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VIA HAND DELIVERY

Mr. William M. Lambe
Antitrust Policy Analyst
U.S. Nuclear Regulatory Commission
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Dear Mr. Lambe:

I enclose a copy of the Answer of El Paso Electric Company and Central and South West Services, Inc. to Motions to Intervene as filed on March 21, 1994, with the Federal Energy Regulatory Commission. I understand from Bill Spears of CSW that you had requested a copy of this filing.

If you need any additional information from CSW in connection with this matter, please do not hesitate to call me.

Sincerely yours,

Timothy E. Flanigan
Counsel for Central and
South West Service, Inc.

Enclosure

cc: Roy P. Lessy, Jr., Esq.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

El Paso Electric Company and Central and South West Services, Inc.)	Docket No. EC94-7-000
Central and South West Services, Inc.)	Docket No. ER94-898-000 (Not Consolidated)

ANSWER OF
EL PASO ELECTRIC COMPANY AND
CENTRAL AND SOUTH WEST SERVICES, INC.
TO MOTIONS TO INTERVENE

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March 21, 1994

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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ANSWER OF
EL PASO ELECTRIC COMPANY AND
CENTRAL AND SOUTH WEST SERVICES, INC.
TO MOTIONS TO INTERVENE

Pursuant to Rule 213 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213 (1993), El Paso Electric Company (EPEC) and Central and South West Services, Inc. (CSWS) (collectively, "Applicants"[1]) hereby respond to the motions to intervene filed in the above captioned proceedings.[2]

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[1] Although the two dockets have not been consolidated, the two cases are interrelated. For ease of reference, this Answer refers to EPEC and CSWS as Applicants for both dockets, although Docket No. ER94-898-000 commenced with a filing made by CSWS alone. A list of the intervenors is attached as Appendix A. Applicants will not oppose the Commission's granting intervenor status to any person that has timely filed a request to intervene. However, the Commission should limit the participation of certain parties as discussed at note 75, *infra*.

[2] Applicants respectfully request that the Commission grant them leave to respond to intervenors' protests. Applicants' response will facilitate the decisional process and aid in the explication of the issues and the development of a full record. Cincinnati Gas & Electric Co. and PSI Energy, Inc., 64 FERC ¶ 61,237 at 62,709 (1993) (CINergy); Entergy Services, Inc. and Gulf States Utilities Co., 62 FERC ¶ 61,073 at 61,369 (1993)(Entergy); see also Transwestern Pipeline Co., 50 FERC ¶ 61,211 (1990); Natural Gas Pipeline Co. of America, 52 FERC ¶ 61,219 (1990); Buckeye Pipe Line Co., L.P., 45 FERC ¶ 61,046 (1988).

On January 10, 1994, Applicants filed their Joint Application for Approval of Merger and Disposition of Facilities (Application) in Docket No. EC94-7-000. Also on January 10, 1994, CSWS tendered for filing an Agreement to Amend the Restated and Amended Operating Agreement (Operating Agreement) among CSWS and the CSW Operating Companies[3], docketed as No. ER94-898-000, under which EPEC would become party to the Operating Agreement after the Transaction is completed and the transmission equalization provisions of the Operating Agreement would be revised. On January 13, 1994 and again on February 3, 1994, Applicants filed workpapers that underlie the testimony and exhibits of their witnesses Bruggeman, Hadaway, Hall and Harrell in Docket No. EC94-7-000.[4] Thirty-one parties intervened in Docket No. EC94-7-000, 13 of which have made substantive arguments regarding the Transaction. Eighteen parties intervened in Docket No. ER94-898-000, only one of which has expressed any specific concern.

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[3] The existing electric utility operating subsidiaries of Central and South West Corporation (CSW) are Central Power and Light Company (CPL), West Texas Utilities Company (WTU), Public Service Company of Oklahoma (PSO) and Southwestern Electric Power Company (SWEPCO). CPL and WTU operate in the Electric Reliability Council of Texas (ERCOT). PSO and SWEPCO operate in the Southwest Power Pool (SPP). EPEC operates in the Western Systems Coordinating Council (WSCC). CPL, WTU, PSO and SWEPCO are sometimes referred to herein as the CSW Operating Companies.

[4] Applicants distributed copies of their filings in these two dockets to all concerned state agencies and all other persons that the Applicants understood to be interested in these proceedings.

Predictably, the Applicants' request that the merger of CSW's subsidiary, CSW Sub, Inc., into El Paso Electric Company (EPEC) (the "Transaction") be approved has resulted in the regurgitation of all the arguments made in recent merger cases why a combination of two electric utility systems should not be allowed, at least without conditions that would advance the peculiar economic or competitive interests of their particular proponents. Indeed, one intervenor even questions Applicants' integrity based on the print date found on a few workpapers.[5]

What follows is a pleading that addresses in somniferous detail all the contentions that intervenors have thrown up in an effort to tie up, delay, and, if possible, prevent the Transaction from being completed and EPEC from emerging from bankruptcy. Applicants offer this detailed discussion in the belief that, under the relevant statutory standard, the issues raised in this particular section 203 proceeding are susceptible of resolution without having to engage in time consuming and expensive trial-type evidentiary hearings.

Southwestern Public Service Company's (Southwestern) efforts to limit the Commission's power under section 211, and to read the integration requirement of the Public Utility Holding Company

[5] Based on the unsupported conclusions of consultant Dr. Keith Berry, the Arkansas Public Service Commission (APSC) asserts that Applicants' credibility should be questioned because certain of the workpapers filed on February 3 show print dates that were later in time than January 10, the date on which Applicants made their original filings in these dockets. This matter is addressed in the affidavit of Mr. James A. Bruggeman, the Applicants' witness whose testimony and exhibits are based in part on the workpapers in question. See Appendix B.

the integration requirement of the Public Utility Holding Company Act in an unprecedented and restrictive manner so as to bar the Transaction, are plainly without merit, as are the strained efforts of Southwestern, the City of Las Cruces, New Mexico (Las Cruces) and others to identify competitive harms resulting from a merger of two utility systems that operate in separate, asynchronous interconnections and consequently have never been actual or potential business competitors in any material sense. Unable to make a serious, conventional showing of injury to competition, various of the intervenors nonetheless adopt the fall-back position that, if approved at all, the Transaction should be conditioned on the adoption of tariff modifications or other conditions having no clear nexus to the Transaction whose only apparent purpose is to strengthen the proponent's prospects.

Intervenors also call into question the extent of the benefits Applicants' careful analyses show are likely to result from the Transaction. A critical review of these contentions, as well as the intervenors' claims that the proposed accounting for the Transaction may be improper and that the purchase price is excessive, reveals the lack of merit in the intervenors' attacks.

Given this lack of merit, it is plainly appropriate for the Commission to adhere to its usual practice and proceed to a resolution of the issues presented without unnecessary delay. The discussion of the intervenors' contentions that follows will make clear that the information Applicants have provided the Commission constitutes a more than adequate basis for finding the

Transaction will enhance, not lessen, competition and will produce clear benefits to the public, not the least of which is the restoration of EPEC's financial strength and its emergence from bankruptcy.

While there are factual issues to be developed and resolved in connection with the related section 211 proceeding, they involve only the need to determine definitively the extent of the minor modifications that Southwestern must make to its system in order to provide the transmission services Applicants require, and the terms and conditions on which such service should be provided. The prompt resolution of these narrowly focused issues will not be aided by the involvement of the 31 parties that have sought to intervene in this section 203 proceeding and the process of promptly resolving such issues will not be enhanced by formal consolidation of this case with Docket No. TX94-2-000. As explained below, Applicants respectfully suggest that the best approach would instead be to find initially that the Transaction is likely to produce benefits to the public and will not lessen competition, but reserve final decision in this section 203 proceeding until the section 211 case is ready for entry of a final order.

THE MERGER SHOULD BE APPROVED BECAUSE IT CAN BE IMPLEMENTED AS PROPOSED IN A MANNER CONSISTENT WITH THE PUBLIC INTEREST

Under section 203 of the Federal Power Act (Act), the Commission is required to approve a proposed disposition of

jurisdictional facilities[6] if it finds that the transaction will be consistent with the public interest by creating economic efficiencies and by providing a vehicle for the emergence of EPEC from bankruptcy. Although Applicants are not required to do so, the Application they have filed demonstrates that the Transaction will result in a positive benefit to the public.[7]

In analyzing whether a proposed transaction is consistent with the statutory standard, the Commission has considered the following non-exclusive list of factors:

1. the effect of the merger on the operating costs and rate levels of the merging utilities;

2. the contemplated accounting treatment;

3. the reasonableness of the purchase price;

4. possible coercion of the acquired utility by the acquiring entity;

5. the effect of the merger on competition; and

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[6] 16 U.S.C. § 824b(a)(1988). This case involves what the Commission has previously characterized as the disposition of indirect control over EPEC's intrastate transmission facilities. See CINergy, 64 FERC ¶ 61,237 at 62,710-11.

[7] Pacific Power & Light Co. v. FPC, 111 F.2d 1014, 1016 (9th Cir. 1940). Rather, Applicants are only required to disclose all material facts and to show that the Transaction will be consistent with the public interest. Entergy, 64 FERC ¶ 61,001 at 61,370. As the Commission has recently explained, "consistent with the public interest does not connote a public benefit to be derived or suggest the idea of a promotion of the public interest." CINergy, 64 FERC ¶ 61,237 at 62,709 n.274. Instead, the Commission understands the statutory standard "to mean that the proposed merger does not harm the public interest." Entergy, 65 FERC ¶ 61,332 at 62,473. Furthermore, consistency with the public interest is to be determined on the basis of the Transaction considered as a whole. Northeast Utilities Service Co. v. FERC, 993 F.2d 937, 951 (1st Cir. 1993).

6. the effect of the merger on the effectiveness of regulation at the state or federal level.[8]

None of the intervenors contends that the Transaction was the result of coercion or that the Transaction would impair the effectiveness of state or federal utility regulation. The intervenors' claims regarding the other factors are insubstantial and raise no disputes as to material facts requiring a hearing in these dockets.

I. Notwithstanding Southwestern's Claims To The Contrary, Applicants' Plan Of Operations Can Be Lawfully Implemented

Southwestern argues that Applicants' plan to integrate the operations of the CSW Operating Companies and EPEC using Southwestern's transmission system cannot be accomplished because the Commission cannot lawfully order Southwestern to provide transmission service to Applicants and because the SEC will not permit the Transaction to be accomplished by using transmission service purchased from Southwestern to coordinate Applicants' power supply operations. These objections are unfounded.[9]

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8 Commonwealth Edison Co., 36 FPC 927 (1966), aff'd sub nom. Utility Users League v. FPC, 394 F.2d 16 (7th Cir.), cert. denied, 393 U.S. 953 (1968).

9 Southwestern continues to exaggerate what is required by Applicants' request for transmission service. Southwestern has built a transmission system that is designed to move Southwestern's 4062 MW of generating capability to its 3370 MW of peak load. The maximum amounts of power that Applicants would move across Southwestern's system (133 MW) represent less than 5% of Southwestern's system capability measured in these terms. In addition, Applicants have made plain that service to them would be subject to interruption to ensure reliable service to Southwestern's native load.

A. The Commission Has The Authority Under Section 211 To Order The Requested Transmission Service

Southwestern's contention that Applicants cannot operate as planned simply repeats arguments made by Southwestern, and addressed by Applicants, in Docket No. TX94-2-000.[10] Here the gossamer nature of Southwestern's argument is plainly revealed in the succinctness with which it is now stated -- that the Commission cannot order the service because it is for an indefinite period. Southwestern continues consciously to ignore Applicants' repeated statements of their willingness to enter into a long-term contract having a stated term.

However, as thin and wispy as its arguments are, Southwestern's continued refusal to agree to provide the requested services and enter into good faith negotiations regarding the terms on which those services will be provided creates uncertainty with regard to the Transaction. This uncertainty can only be resolved by the Commission's promptly ruling that it has the authority to order Southwestern to provide the requested services and putting in place a process which will produce an engineering determination of what additions to Southwestern's system, if any, will be needed to equip it to provide the requested services and a determination of the rates

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[10] Docket No. TX94-2-000 is the proceeding that commenced with the filing by Applicants of an application pursuant to section 211 of the Act asking that the Commission direct Southwestern to provide certain transmission services in connection with Applicants' post-merger operations.

and terms that should govern the provision of such services. This is not an unmanageable task.

B. Southwestern Has Failed To Justify The Need For Extensive System Improvements

With its motion, Southwestern has for the first time offered a definitive list of the internal system improvements that Southwestern asserts are necessary if it is to provide the transmission services that Applicants have requested.[11] With the exception of a proposed upgrade to Southwestern's Eddy County 230/115 kV transformer, Southwestern's studies do not show that the modifications on its list are required to provide service to Applicants. As explained by Mr. Harrison K. Clark in the affidavit attached as Appendix C, the contingencies Southwestern proposes to address with the system modifications Mr. Fulton has identified would result in only minimal overload conditions that are well within the emergency limits commonly accepted in the industry.[12]

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[11] The list is attached to Southwestern's motion as Exhibit JSF-3 to the affidavit of John S. Fulton and is based on new studies that Southwestern has recently completed, the results of which are also attached to Mr. Fulton's affidavit as Exhibit JSF-4.

[12] Southwestern contends that a transformer at its Gray County interchange should be upgraded because of an indicated overload of .2% but, as Mr. Clark explains, Southwestern rates its transformers at only 85% of their continuous ratings. Likewise, Southwestern asserts that the Potter County and Yoakum County lines overload at the time of Winter Peak but appears to base this conclusion on the summer rating of the lines in question. If the Winter thermal ratings of these lines are higher, a study based on Winter ratings may show no overload. These kinds of questions would be best addressed in the technical conferences Applicants have asked the Commission to order in Docket No. TX94-2-000.

The following table lists the system upgrades Mr. Fulton has identified as needed, the cost associated with each modification and the maximum loading on the facility indicated in Southwestern's studies:

Upgrade	Cost	Maximum Overload Percentage
Cunningham Plant Transformer	$2,000,000	None Shown
Eddy County Transformer	$2,000,000	23.9%
Gray County Transformer	$700,000	.2%
Potter County-Harrington Line Rebuild	$1,540,000	3.4%
Yoakum County-ODC Line Reconductoring	$630,000	0%
Osage-Canyon East Line Reconductoring	$510,000	2.2%

As the table indicates, and as Mr. Clark explains in his affidavit, only the Eddy County transformer upgrade is conceivably essential to Southwestern's providing Applicants the services they seek. Applicants have already agreed that an upgrade of the Eddy County transformer may be required.[13] At a carrying charge rate of 16%, the annual carrying cost for the Eddy County upgrade would be $192,000. Mr. Clark concludes that

[13] Southwestern would address the possibility that the Eddy County transformer could be overloaded in certain events by replacing it with an entirely new transformer having greater capacity at an estimated cost of $2 million. SPS, Exhibit JSF-3. Applicants would instead replace a transformer bank in the existing facility to achieve the same end, but at a cost of only $1.2 million. In any event, as Mr. Clark notes, because the overload indicated in Southwestern's studies is measured with respect to a rating that is only 85% of the manufacturer's top rating for the facility, further analysis must be made to determine whether any change in such equipment is actually needed.

the other "overloads," if that is what they are, can be addressed in less costly ways.

Of course, Southwestern continues to insist that a new interconnection with PSO or another SPP utility is needed if the service is to be provided. However, Southwestern has yet to produce anything to support this claim other than anecdotal reports of its unreliable operations before 1984 when Southwestern's 345 kV tie to PSO was completed. Applicants' studies show that Southwestern can withstand the loss of this 345 kV tie or one of Southwestern's 550 MW coal-fired Tolk units (Southwestern's largest units) while moving 133 MW east to west to EPEC from PSO. Although Applicants' request for service was first made nearly a year ago and Southwestern has had the results of Applicants' stability studies since November 4, 1993, Southwestern has not yet produced studies of its own to show otherwise. Applicants agree that, in the event that one of these major contingencies were to occur, the level of transfers between the EPEC and PSO control areas may have to be reduced temporarily to protect Southwestern against the effects of a second contingency. These matters can be covered by operating procedures, however, and do not require the expenditure of tens of millions of dollars.

It is not the existence of these disputes but only the failure to resolve them that will impede Applicants' plan of operations. Southwestern does not seriously contend that it is unable to provide the services Applicants have requested. Hence,

the only issues that must be addressed in the section 211 case are: (1) what upgrades to Southwestern's transmission facilities and those of Applicants' will be required for the service provided to Applicants; and (2) on what terms should Applicants compensate Southwestern for the uses of Southwestern's system they are permitted to make.[14]

These issues need to be addressed. But these are primarily questions raised in Docket No. TX94-2-000 and do not require the participation of 31 parties to resolve. It is clear that the requested transmission services can and should be ordered, following an expedited resolution of the remaining technical issues. The terms of service should be established by negotiation following the process the Commission has ordered in

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[14] Southwestern seeks to inject a third issue by arguing that there is something otherwise improper about Applicants' reservation of a 133 MW path over Southwestern's system in order to optimize their economic dispatch. Shorn of the veils that surround it, this is essentially a plea that all Eddy County tie capacity not needed by Applicants on a firm basis should be "ceded" to Southwestern, thereby giving it nearly complete control of all transfer capability between WSCC and the SPP. Such a claim by Southwestern is fully answered by the *pro forma* EPEC open access transmission tariffs that are attached to Mr. Shockley's testimony. Under those tariffs, Southwestern is an Electric Utility that is entitled to service, in accordance with the terms and conditions thereof, including use of the Eddy County tie. Exhibits (TV-5) APP-6 and (TVS-6) APP-7. See text at note 37, *infra*. However, just as Applicants understand that their use of Southwestern's transmission system must take a backseat to preserving Southwestern's ability to cope with system emergencies, EPEC's Eddy County tie is important to EPEC's ability to provide reliable service to its customers and there may be times when problems on the New Mexico grid or the outage of EPEC's remote generating capability require interruption of firm transmission service on EPEC's transmission system to preserve EPEC's ability to serve its native load customers.

the Florida Municipal Power Agency[15] and Minnesota Municipal Power Agency[16] cases. As explained later, after the section 211 issues have been resolved in that Docket, the Commission can factor the results into its final decision under section 203.

C. Applicants' Proposed Plan For Integration Of EPEC And CSW Is Consistent With The Requirements Of PUHCA

Southwestern also claims that Applicants "cannot permissibly" meet the integration standards of sections 2(a)(29)(A) and 10(c)(2) of the Public Utility Holding Company Act (1935 Act) "by way of Southwestern's transmission system."[17] There is nothing impermissible about Applicants' proposal to meet the 1935 Act's integration standards by interconnecting through Southwestern.[18]

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15 Florida Municipal Power Agency v. Florida Power & Light Co., 65 FERC ¶ 61,125 (1993).

16 Minnesota Municipal Power Agency v. Northern States Power Co., 66 FERC ¶ 61,114 (1994).

17 SPS at 54.

18 There are other alternatives that also are economically prudent in light of the estimated $422 million of merger benefits which are projected to result from Applicants' merger in the first 10 years of post-merger operations alone. Moreover, even if transmission through Southwestern were unavailable, the 1935 Act's integration standards only require that Applicants be "capable of physical interconnection" and Applicants may therefore satisfy the integration standard by proposing to build or otherwise contract for transmission capacity. See Panhandle Eastern Pipe Line Co. v. SEC, 170 F.2d 453 (8th Cir. 1948) (gas utility divestiture applying section 2(a)(29)(B)) (in considering section 11 plans of public utilities, the Commission is not limited to considering only the presently existing system in determining the retainability of other properties, but may consider the effects of future construction in determining the propriety of a proposed plan of compliance). In another case,
(continued...)

Section 10(c) of the 1935 Act provides that the Commission may not approve any acquisition of securities or utility assets unless it finds that (i) such acquisition will not be detrimental to the carrying out of section 11 of the 1935 Act (which addresses the integration and simplification of holding company systems), and (ii) the acquisition will "serve the public interest by tending toward the economical and efficient development of [an] integrated public utility system."[19] Section 2(a)(29)(A) of the 1935 Act defines the term "integrated public utility system" for electric utility companies as follows:

> [A] system . . . whose utility assets, whether owned by one or more electric utility companies, are physically interconnected or capable of physical interconnection and which under normal conditions may be economically operated as a single interconnected and coordinated system confined in its operations to a single area or region, in one or more States, not so large as to impair (considering the state of the art and the area or region affected) the advantages of localized management, efficient operation, and the effectiveness of regulation.[20]

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[18](...continued)
the SEC determined that engineering studies and testimony showing the feasibility of direct interconnections among four small systems (which were then indirectly connected) satisfied the "capable of physical interconnection" requirement of the 1935 Act where the record indicated that the system would be planned and operated on a unified basis. New England Elec. Sys., 38 SEC 193, 198-99 (1958), citing Cities Serv. Power and Light Co., 14 SEC 28 (1943).

[19] See, e.g., Electric Energy, Inc., 38 SEC 658, 664 (1958).

[20] 15 U.S.C. § 79b(a)(29)(A) (1988) (emphasis added).

The SEC has held on several occasions that the interconnection requirements of the 1935 Act may be satisfied by a contract path between merging systems over the lines of other utilities, even though the merging parties do not own the path. Indeed, the SEC has specifically found that direct interconnection is not required in circumstances which would have resulted in an uneconomic duplication of transmission facilities.[21]

By contracting for transmission service provided by Southwestern, Applicants will be sufficiently interconnected to satisfy the requirements of section 2(a)(29). This Commission will assure that Southwestern is properly compensated for the service it is asked to provide and Southwestern will hardly be required to "cede its transmission system"[22] to Applicants' use. Moreover, Southwestern's allegation that Applicants are "distant

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[21] Electric Energy et al., 38 SEC at 669-670; see also Cities Serv. Power and Light Co., 14 SEC 28, 53 n.44 (1943) (two companies within the same holding company are interconnected because energy between the two separated parts could be transmitted over a third party's transmission line pursuant to a contract among the parties); Northeast Utilities, 47 SEC Docket 1270, 1285 (1990) (systems within same power pool are interconnected through a contract right to use a third party's transmission line); Centerior Energy Corp., 35 SEC Docket 769 (1986) (two systems separated by third system's territory are interconnected both by a transmission line through all three territories in which each system owned the portion of the line within its territory and by a power pool arrangement through which transmission capacity was available so long as its use did not materially interfere with intra-power pool transactions). See also Environmental Action, Inc. v. SEC, 895 F.2d 1255, 1263-64 (9th Cir. 1990), citing Centerior Energy, 35 SEC Docket 769 (1986).

[22] SPS at 9.

systems" some "300 miles apart" requiring "extraordinary, extensive and pervasive, long-distance transmission service to integrate their systems"[23] is specious given the present state of the art of central dispatching operations within large systems.[24]

II. The Transaction Will Enhance Rather Than Impair Competition

In keeping with tradition in cases of this sort, several intervenors assert that the Transaction will lessen competition. However, nearly all the "competition" arguments that Southwestern and others advance relate to facts, such as EPEC's ownership of currently uncommitted transfer capability between the WSCC and the SPP and its geographic location adjacent to Ciudad Juârez, Chihuahua, Mexico, that would exist even if EPEC had not agreed to become a CSW subsidiary. These circumstances have no

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[23] SPS at 55-56.

[24] In the Matter of American Electric Power Company, Inc., SEC Rel. No. 20633, July 21, 1979, SEC LEXIS 1103, LEXIS pp. 21-26 (SEC ruled that sections 10(b)(1) and 10(c)(2) of the 1935 Act "require the Commission to exercise its best judgment as to the maximum size of the holding company in a particular area, considering the state of the art and the area or region affected. . . [T]he determination of whether to permit enlargement of a system by acquisition is to be made on the basis of all circumstances, not on the basis of preconceived notions of size." The Commission noted in particular the changes in technological capabilities since 1935: "Under the conditions prevailing in 1935, there was no strong economic or technical need for grouping a large number of local utilities under one holding company, nor were there pre-1935 systems organized on any such basis. But now there are technological justifications for large systems spanning many states.") See Centerior Energy Corp., 35 SEC Docket 769, 771 (1986) (section 10(b)(1) of the Public Utility Holding Company Act "allows the Commission to exercise its best judgment as to the maximum size of a holding company in a particular area, considering the state of the art and the area or region affected.").

relevance to the Commission's review of the Transaction because they will not be changed by the Transaction.[25]

Most of the intervenors' competition arguments, and most particularly those of Southwestern and Las Cruces, are put forward to secure more favorable competitive positions for their proponents than their respective circumstances would otherwise allow. Such claims for individual competitive entitlements should be regarded skeptically, particularly in the electric utility industry.[26] It is injury to competition with which the Commission should be concerned, not potential injury to individual competitors.[27]

In support of their Application, Applicants presented the testimony, exhibits and workpapers of Dr. George R. Hall. Having followed the analytic paradigm laid out in the Commission's recent Entergy and CINergy decisions to assess the competitive effects of the Transaction, Dr. Hall concluded that the Transaction would not reduce competition with respect to the "products" and "markets" the Commission historically has examined

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[25] Entergy, 64 FERC ¶ 61,001 at 61,073 ("Any remedy imposed [in a section 203 proceeding] must be limited to the nexus between the merger application and the alleged anticompetitive harm").

[26] See Town of Concord v. Boston Edison Co., 915 F.2d 17, 21-22 (1st Cir. 1990) (where regulatory and antitrust schemes co-exist, competitive analysis must be sensitive to the distinctive economic and legal setting of the regulated industry to which it applies), cert. denied, 499 U.S. 931 (1991).

[27] Brown Shoe Co. v. United States, 370 U.S. 294, 320 (1962); see Brunswick Corp. v. Pueblo Bowl-O-Mat, Inc., 429 U.S. 477, 488-89 (1977).

to determine whether a merger would enhance or create market power. Dr. Hall further and rightly concluded that the Transaction will not injure competition in any market and that the Transaction will instead enhance competition by increasing the options potentially available to participants in the bulk power markets of the southwestern United States. No intervenor has presented an analysis that effectively challenges this conclusion.

The Transaction is an end-to-end merger that will not result in the aggregation of control over any competing transmission paths. In this respect, the Transaction bears a strong resemblance to UtiliCorp's acquisition of Centel's electric properties. After examining the competitive implications of that acquisition, the Commission observed:

> The merging companies do not appear to own or control any competing transmission paths. There is no evidence that the merger will consolidate control on any transmission lines or interconnections along any valuable trade corridors. In sum, we find no evidence that the changes in transmission ownership will enhance the merged company's ability to raise prices or exclude competitors, either generally or along any specific transmission path.[28]

The Commission should reach the same conclusion here. The Applicants are separated by Southwestern, a utility that has refused to provide transmission service across its system in the

[28] UtiliCorp United, Inc., 56 FERC ¶ 61,031 at 61,122.

past.[29] Thus, Applicants have not competed either in the provision of transmission services or in the sale of power. Hence, the Transaction will not bring under common control former competitors or deprive other bulk-power market participants of an alternative choice of power suppliers or transmission services formerly available to them.[30]

Nevertheless, Southwestern, Las Cruces and American Forest and Paper Association (AFPA) assert that EPEC's control over the "uncommitted" capacity in the Eddy County tie makes it both a monopolist and a monopsonist. As already explained, the Transaction will not give EPEC control over the Eddy County tie. Nor will it deprive Southwestern of any entitlement to the direct or indirect use of the tie.[31] Quite the contrary, because EPEC

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[29] See Appendix D.

[30] See Entergy, 62 FERC ¶ 61,073 at 61,374 (loss of Gulf States as an independent competitor will not adversely affect competition because "present competition between the two systems is . . . de minimis"). The only actual or potential competition between Applicants has been for the purchase and sale of economy energy in transactions with Southwestern. In post-merger operations, Applicants will continue to offer to sell economy energy supplies to, and to purchase economic energy from, Southwestern. Indeed, the Transaction is likely to lead to increased energy trade with Southwestern because, after the Transaction is completed, CSW intends to have EPEC become a member of the Western Systems Power Pool (WSPP), in which PSO and SWEPCO have been active participants.

[31] As stated in their Application, Applicants intend to honor their coordination agreements. Hence, Southwestern will retain its opportunity to sell 50-75 MW of power to EPEC in support of EPEC's sale to Comision Federal de Electricidad (CFE). Professor Kalt argues that EPEC cleverly designed the arrangements under which EPEC purchases power from Southwestern to cover EPEC's sale to CFE to extract monopoly rents. In fact, EPEC first negotiated the sale with CFE, with whom EPEC has a

(continued...)

will offer transmission service over the Eddy County tie once the Transaction is consummated, any market power EPEC now has by virtue of its ownership of those transmission facilities will be lessened and competition will be enhanced.

A. The Transaction Will Not Result In The Exercise Of Monopsony Power By Applicants

Southwestern's witness Professor Kalt argues that the Transaction "warrants extremely close scrutiny and possible remedial conditions" because, in his view, the Transaction will

[31](...continued) longstanding operating relationship, based on the same costs of service that underlie the rates at which EPEC sells power to Imperial Irrigation District (IID) and Texas-New Mexico Power (TNP). (EPEC's average revenue from its 1992 sales to CFE, TNP and IID were $42.84 per MWH, $42.11 per KWH and $47.84 per MWH, respectively.) The negotiations began when CFE informed EPEC that CFE planned to upgrade that part of its transmission system with which EPEC was interconnected from 69 kV to 115 kV. This meant that, unless EPEC also increased the voltage of its facilities that interconnected with CFE, CFE and EPEC would become separated. Because CFE saw the benefit in maintaining its interconnections with EPEC, CFE agreed to purchase firm power from EPEC at rates that would support the cost of EPEC's transmission line upgrades. After the sale had been negotiated, EPEC went into the market to purchase power from other utilities in order to assure its ability to fulfill its obligations to CFE. Southwestern offered to sell EPEC power at Southwestern's standard partial requirements rate, the same rate at which Southwestern sells power to TNP. Because Southwestern refused to provide the required wheeling, EPEC was precluded from buying less expensive power from PSO. See Appendix D. EPEC refused to provide transmission service to Southwestern in 1990 because the compensation that Southwestern offered would not have allowed EPEC to recover on a timely basis the costs of the system expansion that would have been required. Moreover, Southwestern's compensation offer would not have covered the control area and back-up services that EPEC would have been required to provide to support Southwestern's proposed sale to Mexico.

"create problems of monopsony market power" for Southwestern.[32] This argument rests on false premises and a theory that is both irrelevant and improperly applied to the facts presented in this case.

First, both Professor Kalt and Southwestern's counsel imply, but never explicitly state, that Southwestern will have large amounts of uncommitted capacity for sale in the short-run capacity market (1998) Professor Kalt purports to test for the presence of market power, and will be aggressively looking for buyers. Southwestern goes so far as to state that Dr. Hall's finding (shown in Exhibit (GRH-9) APP-101 at 2) "that Southwestern will soon have no uncommitted capacity is flatly in error."[33]

Based on Southwestern's DOE Form 411 report filed in 1993 and the data Southwestern supplied to SPP for that purpose, Dr. Hall found that, after reducing Southwestern's nameplate generating capability for the 15% capacity reserve (18% planning reserve) necessary to satisfy the basic SPP planning guidelines, Southwestern would be 92 MW short in 1998.[34]

Southwestern does not dispute the accuracy of information Southwestern provided to the SPP, which was subsequently reflected in the DOE Form 411 Report on which Dr. Hall relied for his market analysis. Nor does Southwestern seek to explain how

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32 SPS, Kalt Aff. at 40.

33 SPS at 22 n.2.

34 Exhibit (GRH-7) APP-99 at 1.

or why Dr. Hall was "flatly in error." Curiously, on February 25, 1994 (the day on which Southwestern filed its motion to intervene in Docket No. EC94-7-.000), Southwestern sent to the Public Utility Commission of Texas (PUCT) a Load and Capacity Forecast that contains data that reveal that Southwestern will be capacity short by 207 MW in 1998 (based on the assumption Southwestern maintains the basic 15% capacity margin[35] (18% reserve margin) required by SPP guidelines). See Appendix E. In short, Professor Kalt's complaint that Applicants will bottle up Southwestern as a seller of uncommitted capacity in the short run has no practical import. Southwestern's own data show that it will have no capacity for sale.

Professor Kalt's argument is also built on another false premise -- that Applicants will not allow Southwestern to use EPEC's transfer capability in the Eddy County tie that is not otherwise being used for firm power transfers. According to Professor Kalt:

> The CSW/EPE system integration plan directly implies that CSW/EPE intends to claim and control its entire 133 MW capacity of the

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[35] The materials that Southwestern filed with the PUCT suggest that Southwestern may now be planning its system expansion on the basis of a 13% capacity margin (15% reserve margin). If that is the case, then Southwestern would be capacity short by 104 MW in 1998, as Appendix E also demonstrates. Whether Southwestern can properly make claim to a 13% capacity margin is a matter of some doubt because SPP guidelines require that a loss of load probability (LOLP) of once in ten years be established before the lower capacity margin may be used. It appears that Southwestern's claim to the lower capacity margin is not based on a LOLP study, but on some sort of "reliability index" that records interruptions of deliveries to end-use customers. See SPS, Exhibit DTH-3 at 2.

> Artesia interconnection for itself because CSW/EPE intends to reserve 133 MW of firm, bi-directional transmission capacity on SPS through its [sic] Section 211 plan.[36]

This *is* flatly wrong. Under EPEC's pro forma open access transmission tariffs (attached to Mr. Shockley's testimony as Exhibits (TVS-5) APP-6 and (TVS-6) APP-7), Southwestern is an Electric Utility that is entitled to make application for service. Despite Southwestern's attempts to mischaracterize the nature of the service provided under the EPEC tariffs, transmission service through the Eddy County tie will be made available in accordance with the proposed tariff terms.[37] Moreover, under Section 6.6 of the Firm Tariff, if necessary, EPEC will redispatch its system in order to free up transmission capacity for use by others. As Southwestern suggests, in post-merger operations Applicants intend to deploy the Eddy County tie in the economic dispatch of the CSW System. However, under the proposed EPEC firm transmission service tariff, EPEC's dispatch

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[36] SPS, Kalt Aff. at 22.

[37] Section 1.34 of the Firm Tariff defines Transmission System to exclude EPEC's transmission facilities related to its remote generating stations, Four Corners and Palo Verde, because those facilities are not a part of EPEC's core transmission system. However, the definition does not exclude the Eddy County tie or the related AC facilities. To avoid any possibility of confusion, EPEC will amend its pro forma tariffs to specify that the Eddy County tie and the related 345 kV line to EPEC's Amrad substation are included in the definition of Transmission System.

order can be changed to permit Southwestern to sell even more capacity into the WSCC (assuming it has any to sell).[38]

Professor Kalt attempts to buttress his argument that the post-merger CSW system will exercise monopsony power over Southwestern as a seller by constructing a market share/HHI table similar to those that the Commission routinely uses in assessing the monopoly power of particular utilities. According to Professor Kalt,

> [t]he relevant market appropriate to the assessment of monopsony market power in SPS's market consists of the buyers that could realistically and independently register their demands with SPS.[39]

This definition has serious theoretical difficulties,[40] but Professor Kalt compounds his error by improperly calculating market shares in the market he defines.

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38 This case is clearly distinguishable from Pacific Gas & Electric Co., 53 FERC ¶ 61,145 (1990), cited by Southwestern. There, the Sacramento Municipal Utility District had only one outlet for its uncommitted capacity -- into PG&E's system -- and no assurance that PG&E would transmit SMUD's excess capacity to a third party. Id. at 61,504. Here, Applicants have already offered, or will offer if the Transaction is completed, Southwestern access to the east into SPP and to the west into WSCC.

39 SPS, Kalt Aff. at 24.

40 Professor Kalt's market definition obviously overlooks the fact that Southwestern is not the only seller in any properly defined geographic market. If it were, Southwestern would be a monopolist. In Northeast Utilities, Professor Kalt submitted testimony for Northeast Utilities. Professor Kalt made clear that a market examination for monopsony must consider all competing sellers and substitute products and not just a single seller as Professor Kalt does here. Professor Kalt testimony, Northeast Utilities, Docket No. EC90-10-000 (filed March 1990) at 17-18.

Professor Kalt claims he is measuring demands that can be registered with Southwestern as a seller of bulk power, but he consciously ignores demands that already have been effectively and independently registered with Southwestern in the form of existing contracts.[41] These include the 200 MW contract sale that Southwestern will make to Public Service Company of New Mexico (PNM) beginning in 1995, the 35 MW capacity sale Southwestern will make to Empire District Electric Company (EDE) beginning in 1996, and the 66 MW sale that SPS will begin making to Texas New Mexico Power Company (TNP) this year.[42]

Professor Kalt compounds this error by improperly attributing to the CSW System demands for power that certain ERCOT utilities are expected to have in 1998. This attribution is inappropriate for several reasons.

First, as Professor Kalt says himself,[43] a purchaser of power that is located two "wheels" away from a supplier cannot realistically be expected to register a demand for capacity with that supplier. Utilities operating in ERCOT do not operate on the "contract path" scheme of transmission service compensation

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41 See SPS, Hudson Aff. at 11, 13.

42 In addition, Professor Kalt fails to reflect in his calculation the 20 MW of uncommitted capacity in the 220 MW Blackwater HVDC interconnection between Southwestern and PNM that will be available to potential purchasers. Although PNM has no need to purchase additional capacity in 1998 to meet its planning requirements, that is not to say that PNM or some other utility that could reach Southwestern through PNM could not make use of the 20 MW of uncommitted capacity to purchase power from Southwestern's vaunted, low-cost generation.

43. SPS, Kalt Aff. at 13.

used elsewhere in the United States. Rather, ERCOT utilities pay and receive megawatt-mile compensation for impacts on their systems resulting from transmission transactions. Even assuming, *arguendo*, that, notwithstanding the ERCOT transmission arrangements earlier established by the Commission's orders in Docket No. EL79-8 and related cases, it would somehow be proper for an ERCOT purchaser to access capacity supplied by Southwestern by paying a single transmission service rate to the CSW System companies, it would be necessary for Southwestern's purchaser also to compensate other ERCOT utilities for transmission service, including most particularly, Texas Utilities Electric Company (TU Electric), whose system would be impacted by any transaction involving either of the two HVDC interconnections between ERCOT and the SPP. Hence, under Professor Kalt's own "one-wheel" rule, it is improper to count as effective CSW System demand for Southwestern's (non-existent) uncommitted capacity the power demands of other ERCOT utilities.

Second, Professor Kalt ignores the fact that in the short run adequate capacity is available from other ERCOT utilities in amounts more than sufficient to furnish the demands of ERCOT's capacity-short utilities. See Exhibit (GRH-7) APP-99 at pp. 3-4. Third, Professor Kalt overlooks the PUCT's recent directive to Houston Lighting & Power (HL&P) to consider means other than power purchases to address capacity shortfalls.[44]

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[44] Notice of Intent of Houston Lighting and Power Co., PUCT Docket No. 12138 (issued Dec. 22, 1993) (slip op. at 2-4).

Correcting for Professor Kalt's errors yields very different results than those set forth in his Table III-1. Instead of market shares for "effective CSW/EPE" demand of 66%, the post-merger CSW System would register an "effective demand" of only 13%. See Appendix F. For purposes of monopsony analysis, a market share at this level comes nowhere close to warranting competitive concern.[45] Moreover, even accepting Professor Kalt's definition of the wholesale purchase market, the Transaction results in no change in concentration.[46]

B. The Transaction Will Not Result In Monopolization By Applicants With Regard To Power Sales To Juàrez Or Any Other Market

Las Cruces and other intervenors assert a jumble of arguments suggesting that the Transaction will permit Applicants to exercise monopoly power in some (generally unspecified) market or markets. Applicants have already established, using the Commission's established framework for analysis, why there is no danger of monopoly power in any properly defined market.

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[45] See, e.g., Paul W. MacAvoy, Price Formation in Natural Gas Fields (New Haven: Yale University Press, 1962) (finding monopsony power only where largest buyer has market share of over 70 percent, and average buyer HHI of approximately 6,250); cf. U.S. Dept. of Justice & Federal Trade Comm. Statements of Antitrust Enforcement Policy in Health Care Area (Sept. 15, 1993) at 28 (establishing "safety zone" for certain group buying activities; where purchases represent 35% or less of the market total there is not likely to be any ability to force prices below competitive levels).

[46] As noted, Professor Kalt defines the market improperly for his monopsony analysis; HHIs calculated on a more meaningful basis are presented in Appendix G. These data show that the Transaction will not have any cognizable impact.

1. The Eddy County DC Tie Is Not An Essential Facility For Las Cruces

Las Cruces' argument that EPEC controls essential facilities and is using the merger to deny access to Las Cruces[47] fails to meet the well-established legal requirements for such claims.[48] There has been no showing that the Eddy County tie represents an essential facility for Las Cruces.[49] Las Cruces has not even attempted to demonstrate that access through EPEC's transmission system could not practically be duplicated. In fact, in connection with its bid to supply CFE's load growth in Juàrez, Southwestern proposed to construct new transmission lines to Mexico that would have run right by Las Cruces, and Southwestern has shown no reluctance to build transmission lines to serve other new markets. It recently constructed 132.8 miles of 230 kV transmission lines at an estimated cost of over $27 million in order to serve Cap Rock Electric Cooperative load that has been

[47] Las Cruces at 26.

[48] An essential facilities claim requires: (1) control of an essential facility by a monopolist; (2) a competitor's inability, practically or reasonably, to duplicate the essential facility; (3) the denial of the use of the facility to the competitor; and (4) the feasibility of providing the facility to the competitor. <u>MCI Communications Corp. v. AT&T</u>, 708 F.2d 1081, 1132-33 (7th Cir.), <u>cert. denied</u>, 464 U.S. 891 (1983). None of these requirements is satisfied here.

[49] Las Cruces cannot turn the Eddy County tie into an essential facility simply by claiming it represents the cheapest or most convenient access to bulk power. <u>See City of Anaheim v. Southern California Edison Co.</u>, 955 F.2d 1373, 1381 (9th Cir. 1992)("[T]he fact that the Cities could achieve savings at the expense of Edison and its other customers is not enough to turn the Pacific Intertie into an essential facility").

blocked out of TU Electric's ERCOT control area since February 1994.

More important, Las Cruces fails to recognize that the Transaction has nothing whatsoever to do with EPEC's dominion over its Eddy County transmission facilities. EPEC exercises that dominion now. All that the Transaction will change is that, after it is completed, EPEC will make its Eddy County tie facilities available for use by eligible Electric Utilities.

Las Cruces also advances a "monopoly leveraging" argument, suggesting that EPEC is using its control over transmission to secure its retail franchise monopoly over the distribution of power in Las Cruces.[50] This monopoly leveraging theory

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[50] Las Cruces has not established itself as a municipal utility capable of providing service to the public under New Mexico law. Under New Mexico law, to qualify as a municipal utility, an entity must own electric facilities and provide electric service to the inhabitants in its service area. See NMSA §§ 3-1-2 (Michie 1981 Repl. Pamp.), 3-24-1 (Michie 1993 Cum. Supp.), 62-9-1 and -6 (Michie 1993 Repl. Pamp.). Las Cruces has no facilities to provide electric service to the inhabitants presently. EPEC has not agreed to sell to Las Cruces EPEC's Las Cruces electric facilities. EPEC is the only public utility that holds a certificate of public convenience and necessity ("CCN") to provide electric service within Las Cruces. At most, Las Cruces has evidenced an intention to investigate electric service alternatives for itself and its inhabitants. It has not established that it has the authority under New Mexico law to prevent EPEC from offering service in competition with Las Cruces' distribution utility.

Holloman Air Force Base has issued an invitation for bids for the provision of retail electric service. In New Mexico, the provision of retail electric service by public utilities is governed by the New Mexico Public Utility Act (NMPUA), NMSA § 62-3-1 et seq. (Michie 1978, 1993 Repl. Pamp.) See also City of Alberquerque v. New Mexico Public Service Comm'n, 854 P.2d 348 (N.M. 1993). The NMPUA requires a utility to have a CCN in order to provide such service. EPEC holds the CCN to provide the (continued...)

necessarily assumes that EPEC otherwise lacks a legal right to serve Las Cruces under New Mexico law or would somehow be excused from having to provide service in the absence of the alleged control over transmission. This is not the case, however. As the Supreme Court of New Mexico recently reaffirmed, EPEC has a duty to continue to provide service to the residents of Las Cruces. EPEC's duty to serve will not be alleviated by the unilateral action of Las Cruces.[51] Even accepting Las Cruces' assumption that there should be free competition for its franchise, this is a matter of state law and policy in which the Commission should not engage.[52]

[50](...continued)
service which is the subject of the bid. EPEC has filed a lawsuit against the United States Department of the Air Force alleging that the Air Force's solicitation is contrary to federal law and constitutes unauthorized and unlawful agency conduct under the Administrative Procedures Act, 5 U.S.C. § 701 et seq. El Paso Electric Company v. United States Department of the Air Force, et al., No. Civ.-94-6-SC DS (D.N.M., filed Jan. 4, 1994). A final decision in this lawsuit will likely take several years to obtain.

[51] See City of Albuquerque, 854 P.2d 348 at 360 (municipality's power to grant rights to provide electricity to the public does not alter New Mexico Public Utility Commission's (NMPUC) "general and exclusive power" to authorize a particular provider to furnish service within a given territory). Until the NMPUC determines differently, EPEC will have the duty to continue to serve its Las Cruces customers. In re Public Service Co. of New Mexico, 127 PUR 4th 477, 490 (NMPUC 1991).

[52] 16 U.S.C. § 824k(g) ("No order may be issued under this Act which is inconsistent with any State law which governs the retail marketing areas of electric utilities").

2. The Transaction Will Have No Impact On Sales To Mexico

As explained by Dr. Hall, because of physical limitations associated with existing interconnections between Comision Federal de Electricidad (CFE), Mexico's national electric utility, and the United States, the CSW ERCOT Operating Companies "are not viable competitors for export sales to the Juàrez market that EPE currently serves."[53] Based on the affidavit of Professor Kalt, Southwestern argues there are no physical barriers that would prevent competition between EPEC and the CSW ERCOT Operating Companies.[54] Professor Kalt rests this conclusion on his review of a CFE system map that shows a plan to upgrade certain CFE lines that connect the Norte and Noreste regions before 1998. Based on these plans, Professor Kalt, a person with no disclosed engineering training, concludes that EPEC and CPL can compete to serve Mexican loads.

Although Professor Kalt has taken certain generating capability data from a 1991 report sponsored by U.S. DOE and its Mexican counterpart, Professor Kalt has apparently overlooked other important information contained in that report. Concerning EPEC's ties to CFE, the report states:

> Two 69-kilovolt lines currently connect the Juàrez, Mexico system and the El Paso, Texas system with an 80 megawatt bi-directional transfer capability. This transfer capability will increase to 150 megawatts when the two lines are uprated to 115

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[53] Exhibit APP-92 at p. 41, lines 21-23.

[54] SPS at 35-36, citing Kalt Aff. at 51-52.

> kilovolts as planned for the 1991 time frame. . . . Power transfers on the existing 69-kilovolt or planned 115-kilovolt systems require islanding portions of the El Paso or Juārez systems because of the asynchronous operation of the two [CFE and EPEC] systems.[55]

As to the ties between the CSW Operating Companies and CFE, the DOE Report finds:

> CPL and CFE used a system blocking scheme during the late 1970's. At one point, CFE had their Northeast Division isolated from the remaining part of their system and interconnected with ERCOT. The capacity of the interconnection was 120-150 megawatts. When CFE combined their major divisions into one system the ties to ERCOT were opened since they did not have capacity to perform adequately when the total CFE system and ERCOT were being operated in synchronism.
>
> The existing ties are now being used in an emergency mode where portions of either CFE or CPL and WTU can be blocked over to the other system in emergencies. For the future, it might be possible for CFE to isolate larger portions of its system to the ERCOT system on a continuous basis. To do this would require system studies to determine which portions of the CFE system would be best suited to be interconnected with ERCOT. The amount of load and generation blocked to ERCOT would depend upon both the liability created by the CFE system and the capacity of the ties.[56]

As to the probable future market for U.S. exports to CFE, the DOE Report concludes:

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[55] United States/Mexico Electric Trade Study, United States Department of Energy/Secretaria de Energia, Minas e Industria Paraestatal, March 1991 (DOE/IE0020P) at D-8 to D-9 (DOE Report).

[56] DOE Report at C-33.

> In addition, the electrical systems in U.S. regions bordering on Mexico do not operate in synchronism, with the exception of the Baja California region. Existing electrical system characteristics prevent synchronous operation absent significant investment in new transmission facilities. This condition inhibits significant increases in transfer capability through alternating current (AC) interconnections unless major portions of either U.S. utility or CFE electrical systems are isolated from normal supply sources during periods of trans-boundary transactions. <u>Therefore, most U.S.-Mexico electricity trade (with the exception of trade in the southern California-Baja region) through AC interconnections is limited to emergency and small economy transactions</u>.[57]

As Applicants have disclosed, CSW is considering the construction of a DC tie to Mexico that would allow it to export power without having to block load into CSW's system. It is also true that CFE is planning to upgrade the two transmission lines identified by Professor Kalt. However, the problems of transferring power exported by CPL to the region served by EPEC are not the result of limitations on transfer capability between CFE's Norte and Noreste regions. Rather, they result from a bottleneck within the Norte region in the vicinity of Monteczuma. The lines identified by Professor Kalt will strengthen transfer capability between the Norte and Noreste regions, but will do nothing to mitigate this north-south bottleneck which limits power flows north into Juàrez. <u>See</u> Appendix C. More important, Professor Kalt fails to address the fact that, due to the long distances between CPL's ties to CFE and the Juàrez subregion that

[57] DOE Report at 106 (emphasis supplied).

EPEC serves and the fact that the CFE system is comprised mostly of 230 kV lines, transfers over the 800 miles that lie between CPL's ties to CFE and CFE's Juàrez subregion would result in losses as high as 30%, thereby making any attempt to compete for load uneconomic. See Appendix C.

Finally, Southwestern states that Dr. Hall "falsely asserts ... there will be little opportunity for sales to Mexico in the future."[58] In so doing, Southwestern relies on a table Professor Kalt has contrived from data drawn from sources of two different vintages (both now out of date) purporting to show that CFE will rely on imports from "the EPEC gateway" of 78 MW in 1998 and of 77 MW from the "CSW Gateway in 1998."[59] Professor Kalt presents no basis for these conclusions and a careful reading of his affidavit shows that they are simply numbers that are used to fill the capacity shortfalls he has calculated for the combined Norte/Noreste regions.

At best, Professor Kalt's table is misleading. Not even CFE regards its Norte and Noreste regions as a single market.[60] Mr. Bruggeman's affidavit attached hereto as Appendix B shows that, based on the Samalayuca additions alone, CFE's Norte region will have adequate capacity to serve Norte region loads in 1998.

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[58] SPS at 34.

[59] SPS, Kalt Aff. at 49 (Table IV-3), and at 50 n.43.

[60] These regions are akin to the reliability councils that operate in the United States and they engage in their own separate planning and separately report their loads and resource plans.

Likewise, CFE's domestic power supplies will be more than adequate to serve the Noreste region in the years for which Professor Kalt presents data. The data Mr. Bruggeman presents demonstrate, and CFE personnel have confirmed, that CFE will not be depending upon imports of power from the United States to meet its Norte and Noreste region loads in the near future.

Professor Kalt's analysis also makes the implicit, but incorrect, assumption that CFE will be interested in purchasing electricity from Southwestern to fill the capacity shortfalls indicated in his table for 1998 because electricity produced by Southwestern will be cheaper than CFE's new gas-fired generation.[61] Professor Kalt and his client dismiss competing power supplies on the basis that Southwestern's <u>average</u> embedded cost of power is low. This overlooks the question whether it is proper for Southwestern to rob its native load and traditional wholesale requirements customers of the benefit of its coal-fired generation, a principal factor in the relatively low <u>average</u> cost of service of which Southwestern constantly boasts, to supply new load located in the service area of another utility or to supply off-system sales to CFE. That question does not have to be answered here, but it should be noted that Professor Kalt's conclusions as to the competitive prices that Southwestern can offer depend on an assumption that Southwestern can provide coal-fired energy to off-system purchasers, thereby increasing its average system costs, without complaint from its native load

[61] SPS, Kalt Aff. at 46-47.

customers or its state regulators. See SPS, Kalt Aff. at 42, Table IV-2.

In any event, Professor Kalt also fails to acknowledge that in 1998, Southwestern will have no capacity to sell. See Appendix B. Finally, Professor Kalt does not deny that recent experience as well as logic strongly suggest that CFE will meet its incremental capacity needs by constructing new capacity on the ground in Mexico and not by looking across the border for imports.[62] Indeed, CFE is preparing to solicit proposals for 700 MW of coal- or oil-fired generating capacity for the Juàrez subregion.[63] Curiously, Professor Kalt never explains how the Transaction or Applicants' interconnections with CFE would prevent Southwestern or its Quixx subsidiary from exporting their "superior" ability to construct and operate efficient and economical generating stations to Mexico and becoming the low-cost provider in Mexico as well.[64]

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[62] This makes sense because imports do not provide jobs for Mexican workers or new capital to the Mexican economy. Most important, new capacity, like the Samayaluca II project, is built under a build-operate-transfer regime which leaves CFE with title to efficient generating capacity after a stated period of years. The generators used by exporting U.S. utilities continue to be owned by those utilities, not CFE.

[63] Independent Power Report, Feb. 25, 1994 at 14-15 (McGraw-Hill). See Appendix H.

[64] Mr. Ridings, Vice President of Southwestern's non-utility subsidiary, Quixx Corporation, complains in an affidavit attached to Southwestern's motion that CSW declined to provide wheeling from, or to participate in the development of, a lignite-fired generating station located in central Texas. What Quixx sought from CSW was wheeling from the plant approximately 200 miles to the Mexican border for delivery to Mexican retail (continued...)

3. Intervenors Have Raised No Other Valid Monopoly Issues

Plains presents a calculation of southern New Mexico market shares using different data for PNM than PNM provided to Dr. Hall (and which PNM has not questioned here) and attributing to EPEC uncommitted capacity equal to EPEC's 133 MW share of the Eddy County tie.[65] Plains' analysis overlooks the fact that the Eddy County tie is committed in 1995 and 1996 to the import of 50 MW and 75 MW, respectively, by EPEC from Southwestern and also improperly excludes other uncommitted capacity controlled by other market participants shown on Exhibit (GRH-7) APP-99 at p.-5. Finally, Plains assumes that uncommitted capacity provided by PSO or SWEPCO would be a substitute for power sold by EPEC even though movement to or from a southern New Mexico utility other than EPEC would involve two "wheels" across the Southwestern and EPEC systems. A properly constructed analysis of the southern New Mexico market on which Plains focuses is set forth in Appendix I. This shows that EPEC will have no market power after the Transaction is completed.

AFPA challenges the Transaction's alleged potential to decrease competition "by giving CSW and its operating companies a

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[64](...continued)
industrial customers. CSW declined this opportunity, first, because it regarded the project as uneconomic and, second, because its policy was not to provide retail wheeling. The Commission should take note that the tale Mr. Ridings tells is one based upon his mental impressions for which no objective reference is provided.

[65] Plains at 11-12.

virtual 'lock' on the ability to supply the capacity needs of EPEC through the Southwest Power Pool (SPP) and to purchase power from and through EPEC."[66] In particular, AFPA expresses concern that QFs and other independent power producers that might offer lower cost power will be precluded from competing with the CSW-affiliated companies.[67]

AFPA's "favoritism" argument is a red herring: QFs have the right under law to force Applicants to purchase their output. If Applicants otherwise engage in internal transfers of power and energy because that is the least costly means of serving their customers, this is not "favoritism." It is appropriate market behavior, which should be encouraged.[68]

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[66] AFPA at 3.

[67] AFPA at 3-4. AFPA does not identify any relevant market for evaluating the Transaction, nor does it suggest that any specific members participate in such markets. Lacking such basic information, the Commission is in no position to evaluate AFPA's claims and they should be rejected. Entergy Services, Inc., 60 FERC ¶ 61,168, p. 61,617 (1992) ("Mere allegations of disputed facts are insufficient to mandate a trial-type hearing; rather, interested parties must make an adequate proffer of evidence to support them."), citing, City of New Orleans v. SEC, No. 90-1493 (D.C. Cir. July 17, 1992), slip. op. at 9 n.5; Cerro Wire & Cable v. FERC, 677 F.2d 124, 129 (1982); General Motors Corp. v. FERC, 656 F.2d 791, 798 n.20 (1981)). Tennessee Gas Pipeline Co., 26 FERC ¶ 61,144 (1984); see also, General Motors Corp. v. FERC, 613 F.2d 939, 945 n.12 (D.C. Cir. 1979).

[68] The fact that the Transaction may lower Applicants' avoided costs and thereby lower the price paid to QFs is no reason to find the Transaction is anticompetitive. AFPA's second argument -- that Applicants have sought transmission rights across the Southwestern system that competitors could obtain only by making their own section 211 request and that competitors are disadvantaged by this fact (AFPA at 5-6) -- is equally disingenuous. If AFPA's members have a problem obtaining access to Southwestern's transmission system they have Applicants'

(continued...)

Certain Transmission Dependent Customers on the Central and South West Corporation and Southwestern Public Service Company Systems (TDU Customers) advocate a "bigness is bad" line of argument that relies on polemics rather than an identification of specific markets in which specific customers will be damaged because bulk power prices have been increased above competitive levels.[69] Although the TDUs complain that they lack competitive alternatives, they never explain how their alternatives are lessened by the Transaction.

One of the few specific allegations made by the TDU Customers is that CSW would have "a monopoly of the means for interpool coordination" among SPP, ERCOT and WSCC.[70] This is not true for two reasons. First, Applicants will offer transmission services between these reliability councils under tariffs that have been filed with the Commission, or will be if the Transaction is consummated. Second, two other utilities have constructed and own transfer capability between WSCC and SPP, and TU Electric and HL&P will soon (1995) own and operate transfer capability between ERCOT and SPP. In any event, even if Applicants attempted to exploit their ownership of transfer capability between reliability councils to raise the price of

[68] (...continued)
sympathy, but they ought to take that problem up with Southwestern.

[69] TDU Customers at 14-15.

[70] TDU Customers at 13.

bulk power, their efforts would be quickly defeated by alternate suppliers who only deal in one or two coordination regions.[71]

The real problem that seems to be troubling the TDUs is the efficiency gains Applicants will obtain from the Transaction. CSW's ability to transfer power using all three coordinating regions should generate efficiency advantages. But this is procompetitive (i.e., beneficial to consumers, including those served by the TDUs) and should be encouraged.

C. None Of The Changes Intervenors Suggest Should Be Made To Applicants' Existing Or Proposed Transmission Service Tariffs, Nor Are Any Of The Other Conditions Requested Necessary To Assure That The Transaction Is Consistent With The Public Interest

1. The Applicants' Transmission Service Tariffs Are Consistent With Commission Precedent

Several intervenors contend that the Commission should condition approval of the Transaction by requiring the CSW Operating Companies to revise their filed transmission service tariffs. However, the intervenors making such claims have failed to demonstrate any nexus between anticompetitive harm resulting

71 The City of Brownsville, Texas similarly asserts that "neighboring utilities" (presumably including Brownsville in its roles both as CSW competitor and as a potential customer of CSW competitors) are competitively disadvantaged by not having the ability to operate in three reliability regions. Brownsville at 3. In particular, Brownsville cites the "isolation" of ERCOT. Brownsville at 3-4. Brownsville makes no suggestion that CSW is engaging in any monopolistic practices (e.g., artificially restricting supply) and ERCOT's "isolation" is a product of geography and regulation that has nothing to do with the Transaction. In essence, Brownsville too is arguing that it may be at a competitive disadvantage because a supplier/competitor has become more competitive. This is no basis for competitive concern but rather the type of activity that advances the public interest.

from the Transaction and the provisions of the transmission service tariffs they would change. Consequently, such claims should be rejected.[72]

The CSW Operating Companies have on file with the Commission transmission service tariffs under which they provide various transmission services within ERCOT or within SPP or "to, from and over" (TFO) certain high voltage direct current (HVDC) interconnections between ERCOT and SPP. These tariffs have their origin in proceedings before the Commission that were commenced in the late 1970s by the CSW Operating Companies in pursuit of an order of this Commission requiring the construction of such HVDC interconnections.

Those proceedings, which were brought under sections 210 and 211 of the Act, were concluded by settlement. Under the settlement, the CSW Operating Companies, TU Electric and HL&P were ordered to construct two HVDC ties between ERCOT and SPP, to interconnect with each other and to file certain transmission service tariffs described in a draft order approving settlement which was incorporated by reference in the Commission's orders approving the settlement.[73] That draft order required the CSW

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[72] Entergy, 64 FERC ¶ 61,001 at 61,013.

[73] Central Power and Light Co., et al., 17 FERC ¶ 61,078 (1981), reh'g, 18 FERC ¶ 61,100 (1982). Notably, the provisions of the draft order the Commission adopted obligated CSW to extend invitations every three years to other utilities to participate in expanding the HVDC interconnection. Every three years since 1984, CSW has extended the invitations; no one including Southwestern, who now complains so vigorously about the cost of entering ERCOT, has indicated any interest in owning additional (continued...)

Operating Companies that operate in ERCOT to file a TFO tariff and the two CSW Operating Companies that operate in the SPP to file a separate TFO tariff.

To meet the obligations imposed in the Commission's orders in Docket No. EL79-8, the CSW ERCOT Operating Companies, the CSW SPP Operating Companies, TU Electric and HL&P subsequently filed the TFO Tariffs required by the Commission's earlier orders. Those filings were set for hearing in consolidated proceedings docketed as Nos. ER82-545-000, et al.[74] Those proceedings, in turn, were resolved by settlement, which the Commission approved by order issued January 27, 1987.[75]

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[73](...continued)
HVDC capacity. Southwestern misread the provisions that set-aside 15% of East tie capacity for certain small utilities as indicating that TFO service is not available to utilities whose loads exceed 500 MW. SPS at 30. Service is available under the TFO tariffs to all Electric Utilities.

[74] Public Service Co. of Oklahoma, et al., 20 FERC ¶ 61,082 (1982).

[75] Texas Utilities Electric Co., 38 FERC ¶ 61,050 (1987). The parties to the settlement, including many of the TDU Customers, Brownsville and other intervenors present in this proceeding, agreed that in the future they would:

> not (i) contest any provision of the Commission's Orders in Docket No. EL79-8, . . . (ii) contest any provision of TUEC's, HL&P's or CSW's tariffs filed in settlement of Docket Nos. ER82-545-000, et al.;. . . .

Id. at 61,149, Ordering Paragraph 5(a). These provisions did not preclude parties from challenging rate increases. However, none of the signatories to this settlement who seek to intervene here, including Brownsville and most of the TDU Customer group, should be permitted to contest the provisions of the TFO tariffs in contravention of their earlier promises.

The Commission's orders in Docket No. EL79-8 also had required the CSW Operating Companies, but not TU Electric or HL&P, to offer tariffed transmission services within ERCOT and SPP, respectively. In 1993, PSO and SWEPCO, the two CSW Operating Companies which operate in SPP, filed in Docket No. ER93-938-000 new transmission service tariffs for transactions within the SPP, which superseded the intra-SPP tariffs they had originally filed to implement the Commission's orders in Docket No. EL79-8.[76] The Commission accepted the tariffs filed by PSO and SWEPCO by order issued November 8, 1993, in which the Commission required PSO and SWEPCO to make minor tariff modifications but rejected most of the criticisms of the tariffs which had been levied by Southwestern.[77] Now, in this case, Southwestern and AFPA have launched new assaults on the provisions of the PSO/SWEPCO "open access" tariffs, repeating some of the same criticisms earlier made by Southwestern and rejected by the Commission.

a. A "Single System" Tariff Is Inappropriate For Systems Crossing Asynchronous Power Pools

Southwestern asserts that the Commission should require Applicants to provide "open access transmission on all

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[76] The settlement agreement by which Docket Nos. ER82-545-000, et al. were concluded did not preclude changes in the PSO/SWEPCO's intra-SPP tariff.

[77] Southwestern Electric Power Co. and Public Service Co. of Oklahoma, 65 FERC ¶ 61,212 (1993) (PSO/SWEPCO).

subsidiaries of the post-merger company."[78] However, the earlier decisions on which Southwestern relies are inapposite.

As Southwestern suggests, in other cases involving holding company systems, the Commission has required such systems to offer transmission service on a "single system" basis, i.e. where the combined transmission systems of the constituent operating companies are offered to transmission users for a single average cost rate. However, in each of the earlier cases (involving the Southern Company, Entergy and Northeast Utilities) all system operating companies operated entirely within the Eastern Interconnection on a synchronous basis.

In stark contrast, the CSW Operating Companies operate partly in ERCOT and partly in SPP. As the Commission is well aware, the interconnections between ERCOT and SPP are asynchronous. In holding that the Southern Company system should provide transmission service over the transmission systems of all of its subsidiaries for a single-system, average cost rate, the Commission found that Southern's loadflow studies showed that any transmission service would affect the transmission facilities of all of its operating companies and that affiliated operating companies would provide reactive power for which the participating companies would recover costs. Because "all of the Southern companies are involved in providing the service at

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[78] SPS at 43.

issue,"[79] the Commission found that single system pricing was appropriate.[80] Because they are separated by HVDC ties, the transmission systems of the CSW ERCOT Companies do not respond to changes in loads and generation on the systems of the CSW SPP Operating Companies.

Of course, EPEC operates in the WSCC, whose only interconnections with SPP are also asynchronous. Furthermore, EPEC is separated from the other Applicants by the Southwestern "gap," over which the CSW Operating Companies have obviously no control and in respect of which they have no ownership rights.

Finally, unlike the circumstances present in the Southern Company, Entergy and Northeast Utilities cases, ERCOT utilities use an uncommon form of transmission service pricing, which is based upon measurements of the expected megawatt-mile impacts of particular transactions. An important part of the settlement of Docket Nos. ER82-545-000 was to assure the use of consistent pricing in ERCOT and it was for that reason, more than anything

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[79] Southern Company Services, Inc., 60 FERC ¶ 61,273 at 61,925-26 (1992); see also Southern Company Services, Inc., 55 FERC ¶ 61,173 at 61,555-57 (finding that use of a cumulative transmission rate was inappropriate and ordering use of a single system rate), reh'g denied, 57 FERC ¶ 61,093 (1991), aff'd, Alabama Power Co. v. FERC, 993 F.2d 1557 (D.C. Cir. 1993); Southern Company Services, Inc., 57 FERC ¶ 61,035, reh'g denied, 57 FERC ¶ 61,284 (1991), aff'd, Alabama Power Co. v. FERC, 993 F.2d 1557 (D.C. Cir. 1993). The Commission followed this reasoning in the Entergy and Northeast Utilities cases that followed. Entergy, 58 FERC ¶ 61,234 at 61,769 reh'g, 60 FERC ¶ 61,168 (1992); Northeast Utilities, 56 FERC ¶ 61,269 (1991).

[80] Fort Pierce Utilities Authority v. FERC, 730 F.2d 778, 784 (D.C. Cir. 1984) (single-system rate required only where two transmission systems form a single unified network).

else, that the settlement agreement obligated the signatories thereto not to challenge the settlement tariffs filed to conclude those proceedings.[81] In short, the factual underpinnings for imposition of single system pricing that existed in other holding company situations do not exist here. Furthermore, the Commission has earlier found that the paradigm established in Docket No. EL79-8 under which the SPP CSW Operating Companies offer a TFO tariff that is separate from the TFO tariffs offered by the CSW ERCOT Operating Companies, TU Electric and HL&P is fair and reasonable.

In any event, Southwestern cannot explain how the Transaction changes in any way its competitive options with respect to trading with ERCOT utilities. Before the Transaction, Southwestern had transmission access available under the TFO tariffs filed with the Commission. After the Transaction is consummated, Southwestern and others will continue to have access available under those tariffs. Thus, the Commission determined in Docket No. ER93-938-000 that:

> We will deny Southwestern's argument in this regard. Southwestern and all other electric utilities operating within ERCOT or the SPP, can obtain transmission service from the Companies (and their ERCOT associate operating companies) 'to, from and over' the DC facilities under the TFO Tariff. Accordingly, based on the facts of this case, particularly the terms of the ERCOT 211 settlement, we will not order the Companies

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[81] See 16 U.S.C. § 824k(k) (Commission should allow ERCOT utilities to use MW-mile pricing if practicable).

> to provide for such service under the instant tariffs.[82]

None of the intervenors has provided a reason why the Commission should reach a different conclusion now.

b. The PSO/SWEPCO Open Access Tariffs Have Been Accepted By The Commission And Need Not Be Reopened In This Proceeding

Much of AFPA's motion to intervene in this proceeding is dedicated to a belated collateral attack on the Commission's acceptance of the "open access" transmission service tariffs PSO and SWEPCO filed in Docket No. ER93-938-000.[83] None of AFPA's attacks has merit and they should be rejected.

AFPA contends that the provisions of the PSO/SWEPCO Firm Transmission Service Tariff, and the similar provisions of the *pro forma* firm transmission service tariff, which EPEC will file after the Transaction is consummated, that allow the transmitting utilities to seek compensation for "stranded investment costs," are anticompetitive.[84] This argument has been met and addressed by the Commission in Docket No. ER93-938-000:

> We will approve the stranded investment provisions. The Commission has permitted provisions to recover stranded investment costs incurred to serve wholesale customers,

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82 PSO/SWEPCO, 65 FERC ¶ 61,212 at 61,985.

83 Indeed, AFPA admits that it has not even read the tariffs it attacks. AFPA at 7 n.3.

84 AFPA at 7-8.

> if the costs are identified and recovered according to certain protective conditions.[85]

The stranded investment provisions of the tariff are not automatic in their application. They only permit the transmitting utilities the opportunity to seek compensation for stranded investment costs, subject to either agreement by the customer or Commission review. The Commission will of course have every opportunity to review stranded cost provisions in their application. If the application of the provisions has an unreasonable effect, Applicants are confident that the Commission will so find.[86]

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[85] PSO/SWEPCO, 65 FERC ¶ 61,212 at 61,983, citing Entergy, 60 FERC ¶ 61,168 at 61,631-33, and 63 FERC ¶ 61,025 at 61,153; Maine Public Service Co., 61 FERC ¶ 61,319 (1992), reh'g den., 62 FERC ¶ 61,226 (1993) (noting general receptivity to stranded cost recovery, as long as not inconsistent with governing contracts).

[86] The arguments made by Las Cruces that application of the stranded investment cost provisions in connection with transmission of power to serve a Las Cruces municipal utility system would be anticompetitive are clearly premature. Las Cruces at 15. First, there is no Las Cruces municipal utility in operation. Second, neither Las Cruces nor any supplier with a contract to serve a Las Cruces system has requested transmission service from the Applicants. In addition, Las Cruces' contentions that EPEC would have no stranded investment are specious. Las Cruces claims that because EPEC will be able to "sell" excess capacity to the CSW System, any stranded investment caused by the loss of Las Cruces retail load would be mitigated. Las Cruces at 16. Although EPEC will sell energy to its sister operating companies in the future, it is not clear that EPEC will be making "capacity" sales in a magnitude that would offset any loss of load if the Las Cruces municipal utility were to become a reality. The Commission cannot conclude without further analysis in the actual event that loss of Las Cruces load would not injure EPEC or its remaining customers. For that very reason, consideration of the application of stranded investment cost provisions to Las Cruces or a supplier to Las Cruces must await future events. However, approval of the Transaction and the end of EPEC's bankruptcy cannot await the development of such speculative ventures.

c. Southwestern's Repeated Challenges To The Reciprocity Provisions Of The PSO/SWEPCO And EPEC Open Access Tariffs Are Unrelated To The Transaction And Should Be Rejected

The criticisms Southwestern makes here (joined by Plains[87]) are the same criticisms made in the earlier proceeding. Although the Commission held open the door to Southwestern to raise its concerns regarding the reciprocity provisions in light of Applicants' request for approval of the Transaction, Southwestern does not even attempt to indicate the nexus between anticompetitive harm from the Transaction and the reciprocity provision. Here, the arguments asserted by Southwestern are no different than the arguments originally made. Southwestern's real complaint is that the reciprocity provisions in the Applicants' tariffs would frustrate Southwestern's obvious attempts to limit trade in bulk power services in the event Southwestern desired to take service under any of Applicants' tariffs. Southwestern's arguments should be seen for what they are and promptly rejected.[88]

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[87] Plains also suggests without explanation that EPEC should offer network service to mitigate the anticompetitive effects of the merger. In the first place, there will be no anticompetitive effects. Otherwise, network service is not required. See Entergy, 58 FERC ¶ 61,234, reh'g, 60 FERC ¶ 61,168 appeal pending, Cajun Electric Power Coop., Inc. v. FERC, et al., Nos. 92-1461, (D.C. Cir. filed Oct. 23 1992).

[88] As PSO and SWEPCO explained in Docket No. ER93-939-000, reliance on Northeast Utilities is misplaced. PSO/SWEPCO, 65 FERC ¶ 61,212 at 61,982 (1993). The same comment applies to Southwestern's rather obvious attempts to characterize Applicants past dealings with Southwestern as anticompetitive. For example, Southwestern asserts CSW wrongly offered transmission service in (continued...)

d. The Opportunity Cost Provisions Of The PSO/SWEPCO Tariffs Are Consistent With The Commission's Pricing Policy

AFPA also makes a belated attack on the provisions of the PSO/SWEPCO Firm Transmission Service Tariff that permit the collection of "opportunity costs" in certain circumstances.[89] When Southwestern raised similar concerns in the earlier proceeding, the Commission correctly found:

> We find that Southwestern's concerns are, for the most part, premature. The Companies have reserved until the filing of an actual service agreement all aspects of the proposed opportunity cost recovery except their: (1) commitment to implement the Commission's current transmission pricing principles (higher of average system or incremental costs with an expansion cost cap); and (2) their intention to operate

[88](...continued)
connection with a firm power sale Southwestern wished to make to Entergy under the WSPP permanent agreement at a rate of 6-7 mills/kwh, when the maximum non-firm rate under the PSO/SWEPCO tariff is 4.5 mills/kwh. Although Southwestern's lawyers act as "general counsel" to the WSPP, they fail to disclose that, under the WSPP rules, PSO and SWEPCO are entitled to separate wheeling rates that combined could far exceed the quoted rate for wheeling on the two systems. Furthermore, if Southwestern needed a lower rate to do the deal, one was available under the open access tariff. Similarly, Southwestern's charge that EPEC "refuses to honor" an "exchange agreement" between EPEC and Southwestern is totally false. This "exchange agreement" is embodied in Service Schedule D to the interconnection agreement between Southwestern and EPEC, which specifically provides: "Each party should be the sole judge of the conditions under which it is economic or practical for it to take Power Exchange Service hereunder." At the few times that Southwestern has requested exchange service (a service which is only offered in one direction, east to west), EPEC has not judged the circumstances to be beneficial or practical.

[89] AFPA at 8-13.

> during the construction period without an expansion cost cap.[90]

After requiring SWEPCO and PSO to modify the opportunity cost provisions in respects not material here the Commission approved those provisions, as it had done in earlier cases involving other public utilities. AFPA has presented no reason for a different conclusion. AFPA's criticisms are not of the tariffs but of the Commission's pricing policies. They should be seen as such and rejected.

e. Applicants' Tariff Provisions Regarding Third-Party Costs Have Already Been Found To Be Reasonable

However, AFPA is not wholly without originality. It suggests that the provisions of the tariff that require the electric utility requesting service to bear responsibility for making arrangements with, and bearing costs imposed by, other transmitting utilities are somehow unreasonable here, because to move power between the SPP and the WSCC one must cross Southwestern's "bridge."[91] The Commission has in other cases made clear that provisions of this sort are not unreasonable. In fact, the Commission has held that:

> Provisions of this type are common, and they are reasonable because they simply notify the customer in advance that it will bear primary responsibility for third-party transmission costs.[92]

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90 PSO/SWEPCO, 65 FERC ¶ 61,212 at 61,984.

91 AFPA at 5-6.

92 Commonwealth Edison Co., 64 FERC ¶ 61,253 at 62,784 (1993).

If Southwestern stands as the troll at the bridge, thereby impeding a transaction sought by one of AFPA's members, that matter should be taken up with Southwestern, not the Applicants.[93]

f. Brownsville's Claim of Unequal Access Already Has Been Rejected By The Commission

Brownsville argues that, in this proceeding, the Commission should require Applicants to take service under their open access tariffs as non-affiliated entities are required to do.[94] This contention has been made before. In the first proceeding brought to consider the Operating Agreement, Brownsville contended that it was unreasonable that Brownsville would have to pay transmission service charges while CPL obtained transmission from other CSW Operating Companies for nothing. Another intervenor, South Texas Electric Cooperative and Medina Electric Cooperative, argued, on the other hand, that the Operating Agreement should be amended to provide for transmission charges to be paid by each of the CSW Operating Companies for any transmission furnished to it by other CSW Operating Companies.

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[93] AFPA also seems to ignore the fact that EPEC is not the only owner of transmission interconnection capability between Southwestern and the WSCC. TNP and PNM also own significant transfer capability between their systems and Southwestern which are filled with capacity they purchase from Southwestern. But AFPA does not explain why a desire on the part of EPEC to use its interface capability with Southwestern as it sees fit is any different from similar decisions made by TNP and PNM, whose operational decisions have removed transfer capability from the reach of AFPA's members.

[94] Brownsville at 2-3.

The Presiding Administrative Law Judge correctly rejected both of these arguments and no exception from the judge's findings was pressed.[95] Fully aware that its arguments have been made and rejected before, Brownsville does not assert any reason why the Applicants should be required to take service under their own tariffs. The only plausible reason would be to offset some gain in market power resulting from the Transaction. Northeast Utilities voluntarily agreed to take service under its own tariffs to forestall a claim that it otherwise would be able to exercise market power through its control of uncommitted capacity.[96] The Applicants in this case make substantial transmission equalization payments to compensate for the shared use of their transmission systems. Because, unlike Northeast Utilities, Applicants will not exert control over all available uncommitted capacity in any of the markets they serve, there is no need or basis upon which to condition the Transaction with a requirement that Applicants take service under their own tariffs.

2. Other Conditions Sought By Intervenors Are Unrelated To The Transaction And Should Be Rejected

Southwestern, LPSC and Cajun argue that the Commission should condition its approval of the Transaction by imposing various conditions. Under section 203, if the Commission imposes

[95] Central and South West Services, Inc., 35 FERC ¶ 63,003 (1986). Brownsville took exceptions to certain of the judge's findings, but later settled the proceeding and withdrew its exceptions. Central and South West Services, Inc., 48 FERC ¶ 61,197 (1989).

[96] Northeast Utilities, 58 FERC ¶ 61,070 at 61,184 n.6.

a condition, its purpose must be to address some effect of the transaction under review and then the condition must be only the minimum necessary.[97]

Most of these matters with respect to which these parties seek conditions have been addressed above. The remaining conditions address matters that have no relevance to the Commission's consideration of the Transaction under section 203 or are otherwise unnecessary to a finding that the Transaction is consistent with the public interest.

a. A Reservation Of The Eddy County Tie Is Unnecessary Because EPEC's Open Access Tariff Will Provide Access

Southwestern demands that 80 MW of EPEC's 133 MW of Eddy County tie capacity be set aside for 10 years for use by Southwestern "or others."[98] The basis for this claim is that Southwestern is "currently using" 75 MW of the Eddy County tie today in connection with EPEC's sales to Mexico. Apparently, Southwestern thinks this entitles it to a perpetual reservation of the capacity. However, other than its citation to an inapposite precedent, Southwestern offers no explanation of why this condition should be imposed or how the condition would address some untoward effect of the Transaction. In any event, access to the Eddy County tie will be available to Southwestern "or others" under EPEC's firm transmission service tariff if the

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97 Northeast Utilities, 56 FERC ¶ 61,269 at 62,012; Utah, 45 FERC ¶ 61,095 at 61,282.

98 SPS at 83.

Transaction is approved and consummated. The terms of EPEC's tariff are modeled after those of the PSO/SWEPCO tariff the Commission has already reviewed and accepted. No further condition is necessary.

b. **Transmission Service To Mexico Is Not Altered Due To The Transaction**

Southwestern further demands that Applicants be required to provide transmission access to Mexico. As demonstrated above and discussed in Dr. Hall's testimony, the Transaction will not create or enhance market power with respect to Mexican markets for incremental power supplies. CFE's needs for power will be supplied from new capacity constructed on Mexican soil as the recent RFP for new capacity to serve the Juārez subregion amply demonstrated.[99]

Even if the Transaction were found to enable Applicants to exercise power over Mexican power markets, the Commission has no authority to impose the condition Southwestern seeks. As Applicants understand the provisions of new section 212(h) of the Act, the Commission may not order transmission service to end users or foreign utilities. Applicants suggest that, under that provision of the Act, the Commission is prohibited from issuing an order under any provision of the Act that would be conditioned upon or require transmission of electric energy to an ultimate customer or any other entity if such electric energy would be

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[99] APP-92 at pp. 55-59.

sold by such entity to an ultimate customer and such entity is not one of the following:

1. a federal power marketing agency;
2. Tennessee Valley Authority;
3. one of the United States or the District of Columbia or a political subdivision thereof;
4. an entity that has received an REA loan; or
5. a person that has an obligation under "State[100] or local law" to provide service to the public.

CFE, whose authority and public duties are derived from the laws of Mexico, is not one of these entities.[101]

c. PSO's Transmission Rate For Delivery Of Power To Empire District Electric Company Has Been Found To Be Just And Reasonable

PSO will charge Southwestern a rate of $1.31 per kW/month to transmit power from Southwestern to Empire District Electric Company (EDE). The monthly rate for firm transmission service

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[100] The Act defines "State" as a "State admitted to the Union, the District of Columbia, and any organized Territory of the United States." 16 U.S.C. § 3(6)(1988). "Local" law obviously refers to the laws of political subdivisions of states.

[101] Southwestern's contention that a failure to order EPEC to wheel to Mexico would violate the spirit of the North American Free Trade Agreement (SPS at 37-38) deserves no attention. NAFTA is an agreement among nations that they will eliminate trade barriers such as onerous import tariffs and restrictions on competition designed to protect domestic and national industries. Nothing in EPEC's tariffs prevents CFE from seeking transmission service to export power to the United States. Mr. Shockley has clearly stated that after the Transaction is completed EPEC will entertain requests for wheeling to or from CFE's system. APP-1 at p. 32.

under the PSO/SWEPCO open access tariff is $1.21 per kW/month and Southwestern now demands to be released from its contractual obligation to pay the higher rate. Strangely absent from Southwestern's explanation for this demand is any claim that this is a problem that results from the Transaction.

In any event, the EDE rate is higher principally because it involves transmission service only on the PSO system whose transmission costs are higher than SWEPCO's. The "open access" tariff rate is lower principally because it reflects an averaging of PSO's costs and SWEPCO's lower costs. PSO's rate to Southwestern has been filed with the Commission together with cost support for the rate.[102] The Staff reviewed the rate and, with Southwestern's express consent, to respond to informal criticism offered by Staff the rate was adjusted downward from the originally agreed upon rate of $1.50 per kW/month.[103] Hence the rate for EDE has already been found to be just and reasonable.

d. Southwestern's Proposed Section 211 Conditions Should Not be Addressed in this Proceeding

Next Southwestern argues that the Transaction should be conditioned by imposing limitations on the extent of transmission service Applicants are allowed to take under any order the

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[102] Public Service Co. of Oklahoma, Docket No. ER93-746-000, Amended Filing submitted August 30, 1993, Appendix A, accepted by letter order issued September 29, 1993. Southwestern did not intervene in the proceeding and did not oppose the rate.

[103] Id. Initial Filing submitted June 30, 1993, Appendix A.

Commission issues in Docket No. TX94-2-000, assuming the Commission has the authority to issue any such order. Without any explanation other than a reference to a footnote in another pleading, Southwestern contends that service to Applicants should be limited to a fixed 10-year term and that any reservation of firm service should be limited to the amounts of capacity transfers that Applicants now expect to make between the PSO and EPEC control areas. Finally, Southwestern asserts that the price Applicants pay for service should include every cost Southwestern can think of adding to Applicants' bill.

These demands for "conditions" are simply further unauthorized pleadings in the section 211 case. The extent of service to be provided to Applicants and the rates they pay should be determined in the first instance by negotiation after the technical work has been done to determine what if any system modifications are necessary.[104]

e. LPSC's Proposed Conditions Are Unnecessary

The LPSC's consultant suggests that at least three conditions should be imposed on the Commission's approval of the Transaction. First, LPSC requests that CSW's existing Operating Companies be held harmless from any "merger related capital cost increases."[105] There is no need for a specific condition regarding the cost of capital because any increase in CSW's

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104 See Florida Municipal Power Agency, 65 FERC ¶ 61,125; Minnesota Municipal Power Agency, 66 FERC ¶ 61,114.

105 LPSC, Baudino Aff. at ¶ 17.

capital costs attributable to EPEC can be addressed using traditional ratemaking techniques.

LPSC next suggests that the existing CSW Operating Companies be protected from increased transmission service costs resulting from the Transaction.[106] Purchasers of electricity from the CSW Operating Companies will benefit from the Transaction and any increased transmission costs will be offset by other savings. Indeed, as discussed below, SWEPCO, the only Operating Company that the LPSC regulates, will benefit greatly from the change in the transmission equalization procedure. As also indicated below, the CSW Operating Companies will commit not to pass through to their transmission service customers any net increase in transmission charges paid to non-affiliated utilities resulting from the Transaction during the terms of existing contracts.

Finally, the LPSC argues that a mechanism should be created to protect the CSW Operating Companies from losing revenues from pre-existing sales. Unlike the Entergy system, the CSW Operating Companies enter into separate agreements to make off-system capacity sales, the only current pre-existing sales. EPEC will not share in capacity-related revenues from such sales and no condition is needed.

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106 Id.

f. **Las Cruces' Proposed Conditions Are Unnecessary Given EPEC's Open Access Tariff**

Although it has failed utterly to show any nexus between the Transaction and the competitive problems it fears, Las Cruces also demands that approval of the Transaction be conditioned[107] in a way that will insure that Las Cruces (as distinguished from other users of EPEC's transmission system) has access to EPEC's Eddy County tie capacity and firm transmission service at rates based on EPEC's pre-merger embedded costs and that removes any restrictions that might hamper Las Cruces' ability to determine its power supplier or limit its ability to obtain competitive wholesale power supply. After the Transaction is consummated, EPEC will offer firm and non-firm transmission services on terms that the Commission has already found to be reasonable. In light of this commitment, none of the conditions requested by Las Cruces is appropriate or necessary.

III. The Merger Will Produce Substantial Benefits And The Limited Possible Adverse Affects On Particular Entities Do Not Suggest That The Transaction Is Not Consistent With The Public Interest

When reviewing merger benefits in Utah, the Commission stated that the standard

> is to consider all of the benefits (and costs) likely to result. The possibility of achieving a particular benefit through a contractual arrangement does not diminish the cost savings associated with that benefit. The relevant question is whether the benefits of a merger will outweigh its costs such that

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[107] Las Cruces at 30-31.

> the current and future cost of providing electric service will be less.[108]

In Entergy,[109] the Commission stated that an applicant for a section 203 order

> need not provide comprehensive cost-of-service data as part of [its] case-in-chief. Instead [the Commission] anticipate[s] a generalized showing of the types of savings and efficiencies which might be achieved through the proposed merger.

As important, the Commission has ruled that applicants for a section 203 order need not support their projected benefits with "mathematical precision."[110]

A. The Transaction Will Produce Substantial Benefits

Applicants have shown that the Transaction will produce total net benefits of $422 million during the initial ten years of post-merger operations (1995-2004).[111] Applicants' post-merger operations are expected to generate $236 million in non-fuel O&M savings,[112] $152 million in financial savings,[113]

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108 45 FERC ¶ 61,095 at 61,299.

109 65 FERC ¶ 61,332 at 62,474, (emphasis in original); see also Northeast Utilities, 50 FERC ¶ 61,266 at 61,836 (1990); Kansas City Power & Light Co., 53 FERC ¶ 61,097 at 61,285 (1990) (same).

110 Northeast Utilities, 53 FERC ¶ 63,020 at 65,213 (1990), aff'd, 56 FERC ¶ 61,269 at 61,993 (1991).

111 Application, Volume I at p. 32. The net present value of these benefits is approximately $282 million. See SPS, Exhibit DTH-4.

112 Exhibit APP-61 at p. 5; Exhibit (DAH-1) APP-62.

113 Exhibit APP-56 at p. 25.

and $34 million in production and transmission savings.[114] Applicants' estimates of savings they and their customers will enjoy as the result of the Transaction were carefully developed based on objective and verifiable data using appropriate tools and assistance from expert consultants.

Some intervenors, however, attack Applicants' estimates as being either unsupported, speculative or overstated. Some complain that certain of the claimed benefits could be achieved absent the Transaction and should therefore not be counted. At bottom, these intervenors only question the *magnitude* of the net savings that will flow from the Transaction, not whether the Transaction would be beneficial to Applicants or the public. Analyzed under the applicable statutory standard and the Commission's past decisions, Applicants have shown that the Transaction will produce overall benefits. Therefore, the Commission should find that the Transaction is in the public interest and must be approved.

1. The Removal of EPEC From Bankruptcy Is A Significant Benefit To The Public

Several intervenors state that Applicants should not be permitted to count EPEC's emergence from bankruptcy as a post-merger benefit.[115] The Commission has ruled to the contrary and

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[114] Exhibit APP-39 at pp. 5, 45. Applicants also demonstrate that the Transaction will generate an additional $68 million of production related benefits for the 2005-2013 time period. Exhibit APP-39, p. 32.

[115] LPSC, Baudino Aff. at ¶ 13; APSC at 2; SPS at 69-70.

been wholeheartedly affirmed by the Court of Appeals.[116] "[E]mergence from bankruptcy is a distinct benefit . . . Whether such a result could somehow have been produced in some other way is not the question here. [The debtor's] recovery is entitled to substantial weight in the consideration of the acquisition's consistency with the public interest." Id. Such benefits

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[116] Northeast Utilities, 53 FERC ¶ 63,020 at 65,212, aff'd, 56 FERC ¶ 61,269 at 61,993, aff'd, Northeast Utilities v. FERC, 993 F.2d at 946; see also In re Evans, 1 FPC 511, 517 (1937). Southwestern also asserts that elevating EPEC's bonds to investment grade is not a merger benefit. Southwestern's affiant Steinhilper states that

> it is inappropriate to consider these alleged benefits under the circumstances of a company emerging from bankruptcy. I believe that any plan which could win approval of the creditors and be confirmed would have to provide an investment grade credit rating for the EPEC debt.

SPS, Steinhilper Aff. at ¶ 2. The data, however, on companies recently emerging from bankruptcy tell a different story. LTV Corporation emerged from bankruptcy in June 1993 with debt security (debenture) ratings of Caa (triple C, three grades below investment grade) and Ca (double C, four grades below investment grade). On August 2, 1993, Zale Corporation emerged from bankruptcy with debt security (senior note and senior debenture) ratings of Ca (double C). Restructuring of the Southland Corporation was consummated on March 5, 1991. Southland's debt securities (senior notes and first priority senior subordinated debentures) have B1 (single B plus, two grades below investment grade) and B2 (single B) ratings. It is not unusual for companies to emerge from bankruptcy with less than investment grade debt ratings. The assumption made by CSW in its calculation of merger financial benefits is that EPEC would not have been able to emerge from bankruptcy on a stand alone basis as an investment grade company. For that to happen, much higher levels of retail rate relief than CSW is requesting would be required and the uncertainty surrounding such relief would keep long-term, downward pressure on a "stand-alone" EPEC's bond rating.

include ensured reliability of EPEC, improvement of efficiencies and reduction in litigation costs.

2. The Capacity Sales And Capacity Savings Are Based On Conservative And Reasonable Methodologies

Southwestern, LPSC and APSC complain that Applicants' projected capacity savings are overstated because Applicants fail to consider benefits from possible off-system capacity sales that CSW may forego by selling capacity to EPEC.[117]

APSC states that CSW's Integrated Resource Plan is an unreliable basis for determining the Applicants' post-merger capacity requirements because it has not yet been reviewed by a state regulator.[118] APSC also asserts that application of CSW's policy regarding meeting minimum reserves results in EPEC's making additional capacity purchases costing $2.7 million during the ten-year period and that Applicants have failed to account for this additional cost in their benefits calculations.[119] Finally, APSC argues that any savings will only be the result of shifting capacity commitment reserves and costs through the Operating Agreement rather than true savings.[120]

Southwestern questions Applicants' projected capacity savings because it concedes that EPEC is likely to have excess capacity due to a loss of load, that Southwestern's capacity

117 LPSC, Baudino Aff. at ¶ 10; APSC at 12.

118 APSC, Westerfield Aff. at ¶ 9.

119 APSC, Westerfield Aff. at ¶ 10.

120 APSC, Westerfield Aff. at ¶ 11.

prices will not be higher than CSW's, and that Applicants ignore that the public will not gain from CSW's substitution of its excess capacity for Southwestern's or others'.[121]

In preparing its resource expansion plans, EPEC does not plan capacity purchases or additions to offset small forecasted deficiencies in reserve levels. Nonetheless, recognizing the variability of projected customer demands and availability of resources, EPEC continually evaluates those of its planning assumptions that impact EPEC's reserve margins. If a deficiency continues to be forecasted within the lead time required to acquire resources, appropriate mitigating plans will be recommended, which may include the purchase of non-firm and/or firm purchases. In "reiterating" EPEC's resource plan, CSW planned for capacity purchases to be consistent with its assumptions for the rest of its system.[122] This did create a forecasted need for EPEC to make off-system purchases. However, because Applicants cannot be assured of firm service across Southwestern's system before 1999, the small purchases before that year are assumed in both the Case III (EPEC stand-alone) and Case IV (combined) plans. In 1999, EPEC makes a 10 MW purchase in Case III, which is not indicated in Case IV, and in 2001 makes a 15 MW purchase in Case III, which is reduced to 12 MW in Case IV. The 3 MW difference in 2001 added to the 10 MW purchase in

[121] SPS at 61-65.

[122] Both CSW's and EPEC's "stand-alone" resource plans have been filed with the PUCT and EPEC's has been filed with the NMPUC.

1999 that is not shown in Case IV, have a combined cost of $880,000. This compares to the total capacity-related savings in the first 10 years of post-merger operations of $22.6 million.

The post-merger plan shows EPEC making a capacity commitment purchase at a cost ranging from $117 to $122 kW/year to replace purchases that a standalone EPEC would have made from another source at prices ranging from $92 to $95 per kW/year. From a CSW System perspective, capacity commitment sales do not create an incremental capacity cost; such sales only represent an opportunity to redistribute responsibility for embedded costs. In contrast, an off-system purchase at any capacity charge always represents an increased cost to the System. Thus, even if Southwestern could offer capacity at a lower rate, the public interest is best served by the CSW System's engaging in capacity commitment transactions at no incremental cost.[123]

Finally, Southwestern contends that the capacity savings Applicants have forecasted are illusory because EPEC might lose load to other suppliers and therefore have surplus capacity of its own. EPEC does not plan to lose load whether or not the Transaction takes place. It is sheer speculation to suggest that Las Cruces will be able to establish an operating municipal utility within the near future or that the military bases that take retail service from EPEC can lawfully turn to alternative

[123] Over time, the identity of the selling and buying companies involved in such transactions will change as their respective interests in uncommitted capacity shifts as new units are brought on line.

suppliers. However, even if that were to happen, EPEC would then have gas-fired capacity available at a lower price than other CSW Operating Companies and capacity savings would be realized as the result of EPEC's making capacity commitment sales to displace the higher cost capacity of other CSW Operating Companies.

Intervenor assertions that CSW could make off-system sales in the future are also nothing more than speculation.[124] As Southwestern notes, CSW's Operating Companies operate in highly competitive markets. Actual purchases and sales in the future will depend on the relative trends of fuel prices, load changes, generating unit performance, environmental regulations, the degree to which IPPs and QFs enter the market CSW serves, and a host of other factors that are difficult to predict. Rather than engage in speculation, as the intervenors did, Applicants' projected benefits are conservative and more realistic. Indeed, the exclusion of off-system sales likely caused the projected benefits to be understated rather than overstated.

Southwestern's complaint that the projected savings are not true savings but only improper shifts in costs to other utilities is inapplicable here. In Northeast Utilities, 56 FERC ¶ 61,269 at 61,997, the Commission determined that the applicants in that case could not count as a merger benefit any costs simply shifted "dollar-for-dollar" from applicants to other members of the same

[124] Intervenors apparently overlook that CSW's off-system sales contracts (Exhibit (EK-14) APP-27) will expire by 1998 or sooner. Such speculation does not warrant a hearing. Entergy, 62 FERC ¶ 61,073 at 61,373; Kansas City Power and Light Co., 53 FERC ¶ 61,097 at 61,289.

fully-integrated, uniformly-dispatched power pool. It would be inappropriate for the Commission to extend its reasoning in Northeast Utilities to the facts in this case. Here, the savings are not the result of shifting the unchanged costs of one member of a power pool to another member of the same power pool. The capacity commitment sales that will occur because of the Transaction will allow EPEC to avoid paying for capacity purchases at higher cost or to delay the construction of new generation.

3. No Intervenor Demonstrates That Fuel-Related Benefits Will Not Result From The Transaction

LPSC, PNM and Southwestern complain that Applicants failed to support adequately the level of fuel-related savings they project. LPSC states that Southwestern system constraints may limit projected fuel savings to only off-peak periods.[125] Southwestern argues that the costs of transmission service will far outweigh the savings that can be generated in internal economy exchanges,[126] because the costs of expanding its system to provide bi-directional firm wheeling will be $40 million or more.

However, as explained earlier, at most Southwestern's studies support $1.2 million in system modification costs. Applicants calculated the cost of transmission service based on Southwestern's embedded costs as reported in its 1992 FERC Form 1

125 LPSC, Baudino Aff. at ¶ 11.

126 SPS at 65-66.

to which Applicants added $3.1 million[127] which represented their estimate of the cost of internal system improvements that Southwestern would have to make in order to provide bi-directional firm wheeling beginning in 1999 and non-firm wheeling before that time.

Southwestern and others have raised questions whether Applicants will have the full use of EPEC's Eddy County tie capacity available for economy energy exchanges with the CSW Operating Companies. To test the extent to which the use by Southwestern, or another transmission service customer, of Eddy County tie capacity would affect the production cost savings projected for the first 10 years of post-merger operations, Applicants ran additional PROMOD studies. These are described in the affidavit of Mr. Bruggeman attached as Appendix B, and the exhibits thereto. As explained by Mr. Bruggeman and shown in such exhibits, if Southwestern were to reserve firm transmission service in the amount of 80 MW, thereby depriving Applicants of the use of that capacity, 94% of the production cost benefits would nevertheless be realized. This is because the vast

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[127] This is the incremental investment related to upgrading Southwestern's Tuco and Eddy County transformers. The calculation of the wheeling rates used for Southwestern is attached as Appendix J. Southwestern's Mr. Hudson has erroneously compared apples and oranges in concluding that Applicants assumed an annual payment to Southwestern for transmission service of $5,000,000. SPS, Hudson Aff. at 22. The $5,000,000 figure represents the annual carrying cost of system improvements that Applicants projected that WTU must make plus wheeling payments to Southwestern. <u>See</u> Appendix K.

majority of production cost savings are the result of west to east transfers from EPEC to the CSW Operating Companies.[128]

Further proceedings in Docket No. TX94-2-000 will be required in order to determine more definitively the charges Applicants will pay Southwestern for the transmission services Applicants will need. In those section 211 proceedings, the Commission may determine that some or all of Southwestern's system modification costs should be "rolled in" to its embedded costs or that service to the Applicants should be priced on the basis of the cost of the incremental facilities. The decisions the Commission makes will determine the extent to which Applicants may economically use Southwestern's system. However, neither Southwestern nor any other party has shown that such transmission service costs will eat up the expected production cost savings.

4. Benefits Arising From The Transactions May Be Considered Even Though They Could Be Achieved Absent The Transaction

Several intervenors complain that EPEC could achieve some of the claimed benefits without engaging in the Transaction and, therefore, that such benefits should not be counted in analyzing whether the Transaction is consistent with the public interest.[129] These complaints are without merit and should be

[128] Southwestern has admitted that it can safely transfer power from EPEC to PSO after making minor internal system improvements. See Southwestern's response to discovery in PUCT Docket Nos. 12700/12701, attached as Appendix L.

[129] See, e.g., LPSC, Baudino Aff. at ¶ 14; SPS at 69 and 76; APSC at 11, Westerfield Aff. at ¶ 6.

rejected. "[A] claimed benefit should be attributed to the merger even though the benefit could be achieved without the merger."[130] As Applicants' testimony demonstrates, many of the benefits from the Transaction (such as lower financing costs and labor cost savings) could not be achieved from a stand-alone plan of reorganization. Moreover, there is no assurance that, absent the merger, the circumstances necessary to achieve a particular benefit would exist.

5. Applicants' Labor Cost Savings Consider Costs And Savings And Are Fairly Estimated

LPSC, PNM and Southwestern argue that Applicants failed to consider early retirement costs, relocation costs and "golden parachute" costs as offsets to labor cost savings. LPSC further contends that $39 million of the claimed labor cost reduction is attributable to a reduction in retirement benefits offered EPEC employees or changes in cost assumptions under SFAS 106.[131] PNM also asserts that the cost of any new employees that Applicants may hire after reducing their workforce by 250 should also be considered as well as any costs that may be associated with "blending different corporate cultures and seniority systems, increased management turnover, and the need for complex management structures."[132] Southwestern criticizes Applicants'

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130 Northeast Utilities, 56 FERC ¶ 61,269 at 61,995, aff'd, Northeast Utilities v. FERC, 993 F.2d at 946-47; Kansas Power and Light Co., 54 FERC ¶ 61,077 at 61,251-52.

131 LPSC, Baudino Aff. at ¶ 14.

132 PNM at 23-24.

projection that the labor cost benefits will be achieved in three years[133] and complains that Applicants never explain why comparing the CSW Operating Companies is an appropriate method of developing a post-merger staffing model for EPEC.[134]

EPEC has entered into severance compensation agreements ("golden parachutes") with certain of its management employees. However, CSW has committed to the PUCT, and hereby commits to this Commission, that as a CSW subsidiary EPEC will not seek recovery of EPEC's severance compensation agreement costs in retail or wholesale rates.

Applicants have not deducted early retirement costs from its calculation of labor cost savings because they do not expect to incur such costs.[135] As Mr. Harrell has testified,[136] the savings expected from reducing EPEC's post-merger employment levels will be realized from attrition or relocation. Applicants have not deducted relocation costs from the calculated savings because relocation costs do not vary greatly with the location involved[137] and because relocation costs would be incurred to

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[133] SPS at 76.

[134] SPS at 75.

[135] Because EPEC offered an early retirement plan in June 1989, its remaining workforce is relatively young. If EPEC were to offer an early retirement plan today to employees who are 55 or older and have at least 15 years of service, only 29 of EPEC's employees would be eligible.

[136] Exhibit APP-61 at pp. 14-15.

[137] Real estate agent fees, costs for packing and unpacking, temporary housing costs and training time are (continued...)

fill any job at a CSW company whether it is filled by a former EPEC employee or a former employee of another CSW company.[138] Notwithstanding PNM's conjecture to the contrary, Applicants do not plan later to refill any of the jobs that are eliminated.[139]

Similarly, PNM's criticism that Applicants overlook costs is without merit. In respect of the first 10 years of post-merger operations, Applicants recognized the cost of four additional employees in the Information Services department of CSWS as a result of the merger.[140] The additional cost amounts to $288,025 per year or $3.3 million over the first ten years of post-merger operations, as adjusted for inflation by 3.3%. Applicants also include $550,000 per year in additional contract labor costs associated with the reduction of maintenance personnel from

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[137] (...continued) relatively fixed in nature and do not vary with the distance of the move.

[138] In any event, Applicants believe that no more than about 75, or 30%, of the 250 employment position reductions will be effected by relocation. The CSW average relocation cost is about $71,500. Hence, if Applicants incurred relocation costs for 75 of EPEC's employees, the one-time cost would be $5,362,500. In contrast, the labor cost savings for the first 10 years alone are $171,500,000. Moreover, implementation expenditures such as early retirement and relocation expenses are one-time costs which will not significantly affect the projected level of benefits. See, e.g., Entergy, 65 FERC ¶ 61,332 at 62,486-87.

[139] While it is conceivable that EPEC employment levels may increase in the future due to such factors as additional regulatory requirements or load growth, any such increases in employment would not be the result of the Transaction and would occur in any event. Any such growth in employment is likely only to be retarded by EPEC's use of services provided by CSWS.

[140] Exhibit APP-61 at p. 31, lines 23-25.

EPEC's power station maintenance group. Such costs, after adjustment for inflation of 3.3%, will aggregate $6.3 million over the period 1999-2004. These additional costs are reflected on Exhibit (DAH-1) APP-62.[141] Most important, Applicants have allocated $95.6 million of CSWS costs to EPEC of which about 38% consists of labor costs. Accordingly, Applicants' projections appropriately consider both costs and savings expected from the Transaction.

Southwestern's criticisms are also without merit. Applicants' projection that they can achieve a 250-employee reduction in three years is based on the experience of other merging utilities, the judgment of EPEC and CSW senior management, and an assessment of the actual 1992 turnover ratios for EPEC and the four existing CSW Operating Companies.[142]

Contrary to Southwestern's complaint, Applicants did not simply "assume[] that EPEC's staffing needs would be similar to the CSW Operating Companies [sic]." Applicants compared CSW and EPEC staffing models on a function-by-function basis to determine

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141 The $3.3 million in labor costs for Information Services is included in the $11.1 of "Costs to Achieve Benefits" shown on Exhibit (DAH-1) APP-62.

142 Exhibit APP-61 at pp. 13-14; APP-81 at pp. 29-42; Exhibit (JHL-5) APP-86; Exhibit (JHL-10) APP-91. As Dr. Landon testifies, this is effectively only a 15% reduction in employment level, which will take place at a rate, on average, of 5% per year. Exhibit APP-81 at pp. 32-33. By comparison, Centerior managed to effect a 22% reduction in force in two years. Exhibit (JHL-5) APP-86. Other merging utilities have forecasted longer periods to accomplish targeted employment reductions, but these decisions were informed by "social" factors such as a desire to not provoke adverse local public opinion by forcing employment cutbacks at a rapid rate.

the level of staffing EPEC would require as a CSW Operating Company.[143] After the EPEC-proxy staffing model was developed, EPEC managers reviewed with CSWS personnel EPEC's organizational charts by department and compared then to the staffing levels indicated for EPEC by the EPEC-proxy staffing model. The objective of the comparison was to identify employment positions that could be eliminated once EPEC merged with CSW.[144]

Finally, LPSC's consultant's assertion that $39 million of the labor cost savings "are merely reductions in retirement benefits of El Paso employees or changes in costs assumptions under [SFAS] No. 106" is only a complaint that these savings "can be achieved by El Paso absent the merger." This contention is not valid for reasons explained earlier.[145]

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143 Exhibit APP-61 at pp. 9-10.

144 Southwestern's reliance on Entergy, 65 FERC at 62,486, to criticize Applicants' projection of labor cost savings is unavailing. SPS at 75. Although the Commission acknowledged that Entergy's methods for determining the level of benefits were deficient, the Commission nonetheless agreed that Entergy would realize cost savings by eliminating redundant functions and consolidating other activities. The Commission faulted Entergy's analyses because it did not have access to GSU's records and accounting practices and because Entergy assumed certain savings based on a recent restructuring. Applicants' method of calculating savings does not suffer from either of these faults.

145 Indeed, the allegation is not true in any event; the savings are the result of the fact that to be eligible for inclusion in CSW's retirement medical plans an employee must be older and have longer time of employment than is the case under EPEC plans. However, for those employees that do retire from CSW, the benefits under CSW's plans are at least equivalent to those offered by EPEC. It is worth noting that Applicants' study of savings associated with pensions and retirement benefit plans were based on comprehensive analyses conducted by Hewitt Associates, one of the country's foremost consultants in employee
(continued...)

6. Applicants' Calculation Of Employee Benefit Cost Savings Accurately Reflect The Impact Of The Projected Employment Reductions And Merger Costs

The Texas Office of Public Utility Counsel (TOPUC) alleges that Applicants have double-counted certain employee benefits and labor savings. TOPUC also asserts that proposed reductions in the cost of workers' compensation insurance are reflected both in the benefits loadings used to calculate labor cost savings from the elimination of EPEC employment positions and in insurance savings.[146] Finally, TOPUC claims that the increase in medical/dental benefits costs is calculated incorrectly.[147]

Applicants have not double-counted the pension savings. Exhibit (DAH-5) APP-66 shows savings related to the funding of pensions for EPEC's employees. As that Exhibit shows, in the years 1995 through 2000 CSW will make larger funding payments in respect of EPEC employees than EPEC would on a stand-alone basis. This is the result of the fact that EPEC's pension plans are currently underfunded. However, in the later years of the 10-year initial period of post-merger operations, CSW's pension plan will produce benefits that will offset the costs of the increase funding payments in the early years by the total of $2,303,000

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[145] (...continued) compensation matters. Exhibits (DAH-6) APP-67 and (DAH-9) APP-70.

[146] TOPUC at 25, citing Effron Aff. at ¶ 8.

[147] Id.

for the 10-year period.[148] Hence, the savings shown on Exhibit (DAH-5) APP-66 represents a savings attributable to the differences in the cost of funding pensions that will result from the differences between the EPEC and CSW retirement plans.

In contrast, the labor cost savings resulting from a reduction in force at EPEC were increased to reflect a "benefits loading factor," the development of which is shown on Exhibit (DAH-4) APP-65. EPEC, like any other major employer, makes contributions to a retirement fund in respect of eligible active employees. When jobs are reduced, pension funding payments will be reduced. However, the value reflected in the loading factor for retirement funding represents the rate at which EPEC now, relative to CSW, underfunds pension payments. Consequently, there is no double counting. Exhibit (DAH-5) APP-66 shows the differences in costs resulting from different funding levels and policies. Exhibit (DAH-4) APP-65 simply reflects the savings in pension fundings resulting from attrition in employment levels.

The workers' compensation insurance savings reflected on Exhibit (DAH-15) APP-76 result from basing EPEC's workers' compensation insurance costs on a better loss experience than EPEC's past loss experience which forms the basis for EPEC's current cost of obtaining workers' compensation insurance.[149]

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[148] The basis for these figures is found in Exhibit (DAH-9) APP-70 at pp. 17-18 (of the exhibit). This exhibit is a report prepared by Hewitt Associates.

[149] As a result of the Transaction, EPEC will be regarded as a new company with no loss experience for purposes of calculating its workers' compensation insurance premiums.

This quantification of savings does not consider any reduction in workforce. As the result of reducing its workforce, however, EPEC will not have to pay workers' compensation premiums with respect to the positions that are eliminated. Hence, workers' compensation costs were considered in calculating the benefits loading factor shown on Exhibit (DAH-4) APP-65.

TOPUC's consultant misunderstands the calculation of the increase in medical/dental plan costs for active employees shown on Exhibit (DAH-5) APP-66 and explained by Mr. Harrell at pages 23-24 of Exhibit APP-61. The increased cost shown on Exhibit (DAH-5) APP-66 represents *the difference* between the annual costs EPEC would experience absent the Transaction and the costs that Mr. Harrell's analysis indicated that EPEC would incur under the CSW medical and dental plans. It is reasonable to expect that medical costs will escalate at a rate faster than the general inflation rate. However, there is no reason to expect that *the difference* in the costs incurred under the EPEC and CSW plans will escalate at a more rapid rate.

Moreover, the results of Mr. Harrell's analysis of the relative costs EPEC is likely to experience under the two plans are counter-intuitive. All other things being equal, one would expect that CSW's costs of providing medical and dental insurance would be lower simply because CSW represents an experience pool that is 10 times the size of EPEC's. Mr. Harrell explains that the results of his analysis may have been influenced by CSW's adoption of a new medical/dental plan in 1993 thereby making it

difficult to compare costs.[150] Mr. Harrell believes that, in actual experience, EPEC's medical/dental costs will not be higher than they would have been absent the Transaction. However, because the results of his analysis did not support this belief, the Applicants' calculation of labor cost savings was reduced to show a calculated increase in EPEC's medical/dental plan costs after the Transaction is consummated.

7. Adding EPEC to CSWS' Centralized Computer System Will Benefit All Post-Merger CSW Operating Companies

APSC questions why the costs of adding EPEC to the centralized CSWS computer system should be allocated to the pre-merger CSW Operating Companies when it appears that the additions to the computer system will only benefit EPEC.[151]

The costs of adding EPEC to CSWS' Information Systems (IS) workload that can be directly attributed to EPEC (such as the one-time $200,000 cost to retrain EPEC and CSWS information processing employees and the costs of leasing software required to accommodate EPEC-specific activity) will be charged directly to EPEC. Other IS costs incurred to add EPEC to the CSW System will be shared by all System companies because the incremental processing storage and mainframe capability will be used to serve all CSW companies. Although other companies will share in the costs of adding EPEC to the System, EPEC will, for its part, relieve other System companies from paying for part of the cost

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150 APP-61 at p. 23.

151 APSC at 11, Westerfield Aff. at ¶ 5.

of existing IS equipment and personnel, thereby reducing the IS costs of the existing CSW Operating Companies.[152]

8. Applicants Did Not Overlook Costs Of Self-Insurance

LPSC asserts that Applicants' calculation of insurance premium savings is overstated because Applicants failed to reflect the costs of self-insurance as a cost of the merger.[153]

Applicants measured the difference between the costs that EPEC incurs to purchase insurance *from outside insurance companies* and the costs that EPEC will incur to purchase insurance for the same risks as a CSW Operating Company. The difference in insurance premiums was properly counted as a benefit of the Transaction. EPEC will continue to self-insure against the same types of risks that it now self-insures (i.e., by paying the costs of losses out of its pocket). There is no obvious reason to expect that EPEC's cost of self-insurance will increase because it becomes a CSW subsidiary.

9. Applicants' Service Company Cost And Billing Projections Are Reasonable And Are Not Overstated

LPSC suggests that the savings that will accrue to the existing CSW Operating Companies from redistributing service company costs to EPEC are incorrectly stated because the allocation methods CSWS uses to bill its costs were approved by

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[152] If this explanation is insufficient, APSC may examine that issue in retail rate proceedings. <u>See</u>, <u>e.g.</u>, <u>Kansas Power and Light Co.</u>, 54 FERC ¶ 61,077 at 61,255 (1991).

[153] LPSC, Baudino Aff. at ¶ 14.

the Securities and Exchange Commission (SEC) and not "in the context" of the Transaction.[154] LPSC is concerned that the post-merger allocation may be discriminatory and any proposed reduction in billings must be set for hearing.[155] The PUCT complains that the Application contained insufficient information for the PUCT to determine the impact of the proposed change in billings.[156] APSC argues that Applicants fail to explain how CSWS can provide additional administrative services to EPEC at minimal additional costs.[157] APSC concludes that CSW already has sufficient "'capacity' in terms of personnel and equipment" to provide the administrative services to EPEC and such "overcapacity" raises doubt that the redistribution of service company costs is a benefit.[158] Like APSC, PNM complains that Applicants' projected savings are inflated because, with the exception of computer services, CSWS does not expect to incur new costs to provide services to EPEC.[159]

A detailed description of the services that CSWS provides to the CSW Operating Companies, and will provide to EPEC following consummation of the Transaction, is found in the testimony of Ms. Hargus (Exhibit APP-110 at pp. 21-33) and in the Scope of

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[154] LPSC, Baudino Aff. at ¶ 15.

[155] Id.

[156] PUCT at 9.

[157] APSC at 11, Westerfield Aff. at ¶ 4.

[158] Id.

[159] PNM at 24.

Services report attached thereto as Exhibit (WGH-2) APP-112. The effect on the CSW Operating Companies of adding EPEC to CSWS's clientele is detailed in the workpapers of David Harrell filed on February 3, 1994. Hence, the PUCT's claim that the Application did not contain a detailed explanation of the impact on the CSW Operating Companies is incorrect. In any event, the PUCT will have complete access to such data in connection with the Transaction-related proceedings now pending before it in Texas.[160]

As Ms. Hargus explains, CSWS costs that can be attributed to a particular company are directly assigned to that company.[161] Other costs are allocated among the Companies that benefit from the service company activity. Allocations are made using a work order system that is required under the SEC's Uniform System of Accounts for Mutual Service Companies[162] and allocation formulae that consider such factors as peak load, number of customers, kilowatthour sales and number of employees. The particular formula used is selected to best match the nature of the particular activity. The LPSC's consultant apparently contends that the calculation of benefits to the existing CSW Operating Companies from redistributing part of CSWS' cost to EPEC is

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[160] The PUCT is well acquainted with the services that CSWS provides and the related costs and cost allocations. These matters are the subject of detailed scrutiny in every rate case involving the three CSW Operating Companies that operate in Texas.

[161] Exhibit APP-110 at p. 26.

[162] 17 C.F.R. Part 256 (1993).

questionable because the redistributed CSWS costs are allocated using procedures that the SEC approved outside the context of the Transaction. The allocation factors were developed with reference to the kind of activity costs involved, not with reference to the identity of particular beneficiaries. There is no reason to believe that the SEC would require some different set of allocation tools to be used in distributing CSWS costs simply because EPEC has joined the CSW System.

As Mr. Harrell explains, in projecting the benefits of reallocating common service company costs among the members of a CSW System that includes EPEC, each ongoing work order for activity costs that are allocated among a number of CSW companies was individually examined to determine whether it was a work order that would benefit EPEC. In the course of this analysis, Applicants considered whether additional costs would result from EPEC's inclusion among the activity's beneficiaries. When it appeared that additional costs would be incurred, they were added to the total Service Company costs to be redistributed.

In essence, CSWS is a large management consulting and services organization combined with large-scale information processing and accounting capability. Most of CSWS' work is not done for a particular operating company. Rather, CSWS employees typically address matters (e.g., system resource planning) that are system-wide in scope. EPEC represents one more client for CSWS' services. However, the costs that have been redistributed

in calculating the benefits to the existing companies are costs relating to "system-wide" projects.

For example, in post-merger operations CSWS system planners will input data regarding EPEC loads and resources in performing system studies. Otherwise, system planning studies will proceed as before. No additional CSWS employees will be needed to do resource planning and those employees at EPEC that used to do resource planning will become redundant. Thus, the APSC's suggestion that CSWS has excess capacity is nothing more than speculation. APSC apparently wishes to overlook the obvious fact that bringing EPEC to the CSW System will result in economies of scale.[163]

10. Southwestern's Request For Additional Studies Should Be Rejected

Southwestern states that Applicants admit that they do not know whether or how the merger will realize any benefits. Specifically, based on a quotation from Mr. Harrell's testimony taken out of context, Southwestern states that "further studies are necessary 'to implement the changes needed to effect potential post-merger savings in non-fuel O&M costs.'"[164]

Mr. Harrell's testimony actually states:

> Starting in February 1994, CSW will institute further detailed operational studies, which

[163] See Entergy, 65 FERC ¶ 61,332 at 62,486; Northeast Utilities, 53 FERC ¶ 63,020 at 65,212, aff'd, 56 FERC ¶ 61,269 at 61,993 ("the economies of scale [resulting from the merger] are virtually certain to bring some positive (even if not precisely quantifiable) benefits to the merger").

[164] SPS at 75.

> it plans to complete prior to the effective date of the merger. The purpose of such studies is to position CSW to implement the changes needed to effect potential post-merger savings in non-fuel O&M costs once the merger has been consummated.[165]

CSW and EPEC have already determined how they can eliminate redundancies. The work that has been done has produced a strategic plan. The work that is ongoing is the creation of a detailed implementation plan to achieve the objectives identified in the earlier work. These operational studies are being conducted for the purpose of determining precisely which jobs will be eliminated and when, and what functions remaining EPEC employees will perform and how they will interface with CSWS and other CSW System companies.

11. Applicants' Allocation Of Benefits Need Not Be Addressed

APSC complains that given the disparity between EPEC's size and the amount of savings allocated to EPEC raises questions of whether the existing CSW Operating Companies are receiving an unfair or discriminatory portion of the savings.[166] In Kansas Power and Light Co. and Kansas Gas and Electric Co.,[167] the Commission refused to set for hearing the issue of allocation of benefits. The Commission instead determined that any allocation of benefits could be raised when the post-merger companies propose changes in their rate schedules. More recently, the

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165 Exhibit APP-61 at p. 8, lines 9-15.

166 APSC at 8, Berry Aff. at ¶ 6.

167 54 FERC ¶ 61,077 at 61,255 (1991).

Commission held in Entergy,[168] that as long as a net benefit results from the merger for each company, it need not address the specific allocation of benefits. The Commission reasoned that its conclusion was consistent with the legal standard under section 203 as established in Pacific Power & Light. There is no reason why the Commission should depart from its precedent here.

12. Applicants' Financial Savings Are Fully Supported

APSC complains that Applicants fail to support their financial savings, that Applicants incorrectly chose the "high end" of the financial savings range and that "no qualitative basis is provided for the estimated financial savings in common equity costs."[169] APSC also criticizes Applicants for failing to quantify any negative impact on cost of capital as a result of the merger. To support its claim, APSC cites to a recent decline in CSW's stock price as evidence that the merger will increase CSW's risk.[170] APSC also speculates that CSW may "be asked" to make-up any future EPEC dividend shortfall.[171] Finally, APSC states that Applicants fail to propose any mechanism to protect the existing CSW Operating Companies from any "merger-induced risk."[172]

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[168] 65 FERC ¶ 61,332 at 62,491.

[169] APSC at 8, Berry Aff. at ¶ 7.

[170] APSC, Berry Aff. at ¶¶ 8-9.

[171] APSC, Berry Aff. at ¶ 10.

[172] APSC, Berry Aff. at ¶¶ 10, 11.

Southwestern contends that EPEC is a risky company and Applicants do not address any potential increase in capital costs.[173] TOPUC questions whether CSW's plan to "infuse" EPEC with $400 million in cash will increase the cost of capital.[174] LPSC complains that Applicants failed to provide an analysis of the impact of the Transaction on Applicants' financial condition and speculates that several factors may increase the cost of equity capital.[175]

The question that is ultimately relevant here is not whether CSW's investment in EPEC will increase CSW's cost of capital because it represents a further investment in nuclear investment or because EPEC has a financially troubled past or may confront competitive challenges in the future. The right question is whether any perception by the financial markets of increased risk will be allowed to affect the rates the existing CSW Operating Companies charge for service. Dr. Hadaway has explained that "CSW customers will be protected from any additional risk as the result of traditional ratemaking procedures."[176] The Commission reached the same conclusion in Entergy. There, the Commission

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[173] SPS at 70-73. Southwestern's Mr. Steinhilper confidently, but mistakenly, asserts that PNM was not downgraded to less than investment grade until 1993. In fact, Moody's downgraded PNM to Ba in the second quarter of 1990 and PNM's 1991 Annual Report to Shareholders (p. 6) stated that PNM's goal was to "improve bond rating to investment grade as soon as possible."

[174] TOPUC, Szerszen Aff. at ¶ 11.

[175] LPSC, Baudino Aff. at ¶ 8.

[176] APP-56 at p. 17, lines 14-16.

stated that it would protect existing Entergy customers from the risks associated with Gulf States' investment in a nuclear plant by attributing that risk to Gulf States' cost of capital alone.

> As we held in Allegheny Generating Co., 40 FERC ¶ 61,117 at p. 61,318 (1987):
>
> > [O]ur policy is to make an adjustment to a subsidiary's allowance on common equity where the subsidiary faces a different level of risk than the parent and where the parent is used as a proxy for the subsidiary.
>
> If Gulf States faced a different risk from the Entergy System, we would calculate a separate rate of return for that subsidiary in any event.[177]

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[177] Entergy, 65 FERC ¶ 61,332 at 62,524. APSC affiant Berry makes the claim that because the CSW stock price has fallen more than other utility averages since December 7, 1993, that the risk of CSW is increasing which "could translate into greater capital costs for the existing CSW operating companies." APSC, Berry Aff. ¶ 9. Dr. Berry has overstated the drop in CSW stock price by manipulating the period he chose for his analysis. Dr. Berry uses this period because the plan was confirmed by the Bankruptcy Court on the day immediately following December 7., 1993. However, the market has been aware of the CSW/EPEC merger plan for a much longer period. The drop in CSW's stock price is better explained by the interest rate and inflation fears that have marked the period used by Dr. Berry.

At the end of January 1993, after CSW had announced its interest in acquiring EPEC, the CSW stock price was $30.50 and the Dow Jones Utilities Average was 226.6. At the end of November 1993, just prior to the bankruptcy confirmation hearings and the period of increasing interest rates, the CSW stock price was $29.75 and the DJUA was 225.4. Both the CSW stock price and the DJUA were nearly unchanged over this ten month period. Since December 1993, both the CSW stock price and the DJUA have fallen based on fears of escalating inflation and rising interest rates. By choosing a similar period for his analysis, Dr. Berry has confused merger-related factors with general market trends and, as a result has drawn erroneous conclusions from the data.

(continued...)

The restrictions on dividends for EPEC provide a mechanism to increase EPEC's equity capitalization gradually over time in a manner designed to support an investment grade credit rating. CSW has no electric generation under construction and does not plan any new generation until the year 2001.[178] Because the CSW companies are not currently expanding their capital bases to support generation construction, there is no present need to expand the equity capital of the existing Electric Operating Companies through the retention of earnings. This gives CSW the flexibility to fund dividends for shares issued to purchase EPEC for some period. In a short time, EPEC is expected to generate earnings at levels sufficient to support dividends to CSW which are consistent with those of its other utility subsidiaries.

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[177] (...continued)

Stocks of other utilities having no merger plans suffered similar misfortunes as the result of the general decline in utility common stock prices. TECO Energy is a holding company for Tampa Electric. Tampa Electric is a double-A rated utility with no nuclear exposure and no involvement in a large electric utility acquisition. Over the last 52 weeks, its stock declined 22.2 percent (25.875 - 20.125 = 5.750/25.875 = .222). In the same period, CSW stock declined 20.8 percent. KU Energy (parent of Kentucky Utilities, a non-nuclear, double-A rated, non-acquiring utility) stock dropped 19.8 percent and Wisconsin Public Service (a 16 percent nuclear, double-A rated, non-acquiring utility) has seen its stock fall 20.9 percent from its 52-week high. Hence, there are factors other than CSW's plan to acquire EPEC that have caused CSW's stock price to fall. The decline in stock price has no relevance to the evaluation of whether the Transaction is in the public interest. Any review of the impact of stock prices on ratepayers should be performed in rate proceedings.

[178] See Exhibit (JAB-2.3) APP-41.

Dr. Hadaway presented a range of likely savings in the cost of senior securities because no one can predict with absolute certainty how financial markets will perform or what effect exogenous factors will have on EPEC's capital costs. However, Applicants regard Dr. Hadaway's approach as conservative and believe that the high end of the range he predicts will be achieved.

B. Any Impact On Wholesale Rates Will Be Very Limited

In merger proceedings brought under section 203, one of the Commission's principal concerns is the impact of the merger on wholesale rates.[179] Plainly, EPEC will reap the lion's share of the net cost savings that the Transaction will produce. For that reason alone, it is therefore unlikely that any wholesale customer of EPEC will be damaged by any increase in EPEC's costs attributable to the Transaction. Any change in wholesale rates will be reviewed in a Commission rate proceeding. No rate changes are proposed now, and none are anticipated for some time.

As Mr. Serrano explains in his testimony, EPEC provides wholesale requirements service only to the Imperial Irrigation District (IID), Texas-New Mexico Power Company (TNP) and Rio Grande Electric Cooperative (RGEC).[180] Although each of these utilities has intervened in this case, none of them has expressed

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[179] The Commission has held that the effect of mergers on retail rates need not be addressed in section 203 proceedings. Kansas City Power & Light Co., 53 FERC ¶ 61,097 at 61,285 (1990) citing Southern California Edison Co., 49 FERC ¶ 61,091 (1989).

[180] Exhibit App-28 at pp. 25-27.

concern that the rates under which they take service will increase because of the Transaction. The rates at which EPEC provides wholesale service to IID, TNP or RGEC are fixed by contract.[181] The rates charged IID and TNP are not expected to vary from the rates fixed by contract for their remaining terms. The contract with RGEC will be in effect at least through March of 1997.[182]

PSO serves only three wholesale customers -- the Cities of Collinsville and South Coffeyville, Oklahoma and the Oklahoma Municipal Power Authority (OMPA). The rates charged to Collinsville and South Coffeyville have been recently reviewed by the Commission and continue in effect.[183] PSO is subject to, and participates in, vigorous competition to serve wholesale load in

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[181] Exhibit APP-28 at p. 27.

[182] Id. RGEC is party to a rate settlement that took effect in 1988 and continues for ten years thereafter subject to a two-year notice of termination. Under that settlement, RGEC pays only for metered kilowatthours delivered at a rate of $0.048 per kilowatthour. Although a fuel surcharge applies if EPEC's monthly average fuel cost exceeds 2¢ per kilowatthour, to date those conditions have not obtained and the surcharge has not been applied. Exhibit App-28 at p. 27. In any event, EPEC's incremental cost of production and total costs of service will decline as a result of the Transaction.

[183] Indeed, the data PSO filed in Docket No. ER94-435-000 to support its service to Collinsville under its established full requirements rate and in Docket No. ER91-545-000 to support its service to South Coffeyville indicate that PSO earns only a negligible return on wholesale sales. Public Service Co. of Oklahoma, Docket No. ER94-435-000, Supplemental Filing submitted August 9, 1993, Schedule BK, accepted by letter order issued November 1, 1993 (Collinsville); Public Service Co. of Oklahoma, Docket No. ER91-545-000, Supplemental Filing submitted July 17, 1991, accepted by letter order issued August 20, 1991 (South Coffeyville).

Oklahoma and consequently has no plans to seek to raise its wholesale rates in the immediate future. PSO's transmission equalization payments will increase slightly in 1999 under the revised Operating Agreement. Such costs as well as PSO's share of any payments made to Southwestern for firm transmission service would be reflected in PSO's wholesale *base* rates and, therefore, will not be collected from wholesale customers unless PSO seeks to change its rates for wholesale service. Any such rate proposal would, of course, be subject to this Commission's review. OMPA purchases only 10 MW of firm power from PSO as well as various transmission and coordination services, all at rates fixed by contract. OMPA has not intervened in this proceeding.

PSO also provides contract transmission service to KAMO Power, Inc. and to Western Farmers Electric Cooperative, Inc., neither of which has intervened. Although PSO will participate in paying Southwestern for transmission service, PSO hereby commits that any net increase in transmission service payments to non-affiliates resulting from the Transaction will not be reflected in the rates charged its transmission service customers during the remaining terms of their contracts.

SWEPCO provides requirements power service and transmission services to several generation and transmission electric cooperatives and the Cities of Hope and Bentonville, Arkansas under formula rates.[184] Such formula rates capture SWEPCO's

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[184] Such wholesale customers include Northeast Texas Electric Cooperative, Inc. (NTEC), Tex-La Electric Cooperative of (continued...)

actual cost of operations on a retrospective basis.[185] The principal effect of the Transaction on SWEPCO's production costs will be that EPEC will displace SWEPCO as the low-cost marginal producer on the CSW System in many hours. As a consequence, EPEC will receive margins for some internal economy energy transactions that SWEPCO otherwise would have earned. This will increase SWEPCO's costs for the 10-year period less than $1 million. However, the reduction in SWEPCO's internal economy sales increases the amount of SWEPCO capacity available for sale off-system. Dr. Landon indicates in his testimony that the opportunity to make additional off-system sales represents a significant, but unquantifiable, merger benefit.

Under the Operating Agreement, SWEPCO's customers will continue to have the benefit of SWEPCO's lowest cost generating facilities. Moreover, in the first ten years of post-merger operations, SWEPCO's receipts from capacity commitment sales will increase by $5.2 million. Finally, SWEPCO will also benefit from the proposed change in transmission equalization method. As shown in Exhibit APP-ER2 attached to Mr. Bruggeman's testimony

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[184] (...continued)
Texas, Inc., East Texas Electric Cooperative, Inc. and Rayburn County Electric Cooperative, Inc. Of SWEPCO's wholesale requirements customers, only NTEC and Tex-La have intervened and they have not raised any substantive concerns. Neither Hope nor Bentonville intervened in this proceeding.

[185] Under the formulas, SWEPCO initially estimates its costs for the current calendar year and charges for service on the basis of such estimates. In the following calendar year, SWEPCO recomputes its cost of providing service in the previous year and adjusts its billings accordingly.

submitted in Docket No. ER94-898-000, absent the Transaction SWEPCO's transmission equalization payments to its sister companies under the existing method would average about $9 million per year during the period 1999-2004. With the Transaction and the related change in equalization method, SWEPCO's transfers to other CSW System companies will be reduced to about $5 million annually during that same period.[186] SWEPCO's formula rate wholesale customers will be significant beneficiaries of these reduced costs.

SWEPCO also provides firm contract transmission services under formula rates to OMPA, Cajun Electric Power Cooperative, Inc. and the Arkansas Electric Cooperative Corporation. These customers use such transmission service to deliver remote generation to serve their members' loads. These customers will be unaffected by the effect of the Transaction on SWEPCO's production costs. They will benefit from the reduction in service company billings charged to SWEPCO, because these reductions in overhead costs will be reflected in SWEPCO's transmission service rates to these customers as they are redetermined from time to time. SWEPCO hereby commits not to pass through to its transmission service customers any net increase in payments made to Southwestern or other non-affiliated utilities for transmission services resulting from the Transaction during the terms of their existing contracts.

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186 Exhibit (JAB-ER5) APP-ER2.

Consequently, SWEPCO's transmission customers' costs will not be increased because of the Transaction.[187]

WTU provides requirements wholesale service to 13 rural electric cooperatives, the Cities of Brady and Coleman, Texas, and TNP under wholesale rates that were fixed by settlement of Docket No. ER87-65-000.[188] Like PSO, WTU is a vigorous competitor for wholesale loads and has no present plans to increase its wholesale rates in the future. Although WTU will experience some increase in transmission service costs due to the Transaction, those costs are included in WTU's base rates which, as in the case of PSO, can only be changed by filing changed rates with this Commission. WTU provides contract transmission service to Brownsville and several other ERCOT utilities. WTU's charges for transmission service change only when WTU changes its retail rates. WTU's retail rates have not changed since 1987, and WTU has no present plan to seek increases in its retail rates. If and when WTU has another retail rate proceeding and thereby establishes an increased transmission revenue requirement, WTU hereby commits not to pass through to Brownsville or any other transmission customers any net increase in transmission service payments to non-affiliated utilities

[187] As the result of the Transaction, SWEPCO will contribute to the payment of transmission service charges paid to Southwestern. However, this increase in SWEPCO's costs will be offset by a reduction in SWEPCO's share of other transmission service payments made to TU Electric and certain other ERCOT utilities. See Bruggeman workpapers, the relevant excerpts from which are attached as Appendix K.

[188] West Texas Utilities Co., 40 FERC ¶ 61,293 (1987).

resulting from the Transaction during the terms of their existing contracts.

In settling Docket No. ER90-289-000, CPL agreed not to increase its wholesale rates prior to January 1, 1995.[189] CPL's present base rates reflect only about half the value of its investment in the South Texas Project (STP), and are therefore well below the base rates that could be supported by CPL's costs of providing service. CPL has no immediate plan to commence wholesale rate proceedings. Like WTU, CPL's transmission-related costs may rise as the result of post-merger operations. However, these costs are offset by other savings and such costs cannot be passed through to wholesale customers absent a new wholesale rate proceeding. Like WTU, CPL provides contract transmission service to Brownsville and other ERCOT utilities and hereby commits not to pass through to such customers any net increase in transmission service payments made to non-affiliated utilities resulting from the Transaction during the terms of their existing contracts.

In short, Applicants' respective wholesale rates now in effect will continue in effect after the Transaction. In the future, Applicants may propose changes in their wholesale rates, as changes in their costs of service and competitive circumstances dictate. However, any concerns intervenors here have with the effects of the Transaction on Applicants' wholesale

[189] Central Power & Light Co., 56 FERC ¶ 61,139 reh'g, 57 FERC ¶ 61,012 (1991)

rates can be addressed in the proceedings instituted to consider such changes.[190]

C. The Claimed Effect On Interconnected Utilities Offers No Basis To Reject The Merger

In Entergy,[191] the Commission explained that the impacts of a merger "on the costs and rates of . . . interconnected utilities, including the operational impacts of the merger on those utilities," would not be considered in section 203 proceedings. Moreover, the Commission has held repeatedly that

> in a section 203 proceeding, we are concerned only with remedying specific harms *resulting from* a proposed merger. . . . [A]ny problems with the operation of the intervenors' pre-existing contracts are more appropriately addressed in a section 205 rate proceeding or a section 206 complaint proceeding.[192]

The arguments made in this case by utilities which are interconnected with Applicants that their operations or costs will be adversely affected by the Applicants' post-merger operations fail to give heed to these overarching principles.

1. Public Service Company Of New Mexico Has Failed To Show an Adverse Impact Due To The Transaction

As explained by Applicants' witness Pedro Serrano, EPEC and PNM have been engaged in a longstanding dispute regarding the allocation among New Mexico utilities of rights to use the

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190 UtiliCorp United Inc. and Centel Corp., 56 FERC ¶ 61,031 at 61,119 (1991); Utah, 45 FERC ¶ 61,095 at 61,298.

191 62 FERC ¶ 61,156 at 62,095-96.

192 CINergy, 64 FERC ¶ 61,237 at 62,726 (emphasis in original).

transfer capability available on the New Mexico transmission grid.[193] In practical effect, this dispute has revolved around the extent to which EPEC's imports of remotely generated power and energy increase loadings on PNM's Northern New Mexico transmission system and therefore the extent to which EPEC should compensate PNM for transmission service.

In late February 1994, PNM and EPEC agreed to a set of principles that will govern the relationship between PNM and EPEC in the future, a copy of which is attached as Appendix M. Under those principles, PNM and EPEC have agreed to work together to modify the New Mexico transmission grid. Completion of the modifications will increase southern Mexico import capability. These principles will assure to EPEC the long-term availability of the import capability it needs fully to utilize its remote generating capacity. Although the principles contemplate that the parties will negotiate certain operating procedures and nomograms, there is no reason to believe that such negotiations will not move forward in good faith.

Even PNM's Gregory Miller recognizes that this "longstanding dispute"[194] predates the Transaction and is a matter with which EPEC and PNM would be required to contend even if the Merger Agreement had never been signed. Resolution of such longstanding

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193 Exhibit APP-28 at pp. 13-14.

194 PNM, Miller Aff. at 7.

disputes is not properly the subject of a merger review proceeding.[195]

Searching for a nexus with the Transaction, Mr. Miller claims that post-merger operations would increase exposure to reliability problems during more hours of the year than pre-merger EPEC operations. Although Applicants' PROMOD III study of post-merger operations indicates that EPEC will export to other CSW Operating Companies some energy generated at Palo Verde and Four Corners, as Mr. Miller and PNM are well aware such exports will occur predominantly during off-peak hours when the transmission grid is not heavily loaded. In any event, use of the New Mexico grid in connection with such post-merger intra-system exchanges will be in compliance with existing operating procedures, import limits and nomograms. In short, this is precisely the kind of operational matter that the Commission has found is beyond the proper scope of a section 203 proceeding. Even Mr. Miller admits that these concerns should be resolved by the principles to which PNM and EPEC have agreed.[196]

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[195] See Southern Pacific Transp. Co. v. ICC, 736 F.2d 708, 722 (D.C. Cir. 1984), cited in Northeast Utilities Service Co., 53 FERC ¶ 63,020 at 65,231 (1990), reh'g 56 FERC ¶ 61,269 reh'g, 58 FERC ¶ 61,070 (1992), reh'g, 59 FERC ¶ 61,042 (1992), reh'g, 59 FERC ¶ 61,089 (1992), aff'd, Northeast Utilities Service Co. v. FERC, 993 F.2d 937 (1st Cir. 1993).

[196] PNM, Miller Aff. at 9. Mr. Miller also expresses concern that PNM's rights to contingent capacity from Rio Grande Unit Nos. 7 and 8 will be affected by Applicants' post-merger operations. The Applicants have stated that the Transaction will have no effect on the rights, interests and obligations of EPEC under any contract for the sale of electric energy. Application, Volume I at p. 29. Under Schedule A to the EPEC/PNM

(continued...)

Finally, PNM asserts that the Transaction will either impair or make more costly PNM's interruptible purchase from Southwestern. The bases for this fear are unproven allegations made by Southwestern in Docket No. TX94-2-000.

PNM has intervened in Docket No. TX94-2-000 and Applicants have agreed that PNM should be granted intervenor status and be required to participate in Technical Conferences, which Applicants believe will provide the most expeditious means of sorting out the issues raised in that proceeding. Such Technical Conferences will provide a forum for the utilities that would be directly affected by the proposed transmission of power and energy between the EPEC and PSO control areas in which to formulate operating procedures to deal with the occurrence of operational contingencies on the Southwestern system. In any event, the potential for operational impacts on PNM arising out of such transactions, like the other operational concerns raised by PNM, is not properly considered in a section 203 proceeding and is a matter that the Commission has clearly indicated that interconnected utilities "should first attempt to resolve . . . through mechanisms provided for under reliability council

[196] (...continued)
Interconnection Agreement, PNM is entitled to call upon up to 39 MW in those units to the extent that the designated units are available in day to day operation. EPEC will honor that obligation in accordance with its terms just as it has in pre-merger operations.

guidelines . . ., existing contracts or day-to-day inter-utility coordination practices."[197]

2. Plains Electric Generation And Transmission Cooperative, Inc.'s (Plains) Disputes With EPEC Are Not Related To The Transaction And Need Not Be Addressed

As explained by Mr. Serrano,[198] EPEC has also had a longstanding contract dispute with Plains. The dispute arises under a 1987 letter agreement, a copy of which is attached to Plains' motion to intervene in Docket No. EC94-7-000 as Exhibit 2. The letter agreement provides Plains certain options to, among other things, acquire an interest in EPEC's Arizona Interconnection Project (AIP) facilities or, in the alternative, to receive transmission service from EPEC, both contingent on the making of certain system enhancements. Although the letter agreement requires that any dispute under the provisions in question be resolved by arbitration, Plains filed a civil suit in U.S. District Court in New Mexico to press its position in the matter. The suit has been stayed pending resolution of EPEC's bankruptcy. In the meantime, EPEC and Plains have been pursuing settlement of their dispute.

Plains admits that it is "neither necessary or appropriate for the Commission to address the merits of that 'dispute' in

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[197] CINergy, 64 FERC ¶ 61,237 at 62,725-26.

[198] Exhibit APP-28 at p. 14.

this proceeding."[199] However, Plains asks that approval of the Transaction be conditioned upon a requirement that the post-merger EPEC fulfill its obligation to Plains or "bear the full cost of failing to do so."[200] This "hold harmless" provision is neither necessary nor appropriate. As noted earlier, Applicants have committed in their Application to honor their obligations under existing agreements with other interconnected utilities. This commitment includes any obligation EPEC has to Plains under the terms of that agreement.

IV. No Other Reasons Have Been Advanced Suggesting That The Merger Should Not Be Allowed To Go Forward

A. Applicants' Contemplated Accounting Treatment Is Consistent With Generally Accepted Accounting Principles

The APSC contends that the Applicants' proposal to use purchase accounting to record the Transaction should be set for hearing because Applicants' witness Hargus failed to specify the paragraphs of APB No. 16 (Accounting for Business Combinations) that support Ms. Hargus' conclusion that the Transaction does not qualify for treatment as a pooling of interests.

To qualify for pooling, a transaction must meet all of 12 criteria specified in APB No. 16. Ms. Hargus testifies that pooling may not be used to record the Transaction because the

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199 Plains at 18. See also Entergy, 65 FERC ¶ 61,332 at 62,473 ("any argument that a proposed merger . . . is not consistent with the public interest if it harms any individual or group, is 'deeply flawed'.")

200 Plains at 19.

Transaction is not an all-stock deal.[201] As Mr. King explains in his prepared direct testimony, under the Plan EPEC's common stockholders will receive CSW Common Stock in exchange for their equity holdings in existing EPEC, but so will EPEC's unsecured creditors as partial consideration for their claims against the estate.[202] The delivery of CSW Common Stock to unsecured creditors will, as Ms. Hargus has testified, drastically change the relative interests of EPEC's existing common stockholders in EPEC. The rights of EPEC common stockholders will be significantly diluted as a result of the Transaction by virtue of the issuance of CSW Common Stock to other classes of EPEC security holders. This result alone makes the Transaction ineligible for pooling under ¶ 47(b) of APB No. 16.

Furthermore, as Ms. Hargus also explains, the Transaction allows CSW to offer cash instead of Common Stock for certain EPEC obligations. For example, CSW has the option under the Plan to pay cash instead of Common Stock to certain EPEC security holders and bankruptcy claimants.[203] This feature of the Plan also makes the Transaction ineligible for pooling under ¶ 47 of APB No. 16.

In any event, the Commission approved the purchase method of accounting in connection with the Northeast Utilities'

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201 Exhibit APP-110 at p. 13.

202 Exhibit APP-11 at pp. 28-33.

203 Application, Volume II, Exhibit H-2, Section 5.3.C.

acquisition of PSNH,[204] the combination of Kansas Gas and Electric Company with Kansas Power and Light Company,[205] and in connection with Entergy Corporation's acquisition of Gulf States Utilities Company[206]. The APSC has offered no reason why purchase accounting should not be approved in this case and no hearing is required with regard to this issue.

TOPUC[207] accepts the propriety of purchase accounting, but argues that any acquisition adjustment that results from the difference between the value of the reorganized EPEC's net assets and the consideration paid by CSW should be carried on CSW's books and not pushed down to EPEC as the Applicants have proposed.[208] The Entergy and CSW transactions are different. In the Entergy transaction, no public debt was issued. In the CSW/EPEC Transaction, new public debt will be issued. This fact makes push down accounting a requirement under the SEC's Staff Accounting Bulletin No. 54. In Entergy, the Commission allowed Entergy to carry the acquisition adjustment on the parent's books despite the arguments of certain intervenors that generally accepted accounting principles (GAAP) require the push down treatment that the Applicants believe to be appropriate here.

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[204] Northeast Utilities Service Co., 50 FERC ¶ 61,266 at 61,836 (1990).

[205] Kansas Power and Light Co., 54 FERC ¶ 61,077 at 61,256 n.58.

[206] Entergy, 65 FERC ¶ 61,332 at 62,534-56.

[207] TOPUC at 27-28.

[208] See APP-110 at p. 9.

However, the Commission also acknowledged that push down accounting is "an acceptable option under GAAP."[209]

However, in this transaction, the accounting treatment known as "fresh start" accounting must also be applied by EPEC. The application of this accounting treatment will essentially yield the same results as "push down" accounting. Simply stated, it requires the company emerging from bankruptcy to value its assets and liabilities at fair market value at the date it emerges from bankruptcy. It follows the view that a company emerging from bankruptcy has been substantially reorganized and is being given a "fresh start."

This accounting treatment is set out in the AICPA's Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code" (SOP 90-7). It prescribes the use of "fresh start" accounting if both of the following conditions are met:

> 1. the reorganization value of the assets of the emerging entity immediately before the date of confirmation is less than the total of all post petition liabilities and allowed claims . . .; and
>
> 2. holders of existing voting shares immediately before confirmation receive less than 50% of the voting shares of the emerging entity . . . .

In this merger transaction, the first condition will be met because the reorganization value (fair value of reorganized EPEC's assets) of EPEC will be less than its post-petition

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209 Entergy, 65 FERC ¶ 61,332 at 62,537. Applicants understand that push down accounting was used to record the NU/PSNH and KGE/KPL transactions.

liabilities and allowed claims. The second condition will also be met because the existing EPEC shareholders will receive substantially less than 50% of the voting shares of the merged EPEC and CSW.

SOP 90-7 provides that a new accounting basis ("fresh start") be established for an entity emerging from bankruptcy under these conditions. The prescribed accounting treatment results in valuing the entity's individual assets and liabilities at fair market value and the recognition of an intangible asset if the aggregate reorganization value (entity's fair market value) is greater than the total fair market value attributable to each of its identifiable assets and liabilities.

Specifically, SOP 90-7 describes this accounting as follows:

> The reorganization value of the entity [EPEC] should be allocated to the entity's assets in conformity with the procedures specified by APB Opinion 16, Business Combinations, <u>for transactions reported on the basis of the purchase method</u>. If any portion of the reorganization value cannot be attributed to specific tangible or identified intangible assets of the emerging entity, such amounts should be reported as the intangible asset [called reorganization value in excess of amounts allocable to identifiable assets] . . . . This [amount] should be amortized in conformity with APB Opinion 17, Intangible Assets.

The "reorganization value" is defined by SOP 90-7 as follows:

> Reorganization value generally approximates fair value of the entity before considering liabilities and approximates <u>the amount a willing buyer would pay for the assets of the entity immediately after the restructuring</u>.

(emphasis added). In this case, the reorganization value will be determined by the amount CSW is willing to pay for the reorganized EPEC. This determination is made by computing the cost of the securities issued and other consideration paid or exchanged by CSW for the assets of EPEC.

Thus, whether "push down" or "fresh start" accounting is followed, the results will essentially be the same. The fair value of the reorganized EPEC's assets and liabilities will be recognized including an acquisition adjustment (or reorganization value in excess of amount allocable to net assets).

It appears that TOPUC's real concern is that the amortization of any acquisition adjustment not be reflected in rates. Applicants have stated in the PUCT and NMPUC proceedings relating to the Transaction that they will not seek recovery of any acquisition adjustment in rates if they obtain approval of certain income tax treatment in connection with the Transaction.[210] Assuming that the income tax treatment is

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[210] TOPUC is an active participant in the EPEC rate and merger proceedings now pending before the PUCT. In those proceedings, the Applicants have stated that EPEC will not seek recovery through retail rates of the acquisition adjustment or bankruptcy costs if the PUCT will not reduce retail revenue requirement by the cash EPEC will receive as the result of the deduction of lease rejection damages under the CSW consolidated tax return and the CSW System tax allocation agreement. The treatment of any acquisition adjustment that is pushed down to EPEC should not affect EPEC's wholesale rates. As noted earlier, the rates EPEC charges IID and TNP are fixed by contract and will not likely be changed during their primary terms. EPEC's rates to Rio Grande can be changed in 1997. However, even if EPEC proposed to include in its wholesale cost of service some amount to amortize an acquisition adjustment, that rate treatment would be subject to the Commission's scrutiny at the time. Although (continued...)

authorized by the PUCT, EPEC will not seek recovery of the acquisition adjustment in any jurisdiction.[211]

In any event, as the Commission observed in Entergy, any accounting determination made in a section 203 case "is not a rate determination and in no way prejudges whether the acquisition adjustment can be recovered in rates."[212] No hearing is required for the Commission to find that pushing any acquisition adjustment down to EPEC's books is proper accounting under GAAP and that by authorizing such accounting the Commission will not be authorizing or compelling any particular rate treatment either for wholesale or retail services.

Finally, APSC and TOPUC contend that the detailed journal entries discussed by Ms. Hargus in her presentation of the post-merger EPEC balance sheet should be investigated in this proceeding. As Ms. Hargus stated in her testimony and Ms. Westerfeld of the APSC notes in her affidavit, some of such entries will depend upon the outcome of state regulatory

[210](...continued)
Applicants do not believe this Commission need be concerned with the future treatment of acquisition adjustments in this case, an excerpt from the testimony filed by David Carpenter with the PUCT relating to this matter is attached as Appendix N in order that the Commission can better understand the nature of the issue pending before the PUCT.

[211] EPEC will not seek inclusion in rate base of the acquisition adjustment or amortization of the adjustment in cost of service. The acquisition adjustment is calculated to be $26 million as shown in Exhibit (WGH-1) APP-111.

[212] See also UtiliCorp United Inc., 56 FERC ¶ 61,031 at 61,120 (1991) (any proposed recovery of premiums paid above book value can be evaluated in other proceedings and therefore do not have to be considered in section 203 proceedings).

proceedings as well as other events prior to the closing date.[213]

Once those proceedings have been completed and the Transaction has been consummated, the Applicants will make the proper and necessary journal entries in accordance with the Commission's Uniform System of Accounts. Indeed, the Commission's accounting regulations require that the Applicants present proposed journal entries to the Commission's Office of the Chief Accountant.[214] To allay any concerns that the Applicants will improperly account for the Transaction, they will also provide copies of the proposed journal entries to the APSC and all other state regulatory commissions that have jurisdiction over EPEC or any of the CSW Operating Companies.

B. The Purchase Price Was The Result Of Open And Competitive Bidding And, Pursuant To Commission Precedent, Is Reasonable

The City of El Paso, Texas and TOPUC suggest that the Commission should question the reasonableness of the consideration that CSW will pay to acquire EPEC's common stock.[215] In Northeast Utilities Service Co., 50 FERC ¶ 61,266 (1990), the Commission determined that the reasonableness of the

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[213] Exhibit APP-110 at p. 14; APSC, Westerfield Aff. at ¶ 8.

[214] 18 C.F.R. Part 101, Electric Plant Instruction 5 and Account 102; Northeast Utilities Service Co., 50 FERC ¶ 61,266 at 61,836 n.47; Kansas, 54 FERC ¶ 61,077 at 61,256 n.58; UtiliCorp, 56 FERC ¶ 61,031 at 61,123.

[215] City at 3; TOPUC at 28-29. The terms on which EPEC's bankruptcy will be resolved and under which CSW will acquire EPEC are described in detail by Applicants' witness G. Holman King. See Exhibit APP-11 at pp. 28-40.

purchase price did not require further consideration because the plan of reorganization under which Northeast Utilities Company acquired Public Service Company of New Hampshire was developed "as part of an open and competitive bidding process in PSNH's bankruptcy proceeding."[216]

As explained by Applicants' witnesses King and Hoskins, Applicants' Merger Agreement was the result of a similar competitive process.[217] In confirming EPEC's Plan of Reorganization (Plan), the Bankruptcy Court found that:

> The bidding process and the Debtor's conduct of its negotiations for a business combination, including its negotiations with CSW, were done in an arm's-length fashion and in a good faith effort by EPE to fulfill its duties as a debtor in possession to obtain the highest and best offer for its creditors and shareholders, and to regain economic stability for the benefit of its customers.
>
> * * * * *
>
> The value represented by the CSW Merger was determined on an arm's length basis, in a sophisticated and competitive market, after extensive bidding. Accordingly, based on the acceptance of the Plan by creditors and interest holders, the CSW proposal reflects the value for EPE on a reorganization basis, and the Merger Agreement was an appropriate exercise of the Debtor's business judgment.

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216 Northeast Utilities, 50 FERC ¶ 61,266 at 61,836.

217 See Exhibit APP-11 at pp. 24-28 and Exhibit APP-8 at pp. 11-13.

Exhibit H-3 to the Application, ¶¶ 13.d. and 18.n.1. Both the City of El Paso and TOPUC were parties in interest to, and actively participated in, the Bankruptcy proceedings.[218]

The suggestions that the City and TOPUC make here that the purchase price should be questioned are not only inconsistent with the Commission's ruling in Northeast Utilities, they fail to recognize the jurisdiction of the Bankruptcy Court.[219] Under the Bankruptcy Code, the Bankruptcy Court has "exclusive jurisdiction of all the property, wherever located, of the debtor as of the commencement of the case, and of the property of the estate."[220] Hence, the Bankruptcy Court has the exclusive authority to

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[218] See Exhibit H-3 to the Application at ¶ 9. Indeed, at the confirmation hearings held in the Bankruptcy Court in early December, the City initially lodged but later withdrew an objection to confirmation. Southwestern, CSW's chief rival for EPEC, was also active in the Bankruptcy Court proceedings. Southwestern collaterally attacks the reorganization plan the court approved by disingenuously suggesting that EPEC's buyback of Palo Verde assets will be more costly than a new lease. SPS at 73-74. Both Mr. King and Dr. Hadaway have explained in detail why the buyback was the best choice. Southwestern's shameless manipulation of numbers does nothing to undermine the correctness of those analyses. Although the Commission found in the mid-1980s that leasing would produce savings, since that time federal income tax laws have changed and EPEC can make better use of the tax deductions it previously sold to owner participants in the leases.

[219] "Under collateral estoppel, once an issue is determined by a court of competent jurisdiction, that determination is conclusive in subsequent suits based on a different cause of action involving a party to the prior litigation." Montana v. United States, 440 U.S. 147, 153 (1979); Parklane Hosiery Co. v. Shore, 439 U.S. 322, 327 (1979). The doctrine of collateral estoppel applies to administrative as well as judicial proceedings. Astoria Federal S & L Ass'n v. Solimino, 501 U.S. 104 (1991); Second Taxing District of Norwalk v. FERC, 683 F.2d 477, 484 (D.C. Cir. 1982).

[220] 28 U.S.C. § 1334(a) and (d).

determine whether the debtor will be sold pursuant to a plan of reorganization, and exclusive authority to evaluate the reasonableness of the purchase price.

In short, neither the City nor TOPUC has offered any reason why the reasonableness of the consideration that CSW has agreed to pay to acquire EPEC, *per se*, requires any further consideration in this case. Moreover, the Commission has explained in other cases that its interest in the purchase price is in the indirect effect of the purchase price on ratepayers as manifested in the cost of capital.[221] As explained earlier, any adverse effect on the cost of capital can and will be addressed in rate proceedings and need not be addressed here.[222]

V. Because no Serious Protests were Filed in Docket No. ER94-898-000, No Hearing is Required in that Proceeding

On January 10, 1994, Applicants tendered for filing an Agreement to Amend the CSW Operating Agreement to add EPEC as a CSW Operating Company once the Transaction is approved. Although 14 parties intervened in Docket No. ER94-898-000, only one, TDU Customers, protested the filing in any detail.[223] Significantly, none of the intervenors question the reasonableness of the

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[221] CINergy, 64 FERC ¶ 61,237 at 62,727; Southern California Edison Co., 47 FERC ¶ 61,196 at 61,673-74 and nn.19-20, order on reh'g, 49 FERC ¶ 61,091 (1989).

[222] See Section III.A.12, supra.

[223] Other interventions merely included cursory statements that the change to the Operating Agreement should be set for hearing. See, e.g., APSC at 13; LPSC at 6.

proposed changes to the transmission equalization in the Operating Agreement.

TDU Customers' concerns are easily addressed. In essence, TDU Customers complain that the proposed amendment to the Operating Agreement does not "quantify the immediate effect of the amendment on rates of customers of CSW operating companies and EPE."[224] However, the workpapers of James A. Bruggeman filed with the Commission on February 3 and subsequently distributed to interested parties, including counsel for TDU Customers, clearly detail the effect of the addition of EPEC to the Operating Agreement for the ten-year period. Applicants have attached the relevant pages from Mr. Bruggeman's workpapers as Appendix K to this Answer for the TDU Customers' ease of reference.

VI. The Commission Should Proceed In An Expeditious Manner Consistent With Its Prior Practice, And Avoid Unnecessary Proceedings

A. The Disputed Issues Can Be Resolved Without An Evidentiary Hearing Or With A Paper Hearing Limited To Particular Issues

Applicants submit that the intervenors' challenges to the Transaction are without merit and do not raise any issues that warrant a trial-type hearing.[225] When measured against the

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[224] TDU Customers at 12.

[225] Applicants have filed extensive testimony, exhibits and workpapers to support their Application and several intervenors have offered affidavits and other materials in support of their position. "Only issues requiring the receipt of evidence to aid the Commission in reaching a determination" need be set for hearing. Kansas Power & Light Co., 54 FERC ¶ 61,077 at 61,252 (1991). Furthermore,

(continued...)

Commonwealth Edison standards, it is clear that Applicants' proposal is consistent with the public interest. There is plainly no shortage of record evidence in this case to support this conclusion, and no apparent need to develop evidence on any particular issues in order to resolve the matter.[226]

B. The Section 203 And 211 Applications Should Be Finally Resolved By Joint Decision In The Merger Proceeding, Without Consolidation

Several of the intervenors have moved or otherwise expressed their support for consolidation of the merger proceeding, EC94-7-000, with the Application previously filed by CSWS and EPEC in Docket No. TX94-2-000 for an order pursuant to sections 211 and

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[225] (...continued)

> It cannot be underscored sufficiently that a trial-type hearing is required only when the written submissions do not afford an adequate basis for resolving disputes about material facts. Thus, before we will find that a trial-type hearing is required, there must be an offer of evidence that gives rise to a dispute over an issue of material fact. A policy argument is not sufficient to bring a factual assertion into question. Moreover, a dispute over an issue of material fact which can be resolved through the presentation of additional documentary evidence, including affidavits, letters, contracts and technical data will not necessitate the convening of a trial-type hearing.

Iroquois Gas Transmission Sys., 54 FERC ¶ 61,103 at 61,346 (1991).

[226] See Mobil Producing Tex. & N.M., Inc. v. FERC, 886 F.2d 745, 749 (5th Cir. 1989).

212 of the Federal Power Act.[227] The principal argument advanced is that the two proceedings are mutually interdependent -- that is, the viability of the Transaction depends upon the Commission's decision to order Southwestern to provide transmission service.

Applicants agree that the Commission's final decisions whether to order transmission service and approve the merger should be made by the Commission at the same time. It does not follow, however, that the Commission should order consolidation of the proceedings under sections 203 and 211. Indeed, to do so would disrupt the streamlined procedural approach followed by the Commission in prior section 211 proceedings, and would impede rather than enhance the efficient and informed resolution of the matters in issue in these dockets.

The principal purpose of consolidation is to allow for the consistent, efficient and non-duplicative resolution of issues raising factual questions requiring hearing, which arise in more than one proceeding. Consolidation, therefore, should only be considered where it will clearly facilitate rather than unduly complicate, burden or delay the decisional process and expand the

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[227] SPS at 76-80; Las Cruces at 32; PNM at 15-19; AFPA at 6; NMAG at 1; PUCT at 10-11; TOPUC at 5-14. A number of intervenors argue for consolidation of Docket Nos. EC94-7-000 and ER94-898-000. PUCT at 10-11; TOPUC at 5-14; LPSC at 6; Brownsville (Docket No. ER94-898-000) at 3. As stated in their January 10, 1994 Transmittal Letter filed in Docket No. ER94-898-000, CSWS and EPEC do not object to these two proceedings being consolidated.

volume of filings coming from parties lacking any direct interest.[228]

The section 211 proceeding requires determinations of whether and under what conditions transmission service requested by Applicants can be provided without unreasonable impairment of system reliability and, if so, the terms and conditions under which it should be provided so as to fully compensate Southwestern.[229] Applicants have proposed that the next step in Docket No. TX94-2-000 be a technical conference in which, with assistance from the Commission Staff, the parties would be ordered to work to narrow or eliminate their differences as to the modifications to Southwestern's system that will be necessary to allow transmission service to be provided reliably.[230] Such a

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[228] See Tennessee Gas Pipeline Co., 66 FERC ¶ 61,242, 1994 FERC LEXIS 279, *11 (Feb. 28, 1994, corrected March 4, 1994)(cost recovery proceedings kept separate because they will be "more manageable"); Northern Natural Gas Co., 65 FERC ¶ 63,023 at 65,150 (1993) (consolidation denied where it could "complicate the hearing process in these cases").

[229] Section 211(a) requires, in addition, that the order of transmission service must be in the public interest. The Commission has stated, however, that "as a general matter, the availability of transmission service will enhance competition in the market for power supplies and lead to lower costs for consumers. Thus, as long as the transmitting utility is fully and fairly compensated and there is no unreasonable impairment of reliability, transmission service is in the public interest." Minnesota Municipal Power Agency v. Northern States Power Co., 66 FERC ¶ 61,114 (mimeo at 6) (Jan. 26, 1994). Accord Florida Municipal Power Agency v. Florida Power & Light Co., 65 FERC ¶ 61,125 at 61,615 (1993).

[230] For the first time, Southwestern has provided its own assessment of the modifications needed to enable it to provide the requested transmission services. SPS, Fulton Aff. at 4-8. Southwestern's list will allow the parties to illuminate their (continued...)

conference should focus the factual record and either eliminate or sharpen the areas of disagreement, in a manner that will facilitate resolution by the Commission of any remaining disputes concerning reliability. Any differences remaining between the parties after the technical conference should be resolved by a proposed interlocutory order of the Commission entered upon submissions by the Applicants and Southwestern.

Following the determination of the modifications that must be made to Southwestern's system, the Applicants will for the first time be in possession of the information necessary to formulate and negotiate with Southwestern appropriate rates, terms and conditions. At that point, Applicants suggest, the Commission should do as it has in the past, pursuant to section 212(c)(1), and

> issue a proposed order setting a reasonable time for the parties to the proposed transmission order to agree to terms and conditions for carrying out the order, including the compensation and apportionment of costs.[231]

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[230](...continued)
differences and set the stage for an effective technical conference to proceed.

[231] Florida Municipal Power Agency v. Florida Power & Light Co., 65 FERC ¶ 61,125 at 61,617 (1993); Minnesota Municipal Power Agency v. Northern States Power Co., 66 FERC ¶ 61,114, (mimeo at 8)(Jan. 26, 1994). As suggested in Applicant's previous filings in the section 211 proceeding, that initial proposed order should also set forth a preliminary judgment that there will be no multiple charges for simultaneous transmissions in opposite directions. Applicants' Response to Protest, Motion to Dismiss, Motion to Intervene, and Answer of Southwestern Public Service Co., at 29, in Docket No. TX94-2-000 (January 13, 1994). See Florida Municipal Power Agency, 65 FERC ¶ 61,125 at 61,613
(continued...)

Following expiration of the time period stated in the order, Applicants and Southwestern would report back to the Commission the extent of agreement or disagreement between them. Issues remaining disputed with regard to terms and conditions of service would be briefed by those parties,[232] who would provide the data necessary to allow the Commission to establish final rates.[233] Following those submissions by Applicants and Southwestern, the section 211 application will be ready for final resolution by the Commission. The central remaining issue -- whether to order transmission service -- should at that point be resolved (along with any remaining disputed issues relating to terms and conditions) in concert with the Commission's decision whether to approve the Transaction.

The Commission has recognized that such a joint decision of interrelated issues pending in separate proceedings is proper without any formal order of consolidation.[234] In this context,

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[231] (...continued)
(rejecting multiple point-to-point charges for network service in proposed order directing parties to negotiate rates).

[232] In accordance with the procedure followed in Florida Municipal Power Agency, only the Applicants and Southwestern should be allowed to file briefs on the remaining disputed issues concerning rates, terms, and conditions. 65 FERC ¶ 61,125 at 61,618.

[233] Minnesota Municipal Power Agency, 66 FERC ¶ 61,114 (mimeo at 9)(allowing 15 days after expiration of the 60-day negotiation period for negotiation of rates to submit to Commission statements of areas of agreement, explanations and cost support, and briefs and supporting data with regard to areas of continuing disagreement).

[234] City of Tacoma, 64 FERC ¶ 61,116 at 61,931 (1993); Middle South Energy, Inc., 31 FERC ¶ 61,305 at 61,631 (1985).

Applicants suggest that the final, joint decision be entered in the section 203 merger proceeding, where the Commission must decide whether the Applicants' proposed course of action is consistent with the public interest.

In sum, the Commission's other section 211 proceedings provide clear direction for the manner in which the Commission should manage and decide the pending sections 203 and 211 applications should proceed to decision. The Commission should promptly enter an initial order in Docket No. TX94-2-000 holding that it has full authority to order Southwestern to provide service to the Applicants and that it will do so after a determination as to what system modifications, if any, are needed. The Commission should order the requesting and transmitting parties to resolve the reliability and terms and conditions issues unhampered by the intervention of others not directly affected by the Transaction in question. In this proceeding, the Commission should enter an initial order finding that the Transaction will produce annual net benefits to the public and will not lessen competition. The Commission should reserve its final decision until it can decide the terms on which it will order Southwestern to transmit power and energy for Applicants. By proceeding in this manner, the Commission can best achieve the joint decision of interrelated issues while

avoiding the delay and inefficiency that would come from inappropriate consolidation.[235]

C. There Is No Reason To Delay Resolution Of The Merger Proceeding Until The State Rate Proceedings Are Completed

PUCT argues that no public interest finding can be made by the Commission until EPEC's application for a rate increase has been acted on at the state level.[236] It further observes that the justness and reasonableness of the requested increase are likely to be hotly contested, and an interim order can reasonably be expected no sooner than February 1, 1995. Thus, it suggests, no decision in this proceeding is possible until at least that time.

This Commission's judgment about whether the merger is consistent with the public interest is not dependent on the outcome of state rate proceedings. Because the Transaction will clearly result in savings to Applicants, and because it portends

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[235] Because all determinations made in any initial section 211 order regarding system reliability and modifications, and in the subsequent order directing the parties to negotiate on terms and conditions, would be preliminary and interlocutory, they would not be reviewable or enforceable, nor subject to requests for rehearing. Florida Municipal Power Agency, 65 FERC ¶ 61,125, at 61,617; Minnesota Municipal Power Agency, 66 FERC ¶ 61,114, (mimeo at 9)(Jan. 26, 1994). However, following final joint decision of the section 211 and merger issues, both would be subject to rehearing and ultimate judicial review at the behest of any aggrieved party. Parties not allowed to participate in the technical conference or the resolution of other disputed issues because they lacked a direct interest would nonetheless be able to raise any contentions at that time. Thus the streamlining of the process fully comports with the rights of all parties to a day in court.

[236] PUCT at 5-8.

no lessening of competition, the Transaction is consistent with the public interest, whatever rates ultimately may be set by state regulators. Denial by state regulators of the requested rate increase may render the operation of EPEC an uneconomic venture and even lead CSW to reevaluate its options, but it would not indicate that the Transaction is inconsistent with the public interest. Accordingly, there is no reason to delay resolution of the section 203 proceeding to await the rate determinations of the state regulators.

In the Entergy merger proceeding, the state commissions and the Commission conducted their reviews on a concurrent basis. The PUCT issued an interim order, which was subsequently made final after the Commission rendered its decision under section 203. Applicants submit that a similar process should be followed to permit processing of this Application within a reasonable time frame. The PUCT has suggested that its work will be completed no later than February 1995. Applicants request that any procedural schedule set in these dockets be designed to enable the Commission to issue its final decision by that time.

WHEREFORE, for the foregoing reasons, Applicants request that the Commission find that the Transaction is consistent with the public interest and that the Agreement to Amend the Operating Agreement is not unjust or unreasonable and may be accepted for filing.

Respectfully submitted,

EL PASO ELECTRIC COMPANY
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Dated: March 21, 1994

CERTIFICATE OF SERVICE

I hereby certify that I have on this 21st day of March 1994 served a copy of the foregoing document on all parties listed on the official service list maintained by the Secretary.

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UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

El Paso Electric Company and Central and South West Services, Inc.)	Docket No. EC94-7-000
Central and South West Services, Inc.)	Docket No. ER94-898-000 (Not Consolidated)

APPENDICES TO ANSWER OF EL PASO ELECTRIC COMPANY AND CENTRAL AND SOUTH WEST SERVICES, INC. TO MOTIONS TO INTERVENE

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March 21, 1994

LIST OF APPENDICES

APPENDIX	DESCRIPTION
A	Lists of Interventions filed in Docket Nos. EC94-7-000 and ER94-898-000
B	Affidavit of James A. Bruggeman
C	Affidavit of Harrison K. Clark
D	Affidavit of Frederic E. Mattson filed by Applicants in Docket No. TX94-2-000
E	Analysis of Southwestern's Load and Capacity Resource Plan Filed March 1, 1994 with the Public Utility Commission of Texas and a Copy of the Plan
F	Recalculation of Professor Kalt's Table III-1
G	Measurement of Buyer Market Power, SPS "Market": Capacity Purchases, 1995
H	Article from Independent Power Report "Mexican Industrials Eyeing 400 MW of Generation Around Monterrey"
I	Corrected Plains Forecast of Post-Merger Uncommitted Capacity Available for Sale into Southern New Mexico
J	Firm and Non-Firm Transmission Service Rate Calculations
K	Excerpts from Workpapers of James A. Bruggeman filed on February 3, 1994 in Docket No. EC94-7-000
L	Response of Southwestern to General Counsel's First Request for Information in PUCT Docket Nos. 12700/12701
M	PNM/EPEC Principles
N	Excerpts from Direct Testimony of David G. Carpenter for Applicants filed in PUCT Docket No. 12700/12701

Lists of Interventions filed in
Docket Nos. EC94-7-000 and ER94-898-000

EC94-7-000

American Forest and Paper Association
Arizona Public Service Company
Arkansas Public Service Commission
Cajun Electric Power Cooperative
City of Brownsville, Texas
City of El Paso, Texas
City of Las Cruces, New Mexico
Dona Ana County, New Mexico
Entergy Services, Inc.
Houston Lighting & Power Company
Imperial Irrigation District
Louisiana Public Service Commission
New Mexico Attorney General
New Mexico Public Utility Commission
Northeast Texas Electric Cooperative, Inc.
Oklahoma Corporation Commission
Plains Electric Generation and Transmission Cooperative
Public Service Company of New Mexico
Public Utility Commission of Texas
Salt River Project
Southern California Edison Company
Southern California Public Power Authority
Southwestern Public Service Company
Tex-La Electric Cooperative
Texas-New Mexico Power Company
Texas Office of Public Utility Counsel
Texas Utilities Electric Company
Transmission Dependant Customers
Tucson Electric Power Company

ER94-898-000

Arizona Public Service Company
Arkansas Public Service Commission
Cajun Electric Power Cooperative, Inc.
City of Brownsville, Texas
Houston Lighting and Power Company
Louisiana Public Service Commission
New Mexico Attorney General
New Mexico Public Utility Commission
Northeast Texas Electric Cooperative, Inc.
Oklahoma Corporation Commission
Public Service Company of New Mexico
Public Utility Commission of Texas
Southern California Edison Company
Southwestern Public Service Company
Tex-La Electric Cooperative of Texas, Inc.
Texas Office of Public Utility Counsel
Texas Utilities Electric Company
Transmission Dependent Customers

County of Dallas)
) SS.
State of Texas   )

AFFIDAVIT

My name is James A. Bruggeman. I am Vice President of Technical Services for Central and South West Services, Inc. I have prepared direct testimony and accompanying exhibits which were filed in Docket No. EC94-7-000 on January 10, 1994. On February 3, 1994, workpapers that underlie my testimony and exhibits were also filed with the Commission.

Dr. S. Keith Berry has prepared an affidavit on behalf of the Arkansas Public Service Commission in which he stated that "a significant number of workpapers [supporting my testimony and exhibits] were prepared after the filing of the Testimony and Exhibits." Based on this conclusion, Dr. Berry asserts that there "is a serious question regarding the credibility of" my testimony and exhibits.

Apparently, Dr. Berry is unfamiliar with the technical tools used in system planning. As explained in my testimony and exhibits, we use a number of sophisticated computer software tools in system planning. These include the PROMOD software with which many persons working in the electric utility industry have some familiarity. Our PROMOD studies yield different types of information that are kept in separate modules within the computer record of a particular PROMOD application. Such studies often involve a process of iteration and change. Hence, the software

is designed to print the date and time of any printing of all or part of the contents of a particular application. However, if we were to print today the same workpapers that Dr. Berry questions solely on the basis of the print date and time they bear, we would get a print of the same data showing a different date and time of printing.

In fact, my staff completed the PROMOD runs on which my testimony and exhibits were based on December 14, 1993. We made another print of the information we included in the filed workpapers in order to select meaningful information from the thousands of pages of data that would be included in a complete print of a PROMOD application. We ran new copies of the relevant studies in order to print them on 8-1/2 x 11 paper rather than having to separate large stacks of tractor-fed computer paper on which the studies had been originally printed.

In short, Dr. Berry is way off base. His conclusion that because certain of my workpapers were printed after my testimony had been filed meant that the workpapers had been created or changed after ny testimony was filed is a non sequitur of the first order.

I have also reviewed the testimony and supporting materials filed by Southwestern Public Service Company in support of its February 25, 1994 Motion to Intervene. Among other things, Southwestern questions the ability of the Applicants to produce the production cost savings identified and discussed in my testimony and exhibits. Furthermore, Southwestern's demands to displace part of the Applicants' non-firm use of EPEC's Eddy

County tie capacity contemplated by our PROMOD analyses with its own firm power transactions raises questions as to the extent of production cost benefits that could be produced in the first ten years of post-merger operations if the Eddy County tie capacity were reserved by Southwestern. Although it suggests other possibilities, Southwestern focuses on its potential use of the Eddy County tie capacity to make an 80 MW sale to a Las Cruces municipal utility if one were ever established and Southwestern actually had the power to sell.

To test this hypothesis we did studies to determine what part of the production cost savings we originally estimated would remain if one assumed that Southwestern, or some other utility, reserved 80 MW of the Eddy County capacity thereby making it unavailable for use by the CSW System. Under this scenario, we would still be able to move 133 MW of economy energy from west to east from EPEC to the CSW operating companies. Moreover, if one assumed that Southwestern would schedule 80 MW across the Eddy County tie at a 100% load factor, the Applicants would be able to counterschedule an additional 80 MW of economy transfers from EPEC to the east. Obviously, even if Southwestern reserved 80 MW in the Eddy County tie, it would not be scheduling 80 MW at all times. However, to measure the upside level of potential economy energy transfers available if an 80 MW east-west reservation were made, we made further calculations of production cost savings based on this scenario.

The studies we performed assumed that we could transfer either:

1. a maximum of 53 MW east to west and a maximum of 133 MW west to east; or

2. a maximum of 53 MW east to west and a maximum of 213 MW from west to east.

The results of these studies are shown graphically on Exhibits JB-1 and JB-2 attached hereto. Our studies indicate that $36.2 million or <u>about 94</u>% of the production cost savings originally estimated would be realized even in the event that Southwestern were to reserve 80 MW of capacity in the Eddy County tie, thereby inhibiting the ability of the applicants to make use of such capacity in east-west economy transfers, assuming we counterscheduled no more than 133 MW west to east. If we were able to counterschedule 213 MW west to east at a 100% load factor, we could produce production cost savings at a level about 115% of our base forecast. Hence, even assuming an 80 MW reservation by Southwestern, the merger will produce significant, cost savings in the period 1995-2004.

I have also reviewed the affidavit and supporting materials offered by Professor Kalt. At page 49 of his affidavit, Professor Kalt presents a table that purports to represent the forecasted loads and resources for the combined Norte and Noreste regions of CFE. Professor Kalt is unclear as to the sources of his information. However, it is clear that he relied on out of date publications for CFE's expected loads. It is also clear that by combining information for the two areas, which CFE regards as distinct, he managed only to confuse matters.

Therefore, I had our staff prepare tables that show in more detail what CFE expects its load and resource situation to be in the years 1994 through 1998 for the Norte and Noreste regions, stated separately. Those tables are attached as Exhibits JB-3 and JB-4. The tables reflect information taken from CFE's latest official forecast and information regarding the plans of the operators of two regions regarding imports from other CFE regions or the United States. Notably, as the tables indicate, neither the Norte nor the Noreste regions rely on U.S. imports in meeting their peak loads in the period studied. In fact, both regions predict having small surpluses in the relevant years.

James A. Bruggeman

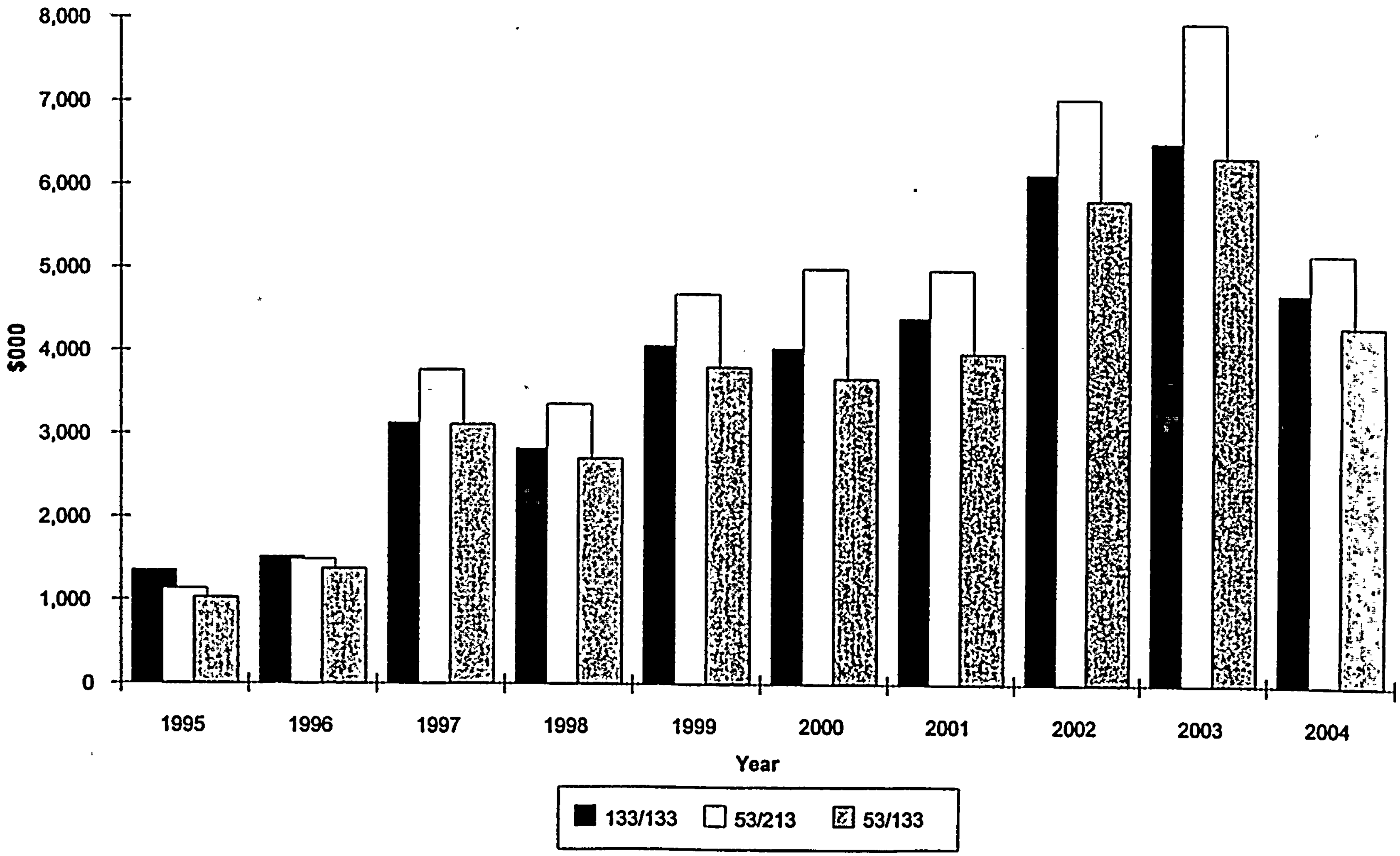
James A. Bruggeman

Subscribed and sworn to
before me this 18th day
of March, 1994.

Mavis A. Ehly

Notary Public

Production Cost Savings

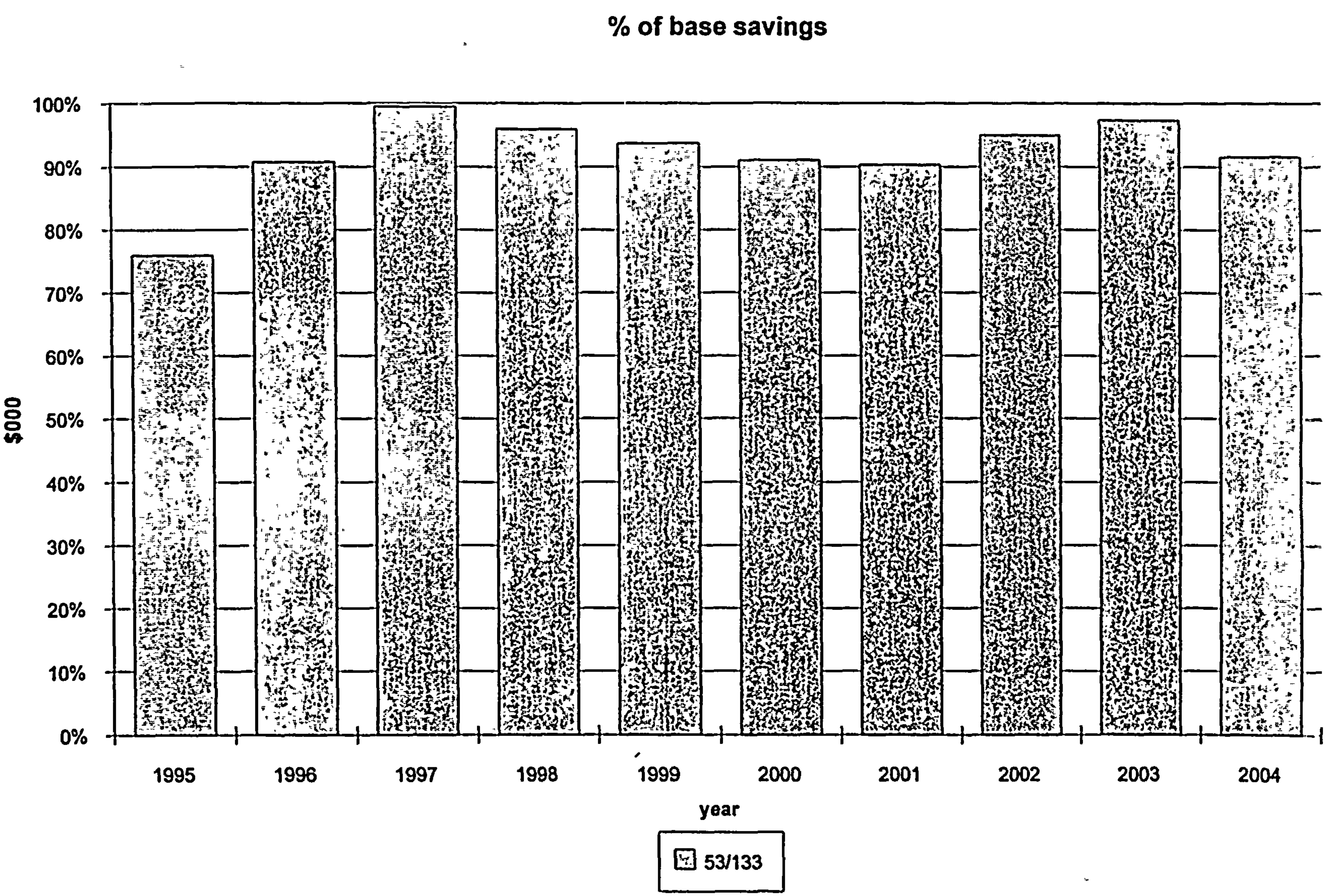


JB-1

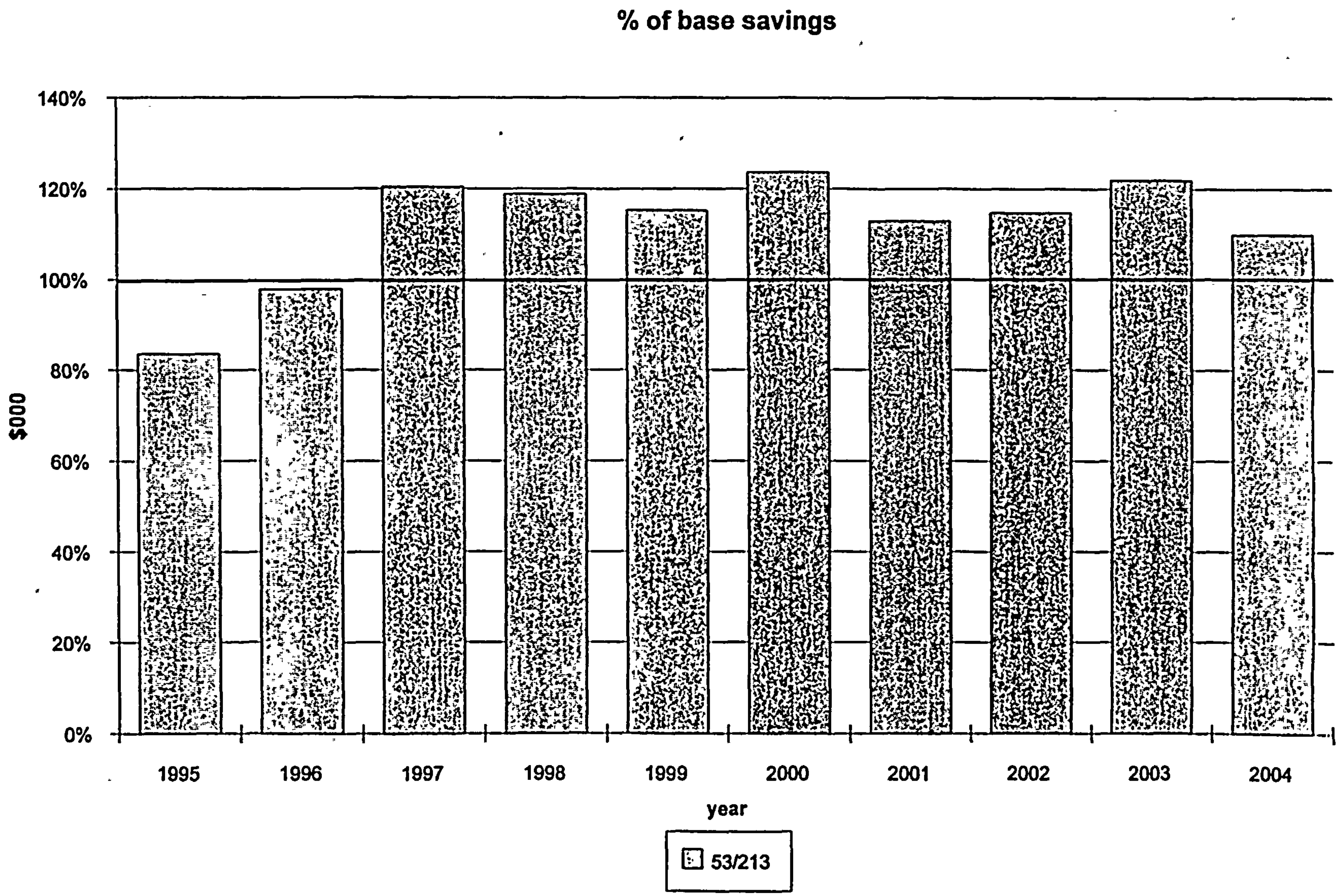
Production Cost S[illegible] Comparison

		1,995	1,996	1,997	1,998	1,999	2,000	2,001	2,002	2,003	2,004	TOTAL	
Production Costs													
Stand Alone	0/0	1,629,637	1,709,013	1,835,323	1,969,618	2,135,056	2,283,658	2,484,319	2,633,769	2,773,886	2,977,317	22,431,596	
Combined	133/133	1,628,267	1,707,421	1,831,992	1,966,695	2,130,163	2,279,500	2,479,633	2,627,455	2,767,117	2,972,901	22,391,144	
S3	53/213	1,628,489	1,707,453	1,831,332	1,966,160	2,129,536	2,278,524	2,479,060	2,626,538	2,765,655	2,972,425	22,385,172	
S2	53/133	1,628,592	1,707,561	1,832,007	1,966,808	2,130,418	2,279,860	2,480,059	2,627,760	2,767,286	2,973,297	22,393,648	
S1	53/53	1,628,210	1,707,378	1,831,992	1,967,871	2,132,082	2,281,688	2,482,086	2,630,297	2,771,244	2,975,014	22,407,862	
Benefit													
Base	133/133	1,370	1,592	3,331	2,923	4,893	4,158	4,686	6,314	6,769	4,416	40,452	
S3	53/213	1,148	1,560	3,991	3,458	5,520	5,134	5,259	7,231	8,231	4,892	46,424	
S2	53/133	1,045	1,452	3,316	2,810	4,638	3,798	4,260	6,009	6,600	4,020	37,948	
S1	53/53	1,427	1,635	3,331	1,747	2,974	1,970	2,233	3,472	2,642	2,303	23,734	
PVerde Gwh													
Stand Alone	0/0	3,796	4,232	4,292	4,054	4,171	4,358	4,063	4,164	4,350	3,983	41,462	
Combined	133/133	3,803	4,268	4,394	4,104	4,253	4,419	4,094	4,250	4,469	4,034	42,088	
S3	53/213	3,803	4,268	4,405	4,104	4,254	4,428	4,095	4,253	4,480	4,036	42,126	
S2	53/133	3,803	4,268	4,394	4,104	4,253	4,419	4,094	4,250	4,469	4,034	42,088	
S1	53/53	3,803	4,268	4,394	4,090	4,226	4,398	4,080	4,231	4,407	4,029	41,927	
PVerde Surplus ($000)													
Combined	133/133	-15	-73	-204	-101	-163	-121	-61	-173	-237	-103	-1,251	
S3	53/213	-15	-73	-225	-101	-167	-139	-64	-180	-260	-105	-1,328	
S2	53/133	-15	-73	-204	-101	-163	-121	-61	-173	-237	-103	-1,251	
S1	53/53	-15	-73	-204	-73	-109	-80	-34	-135	-114	-92	-929	
Capacity Costs - Short Term Purchase													
Stand Alone	0/0	591	364	0	0	665	0	1,074	0	0	0	2,694	
Combined	133/133	591	364	0	0	0	0	859	0	0	402	2,216	
S3	53/213	591	364	0	0	0	0	859	0	0	402	2,216	
S2	53/133	591	364	0	0	0	0	859	0	0	402	2,216	
S1	53/53	591	364	0	0	0	0	859	0	0	402	2,216	
Capacity Costs Benefits ($000)													
Combined	133/133	0	0	0	0	665	0	215	0	0	-402	478	
S3	53/213	0	0	0	0	665	0	215	0	0	-402	478	
S2	53/133	0	0	0	0	665	0	215	0	0	-402	478	
S1	53/53	0	0	0	0	665	0	215	0	0	-402	478	
Final Benefit		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004		
Combined	133/133	1,355	1,519	3,127	2,822	4,065	4,037	4,410	6,141	6,532	4,715	38,723	
S3	53/213	1,133	1,487	3,766	3,357	4,688	4,995	4,980	7,051	7,971	5,189	44,618	115.22%
S2	53/133	1,030	1,379	3,112	2,709	3,810	3,677	3,984	5,836	6,363	4,319	36,219	93.53%
S1	53/53	1,412	1,562	3,127	1,674	2,200	1,890	1,984	3,337	2,528	2,613	22,327	57.66%

% of base		1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
S3	53/213	84%	98%	120%	119%	115%	124%	113%	115%	122%	110%
S2	53/133	76%	91%	100%	96%	94%	91%	90%	95%	97%	92%
S1	53/53	104%	103%	100%	59%	54%	47%	45%	54%	39%	55%


% of base savings
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
$000
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
year
53/133

JB-2


% of base savings
140%
120%
100%
80%
60%
40%
20%
0%
$000
1995
1996
1997
1998
1999
2000
2001
2002
2003
2004
year
53/213

EL PASO ELECTRIC COMPANY
ESTIMATED CFE NORTH REGION

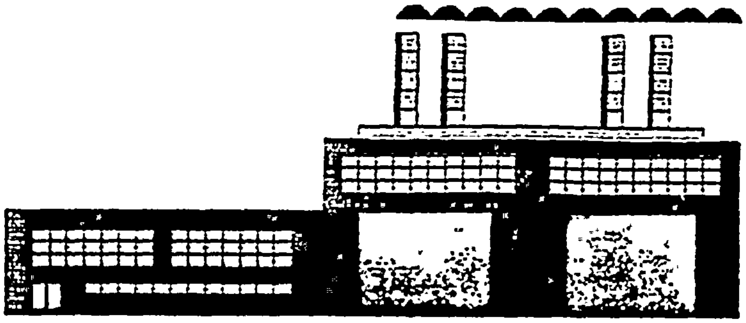
	1993	1994	1995	1996	1997	1998
1.0 GENERATION RESOURCES						
1.1 CD. JUAREZ	434	434	434	434	434	434
1.2 F. VILLA	415	415	415	415	415	415
1.3 CHIHUAHUA	64	64	64	64	64	64
1.4 G. PALACIO	209	209	209	209	209	209
1.5 BOQUILLA	24	24	24	24	24	24
1.6 LAGUNA	39	39	39	39	39	39
1.7 LERDO	320	320	320	320	320	320
1.8 MAZATLAN	210	210	210	210	210	210
1.9 PLANNED ADDITIONS:						
1.9.1 SAMALAYUCA 1				173	173	173
1.9.2 SAMALAYUCA 2					173	173
1.9.3 SAMALAYUCA 3						173
1.0 TOTAL GENERATION RESOURCES	**1715**	**1715**	**1715**	**1888**	**2061**	**2234**
2.0 IMPORTS:						
2.1 EL PASO ELECTRIC	150	150	150	150	0	0
2.2 HERCULES TIE *	0	200	200	200	200	200
2.0 TOTAL IMPORTS:	**150**	**350**	**350**	**350**	**200**	**200**
3.0 NET RESOURCES FOR DEMAND	**1865**	**2065**	**2065**	**2238**	**2261**	**2434**
4.0 TOTAL SYSTEM DEMAND	**1639**	**1741**	**1829**	**1919**	**2002**	**2092**
5.0 MARGIN OVER TOTAL DEMAND (MW)	226	324	236	319	259	342
5.1 MARGIN OVER TOTAL DEMAND (PCT)	14%	19%	13%	17%	13%	16%
6.0 LARGEST SINGLE HAZARD **	**210**	**210**	**210**	**210**	**210**	**210**

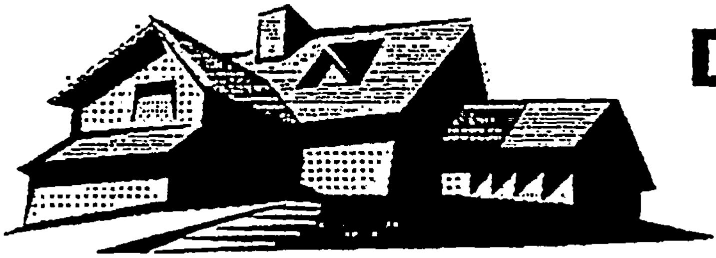
NOTE: * ESTIMATED IMPORT FROM NORESTE REGION.

** BASED ON 210 MW FROM MAZATLAN.

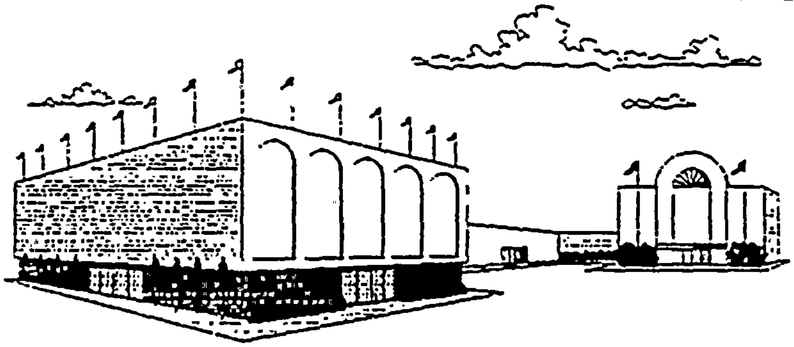
1) ELECTRICITY DEMAND FORECASTS TO 2002 APPEAR IN CFE'S "DESARROLLO DEL MERCADO ELECTRICO", PULISHED IN 1993.

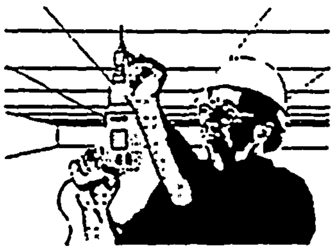
2) EXISTING AS WELL AS PLANNED RESOURCES INFORMATION WAS ACQUIRED FROM CFE'S NORTH REGION STAFF.





DESARROLLO DEL MERCADO ELECTRICO 1988 - 2002





1988

COMISION FEDERAL DE ELECTRICIDAD

SUBDIRECCION DE PROGRAMACION

Gerencia de Programación de Sistemas Eléctricos

SUBDIRECCION DE PROGRAMACION
GERENCIA DE PROGRAMACION DE SISTEMAS ELECTRICOS

Total Gross Demand (MW) By Area

ESTUDIO DEL MERCADO ELECTRICO 1988 – 2002
RESUMEN SECTOR ELECTRICO
DEMANDA MAXIMA BRUTA (MW)

AREA O SISTEMA	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
01 NORESTE	2348	2648	2724	2893	3008	3251	3462	3745	4045	4322	4616	4979	5350	5686	6044
INCREMENTO (%)	0.73	12.78	2.87	6.21	8.09	4.94	6.49	8.17	8.01	6.85	6.80	7.86	7.45	6.32	6.29
02 NOROESTE	1383	1472	1574	1626	1648	1704	1790	1892	2000	2110	2231	2381	2529	2669	2829
INCREMENTO (%)	2.07	6.44	6.93	3.30	1.36	3.40	5.05	5.70	5.71	5.50	5.73	6.72	6.22	5.54	5.99
03 NORTE	1220	1365	1511	1499	1533	1639	1741	1829	1919	2002	2092	2190	2290	2395	2506
INCREMENTO (%)	0.83	11.87	10.81	–0.78	2.27	6.91	6.22	5.06	4.92	4.33	4.50	4.68	4.57	4.59	4.63
04 BAJA CALIFORNIA NTE	932	1081	1136	1122	1226	1327	1413	1486	1581	1684	1568	1672	1784	1905	2034
INCREMENTO (%)	6.00	15.99	5.09	–1.23	9.46	8.08	6.48	5.17	6.39	6.51	–6.89	6.63	6.70	6.78	6.77
05 BAJA CALIFORNIA SUR	111	115	127	132	139	145	152	159	167	175	185	195	206	218	230
INCREMENTO (%)	12.12	3.60	10.43	3.94	5.30	4.32	4.83	4.61	5.03	4.79	5.71	5.41	5.64	5.83	5.50
06 CENTRAL–CFE	768	869	935	939	965	1029	1160	1241	1325	1468	1585	1670	1774	1861	1952
INCREMENTO (%)	17.48	13.45	7.59	0.43	2.77	6.63	12.73	6.98	6.77	10.79	7.97	5.36	6.23	4.90	4.89
07 OCCIDENTAL	3171	3447	3692	3850	3842	4162	4439	4687	4974	5256	5556	5911	6244	6634	7045
INCREMENTO (%)	7.16	8.70	7.11	4.28	–0.21	8.33	6.66	5.59	6.12	5.67	5.71	6.39	5.63	6.25	6.20
08 ORIENTAL	3277	3315	3458	3536	3540	3711	4008	4256	4478	4691	4946	5195	5454	5747	6020
INCREMENTO (%)	6.64	1.16	4.31	2.26	0.11	4.83	7.85	6.22	5.19	4.80	5.44	5.03	4.99	5.37	4.75
09 PENINSULAR	429	472	512	542	589	632	692	760	834	904	978	1056	1137	1228	1323
INCREMENTO (%)	9.72	10.02	8.47	5.86	8.67	7.30	9.49	9.83	9.74	8.39	8.19	7.98	7.67	8.00	7.74
10 CENTRAL–CLFC	3783	4000	4155	4263	4337	4496	4653	4809	4969	5135	5309	5488	5673	5851	6067
INCREMENTO (%)	0.29	5.87	3.84	2.60	1.74	3.67	3.49	3.35	3.33	3.34	3.39	3.37	3.37	3.14	3.69
SUBTOTAL	17420	18794	19824	20375	20919	22096	23508	24863	26290	27747	29066	30737	32441	34186	36050
INCREMENTO (%)	4.28	7.89	5.48	2.78	2.67	5.63	6.39	5.76	5.74	5.54	4.75	5.75	5.54	5.41	5.42
11 PEQUEÑOS SISTEMAS	13	13	13	15	14	16	17	17	18	19	20	21	23	24	25
INCREMENTO (%)	8.33	0.00	0.00	15.38	–6.67	14.29	6.25	0.00	5.88	5.56	5.26	5.00	9.52	4.35	4.17
TOTAL	17433	18807	19837	20390	20933	22112	23525	24880	26308	27766	29086	30758	32464	34220	36075
INCREMENTO (%)	4.28	7.88	5.48	2.79	2.66	5.63	6.39	5.78	5.74	5.54	4.75	5.75	5.56	5.41	5.42

EL PASO ELECTRIC COMPANY
ESTIMATED CFE NORTHEAST REGION

	1993	1994	1995	1996	1997	1998
1.0 GENERATION RESOURCES						
1.1 ALTAMIRA	770	770	770	770	770	770
1.2 MONTERREY	590	590	590	590	590	590
1.3 RIO BRAVO	375	375	375	375	375	375
1.4 NAVA	1900	1900	1900	1900	1900	1900
1.5 POSQUERIA	376	376	376	376	376	376
1.6 NUEVO LAREDO	22	22	22	22	22	22
1.7 MUZQUIZ	24	24	24	24	24	24
1.8 S.P. GARCIA	24	24	24	24	24	24
1.9 MONCLOVA	78	78	78	78	78	78
1.10 CD. DEL MAIZ	18	18	18	18	18	18
1.11 NVA. CD. GUERRERO	32	32	32	32	32	32
1.12 ACUNA	66	66	66	66	66	66
1.13 PLANNED ADDITIONS:						
1.13.1 CARBON 3		350	350	350	350	350
1.13.1 CARBON 4			350	350	350	350
1.0 TOTAL GENERATION RESOURCES	4275	4625	4975	4975	4975	4975
2.0 IMPORTS/EXPORTS * :						
2.1 NORTE REGION	(200)	(200)	(200)	(200)	(200)	(200)
2.2 SOUTHERN	600	600	600	600	600	600
0 TOTAL IMPORTS:	400	400	400	400	400	400
3.0 NET RESOURCES FOR DEMAND	4675	5025	5375	5375	5375	5375
4.0 TOTAL SYSTEM DEMAND	3251	3462	3745	4045	4322	4616
5.0 MARGIN OVER TOTAL DEMAND (MW)	1424	1563	1630	1330	1053	759
5.1 MARGIN OVER TOTAL DEMAND (PCT)	44%	45%	44%	33%	24%	16%
6.0 LARGEST SINGLE HAZARD **	350	350	350	350	350	350

NOTE: * ESTIMATED IMPORTS/EXPORTS.

** CFE LARGEST PLANT OF 350 MW AT CARBON II.

1) ELECTRICITY DEMAND FORECASTS TO 2002 APPEAR IN CFE'S "DESARROLLO DEL MERCADO ELECTRICO", PULISHED IN 1993.

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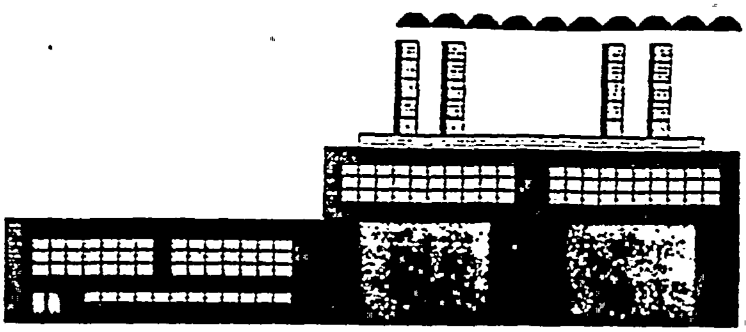
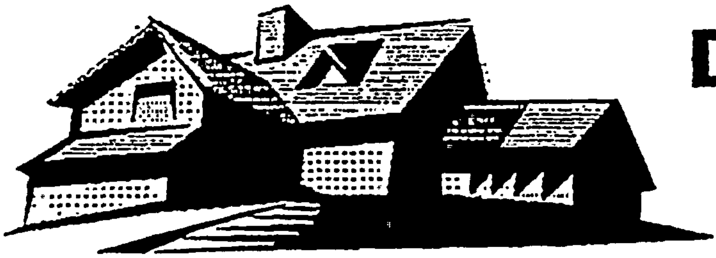
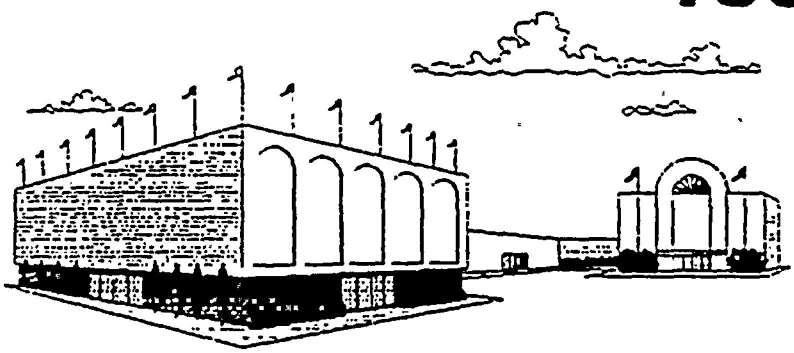




DESARROLLO DEL MERCADO ELECTRICO 1988 - 2002



1993

COMISION FEDERAL DE ELECTRICIDAD

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02 NOROESTE	1383	1472	1574	1626	1648	1704	1790	1892	2000	2110	2231	2381	2529	2669	2829
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03 NORTE	1220	1368	1511	1499	1533	1639	1741	1829	1919	2002	2092	2190	2290	2395	2506
INCREMENTO (%)	0.83	11.87	10.81	−0.79	2.27	6.91	6.22	5.05	4.92	4.33	4.50	4.68	4.57	4.59	4.63
04 BAJA CALIFORNIA NTE	932	1081	1136	1122	1228	1327	1413	1486	1581	1684	1568	1672	1784	1905	2034
INCREMENTO (%)	8.00	15.99	5.09	−1.23	9.45	8.06	6.48	5.17	6.39	6.51	−6.89	6.63	6.70	6.78	6.77
05 BAJA CALIFORNIA SUR	111	115	127	132	139	145	152	159	167	175	185	196	208	218	230
INCREMENTO (%)	12.12	3.60	10.43	3.94	5.30	4.32	4.83	4.61	5.03	4.79	5.71	5.41	5.64	5.63	5.50
06 CENTRAL–CFE	766	869	935	939	965	1029	1160	1241	1325	1466	1585	1670	1774	1861	1952
INCREMENTO (%)	17.46	13.45	7.59	0.43	2.77	6.63	12.73	6.98	6.77	10.79	7.97	5.36	6.23	4.90	4.89
07 OCCIDENTAL	3171	3447	3692	3850	3842	4162	4439	4687	4974	5256	5556	5911	6244	6634	7045
INCREMENTO (%)	7.18	8.70	7.11	4.28	−0.21	8.33	6.66	5.59	6.12	5.67	5.71	6.39	5.63	6.25	6.20
08 ORIENTAL	3277	3315	3458	3536	3540	3711	4006	4255	4478	4691	4946	5186	5454	5747	6020
INCREMENTO (%)	6.64	1.16	4.31	2.26	0.11	4.83	7.95	6.22	5.19	4.80	5.44	5.03	4.90	5.37	4.75
PENINSULAR	429	472	512	542	589	632	692	760	834	904	978	1056	1137	1228	1323
INCREMENTO (%)	9.72	10.02	8.47	5.86	8.67	7.30	9.49	9.83	9.74	8.39	8.19	7.98	7.67	8.00	7.74
10 CENTRAL–CLFC	3783	4009	4155	4263	4337	4498	4653	4809	4969	5136	5309	5488	5673	5851	6067
INCREMENTO (%)	0.29	5.97	3.64	2.60	1.74	3.67	3.49	3.35	3.33	3.34	3.39	3.37	3.37	3.14	3.69
SUBTOTAL	17420	18794	19824	20375	20919	22096	23508	24863	26290	27747	29066	30737	32441	34196	36060
INCREMENTO (%)	4.28	7.89	5.48	2.78	2.67	5.63	6.39	5.76	5.74	5.54	4.75	5.75	5.54	5.41	5.42
11 PEQUEÑOS SISTEMAS	13	13	13	15	14	16	17	17	18	19	20	21	23	24	25
INCREMENTO (%)	8.33	0.00	0.00	15.38	−6.67	14.29	6.25	0.00	5.88	5.56	5.26	5.00	9.52	4.35	4.17
TOTAL	17433	18807	19837	20390	20933	22112	23525	24880	26308	27766	29086	30758	32464	34220	36075
INCREMENTO (%)	4.28	7.88	5.48	2.78	2.66	5.63	6.39	5.76	5.74	5.54	4.75	5.75	5.56	5.41	5.42

County of Placer)
) SS.
State of California)

AFFIDAVIT OF HARRISON K. CLARK

My name is Harrison K. Clark. I am Manager of the Western Office of Power Technologies, Inc. (PTI). I have previously prepared affidavits that have been filed in Docket NO. TX94-2-000 regarding the improvements to the transmission system of Southwestern Public Service Company (Southwestern) that may be needed to enable Southwestern to provide the transmission services requested by El Paso Electric Company (EPEC) and the CSW Operating Companies.

Response to Fulton Affidavit and New Studies

As discussed in my earlier affidavits, under my guidance PSO ran load flow and stability studies to estimate what system improvements would be necessary. Those studies indicate that Southwestern would only need to make minor system modifications to provide the services. In particular, the studies showed that Southwestern may need to upgrade two transformers -- the Eddy County 230/115 kV transformer and the Tuco 230/115 kV transformer. Affidavit of Harrison K. Clark (TX94-2-000, Nov. 4, 1993) at 6. In my earlier affidavits, I indicated that it might also be necessary to install some new capacitor banks on Southwestern's system to support voltage. Id. I also explained that PSO's studies were based upon an amalgam of the official 1999 Southwest Power Pool and West Central Region base case models. Affidavit of Harrison K. Clark (TX94-2-000, Jan. 12, 1994), at 3-4. This model did not include a detailed representation of all of the buses on

Southwestern's system because PSO did not have access to such data. However, in my earlier affidavits I explained that studies performed on a more detailed Southwestern system model may show need for some minor equipment upgrades on lower voltage circuits that are not explicitly represented in the SPP model. I also expressed my confidence that such studies of Southwestern's system would not show the need for major transmission line changes or additions at 230 kV. Clark Aff. (Jan. 12, 1994) at 2.

I have reviewed the affidavit and exhibits of Mr. Fulton that were attached to Southwestern's Motion to Intervene in FERC Docket No. EC94-7-000. Affidavit of John S. Fulton (EC94-2-000, Feb. 23, 1994). Attached to Mr. Fulton's affidavit as Exhibit JSF-3 is a list of the internal system improvements he indicates would be required to provide the requested transmission services. Mr. Fulton's list reflects the results of additional load flow studies he performed since the time that Southwestern filed its Motion to Intervene in Docket No. TX94-2-000.

In that proceeding, we criticized Southwestern's earlier studies for failure to measure needed system modifications against base cases which would show the modifications that would be needed in the absence of the requested transfers. Clark Aff. (Jan. 12, 1994), at 4-5. We also criticized Mr. Fulton's earlier studies for using transfer amounts in excess of those for which service had been requested. Clark Aff. (Jan. 12, 1994), at 5-6. Apparently in preparation of Southwestern's Motion to Intervene in the merger proceeding, Mr. Fulton ran additional studies in which he took care not to repeat these errors.

In these new studies, Mr. Fulton used a feature of the PTI software that permits a seriatum analysis of the effects of outages

of individual system components on the loads imposed on other system components. He ran three sets of cases for each of the Winter peak period and the Summer peak period of the year 2000, or six cases in all. Fulton Aff. (Feb. 23, 1994), Exh. JSF-4. The three cases for each peak period consisted of a base case without any transfers, a change case modeling a 133 MW west to east transfer and a change case modelling a 133 MW east to west transfer. From these cases he identified contingencies that resulted in overloading of particular system components.

As did the Applicants, Mr. Fulton includes on his list of system components that require upgrading the Eddy County 230/115 kV transformer. Fulton Aff. (Feb. 23, 1994), Exh. JSF-3. The Applicants proposed to address this problem by changing out a transformer bank in the existing substation at an estimated net cost of about $1.2 million (1993 dollars). Workpapers of James A. Bruggeman, filed Feb. 3, 1994, at 9. In contrast, Southwestern proposes to replace its existing transformer with a new, larger transformer at a cost of $2.0 million (1993 dollars). Fulton Aff. (Feb. 23, 1994), Exh.JSF-3. Southwestern's cost is excessive considering that the circuit breakers are existing and the replaced transformer will be available for use elsewhere.

Mr. Fulton also includes on his list of necessary upgrades the replacement of the Cunningham Plant transformer, also at a cost of $2 million. Fulton Aff. (Feb. 23, 1994), Exh.JSF-3. Because the exhibits provide no justification for this modification, I am unable to offer further comment.

Mr. Fulton has further included on his list of required internal system improvement the reconductoring and/or rebuilding of three transmission lines and the addition of a transformer at the

Gray County Interchange at a total cost of $2.68 Million. Fulton Aff. (Feb. 23, 1994), Exh.JSF-3. All of these changes are proposed to address overloads of just a few percent or less, and are unnecessary if Southwestern employs the SPP Reliability Criteria or a otherwise were to follow normal utility reliability practices.

For example, Mr. Fulton contends it is necessary to add a new transformer at the Gray County Interchange to take account of a contingency that results in a loading that is just 85.2% of the manufacturer's top continuous rating, or 100.2% of the continuous thermal rating applied by Southwestern, which is 85% of the manufacturer's top continuous rating. Fulton Aff. (Feb. 23, 1994), Exh.JSF-4.

Ordinarily, a utility will not add a new transformer to guard against a two-tenths of 1% loading above the continuous thermal rating regardless of the philosophy of selecting the continuous thermal rating. Instead, the utility will adopt operating procedures such as generation dispatch changes, system re-configuration, opening overloaded lines, or transfer curtailment that can be done to eliminate the overload within 15 minutes after it occurs. Such operating procedures are widely used to accommodate transformer overloads of 120% or more of the continuous thermal rating. In his affidavit filed in Docket TX94-2-000, Mr. Fulton stated that "the remaining 15% of the transformer capacity is available for emergencies" indicating that Southwestern follows this procedure. Affidavit of John S. Fulton (TX94-2-000, Dec. 20, 1993), at 6. On this basis, Southwestern would allow transformer overloads to reach 118% of its "85%" rating, such overload being 100% of the manufacturer's top continuous rating (1.18 x 0.85 = 1.0). However, Mr. Fulton apparently believes it

reasonable to place its emergency transformer capability off limits to the Applicants.

Similarly, Mr. Fulton proposes to reconductor several transmission lines on the basis of minimal overloads. He suggests that $630,000 be spent to reconductor the Yoakum County Interchange to ODC 115 kV line because in one contingency the line was loaded to 100% of its continuous thermal rating. Fulton Aff. (Feb. 23, 1994), Exh. JSF-4, Schedule 5, 3rd page. Likewise he calls for reconductoring the Osage-East Canyon 115 kV line based upon a 2% overload, Fulton Aff. (Feb. 23, 1994), Exhibit JSF-4, Schedule 2, 3rd page, and to upgrade the Potter County-Harrington 230 kV line based upon a 3.4% overload. Fulton Aff. (Feb. 23, 1994), Exh. JSF-4, Schedule 5, 4th page. As is the case for transformers, utilities normally allow much larger overloads than these where re-dispatch, system re-configuration, opening overloaded lines, or transfer curtailment can correct the overload well before damage can be done. Under most line thermal rating practices, lines are given long-time overload ratings of 105 to 110% of continuous rating and short-time overload ratings of 110 to 120% of continuous ratings. Long-time ratings are usually four hour ratings and short-time ratings are usually 15 minute ratings. Mr. Fulton has not addressed the practice of using overload capability of transformers and lines or the dispatch, system reconfiguration, or transfer curtailment options which are available to Southwestern and are accepted practices covered by the SPP Reliability Criteria. Southwestern controls the Eddy County converter, and thus has at least the transfer curtailment option available to it.

On page 5 of his Affidavit, Mr. Fulton states that "internal system improvements, as shown in Exhibit JSF-4, will have to be

made due solely to Applicants proposed transaction across Southwestern's system." These additions may be triggered by the introduction of the 133 MW transfer, but they are hardly "due solely" to the 133 MW transfer. Some of the facilities may be very close to their thermal ratings without the 133 MW transfer and would reach those ratings in a few short years even without the 133 MW transfer. Also, in all cases, the upgrades called for by Mr. Fulton provide capacity well above that required to accommodate the 133 MW transfer.

In addition, in estimating new equipment costs, Mr. Fulton has apparently not allowed for the salvage value of replaced transformers. Transformers have a life expectancy of about 40 years, and are normally moved to new locations where their ratings are adequate for some future period of growth.

Based upon the information contained in Mr. Fulton's affidavit and exhibits, I conclude that the only internal upgrade that can be definitively identified as being necessary based on the studies completed to date is the Eddy County transformer. This upgrade is necessary to accommodate Southwestern's practice of rating its transformers at 85% of the manufacturer's top continuous rating because the existing transformer would operate continuously above this rating under certain normal operating conditions.

Mr. Fulton also states he did "additional studies" that show "that Southwestern needs to increase its interconnection capability with the SPP" to accommodate the 133 MW transfer requested by the Applicants. Fulton Aff. (Feb. 23, 1994), at 6. However, he does not state the nature of these studies, load flow or stability, and does not present them. Until such studies are presented and Southwestern clearly demonstrates that there are errors in the

Applicants' load flow and stability studies showing the existing system is adequate for the 133 MW transfers, I will continue to believe no new interconnection between Southwestern and the SPP is required.

Mr. Fulton states: "The studies filed in my affidavit in Docket No. TX94-2-000 fully support the fact that another strong 345 kV interconnect is needed...." Fulton Aff. (Feb. 23, 1994), at 7. However, Mr. Fulton did not present any such studies with that affidavit either. Southwestern has provided only a record of system failures associated with loss of generation. Southwestern's past experience only demonstrates that severe unreliability resulted from installing a large generator without the necessary supporting ties, and that when the needed tie from Tuco to Oklaunion was added, the system was made very reliable.[1] This experience in no way demonstrates the need for another tie or a tie upgrade to accommodate a 133 MW transfer. Applicants load flow and stability studies have confirmed that there is sufficient margin in the Southwestern to SPP ties to accommodate their request.

Additionally, Mr. Fulton references early work done by the Applicants as indicating a possible need for the construction of a 345 kV interconnect from PSO's Southwestern Station to Elk City and on to Amarillo at a cost of $53,760,000 to support the 133 MW transfer. Fulton Aff. (Feb. 23, 1994), at 7. In this early work, Applicants, based on earlier representation made by Southwest assumed an additional tie would be needed for stability, but did not perform stability studies to confirm this. When I was engaged

[1] Interestingly, the SPP Reliability Criteria warn against building large generating plants without sufficient ties to provide reliable backup.

last summer to assist Applicants, one of my first tasks was to guide PSO in making appropriate stability studies to study the need for this interconnect. As explained in my earlier affidavits, this stability work, as well as the associated load flow work, showed no need for a new interconnect. Clark Aff. (Nov. 4, 1993), at 5-6.

Response to Kalt Affidavit

I have also read the affidavit of Professor Joseph P. Kalt and his contentions regarding the ability of CFE to move power between the Juarez area of CFE's Norte region and the Noreste region near the Central Power and Light (CPL) system, and the resulting ability of EPEC and CPL to compete for electricity markets in Mexico. Professor Kalt correctly indicates that CFE has plans to upgrade one transmission line and add another and that these lines will increase the transfer capability between the Noreste and Norte regions. However, these upgrades will not make it possible for CPL to economically reach the Juarez area that EPEC now serves through EPEC's two 115 kV interties to CFE at Juarez, or for EPEC to reach the Laredo or Matamoros area loads to which CPL's system can be connected.

One of my first tasks for CSW was to study the technical feasibility and costs of moving power between CPL and EPEC through the CFE Noreste and Norte regions. There exists a major north-south bottleneck within the Norte region between Chihuahua and Juarez that is well known to CFE. The line upgrade and addition mentioned by Professor Kalt will not relieve this bottleneck.

The bottleneck is associated with transmission lines from Juarez south to Chihuahua. The problem is evident in the one-line which is attached to this affidavit as Exhibit HKC-1. The first

two line sections south of Juarez are very long. They operate at 230 kV and impose voltage and stability limits on flows between Juarez and the remainder of the Norte region to the south. There is another bottleneck south of Camargo. It consists of two very long 230 kV lines.

The most helpful of the lines mentioned by Professor Kalt is a new line from Hercules eastward to Rio Escondido. It is shown as a dashed line in Exhibit HKC-1. This line gives CFE, effectively, three 230 kV lines from Chihuahua to the remainder of the Norte region and the Noreste region. However, because this line connects with the existing Norte north-south system at a point south of Chihuahua, operates at 230 kV, and itself is very long, it does very little to augment CFE's transfer capability north of Chihuahua.

The line upgrade between Monterrey and Torreon Sur, mentioned by Professor Kalt, is a change in the operating voltage of an existing line. The line voltage will be increased from 230 kV to 400 kV. It is the southernmost of the two dashed lines shown Exhibit HKC-1. This line significantly improves Norte to Noreste transfer capability in the south of these regions, but is too far from Chihuahua to measurably reduce the north-south bottleneck.

The capacity of the lines north of Chihuahua is severely limited by voltage and stability. The severely limited capacity of these lines is and will continue to be utilized by CFE, leaving little opportunity for EPEC or CPL to use them to access CFE loads near the other's border.

There are less severe but significant similar problems within the Noreste region. CFE lines from Monterrey to the Reynosa area are about 160 km (100 miles) in length and are not sufficient to

backup generation at Rio Bravo in the summer months when Reynosa, Rio Bravo, and Matamoros loads are high. CFE faces costly solutions to this problem simply to cover its own transfers into the area. Any attempt to ship power from the Juarez area into the Matamoros area during the summer when loads in the area are high would severely compound this problem.

Finally, the distance from CPL's access point at Matamoros and EPEC's access point at Juarez is, effectively, over 1370 km (850 miles) via the CFE transmission system. Most of this transmission operates at a voltage of no more than 230 kV. As a result, losses are very high for any power that might leave CPL and reach Juarez - or leave EPEC and reach Matamoros. The losses associated with such transfers would be on the order of 30%. In other words CPL would have to send 100 MW across the border into Mexico to have 70 MW reach Juarez. Such high losses impose a severe economic stumbling block for any potential transactions attempting to reach beyond Juarez in the case of EPEC or beyond Monterrey in the case of CPL.

Harrison K. Clark

Harrison K. Clark

CERTIFICATE OF ACKNOWLEDGMENT

State of California

County of Placer } SS.

On 3-18-94 (date) before me, Linda Sue Hall (Notary)

personally appeared Harrison K. Clark

personally known to me (or proved to me on the basis of satisfactory evidence) to be the person(s) whose name(s) is/are subscribed to the within instrument and acknowledged to me that he/she/they executed the same in his/her/their authorized capacity(ies), and that by his/her/their signature(s) on the instrument the person(s), or the entity upon behalf of which the person(s) acted, executed the instrument.

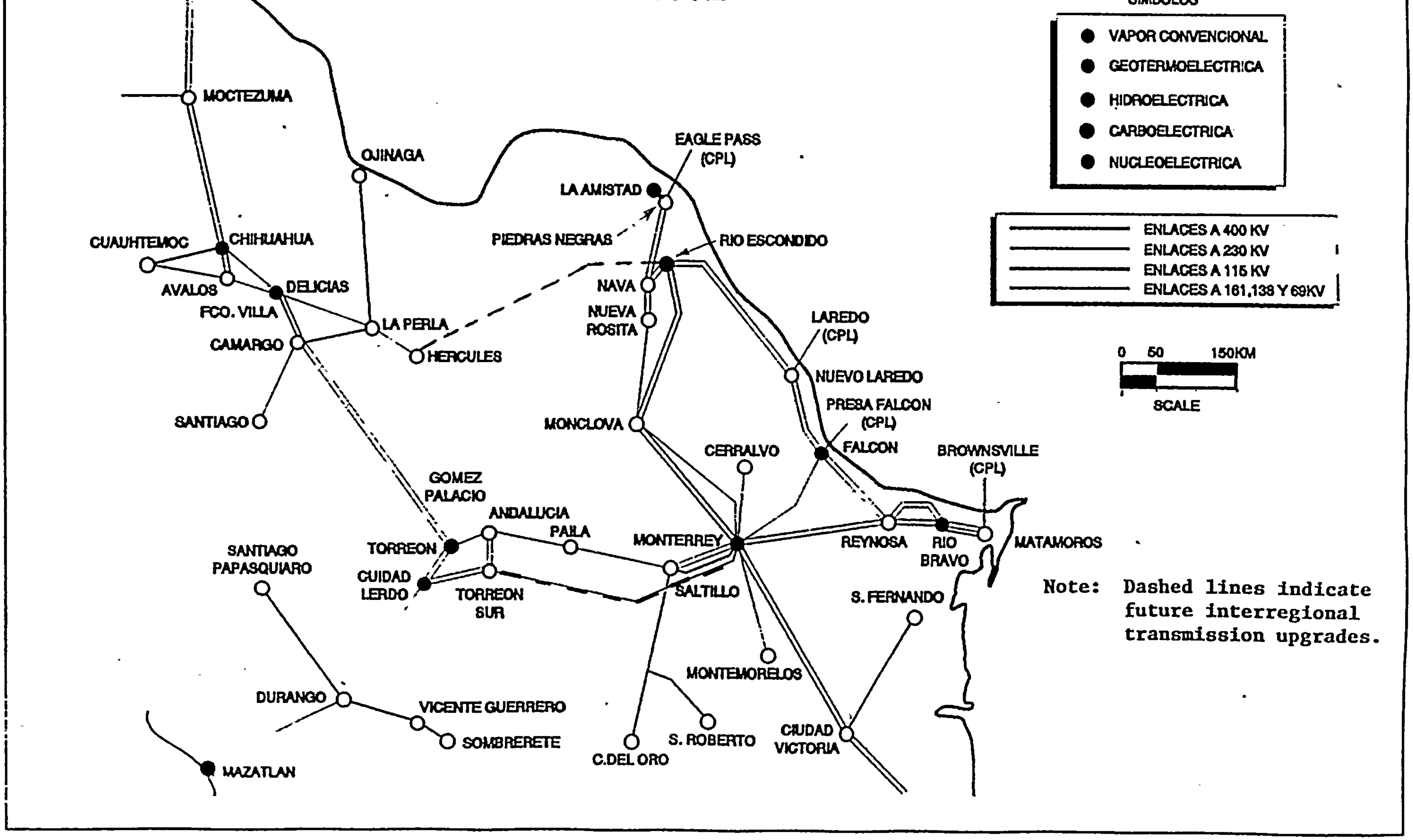
WITNESS my hand and official seal.

Linda S Hall

Notary's Signature

PWR1 LINDA SUE HALL Comm. # 1002785 NOTARY PUBLIC - CALIFORNIA Placer County My Comm. Expires Aug. 22, 1997 PWR1

CFE SISTEMAS ELECTRICOS AREA NORESTE Y NORTE 1992



Note: Dashed lines indicate future interregional transmission upgrades.

EXHIBIT HKC-1

COUNTY OF EL PASO)
) SS.
STATE OF TEXAS)

AFFIDAVIT OF FREDERIC E. MATTSON

My name is Frederic E. Mattson. I am Vice President of Power Supply of El Paso Electric Company.

On June 1, 1992, I telephoned Mr. David Wilks of Southwestern Public Service Company (SPS) to ask that SPS provide El Paso firm transmission service across SPS' system so that El Paso could purchase from Public Service Company of Oklahoma (PSO) power needed to backup El Paso's 150 MW sale of power and energy to Comisión Federal de Electricidad (CFE). In April 1991, El Paso and CFE had entered into a power sales agreement that has a 5½ year term ending December 31, 1996. In order to assure that we could meet our commitment to CFE, in 1992 we sought back-up power supplies for the then remaining term of the CFE sale.

At the time that I made the phone call to Mr. Wilks, El Paso was negotiating, but had not signed, an agreement with SPS for the purchase of the required back-up power supply. However, while El Paso's negotiations with SPS were ongoing, I learned that a lower cost supply could be purchased from PSO. In order to gain access to firm power supplies from PSO, it was necessary to obtain transmission service from SPS.

Mr. Wilks denied the request. Mr. Wilks said that SPS could not provide wheeling on its transmission system in an east to west direction without overloading its Tuco 230-345 KV autotransformer in the event that SPS were to lose one of its 550 MW Tolk generating units. Mr. Wilks also said that the SPS system would experience voltage sags in such an event if wheeling were also being provided. Mr. Wilks said that the autotransformer had a 570 MW limit.

Mr. Wilks said that his explanation for the denial of service was based on a load flow study that SPS had done in April 1989. Mr. Wilks also explained that one of SPS' wholesale customers, Lubbock Power and Light, had earlier requested SPS to wheel power and that SPS had had to explain its refusal to the Public Utility Commission of Texas. Finally, Mr. Wilks said that a planned intertie to the east would give SPS the ability to provide east to west wheeling on its system in the future.

Because SPS would not provide transmission service to deliver to El Paso the lower cost power supply that was available from PSO, El Paso went forward with the more expensive purchase from SPS. Through September 30, 1993, El Paso has paid $8.3 million for firm power to back up El Paso's sale of firm power to CFE.

Frederic E. Mattson

Frederic E. Mattson

Subscribed and sworn to before me
this 29 day of October 1993.

Linda Martz

Notary Public

SOUTHWESTERN PUBLIC SERVICE COMPANY
LOAD AND CAPACITY RESOURCE PLAN
FILED MARCH 1, 1994 WITH THE PUBLIC UTILITY COMMISSION OF TEXAS

Calendar Year 1995	MW
Peak Demand After Adjustments	3,242
Installed Capacity	4,062
Less Sales to Other Utilities:	
PNM[1]	200
TNP	66
EPE	50
Less Sales to Municipal Customers:[2]	
City of Floydada	11
City of Brownfield	53
City of Tulia	26
Lubbock Power & Light	40
Net Resources	3,616
Peak demand plus 15% reserve margin[3]	3,794
Deficit at 15% reserve margin	**(178)**
Peak demand plus 18% reserve margin	3,826
Deficit at 18% reserve margin	**(210)**

1 Southwestern calls this "contract power" (Hudson, page 9).

Mr. Hudson implies this is a capacity sale, suggesting: "Southwestern will not be able to make any *additional capacity* sales through the Blackwater HVDC interconnection." [Emphasis added.]

The New Mexico PSC considers this transaction to be the equivalent of a firm capacity purchase by PNM. (Case No. 2146, Part II.)

2 Southwestern's February 28, 1994 Resource Plan, Request 4.02, pages 42-45 of 52.

3 Southwestern's PUCT filing indicates that it recently reduced the capacity margin it uses for planning purposes to 13 percent (equivalent of a 15 percent reserve margin) from 15.25 percent capacity margin (equivalent to an 18 percent reserve margin). SPP guidelines "require individual systems to maintain minimum capacity margins of 15.25 percent or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available shall not be greater than one occurrence in ten years provided that in no case shall the minimum capacity margin be less than...13 percent..." Southwestern's PUCT filing contains no evidence that Southwestern has conducted a loss of load probability study to support its use of a 13 percent capacity margin for planning purposes.

SOUTHWESTERN DECEMBER 31, 1993
LOAD AND CAPACITY RESOURCE PLAN
FILED MARCH 1, 1994 WITH THE PUBLIC UTILITY COMMISSION OF TEXAS

Calendar Year 1996	MW
Peak Demand After Adjustments	3,299
Installed Capacity	4,110
Less Sales to Other Utilities:	
PNM[1]	200
EDE[2]	35
TNP	66
EPE	75
Less Sales to Municipal Customers:[3]	
City of Floydada	11
City of Brownfield	53
City of Tulia	26
Lubbock Power & Light	45
Net Resources	3,599
Peak demand plus 15% reserve margin[4]	3,794
Deficit at 15% reserve margin	(195)
Peak demand plus 18% reserve margin	3,893
Deficit at 18% reserve margin	(294)

1 Southwestern calls this "contract power" (Hudson, page 9).

Mr. Hudson implies this is a capacity sale, suggesting: "Southwestern will not be able to make any *additional capacity* sales through the Blackwater HVDC interconnection." [Emphasis added.]

The New Mexico PSC considers this transaction to be the equivalent of a firm capacity purchase by PNM. (Case No. 2146, Part II.)

2 Southwestern calls this "an electric power service agreement" (Hudson, page 13). However, Mr. Hudson states: ". . . in order to make the Sale to Empire District, Southwestern had to make a "System Participation Capacity" sale . . . ." EDE shows this as a capacity purchase in its Load and Resource plan.

3 Southwestern's February 28, 1994 Resource Plan, Request 4.02, pages 42-45 of 52.

4 Southwestern's PUCT filing indicates that it recently reduced the capacity margin it uses for planning purposes to 13 percent (equivalent of a 15 percent reserve margin) from 15.25 percent capacity margin (equivalent to an 18 percent reserve margin). SPP guidelines "require individual systems to maintain minimum capacity margins of 15.25 percent or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available shall not be greater than one occurrence in ten years provided that in no case shall the minimum capacity margin be less than...13 percent..." Southwestern's PUCT filing contains no evidence that Southwestern has conducted a loss of load probability study to support its use of a 13 percent capacity margin for planning purposes.

SOUTHWESTERN PUBLIC SERVICE COMPANY
LOAD AND CAPACITY RESOURCE PLAN
FILED MARCH 1, 1994 WITH THE PUBLIC UTILITY COMMISSION OF TEXAS

Calendar Year 1997	MW
Peak Demand After Adjustments	3,355
Installed Capacity	4,135
Less Sales to Other Utilities:	
PNM[1]	200
EDE[2]	35
TNP	66
Less Sales to Municipal Customers:[3]	
City of Floydada	11
City of Brownfield	53
City of Tulia	26
Lubbock Power & Light	55
Net Resources	3,689
Peak demand plus 15% reserve margin[4]	3,858
Deficit at 15% reserve margin	**(169)**
Peak demand plus 18% reserve margin	3,959
Deficit at 18% reserve margin	**(270)**

1 Southwestern calls this "contract power" (Hudson, page 9).

Mr. Hudson implies this is a capacity sale, suggesting: "Southwestern will not be able to make any *additional capacity* sales through the Blackwater HVDC interconnection." [Emphasis added.]

The New Mexico PSC considers this transaction to be the equivalent of a firm capacity purchase by PNM. (Case No. 2146, Part II.)

2 Southwestern calls this "an electric power service agreement" (Hudson, page 13). However, Mr. Hudson states: ". . . in order to make the Sale to Empire District, Southwestern had to make a "System Participation Capacity" sale . . . ." EDE shows this as a capacity purchase in its Load and Resource plan.

3 Southwestern's February 18, 1994 Resource Plan, Request 4.02, pages 22-45 of 52.

4 Southwestern's PUCT filing indicates that it recently reduced the capacity margin it uses for planning purposes to 13 percent (equivalent of a 15 percent reserve margin) from 15.25 percent capacity margin (equivalent to an 18 percent reserve margin). SPP guidelines "require individual systems to maintain minimum capacity margins of 15.25 percent or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available shall not be greater than one occurrence in ten years provided that in no case shall the minimum capacity margin be less than...13 percent..." Southwestern's PUCT filing contains no evidence that Southwestern has conducted a loss of load probability study to support its use of a 13 percent capacity margin for planning purposes.

SOUTHWESTERN PUBLIC SERVICE COMPANY
LOAD AND CAPACITY RESOURCE PLAN
FILED MARCH 1, 1994 WITH THE PUBLIC UTILITY COMMISSION OF TEXAS

Calendar Year 1998	MW
Peak Demand After Adjustments	3,414
Installed Capacity	4,273
Less Sales to Other Utilities:	
PNM[1]	200
EDE[2]	35
TNP	66
Less Sales to Municipal Customers:[3]	
City of Floydada	11
City of Brownfield	53
City of Tulia	26
Lubbock Power & Light	60
Net Resources	3,822
Peak demand plus 15% reserve margin[4]	3,926
Deficit at 15% reserve margin	(104)
Peak demand at 18% reserve margin	4,029
Deficit at 18% reserve margin	(207)

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1 Southwestern calls this "contract power" (Hudson, page 9).

Mr. Hudson implies this is a capacity sale, suggesting: "Southwestern will not be able to make any *additional capacity* sales through the Blackwater HVDC interconnection." . [Emphasis added.]

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2 Southwestern calls this "an electric power service agreement" (Hudson, page 13). However, Mr. Hudson states: ". . . in order to make the Sale to Empire District, Southwestern had to make a "System Participation Capacity" sale . . . ." EDE shows this as a capacity purchase in its Load and Resource plan.

3 Southwestern's February 28, 1994 Resource Plan, Request 4.02, pages 42-45 of 52.

4 Southwestern's PUCT filing indicates that it recently reduced the capacity margin it uses for planning purposes to 13 percent (equivalent of a 15 percent reserve margin) from 15.25 percent capacity margin (equivalent to an 18 percent reserve margin). SPP guidelines "require individual systems to maintain minimum capacity margins of 15.25 percent or as an alternative, a probability study made so as to insure that the probability of load exceeding capacity available shall not be greater than one occurrence in ten years provided that in no case shall the minimum capacity margin be less than...13 percent..." Southwestern's PUCT filing contains no evidence that Southwestern has conducted a loss of load probability study to support its use of a 13 percent capacity margin for planning purposes.

SOUTHWESTERN PUBLIC SERVICE COMPANY
P. O. BOX 1261 • AMARILLO, TEXAS 79170 • 806/378-2121

GERALD J DILLER
VICE PRESIDENT
RATES AND REGULATION

February 25, 1994

Commission Filing Clerk
Central Records Division
PUBLIC UTILITY COMMISSION OF TEXAS
7800 Shoal Creek Boulevard
Suite 124S
Austin, TX 78757

RE: Southwestern Public Service Company's December 1993 Load and Capacity Resource Forecast

Dear Commission Filing Clerk:

Pursuant to the Commissions' regulations (P.U.C. SUBST. R. 23.13) and the Commission Staff's filing format, Southwestern Public Service Company ("Southwestern") submits five (5) copies of its December 31, 1993 Load and Capacity Resource Forecast. Included is one diskette copy of the narratives and tables presented in the filing.

If Southwestern can provide the Commission with additional information, please kindly let me know.

Sincerely,

Gerald J Diller

Gerald J. Diller

GJD/bdr

Enclosure

SOUTHWESTERN PUBLIC SERVICE COMPANY

1993 LOAD AND CAPACITY RESOURCE FORECAST

REQUIRED SUBMISSION FOR

FEBRUARY 28, 1994

Southwestern Public Service Company
1993 Load and Capacity Resource Forecast

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PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993

SOUTHWESTERN PUBLIC SERVICE COMPANY

GENERAL REQUEST – UTILITY STATISTICS

UTILITY FULL NAME :	SOUTHWESTERN PUBLIC SERVICE COMPANY
ADDRESS :	P. O. BOX 1261 AMARILLO, TX 79170
PHONE NUMBER :	(806) 378 – 2121
COUNTIES SERVED :	Texas – Armstrong, Bailey, Briscoe, Carson, Castro, Cochran, Crosby, Dallam, Dawson, Deaf Smith, Donley, Floyd, Gaines, Garza, Gray, Hale, Hansford, Hartley, Hemphill, Hockley, Hutchinson, Lamb, Lubbock, Lynn, Moore, Oldham, Parmer, Potter, Randal, Roberts, Sherman, Swisher, Terry, Wheeler, Yoakum New Mexico – Chaves, Curry, Eddy, Lea, Quay, Roosevelt Oklahoma – Beaver, Cimarron, Texas Kansas – Morton

UTILITY CONTACTS:

	NAME	TITLE	PHONE NUMBER	REQUESTS RESPONSIBLE FOR
1	Gerald J. Diller	Vice President, Rates and Regulation	(806) 378–2822	All
2	Lester L. Baldock	Manager, Revenue Requirements	(806) 378–2825	All
3	David T. Hudson	Senior Engineer, Rate Research	(806) 378–2824	All
4	Kathleen Bailey	Manager, Forecasting & Statistical Analysis	(806) 378–2165	All
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PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993
REQUEST 1.01 – BREAKDOWN OF SYSTEM REQUIREMENTS (MW)

SOUTHWESTERN PUBLIC SERVICE COMPANY

TOTAL SYSTEM DATA

COINCIDENT PEAK DEMAND BY SECTOR (MW)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
											PEAK	ADJUSTMENTS TO PEAK DEMAND				PEAK
	RETAIL	RETAIL	RETAIL			STREET			TOTAL		DEMAND (ACTUAL/	EXOGENOUS	ACTIVE	PASSIVE		DEMAND AFTER
YEAR	RESIDENTIAL	COMMERCIAL	INDUSTRIAL	COTTON GINS	IRRIGATION	LIGHTING	MUNIS	MISC.	RETAIL	WHOLESALE	BEFORE ADJS.)	FACTORS	DSM	DSM	TOTAL	ADJS.
1979	421	287	672	1	27	0	41	0	1,449	536	1,985	0	(5)	0	(5)	1,980
1980	526	359	839	1	33	0	51	0	1,809	670	2,479	0	(23)	0	(23)	2,456
1981	544	371	868	1	35	0	53	0	1,872	697	2,569	0	(22)	0	(22)	2,547
1982	503	343	802	1	32	0	49	0	1,730	643	2,373	0	(20)	0	(20)	2,353
1983	563	364	899	1	36	0	55	0	1,958	621	2,579	0	(19)	0	(19)	2,560
1984	579	395	923	1	37	0	56	0	1,991	722	2,713	0	(16)	0	(16)	2,697
1985	603	411	946	1	40	0	58	0	2,059	702	2,761	0	(13)	0	(13)	2,748
1986	613	418	961	1	40	0	59	0	2,092	745	2,837	0	(34)	0	(34)	2,803
1987	594	405	929	1	39	0	57	0	2,025	692	2,717	0	(34)	0	(34)	2,683
1988	611	412	954	1	37	0	50	0	2,065	676	2,741	0	(36)	0	(36)	2,705
1989	652	420	1,042	1	39	0	58	0	2,212	718	2,930	0	(36)	0	(36)	2,894
1990	750	466	1,024	1	37	0	78	0	2,356	800	3,156	0	(78)	0	(78)	3,078
1991	717	450	1,023	1	40	0	88	0	2,319	778	3,097	0	(78)	0	(78)	3,019
1992	697	461	1,022	1	61	0	76	0	2,318	772	3,090	0	(75)	0	(75)	3,015
1993	737	478	1,031	1	90	0	79	0	2,416	838	3,254	0	(76)	0	(76)	3,178
1994	746	481	1,053	1	64	0	81	0	2,426	839	3,265	24	(87)	(8)	(71)	3,194
1995	755	485	1,068	1	65	0	81	0	2,455	869	3,324	97	(162)	(17)	(82)	3,242
1996	766	491	1,087	1	66	0	82	0	2,493	891	3,384	103	(162)	(26)	(85)	3,299
1997	778	498	1,108	1	67	0	83	0	2,535	910	3,445	106	(162)	(34)	(90)	3,355
1998											3,507	112	(162)	(43)	(93)	3,414
1999											3,570	115	(162)	(52)	(99)	3,471
2000											3,635	119	(162)	(61)	(104)	3,531
2001											3,700	122	(162)	(70)	(110)	3,590
2002											3,767	126	(162)	(78)	(114)	3,653
2003											3,834	130	(162)	(87)	(119)	3,715
2004																
2005																
2006																
2007																
2008																

Column (k) historical (1979 – 1993) must be actual peak demand.
Column (k) projected (1994 – 2008) must be peak demand prior to DSM adjustments..

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993
REQUEST 1.01 – BREAKDOWN OF SYSTEM REQUIREMENTS (MW)

SOUTHWESTERN PUBLIC SERVICE COMPANY

TOTAL SYSTEM DATA

	INSTALLED CAPACITY BY FUEL TYPE (NDC)								FIRM PURCHASES FROM:							
	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)
YEAR	TOTAL NG/OIL	COAL	LIGNITE	NUCLEAR	HYDRO	ALT. ENERGY SOURCES	TOTAL INSTALLED CAPACITY	ALLOCATOR	UTILITIES	QFs	OTHER	TOTAL	FIRM OFF-SYSTEM SALES	NET SYSTEM CAPACITY	RESERVE MARGIN MW	RESERVE MARGIN %
1979	2,074	671				42	2,787	100.00000%	66			66	42	2,805	823	41.61%
1980	2,063	1,009				42	3,114	100.00000%	66			66	41	3,111	673	27.47%
1981	1,917	1,044				35	2,996	100.00000%	66			66	49	3,008	659	18.61%
1982	1,911	1,552				35	3,498	100.00000%	66			66	104	3,444	1,091	46.38%
1983	2,030	1,568				35	3,633	100.00000%	0			0	51	3,574	1,028	40.39%
1984	1,983	1,568				35	3,586	100.00000%	0			0	23	3,560	861	31.84%
1985	1,866	2,076				39	3,981	100.00000%	200			200	89	4,079	1,331	48.42%
1986	1,866	2,146				39	4,051	100.00000%	200			200	83	4,156	1,333	44.25%
1987	1,866	2,146				39	4,051	100.00000%	200			200	86	4,152	1,069	34.76%
1988	1,866	2,146				39	4,051	100.00000%	200			200	72	4,168	1,063	34.09%
1989	1,866	2,146				39	4,051	100.00000%	200			200	72	4,168	1,274	44.03%
1990	1,866	2,146				39	4,051	100.00000%	0			0	79	3,960	862	28.66%
1991	1,866	2,146				39	4,051	100.00000%	0			0	39	4,006	987	32.70%
1992	1,877	2,146				39	4,062	100.00000%	0			0	130	3,913	896	29.71%
1993	1,877	2,146				39	4,062	100.00000%	0			0	132	3,910	732	23.04%
1994	1,877	2,146				39	4,062	100.00000%	0			0	166	3,871	677	21.20%
1995	1,877	2,146				39	4,062	100.00000%	0			0	166	3,871	629	19.40%
1996	1,925	2,146				39	4,110	100.00000%	0			0	196	3,865	586	17.75%
1997	1,950	2,146				39	4,135	100.00000%	0			0	181	3,927	572	17.04%
1998	2,088	2,146				39	4,273	100.00000%	0			0	211	4,030	616	18.05%
1999	2,088	2,146				39	4,273	100.00000%	0			0	136	4,137	646	18.60%
2000	2,226	2,146				39	4,411	100.00000%	0			0	136	4,255	724	20.49%
2001	2,226	2,146				39	4,411	100.00000%	0			0	136	4,255	665	18.51%
2002	2,298	2,146				39	4,443	100.00000%	0			0	136	4,327	674	18.44%
2003	2,436	2,146				39	4,621	100.00000%	0			0	136	4,465	750	20.18%
2004																
2005																
2006																
2007																
[illegible]																

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993
REQUEST 1.01 – BREAKDOWN OF SYSTEM REQUIREMENTS (MW)

SOUTHWESTERN PUBLIC SERVICE COMPANY

STATE OF TEXAS DATA

COINCIDENT PEAK DEMAND BY SECTOR (MW)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)	(p)
											PEAK DEMAND	ADJUSTMENTS TO PEAK DEMAND				PEAK DEMAND
YEAR	RETAIL RESIDENTIAL	RETAIL COMMERCIAL	RETAIL INDUSTRIAL	COTTON GINS	IRRIGATION	STREET LIGHTING	MUNIS	MISC.	TOTAL RETAIL	WHOLESALE	(ACTUAL/ BEFORE ADJS.)	EXOGENOUS FACTORS	ACTIVE DSM	PASSIVE DSM	TOTAL	AFTER ADJS.
1979												0	(5)	0	(5)	
1980	448	292	665	1	24	0	41	0	1,471	442	1,913	0	(23)	0	(23)	1,890
1981	451	312	723	1	25	0	44	0	1,556	467	2,023	0	(22)	0	(22)	2,001
1982	397	271	637	1	22	0	38	0	1,366	410	1,776	0	(20)	0	(20)	1,756
1983	447	305	718	1	25	0	43	0	1,539	462	2,001	0	(13)	0	(13)	1,988
1984	438	290	702	1	24	0	42	0	1,506	483	1,989	0	(14)	0	(14)	1,975
1985	441	301	702	1	25	0	43	0	1,513	455	1,968	0	(13)	0	(13)	1,955
1986	455	311	714	1	26	0	44	0	1,551	471	2,022	0	(30)	0	(30)	1,992
1987	441	301	702	1	25	0	43	0	1,513	392	1,905	0	(30)	0	(30)	1,875
1988	443	296	753	1	23	0	43	0	1,557	448	2,005	0	(32)	0	(32)	1,973
1989	471	311	827	1	26	0	44	0	1,678	509	2,187	0	(32)	0	(32)	2,155
1990	546	315	835	1	32	0	64	0	1,793	554	2,347	0	(37)	0	(37)	2,310
1991	535	329	803	1	25	0	61	0	1,754	546	2,300	0	(69)	0	(69)	2,231
1992	518	347	807	0	37	0	57	0	1,766	523	2,289	0	(64)	0	(64)	2,225
1993	554	363	824	0	61	0	60	0	1,862	589	2,451	0	(67)	0	(67)	2,384
1994	543	355	817	0	38	0	60	0	1,813	585	2,400	24	(78)	(6)	(60)	2,340
1995	548	356	824	0	38	0	60	0	1,826	617	2,443	97	(155)	(13)	(71)	2,372
1996	555	360	837	0	39	0	61	0	1,852	635	2,487	103	(155)	(19)	(71)	2,416
1997	564	363	853	0	39	0	61	0	1,882	649	2,531	106	(155)	(26)	(75)	2,456
1998																
1999																
2000																
2001																
2002																
2003																
2004																
2005																
2006																
2007																
2008																

Column (k) historical (1979 – 1993) must be actual peak demand.
Column (k) projected (1994 – 2008) must be peak demand prior to DSM adjustments.

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993
REQUEST 1.01 – BREAKDOWN OF SYSTEM REQUIREMENTS (MW)

SOUTHWESTERN PUBLIC SERVICE COMPANY

STATE OF TEXAS DATA

	(q)	(r)	(s)	(t)	(u)	(v)	(w)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)	(af)
	INSTALLED CAPACITY BY FUEL TYPE (NDC)								FIRM PURCHASES FROM:							
YEAR	TOTAL NG/OIL	COAL	LIGNITE	NUCLEAR	HYDRO	ALT. ENERGY SOURCES	TOTAL INSTALLED CAPACITY	TEXAS ALLOCATOR	UTILITIES	QFs	OTHER	TOTAL	FIRM OFF-SYSTEM SALES	NET SYSTEM CAPACITY	RESERVE MARGIN MW	RESERVE MARGIN %
1979																
1980	1,588	776	0	0	0	32	2,396	76.95640%	33	0	0	33	33	2,409	519	27.47%
1981	1,506	820	0	0	0	27	2,354	78.54302%	32	0	0	32	38	2,341	360	18.01%
1982	1,426	1,158	0	0	0	26	2,610	74.42813%	49	0	0	49	70	2,570	814	44.38%
1983	1,585	1,224	0	0	0	27	2,837	70.08327%	0	0	0	0	60	2,793	803	40.39%
1984	1,451	1,147	0	0	0	26	2,624	73.17532%	0	0	0	0	17	2,605	630	31.84%
1985	1,328	1,477	0	0	0	28	2,832	71.14365%	142	0	0	142	63	2,902	947	48.42%
1986	1,326	1,525	0	0	0	28	2,879	71.06671%	142	0	0	142	59	2,953	961	48.23%
1987	1,304	1,500	0	0	0	27	2,831	68.88646%	140	0	0	140	60	2,902	1,027	34.36%
1988	1,341	1,565	0	0	0	28	2,935	72.83800%	144	0	0	144	53	3,040	1,067	34.09%
1989	1,590	1,398	0	0	0	29	3,017	74.46441%	149	0	0	149	54	3,104	949	44.03%
1990	1,405	1,616	0	0	0	29	3,051	73.30864%	0	0	0	0	59	2,982	664	28.66%
1991	1,379	1,586	0	0	0	29	2,994	73.89864%	0	0	0	0	29	2,960	729	32.70%
1992	1,384	1,582	0	0	0	29	2,995	73.73134%	0	0	0	0	96	2,883	662	29.77%
1993	1,408	1,610	0	0	0	29	3,047	73.01537%	0	0	0	0	99	2,933	349	23.04%
1994	1,375	1,572	0	0	0	29	2,976	73.26237%	0	0	0	0	122	2,834	496	21.30%
1995	1,374	1,571	0	0	0	29	2,974	73.22640%	0	0	0	0	112	2,835	461	19.40%
1996	1,411	1,572	0	0	0	29	3,012	73.29404%	0	0	0	0	164	2,847	470	17.73%
1997	1,429	1,572	0	0	0	29	3,029	73.26379%	0	0	0	0	133	2,877	419	17.04%
1998																
1999																
2000																
2001																
2002																
2003																
2004																
2005																
2006																
2007																
2008																

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	
PURCHASER NAME:	SUMMARY – ALL WHOLESALE CUSTOMERS
PURCHASER TYPE:	
PURCHASER LOCATION:	

	FIRM				NON-FIRM			TOTALS		
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	42	255,515	$1,500	$4,949	152,916	$0	$5,350	428,431	$1,500	$10,299
1980	43	305,874	$3,087	$7,149	93,106	$0	$2,766	398,980	$3,087	$9,915
1981	40	320,345	$5,081	$8,144	37,783	$0	$1,361	358,128	$5,081	$9,505
1982	104	315,604	$7,190	$15,026	36,657	$0	$1,525	352,261	$7,190	$16,551
1983	31	465,819	$5,092	$15,168	42,926	$0	$3,560	508,745	$5,092	$18,728
1984	23	216,695	$2,573	$6,563	477,754	$2,234	$13,190	694,449	$4,807	$19,762
1985	89	779,299	$8,310	$19,418	2,318,156	$8,041	$57,962	3,097,455	$16,351	$77,380
1986	63	648,047	$8,812	$16,194	1,124,561	$8,041	$18,875	1,772,608	$16,853	$35,269
1987	86	501,526	$8,394	$11,640	1,631,722	$6,198	$27,700	2,133,248	$14,592	$39,340
1988	72	288,224	$6,960	$4,809	2,347,007	$4,188	$42,035	2,635,231	$11,148	$46,844
1989	72	355,036	$4,817	$7,534	3,101,408	$3,082	$63,286	3,456,444	$8,899	$70,820
1990	79	369,037	$6,025	$7,300	1,680,399	$2,234	$33,260	2,049,436	$8,259	$40,560
1991	79	323,632	$5,801	$5,998	1,424,539	$6,207	$24,740	1,748,171	$12,098	$30,738
1992	128	490,171	$8,014	$8,341	1,953,161	$9,134	$36,320	2,443,332	$17,148	$45,461
1993	122	570,385	$11,218	$11,690	2,064,230	$9,554	$42,245	2,634,615	$20,772	$53,935
1994	166	815,640	$14,179	$14,288	1,321,246	$7,024	$28,208	2,136,886	$21,203	$42,496
1995	166	823,640	$14,353	$14,900	1,315,673	$11,704	$29,139	2,139,313	$26,057	$44,042
1996	186	884,520	$17,124	$19,218	1,355,353	$15,479	$31,374	2,240,873	$32,603	$50,592
1997	181	963,840	$15,939	$21,853	1,396,274	$16,505	$34,938	2,359,314	$32,444	$56,791
1998	211	980,840	$0	$0	1,433,046	$0	$0	2,413,886	$0	$0
1999	136	783,840	$0	$0	1,630,868	$0	$0	2,414,708	$0	$0
2000	136	783,840	$0	$0	1,635,736	$0	$0	2,419,576	$0	$0
2001	136	783,840	$0	$0	1,563,652	$0	$0	2,347,492	$0	$0
2002	136	783,840	$0	$0	1,550,620	$0	$0	2,334,460	$0	$0
2003	136	783,840	$0	$0	1,553,658	$0	$0	2,337,498	$0	$0
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	
PURCHASER NAME:	SUMMARY – UTILITIES
PURCHASER TYPE:	
PURCHASER LOCATION:	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	35	200,299	$1,220	$4,196	183,645	$0	$5,053	383,944	$1,220	$9,249
1980	35	253,254	$2,423	$5,917	74,372	$0	$2,187	327,626	$2,423	$8,104
1981	44	264,058	$4,546	$6,759	30,712	$0	$701	294,770	$4,546	$7,460
1982	48	342,732	$3,317	$9,972	7,250	$0	$239	349,982	$3,317	$10,211
1983	28	294,076	$3,056	$9,144	28,981	$0	$1,265	323,057	$3,056	$10,409
1984	0	14,581	$203	$536	414,452	$2,234	$10,977	429,033	$2,437	$11,513
1985	66	576,893	$6,135	$13,371	2,049,570	$8,041	$50,156	2,626,463	$14,176	$63,527
1986	60	446,532	$6,340	$11,110	1,020,841	$8,041	$16,218	1,467,373	$14,381	$27,328
1987	34	285,222	$3,345	$6,645	1,534,000	$8,198	$25,343	1,819,222	$11,543	$31,988
1988	40	82,006	$4,663	$840	2,166,130	$4,188	$37,381	2,248,136	$8,851	$38,221
1989	64	108,903	$4,143	$2,304	2,469,113	$3,082	$57,188	2,578,016	$7,225	$59,492
1990	40	117,748	$3,379	$2,079	1,487,707	$2,234	$28,844	1,605,455	$5,613	$30,923
1991	40	47,400	$3,268	$814	1,313,176	$6,207	$22,085	1,360,576	$9,475	$22,899
1992	86	169,335	$4,983	$3,344	1,400,869	$9,134	$32,369	1,570,364	$14,117	$35,713
1993	80	205,825	$7,313	$4,234	1,635,407	$9,334	$32,406	1,841,232	$16,647	$36,640
1994	136	375,000	$8,736	$7,483	1,173,000	$8,024	$24,806	1,548,000	$16,760	$32,289
1995	136	383,000	$9,910	$7,849	1,163,000	$11,704	$25,636	1,546,000	$21,614	$33,485
1996	141	399,000	$12,228	$8,648	1,202,000	$15,479	$27,633	1,601,000	$27,707	$36,281
1997	136	391,000	$10,103	$8,849	1,240,000	$16,545	$31,817	1,631,000	$26,648	$40,666
1998	141	343,000	$0	$0	1,266,000	$0	$0	1,609,000	$0	$0
1999	66	170,000	$0	$0	1,439,000	$0	$0	1,609,000	$0	$0
2000	66	170,000	$0	$0	1,439,000	$0	$0	1,609,000	$0	$0
2001	66	170,000	$0	$0	1,416,000	$0	$0	1,586,000	$0	$0
2002	66	170,000	$0	$0	1,378,000	$0	$0	1,548,000	$0	$0
2003	66	170,000	$0	$0	1,378,000	$0	$0	1,548,000	$0	$0
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	
PURCHASER NAME:	SUMMARY – MUNICIPALS
PURCHASER TYPE:	
PURCHASER LOCATION:	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	7	35,236	$290	$753	9,231	$0	$297	44,467	$290	$1,050
1980	8	52,620	$472	$1,232	18,734	$0	$579	71,354	$472	$1,811
1981	5	54,287	$535	$1,385	19,071	$0	$660	73,358	$535	$2,045
1982	36	172,872	$1,673	$3,054	32,407	$0	$1,286	205,279	$1,673	$4,340
1983	25	191,740	$2,036	$6,028	53,945	$0	$2,295	245,685	$2,036	$8,323
1984	23	222,114	$2,170	$6,027	33,302	$0	$2,222	255,416	$2,170	$8,249
1985	23	222,406	$2,175	$5,047	248,536	$0	$7,106	470,942	$2,175	$12,153
1986	23	202,495	$2,472	$5,031	103,720	$0	$2,857	306,215	$2,472	$7,888
1987	32	216,304	$2,649	$5,035	78,133	$0	$2,039	294,437	$2,649	$7,074
1988	23	206,218	$2,297	$5,369	136,374	$0	$2,343	342,592	$2,297	$7,712
1989	28	246,153	$2,674	$5,230	133,329	$0	$3,995	379,482	$2,674	$9,225
1990	30	271,289	$2,646	$5,221	114,657	$0	$3,308	385,946	$2,646	$8,529
1991	30	275,232	$2,623	$5,084	72,923	$0	$2,336	348,155	$2,623	$7,420
1992	34	320,796	$3,031	$6,197	117,633	$0	$3,343	438,429	$3,031	$9,540
1993	30	364,570	$3,905	$7,656	143,160	$0	$4,018	507,730	$3,905	$11,674
1994	30	440,640	$4,443	$8,803	148,246	$0	$3,404	588,886	$4,443	$12,207
1995	30	440,640	$4,443	$9,054	150,873	$0	$3,523	591,513	$4,443	$12,577
1996	35	485,520	$4,896	$10,570	153,553	$0	$3,741	639,073	$4,896	$14,311
1997	45	572,040	$5,756	$13,004	156,274	$0	$3,921	728,314	$5,756	$16,925
1998	70	615,840	$0	$0	159,048	$0	$0	774,888	$0	$0
1999	70	615,840	$0	$0	161,868	$0	$0	777,708	$0	$0
2000	70	615,840	$0	$0	164,736	$0	$0	780,576	$0	$0
2001	70	615,840	$0	$0	167,652	$0	$0	783,492	$0	$0
2002	70	615,840	$0	$0	170,629	$0	$0	786,469	$0	$0
2003	70	615,840	$0	$0	173,658	$0	$0	789,498	$0	$0
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	
PURCHASER NAME:	SUMMARY – OTHERS
PURCHASER TYPE:	
PURCHASER LOCATION:	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	0	0	$0	$0	0	$0	$0	0	$0	$0
1980	0	0	$0	$0	0	$0	$0	0	$0	$0
1981	0	0	$0	$0	0	$0	$0	0	$0	$0
1982	0	0	$0	$0	0	$0	$0	0	$0	$0
1983	0	0	$0	$0	0	$0	$0	0	$0	$0
1984	0	0	$0	$0	0	$0	$0	0	$0	$0
1985	0	0	$0	$0	0	$0	$0	0	$0	$0
1986	0	0	$0	$0	0	$0	$0	0	$0	$0
1987	0	0	$0	$0	19,549	$0	$327	19,549	$0	$327
1988	0	0	$0	$0	44,483	$0	$911	44,483	$0	$911
1989	0	0	$0	$0	99,166	$0	$2,103	99,166	$0	$2,103
1990	0	0	$0	$0	78,033	$0	$1,316	78,033	$0	$1,316
1991	0	0	$0	$0	18,440	$0	$319	18,440	$0	$319
1992	0	0	$0	$0	34,039	$0	$808	34,039	$0	$808
1993	0	0	$0	$0	299,673	$0	$5,801	299,673	$0	$5,801
1994	0	0	$0	$0	0	$0	$0	0	$0	$0
1995	0	0	$0	$0	0	$0	$0	0	$0	$0
1996	0	0	$0	$0	0	$0	$0	0	$0	$0
1997	0	0	$0	$0	0	$0	$0	0	$0	$0
1998	0	0	$0	$0	0	$0	$0	0	$0	$0
1999	0	0	$0	$0	0	$0	$0	0	$0	$0
2000	0	0	$0	$0	0	$0	$0	0	$0	$0
2001	0	0	$0	$0	0	$0	$0	0	$0	$0
2002	0	0	$0	$0	0	$0	$0	0	$0	$0
2003	0	0	$0	$0	0	$0	$0	0	$0	$0
2004	0	0	$0	$0	0	$0	$0	0	$0	$0
2005	0	0	$0	$0	0	$0	$0	0	$0	$0
2006	0	0	$0	$0	0	$0	$0	0	$0	$0
2007	0	0	$0	$0	0	$0	$0	0	$0	$0
2008	0	0	$0	$0	0	$0	$0	0	$0	$0

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	1
PURCHASER NAME:	TEXAS-NEW MEXICO POWER COMPANY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984					3,996		$227	3,996	$0	$227
1985	66	576,189	$6,135	$14,371				576,189	$6,135	$14,371
1986	60	446,532	$6,340	$11,163				446,532	$6,340	$11,163
1987	54	285,222	$5,745	$6,645	37,322		$579	322,544	$5,745	$7,224
1988	69	82,006	$4,663	$840	207,184		$3,569	289,190	$4,663	$4,409
1989	64	108,903	$4,143	$2,304	297,119		$3,753	406,022	$4,143	$6,057
1990	60	117,748	$3,379	$2,079	156,098		$3,009	273,846	$3,379	$5,088
1991	60	47,400	$3,268	$814	101,433		$1,745	148,833	$3,268	$2,559
1992	36	95,737	$2,941	$1,875	170,124		$3,078	265,861	$2,941	$4,953
1993	33	83,374	$3,229	$1,715	250,216		$4,860	333,590	$3,229	$6,575
1994	66	156,000	$5,300	$3,161				156,000	$5,300	$3,161
1995	66	162,000	$5,671	$3,329				162,000	$5,671	$3,329
1996	66	170,000	$5,944	$3,781				170,000		
1997	66	170,000	$5,944	$3,860				170,000		
1998	66	170,000						170,000		
1999	66	170,000						170,000		
2000	66	170,000						170,000		
2001	66	170,000						170,000		
2002	66	170,000						170,000		
2003	66	170,000						170,000		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	2
PURCHASER NAME:	UTILICORP UNITED INC. (CENTEL ELECTRIC) WESTPLAINS ENERGY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979					54,067		$1,482	54,067	$0	$1,482
1980					22,360		$682	22,360	$0	$682
1981					6,340		$248	6,340	$0	$248
1982					530		$23	610	$0	$23
1983								0	$0	$0
1984								0	$0	$0
1985					620		$19	620	$0	$19
1986					166,343		$2,419	166,343	$0	$2,419
1987					199,633		$3,172	199,633	$0	$3,172
1988					68,925		$1,260	68,925	$0	$1,260
1989					24,549		$488	24,549	$0	$488
1990					53,327		$832	53,327	$0	$832
1991					290,312		$4,529	290,312	$0	$4,529
1992					291,543		$4,431	291,543	$0	$4,431
1993					40,470		$666	40,470	$0	$666
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	3
PURCHASER NAME:	PUBLIC SERVICE COMPANY OF OKLAHOMA
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979					128,140		$3,514	128,140	$0	$3,514
1980					51,353		$1,475	51,353	$0	$1,475
1981					12,343		$433	12,343	$0	$433
1982					6,440		$211	6,440	$0	$211
1983					28,919		$1,262	28,919	$0	$1,262
1984					247,558		$4,923	247,558	$0	$4,923
1985					153,825		$2,685	153,825	$0	$2,685
1986					401,279		$4,219	401,279	$0	$4,219
1987					257,168		$3,932	257,168	$0	$3,932
1988					286,732		$4,328	286,732	$0	$4,328
1989					63,695		$1,066	63,695	$0	$1,066
1990					7,400		$110	7,400	$0	$110
1991					18,369		$341	18,369	$0	$341
1992					12,135		$200	12,135	$0	$200
1993					201		$3	201	$0	$3
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	4
PURCHASER NAME:	EL PASO ELECTRIC COMPANY – ECONOMY RATE 914
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984					1,815		$54	1,815	$0	$54
1985								0	$0	$0
1986					249,731		$4,345	249,731	$0	$4,345
1987					452,134		$7,619	452,134	$0	$7,619
1988					457,616		$8,166	457,616	$0	$8,166
1989					701,422		$14,032	701,422	$0	$14,032
1990					336,967		$6,303	336,967	$0	$6,303
1991					342,678		$6,309	342,678	$0	$6,309
1992					348,136		$6,449	348,136	$0	$6,449
1993					366,192		$7,800	366,192	$0	$7,800
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	5
PURCHASER NAME:	EL PASO ELECTRIC COMPANY – INTERRUPTIBLE RATE 915
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984					157,032	$2,234	$5,383	157,032	$2,234	$5,383
1985					737,280	$8,041	$18,133	737,280	$8,041	$18,133
1986					96,708	$8,041	$1,877	96,708	$8,041	$1,877
1987					84,253	$6,138	$1,938	84,253	$4,138	$1,938
1988					114,438	$4,148	$1,794	114,438	$4,188	$1,794
1989					172,396	$3,082	$2,719	172,396	$3,082	$2,719
1990					110,251	$2,234	$2,496	110,251	$2,234	$2,496
1991					68,744	$2,110	$1,238	68,744	$2,110	$1,238
1992					85,870	$2,116	$1,618	85,870	$2,110	$1,618
1993					77,662	$2,110	$1,546	77,662	$2,110	$1,544
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	6
PURCHASER NAME:	EL PASO ELECTRIC COMPANY – FIRM
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992	50	73,658	$2,042	$1,449				73,658	$2,042	$1,449
1993	50	122,451	$4,084	$2,519				122,451	$4,084	$2,519
1994	50	217,000	$4,236	$4,524				217,000	$4,236	$4,524
1995	50	221,000	$4,239	$4,520				221,000	$4,239	$4,520
1996	75	229,000	$4,284	$4,947				229,000	$4,284	$4,947
1997	50	221,000	$4,239	$4,989				221,000	$4,239	$4,989
1998	75	173,000						173,000		
1999	0									
2000	0									
2001	0									
2002	0									
2003	0									
2004										
2005										
2006										
2007										
2008										

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	7
PURCHASER NAME:	EPE – BULK POWER SALES – RATES 917,983,984,985,986
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984					11,621		$364	11,621	$0	$364
1985					621,045		$20,967	621,045	$0	$20,967
1986								0	$0	$0
1987					61,016		$1,130	61,016	$0	$1,130
1988					59,843		$1,721	59,843	$0	$1,721
1989					100,234		$3,821	100,234	$0	$3,821
1990					13,202		$273	13,202	$0	$273
1991					332		$3	332	$0	$3
1992										
1993										
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST FILING 1993

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	8
PURCHASER NAME:	PUBLIC SERVICE COMPANY OF NEW MEXICO – EXCLUDES BULK POWER
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984		14,581	$203	$536				14,581	$203	$536
1985					728		$32	728	$0	$32
1986					106,760		$2,158	106,760	$0	$2,158
1987					104,039		$1,788	104,039	$0	$1,788
1988					171,729		$3,232	171,729	$0	$3,232
1989					246,621		$3,376	246,621	$0	$3,376
1990					88,908		$1,880	88,908	$0	$1,880
1991					112,943	$4,087	$2,081	112,943	$4,087	$2,091
1992					272,690	$7,024	$3,094	272,690	$7,024	$3,094
1993					319,377	$7,024	$6,182	319,377	$7,024	$6,182
1994					211,000	$7,024	$4,211	211,000	$7,024	$4,211
1995					215,000	$11,706	$4,414	215,000	$11,706	$4,414
1996					223,000	$14,044	$4,841	223,000	$14,044	$4,841
1997					223,000	$14,044	$5,063	223,000	$14,044	$5,063
1998					223,000			223,000		
1999					223,000			223,000		
2000					223,000			223,000		
2001					223,000			223,000		
2002					223,000			223,000		
2003					223,000			223,000		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	9
PURCHASER NAME:	PUBLIC SERVICE COMPANY OF NEW MEXICO – BULK POWER –SWBPE RATE
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984					530		$24	530	$0	$24
1985					241,700		$6,240	241,700	$0	$6,240
1986								0	$0	$0
1987					18,139		$343	18,139	$0	$343
1988					83,018		$2,048	83,018	$0	$2,048
1989					172,880		$4,754	172,880	$0	$4,754
1990					19,503		$490	19,503	$0	$490
1991					670		$0	670	$0	$0
1992					440		$70	440	$0	$70
1993					4,313		$140	4,313	$0	$140
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	10
PURCHASER NAME:	ARIZONA PUBLIC SERVICE COMPANY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985					67,183		$2,740	67,183	$0	$2,740
1986								0	$0	$0
1987					108,291		$1,867	108,291	$0	$1,867
1988					102,152		$2,015	102,152	$0	$2,015
1989					106,856		$2,446	106,856	$0	$2,446
1990					84,027		$1,779	84,027	$0	$1,779
1991					42,010		$703	42,010	$0	$703
1992					28,416		$479	28,416	$0	$479
1993					25,587	$420	$578	25,587	$420	$578
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	11
PURCHASER NAME:	LOUIS DREYFUS ELECTRIC POWER, INC.
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					3,954		$156	3,954	$0	$156
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	12
PURCHASER NAME:	PORTLAND GENERAL ELECTRIC COMPANY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					197		53	197	30	53
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	13
PURCHASER NAME:	PUBLIC SERVICE COMPANY OF COLORADO
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					150		$2	150	$0	$2
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	14
PURCHASER NAME:	WESTPLAINS ENERGY OF COLORADO
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					835		$26	835	$0	$26
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	15
PURCHASER NAME:	SOUTHERN CALIFORNIA EDISON
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					105,476		$1,507	105,476	$0	$1,507
1988					283,640		$4,334	283,640	$0	$4,334
1989					434,731		$8,057	434,731	$0	$8,057
1990					277,748		$4,862	277,748	$0	$4,862
1991					135,717		$1,984	135,717	$0	$1,984
1992					177,418		$2,667	177,418	$0	$2,667
1993					64,303		$1,034	64,303	$0	$1,034
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	16
PURCHASER NAME:	PACIFIC GAS AND ELECTRIC
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					30,915		$432	30,915	$0	$432
1988					90,449		$1,330	90,449	$0	$1,310
1989					13,215		$236	13,215	$0	$236
1990					3,975		$64	3,975	$0	$64
1991					1,025		$14	1,025	$0	$14
1992					19,730		$302	19,730	$0	$302
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	17
PURCHASER NAME:	SAN DIEGO GAS & ELECTRIC
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					63,862		$922	63,862	$0	$922
1988					211,126		$3,064	211,126	$0	$3,064
1989					60,505		$583	60,505	$0	$583
1990					3,580		$73	3,580	$0	$73
1991					4,749		$77	4,749	$0	$77
1992					15,824		$215	15,824	$0	$215
1993					2,550		$39	2,550	$0	$39
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	18
PURCHASER NAME:	NEVADA POWER COMPANY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988					23,823		$451	23,823	$0	$451
1989					10,188		$211	10,188	$0	$211
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993					120		$3	120	$0	$3
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	19
PURCHASER NAME:	PACIFIC POWER & LIGHT
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWH	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWH	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWH	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989					321,440		$6,134	321,440	$0	$6,134
1990					33,790		$627	33,790	$0	$627
1991					8,963		$140	8,963	$0	$140
1992					89,956		$1,604	89,956	$0	$1,608
1993					63,614		$1,149	63,614	$0	$1,149
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	20
PURCHASER NAME:	CENTRAL & SOUTH WEST CORPORATION
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989					53,819		$1,000	53,819	$0	$1,000
1990					140,394		$2,295	140,394	$0	$2,295
1991					98,555		$1,036	98,555	$0	$1,036
1992					249,246		$3,424	249,246	$0	$3,424
1993					167,813		$2,951	167,813	$0	$2,951
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	21
PURCHASER NAME:	ENTERGY SERVICES
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989					1,675		$24	1,675	$0	$24
1990					58,821		$1,543	58,821	$0	$1,543
1991					985		$15	985	$0	$15
1992					2,400		$34	2,400	$0	$34
1993					46,775		$949	46,775	$0	$949
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	22
PURCHASER NAME:	ARIZONA ELECTRIC COOPERATIVE
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					3,110		$72	3,110	$0	$72
1988					1,406		$29	1,406	$0	$29
1989					1,430		$48	1,430	$0	$48
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	23
PURCHASER NAME:	GULF STATES UTILITIES
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990					23,805		$313	23,805	$0	$313
1991								0	$0	$0
1992								0	$0	$0
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

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SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	24
PURCHASER NAME:	TUSCON ELECTRIC POWER
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990					17,020		$290	17,020	$0	$290
1991					16,604		$271	16,604	$0	$271
1992					31,049		$606	31,049	$0	$606
1993					15,172		$372	15,172	$0	$372
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	25
PURCHASER NAME:	EMPIRE DISTRICT ELECTRIC COMPANY
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993					0	$0	$0	0	$0	$0
1994					0	$0	$0	0	$0	$0
1995					0	$0	$0	0	$0	$0
1996					33,000	$1,433	$1,169	33,000	$1,433	$1,169
1997					91,000	$2,461	$2,070	91,000	$2,461	$2,070
1998					91,000			91,000		
1999					91,000			91,000		
2000					91,000			91,000		
2001					34,000			34,000		
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	26
PURCHASER NAME:	COCHRAN POWER & LIGHT
PURCHASER TYPE:	NON-ASSOCIATED UTILITY
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	3	15,730	$59	$342				15,730	$59	$342
1980	3	15,929	$163	$378				15,929	$163	$378
1981	3	15,866	$235	$404				15,866	$235	$404
1982	4	12,783	$234	$352				12,783	$234	$352
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993										
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	27
PURCHASER NAME:	NEW MEXICO ELECTRIC SERVICE
PURCHASER TYPE:	NON-ASSOCIATED UTILITY
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	32	184,540	$1,161	$3,354	415		$17	184,986	$1,161	$3,371
1980	32	237,325	$2,460	$3,339	759		$30	238,084	$2,460	$3,369
1981	41	250,192	$4,311	$4,355				250,192	$4,311	$4,355
1982	64	323,949	$3,279	$9,620				323,949	$3,279	$9,620
1983	25	294,076	$3,056	$9,140	62		$3	294,138	$3,056	$9,143
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993										
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	28
PURCHASER NAME:	OTHER INTERRUPTIBLE
PURCHASER TYPE:	IOU
PURCHASER LOCATION:	

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993										
1994										
1995										
1996										
1997										
1998					54,000			54,000		
1999					229,000			229,000		
2000					229,000			229,000		
2001					229,000			229,000		
2002					229,000			229,000		
2003					229,000			229,000		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	29
PURCHASER NAME:	CENTRAL LOUSIANA ELECTRIC COOPERATIVE
PURCHASER TYPE:	COOP
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990					56,201		$904	56,201	$0	$904
1991					19,245		$298	19,245	$0	$298
1992					6,872		$167	6,872	$0	$167
1993					31,660		$327	31,660	$0	$327
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	30
PURCHASER NAME:	CAJUN ELECTRIC POWER COOP
PURCHASER TYPE:	COOP
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					141,225		$3,124	141,225	$0	$3,124
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	31
PURCHASER NAME:	DESERET GENERATION & TRANSMISSION COOP
PURCHASER TYPE:	COOP
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					23,993		$525	23,993	$0	$525
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	32
PURCHASER NAME:	PLAINS ELECTRIC GENERATION & TRANSMISSION COOP, INC.
PURCHASER TYPE:	COOP
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992										
1993					1,023		$24	1,023	$0	$24
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	33
PURCHASER NAME:	SALT RIVER PROJECT
PURCHASER TYPE:	FA
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					19,549		$327	19,549	$0	$327
1988					44,483		$911	44,483	$0	$911
1989					88,106		$1,504	88,106	$0	$1,504
1990					72,250		$1,192	72,250	$0	$1,192
1991					17,930		$306	17,930	$0	$306
1992					10,350		$258	10,350	$0	$258
1993					5,105		$117	5,105	$0	$117
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	34
PURCHASER NAME:	BONNEVILLE POWER ADMINISTRATION
PURCHASER TYPE:	FA
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989					10,060		$199	10,060	$0	$199
1990								0	$0	$0
1991								0	$0	$0
1992					24,054		$544	24,054	$0	$544
1993					234,568		$3,684	234,568	$0	$3,684
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	35
PURCHASER NAME:	WESTERN AREA POWER ADMINISTRATION
PURCHASER TYPE:	FA
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990					5,785		$124	5,785	$0	$124
1991					510		$13	510	$0	$13
1992					235		$6	235	$0	$6
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	36
PURCHASER NAME:	VAN NUYS, CA
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992					200		$2	200	$0	$2
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	37
PURCHASER NAME:	LOS ALAMOS COUNTY
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979										
1980										
1981										
1982										
1983										
1984										
1985										
1986										
1987										
1988										
1989										
1990										
1991										
1992					636		$15	636	$0	$15
1993					617		$15	617	$0	$15
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	38
PURCHASER NAME:	CITY OF FLOYDADA
PURCHASER TYPE:	MUNI.
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979					4,066		$143	4,066	$0	$143
1980	1	5,815	$36	$134	5,120		$175	10,935	$36	$309
1981	1	10,921	$99	$281	2,971		$107	13,892	$99	$388
1982	1	10,769	$106	$314	4,149		$172	14,918	$106	$486
1983	1	10,790	$115	$341	4,550		$207	15,340	$115	$548
1984	1	11,307	$124	$340	3,309		$145	14,616	$124	$485
1985	1	11,583	$130	$250	2,659		$93	14,242	$130	$343
1986	1	11,705	$148	$292	3,096		$98	14,801	$148	$390
1987	1	11,015	$149	$259	3,532		$113	14,547	$149	$372
1988	1	11,039	$133	$215	4,331		$135	15,370	$133	$350
1989	1	11,295	$132	$242	5,156		$166	16,451	$132	$408
1990	1	11,251	$119	$221	5,098		$155	16,349	$119	$376
1991	1	11,197	$118	$207	4,785		$140	15,982	$118	$347
1992	1	11,187	$118	$216	4,673		$138	15,860	$118	$354
1993	1	11,352	$143	$232	5,463		$168	16,815	$143	$400
1994	1	11,400			5,098			16,498		
1995	1	11,400			5,151			16,551		
1996	1	11,400			5,204			16,604		
1997	1	11,400			5,257			16,657		
1998	1	11,400			5,310			16,710		
1999	1	11,400			5,363			16,763		
2000	1	11,400			5,416			16,816		
2001	1	11,400			5,469			16,869		
2002	1	11,400			5,524			14,924		
2003	1	11,400			5,579			14,979		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	39
PURCHASER NAME:	CITY OF BROWNFIELD
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	4	28,929	$172	$422	5,185		$334	34,114	$172	$756
1980	4	34,290	$221	$806	13,614		$404	47,904	$221	$1,210
1981	4	33,551	$314	$867	16,100		$553	49,651	$314	$1,420
1982	4	34,447	$337	$1,006	20,628		$810	55,075	$337	$1,816
1983	4	34,393	$349	$1,083	21,470		$928	55,863	$349	$2,011
1984	4	34,741	$372	$1,056	22,504		$942	57,245	$372	$1,998
1985	4	35,011	$372	$873	26,016		$1,000	61,027	$372	$1,873
1986	4	34,812	$422	$866	23,988		$763	58,800	$422	$1,629
1987	4	35,346	$426	$825	24,818		$694	60,164	$426	$1,519
1988	4	35,020	$341	$677	27,271		$901	62,291	$341	$1,578
1989	4	34,925	$377	$743	27,491		$944	62,416	$377	$1,687
1990	5	41,575	$408	$809	19,785		$600	61,360	$408	$1,409
1991	5	42,965	$412	$795	18,995		$597	61,960	$412	$1,392
1992	5	43,030	$412	$832	19,225		$611	62,255	$412	$1,443
1993	5	43,204	$485	$883	23,098		$714	66,302	$485	$1,597
1994	6	52,560			28,225			80,785		
1995	6	52,560			28,732			81,292		
1996	6	52,560			29,249			81,809		
1997	6	52,560			29,774			82,334		
1998	6	52,560			30,312			82,872		
1999	6	52,560			30,858			83,418		
2000	6	52,560			31,413			83,973		
2001	6	52,560			31,975			84,535		
2002	6	52,560			32,552			85,112		
2003	6	52,560			33,136			85,696		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	40
PURCHASER NAME:	CITY OF TULIA
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983	3	15,150	$167	$473	4,511		$196	19,661	$167	$669
1984	3	24,332	$279	$727	4,036		$177	28,368	$279	$904
1985	3	24,472	$279	$610	4,882		$170	29,354	$279	$780
1986	3	24,578	$317	$611	4,932		$149	29,510	$317	$760
1987	3	25,151	$319	$588	5,141		$158	30,292	$319	$746
1988	3	24,679	$286	$476	4,881		$149	29,560	$286	$625
1989	3	24,733	$282	$527	5,070		$163	29,803	$282	$690
1990	3	24,783	$254	$472	5,722		$174	30,505	$254	$646
1991	3	24,790	$249	$459	5,405		$170	30,195	$249	$629
1992	3	24,879	$249	$461	5,364		$170	30,243	$249	$631
1993	3	25,134	$304	$514	6,494		$234	31,628	$304	$748
1994	3	26,280			8,363			34,643		
1995	3	26,280			8,514			34,794		
1996	3	26,280			8,670			34,950		
1997	3	26,280			8,827			35,107		
1998	3	26,280			8,986			35,266		
1999	3	26,280			9,146			35,426		
2000	3	26,280			9,311			35,591		
2001	3	26,280			9,480			35,760		
2002	3	26,280			9,650			35,930		
2003	3	26,280			9,825			36,105		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	41
PURCHASER NAME:	LUBBOCK POWER & LIGHT
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981	0	7,332	$70	$175				7,332	$70	$175
1982	31	127,656	$1,230	$3,734	7,600		$304	135,256	$1,230	$4,038
1983	15	131,410	$1,345	$4,131	23,414		$964	154,824	$1,345	$5,095
1984	15	131,734	$1,395	$3,924	23,433		$938	155,167	$1,395	$4,862
1985	15	133,340	$1,394	$3,274	44,139		$1,452	177,479	$1,394	$4,726
1986	15	131,400	$1,585	$3,262	71,704		$1,847	203,104	$1,585	$5,109
1987	24	144,792	$1,755	$3,363	35,433		$891	180,225	$1,755	$4,254
1988	15	135,480	$1,497	$2,601	85,178		$2,278	220,658	$1,497	$4,879
1989	20	175,200	$1,883	$3,718	89,127		$2,573	264,327	$1,883	$6,291
1990	30	193,680	$1,865	$3,719	83,197		$2,141	276,877	$1,865	$5,860
1991	30	197,280	$1,844	$3,623	60,563		$1,378	257,843	$1,844	$5,001
1992	25	241,680	$2,252	$4,668	87,555		$2,207	329,235	$2,252	$6,875
1993	30	284,880	$2,973	$5,827	106,718		$2,874	391,598	$2,973	$8,701
1994	40	350,400			106,554			456,954		
1995	40	350,400			108,476			458,876		
1996	45	395,280			110,430			505,710		
1997	55	481,800			112,416			594,216		
1998	60	525,600			114,440			640,040		
1999	60	525,600			116,501			642,101		
2000	60	525,600			118,596			644,196		
2001	60	525,600			120,728			646,328		
2002	60	525,600			122,908			648,508		
2003	60	525,600			125,118			650,718		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	42
PURCHASER NAME:	CITY OF FARMINGTON
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985					188,890		$4,391	188,890	$0	$4,391
1986								0	$0	$0
1987								0	$0	$0
1988					8,445		$164	8,445	$0	$164
1989					1,255		$27	1,255	$0	$27
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	43
PURCHASER NAME:	CITY OF RIVERSIDE
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987					9,209		$183	9,209	$0	$183
1988					3,664		$103	3,664	$0	$103
1989					3,050		$117	3,050	$0	$117
1990					855		$18	855	$0	$18
1991					3,155		$51	3,155	$0	$51
1992					0		$0	0	$0	$0
1993					730		$13	730	$0	$13
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	44
PURCHASER NAME:	CITY OF ANAHEIM
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988					404		$13	404	$0	$13
1989					180		$5	180	$0	$5
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993					0		$0	0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	45
PURCHASER NAME:	CITY OF CANADIAN
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON-ERCOT, TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979	3	6,307	$108	$131				6,307	$108	$131
1980	3	10,939	$187	$255				10,939	$187	$255
1981		2,483	$52	$62				2,483	$52	$62
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993								0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF–SYSTEM SALES TRANSACTIONS

TRANSACTION #:	46
PURCHASER NAME:	CITY OF TUCUMCARI
PURCHASER TYPE:	MUNI
PURCHASER LOCATION:	NON–ERCOT, NON–TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON–FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON–FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980		1,576	$28	$37				1,576	$28	$37
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993								0	$0	$0
1994										
1995										
1996										
1997										
1998										
1999										
2000										
2001										
2002										
2003										
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	47
PURCHASER NAME:	WSCC (INCLUDES WSPP)
PURCHASER TYPE:	
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993								0	$0	$0
1994					756,000		$16,239	756,000	$0	$16,239
1995					752,000		$16,894	752,000	$0	$16,894
1996					744,000		$17,440	744,000	$0	$17,440
1997					744,000		$19,305	744,000	$0	$19,305
1998					744,000			744,000		
1999					744,000			744,000		
2000					744,000			744,000		
2001					744,000			744,000		
2002					744,000			744,000		
2003					744,000			744,000		
2004										
2005										
2006										
2007										
2008										

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 4.02 – OFF-SYSTEM SALES TRANSACTIONS

TRANSACTION #:	48
PURCHASER NAME:	SOUTHWEST POWER POOL
PURCHASER TYPE:	
PURCHASER LOCATION:	NON-ERCOT, NON-TEXAS

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
	FIRM				NON-FIRM			TOTALS		
YEAR	FIRM MW	FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	NON-FIRM MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)	TOTAL MWh	CAPACITY REVENUE ($)	DEMAND REVENUE ($)
1979								0	$0	$0
1980								0	$0	$0
1981								0	$0	$0
1982								0	$0	$0
1983								0	$0	$0
1984								0	$0	$0
1985								0	$0	$0
1986								0	$0	$0
1987								0	$0	$0
1988								0	$0	$0
1989								0	$0	$0
1990								0	$0	$0
1991								0	$0	$0
1992								0	$0	$0
1993								0	$0	$0
1994					206,000		$4,354	206,000	$0	$4,354
1995					198,000		$4,328	198,000	$0	$4,328
1996					182,000		$4,183	182,000	$0	$4,183
1997					182,000		$4,399	182,000	$0	$4,399
1998					182,000			182,000		
1999					182,000			182,000		
2000					182,000			182,000		
2001					182,000			182,000		
2002					182,000			182,000		
2003					182,000			182,000		
2004										
2005										
2006										
2007										
2008										

PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST

REQUEST 7.02
PAGE 1 OF 4

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 7.02 -- UNITS UNDER CONSTRUCTION, PLANNED & POTENTIAL UNITS
(INCLUDING UNITS BEING REFURBISHED/RETROFITTED)

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
			FACILITY CAPACITY RATINGS (MW)					FACILITY AGE DATA			
	PLANT NAME	UNIT SPECIFIER	NAMEPLATE	DER	ODC	NDC	NDC OWNED	DATE CONSTRUCTION BEGAN	DATE OF COMMERCIAL OPERATION	PROJECTED RETIREMENT DATE	OPERATING STATUS
1	Moore County Unit 3	50	48.0	48.0	51.0	44.0	44.0	01-Dec-94	01-May-96	01-Dec-2011	PLAN
2	Riverview Gas Turbine	76	27.0	27.0	25.0	25.0	25.0	01-Oct-96	01-May-97	01-Dec-2012	PLAN
3	Gas Turbine 136MW	GT136A	161.3	138.8	138.8	138.3	138.3	01-May-96	01-May-98	01-Dec-2023	PLAN
4	Gas Turbine 136MW	GT136B	161.3	138.8	138.8	138.3	138.3	01-May-98	01-May-00	01-Dec-2025	PLAN
5	Gas Turbine 72MW	GT72A	83.5	72.1	72.1	71.6	71.6	01-May-00	01-May-02	01-Dec-2027	PLAN
6	Gas Turbine 136MW	GT136C	161.3	138.8	138.8	138.3	138.3	01-May-01	01-May-03	01-Dec-2028	PLAN
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SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 7.02 – UNITS UNDER CONSTRUCTION, PLANNED & POTENTIAL UNITS
(INCLUDING UNITS BEING REFURBISHED/RETROFITTED)

FACILITY FUEL DATA

	(a)	(l)	(m)	(n)	(o)
	PLANT NAME	PRIMARY FUEL TYPE	AMOUNT OF PRIMARY FUEL STORAGE	SECONDARY FUEL TYPE	AMOUNT OF SECONDARY FUEL STORAGE
1	Moore County Unit 3	NG	0.0	N/A	0
2	Riverview Gas Turbine	NG	0.0	N/A	0
3	Gas Turbine 136MW	NG	0.0	N/A	0
4	Gas Turbine 136MW	NG	0.0	N/A	0
5	Gas Turbine 72MW	NG	0.0	N/A	0
6	Gas Turbine 136MW	NG	0.0	N/A	0
7					
8					
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PUBLIC UTILITY COMMISSION OF TEXAS
LOAD AND CAPACITY RESOURCE FORECAST

SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 7.02 -- UNITS UNDER CONSTRUCTION, PLANNED & POTENTIAL UNITS
(INCLUDING UNITS BEING REFURBISHED/RETROFITTED)

FACILITY CONSTRUCTION DATA

	(a)	(p)	(q)	(r)	(s)	(t)	(u)	(v)	(w)
	PLANT NAME	PRIME MOVER	STEAM SOURCE	STACK GAS TREATMENT	TYPE OF COOLING	SOURCE OF COOLING	ARCHITECT/ ENGINEER	CONSTRUCTOR	OPERATOR
1	Moore County Unit 3	ST	NRB	N/A	TOWER	WELL	UBC	SPS	SPS
2	Riverview Gas Turbine	CT	N/A	N/A	AIR	N/A	UBC	SPS	SPS
3	Gas Turbine 136MW	CT	N/A	N/A	AIR	N/A	UBC	SPS	SPS
4	Gas Turbine 138MW	CT	N/A	N/A	AIR	N/A	UBC	SPS	SPS
5	Gas Turbine 72MW	CT	N/A	N/A	AIR	N/A	UBC	SPS	SPS
6	Gas Turbine 136MW	CT	N/A	N/A	AIR	N/A	UBC	SPS	SPS
7									
8									
9									
10									
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SOUTHWESTERN PUBLIC SERVICE COMPANY

REQUEST 7.02 -- UNITS UNDER CONSTRUCTION, PLANNED & POTENTIAL UNITS
(INCLUDING UNITS BEING REFURBISHED/RETROFITTED)

FACILITY COST DATA

	(a)	(x)	(y)	(z)	(aa)	(ab)	(ac)	(ad)	(ae)
	PLANT NAME	DIRECT COST	INDIRECT COST	CONTINGENCY COST	COMMON FACILITIES COST	PROJECT SUBTOTAL	AFUDC	TOTAL UNIT COST	TOTAL DISBURSED
1	Moore County Unit 3	$3,148,000				$3,148,000	$334,000	$3,482,000	0
2	Riverview Gas Turbine	$2,398,000				$2,398,000	$109,000	$2,507,000	$0
3	Gas Turbine 134MW	$67,800,000				$67,800,000	$4,805,000	$72,605,000	$0
4	Gas Turbine 138MW	$73,332,000				$73,332,000	$5,203,000	$78,535,000	$0
5	Gas Turbine 72MW	$46,828,000				$46,828,000	$5,337,000	$52,165,000	$0
6	Gas Turbine 138MW	$82,489,000				$82,489,000	$5,853,000	$88,342,000	$0
7						$0		$0	
8						$0		$0	
9						$0		$0	
10						$0		$0	
11						$0		$0	
12						$0		$0	
13						$0		$0	
14						$0		$0	
15						$0		$0	
16						$0		$0	
17						$0		$0	
18						$0		$0	
19						$0		$0	
20						$0		$0	
21						$0		$0	
22						$0		$0	
23						$0		$0	
24						$0		$0	
25						$0		$0	
26						$0		$0	
27						$0		$0	
28						$0		$0	
29						$0		$0	
30						$0		$0	

Recalculation of Kalt's Table III-1:
Measures of Monopsony For SPS As Seller:
Effective Demand and 'Buyer' Capacity Deficits
1998

Company	Lesser of Tie/Line Capacity or Capacity Deficit (MW)	Pre-Merger Market Share	Post-Merger Market Share	Pre-Merger HHI	Post-Merger HHI
Buyers Accessibe Through Artesia Tie					
TNP	66	12.48%	12.48%	156	156
Effective EPE Demand	67	12.67%	–	160	–
Buyers Accessible In or Through ERCOT					
Effective CSW Demand	0	0.00%	–	0	–
Buyers Accessible Through PSO-SWEPCO Open Access Tariff					
KAMO	68	12.85%	12.85%	165	165
CLECO	43	8.13%	8.13%	66	66
EDE	35 – 45	6.62%	6.62%	44	44
Buyers Accessible To/Through West Plains					
Line Open	0	0.00%	0.00%	0	0
Buyers Accessible Through PNM					
PNM	200	37.81%	37.81%	1,429	1,429
Buyers Accessible Through CFE					
CFE	50 – 75	9.45%	9.45%	89	89
Merged Company Total[1]	67 + 0 = 67	–	12.67%	–	160
Pre-Merger Market Total	529	100.00%		2,110	
Post-Merger Market Total	529		100.00%		2,110
Change in HHI					0

Source:
TNP: Hudson, p. 13
EDE: Mokan forecast 1993-2000
PNM: Hudson, p. 9
CFE: Hudson, p. 101

[1] Merged Company Total represents CSW total (CSW/EPE demand) if the merger is consummated

Measurement of Buyer Market Power
SPS "Market": Capacity Purchases
1995

	(a)	(b)	(c)	(d)	(e)	(f)
	Company	Capacity Purchases	Pre-Merger Market Share	Post-Merger Market Share	Pre-Merger HHI	Post-Merger HHI
[1]	SPS	0	0.00%	0.00%	0	0
	Interconnected Utilities					
[2]	EPE	50	1.12%		1	
	CSW:					
[3]	PSO	40	0.89%		1	
[4]	SWEPCO	339	7.58%		57	
[5]	CPL	0	0.00%		0	
[6]	WTU	28	0.63%		0	
[7]	Total	407	9.09%		83	
[8]	Merged Company Total	457		8.98%		81
[9]	PNM	239	5.34%	4.70%	29	22
[10]	TNP	91	2.03%	1.79%	4	3
	Utilities Accessible due to PSO and SWEPCO Open Access Tariff					
[11]	AECC	189	4.22%	3.72%	18	14
[12]	AECI	1,718	38.39%	33.77%	1,474	1,140
[13]	CAJUN	89	1.99%	1.75%	4	3
[14]	CLECO	20	0.45%	0.39%	0	0
[15]	EDE	371	8.29%	7.29%	69	53
6]	Entergy/GSU	299	6.68%	5.88%	45	35
]	GRDA	11	0.25%	0.22%	0	0
8]	KAMO	350	7.82%	6.88%	61	47
[19]	OGE	31	0.69%	0.61%	0	0
[20]	WFEC	260	5.81%	5.11%	34	26
[21]	WR	350	7.82%	6.88%	61	47
	Utilities Accessible due to EPE Open Access Tariff					
[22]	AEPCO	81		1.60%		3
[23]	PEGT	173		3.40%		12
[24]	SRP	352		6.92%		48
[25]	TEP	6		0.12%		0
[26]	Pre-Merger Market Total	4,475	100.00%		1,883	
[27]	Post-Merger Market Total	5,087		100.00%		1,534
[28]	Change in HHI					(348)

[1],[11]-[21] Southwest Power Pool Projected Capacity and Demand for 10 Years
[2] El Paso Electric Company Loads and Resources 1992 Long-term Base Load Forecast (7/92)
[3]-[6] Central and Southwest Services Forecast of Capabilities, Peak Demands, and Reserves in Megawatts 1993-2003 (11/15/93)
[7]: [3]+[4]+[5]+[6]
[8]: [2]+[7]
[9] Public Service Company of New Mexico Load and Resource Projection (MW), 2/25/93
[10]: Capacity purchased from SPS (66) and EPE (25). Number may be understated because it was derived from only SPS and EPE's load and resources forecasts.
[22]: AEPCO Load and Resource Detail – Sales and Purchases
[23]: Number not available
[24]: Salt River Project Forecast of Loads & Resources (12/1/93) – Reported in SRP Fiscal Year ending in April
[25] Tucson Electric Power 1993 Sales Forecast Integrated Plan-Preferred Plan Table 1: Loads and Resources-MW 1992-2007
[26]: [1]+[2]+[7]+[9]..[21]
]: [1]+[8]+[9]..[25]
]: Line [27] Column (f) – Line [26] Column (e)

Measurement of Buyer Market Power
SPS "Market": Capacity Purchases
1996

	(a)	(b)	(c)	(d)	(e)	(f)
	Company	Capacity Purchases	Pre-Merger Market Share	Post-Merger Market Share	Pre-Merger HHI	Post-Merger HHI
[1]	SPS	0	0.00%	0.00%	0	0
	Interconnected Utilities					
[2]	EPE	75	1.70%		3	
	CSW:					
[3]	PSO	40	0.91%		1	
[4]	SWEPCO	339	7.67%		59	
[5]	CPL	0	0.00%		0	
[6]	WTU	28	0.63%		0	
[7]	Total	407	9.21%		85	
[8]	Merged Company Total	482		9.58%		92
[9]	PNM	239	5.41%	4.75%	29	23
[10]	TNP	91	2.06%	1.81%	4	3
	Utilities Accessible due to PSO and SWEPCO Open Access Tariff					
[11]	AECC	189	4.28%	3.76%	18	14
[12]	AECI	1,651	37.37%	32.82%	1,397	1,077
[13]	CAJUN	89	2.01%	1.77%	4	3
[14]	CLECO	20	0.45%	0.40%	0	0
[15]	EDE	391	8.85%	7.77%	78	60
[16]	Entergy/GSU	279	6.32%	5.55%	40	31
[17]	GRDA	11	0.25%	0.22%	0	0
[18]	KAMO	350	7.92%	6.96%	63	48
[19]	OGE	31	0.70%	0.62%	0	0
[20]	WFEC	260	5.89%	5.17%	35	27
[21]	WR	335	7.58%	6.66%	57	44
	Utilities Accessible due to EPE Open Access Tariff					
[22]	AEPCO	81		1.62%		3
[23]	PEGT	173		3.44%		12
[24]	SRP	352		7.00%		49
[25]	TEP	6		0.12%		0
[26]	Pre-Merger Market Total	4,418	100.00%		1,814	
[27]	Post-Merger Market Total	5,030		100.00%		1,487
[28]	Change in HHI					(327)

[1],[11]-[21] Southwest Power Pool Projected Capacity and Demand for 10 Years
[2] El Paso Electric Company Loads and Resources 1992 Long-term Base Load Forecast (7/92)
[3]-[6] Central and Southwest Services Forecast of Capabilities, Peak Demands, and Reserves in Megawatts 1993-2003 (11/15/93)
[7]: [3]+[4]+[5]+[6]
[8]: [2]+[7]
[9] Public Service Company of New Mexico Load and Resource Projection (MW), 2/25/93
[10]: Capacity purchased from SPS (66) and EPE (25). Number may be understated because it was derived from only SPS and EPE's load and resources forecasts.
[22]: AEPCO Load and Resource Detail – Sales and Purchases
[23]: Number not available
[24]: Salt River Project Forecast of Loads & Resources (12/1/93) – Reported in SRP Fiscal Year ending in April
[25] Tucson Electric Power 1993 Sales Forecast Integrated Plan–Preferred Plan Table 1: Loads and Resources–MW 1992-2007
[26]: [1]+[2]+[7]+[9]..[21]
[27]: [1]+[8]+[9]..[25]
[28]: Line [27] Column (f) – Line [26] Column (e)

18-Mar-94

Measurement of Buyer Market Power
SPS "Market": Capacity Purchases
1997

	(a)	(b)	(c)	(d)	(e)	(f)
	Company	Capacity Purchases	Pre-Merger Market Share	Post-Merger Market Share	Pre-Merger HHI	Post-Merger HHI
[1]	SPS	0	0.00%	0.00%	0	0
	Interconnected Utilities					
[2]	EPE	0	0.00%		0	
	CSW:					
[3]	PSO	40	0.93%		1	
[4]	SWEPCO	336	7.81%		61	
[5]	CPL	0	0.00%		0	
[6]	WTU	28	0.65%		0	
[7]	Total	404	9.40%		88	
[8]	Merged Company Total	404		8.20%		67
[9]	PNM	239	5.56%	4.85%	31	24
[10]	TNP	91	2.12%	1.85%	4	3
	Utilities Accessible due to PSO and SWEPCO Open Access Tariff					
[11]	AECC	189	4.40%	3.84%	19	15
[12]	AECI	1,637	38.07%	33.22%	1,449	1,104
[13]	CAJUN	89	2.07%	1.81%	4	3
[14]	CLECO	20	0.47%	0.41%	0	0
[15]	EDE	366	8.51%	7.43%	72	55
[16]	Entergy/GSU	279	6.49%	5.66%	42	32
[17]	GRDA	11	0.26%	0.22%	0	0
[18]	KAMO	350	8.14%	7.10%	66	50
[19]	OGE	31	0.72%	0.63%	1	0
[20]	WFEC	260	6.05%	5.28%	37	28
[21]	WR	334	7.77%	6.78%	60	46
	Utilities Accessible due to EPE Open Access Tariff					
[22]	AEPCO	96		1.96%		4
[23]	PEGT	173		3.51%		12
[24]	SRP	352		7.14%		51
[25]	TEP	6		0.12%		0
[26]	Pre-Merger Market Total	4,300	100.00%		1,875	
[27]	Post-Merger Market Total	4,927		100.00%		1,495
[28]	Change in HHI					(380)

[1],[11]-[21] Southwest Power Pool Projected Capacity and Demand for 10 Years
[2] El Paso Electric Company Loads and Resources 1992 Long-term Base Load Forecast (7/92)
[3]-[6] Central and Southwest Services Forecast of Capabilities, Peak Demands, and Reserves in Megawatts 1993-2003 (11/15/93)
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[22]: AEPCO Load and Resource Detail – Sales and Purchases
[23]: Number not available
[24]: Salt River Project Forecast of Loads & Resources (12/1/93) – Reported in SRP Fiscal Year ending in April
[25] Tucson Electric Power 1993 Sales Forecast Integrated Plan-Preferred Plan Table 1: Loads and Resources-MW 1992-2007
[26]: [1]+[2]+[7]+[9]..[21]
[27]: [1]+[8]+[9]..[25]
[28]: Line [27] Column (f) – Line [26] Column (e)

18-Mar-94

Measurement of Buyer Market Power
SPS "Market": Capacity Purchases
1998

	(a)	(b)	(c)	(d)	(e)	(f)
	Company	Capacity Purchases	Pre-Merger Market Share	Post-Merger Market Share	Pre-Merger HHI	Post-Merger HHI
[1]	SPS	0	0.00%	0.00%	0	0
	Interconnected Utilities					
[2]	EPE	0	0.00%		0	
	CSW:					
[3]	PSO	40	0.94%		1	
[4]	SWEPCO	336	7.86%		62	
[5]	CPL	0	0.00%		0	
[6]	WTU	28	0.66%		0	
[7]	Total	404	9.45%		89	
[8]	Merged Company Total	404		8.24%		68
[9]	PNM	239	5.59%	4.88%	31	24
[10]	TNP	91	2.13%	1.86%	5	3
	Utilities Accessible due to PSO and SWEPCO Open Access Tariff					
[11]	AECC	189	4.42%	3.86%	20	15
[12]	AECI	1,624	38.00%	33.13%	1,444	1,098
[13]	CAJUN	89	2.08%	1.82%	4	3
[14]	CLECO	20	0.47%	0.41%	0	0
[15]	EDE	356	8.33%	7.26%	69	53
[16]	Entergy/GSU	278	6.50%	5.67%	42	32
[17]	GRDA	11	0.26%	0.22%	0	0
[18]	KAMO	350	8.19%	7.14%	67	51
[19]	OGE	31	0.73%	0.63%	1	0
[20]	WFEC	260	6.08%	5.30%	37	28
[21]	WR	332	7.77%	6.77%	60	46
	Utilities Accessible due to EPE Open Access Tariff					
[22]	AEPCO	96		1.97%		4
[23]	PEGT	173		3.53%		12
[24]	SRP	352		7.18%		52
[25]	TEP	6		0.12%		0
[26]	Pre-Merger Market Total	4,274	100.00%		1,870	
[27]	Post-Merger Market Total	4,901		100.00%		1,490
[28]	Change in HHI					(380)

[1],[11]-[21] Southwest Power Pool Projected Capacity and Demand for 10 Years
[2] El Paso Electric Company Loads and Resources 1992 Long-term Base Load Forecast (7/92)
[3]-[6] Central and Southwest Services Forecast of Capabilities, Peak Demands, and Reserves in Megawatts 1993-2003 (11/15/93)
[7]: [3]+[4]+[5]+[6]
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[9] Public Service Company of New Mexico Load and Resource Projection (MW), 2/25/93
[10]: Capacity purchased from SPS (66) and EPE (25). Number may be understated because it was derived from only SPS and EPE's load and resources forecasts.
[22]: AEPCO Load and Resource Detail – Sales and Purchases
[23]: Number not available
[24]: Salt River Project Forecast of Loads & Resources (12/1/93) – Reported in SRP Fiscal Year ending in April
[25] Tucson Electric Power 1993 Sales Forecast Integrated Plan–Preferred Plan Table 1: Loads and Resources–MW 1992-2007
[26]: [1]+[2]+[7]+[9]..[21]
[27]: [1]+[8]+[9]..[25]
[28]: Line [27] Column (f) – Line [26] Column (e)

18-Mar-94

MEXICAN INDUSTRIALS EYEING 400 MW OF COGENERATION AROUND MONTERREY

Ten industrial companies in Monterrey, Mexico, are studying development of two cogeneration plants totaling 400 MW and will consider participation by third-party developers. A 300-MW plant will be located in Tampico and a second, 100-MW plant has been proposed for Monterrey.

The companies are convinced of the economics of the plants, but are trying to work around Comision Federal de Electricidad's refusal to buy excess capacity outside the hours of 5:00 p.m. to 10:00 p.m., when the state-owned utility's domestic demand peaks, said a spokesman for one of the 10 industrials, Grupo Industrial Alfa.

For the Tampico plant, CFE's current policy may be insurmountable and development of the plant may be doomed, but the industrials may be able to build the plant in Monterrey by contracting to buy all the power themselves, a technique that has worked for several cogeneration projects in the past.

The Monterrey plant would then be built as a joint venture with each of the industrials acting as a stockholder and power purchaser. Such a scheme could also include an outside party.

Several years ago, CFE would buy all the excess power it could find. Since then, CFE has added several peaking units and a lingering recession has depressed demand. CFE now estimates it needs no new power facilities until 1997.

CFE's current policy is dulling the Mexican market for conventional cogeneration project developments, unless the industrial involved seriously needs the thermal energy, Groupo Alfa said. The company said the cogeneration market could be strong, if enough industrial customers can be found to buy the power and steam produced.

Separately, CFE is preparing to release in March a solicitation for a 440-MW gas- or low-sulfur oil-fired independent power plant in Merida, Yucatan known as Merida 3 (IPR, 27 Aug '93, 15). The project is being offered on a build-own-operate basis for a term of 25 years. CFE is not expected to select the preferred bidder until January 1995.

Mexican officials already have in hand more than 50 proposals for the plant, which must be built with no financial help from the government. The bid for the Merida plant would be the first under Mexico's recently reformed Electric Power Public Utility Law.

The Merida-3 solicitation is expected to be followed by solicitations for three 700-MW plants, each fired by either oil or coal and located in Juarez, Chihuahua; Dos Bocas, Tabasco; and Ensenada, Baja California Norte.

CORRECTED PLAINS FORECAST OF POST-MERGER UNCOMMITTED CAPACITY
AVAILABLE FOR SALE INTO SOUTHERN NEW MEXICO
(MW and Post-Merger Market Shares)

	1995	1996	1997	1998
EPE (MW)	0	0	45	35
EPE (share)	0.00%	0.00%	9.53%	8.22%
PNM (MW)	387	315	280	251
PNM (share)	68.62%	52.15%	59.32%	58.92%
TEP (MW)	142	145	112	78
TEP (share)	25.18%	24.01%	23.73%	18.31%
SRP (MW)	0	109	0	27
SRP (share)	0.00%	18.05%	0.00%	6.34%
Utilities Accessible due to EPE Open Access Tariff				
SPS (MW)	0	0	0	0
SPS (share)	0.00%	0.00%	0.00%	0.00%
TNP (MW)	0	0	0	0
TNP (share)	0.00%	0.00%	0.00%	0.00%
AEPCO (MW)	35	35	35	35
AEPCO (share)	6.21%	5.79%	7.42%	8.22%
Post-Merger Market Total	564	604	472	426

18-Mar-94

SOUTHWESTERN PUBLIC SERVICE COMPANY

Firm and Non-Firm Transmission Service Rate Calculations

	Pre-1998	1998
Average Investment (per 1992 FERC Form 1)	$347,137,807	
Estimated SPS System Improvements		$3,149,915[1]
Revised Average Investment		$350,287,772
Annual Revenue Requirement[2]	$57,084,695	$57,602,679
Less: Transmission Revenue	$3,181,419	$3,181,419
Adjusted Annual Revenue Requirement	$53,903,276	$54,421,260
Net Area System Peak	3,220	3,220
Annual Costs per MW	$16,740.15	$16,901.01
Monthly Firm Rate ($/MW/MO.)	$1,395.01	$1,408.42
Hourly Non-Firm Rate ($/MWH)	$1.91	$1.93

1. Represents estimated cost of upgrading (1) Eddy County 230/115 kV transformer and (2) TUCO 230/115 kV transformer in 1998 dollars.

2. At 16.44439% fixed charge rate.

UNITED STATES OF AMERICA
Before the
FEDERAL ENERGY REGULATORY COMMISSION

El Paso Electric Company and Central and South West Services, Inc.	))	Docket No. EC94-7-000

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February 3, 1994

TOTAL MERGER COST SAVINGS

YEAR	1995	1996	1997	1998	1999 (000)	2000	2001	2002	2003	2004	TOTAL
PRODUCTION & TRANSMISSION	$249	$147	$1,362	$1,140	$1,342	$4,599	$5,276	$6,729	$7,243	$5,439	$33,526
NON-FUEL O&M											
COST SAVINGS	$8,380	$18,165	$23,903	$25,162	$25,881	$26,492	$28,237	$30,223	$31,119	$29,884	$247,456
SERVICE COMPANY BILLINGS	($961)	($993)	($1,026)	($1,059)	($1,094)	($1,130)	($1,160)	($1,206)	($1,246)	($1,287)	($11,171)
NET NON-FUEL O&M	$7,419	$17,172	$22,877	$24,102	$24,787	$25,362	$27,070	$29,017	$29,872	$28,597	$236,284
FINANCIAL	$24,223	$24,044	$23,747	$23,310	$22,961	$6,862	$6,750	$6,649	$6,617	$6,675	$151,846
TOTAL MERGER COST SAVINGS	$31,891	$41,363	$47,986	$48,560	$49,100	$36,823	$39,096	$42,396	$43,732	$40,711	$421,656

1993 CSW/EPE STAND ALONE VS. INTEGRATED PLAN
DELTA SYSTEM TOTALS - ALLOCATION ($ 000's)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	SUM 1995 - 2004
1 Production Cost											
EPE	(854)	(1,200)	(2,870)	(2,226)	(2,589)	(2,763)	(2,901)	(3,985)	(4,086)	(3,471)	(26,947)
CPL	99	(330)	(868)	(655)	(1,031)	(1,067)	(850)	(1,775)	(2,655)	(998)	(10,149)
PSO	(338)	(111)	142	(70)	(148)	(248)	(433)	(228)	285	(195)	(1,545)
SWEPCO	(269)	166	382	212	161	125	(149)	(33)	167	73	1,038
WTU	2	(45)	(114)	(83)	(252)	(85)	(25)	(132)	(243)	(126)	(1,123)
Total	(1,354)	(1,520)	(3,128)	(2,822)	(4,066)	(4,038)	(4,411)	(6,141)	(6,532)	(4,716)	(38,726)
2 SO2 Allowance Cost											
EPE	0	0	0	0	0	127	84	237	207	102	759
CPL	0	0	0	0	0	8	13	1	5	10	36
PSO	0	0	0	0	0	(2)	(2)	(2)	(1)	(1)	(9)
SWEPCO	0	0	0	0	0	3	6	2	(15)	9	5
WTU	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	136	101	238	197	120	792
3 Generation Capacity Rev Reqmt											
EPE	0	0	0	0	0	0	0	0	0	0	0
CPL	0	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0	0
WTU	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	0	0
4 Capacity Commitment											
EPE	0	0	0	0	176	582	1,204	(193)	1,768	4,399	7,934
CPL	0	0	0	0	0	0	195	(759)	0	21	(543)
PSO	0	0	0	0	0	0	0	(95)	(1,786)	0	(1,881)
SWEPCO	0	0	0	0	(176)	(582)	0	0	18	(4,420)	(5,160)
WTU	0	0	0	0	0	0	(1,399)	1,049	0	0	(350)
Total	0	0	0	0	0	0	0	0	0	0	0
5 Capacity Purchases (Off-System)											
EPE	0	0	0	0	(663)	(4,080)	(4,457)	(4,410)	(4,590)	(4,374)	(22,576)
CPL	0	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0	0
WTU	0	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	(663)	(4,080)	(4,457)	(4,410)	(4,590)	(4,374)	(22,576)

URCES:

(1) PRODUCTION COST SAVINGS RESULTING FROM PROMOD SIMULATIONS (SEE PAGES 5-6)
(2) SO_2 ALLOWANCE COST SAVINGS RESULTING FROM PROMOD SIMULATIONS (SEE PAGES 7-8)
(3) DELTA REVENUE REQUIREMENTS (SEE PAGE 9)
(4) EXHIBIT JAB-9 (SEE BACK-UP PAGES 32-35)
(5) EXHIBIT JAB-8

1993 CSW/EPE STAND ALONE VS. INTEGRATED PLAN
DELTA SYSTEM TOTALS - ALLOCATION ($ 000's)

	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	SUM 1995 - 2004
6 Transmission Rev Rqmt											
EPE	0	0	0	0	0	0	0	0	0	0	0
CPL	0	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0	0
WTU	0	0	0	0	428	420	410	399	389	379	2,425
Total	0	0	0	0	428	420	410	399	389	379	2,425
7 Transmission Equalization											
EPE	0	0	0	0	(9,333)	(9,427)	(9,364)	(9,274)	(9,219)	(9,168)	(55,985)
CPL	0	0	0	0	2,985	2,976	2,977	2,963	2,962	2,958	17,821
PSO	0	0	0	0	2,668	2,606	2,565	2,523	2,485	2,470	15,317
SWEPCO	0	0	0	0	3,203	3,181	3,168	3,148	3,143	3,123	18,967
WTU	0	0	0	0	677	664	654	640	629	617	3,880
Total	0	0	0	0	0	0	0	0	0	0	0
8 Wheeling Costs - ERCOT Reallocation											
EPE	179	250	291	272	413	417	409	384	350	468	3,639
CPL	(78)	(83)	(19)	(78)	(122)	(149)	(166)	(21)	48	(101)	(771)
PSO	(18)	(36)	(53)	(40)	(36)	(60)	(47)	(51)	(123)	(51)	(517)
SWEPCO	(106)	(88)	(121)	(108)	(140)	(131)	(136)	(75)	(92)	(162)	(1,158)
WTU	(51)	(17)	(2)	(16)	(38)	(29)	(17)	(16)	(14)	(13)	(201)
Total	(63)	26	92	29	81	58	42	218	170	140	993
9 Wheeling Costs - TU TEO Reallocation											
EPE	0	0	0	0	1,337	1,342	1,354	1,358	1,362	1,366	8,120
CPL	0	0	0	0	(409)	(413)	(419)	(421)	(425)	(429)	(2,518)
PSO	0	0	0	0	(358)	(356)	(357)	(354)	(353)	(354)	(2,135)
SWEPCO	0	0	0	0	(437)	(440)	(445)	(448)	(449)	(450)	(2,670)
WTU	0	0	0	0	(133)	(133)	(133)	(133)	(132)	(133)	(222)
Total	0	0	0	0	0	0	0	0	0	0	0
10 Wheeling Costs - SPS											
EPE	120	96	127	119	239	262	276	271	268	276	2,073
CPL	260	504	657	637	802	814	855	819	830	860	7,057
PSO	193	195	245	265	702	701	728	703	693	710	5,136
SWEPCO	429	451	519	512	857	866	908	890	876	902	7,210
WTU	166	101	127	112	261	262	272	261	258	266	2,095
Total	1,168	1,347	1,675	1,653	2,880	2,904	3,039	2,966	2,925	3,014	23,572
Net Impact											
EPE	(555)	(854)	(2,452)	(1,835)	(10,597)	(13,540)	(13,397)	(15,613)	(13,739)	(10,401)	(82,783)
CPL	280	91	(239)	(96)	2,284	2,168	2,685	822	766	2,321	10,933
PSO	(163)	48	334	155	2,628	2,641	2,454	2,494	1,196	2,579	14,365
SWEPCO	54	519	980	616	3,470	3,022	3,353	3,484	3,649	(925)	18,232
WTU	122	32	6	28	253	1,182	(321)	2,985	887	282	5,730
Total	(251)	(147)	(1,361)	(1,139)	(1,343)	(4,599)	(5,276)	(6,730)	(7,241)	(5,437)	
Cumulative Net Impact										(33,524)	(33,524)

6) SEE PAGE 10
7) DIFFERENCE BETWEEN PRE-MERGER (PAGE 11) AND POST-MERGER (PAGE 12)
8) SEE PAGES 13-15
9) SEE PAGES 16-17
10) SEE PAGES 18-22

1993 CSW/EPE STAND ALONE VS. INTEGRATED PLAN
DELTA SYSTEM TOTALS - ALLOCATION ($ 000's)

	1995	1996	1997	1998	1999	2010	2011	2012	2013	SUM 1995 - 2013
1 Production Cost										
EPE	(12,160)	(13,657)	(7,619)	(4,303)	(3,485)	(8,490)	(4,993)	2,068	7,298	(73,288)
CPL	(3,141)	(1,163)	(1,499)	(1,487)	(792)	132	612	1,503	700	(15,284)
PSO	875	(233)	(484)	(811)	(41)	417	517	539	878	112
SWEPCO	690	193	675	444	232	(571)	(1,183)	(1,045)	(1,383)	(911)
WTU	(1,021)	(22)	(111)	(32)	(79)	(191)	(163)	(652)	(662)	(4,515)
Total	(14,826)	(14,953)	(9,038)	(6,230)	(4,164)	(8,703)	(5,491)	2,413	6,831	(92,886)
2 SO2 Allowance Cost										
EPE	73	9	185	118	(6)	(93)	175	76	(62)	1,233
CPL	2	15	6	8	21	46	28	24	106	292
PSO	(4)	(6)	(5)	0	0	5	6	15	17	18
SWEPCO	(7)	(3)	(1)	3	34	97	92	105	220	546
WTU	0	0	0	0	0	0	1	5	6	12
Total	65	16	184	129	50	54	301	224	287	2,102
3 Generation Capacity Rev Reqmt										
EPE	11,978	11,523	11,085	(2,963)	(2,847)	(2,738)	(17,592)	(30,466)	(29,320)	(51,340)
CPL	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0
WTU	0	0	0	0	0	0	0	0	0	0
Total	11,978	11,523	11,085	(2,963)	(2,847)	(2,738)	(17,592)	(30,466)	(29,320)	(51,340)
4 Capacity Commitment										
EPE	0	0	0	0	(9,448)	0	8,775	12,829	16,258	36,348
CPL	0	0	0	0	865	0	0	0	0	322
PSO	0	0	0	0	3,594	0	(4,696)	(7,235)	(9,266)	(19,484)
SWEPCO	0	0	0	0	9,231	0	0	0	0	4,071
WTU	0	0	0	0	(4,242)	0	(4,079)	(5,594)	(6,992)	(21,252)
Total	0	0	0	0	0	0	0	0	0	0
5 Capacity Purchases (Off-System)										
EPE	0	0	0	0	0	0	0	0	0	(12,576)
CPL	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0
WTU	0	0	0	0	0	0	0	0	0	0
Total	0	0	0	0	0	0	0	0	0	(12,576)

1993 CSW/EPE STAND ALONE VS. INTEGRATED PLAN
DELTA SYSTEM TOTALS - ALLOCATION ($ 000's)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	SUM 1995 - 2013
6 Transmission Rev Reqmt										
EPE	0	0	0	0	0	0	0	0	0	0
CPL	0	0	0	0	0	0	0	0	0	0
PSO	0	0	0	0	0	0	0	0	0	0
SWEPCO	0	0	0	0	0	0	0	0	0	0
WTU	370	362	338	344	337	329	321	314	306	5,462
Total	370	362	338	344	337	329	321	314	306	5,462
7 Transmission Equalization										
EPE	(9,168)	(9,168)	(9,168)	(9,168)	(9,168)	(9,168)	(9,168)	(9,168)	(9,168)	(138,456)
CPL	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	2,958	44,445
PSO	2,470	2,470	2,470	2,470	2,470	2,470	2,470	2,470	2,470	37,558
SWEPCO	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	3,123	47,073
WTU	612	612	612	612	612	612	612	612	612	9,182
Total	0	0	0	0	0	0	0	0	0	0
8 Wheeling Costs - ERCOT Reallocation										
EPE	646	658	639	606	496	418	445	478	585	8,639
CPL	91	(163)	(136)	(59)	(31)	(138)	(156)	(241)	(158)	(1,764)
PSO	(154)	(132)	(44)	(12)	(42)	(62)	(102)	(145)	(157)	(1,386)
SWEPCO	(156)	(220)	(271)	(198)	(129)	(89)	(114)	(143)	(70)	(2,550)
WTU	(3)	(52)	(11)	(54)	(33)	(50)	(73)	(121)	(93)	(713)
Total	424	82	151	282	261	79	0	(171)	104	2,205
9 Wheeling Costs - TU TFO Reallocation										
EPE	1,373	1,375	1,374	1,374	1,378	1,378	1,377	1,372	1,368	20,489
CPL	(434)	(436)	(438)	(441)	(445)	(448)	(451)	(450)	(452)	(6,513)
PSO	(352)	(351)	(351)	(347)	(346)	(344)	(341)	(340)	(336)	(5,242)
SWEPCO	(453)	(453)	(453)	(453)	(454)	(454)	(453)	(450)	(448)	(6,739)
WTU	(134)	(134)	(133)	(133)	(133)	(133)	(131)	(132)	(132)	(1,995)
Total	0	0	0	0	0	0	0	0	0	0
10 Wheeling Costs - SPS										
EPE	286	287	288	301	304	328	356	367	442	5,031
CPL	890	896	902	950	961	1,045	1,143	1,187	1,442	16,473
PSO	722	720	722	748	747	803	864	895	1,074	12,431
SWEPCO	929	931	931	976	981	1,059	1,148	1,186	1,430	16,781
WTU	225	225	225	236	288	310	332	348	421	3,211
Total	3,102	3,108	3,118	3,261	3,282	3,544	3,847	3,983	4,809	55,626
Net Impact										
EPE	(6,971)	(8,974)	(3,197)	(14,036)	(22,775)	(18,365)	(20,626)	(22,444)	(12,600)	(212,970)
CPL	367	2,104	1,792	1,928	3,538	3,595	4,135	4,981	4,596	37,969
PSO	3,557	2,469	2,309	2,008	6,384	3,288	(1,262)	(3,800)	(5,310)	23,998
SWEPCO	4,127	3,570	4,005	3,895	13,017	3,165	2,613	2,776	2,872	58,270
WTU	33	262	918	1,827	(3,245)	882	(3,473)	(5,215)	(6,521)	(8,624)
Total	1,113	138	5,857	(5,177)	(3,081)	(7,435)	(18,613)	(23,702)	(16,982)	
Cumulative Net Impact									(101,407)	(101,407)

SOUTHWESTERN PUBLIC SERVICE COMPANY
P. O. BOX 1261 • AMARILLO, TEXAS 79170 • 806/378-2121

GERALD J. DILLER
VICE PRESIDENT
RATES AND REGULATION

March 7, 1994

Mr. James Galloway, Filing Clerk
Public Utility Commission of Texas
7800 Shoal Creek Boulevard, Suite 124S
Austin, TX 78757

Dear Mr. Galloway:

Enclosed for filing is an original and four copies of Southwestern Public Service Company's response to General Counsel's First Request for Information.

Yours truly,

Gerald J Diller

Gerald J. Diller

GJD/mlt

c: Attached Service List

DOCKETS NOS. 12700/12701

GENERAL COUNSEL'S FIRST REQUEST FOR INFORMATION TO

SOUTHWESTERN PUBLIC SERVICE COMPANY

QUESTIONS NOS. SG-001 THROUGH SG-004

(ACQUISITION PHASE)

The term wheeling will refer to transfer of capacity from EPEC across SPS electric system to CSW using the 133 MW portion of the 200 MW HVDC interconnection with SPS.

QUESTION NO. SG-001

Provide the amount(s) of power (in MW) that can be safely wheeled from EPEC to CSW for the years 1993 to 2004. If these amounts vary by month, provide the monthly permissible transfers. For each feasible transaction provide the numbers of hours for which it can take place.

ANSWER

Southwestern Public Service Company ("Southwestern") can safely wheel from EPEC to CSW (west to east) up to 133 MW of power if necessary system improvements are made to Southwestern's electrical system. EPEC and CSW ("Applicants") have requested 133 MW of firm bi-directional transmission service across Southwestern's electrical system (refer to Shockley Direct Testimony, p. 21, and Bruggeman Direct Testimony, p. 32). However, Southwestern's system is constrained with respect to the importation of power and energy from the east (CSW) for delivery to the west (EPEC). Southwestern's interconnections with the Southwest Power Pool were constructed to instantaneously import power in case of a forced outage of one of Southwestern's generating units. The prescheduling of power across those interconnections from east to west will reduce Southwestern's effective instantaneous import capability and decrease Southwestern's reliability. Applicants' proposed 133 MW transfer will also impact facility requirements internal to Southwestern's system. Southwestern has not analyzed the amounts of power flows by month because Applicants have failed to provide their proposed transfer load profiles to Southwestern, even though they have assumed load profiles in developing their production-related cost savings. Applicants have filed an application with the Federal Energy Regulatory Commission ("FERC") pursuant to Section 211 of the Federal Power Act requesting that the FERC order Southwestern to provide the transmission services

DOCKETS NOS. 12700/12701

GENERAL COUNSEL'S FIRST REQUEST FOR INFORMATION TO

SOUTHWESTERN PUBLIC SERVICE COMPANY

QUESTIONS NOS. SG-001 THROUGH SG-004

(ACQUISITION PHASE)

for the Applicants (FERC Docket No. TX94-2-000). Southwestern, in its response to that filing, has raised numerous legal, reliability, cost, and competitive issues with respect to the Applicants' proposed use of Southwestern's electrical system. Refer to Southwestern's response to the FERC, provided as Exhibit SG-001.

SPONSOR: John S. Fulton

Public Service Company of New Mexico

February 22, 1994

VIA FEDERAL EXPRESS

Mr. Curtis L. Hoskins
President and Chief Operating Officer
El Paso Electric Company
303 North Oregon
El Paso, TX 79901

Dear Mr. Hoskins:

Subject: Phase Shifter Support Principles

Enclosed for execution are two originals of the subject principles signed by me on behalf of Public Service Company of New Mexico. Please return one signed original for our files.

This signing is cause to look forward to a renewed spirit of cooperation and trust between our respective companies.

Sincerely,

M. Phyllis Bourque

M. Phyllis Bourque
Senior Vice President
Marketing & Customer Service

MPB:bsa

cc: Mr. Jack Maddox, PNM
Mr. Cindy Murray, PNM

Alvarado Square
Albuquerque, New Mexico 87158
505/848-2700

ᴊNFIDENTIAL
FOR SETTLEMENT DISCUSSIONS ONLY

FEBRUARY 22, 1994

PHASE SHIFTER SUPPORT PRINCIPLES

DEFINITIONS:

EPE SS"A" Rights: Wheeling provided by PNM to EPE pursuant to Service Schedule A (SS"A") to the PNM/EPE Interconnection Agreement (currently 104 MW).

PNM SS"A" Rights: Wheeling provided by EPE to PNM pursuant to SS"A" (currently 25 MW).

PNM SNM RIGHTS: The sum of PNM SWNMT Line A Rights (currently 50 MW) plus PNM SS"A" Rights.

PST Base Setting: The sum of (1) EPE's scheduled use of EPE SS"A" Rights, plus (2) PNM's scheduled use of PNM SS"A" Rights, plus (3) an additional amount of 20 MW.

Real Time Check Points: The operating status of certain generating units and shunt reactors, as defined in the Interim Southern New Mexico Transmission Operating Procedure attached as Exhibit "A" to the Interim Transmission Capability Agreement and Agreement to Arbitrate between EPE and PNM dated March 30, 1990 (Interim Agreement).

SNM Limit: The SNM Import capability in MW at the knee of the NNM vs. SNM operating nomogram in effect from time to time, with the PST in-service and operating at the PST Base Setting. The maximum SNM Limit from the attached preliminary nomogram is expected to be 890 MW when the PST Base Setting is fully scheduled by EPE and PNM.

PRINCIPLES OF AGREEMENT: PNM and EPE (Parties) agree to enter into a stipulation in NMPUC Case No. 2527 based on the following principles of agreement:

PNM will support the construction and operation by EPE of a PST on EPE's West Mesa to Arroyo 345kV line, and EPE will allow PNM to operate EPE's 345kV reactor switch located at West Mesa pursuant to the West Mesa Reactor Switch Agreement, in conjunction with the following principles:

1. Under normal operating conditions with the PST in-service and operating at the PST Base Setting, the SNM Limit will be in effect under the following conditions:

a. EPE shall pay PNM (1) for 20 MW of reserved transmission capacity at PNM's embedded transmission service rate; and, (2) for up to a 20 MW portion of PNM's incremental energy cost of local gas-fired generation and/or purchased energy when such energy is actually used due to PNM's need to increase use of NNM Import capability. (In this paragraph, the term "incremental energy cost" shall mean the difference between the energy cost of PNM's locally generated or purchased energy and the energy cost of PNM's foregone remotely generated or purchased energy. Additionally, the Parties agree that running PNM local generation increases NNM Import Capability on a basis higher than 1 to 1.) The Parties agree to enter into an operating procedure to implement the provisions of this item (2). Prior to committing such energy for this purpose, PNM shall notify EPE verbally of its intent to use local generation and/or purchased energy, and EPE shall either (1) lower its SNM Imports to accomodate NNM Import needs, or (2) pay PNM its incremental cost of such energy. Neither Party waives its right to have other SNM entities participate in these payments to PNM.

b. PNM shall ensure that its share of SNM Imports are at all times within PNM SNM Rights. EPE shall ensure that the SNM Limit in effect is not exceeded. With respect to curtailments: (1) EPE shall effect all curtailments of SNM Imports when (i) decreases in the SNM Limit are caused by failure to achieve or maintain Real Time Check Points, and (ii) limits are placed on flows into SNM from TEP's System; and, (2) PNM shall effect all curtailments of NNM Imports when decreases in NNM Import capability are caused by failure to achieve or maintain the necessary status of NNM capacitors and/or shunt reactors. Neither Party waives its right to have third party entities participate in these curtailments.

c. Due to the impact on NNM Import capability of PST settings higher than the PST Base Setting and PNM's need to assess whether NNM Import capability is available, EPE and/or EPE with any third party shall enter into written agreements with PNM before implementing and/or agreeing with third parties to implement firm schedules of SNM Imports (and verbal agreement is required for non-firm schedules) through the PST that are above schedules related to the PST Base Setting. EPE agrees that such agreements, to the extent that PNM determines necessary, may involve additional service and hence additional compensation to PNM by EPE and/or the third party, unless PNM agrees in advance to the contrary. The Parties agree that compensation to PNM for such additional service will be based on the cost of the type of wheeling (i.e., firm or interruptible) or other services involved.

2. When the PST is out-of-service, EPE shall curtail its SNM Imports as required to ensure that the PST out-of-service nomogram limits are not exceeded.

3. For the period prior to the earlier of the termination of Service Schedule

G to the PNM/EPE Interconnection Agreement (SS"G") or the in-service date of the PST, the Parties agree to implement in written agreement the modifications to the Interim Agreement that were contemplated in Sections 6.3 and 6.4 of the Transition Agreement between EPE and PNM dated September 2, 1993. If SS"G" expires or terminates prior to the in-service date of the PST, the Parties agree to negotiate in good faith the terms and conditions under which the Interim Agreement could be extended.

4. Operating procedures to implement the post-PST principles set forth above and to address related operating parameters (including new operating nomograms) shall be executed prior to the in-service date of the PST. The Parties agree to use best efforts to agree to both pre- and post-PST operating procedures and to implement such operating procedures in conjunction with the enabling agreements that will result from these principles. Once both pre- and post-PST operating procedures are executed by the Parties, EPE shall become Operating Agent for the SNM transmission system.

5. No later than 60 days following the conclusion of EPE's NMPUC CCN case for the PST, PNM and EPE shall begin joint planning studies to determine a least cost system capital addition distinct from PNM's OLE Project (or its replacement) that, when in-service, would permit EPE and PNM and participating third parties to realize the entirety of the incremental transmission capability needed in NNM and SNM by PNM, EPE and such third parties. Until such system addition is in service, PNM and EPE shall work together to encourage third parties to accept entitlements to SNM Import capability that are within the NNM Import capability and SNM Limit as each is established hereunder. PNM and EPE shall not contract with third parties to recognize NNM or SNM entitlements or facilitate NNM or SNM Imports that cause SNM Imports to exceed the SNM Limit under the operating nomograms resulting from these principles.

6. The agreements and operating procedures that result from these principles shall be in effect until the earlier of May 1, 1998, or the in-service date of the least cost system addition distinct from PNM's OLE Project as contemplated in paragraph 5, and shall continue in effect from year to year thereafter until terminated by either EPE or PNM giving one year's prior written notice to the other.

7. EPE agrees to support PNM's FERC filings for acceptance of the enabling service agreements that will result from these principles.

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Accepted and agreed to this 22nd day of February, 1994.

Public Service Company of New Mexico

BY: M. Phyllis Bourque

ITS: Senior Vice President

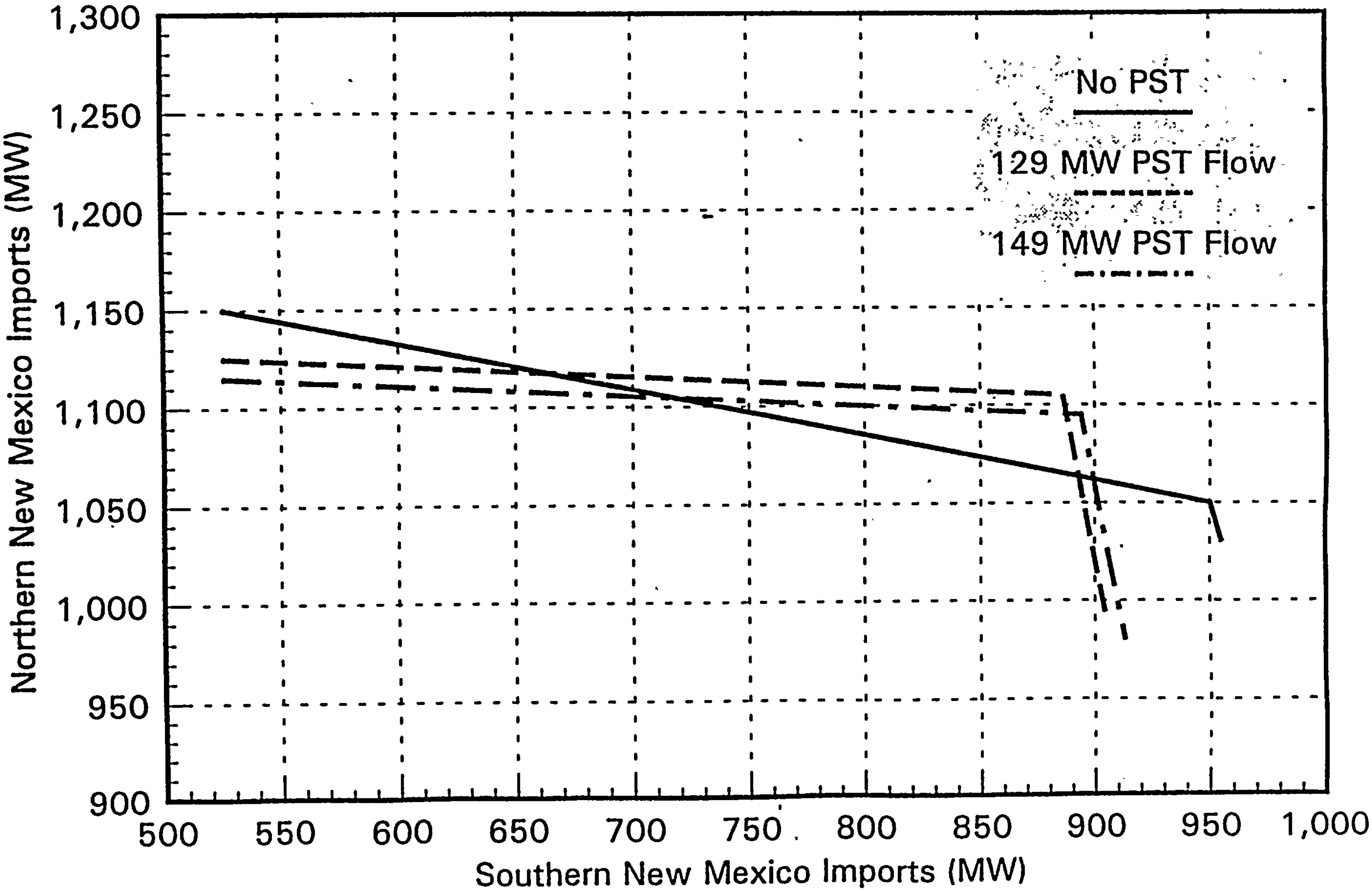
El Paso Electric Company

BY: C. L. Hoskins

ITS: President

b:epepst5

Estimated 1995 NM Transmission Import Capability Pre-PST and Post-PST



PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF CENTRAL AND SOUTH WEST CORPORATION

AND EL PASO ELECTRIC COMPANY

FOR APPROVAL OF ACQUISITION

DIRECT TESTIMONY OF

DAVID G. CARPENTER

FOR

APPLICANTS

JANUARY 1994

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I. INTRODUCTION AND QUALIFICATIONS

Q. PLEASE STATE YOUR NAME, POSITION WITH THE COMPANY AND BUSINESS ADDRESS.

A. My name is David G. Carpenter and I am the State Case Director for the El Paso Electric Transition Team of Central and South West Corporation (CSW). My business address is 1616 Woodall Rodgers Freeway, Dallas, Texas 75202.

Q. WHAT ARE YOUR PRINCIPAL AREAS OF RESPONSIBILITY?

A. My responsibilities include the supervision and management of the applications for state regulatory approvals and authorizations required for consummation of the acquisition by CSW of 100% of the common stock of El Paso Electric Company (EPEC). CSW is acquiring

EPEC pursuant to the Modified Third Amended Plan of Reorganization of EPEC (Plan) which has been confirmed by the United States Bankruptcy Court, Western District of Texas, Austin Division. The acquisition is conditioned on the entry of appropriate orders by both the Public Utility Commission of Texas (PUCT, or Commission) and the New Mexico Public Utility Commission (NMPUC) among others. Additionally, the acquisition is conditioned on approval of adequate retail base rate increases by the PUCT and the NMPUC. I am also responsible for the supervision and management of the rate case filings.

Q. PLEASE STATE BRIEFLY YOUR EDUCATIONAL BACKGROUND, AND BUSINESS EXPERIENCE.

A. I graduated from Texas Tech University in 1977 with a Bachelor of Business Administration degree in Accounting. I am a Certified Public Accountant licensed to practice in the State of Texas. I am a member of the American Institute of Certified Public Accountants and the Texas Society of Certified Public Accountants. During my career, I have attended numerous seminars and short courses on accounting, management and regulatory topics. I have completed the Electric Utility Management Course at Baylor University and the Public

Utility Executive Program at the University of Michigan.

After graduation, I worked as a staff accountant in the regulatory accounting area of Houston Lighting and Power Company. In 1978, I joined the CSW system at its West Texas Utilities Company (WTU) subsidiary. At WTU, I held the positions of Accountant II, Chief Accountant, Supervisor of Statistics and Taxes, Assistant to the Controller and Controller and Chief Accounting Officer. In August 1989, I transferred to Central and South West Services, Inc. (CSWS) as Assistant Controller and Director of Accounting. In October 1991, I transferred to Central Power and Light Company (CPL) as Director of Rates and Regulatory Affairs. In May 1993, I transferred to CSW in my current position.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE PUBLIC UTILITY COMMISSION OF TEXAS?

A. Yes, I have testified before the PUCT in proceedings involving WTU and CPL.

II. SUMMARY

Q. WHAT AREAS DO YOU ADDRESS IN YOUR TESTIMONY?

the extent they constitute known and measurable test year adjustments.

Q. HOW DOES THE MODIFIED CSW SETTLEMENT RATE PLAN COMPARE TO WHAT A NON-MERGER, STAND-ALONE RATE PLAN FOR THE REORGANIZED EPEC MIGHT HAVE BEEN?

A. Under any scenario, using common assumptions to develop hypothetical merger and stand-alone rate plans, the merger rate plan will always produce lower costs for EPEC's customers because of the cost savings realized from the merger. If the CSW settlement rate plan is implemented by the Commission, the rates for the merged EPEC will be even lower.

V. OTHER ACCOUNTING AND TAX ASPECTS OF THE MERGER

Q. HAS AN ACQUISITION ADJUSTMENT BEEN CALCULATED BY CSW?

A. Yes, CSW has calculated a $26 million acquisition adjustment currently expected to result at the effective date of the merger. The amount of the acquisition adjustment is based upon a forecast of asset values for EPEC at December 31, 1994, the date immediately before the presumed effective date of the merger. Ms. Wendy Hargus explains the development of the acquisition adjustment in her testimony.

Q. WHAT REGULATORY TREATMENT IS CSW SEEKING FOR THE ACQUISITION ADJUSTMENT?

A. If the acquisition of EPEC by CSW is found to be consistent with the public interest and appropriate rates and other regulatory treatments are implemented that are consistent with the approach requested by CSW, CSW will not seek recovery of the acquisition adjustment from EPEC's customers. CSW's objective is to structure a plan that is fair to both EPEC's customers and to CSW's shareholders. Obviously, those shareholders expect CSW to earn a fair return on its investment in EPEC. CSW believes that there are other plans that could be structured to accomplish an acceptable sharing of the benefits and earn a fair return on investment including plans which provide for rate recovery of the amortization of the acquisition adjustment.

Q. WHAT IS THE STRUCTURE OF THE RESOLUTION OF THE PALO VERDE LEASE ISSUES?

A. As I have discussed, to resolve disputes involving the Palo Verde leases, the Plan provides for EPEC to reacquire its interests in Palo Verde Units 2 and 3 which it sold and leased-back in 1986 and 1987. Such

reacquisition results from settlements reached with the Palo Verde Owner Participants and the Palo Verde lease obligation bondholders (collectively "Palo Verde lease interests"). As consideration for their releasing their interest in these assets and in satisfaction of other claims against EPEC, the Palo Verde Owner Participants retain the $288 million which they drew on the Palo Verde letters of credit. The Palo Verde lease obligation bondholders will be paid $669 million in Series A, Senior Notes (Senior Notes) and CSW common stock to satisfy their claims against EPEC and release their interest in the assets. Of the aggregate $957 ($288 + $669) million in payments to the Palo Verde lease interests, $352 million represents lease-rejection damages. The damages are calculated by subtracting from the total $957 million paid to reacquire the Palo Verde leased assets, the reasonable and prudent net depreciated original cost of the reacquired assets, which is $605 million as of June 30, 1993.

Q. WHY WAS IT DECIDED TO REACQUIRE THE LEASED PALO VERDE ASSETS AND PAY LEASE-REJECTION DAMAGES?

A. As I discussed previously and as Mr. G. H. King and Dr. Samuel Hadaway testified, CSW determined that settling

the disputes with the Palo Verde lease interests through reacquisition of the previously leased assets would result in lower revenue requirements to customers over the life of the Palo Verde assets and permit EPEC's financial condition to be strengthened. The payments to the lease obligation bondholders in Senior Notes and CSW common stock were structured to minimize CSW's cost of acquiring EPEC by permitting the tax effect of the lease-rejection damages to produce a net damage payment. In addition, because CSW structured the settlement with Palo Verde lease interests for EPEC to reacquire the previously leased Palo Verde assets, and was willing to incur the lease-rejection damages, additional tax benefits will be available and inure to the benefit of EPEC's customers through taking accelerated depreciation on the $605 million net book value of the reacquired assets.

Q. WILL CSW SEEK RECOVERY OF THE LEASE-REJECTION DAMAGES?

A. No.

Q. HOW WILL THE LEASE-REJECTION DAMAGES BE REFLECTED IN EPEC'S FINANCIAL STATEMENTS AFTER THE MERGER?

A. The plant acquisition adjustment recorded as a result of the acquisition is increased to reflect that no

recovery of the lease rejection damages will be sought. The lease-rejection damages, net of tax effects, will be reflected in the purchase price recorded to account for the acquisition of EPEC by CSW. The accounting entries to record the electric plant acquisition adjustment, including the net lease-rejection damages, are addressed in the testimony of Ms. Wendy Hargus.

Q. WHAT TAX BENEFIT CAN BE OBTAINED BY EPEC's PAYING LEASE-REJECTION DAMAGES?

A. Under the Internal Revenue Code, EPEC is able to deduct the damages when economic performance occurs. As I discussed earlier, the Palo Verde lease-obligation bondholders will receive Senior Notes under the Plan. After the effective date of the merger, when the Senior Notes are redeemed, a deduction for the lease-rejection damages will be available to EPEC. However, because, at the time the deduction is taken, EPEC will not have sufficient income to utilize the tax deduction on a stand-alone basis, the tax deduction will only be realized through the CSW consolidated tax return. Under the CSW tax allocation agreement, EPEC will receive a cash payment for the tax effect of the deduction, when the deduction is utilized on the CSW consolidated tax return.

Q. WHEN WILL THE TAX DEDUCTION FOR THE LEASE-REJECTION DAMAGES BE TAKEN?

A. The precise timing of this tax deduction is not known. While assumptions must be made in the forecast process and while EPEC's current forecast, as discussed by Applicants' witness Michael Blough, shows the Senior Notes being redeemed and the damages being deducted in 1995, the actual timing of the deduction will depend upon several factors. Since the Senior Notes issued to the lease obligation bondholders must be redeemed to claim the deduction, realization of the tax deduction for the lease-rejection damages will be dependent on EPEC's ability to redeem the Senior Notes following the effective date of the acquisition. In addition, the timing of the full deduction may be affected by the level of taxable income available to CSW on a consolidated basis and on any applicable alternative minimum tax considerations. As a result, the exact timing of the redemption and deduction is not now known.

Q. HOW WILL EPEC ACCOUNT FOR THE TAX BENEFIT ASSOCIATED WITH THE LEASE-REJECTION DAMAGES?

A. Since the tax deduction is not realized until economic performance occurs, initially a deferred tax asset will

be recorded on EPEC's books and the electric plant acquisition adjustment will be credited. The net effect is that the tax effect of the lease-rejection damages reduces the increase in the electric plant acquisition adjustment resulting from the liability for the damages.

Q. WAS THE TAX DEDUCTION FOR THE LEASE-REJECTION DAMAGES INCLUDED IN THE CALCULATION OF INCOME TAXES IN EPEC's CURRENT RATE CASE?

A. No, it is not reflected in the income tax calculation in EPEC's current rate case. Likewise, neither are the amounts giving rise to the lease-rejection damages, nor the deferred tax asset, reflected in rate base in EPEC's current rate case.

Q. IS THE TREATMENT OF THE TAX BENEFITS ASSOCIATED WITH THE LEASE-REJECTION DAMAGES PROPOSED BY CSW A "FAIR SHARE" FOR EPEC'S CUSTOMERS?

A. Yes, it is. EPEC's customers receive a fair share of the total tax benefits associated with the lease-rejection damages. While they do not receive a benefit from the damages tax deduction directly, they are also not asked to pay for the amounts giving rise to the net lease-rejection damages or a return on the deferred tax asset.

The ability to have a reduced damage payment by netting the tax effect of the damages against the lease-rejection damages allowed CSW to reach a settlement with both the Palo Verde lease obligation bondholders and the Owner Participants. This settlement is integral to EPEC's emergence from bankruptcy and the reflection of the net of tax benefit amount in the acquisition adjustment is the proper accounting under generally accepted accounting principles and the uniform system of accounts adopted by this Commission.

As already discussed in my testimony, EPEC is projected to realize cost savings of over $380 million from the merger during the next ten years following the acquisition of EPEC by CSW. Under the treatment set forth above, CSW will not seek recovery of the amounts giving rise to the net lease-rejection damages, the electric plant acquisition adjustment or the costs of the bankruptcy. Additionally customers will also experience lower revenue requirements over the life of the leased Palo Verde assets and will receive the benefits of rate base reductions from the deferred taxes resulting from accelerated depreciation on the reacquired assets. Also, customers will benefit from rates that are below the full cost of service for a number of years if the settlement rate plan offered by

CSW is implemented. By virtue of CSW's willingness to incur the net lease damages in order to settle the claims of the Palo Verde lease interests, and bring EPEC out of bankruptcy as a CSW subsidiary, EPEC's customers not only receive a fair share of tax benefits, but also many other benefits.

Q. IS THE COMMISSION'S RECOGNITION OF THE ACCOUNTING TREATMENT THAT CSW PROPOSES FOR THE LEASE REJECTION DAMAGES AN IMPORTANT CONSIDERATION FOR CSW IN SATISFYING THE CONDITIONS FOR CONSUMMATION OF THE ACQUISITION?

A. Yes, it is. In fact, the treatment CSW proposes is an element in the CSW settlement rate plan. The accounting and ratemaking treatments of the damages and associated tax deduction are important considerations in satisfying the conditions for consummation of the acquisition. CSW requests the Commission, in its order finding the acquisition by CSW of EPEC to be consistent with the public interest, to specifically order the lease-rejection damages be treated for regulatory and ratemaking purposes as described above. In addition, CSW requests that the Commission find that the proposed treatment of the tax benefits resulting from the lease-rejection damages constitutes a "fair share" for purposes of PURA Section 41(c)(2).

Q. ARE THERE ANY ADDITIONAL DETERMINATIONS WHICH CSW AND EPEC REQUEST THE COMMISSION MAKE AS TO THIS MATTER?

A. Yes, there are. In light of the treatment of this tax item requested above, the Commission should also order that the reduction in taxes which arises through taking this tax deduction on the consolidated CSW federal income tax return will not be used for ratemaking purposes to reduce the federal income taxes of other CSW electric operating companies, because such use would be inconsistent with the "fair share" determined by the Commission in this case. In essence, such an action would represent double-utilization through the regulatory process of the tax benefit.

If the Commission establishes a different treatment for the tax deduction, CSW would request that an alternative, such as recovery of the electric plant acquisition adjustment, be approved to afford CSW with an opportunity to earn a fair return on its investment in EPEC.

Q. WILL EPEC INCUR ANY TAXABLE INCOME AS A RESULT OF THE RESOLUTION OF THE CREDITOR'S CLAIMS UNDER THE PLAN?

A. Yes, to the extent certain recoveries by EPEC's creditors under the Plan are satisfied at less than the

amount of the underlying obligations, this may give rise to debt forgiveness income. The resulting tax liability will increase the acquisition adjustment.

Q. ARE THERE ANY OTHER TAX ASPECTS OF THE ACQUISITION THAT YOU WISH TO MENTION?

A. A factor which often comes into play in mergers or acquisitions is the effect of the merger on the ability of the acquired company to use net operating losses (NOLs). Internal Revenue Code Section 382 imposes certain limitations on the use by an acquired firm of NOLs realized prior to the merger or acquisition. The acquisition by CSW of EPEC, however, is not expected to adversely affect EPEC's ability to utilize the NOLs that are on its books immediately prior to the acquisition. By the effective date of the merger, EPEC is projected to have fully utilized its NOL carry forwards.

VIII. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. CSW has developed the Plan to enable EPEC to emerge from bankruptcy as a financially viable utility through its acquisition by CSW. EPEC will realize cost savings of over $380 million during the next ten years as a result of the merger. CSW has proposed a settlement of