharges based upon FCAC billings for 2003, and because the complainants had the resources to discover problems earlier, and did not institute a formal dispute resolution process earlier, SPS would limit the scope of the case to the period 2003 forward.

Discussion and conclusion

124. It is apparent that the change from a cost-based ratemaking paradigm to market-based rates created enormous tumult in the relationships of buyers and sellers in the energy markets of the 1990's and 2000's. What was acceptable and reasonable in a cost-based regime might not be so in a market-based milieu. The record demonstrates that the implications of FCAC implementation practices became questionable around the 1999 period, after the Commission implemented open access and when market-based sales increased. SPS was under a duty, in my opinion, to examine its FCAC implementation practices in light of the sea change in the basis for energy transactions that it knew was underfoot at that time. In light of this, I think it would be unreasonable to go back as far as 1994 to examine FCAC implementation practices, because the framework of the marketplace in the 1994 to 1998 time period was established and accepted without complaint, and, more important, without reason to complain. The introduction of open access and competitive markets for energy created the reason to re-examine FCAC implementation and its effects on market participants and competition in the marketplace. That reason was not extant in the 1994-1998 time frame. The case here should be bounded by 1999, at the earliest.

125. I also reject the Company's argument on brief that the period should commence as late as 2003. Problems discovered and complained about based upon 2003 data may have predated those data. The complainants should not be foreclosed from pursuing an investigation back in time, so long as it is reasonably bounded. I believe that 1999 forward is the proper period for this inquiry.

2. Was SPS' recovery through the old FCAC of energy-related costs incurred under long-term QF contract consistent with SPS' rate schedules and Commission regulations, precedent and policy?

126. SPS contends that recovery via the FCAC of energy related costs incurred under long term QF contracts was based upon the Commission's approval of an uncontested settlement that specifically contemplated such recovery and was otherwise consistent with the Commission's FCAC regulations at 18 C.F.R. § 35.14. SPS witness Hudson noted that the settlement in Docket No. EL89-50-000 between SPS and Golden Spread states:

> Southwestern and Customer agree that purchases from Qualifying Facilities at or below Southwestern's avoided variable energy cost, as approved by Southwestern's state jurisdictional authorities, shall be included in Southwestern's Wholesale Fuel Cost Adjustment Clause calculation. Exh. SPS-6 at 8.

127. Mr. Hudson further testified that this language has been retained and agreed to by all wholesale obligation load customers. Exhs. SPS-1 at 13; SPS-12 at 43; SPS-26. SPS

points out that prior agreements with each of the CCG members provides that the FCAC be amended to allow for the inclusion of the portion of the cost of purchases from QFs at or below SPS' avoided variable costs. Exh. SPS-26. Mr. Hudson further asserts that Commission regulations under Part 292 encourage purchases from QFs at prices equal to or less than avoided costs, and argues that SPS's purchases on that basis are just and reasonable to the electric consumer. Exh. SPS-1 at 14. Mr. Hudson describes in his testimony a process of billing and follow-up customer meetings from which it is argued that the customers received monthly information that provided details of billings that included QF costs. Exh. SPS-45 at 58-59.

128. CCG witness Daniel argues that the Company has taken an overly expansive view of the provision in its old FCAC that allows inclusion of "the portion of the cost of purchases from Qualifying Facilities at or below Company's avoided variable energy cost." Exh. CCG-3 at 1, Section 2(ii). Mr. Daniel believes this provision to be "non-conforming" to the Commission's FCAC regulations as set forth in Order 517.[24] The Commission's model Order 517 language allows the net energy cost of a QF purchase to be included in the FCAC, according to Mr. Daniel, if the purchase was made on an economic dispatch basis as a substitute for the Company's higher cost energy. Also allowed, according to Mr. Daniel, is the "associated actual identifiable fuel cost" of non-economic dispatch QF purchases that are not reliability purchases. Exh. CCG-46 at 52-53. What is not allowed for recovery in the FCAC, says Mr. Daniel, are purchases with no identifiable fuel cost, or non-fuel energy costs associated with any QF that was a non-reliability QF put. *Id.*

129. Staff agrees with CCG that the Commission's FCAC regulations did not contemplate the broad recovery of all energy related QF costs through the fuel clause, contending that they only allow for recovery of the net energy cost of a QF purchase made on an economic dispatch basis. Staff's witness Sammon testified that SPS did not have any QF capacity purchases at the time of the settlement that added the QF recovery provision to the Company's FCAC. Since then, he noted, the Company has entered into capacity purchases from QFs. Staff maintains that SPS's recovery of the energy-related costs of these long-term QF purchases was inconsistent with the Company's rate schedules, Commission regulations, precedent and policy.

Discussion and conclusion

130. I believe that the record supports a finding that SPS was permitted, as a result of the settlement in Docket No. ER89-50-000, and subsequent agreements with its wholesale customers, to collect energy-related costs of its QF purchases at or below its avoided variable energy costs, as determined by state regulatory determinations. Exhs.

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[24] *Fuel Adjustment Clauses in Wholesale Rate Schedules*, Order No. 517, 52 FPC 1304 (1974).

SPS-6 at 8; SPS-7 at 8; and SPS-26. CCG witness Daniel and Staff witness Sammon interpret the provision of the old SPS FCAC in a more limited fashion, claiming it must not mean what it in fact says, that fuel costs will include "the portion of the cost of purchases from Qualifying Facitilties at or below the Company's avoided variable energy costs." Exh. CCG-3 at 1. I do not find the views espoused by Messrs. Daniel and Sammon persuasive, preferring instead the plain meaning of the plain language of the settlement provision and the contracts that followed. Exhs. SPS-6 at 8; and SPS-26. Moreover, when all is said and done, the Commission approved the uncontested settlement that contains broad recovery language as to QF purchases. I conclude that, in approving this settlement, the Commission acquiesced to any provisions in that settlement that might not have conformed to the model fuel clause language, which might be susceptible to a more narrow interpretation, as argued by Staff and CCG.

131. Further, the intervenors here did nothing to complain about the inclusion of improper costs in the FCAC calculations that they routinely received and reviewed. Therefore, the current situation is that the energy-related costs of the QF purchases have been flowed through the FCAC and were not considered in the establishment of base energy rates. Exh. SPS-25. If the non-fuel cost of energy purchases made from the relevant QFs were returned to the customers, because of a technical violation of the fuel clause regulations (assuming, which I do not, that the regulations superceded the settlement approval and subsequent agreements), there would be no mechanism to make SPS whole, since the base rates did not include such costs. In these circumstances involving the old fuel clause, it might be an intriguing academic exercise to pursue the course suggested by Staff and CCG. However, I see no reason to engage any further in the pursuit of that answer. The record confirms that SPS had a sound basis for including these QF-related costs in the FCAC (the Commission-approved settlement and subsequent agreements of affected parties), and no good purpose would be served by trying to undo that procedure even if it is determined to have been inconsistent with the Commission's FCAC regulations.

3. Was SPS' attribution of system average fuel costs to long-term market-based capacity sales consistent with SPS' rate schedules and Commission regulations, precedent and policy?

132. CCG, Golden Spread, PNM and Occidental contend that SPS misapplied its FCAC and violated the Commission's fuel clause regulations by attributing system average fuel costs to long-term market-based capacity sales, and flowing the fuel costs associated with those sales through the FCAC, instead of directly assigning the incremental fuel cost associated with those purchases to those off-system sales.

133. SPS has had a long-standing practice of allocating system average fuel and purchased energy costs to firm system capacity sales irrespective of whether such sales are made under a market-based tariff or under a cost-based tariff. Exh. SPS-12 at 15.

SPS argues that this is as appropriate for market-based off-system sales as is the allocation of average system costs to on-system requirements sales. By consistently allocating average fuel costs to all firm customers, SPS argues that it is complying with the Federal Power Act's prohibition against undue differences in rates based upon locality or class of service. Doing otherwise, SPS witness Hudson explains, would result in inconsistencies and opportunities for non-comparable or discriminatory treatment. *Id.* at 16.

134. SPS's market-based off-system sales contracts provide for energy to be priced at SPS' monthly average fuel cost, and the Company bills them accordingly. SPS' FCAC provides that the Company shall reduce the fuel and purchased power costs that it recovers in monthly FCAC billings by the cost of fossil and nuclear fuel recovered through inter-system sales, including the fuel costs recovered from economy energy sales and other energy sold on an economic dispatch. Exh. CCG-3 at 1. SPS argues that this is completely consistent with the fuel clause rules that the Commission established in Order No. 517, which requires a utility to deduct from its fuel clause the amount of fuel that it has recovered from off-system sales. SPS witness Heintz testified that there is no requirement that the fuel cost for off-system sales reflect a specific amount that is tied to incremental fuel cost. Exh. SPS-87 at 15, citing *Tampa Electric Company*, 83 FERC ¶ 61,262 at 62,039 (1998). SPS therefore concludes that, even if the sales at issue here are viewed as "inter-system sales", which it contests, there is no basis upon which to impute to these sales an incremental cost, for purposes of FCAC calculations.

135. PNM asserts that the effect of SPS' FCAC practice is to impose on cost-of-service customers a portion of the higher incremental fuel costs associated with SPS' market-based sales. PNM argues that a failure to assign incremental fuel costs to these market-based sales permits SPS to cross-subsidize its wholesale market-based sales activities, which effect is neither intended nor permitted under the Commission's FCAC regulations or SPS' actual FCAC.

136. CCG contends that the FCAC was never intended to be utilized in market-based ratesetting. CCG goes on to argue that Commission precedent requires that off-system sales be made at the system's incremental cost, citing *Entergy Services, Inc.* 58 FERC ¶ 61,234 at 61,772 (1992) (*Entergy*), where the Commission prohibited off-system sales below incremental cost. CCG also maintains that SPS was aware of the risk it was taking that regulators would realize that the Company was willing to offer wholesale system sales at system average cost, yet did nothing to stop such sales. Tr. at 962-964. CCG further argues that including market-based sales in the cost-based FCAC calculations necessarily increased charges to the Company's regulated customers; however, such customers were not aware of this, because the FCAC is a formula rate, the content of which is unknown to customers. CCG contends that the proper way to reflect opportunity sales is to allocate hourly incremental fuel and purchased power costs incurred to support these sales; remove incremental fuel and purchased power expense

from the numerator of the FCAC; and remove the sales from the denominator of the FCAC. This, CCG argues, would be consistent with Section 2(iv) of the old SPS fuel clause, which requires removal of the cost of energy purchases recovered through inter-system sales. Exhs. SPS-2 at 2; CCG-1 at 71, CCG-3 at 1.

137. OCC argues that the SPS practice was unusual in the industry. Noting the testimony of Golden Spread's Mr. Wise that other utility officials believed that system average fuel really belonged to regulated customers,[25] OCC maintains that SPS was plainly cross-subsidizing its market-based sales by the practice of recovering incremental costs of such sales through the regulated FCAC. OCC argues that the Company retained all of the profits associated with market-based sales (due to the absence of litigated rate cases since obtaining market-based rate authority), while cost-based customers paid a significant portion of the higher costs associated with such sales. The practice is particularly offensive, according to OCC, because it encourages the acquisition of high fuel cost, uneconomic generation to serve market-based sale customers, transactions that would not occur in a properly functioning competitive marketplace. The bottom line, OCC argues, is that SPS' fuel clause practices force the Company's cost-based customers to subsidize its wholesale market-based rate activities, and to flow those subsidies through to SPS shareholders.

138. OCC further maintains that SPS' practice is at odds with the fundamental purpose of the FCAC, which is to ensure that utilities recover the cost of fuel without having to make rate filings as costs change, while protecting consumers against harmful actions of utilities. Fuel costs associated with certain sales would not be recovered through the clause, OOC states, referring to inter-system sales, the fuel costs of which would be directly assigned to those sales. Exh. S-8 at 13. OCC (and Staff) argue that SPS' long-term, firm, off-system sales are in fact "inter-system sales" of the type excluded from the FCAC. SPS, OCC contends, did not apply the FCAC in this manner. Instead, SPS included the fuel costs of its market-based sales in its fuel clause calculation. Therefore, OCC argues, SPS' use of the FCAC to force its cost-based customers to subsidize its market-based rate sales by assigning system average fuel cost to those sales violates both the specific language of the fuel clause and the basic purpose of the clause.

139. OCC continues by asserting that SPS' fuel clause practices are also inconsistent with Commission precedent. In *Appalachian Power Co.*, 21 FERC ¶ 61,309, at 61,813 (1982), the Commission stated:

> We believe it is both appropriate, and a common industry practice, to assign the highest fuel cost to off-system sales, while lower fuel cost resources are reserved for the benefit of the [utility's] native load customers who, through their rates, provide for the construction and operation of generation facilities.

[25] Tr. at 961-963.

140. OCC argues that assignment of incremental fuel costs to off-system sales ensures that "requirements customers pay no more than they would have paid had the off-system sale never occurred." *Minnesota Power & Light Co.*, 47 FERC ¶ 61,064 at 61,183 n.2 (1989) OCC also cites *Consumers Energy Co.*, 94 FERC ¶ 61,180 at 61,623-24 (2001), which it believes applies this same rationale in a market-based rate setting, and *Entergy*, as noted above by CCG.

141. OCC additionally contends that the SPS fuel clause practices at issue here violate the Commission's precedent prohibiting cross-subsidization and affiliate abuse. OCC cites *Heartland Energy Services, Inc.*, 68 FERC ¶ 61,223 (1994) (*Heartland*), which set forth standards to apply in cases where a marketer affiliate of a utility with captive customers might be subsidized at the expense of captive customers. The Commission held there that affiliate abuse occurs when "there is a transfer of benefits from the affiliated public utility (and its ratepayers) to the affiliated power marketer (and its shareholders)." *Id.* at 61,062. Although the case is not on all fours with the instant proceeding in that it does not involve affiliate abuse, OCC argues that the underlying principle is as applicable here, as there, because the basic strategy involves a subsidy from captive customers to support market-based sales activity. Exh. OCC-17 at 7. OCC goes on to point out examples of market pricing behavior which it believes were motivated by the ability of SPS to cross-subsidize its market-based sales through the FCAC, including a series of linked transactions from 2002 to 2004, which were designed, OCC argues, to circumvent the provisions of the Xcel Energy Joint Operating Agreement, which requires assignment of incremental fuel costs from one Xcel affiliate to another. Exh. OCC-1 at 13-14. OCC asserts that these linked transactions, which allowed inter-affiliate sales under market-based rate authority at system average costs through transactions with unaffiliated third parties, violated the JOA, a Commission-filed tariff. A second example of this type of abuse, according to OCC, involves SPS' affiliate Borger, which owns and operates a gas-fired cogeneration plant in the SPS control area. OCC maintains that SPS dispatches the Borger facility over its contract requirements to make market-based sales, shifting the incremental cost of operating the facility to cost-based customers. Exh. OCC-1 at 12-13.

142. Staff witness Sammon observed that SPS' fuel clause practices have: (1) had an adverse effect on billings to wholesale requirements customers; (2) effectively redirected cheap coal-fired energy away from wholesale requirements customers to off-system sale customers and caused wholesale customers to pay a share of higher cost gas-fired generation caused by the off-system sales; (3) skewed the incentives toward making uneconomic sales; (4) allowed SPS to pocket profits from market-based off system sales due to an absence of rate cases; (5) allowed SPS customers with fuel clauses to subsidize firm off system customers; and (6) encouraged disturbing effects on captive customers and unreasonable practices. Mr. Sammon nevertheless concluded that SPS' attribution of system average fuel costs to long-term market-based sales is permissible under the cost-

based FCAC. Staff's theory is that, because SPS has contracts for the off-system sales at issue here that provide for energy to be priced at the SPS monthly average fuel cost, and that it bills accordingly, it is authorized to recover those costs through the FCAC. Exh. S-8 at 16.

143. Staff's Mr. Sammon testified that SPS' obligation to any wholesale customer is determined by its contract with the customer. He found that the strongest defense for the SPS practice can be found by examining how the sales would be treated for ratemaking purposes if they were cost-based sales. Looking at the Commission's default mitigation requirements established in *AEP Power Marketing, Inc. et al., Order on Rehearing and Modifying Interim Generation Market Power Analysis and Mitigation Policy*, 107 FERC ¶61,018 at 40, *reh'g*, 108 FERC ¶ 61,026 (2004), Staff found that the default cost based capacity rate would be the embedded cost of generation and the energy rate would be based on average fuel cost. Tr. at 2480-81; 2488.

144. Staff concludes that, based on Commission regulations and precedent, the language of the market-based contract controls. However, on brief, Staff advises that, "[a]t the very least, SPS could have, and probably should have, sought an approval from the Commission before it started this practice of attributing average fuel costs to off-system sales in its cost-based monthly FCAC calculations when designing market-based rates." Staff I.B. at 52. Staff also felt it unclear whether the SPS FCAC practice was contemplated by the Commission or was a practice the Commission would want to encourage. *Id.* at 53.

Discussion and Conclusion

145. After reading the testimony of Staff witness Sammon summarized above, one can readily understand the frustration of the intervenors. One must wonder how it can be possible that a practice that has a laundry list of negative implications, such as described by Mr. Sammon and other witnesses in this case, nevertheless be found acceptable. Indeed, I find that it is not possible to agree with Mr. Sammon's strained and tortured conclusion. If SPS' FCAC practices were so abusive as to create the effects to which Mr. Sammon and others have testified, they cannot be considered permissible.

146. To begin, the record demonstrates that SPS had a long-standing practice of allocating system average fuel and purchased energy costs to firm system capacity sales. That practice had its roots in the era where there were only cost-based sales, and there was little reason at that time to question the propriety of the well-accepted practice. When the industry paradigm shifted in the late nineties to one with a mix of cost-based and market-based sales, SPS did nothing to reexamine the propriety of its practice of allocating system average fuel and purchased energy costs to its capacity sales, and it continued to do so, irrespective of whether such sales were opportunity-type sales made under a market-based tariff or traditional requirements sales made under a cost-based

tariff. Whether wittingly or unwittingly, SPS clearly at some point recognized the competitive advantage it had by continuing this practice, as it is described in "How We Make Money", an Xcel June 2004 presentation. Exh OCC-27 at 12 of 784 (Protected Material).

147. The evidence offered by CCG, OCC and PNM is persuasive as to the pernicious effects of the FCAC practice engaged in by SPS. Even Staff's testimony is in accord as to the negative implications of the SPS FCAC practices. In this context, I find somewhat disingenuous the Company's argument, subscribed to also by Staff, that the practice simply reflects what's in the contracts, which must, therefore, be reflected in the FCAC. They argue that the FCAC regulation provides that the cost of fuel actually recovered from the sales at issue be credited back to the fuel clause and only the actual costs recovered from such customers are to be credited. Exhs. SPS-108 at 36; S-8 at 29. The circularity of this reasoning is readily apparent. All it does it take you one step back, to determine the proper pricing policy for opportunity sales contracts that would have fuel costs flowed through the FCAC.

148. As to this point, Commission precedent and well-recognized policy is that opportunity sales are generally priced to reflect incremental fuel cost, so that the risk of recovery would fall upon the utility, not other customers. *Entergy* 58 FERC ¶ 61,234 at 61,772; *Appalachian Power Co.*, 21 FERC ¶ 61,309 at 61,813 (1982); see also *Minnesota Power & Light Co.*, 47 FERC ¶ 61,064 at 61,183 n.2 (1989).[26] Moreover, the record supports the view that this policy was well understood in the industry, as Mr. Wise suggested, when he stated that other utilities believed that system average fuel belonged to "the regulated customers, being native load customers, retail, long-term wholesale, those that are considered native or captive customers within their jurisdiction." Tr. at 962-63.

149. Staff witness Sammon, however, testified that wholesale requirements customers do not have a superior claim to service from a supplier's generation assets than a non-requirements customer. Exh. S-8 at 29. Again, he believes that the contract governs. However, these contracts to charge market-based rate customers system average fuel costs should not bind non-signatory wholesale customers and the Company's retail customers to subsidize such sales through the FCAC by failing to recover from the opportunity sale customers the real incremental fuel costs associated with the market-based sales. OCC reasons correctly that this argument confuses the Company's contract price obligations to its market-based customers with the obligation to allocate appropriate

[26] *Tampa Electric Co.*, 71 FERC ¶ 61,254 (1995) (TECO I); *reh'g denied*, 83 FERC ¶ 61,262 (TECO II) are not inconsistent. See CCG R.B. at 30-33. I agree that *TECO I* and *II* stand for the proposition that off-system sales should be priced at incremental fuel cost. What makes that case different is that incremental fuel costs there were below average fuel costs.

fuel costs to cost-based customers. As OCC argues: "[w]hile Staff is correct that SPS must honor its contractual commitments to its market-based customers, it does not follow that the allocation of fuel costs to cost-based customers is determined by whatever SPS elects to negotiate." OCC R.B. at 12. This is where the Commission's sound and oft-cited policy to ensure against subsidization of market-based activities by captive, cost-based customers fits in. *Heartland, Entergy, supra*, and *Consumers Energy Co.*, 94 FERC ¶ 61,180. I am persuaded that the principle underlying these cases, all of which involved intra-corporate subsidization in favor of affiliates, applies as well in the context here, which appears to be *sui generis*. Then, again, the record suggests that other utilities understood the risk of such a practice and shied away from this sort of subsidization by contract. Tr.at 961-963.

150. I find the arguments presented by CCG, OCC, PNM and allied interests to be compelling, and broadly supported by the record evidence in this proceeding, as well as by pertinent Commission precedent and policy. The pernicious effects of the SPS FCAC practice of using cost-based customers to subsidize market-based sales cannot be excused by hyper-technical and circuitous reasoning. It also cannot be ignored given the Commission's obligation in the Federal Power Act to ensure that utility rates are just and reasonable. The plain facts are that SPS improved its competitive position in making market-based sales by charging market-based customers lower system average fuel costs, and collected the difference from the Company's cost-based customers, who were forced to cover their own fuel costs and the difference between average costs and the incremental fuel costs associated with the market-based sales.

4. Did SPS' attribution of system average fuel costs to long term market-based capacity sales harm competition?

151. OCC maintains that SPS' attribution of system average fuel costs to long-term market-based capacity sales is inconsistent with a properly functioning competitive wholesale energy market, and harms competition. It argues that the SPS fuel clause practice results in a cross-subsidization of market-based sales by cost-based customers, which advantages SPS as against other competitors who do not have a captive base of cost-based customers to use for subsidization of market sales. This inherent advantage creates an unlevel playing field, according to OCC. The shifting of costs from unregulated to regulated businesses creates this unfair advantage. Exh. OCC-14 at 4-8. OCC witness DeRamus explained this position as follows:

> [T]he way in which SPS implements its FCAC effectively forces SPS' regulated customers to subsidize sales by SPS to its market-based customers, which harms not only SPS' regulated customers, but wholesale competition more generally. Such anti-competitive cross-subsidization, which has long been a central concern of regulators when utilities engage in both regulated and unregulated activities, provides SPS with an improper advantage over its competitors, allowing SPS to

dispatch otherwise uneconomic generating resources and increase artificially its wholesale sales above the level that would prevail in a competitive market. Such an improper competitive advantage benefits Xcel's shareholders at the expense of SPS' regulated customers. Exh. OCC-17 at 2-3.

152. OCC points out that SPS has actually required some of its wholesale customers not to challenge its ability to make market-based sales at system average fuel cost. Exhs. OCC-22; OCC-31, Att. A, Section 4.1. OCC continues, maintaining that the SPS fuel clause strategy creates a powerful incentive to acquire and dispatch inefficient resources. The Company's indifference to fuel costs of acquisitions causes it to favor resources with low capacity costs, so that it might retain a larger margin between capacity payments and receipts. Exh. OCC-1 at 15-25. Its FCAC strategy, OCC argues, rewards SPS for acquiring inefficient additional resources with high incremental fuel cost, instead of those with low fuel costs. OCC singles out the "Lubbock transaction" to make its point. This involved a three-way deal under which SPS agreed to sell power to West Texas Municipal Power Agency (WTMPA) under a market based contract with system average fuel, and SPS executed two unit contingent power purchase agreements with the Lubbock municipal utility for power from relatively inefficient gas-fired generation. Exh. OCC-30. The effect of this sort of practice, OCC contends, is to significantly distort the operation of the wholesale market.

153. Use of the system average fuel cost also causes SPS to dispatch uneconomic generation, where the incremental cost of generation exceeds the market price, argues OCC. In competitive market conditions, units with incremental cost above the assumed market price would not be dispatched, OCC points out. But here, where SPS can price its wholesale sales on the basis of system average fuel costs and still profit due to the subsidy received from cost-based customers, it can dispatch units with high incremental fuel cost, OCC asserts.

154. The SPS fuel clause strategy also forecloses competitors from entering the market, since they do not have a base of regulated customers to subsidize wholesale market based sales, claims OCC. Exh. OCC-14.

155. SPS argues that there is no hard evidence that the pricing of market-based sales using average system fuel costs causes anti-competitive effects, suggesting that no witness was able to point to a case where a potential competitor lost a sale on that account. Moreover, SPS argues, its witness Dr. Hieronymous observed that the parties making this claim ignore the fact that the contracts are market-based, i.e., made at prices that are at market and over the "subsidized" cost. Exh. SPS-74 at 16-17. SPS further contends that the Commission has determined that different price structures for off-system sales are permissible, including pricing that uses average system costs. *Illinois Power Co.*, 57 FERC 61,213 at 61,699 (1991). SPS also calls attention to recent rules of the Commission dealing with default mitigation rates set in *AEP*, *supra.*, where, sales

of power for one year or more are to be priced on an embedded cost basis. Exh. SPS-74 at 3. SPS finally argues that on-system firm service customers who pay cost-based rates do not have an entitlement to low cost power supply resources, agreeing with Staff witness Sammon, who observed that there did not seem to be "any reason to favor cost-based rate customers over market-based rate customers to the extent the nature of the service is the same. Exh. S-8 at 27.

156. SPS again relies on its theory that it is entitled to credit cost of service customers with the cost of fuel recovered from the off-system customer, without regard to whether the cost is higher or lower than that charged to requirements customers. The Company also claims that the sales at issue here are not "inter-system" sales, or shorter term opportunity sales.

157. PNM witness Christopher testified to a specific instance where he believed PNM lost out to SPS on a competitive opportunity sale because SPS' misapplication of the fuel clause enabled SPS to win the sale. Tr. at 1468. By using the FCAC to recover a portion of its incremental fuel costs associated with market-based sales, SPS could price such sales at less than the actual incremental cost of producing energy for those sales, PNM asserts. It contends that the cost of this subsidy is borne by the SPS customers who purchase power at system average costs. They, therefore, bear increased costs associated with SPS' wholesale marketing activity. PNM observes that, as an entity, it loses two ways, first as a customer who helps subsidize SPS' market-based sales activity, and second, as a potential and actual competitor lacking a similar subsidy. Exh. PNM-1 at 6. PNM further points out that SPS' fuel clause practice produces an erroneous price signal to the market, which leads to an inefficient allocation of scarce resources. *Id.*

158. PNM considers misplaced SPS witness Dr. Hieronymous' point about the Commission's allowance of system average fuel cost in the context of the default mitigation scheme. PNM points out that the mitigation scheme is intended to apply where an entity has generation market power, so that negotiations cannot be relied upon to produce just and reasonable rates. Here, that is not the case, PNM argues. The mitigation scheme has no application to any of the sales by which SPS is receiving the challenged cross-subsidy, PMN asserts. SPS has not been determined to have generation market power, nor has it filed any of the contracts at issue for approval as part of a mitigation scheme. The bottom line here, according to PNM, is whether SPS has engaged in anti-competitive behavior by obtaining a competitive advantage through misapplication of the fuel clause. It argues that the answer is yes.

159. CCG's position is largely in accord with that of OCC and PNM. Exh. CCG-46-50, and 55.

160. Staff, citing to the Commission's mitigation rules in *AEP*, finds no evidence of harm to competition. Its witness Sammon acknowledged that SPS gained a competitive

advantage from its practice of attributing average fuel costs to long-term market-based sales. Exh. S-8 at 17-18. However, he further testified that, in structuring the pricing of market-based sales, SPS "can do anything it can get away with in the off-system market." Tr. at 2492. Staff concludes by contending that OCC, PNM and CCG have not made a serious effort to support their claim of harm to competition.

Discussion and Conclusion

161. I find, to the contrary of the positions taken by Staff and SPS, that OCC, PNM and CCG have demonstrated by both fact and by theory that the SPS fuel clause practice of attributing system average fuel costs to long-term market-based capacity sales has harmed competition. At the outset, I am persuaded by the testimony of PNM witness Christopher, its Vice-President of Energy Supply and Marketing, who described both the theory underlying the adverse effects of this practice on competition, and also recounted a real life incident where PNM believed that it lost out to SPS on a competitive opportunity because SPS was able to price the sale below competitors due to the subsidy provided by the cost of service customers. Exh. PNM-1 at 6.

> PNM was a direct competitor [of SPS] in that RFP process and put together a very competitive bid, and we were told by El Paso that we were way off, that we were very high in our bid and the winner, which turned out to be SPS, was able to significantly underbid us. In hindsight, I have no doubt it's because of the misapplication of the fuel clause. Tr. at 1468.

162. The theory advanced by Mr. Christopher is unassailable. He describes how the SPS conduct creates dysfunction in the market, by sending erroneous price signals that end up increasing PNM's costs of doing business, and allows SPS to make market-based sales at a price that does not reflect marginal costs. The payment of higher fuel and purchased power costs by SPS' cost-based customers gives SPS a clear advantage over other sellers in the market. Those other sellers ironically might have been able to produce the power more efficiently. That is what really messes up the marketplace. The evidence supports a conclusion that the SPS FCAC practice negatively affects the effectiveness and competitiveness of the market.

163. OCC and CCG offer evidence in accord with this conclusion. Golden Spread witness Wise testified that Oklahoma Gas & Electric Company and others in the Southwest Power Pool were unwilling to compete with SPS because they were unwilling to take the risk that regulators would disapprove of pricing market-based sales at average fuel cost. Tr. at 960. OCC witness DeRamus and CCG witness Daniel both concluded that the SPS fuel practice harmed competition and gave SPS a competitive advantage. Tr. at 1412; Exh. CCG-46 at 46-50, 55-58.

164. Turning to Staff's position, it has carried its theory of the FCAC to an absurd

conclusion — that the Company can do anything it can get away with in pricing market-based sales, even, apparently, signing contracts priced below cost and using its cost-based customers to subsidize such sales through its stained interpretation of the FCAC. Advocates for the public interest should not be making such an unworthy argument.

165. As for SPS' argument that it was entitled to use the FCAC in the manner that it did, that is the circular argument raised in Issue II.A.3, supra., favored also by Staff, which suggests that the Company is entitled to collect through the FCAC whatever it has contractually agreed with its market-based customers. That argument is as unpersuasive here as it was there. The fact remains that the practice is anticompetitive and should not be taking place, not that it is acceptable because the structure of the FCAC can be interpreted to permit it. One needs to go beyond the structure of the FCAC to the underlying transactions to determine if the practice engaged in is reasonable and not anti-competitive. When one does that here, it is apparent that something is amiss.

166. Finally, as to the SPS argument that the sales here are not "inter-system" or opportunity sales, I rejected that argument above, in finding that the sales in question, identified by CCG at Exh. CCG-1 at 39-42, are not the type of sales for which the Company must plan, maintain and operate its system. They cannot be considered akin to firm requirements load for which the Company is responsible for such planning, maintenance and operation, and must be treated as opportunity sales made because of excess capacity.

5. Did SPS test its energy purchases against hourly avoided costs to determine whether they were economic?

167. CCG argues that Section 2(iii) of SPS' FCAC through 2004 and the Commission's Order No. 517 (old clause) regulations required a test to determine whether short-term firm and non-firm "economy purchases" are eligible for recovery through the clause. Exhs. CCG-1 at 74-80 and CCG-3 at 1. CCG contends that SPS agreed that an evaluation of whether the costs of short-term firm and non-firm energy purchases qualify as economy energy must be made on an hourly basis. Exh. CCG-22 at 4. However, CCG claims that SPS relied upon projected avoided costs to screen purchases to determine that they were expected to be at or below projections. CCG argues that the rule contemplated the use of actual system hourly avoided variable costs to determine whether purchases were economic on an hourly basis, something which CCG says SPS did not do. Moreover, CCG contends that hourly prices in a sample that it performed often exceeded SPS' projected hourly avoided costs, resulting in erroneous billing of overcharges (amounts that should not have been included as economy purchases in light of actual hourly avoided costs). CCG seeks a second phase of this proceeding to perform the studies to determine the extent of overbilling and a process for refunds.

168. Staff agrees that the Commission's FCAC rules require an after the fact hourly

analysis to determine if the purchase sought to be included in the clause was actually less than the utility's actual avoided cost for that hour. Exh. S-8 at 33. It agrees with CCG that the FCAC should be strictly construed and supports the call for further investigation of possible overcharges.

169. SPS maintains that it made its purchase decisions conservatively, since it had always been a low-cost producer, and wanted to leave a cushion for misestimation of hourly avoided costs. Tr. at 2354-55 and 2358. In any case, it sees nothing in Order 517 that requires the economic analysis of purchased energy costs be accomplished after the fact, only that purchase decisions be made on an economic dispatch basis, hour-by-hour. SPS contends that this logically connotes a before-the-fact analysis.

170. As to the overcharge analysis presented by CCG, SPS witness Grant performed a backcast analysis of several randomly selected months which he claims shows that, for the most part, SPS' energy purchases greatly benefited SPS' requirements customers. Exh. SPS-72 at 11-13. SPS further suggests that Golden Spread and CCG had adequate data to make the case regarding recovery of uneconomic purchases through the FCAC, but failed to carry the burden. It sees no basis to order a time consuming and costly compliance study of this subject.

Discussion and conclusion

171. I agree with SPS that there is nothing in Order No. 517 that requires after-the-fact testing of purchases to ensure that they were on an economic basis. The reference in Order No. 517 to "purchased on an economic dispatch basis" was, as argued by SPS, a reference to dispatching decisions to select those resources that would provide the lowest cost of energy in the next hour. Such decisions must be based upon the anticipated cost of the resources that otherwise would provide the energy if the purchase was not made.

172. The Commission changed this regime in Order No. 352, to one where recovery of energy purchases would be permitted, so long as, for the duration of the transaction, the sum of the energy purchase costs are not more that the total costs of alternative energy avoided by the purchase. See 18 C.F.R § 35.14(a)(2)(iv) (2005). This necessarily involves an after-the-fact analysis to make this determination.

173. There is, accordingly, no reason to plan a second phase of this proceeding to research whether energy purchases under the old clause were in fact economic when compared with costs actually avoided by making the purchase in a particular hour.

6. Did SPS properly recover the cost paid to its coal supplier TUCO, Inc. for coal used at Harrington Station that was sold by SPS affiliate NSP to TUCO's supplier?

conclusion --- that the Company can do anything it can get away with in pricing market-based sales, even, apparently, signing contracts priced below cost and using its cost-based customers to subsidize such sales through its stained interpretation of the FCAC. Advocates for the public interest should not be making such an unworthy argument.

165. As for SPS' argument that it was entitled to use the FCAC in the manner that it did, that is the circular argument raised in Issue II.A.3, supra., favored also by Staff, which suggests that the Company is entitled to collect through the FCAC whatever it has contractually agreed with its market-based customers. That argument is as unpersuasive here as it was there. The fact remains that the practice is anticompetitive and should not be taking place, not that it is acceptable because the structure of the FCAC can be interpreted to permit it. One needs to go beyond the structure of the FCAC to the underlying transactions to determine if the practice engaged in is reasonable and not anti-competitive. When one does that here, it is apparent that something is amiss.

166. Finally, as to the SPS argument that the sales here are not "inter-system" or opportunity sales, I rejected that argument above, in finding that the sales in question, identified by CCG at Exh. CCG-1 at 39-42, are not the type of sales for which the Company must plan, maintain and operate its system. They cannot be considered akin to firm requirements load for which the Company is responsible for such planning, maintenance and operation, and must be treated as opportunity sales made because of excess capacity.

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173. There is, accordingly, no reason to plan a second phase of this proceeding to research whether energy purchases under the old clause were in fact economic when compared with costs actually avoided by making the purchase in a particular hour.

6. Did SPS properly recover the cost paid to its coal supplier TUCO, Inc. for coal used at Harrington Station that was sold by SPS affiliate NSP to TUCO's supplier?

174. CCG has alleged that SPS engaged in a complex arrangement for the purchase of coal for its Harrington station that resulted in wholesale customers paying a higher amount for coal than if SPS had dealt directly with its affiliate Northern States Power Company (NSP). SPS secures coal for its Harrington and Tolk stations pursuant to long term supply contracts with TUCO, an unaffiliated corporation. Exh. SPS-71 at 5. In 2001, all of the coal required for Tolk and 75 percent of that required for Harrington were under long term contract. While SPS affiliate NSP had contract rights for additional coal, CCG argues that TUCO was instructed to solicit bids for the remaining 25 percent of Harrington's need, instead of SPS dealing directly with NSP. Tr. at 2367-68; 2376-77. The resulting bid was won by Peabody Coal Sales (Peabody), which bid coal from the Caballo mine. Tr. at 2370. CCG contends that, through a swapping arrangement, Harrington eventually got the NSP coal, but at a higher price than it would have cost if the Company had dealt directly with NSP. CCG witness Daniel calculated the damages and CCG urges that the relief be granted to SPS' ratepayers. Exh. CCG-1 at 91-95 (Protected Materials).

175. Staff agrees with CCG that SPS knew that the Harrington plant required coal of a higher quality than was available from the Caballo mine, and knew as well that higher quality coal was available from NSP. It nevertheless contracted for the lower quality coal from the Caballo mine, and paid more under the coal swap than NSP's cost with intermediate suppliers for higher quality coal. It contends that the difference in cost between the cost of the NSP coal and the price paid by SPS should be disallowed.

176. SPS maintains that it is contractually obligated to obtain coal from TUCO for the Harrington and Tolk stations, so could not deal directly with NSP. Exh. SPS-71 at 5. In response to price spikes in late 2000 and early 2001, SPS claims to have encouraged TUCO to secure 2002 coal supplies to cover remaining needs at the Harrington station. TUCO accepted a bid for Caballo mine coal from Peabody. The Harrington station operations personnel were wary of the quality of the Caballo coal based on prior experience and sought to blend that coal with higher BTU supplies. Such supplies were available via NSP, and a swap took place with the intent to blend the Caballo and NSP supplied coal. Eventually, however, the Harrington plant used primarily the higher BTU coal that came from the swap, leading CCG to conclude that something was amiss. Exh. SPS-71 at 7-8

177. SPS says that the coal swap neither disadvantaged SPS' ratepayers nor provided a windfall to NSP or its parent Xcel. According to SPS, the price of coal had fallen by the time that it managed the swap, which resulted in the purchase by SPS of higher BTU coal (through the NSP rights) at a price equal to that of the lower BTU Caballo mine coal. Exh. SPS-71 at 12 (Protected Material). According to SPS, it paid no more than market price for coal from TUCO.

Discussion and Conclusion

178. SPS has adequately and convincingly explained that ratepayers have paid no more that market price for the coal used at Harrington and supplied by TUCO. The record confirms that the Company was under exclusive contract with TUCO for the purchase of coal for Harrington and Tolk and was obligated to deal with TUCO for all of the coal requirements. Exh. SPS-71 at 5-6. It could not have dealt with NSP directly for the coal rights that its affiliate had. But the way things turned out, SPS' ratepayers actually benefited, since Powder River Basin coal prices declined by the time of the swap, so that SPS could purchase and use higher quality coal for the same delivered price as the lower quality Caballo coal. Exh. SPS-71 at 12 (Protected Material). I find no basis to conclude that SPS' activity in this area was unreasonable or led to the imposition of unjust or unreasonable charges.

B. New Fuel Clause (Order No. 352)

1. Is SPS' recovery of the energy-related costs of purchases from QFs under long-term contracts consistent with Commission regulations, precedent, and policy?

179. Now that the settlement that governed the old fuel clause has expired, due to the SPS filing of a new FCAC under the provisions of the Commission's current fuel clause provisions,[27] CCG argues that it is necessary to decide if the new FCAC complies with the current FCAC regulatory scheme. It will be recalled that I decided above that the provisions of the Commission-approved settlement in Docket No. EL89-50 and conforming agreements with the parties constituted approval of any provisions in the SPS FCAC that did not conform to the old fuel clause regulations, so that the Company's practice of including energy-related costs of QF purchases that were made at or below avoided costs was permissible.

180. SPS argues that the cost of energy purchased from its QF contracts (Borger, ECI and Sid Richardson), and the cost of wind energy purchases, are all eligible for FCAC recovery under the new fuel clause regulations, to the extent that they are less than avoided costs over the duration of the related contract. Exh. SPS-87 at 11-13. The SPS theory is that 18 C.F.R. § 35.14(a)(2)(iv) expressly permits the recovery of any purchased energy charges as long as they are less than the total avoided costs during the same purchase period. *Id.* SPS further contends that recovery of the cost of QF energy purchases through FCAC billings is a settled practice that has not been shown to be unreasonable, and, therefore should be allowed to continue.

181. CCG considers these purchases to be long-term reliability purchases, and, as such,

[27] *Treatment of Purchased Power in the Fuel Cost Adjustment Clause for Electric Utilities*, Order No. 352, FERC Stats. and Regs. ¶ 30,525 (1983), *reh'g denied*, Order No. 352-A, 26 FERC ¶ 61,266 (1984).

limited to recovery of fuel costs through the FCAC. CCG sees Section 35.14(a)(2)(iv) as inapplicable here because the purchases were not made for economic reasons in comparison to the buyer's total avoided variable cost in an effort to reduce cost. CCG contends that SPS is limited to recovery of the fuel component of these purchases as contemplated in Section 35.14(a)(2)(ii).

182. Staff witness Sammon is in accord with SPS that all energy purchases can flow through the fuel clause, even those made for reliability purposes; however, he believes that the energy associated with a life-of-the-unit power purchase was not intended by the Commission to be so included. Tr. at 2462. Staff argues that the Company's new FCAC must be corrected to limit FCAC inclusion to energy charges incurred that are less than the buyer's total avoided variable cost.[28] SPS originally sought to include the total cost of energy purchases, so long as they were less than the total avoided costs during the purchase period. However, in its Reply Brief at 40, SPS states that it is willing to amend the wording of subsection 2(v) of the New Fuel Clause to limit recoveries to energy charges

Discussion and Conclusion

183. SPS has agreed to amend its FCAC to include only energy charges associated with QF energy purchases on a going forward basis. I believe that concession satisfactorily resolves this issue as between Staff and SPS. It is clear to me that a reading of the plain language of Section 35.14(a)(2)(iv) contemplates inclusion of energy charges (only) if the total of such charges is less than the buyer's total avoided variable costs. That's what the regulation requires and that's what ought to be in the Company's FCAC.

184. I simply fail to understand and therefore reject CCG's argument that this section is not applicable to the purchases at issue here. See CCG I.B. at 61. The Boston Edison Company audit report in Docket No. FA96-10-000 (unpublished letter order dated January 24, 1997) cited and heavily relied upon by CCG to support its position adds gloss and additional provisions to the actual Commission regulation, and cannot be relied upon to support the CCG argument.[29] The actual regulation is pretty straightforward:

> (2) Fuel and purchased economic power costs shall be the cost of:...(iv) Energy charges for any purchase if the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost. 18 C.F.R. § 35.14(a)(2)(iv).

[28] 18 C.F.R. § 35.14(a)(2)(iv) (2005). Staff also argues that a back-cast test of whether such energy charges were actually less than avoided variable costs is required.

[29] Neither is *Philadelphia Electric Co.*, 57 FERC ¶ 61,147 (1991) apposite here. That case dealt with recovery of purchased power costs under the old fuel clause.

185. I find that this subsection of the FCAC regulations rather clearly contemplates inclusion of energy charges (only) if the total of such charges is less than the buyer's total avoided variable costs.

2. Is SPS' recovery of the energy-related costs of all wind energy purchases consistent with Commission regulations, precedent, and policy?

186. Similar arguments were raised with respect to inclusion of the energy-related costs of wind energy purchases. SPS has agreed to revise the language of Section 2(iv) of its FCAC to refer only to energy charges incurred for wind energy purchases, which resolves this issue.

187. On brief, Staff raised a concern about possible intergenerational inequities that might flow from an accumulation of wind energy costs that exceed avoided costs in one month for application in subsequent months during which the costs of wind energy are below avoided costs. Staff I.B. at 62.

188. SPS counters in its Reply Brief with the argument that the scenario that troubles Staff is unlikely to occur, and would not impact customers in any case since SPS intends to test the economic effectiveness of its wind purchases on an aggregate monthly basis. This procedure will ensure that any costs flowed through in hours that exceed avoided costs would be offset against hours with positive savings, so that in no month would customers pay more that total avoided costs for that month

189. I find the SPS explanation to be satisfactory and see no issue remaining in dispute as to this item.

190. PNM urges that the Company be directed to delete the section of its new FCAC that deals specifically with wind purchases. It argues that inclusion of a separate section for wind purchases may lead to different, and possibly more favorable, treatment for wind *vis-à-vis* other purchases for purposes of FCAC recovery. See Exh. CCG-38 at 16-17. I see no reason to require SPS to delete the wind provision. SPS witness Hudson notes that the provision is for the purpose of notifying customers that wind energy costs will be flowed through the FCAC. I believe the notification justification is sufficient to outweigh the concern expressed by PNM. There is a valid reason to justify the practice, and the PNM concern may never come to fruition.

3. Is SPS' aggregation of wind energy purchases for the purposes of evaluation under the new FCAC consistent with Commission regulations, precedent, and policy?

191. The Company does not evaluate each wind energy purchase against total avoided variable cost. Instead, it aggregates wind purchases in a group for this economic test.

Exh. CCG-39 at 1. CCG argues that there is nothing in the Commission's fuel clause regulations that authorizes an aggregation of different sources for the required economic test. Noting that Section 35.14(a)(2)(iv) of the Commission's regulations uses singular language, i.e., referring to "any purchase", and "the purchase", CCG is hard pressed to see any justification for the aggregation of purchases for this purpose. It contends that the SPS group test approach would improperly avoid the individual, contract-by-contract analysis contemplated by the Commission's FCAC regulations. CCG further complains that the SPS practice complicates the review process of FCAC billings, making it more difficult for customers to check the veracity of the filings. It argues that a likely increase in future wind purchases will make matters even worse.

192. Staff and PNM agree that aggregation of these purchases is not permitted by the FCAC regulations. Staff I.B. at 63. PNM further takes issue with SPS' plan to evaluate wind purchases over the life of the contract. It contends that wind energy purchases should be evaluated on the same basis as other purchases. Exh. PNM-2 at 28.

193. SPS responds that it would be extremely time consuming to undertake the contract by contract kind of analysis sought by these parties. It argues that ordinarily, there will be little question that a wind purchase is economic, and only occasionally will it prove uneconomic. Those instances, SPS contends, will be more than offset by the periods when the purchases are economic.

Discussion and Conclusion

194. In carrying out the intent of the Commission's regulations, it sometimes may be necessary to develop techniques to reduce the burden associated with a literal reading of the rule. These may involve necessary short-cuts to avoid the expense and burden of implementing certain provisions in the rule that the Commission might not have thought about when crafting the document. Such short-cuts are not *per se* inconsistent with the rule, especially where there is no prohibition against such practices. I believe that SPS has stated a valid reason for aggregating the wind purchases for economic test purposes, namely, the time-consuming nature of doing individual contractual analyses. No persuasive arguments have been raised by the parties objecting to an aggregated test that would warrant the expense and burden of performing a contract-by-contract analysis of these sales. I do agree with PNM, however, that the actual method of economic evaluation for wind purchases should not be different from that conducted for other purchases, but SPS may aggregate the contracts in performing that evaluation.

4. Should SPS be permitted to recover SPP losses through the new FCAC?

195. SPS proposes to recover, through the new FCAC, the cost of transmission losses purchased from the Southwestern Power Pool (SPP), less the payments for transmission losses that it receives from SPP. It claims the right to do that by virtue of 18 C.F.R. §

35.14(a)(4), which provides:

> The adjustment factor developed according to this procedure shall be modified to properly allow for losses (estimated if necessary) associated only with wholesale sales for resale.

196. SPS contends that its transmission losses are associated only with wholesale transactions and are recoverable through the FCAC, pursuant to the above provision, as "losses...associated with wholesale sales for resale." SPS will collect the net difference between amounts SPS pays to the SPP for transmission losses and amounts that the SPP distributes to SPS to compensate it for supplying energy to cover transmission losses.

197. CCG argues that SPS does not buy losses from the SPP to serve the wholesale requirement loads whose rates are in issue here. SPS directly supplies such losses, CCG contends. Exh. CCG-38 at 34. The losses which SPS wants to flow through the FCAC, CCG maintains, are more likely to arise in connection with "opportunity sales", and should not be flowed through the FCAC to wholesale requirements customers. Moreover, CCG contends that wholesale requirements customers should not pay SPS for costs related to its unregulated, market-based transactions. CCG also points out that one wholesale customer, Golden Spread, self-supplies losses. CCG further argues that some of SPS' market-based contracts contain separate provisions for recovery of losses outside of the FCAC. Exh. CCG-9 at 17; see also Exh. CCG-10 at 12 (Protected Material). CCG states: "Quite simply, this deviation from Section 35.14 is another instance where it is time to slap the hogs away from the trough, and that should be the end of the matter." CCG R.B. at 43.

198. SPS answers that it incurs loss payment obligations to SPP when it imports power to serve its control area load as well as when it reserves transmission for off-system sales. Tr. at 1966. It claims that the monthly billings from SPP do not separately identify each transaction for which SPS is charged losses. Neither are the payments it receives from SPP identified to particular transactions. Sometimes, it has net revenues from these transactions. *Id.* It concludes that the transmission loss costs are real and should be allowed to flow through the FCAC.

Discussion and Conclusion

199. I find that the evidence supports the position of CCG, and that recovery of transmission losses through the FCAC should not be allowed as proposed by SPS. SPS admits that it is unable to identify the transactions for which it is charged losses. In light of the evidence presented by CCG that suggests the possibility of double recovery, and the likelihood that loss costs are in some part related to market-based opportunity sales, it would be unfair and inequitable to assess wholesale requirements customers with SPS transmission loss costs through the FCAC without ensuring that they are related to the

wholesale sales.

5. Should SPS be permitted to recover the energy-related costs associated with long-term (one year or more) purchases if such purchase costs are less than avoided costs over the term of the contract?

200. The finding for this issue is governed by the conclusion in Issue II.B.2 above. The Commission's regulations permit the recovery of energy-related costs for <u>any</u> purchase where the total amount of energy charges incurred for the purchase is less than the buyer's total avoided variable cost. 18 C.F.R. § 35.14(a)(2)(iv).

6. Should the new FCAC be supplemented with detailed protocols governing its application and, if so, what those protocols include?

201. CCG witness Daniel proposed that, in light of the major changes in the electric industry since the Commission last addressed itself to the subject of the fuel clause, it would be desirable to have a set of protocols as part of the filed rate that explain in detail how SPS will implement the new FCAC on a monthly basis. He further argued that the context of the instant proceeding and the confusion caused by the old fuel clause, particularly how the terms of the settlement in Docket No. EL89-50 plays out in 2006, suggest the propriety of detailed protocols to avoid future problems of the kind we are examining in this record. Exh. CCG-38 at 41-42. He envisions something like the protocols that were agreed to recently by SPS' affiliate Public Service Company of Colorado (PSCO). Exh. CCG-42.

202. SPS contends that industry changes provide insufficient reason to single out SPS and burden it with 40 pages of detailed protocols. SPS argues that the PSCO protocols followed a case settlement, and that it should not stand as precedent for a case that is being litigated. It argues that the Commission's regulations and the detailed information its FCAC customers receive provide sufficient explanation of the FCAC billing process. Exhs. SPS-8 at 8, 10, and SPS-108 at 31. It believes more is not required.

203. Staff takes this opportunity to restate its views that whatever approach is selected, the Commission must be able to evaluate SPS' compliance with the Commission's regulations. Staff further points to its position that QF purchases must be able to be evaluated against the Company's actual total avoided variable costs, not some estimate of same. Staff also reiterates its position that each transaction must be evaluated, not an aggregated compilation of purchases.

Discussion and Conclusion

204. The record of this proceeding provides solid support for Mr. Daniel's view that more is required to support FCAC calculations and billings than is laid out in Section

35.14 of the Commission's regulations or that is available currently from SPS. Whether or not 40 pages of detailed protocols is the only solution to the problems identified is questionable; however, I am persuaded that the CCG position should be adopted here. I recommend that the parties form a study group to identify the information and protocols that will provide the additional support for the FCAC calculations and billings necessary to obtain a greater understanding of the costs included in the charges. The record fully supports this result. *See* Tr. at 2271-72; 2259-2265; 2290-91; Exhs. CCG-114, 115, 116.

7. Is SPS' attribution of system average fuel costs to long-term market-based capacity sales consistent with Commission regulations, precedent, and policy?

205. The answer to this question is provided in Issue II.A.3 above.

8. What FCAC crediting, if any, of fuel costs associated with long-term market based capacity sales is proper under Commission regulations, precedent, and policy?

206. The answer to this question is provided in Issue II.A.3 above.

9. Does SPS' attribution of system average fuel costs to long-term market-based capacity sales harm competition?

207. The answer to this question is provided in Issue II.A.4 above.

10. Is Section 2(iv) of the New FCAC consistent with Commission regulations, precedent, and policy?

208. Section 2(iv) of SPS' new FCAC contains the following language:

> plus, energy charges for any purchase, including, without limitation, the total energy costs associated with purchases from any wind energy projects to the extent that the energy-related charges incurred for the purchase over the term of the purchase are less than the Company's total avoided variable costs. For energy purchases greater than one year, the Company will measure the monthly purchase price relative to the Company's total monthly avoided variable cost. The Company will only include in the FCA the lesser of the cumulative purchase price or the total avoided variable cost incurred through the term of the purchase to date[.]

209. Staff contends that Section 2(iv) of the new SPS FCAC is deficient in that it expands the scope of costs to include total energy costs associated with purchases as eligible for flow through, whereas the regulation is limited to "energy charges." Staff also maintains that the SPS clause overreaches in that it includes accumulating and carrying costs over the full term of the purchase, instead of a periodic evaluation of

purchases. Finally, Staff questions whether the clause contemplates a post-purchase evaluation on a transaction by transaction basis, which it contends is required by the regulations.

210. CCG adheres to its position, described earlier in Issue Nos. II.A.2 and II.A.3, that the new clause is too broad in that it seeks recovery of the energy costs related to any purchase, regardless of length or whether or not it is made for reliability purposes. CCG contends that only actual identifiable fuel is allowed to be recovered if the purchase is made for reliability reasons and not as an economy purchase. Exh. CCG-38 at 31-32.

211. SPS argues that the Commission's regulation quoted above plainly states that energy charges (only) associated with any purchase may be recovered through the fuel clause if such charges are less than the buyer's total avoided cost over the purchase period. It further maintains that it specifically singled out wind energy costs because it expects future transactions from wind projects too large to qualify for QF status, and wanted to provide notice as to what costs would be flowed through the clause.

Discussion and Conclusion

212. SPS is correct, as noted above, that the Commission's fuel clause regulation permits recovery through the fuel clause of the energy charges associated with any purchase may be recovered through the fuel clause if such charges are less than the buyer's total avoided cost over the purchase period. Its mention of wind energy costs in its fuel clause is not inconsistent with the Commission's regulations. I rejected earlier the Staff objection to aggregation, and find that the SPS plan for testing wind energy charges against avoided costs necessarily involves a comparison with actual avoided costs.

11. What is the appropriate interpretation of the phrase "company's avoided variable costs" in Section 2(v) of SPS' proposed FCAC?

213. SPS maintains that its settlement agreement with Golden Spread in Docket No. EL89-50 anticipated that SPS would recover through FCAC billings the cost of energy purchases from QFs that were equal to or less than SPS' avoided variable energy costs as approved by state jurisdictional authorities. Exh. SPS-6 at 8. It notes that Lyntegar and the four New Mexico Cooperatives agreed to the same terms. Exh. SPS-26. Although the reference to state authorities is not in the FCAC, SPS contends that it was the intention of the parties that avoided costs be so determined.

214. CCG and Staff argue that the filing of a new FCAC by SPS provides an opportunity to align the Company's clause better with the intent of the Commission's regulations, as opposed to a decades old settlement. They assert that the phrase "Company's avoided variable energy cost" in the Company's FCAC should be interpreted in the same manner as the phrase "buyer's total avoided energy cost" in 18

C.F.R. 35.14 (a)(2)(iv). Exh. SPS-2 at 2. CCG also refers to the definition of "Total Avoided Variable Cost" in Section 35.14(a)(11)(iii):

> Total avoided variable cost is all identified and documented variable costs that would have been incurred by the buyer had a particular purchase not been made. Such costs include, but are not limited to, those associated with fuel, start-up, shut-down or any purchases that would have been made in lieu of the purchase made.

215. While CCG goes on to argue that this definition supports its other arguments against aggregation of purchases in making the test and its contention that flow through must be limited to economy purchases, it asserts that the definitions plainly contemplate an after-the-fact examination of actual effectiveness, and not just a projection.

216. Staff argues that the fifteen year old settlement was not intended to bind the Commission in perpetuity, and the Commission is entitled to review the new FCAC against its current regulations and policy. Staff concludes that the phrase "Company's avoided variable cost" in the new SPS FCAC should be consistent with the Commission's current fuel clause regulations.

Discussion and conclusion

217. I agree with Staff that the new FCAC must be consistent with the Commission's current fuel clause regulations. This means, primarily, that the Company must find a way to test the purchases it wants to flow through the FCAC against actual avoided costs. While I continue to find nothing specific in the new regulations on this point, it seems hard to envision how the intent of the Commission's regulation could be satisfied with anything less than an after-the-fact comparison of actual avoided costs against the purchase cost. One thing is certain. SPS can no longer rely on the old settlement and associated agreements now that it has filed a new clause. Staff and CCG are correct that the filing of a new clause opened the door to a fresh look at the provisions of the clause. In the absence of any agreement among the parties to continue the regime from Docket No. EL89-50, the proper test of reasonableness is the Commission's current fuel clause regulations.

12. Whether it is just and reasonable to have a separate provision for QFs in SPS' proposed FCAC?

218. CCG argues that the separate provision that SPS has in its FCAC to deal with QF purchases (Section 2(v)) is not contemplated by and is inconsistent with the Commission's FCAC regulations. CCG urges the Commission to strictly apply the FCAC regulations and to not countenance nonconforming provisions in individual utility FCACs.

219. Staff cites Section 35.14 (a) for the proposition that fuel adjustment clauses that are not in conformance with the principles laid out in the regulations are not in the public interest. Staff found "incongruities" between section 2(v) of the new SPS FCAC and the Commission's regulations, such as SPS' failure to evaluate QF purchases against its total avoided variable cost, and potential discrepancies between the state determined estimated avoided costs and those which Staff contends were contemplated by the new Commission regulations.

220. SPS argues that its inclusion of QF purchase costs via the FCAC has been a settled practice with the acceptance of the CCG members since 1991. Even though the Commission's fuel clause regulations do not specifically contemplate the recovery of energy cost payments to QF costs, the practice has not been shown to be unreasonable and ought to be allowed to continue, the Company argues, citing *Public Service Commission of New York v. FERC*, 642 F.2d 1335, 1342-45 (D.C. Cir. 1980). SPS says that, in any case, CCG's main argument is that non-fuel energy costs associated with long term contracts are not eligible for fuel clause recovery, a position that has been shown to be wrong. SPS contends that the energy related costs of any purchase are eligible for fuel clause recovery so long as they are less than avoided costs over the duration of the transaction.

Discussion and conclusion

221. SPS is correct that energy-related costs of any purchase are eligible for fuel clause recovery so long as they are less than the buyer's total avoided variable cost 18 C.F.R. § 35.14(a)(2)(iv). So, I see nothing wrong or inconsistent with this regulation for SPS to include a separate provision regarding QF purchases in its fuel clause. However, a problem arises in that the new SPS language fails to capture the appropriate test to ensure that the energy-related costs of the QF purchases are less than the buyer's total avoided variable costs. As just determined above, I believe that the new clause regulations from Order No. 352 contemplate a test against actual avoided costs, not against state authority estimates. Accordingly, the new SPS FCAC must be amended to specify an after-the-fact analysis to support recovery of such costs via the FCAC.

III. Remedies

A. Base Rates

1. What are the just and reasonable base rates to be applied to the service provided to the full requirements and partial requirements complainants on and after the refund effective date in this proceeding?

222. CCG indicates that once remaining cost of service issues are adjudicated, a further adjustment of rates will have to occur in the compliance phase and any difference

between the just and reasonable and the present rates should be refunded to CCG's members, effective January 1, 2005, with interest.

223. SPS argues that the Commission should order it to prepare a compliance cost of service analysis and rate design which would take into account the Joint Stipulation, and the findings and conclusions of the Commission after its actions on any timely requests for rehearing. After the Commission has reviewed and accepted the compliance rates, SPS would compare the revenues produced from the application of the compliance rate for service rendered between January 1, 2005 and June 9, 2006 to the revenues SPS has collected under the currently effective rates for service rendered in the same period and refund any negative difference in revenues to the customers at issue in this proceeding.

224. Cap Rock argues that the rates should be derived based on the cost of service approved in this proceeding, using the 12-CP demand cost allocators recommended by Cap Rock.

225. Staff indicates that the demand rate for the partial requirements contracts is unjust and unreasonable, that the energy rates for the full requirements customers are excessive and that a compliance filing is required. Staff indicates that its cost of service does not take into account the trial stipulations.

Discussion and Conclusion

226. A compliance phase is needed to quantify refunds. SPS is ordered to file and serve a compliance filing consistent with this decision.

2. Should the service to Cap Rock, on and after the refund effective date, be subject to the full requirements base rates determined in this proceeding?

227. The Regulatory Fairness Act, at 16 U.S.C. § 824e (b) (2004) states that "those persons who have paid those rates or charges which are the subject of the proceeding" are eligible to receive the refunds. The Commission has expressly acknowledged, in *Blue Ridge Power Agency*, 55 FERC ¶ 61,509 at 62,781 (1991), that the RFA is a remedial statute that was intended to correct the inequity that arose because ratepayers could not receive refunds when they filed a Section 206 complaint. The Commission has found that under the RFA it has the authority to establish refund protection for all rates which are investigated under Section 206, in *Yankee Atomic Electric Co.*, 49 FERC ¶ 61,428 at 62,505 (1989). Finally, in *North Carolina Electric Membership Corp. v. Carolina Power & Light Co.*, 57 FERC ¶ 61,332 at 62,067 (1991) (*North Carolina Electric*), the Commission has held that when the same customer class and the same rates are at issue, a separate complaint is not required, and all refunds ordered will apply to all customers served under that rate.

228. Cap Rock argues that while it is not a named party complainant in the CCG complaint it did request the Commission to treat its motion to intervene as a complaint and that Cap Rock be given complainant status in the proceeding. Since Cap Rock pays the same rates as the Cooperative FR Customers who are members of the CCG and are named parties to this case, this treatment of Cap Rock would be appropriate.

229. Cap Rock argues that its right to refunds does not turn on whether or not the Commission grants them complainant status, but rather its rights to refunds come from its status as a member of the class of customers whose rates were put at issue by the CCG complaint. Cap Rock contends that, its situation is like that of French Board in *North Carolina Electric,* 57 FERC ¶ 61,332 at 62,067, because its rate is a class rate shared with the FR Cooperatives.. Cap Rock argues that these rates are based on costs allocated to all members as a class and use billing determinants measured for the class. Cap Rock indicates that the rates in effect for the FR customers, when the complaint was filed, were $3.88/kW Demand and $0.002/kW Energy, which are the same rates that are specified in Cap Rock's service agreement. Exh. CCG-1 at 22 and CRE-10; CRE-21. Cap Rock indicates that SPS' witness Mr. Hudson has testified that Cap Rock does pay the same rates. Tr. at 1815. Cap Rock also explains that Mr. Hudson testified that SPS' groups the cooperative customers and the full requirements customers when setting rates. *Id.* at 1822. Cap Rock indicates that SPS' settled practice is to treat the full requirements wholesale customers as a distinct class, allocating costs to the class, designing a single set of rates for the class, and charges each member of the class the same exact four part rate. Exh. CRE-22. Cap Rock indicates that Mr. Hudson admitted on cross-examination that the rate schedules for each of the FR customers are identical. Tr. at 1819.

230. SPS contends that Cap Rock's base rates are not subject to refund in this case, and any base rate changes can only be applied prospectively to Cap Rock. SPS indicates that this also applies to PNM's base rates for interruptible capacity services. SPS argues that Cap Rock should have filed its own complaint, as PNM did, but it has not, and the hearing order in this proceeding only established a refund effective date for the CCG members. SPS' witness Mr. Hudson testified that Cap Rock is served under a different rate from that used to serve the full requirements customers, that they are served under separate contracts and designated by FERC as separate rate schedules, but all have the same full requirements rate on the schedules. *Id.* at 1815-1816.

231. Staff disagrees with SPS' position, arguing that the Commission has found that when the same customer class and the same rates are at issue, a separate complaint is not required, and all refunds ordered will apply to all customers served under that rate. *North Carolina Electric,* 57 FERC ¶ 61,332 at 62,067. Staff explains that Cap Rock is a member of the same full requirements customer group involved in this proceeding. Staff argues that Cap Rock is entitled to status as a party complainant and to receive refunds accordingly, pending a Commission order on Cap Rock's request for clarification.

232. CCG's position is the same as set forth in III.A.1 above.

Discussion and Conclusions

233. On May 2, 2006 the Commission issued an order on Cap Rock's motion for clarification, indicating that for purposes of this proceeding, Cap Rock is not a party complainant, but an intervenor. *Order on Motion for Clarification,* 115 FERC ¶ 61,136 (2006). The Commission stated that the order did not foreclose Cap Rock from participating as a party in this proceeding, or from filing its own complaint. *Id.* Further, the Commission explained that the order does not address the issue of whether Cap Rock's base rates are subject to refund in this proceeding. *Id.*

234. Cap Rock is not a party complainant, however, this does not preclude Cap Rock's service, on and after the refund effective date, from being subject to the full requirements base rates determined in this proceeding. The evidence clearly shows that while SPS states that Cap Rock is served under separate contracts that are designated as separate rate schedules, the rates are the same. Cap Rock pays the same charges that the FR customers pay, SPS has admitted that all the customers have the same full rate on the schedules, and that it groups them when setting the rates. On brief, SPS does not even try to dispute these facts. Even SPS' argument on brief supports Cap Rock's position as SPS relies on the assertion that Cap Rock should have filed its own complaint, that "simply echoed the allegations of the CCG members," indicating that SPS felt the issues would have been the same. SPS I.B. at 64. Commission precedent clearly indicates that when the same rates are at issue a separate complaint is not required. Therefore, Cap Rock's service is subject to the full requirements base rates determined in this proceeding.

3. What refunds (including interest at the Commission's prescribed rate) should be made to SPS' full requirements and partial requirements customers as a result of the application of such rates on and after the refund effective date, which customers should receive such refunds, and how should such refunds be calculated?

235. Cap Rock argues that for the reasons set forth above, it should be treated the same as SPS' CCG full requirements wholesale customers.

236. SPS's position is the same as set forth in III.A.1 above.

237. CCG's position is the same as set forth in III.A.1 above.

238. Staff's position is the same as set forth in III.A.1 above.

Discussion and Conclusions

239. A compliance phase is needed to quantify refunds. SPS is ordered to file and

serve a compliance filing consistent with this decision.

B. Old Fuel Clause

1. Are the CCG customers entitled to refunds as a result of SPS' charges under the old Fuel Clause, and if so, how should such refunds be calculated?

240. SPS acknowledges that the CCG members, Cap Rock and PNM are all entitled to refunds to the extent that the Commission finds that the Company has misapplied the FCAC provisions of its wholesale rate schedules, including a retroactive remedy. SPS I.B. at 64. However, the Company asserts that there are some countervailing considerations that must be weighed by the Commission before a decision is made to proceed with any refunds. These are: (1) the challenges to the SPS FCAC application are not valid; (2) equity requires that the wholesale customers not be rewarded for sitting on their hands; and (3) none of the costs that SPS thought were eligible for FCAC recovery have been included in base energy rates, and are essentially now unrecoverable.

241. SPS argues that, for 15 years, no customer questioned its practice of billing market-based sales customers at the system average fuel cost, despite information routinely supplied to them. It also points out that none of the costs questioned were included in the design of base energy rates, so that SPS would have to absorb any amounts it would be required to disgorge for the benefit of the wholesale requirements customers. SPS suggests that these customers were dilatory in raising the argument.

242. SPS refers to *Commonwealth Edison Company*, 23 FERC ¶ 61,219 at 61,47 fn27 (1983), where the Commission ordered a new pricing scheme to be applied prospectively, in partial recognition of the administrative problems and possible inequities associated with determining an applicable price at which prior sales could be repriced. SPS goes on to argue that the Commission has discretion to consider pertinent facts on deciding whether refunds are appropriate in a particular case, noting that, in *Minnesota Power & Light Co.*, 14 FERC ¶ 61,143 at 61,258, *reh'g*, 15 FERC ¶ 61,061 (1981), the Commission required that a demand ratchet be discontinued, but refused to apply a refund obligation that would not permit the utility to recover its costs.[30] Finally, SPS points out that the Texas PUCT rejected similar claims as to the treatment of SPS' long-term firm capacity sales, which suggests that regulators could reach different conclusions as to the equities involved in the practice. SPS urges the Commission to apply any relief prospectively.

243. CCG maintains that the level of appropriate refunds cannot be ascertained at this time. It suggests that the Commission order SPS to recalculate its FCAC factors for 1999-2004, with support in a compliance filing, and issue refunds with interest for all

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[30] See also *Connecticut Light and Power Co.*, 15 FERC ¶ 61,056 (1981).

overcharges. As noted above, CCG would have the period of inquiry go back to 1994, but recognizes that additional process and discovery would be required to do that. Exh. CCG-1 at 89.

244. CCG further responds to SPS' arguments that additional considerations are applicable here. It argues that the SPS FCAC practice has been proven on the record of this proceeding to have been unreasonable. It sees no equities running in favor of SPS as to the claim of dilatoriness, contending that SPS actually took affirmative steps to conceal its FCAC violations. It sees *Commonwealth* as "completely off the mark,"[31] in that it involved a Section 205 proceeding, not a Section 206 complaint by customers. Neither does it believe that the Texas PUCT proceeding has much relevance here, given that this Commission has performed its own inquiry, and is not bound by a prior state determination, in any event.[32]

245. OCC argues that each of the Company's cost-based wholesale customers that were subject to SPS' FCAC in the 1999-2004 period is entitled to refunds. Failure to apply refunds would reward SPS for intentional misapplication of the FCAC and would unjustly enrich SPS and its shareholders at the expense of the wholesale customers, OCC contends. OCC claims the Commission has the legal authority under Sections 205, 206 and 309 of the Federal Power Act to order such refunds and disgorgement of unjust profits. *Consolidated Edison Co. v. FERC*, 347 F.3d 964, at 967 (D.C. Cir. 2003). OCC reviews the record evidence suggesting that the Company was aware of the risk it was taking in applying system average fuel costs to the market-based sales customers, yet assumed the risk. It sees no equity or special considerations running in SPS' favor that would justify a result different than a full refund of amounts needed to restore customers to the position in which they would have been paying a just and reasonable rate.

246. OCC argues that the refund should be determined by calculating the difference between the amounts recovered from cost-based customers under the SPS fuel clause strategy and the amounts such customers would have paid if SPS had allocated incremental fuel costs to its market-based customers. OCC sees no compelling justification for the Commission to deviate from its policy of full refunds in circumstances like these. OCC would have SPS make a compliance filing in which it recalculates its monthly FCAC factors for 1999-2004, supported by detailed calculations and documentation. OCC proposes a protocol for the recalculation. OCC I.B. at 55.

247. Staff points out that no valid quantitative determination of an appropriate refund

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[31] CCG R.B. at 49.

[32] *Central Power and Light Co., et al.*, 98 FERC ¶ 61,069 at 61,184 n.24 (2002), citing *Cities of Bethany, et al. v. FERC*, 727 F.2d 1131, at 1137 (D.C. Cir. 1984); *Potomac Edison Co.*, 70 FERC ¶ 61,037 at 61,121 (1995); and *Houlton Water Co., et al. v. Maine Pub. Svc. Co.*, 60 FERC ¶ 61,141 at 61,514 (1992).

amount has been made. Staff further acknowledges that the Commission has equitable discretion to fashion remedies, where formula rates, which are not typically reviewed by the Commission before they take effect, are the subject of complaint, citing *Town of Concord et al. v. FERC*, 955 F.2d 67 at 73, at 76 (D.C. Cir. 1992) for the proposition that refunds are not an inevitable remedy for fuel clause violations, given the Commission's remedial discretion.

248. Cap Rock contends that it is entitled to refunds in the same status as CCG full requirements customers, as it argues above with respect to base rate refunds. Cap Rock maintains that it has paid the same FCAC as the CCG customers, and is entitled to refunds along with other payors of the rates determined to be unjust and unreasonable.

Discussion and conclusion

249. SPS has acknowledged that the CCG members, Cap Rock and PNM are all entitled to refunds to the extent that the Commission finds that the Company has misapplied the FCAC provisions of its wholesale rate schedules, including a retroactive remedy. SPS I.B. at 64. Since I have made that finding, I am in accord with this view.

250. I do not believe that SPS has justified a departure from this precedent by arguing that special considerations should apply here. First, its statement that the charges of misapplication are not valid is unsupported and is contradicted by the record evidence, as discussed above. Its claim that the customers should not be rewarded for their dilatory conduct rings hollow in light of the evidence in this record that suggests SPS was not fully forthcoming to its customer inquiries, and in the information supplied to its customers. Tr . at 1995-96; Exh. SPS- 148. Its claim for special consideration because it would not be able to recover costs associated with refunds seems especially misplaced when viewed in light of its clear assumption of the risk of a questionable FCAC strategy. Exh. OCC-27 at 21-22. The record here demonstrates convincingly that SPS knew what it was doing when it decided to employ the FCAC strategy, and it must now be held to account for the misapplication of the clause to its cost-based wholesale requirements customers.

251. While the Commission clearly has discretion to design a proper remedy here, I see no reason to depart from the traditional rule. Indeed, I believe that the case has been made for a strict application of the rule. As noted above, it may be that SPS innocently started out with a general policy of charging system average fuel costs to its off-system sales customers, and simply continued to follow that policy. However, it is also clear that, at some point, it became aware that this practice provided it with a competitive advantage and an opportunity to subsidize market-based sales through FCAC charges to cost-based customers. SPS saw this as a way to make money. It did make that money, through an inappropriate, unjust and unreasonable practice. As a result, it is not a candidate for mercy.

252. The Company is directed to make a compliance filing designed to restore its wholesale customers to the position in which they would have been had they been paying a just and reasonable rate, i.e., one calculated to assign incremental fuel costs to market-based customers from 1999 to 2004. Refunds should be provided to the CCG customers, PNM and Cap Rock to reflect the difference between the SPS actual fuel clause billings for the period 1999-2004 and the amount that SPS would have billed had it allocated incremental fuel costs to market-based sales.

2. Is Cap Rock entitled to refunds as a result of SPS' charges under the old Fuel Clause, and if so, how should they be calculated?

253. There is no dispute that Cap Rock should receive refunds, along with CCG's members and PNM, calculated on the same basis for the same period.

C. New Fuel Clause

1. Are SPS' wholesale customers that are subject to the new Fuel Clause entitled to any refunds as a result of SPS' charges under the new Fuel Clause, and, if so, how should such refunds be calculated?

254. To the extent that the substantive decisions above suggest the propriety of refunds under the new Fuel Clause, they should be the subject of a compliance filing, and refund plan, as decided above.

2. Does SPS' new Fuel Clause need to be revised to comport with any rulings on the issues related to the new Fuel Clause?

255. Revisions are required to SPS' new Fuel Clause, as set forth above in Section II.B. The Company is directed to make a compliance filing to align the new Fuel Clause with the determinations herein.[33]

ORDER

256. It is therefore ordered, subject to review by the Commission on exceptions or on its own motion, as provided in the Commission's Rules of Practice and Procedure, that within thirty days of the issuance of the Final Order in this proceeding, all parties shall take appropriate action to implement all of the rulings in this decision. All arguments made by the participants, which may or may not have been discussed and/or adopted by

[33] The compliance filings referred to in this Initial Decision should follow the final Commission order in these proceedings and be consistent therewith.

this decision, have been considered, and if not adopted, are rejected.

It is so **ORDERED**.

William J. Cowan
Presiding Administrative Law Judge