In the United States Court of Federal Claims

No. 00-238C
Filed November 30, 2005
TO BE PUBLISHED

NORTH STAR STEEL CO.,	*	
	*	Breach of Contract;
Plaintiff,	*	Court-Appointed Expert, FED. R. EVID. 706;
	*	Duty of Good Faith and Fair Dealing;
	*	Economic Duress;
v.	*	RESTATEMENT (SECOND) CONTRACTS (1981).
THE UNITED STATES,	*	
Defendant.	*	

Philip L. Chabot, Jr., McCarthy, Sweeney & Harkaway, P.C., Washington, D.C., counsel for plaintiff.

Jonathan R. Prouty, United States Department of Justice, Washington, D.C., counsel for defendant. Of Counsel, **Liova D. Juarez**, General Counsel, Western Area Power Administration, Lakewood, Colorado.

MEMORANDUM OPINION AND FINAL ORDER REGARDING CONTRACTUAL LIABILITY AND DAMAGES

BRADEN, *Judge*

This *sui generis* case concerns an August 16, 1994 contract for services to regulate electric power transmitted between the Western Area Power Administration ("WAPA") and the Arizona Electric Power Cooperative, Inc. ("AEPCO") for the benefit of North Star Steel Co. ("North Star"). *See United States* v. *North Star Steel Co.*, 58 Fed. Cl. 720, 734-35 (Fed. Cl. 2003). The contract at issue required WAPA to "jointly establish an appropriate cost-based methodology," before the conclusion of the first year of normal operations of the North Star plant. In this action, North Star sought damages of $6,465,889.65 for breach of that contractual requirement and WAPA's failure to negotiate in good faith. WAPA countered that there was no breach and WAPA negotiated with AEPCO/North Star in good faith for rates that were reasonable. For the reasons discussed herein, to ascertain whether a breach occurred and the appropriate amount of damages, the appointment of a court-appointed expert in utility ratemaking was required.

To facilitate a review of this Memorandum Opinion, the court has provided the following outline:

BACKGROUND

A. Federal Regulation Of The Electric Utility Industry.

1. The Effect Of Federal Legislation Enacted 1920-1977.

2. Effect Of The Department Of Energy Organization Act Of 1977 And Creation Of The Western Area Power Administration.

B. Relevant Facts.

1. Early 1990-August 17, 1994 -- Negotiations Between North Star Steel Co. And The Western Area Power Administration For Regulating Services.

2. August 17, 1994 -- The Western Area Power Administration And North Star Steel Co. Execute Interconnection And Consolidated Contracts.

3. October 23, 1997-July 28, 1999 -- The Western Area Power Administration Failed To Establish "An Appropriate Cost-Based Methodology" For The "In-Kind Energy" Payment.

a. October 23, 1997-June 19, 1998 -- Post Consolidated Contract Negotiations.

b. December 7, 1998 -- The Western Area Power Administration Files An Open Access Transmission Tariff With The Federal Energy Regulatory Commission.

c. December 8, 1998-September 15, 1999 -- The Western Area Power Administration And North Star Steel Co. Continue To Negotiate Until The Unilateral Imposition Of Amendment No. 3 On September 15, 1999.

d. During 2000, The Western Area Power Administration And North Star Steel Co. Resumed Negotiations Until North Star Steel Co. Rejected Revision 1 On October 17, 2001.

C. Procedural Background.

DISCUSSION

A. Jurisdiction.

B. North Star Steel Co. Has Standing As A Third-Party Beneficiary To The August 17, 1994 Consolidated Contract For Regulating Services.

C. The Court's Resolution Of The Remaining Substantive Issues.

1. The Western Area Power Administration Had No Contractual Obligation To North Star Steel Co. To "True Up" Over Or Under Payments Of "In-Kind Energy" On An Annual Basis And No Duty To Refund Retroactively Any Overpayment For Regulating Services.

2. The Terms Of The Consolidated Contract Evidence Sufficient Certainty To Determine: The Intent Of The Parties To Enter a Contract; Whether And When A Breach Occurred; And An Appropriate Remedy For Breach.

3. The Western Area Power Administration Breached The Consolidated Contract By Failing To Establish A "Cost-Based Methodology" For Regulating Services On July 1, 1998 Or Thereafter.

a. In Discovery And At Trial, The Western Area Power Administration Claimed That No Data Existed To Evidence Annual Operations And Maintenance Costs For The Regulating Services Provided To North Star Steel Co.

b. Substantial Expert Testimony Confirmed That The Western Area Power Administration Did Not Establish A "Cost-Based" Methodology With North Star Steel Co.

(1) June 22, 2004 Direct Testimony Of North Star Steel Co.'s Expert -- Dr. Carl Pechman.

(a) Qualifications.

(b) Expertise.

(c) Opinion.

(2) July 27, 2004 Direct Testimony Of North Star Steel Co.'s Expert -- R. Mark Clements.

(a) Qualifications.

(b) Expertise.

(c) Opinion.

(i) Generation Capacity Costs.

(ii) Automatic Generation And Communications Costs.

(iii) Variable Operating And Maintenance Costs.

(iv) Opportunity Costs.

(v) Conclusion.

(d) Cross Examination.

(3) July 2, 2004 Direct Testimony Of The Western Area Power Administration's Expert -- Dr. Douglas A. Gegax.

(a) Qualifications.

(b) Expertise.

(c) Opinion.

(4) July 27, 2004 Rebuttal Of North Star Steel Co.'s Expert -- R. Mark Clements To The Western Area Power Administration's Expert -- Dr. Gegax.

(a) Summary Critique Of Dr. Gegax's Report.

(b) Calculation Of Actual Costs For Regulating Services Provided To North Star Steel Co. For The Period July 1997–March 2003.

(5) October 25, 2004 Direct Testimony Of The Court's Expert -- Dr. Barbara R. Barkovich.

(a) Qualifications.

(b) Expertise.

(c) Opinion.

(i) Comparison Of Alternative Cost Models.

(ii) The Western Area Power Administration's Regulating Services Were Not Provided To North Star Steel Co. On A "Cost-Of-Service" Basis.

(iii) Dr. Barkovich's Initial "Cost-Of-Service" Calculations.

(6) November 16, 2004 Supplemental Report Of The Court's Expert -- Dr. Barbara R. Barkovich.

(7) February 1, 2005 Post-Trial Additional Report Of The Court's Expert - -Dr. Barbara R. Barkovich.

(8) February 15, 2005 Post-Trial Sur-Rebuttal Report Of North Star Steel Co.'s Expert -- R. Mark Clements.

(9) November 7, 2005 Post-Trial Response Of The Court's Expert -- Dr. Barkovich To February 15, 2005 Post-Trial Sur-Rebuttal Report Of North Star Steel Co.'s Expert -- R. Mark Clements.

4. The Western Area Power Administration's Unilateral Imposition Of Amendment No. 3 On September 15, 1999 Was An Act Of "Economic Duress" And A Breach Of The Obligation To Negotiate In Good Faith.

a. North Star Steel Co. "Involuntarily Accepted" Amendment No. 3.

b. The "Circumstances Permitted" North Star Steel Co. "No Other Alternative," Than To Accept Amendment No. 3.

c. Amendment No. 3 Was Not "Cost-Based."

D. North Star Steel Co. Is Entitled To Damages In The Amount Of $1,521,626.

CONCLUSION

BACKGROUND

A. Federal Regulation Of The Electric Utility Industry.[1]

To understand the context of this contractual dispute, a summary review of the labyrinth of laws enacted by Congress that regulate virtually all aspects of the electric utility industry is required.

1. The Effect Of Federal Legislation Enacted 1920-1977.

The genesis of federal regulation of the electric utility industry occurred when Congress authorized the funding of massive public work projects to utilize hydropower resources to create jobs and extend and expand electric power service to rural and undeveloped areas of the country, primarily in the southern and western states.

In 1902, Congress enacted the Reclamation Fund Act, Pub. L. No. 57-161, 32 Stat. 388 (June 17, 1902) (codified, as amended in relevant part at 43 U.S.C. § 391) ("Reclamation Act"), to establish a Bureau of Reclamation within the Department of Interior to finance "reclaiming" dry land in the western United States through irrigation projects that would facilitate agriculture and other economic development. In 1920, the Federal Water Power Act, Pub. L. No. 66-280, 41 Stat. 1063 (June 10, 1920) (codified, as amended, at 16 U.S.C. §§ 791a, *et seq*.) was enacted to provide flood control and inexpensive power to rural areas and publicly-owned utilities.

In 1928, the Boulder Canyon Project Act, Pub. L. No. 70-642, 45 Stat. 1057 (Dec. 21, 1928), (codified, as amended, at 43 U.S.C. §§ 617, *et seq*.), authorized the Secretary of the Department of

---

[1] The following landmark decisions were helpful to the court's understanding of how the electric utility industry became one of the most highly regulated industries in our nation's economy: *New York* v. *FERC*, 535 U.S. 1, 4-16 (2002) (discussing: the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified at 16 U.S.C. §§ 2601*, et seq.* (2000); the Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (codified at 16 U.S.C.§§ 824, *et seq.* (2000); the jurisdiction of Federal Energy Regulatory Commission ("FERC"); and the impact of FERC Order No. 888); *United States* v. *City of Fulton*, 475 U.S. 657, 659-64 (1986) (discussing the history of the Flood Control Act of 1944, ch. 665, 58 Stat. 887 (codified at 16 U.S.C. § 460d (2000), 33 U.S.C. §§ 701-09 (2000), 43 U.S.C. § 390 (2000)); and the United States Department of Energy, Organization Act of 1977 ("DOE Organization Act"), Pub. L. No. 95-91, 91 Stat. 565 (codified at 42 U.S.C. §§ 7101, *et seq.* (2000))); *Otter Tail Power Co.* v. *United States,* 410 U.S. 366 (1972) (discussing the Federal Power Act of 1935, 49 Stat. 838, and its relationship to federal antitrust laws); *Detroit Edison Co.* v. *FERC*, 334 F.3d 48, 50-51 (D.C. Cir. 2003) (discussing FERC Order No. 888); *S. Cal. Edison Co.* v. *United States*, 226 F.3d 1349, 1351-54 (Fed. Cir. 2000) (discussing the Boulder Canyon Project Act of 1928, Pub. L. No. 70-642, 45 Stat. 1057 (codified at 43 U.S.C. §§ 617-617v (2000)) and the Boulder Canyon Project Adjustment Act of 1940, Pub. L. No. 76-756, 54 Stat. 774 (codified at 43 U.S.C. §§ 618-618p (2000)); *United States* v. *Tex-La Elec. Coop., Inc.*, 693 F.2d 392, 395-97 (5th Cir. 1982) (also discussing the Flood Control Act of 1944).

Interior to construct a dam and hydroelectric power plant on the Colorado River near the Nevada and Arizona border, known today as Hoover Dam. This Act also authorized the Secretary to enter into contracts for the sale of energy produced at that site. *See* 43 U.S.C. § 617d. Congress, however, required that the Secretary of Interior enter into contracts, *i.e.*, for the sale of hydroelectric power, that would "insure payment of all expenses of construction, operation, and maintenance[.]" 43 U.S.C. § 617c(b). In addition, Congress expanded the criteria to be considered in establishing rates for sales of hydroelectric power, *i.e.*, to provide "reasonable returns," subject to an adjustment "upward or downward as to price, as the Secretary . . . may find to be justified by competitive conditions at the distributing points of competitive centers[.]" 43 U.S.C. § 617d(a).

In 1935, Congress passed the Federal Power Act, Pub. L. No. 74-333, 49 Stat. 838 (Aug. 26, 1935) (codified in relevant part at 16 U.S.C. §§ 824, *et seq*.) "to curb abusive [monopolistic] practices of public utility companies by bringing them under effective control, and to provide effective federal regulation of the expanding business of transmitting and selling electric power in interstate commerce." *Gulf States Util. Co.* v. *FPC*, 411 U.S. 747, 758 (1973) (citations omitted). This revolutionary legislation created the Federal Power Commission ("FPC") to regulate the nascent, but growing, business of selling electric power in interstate commerce and was the catalyst for the modernization of the electric utility industry. The scope of authority exercised by FPC is best summarized in the agency's own words:

> The public interest is far broader than the economic interest of a particular power supplier. It is our legal responsibility, as the [United States] Supreme Court made clear in *Pa. Water & Power Co.* v. *FPC*, 343 U.S. 414 (1952), to use our statutory authority to assure 'an abundant supply of electric energy throughout the United States,' and particularly to use our statutory power . . . to compel interconnection and coordination when the public interest requires it.

Otter Tail Power Co., 410 U.S. at 380 n.10 (internal citation omitted).

Several years later, Congress' interests turned to the financial terms under which power generated at Hoover Dam was being sold. Oversight hearings resulted in the enactment of the Reclamation Project Act of 1939, Pub. L. No. 76-260, 53 Stat. 1187 (Aug. 4, 1939) (codified, as amended, at 43 U.S.C. §§ 485, *et seq.*). Section 9(c) of the Reclamation Project Act required that the rates charged to power customers must be set at a level high enough to recover the full costs of purchasing, transmitting, and selling power generated by Bureau of Reclamation projects. *See* 43 U.S.C. § 485h(c) (*"Any sale of electric power[,]* . . . made by the Secretary [of Interior] in connection with the operation of any project or division of a project, shall be . . . *at such rates as in [the Secretary's] judgment will produce power revenues at least sufficient to cover an appropriate share of annual operation* and maintenance cost, interest on an appropriate share of the construction investment at not less than 3 per centum per annum, and such other the fixed charges as the Secretary deems proper[.]") (emphasis added). The purpose of this "cost-based methodology" for determining power rates was to ensure that customers paid for public financed power projects. Thereafter, regulations were enacted to clarify that the Secretary of Interior had sole authority to set rates for the

sale of firm power[2] and secondary power generated at Hoover Dam, subject to annual adjustments for fluctuations in project operation and maintenance costs. *See* 10 C.F.R. § 904.1.

Congress then enacted the Flood Control Act of 1944, Pub. L. No. 78-534, 58 Stat. 887 (Dec. 22, 1944), to ensure that all such contracts would be coordinated with the Secretary of Interior, who established five regional federal Power Marketing Administrations ("PMAs"). *See* 16 U.S.C. § 825s. Each PMA was required to prepare interim rate schedules for generation and transmission services,[3] based on accounting and cost allocation studies. *Id.* Congress allowed the Secretary of Interior to continue to approve federal PMA rates on an interim basis, but vested the increasingly powerful FPC with exclusive jurisdiction to finalize such rates applying its "special expertise in ratemaking," pursuant to a "dual statutory standard of providing consumers with the benefits of power at the lowest possible price consistent with good business practices as well as protecting the interests of the United States in amortizing its investment in the projects within a reasonable period." *See Bonneville Power Admin.,* 34 F.P.C. 1462, 1465 (1965). This legislation effectively placed the final rates for federal hydroelectric projects and private utilities in the hands of one federal agency.

2. Effect Of The Department Of Energy Organization Act Of 1977 And Creation Of The Western Area Power Administration.

By the late 1970's, the public became concerned about perceived and real energy shortages and the rising price of energy, primarily gasoline. In response, Congress enacted the Department of Energy Organization Act of 1977, Pub. L. No. 95-91, 91 Stat. 565 (Aug. 4, 1977) (codified at 42 U.S.C. § 7152) to consolidate energy-related programs and agencies throughout the federal government into the new Department of Energy. As part of this massive reorganization, Congress authorized the Department of Energy to assume responsibility of existing PMAs, including "the power marketing functions of the Bureau of Reclamation . . . [and] construction, operation, and maintenance of transmission lines and attendant facilities[.]" 42 U.S.C. § 7152(a)(1)(D). In addition, Congress authorized the Department of Energy to establish additional federal Power Marketing Authorities. *See* 42 U.S.C. § 7152(a)(3). Pursuant thereto, WAPA was established in

---

[2] Firm power is "electric energy which is intended to have assured availability to the customer to meet all or any agreed portion of his load requirements . . . 'Firm power' is power which is guaranteed by the supplier to be available at all times[.]" *Salt Lake City* v. *Western Area Power Admin.*, 926 F.2d 974, 980 n. 4 (10th Cir. 1991) (internal citations omitted). Non-firm power is that which may be interrupted for any reason at any time. Therefore, its availability is unpredictable. *See Pacific Gas & Elec. Co.*, 53 FERC ¶ 61,146 (1990) ("[N]on-firm service is interruptible.") (citation precedes note 156 in the text).

[3] Transmission is "[a]n interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." PX 81, Appendix A ("WAPA Definitions") at A-3. Transmission service includes "Point-to-Point Transmission Service provided on a Firm or Non-Firm basis." *Id.*

December 1977. WAPA was to receive and meet financing requirements from the Reclamation Fund, however, two pre-existing laws governed the revenues that WAPA received from the sale of power: the Hayden-O'Mahoney Amendment, 43 U.S.C. § 392a, and Section 9(c) of the Reclamation Project Act, 43 U.S.C. § 485h(c). The Hayden-O'Mahoney Amendment required that revenue generated by Reclamation Fund projects, including revenue from the sale of power, be deposited back into the Reclamation Fund. *See* 43 U.S.C. § 392a. In the event that net revenues from the sale of power repaid the construction costs and related obligations of the United States, any excess revenue was to be transferred to the General Treasury. *Id.* Oversight of the marketing and transmission functions of the PMAs, including WAPA, like other federal hydroelectric projects and reservoirs, was transferred from Department of Interior to the Department of Energy. *See* 42 U.S.C. § 7152(a).

In addition, the Federal Energy Regulatory Commission ("FERC") was established within the Department of Energy as an independent commission to assume the functions of FPC, regarding the regulation of private, investor-owned utilities ("IOUs") and exempt wholesale generators, engaged in the interstate sale of wholesale electric power and transmission services. *See* Department of Energy, Power Market Rates, Delegation Order for Confirmation and Approval, 43 FED. REG. 60,636, 60,636-37 (Dec. 28, 1978). FERC also was given exclusive jurisdiction to "confirm, approve, and place in effect on a final basis, to remand, or to disapprove" PMA power rates. *See* Delegation Order for Approval of Power Marketing Administration Power and Transmission Rates, 48 FED. REG. 55,664, 55,664-65 (Dec. 14, 1983).

On August 1, 1984, Congress passed the Hoover Power Plant Act of 1984, Pub. L. No. 98-381, 98 Stat. 1333 (codified at 43 U.S.C. §§ 619, *et seq.*), which authorized significant upgrades and increases to the generation capacity at Hoover Dam. This Act also allocated specific amounts of long term firm energy and capacity to be available for contract renewals for the period of June 1, 1987 to September 30, 2017. *See* 43 U.S.C. §§ 619a, 619b. The principal purpose of this Act was to ensure that preference customers, specifically designated in the statute, had sufficient energy capacity reserved for their exclusive use. *Id.*

Next, Congress enacted the Energy Policy Act of 1992, Pub. L. No. 102-486, 106 Stat. 2776 (Oct. 24, 1992), authorizing FERC to order any public utility, including IOU's and federal PMAs, to provide, on a case-by-case basis, transmission services to unaffiliated wholesale generators, such as rural electric cooperatives and municipalities, where such action was determined to be in the "public interest." 16 U.S.C. §§ 824j, 824k. Such services were to be priced to include "all the costs incurred in connection with the transmission services and necessary associated services . . . and shall be just and reasonable, and not unduly discriminatory or preferential." 16 U.S.C. § 824k.

On May 10, 1996, FERC issued Order No. 888 as a result of an exhaustive agency investigation, numerous congressional and agency hearings, and hundreds of studies, concluding that most of the nation's larger electric utilities were discriminating in the "bulk power marketplace," by providing inferior service or no access to third-party power wholesalers. *See* 61 FED. REG. 21,540, 21,541-50 (May 10, 1996). To remedy this situation, Order No. 888 required IOU's to

"functional[ly] unbundle" wholesale generation and transmission services, *i.e.*, private utilities had to provide customers with separate rates for wholesale generation, transmission, and ancillary services,[4] such as regulating services.[5] *Id.* at 21,551-52. In addition, these utilities had to include the transmission of wholesale sales and purchases under a single general rate, applicable to these utilities and their customers. *Id.* at 21,541. FERC also required the filing of Open Access Transmission Tariffs ("OATTs") to unbundle electric power services in interstate commerce. Following exhaustive litigation, the United States Court of Appeals for the District of Columbia Circuit upheld Order No. 888. *See Transmission Access Policy Study Group* v. *FERC*, 225 F.3d 667, 683 (D.C. Cir. 2000) ("[The open access requirement of Order 888 is premised not on individualized findings of discrimination by specific transmission providers, but on FERC's identification of a fundamental systemic problem in the industry."), *aff'd sub nom.*, *New York* v. *FERC,* 535 U.S. 1 (2002).

WAPA and other PMAs, however, were exempt from compliance with FERC Order No. 888. *See* Order No. 888, FERC Stats. & Regs. (1996) at 31,665, 31,858; *see also* Order No. 888-A, FERC Stats. & Regs. (1997) at 30,448. Instead, WAPA's rates continued to be set by the Federal Power Marking Administration, approved by the Secretary of Energy, and only filed with FERC for "confirmation and approval," where these rates appear to have received only a superficial review. *See* TR 1001-02; *see also* Court Ex. 2 at 2.

---

[4] Ancillary services are "services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operations of the Transmission Provider's Transmission system in accordance with Good Utility Practice." WAPA Definitions at A-1.

[5] Regulation and Frequency Response Service entails "following the moment-to-moment variations in the demand or supply in a Control Area (*i.e.,* an electric system bounded by interconnections metering and telemetry, capable of controlling generation to maintain its interchange schedule with other Control Areas and contributing frequency regulation of the Interconnection) and maintaining scheduled interconnection frequency." WAPA Definitions at A-1 & A-2.

B. Relevant Facts.[6]

---

[6] The relevant facts recited herein, in part, were discussed in *North Star Steel, Co.* v. *United States*, 58 Fed. Cl. 720 (Fed. Cl. 2003) and derived from the following portions of the record: the April 8, 2001 First Amended Complaint; WAPA's December 7, 2001 Motion for Summary Judgment ("Def. Mot. S.J."); WAPA's December 7, 2001 Proposed Findings of Uncontroverted Fact ("DPF"); WAPA's December 17, 2001 Appendix ("Def. App. 1-258"); North Star's January 22, 2002 Answer in Opposition ("Pl. Opp."); North Star's January 22, 2002 Appendix ("Pl. App. A-N"); North Star's January 22, 2002 Statement of Genuine Issues ("PSGI"); WAPA's July 5, 2002 Response to Plaintiff's Opposition ("Def. Resp.").

Subsequently, additional facts were developed and are found in: the January 9, 2004 Second Amended Complaint; WAPA's January 20, 2004 Answer to Second Amended Complaint; North Star's October 6, 2004 Memorandum of Contentions of Fact and Law ("North Star Trial Brief"); WAPA's October 25, 2004 Pre-Trial Memorandum of Contentions of Fact and Law ("WAPA Trial Brief"); Transcript of trial held November 15-19, 2004 ("TR ___"), during which North Star proffered testimony from the following witnesses: Mr. Michael Sarafolean, former Financial Manager, Cost Accounting Manager, and Energy Specialist for North Star's eight steel mills and currently Secretary of the Texas Industrial Energy Group (TR 19-142; 1091-96); Mr. James Rein, former Design Phase Engineer, Manager of Engineering, and Director of Power Services (including contracting) at AEPCO (TR 143-264; 1085-90); Mr. R. Mark Clements, Senior Consultant, Energy & Resource Consulting Group, LLC (TR 311-46); Dr. Carl Pechman, President of Power Economics, Inc., a former Director of LEGC, and former Supervisor of Energy and Environmental Economics in the New York Public Service Commission (TR 347-58); Mr. Kenneth L. Iliff, former WAPA Operations Manager from 1990-1998 (TR 359-442); and Mr. John Tyler Carlson, WAPA Deputy Area Manager responsible for construction, engineering, power marketing, power operations, power maintenance, and administrative services (TR 475-96; 1262-66). At trial, North Star proffered, and the court admitted, Plaintiff's Exhibits 1-128, 200-05 into evidence. *See* TR 15 (five volumes); TR 1269-70 (PX 200; PX 201); TR 1272 (PX 203).

The Government also proffered testimony at trial from the following witnesses: Mr. Anthony H. Montoya, an Assistant Regional Manager for WAPA's Power System Operations (TR 443-74; 1216-44); Ms. Jean M. Gray, WAPA's Assistant Regional Manager of Power Marketing (TR 497-637; 1186-1215); Ms. Kim Elaine Clark, former WAPA Power Operations Specialist in Dispatch (TR 638-716); and Dr. Douglas Gegax, PhD, (TR 717-803; 1245-62). In addition, the Government proffered, and the court admitted, Government Exhibits 1-9, 100-04, 203 into evidence. *See* TR 15 (one volume).

At trial, the court also admitted the Direct Testimony and Supplement Report of the court's expert, Dr. Barbara Barkovich, and heard cross examination by the parties' counsel. *See* Court Exs. 1-3; *see also* TR 907-1084; 1260-62.

1. Early 1990-August 17, 1994 -- Negotiations Between North Star Steel Co. And The Western Area Power Administration For Regulating Services.

In the early 1990s, North Star decided to build, own, and operate a recycling mill near Kingman, Arizona, consisting of two electric arc furnaces that would manufacture steel rod and bar. *See* TR 28, 32-40. This facility required large amounts of electricity to recycle scrap steel into new steel products. *See* TR 25-26.

At this time, WAPA was engaged in selling wholesale power generated at the Hoover Dam and fifty-four other hydroelectric powerplants to statutory preference customers. *See* 43 U.S.C. § 485h(c);[7] *see also* PX 65; PX 75; TR 155, 162, 186-87. WAPA also operated and maintained 16,819 miles of electric transmission lines, including the Parker-Davis Project Electric Transmission System. *See* DPF ¶ 4 at 2-3. In addition, WAPA owned the only transmission lines in the geographic area of Kingman, Arizona with sufficient voltage (230 kv) to satisfy North Star's electric power requirements. *See* DX 9 at 3-3; *see also* TR 30.

WAPA, however, was not authorized to sell firm power to North Star, because WAPA previously had committed all such power to statutory preference customers. *See* 43 U.S.C. § 485h(c); *see also* PX 75; TR 155-60, 162, 320-21. Therefore, in order to use WAPA's transmission lines and facilities to wheel power from other sources, North Star, AEPCO,[8] and Mohave Electric Cooperative, Inc. ("MEC"), a generation and transmission cooperative eligible to purchase power and other services from WAPA, worked to find a creative solution to meet North Star's power requirements, within the confines of a complex regulatory structure. *See* PX 3; *see also* TR 32-33, 151-52, 156-58, 162-65, 167-71, 446-50, 479-88. First, North Star petitioned the State of Arizona to transfer the retail area power franchise from Citizens Utilities Company to MEC. *See* TR 32. Then, on August 16, 1994, North Star, AEPCO, and MEC entered into a Non-Firm Electric Service

---

Following trial, the parties submitted additional argument: WAPA's March 1, 2005 Post-Trial Brief; North Star March 1, 2005 Post-Trial Brief; North Star's March 22, 2005 Post-Trial Reply; WAPA's March 22, 2005 Post-Trial Reply ("WAPA Post-Trial Reply Brief"). In addition, North Star's expert, R. Mark Clements, submitted a Sur-Rebuttal Report on February 15, 2005 and the court's expert, Dr. Barbara Barkovich, submitted a Post-Trial Additional Report on February 15, 2005 ("Court Ex. 4") and a Post-Trial Response on November 7, 2005 ("Court Ex. 5").

[7] *See* 43 U.S.C. § 485h(c) ("[I]n . . . sales or leases [of electric power] preference shall be given [by WAPA] to municipalities and other public corporations or agencies; and also to cooperatives and other nonprofit organizations financed in whole or in part by loans made pursuant to the Rural Electrification Act of 1936.").

[8] AEPCO was organized under the Department of Agriculture Rural Utility Service Administration as a generation and transmission cooperative to service Class A loads. *See* TR 148-49. Subsequently, AEPCO sold transmission functions to Southwest Transmission Cooperative, but retained generation functions and metering. *See* TR 149, 154.

Agreement ("ES Agreement"), obligating AEPCO, acting on behalf of MEC and North Star, to purchase non-firm electric power for North Star from sources outside the Western Area Lower Colorado Control Area, the relevant geographic area, and deliver that power to WAPA via interconnecting transmission systems. *See* PX 7; *see also* TR 432. Since that electric power was non-firm and could be interrupted at any time, neither WAPA, AEPCO, nor MEC was required to reserve any generation capacity or any transmission assets to serve North Star. *See* PX 7; *see also* TR 39-40. Under the ES Agreement, North Star was obligated only to pay AEPCO the costs of power purchased, plus 15%. *See* TR 1088-89. AEPCO/North Star paid WAPA for transmission services to the steel mill, pursuant to WAPA's FERC Rate Schedule PD-NFT4, plus additional specified charges. *See* PX 7; *see also* TR 32, 45, 1088-89. WAPA also was responsible for maintaining sufficient electric power levels within system control areas to meet demand. *See* TR 364, 432, 447.

2. August 17, 1994 -- The Western Area Power Administration And North Star Steel Co. Execute Interconnection And Consolidated Contracts.

On August 17, 1994, WAPA and AEPCO entered into two other contracts of which North Star was the intended third-party beneficiary. The first, Contract No. 94-PAO-10588, provided for the construction and interconnection of facilities required to connect North Star's mill to WAPA's transmission system and deliver power to North Star. *See* PX 5; *see also* TR 37, 482.

The second, Contract, No. 94-PAO-10590, known as the Consolidated Arrangements Contract ("Consolidated Contract"), provided for transmission services, operating arrangements, regulating services, and operation and maintenance to enable WAPA to meet North Star's load.[9] *See* PX 6. Pursuant to Section 7.1 of the Consolidated Contract, WAPA charged AEPCO/North Star for "rates, charges, and conditions set forth in [FERC] Rate Schedule PD-NFT4 . . . for Non-Firm Transmission service," as a supplier of energy to MEC that, in turn, provided retail electric service to North Star. *Id.*; TR 38-39. In turn, WAPA agreed to provide AEPCO with regulating services for North Star's load. *See* PX 6 at DA32 (Consolidated Contract at § 14.1); *see also* TR 449, 481. At this time, however, WAPA did not offer such ancillary services as regulating services, as part of WAPA's standard transmission FERC Rate Schedule PD-NFT4. *See* TR 243-44. Moreover, any request that WAPA's transmission customers may have had for regulating services would have been based on a significantly smaller load than the amount North Star required.[10] *See* TR 52-55, 244-246;

---

[9] A "load" is "[a]n end-use device or customer that receives power from the electric system." WAPA Definitions at A-1. "An average load is over a period of time[.]" TR 441. WAPA's "average load" was 256 MW. *See* TR 434, 441. A "peak load" is an "instantaneous load value." TR 441. A "control area load" includes customers that reside within the control area boundaries. *See* TR 363. The "load variation" for a typical WAPA wholesale customer was in the range of 6 MW. *See* Def. App. at 169-81. North Star's load was in the range of 85 MW. *Id.*

[10] WAPA defined "regulating services" as "the use of generation equipped with governors and automatic generation control to balance generation and load moment-to-moment." PX 35 at 1-

see also TR 25-26, 30-31. Therefore, WAPA and AEPCO agreed that the "regulating services" to be provided to North Star would be made and paid for pursuant to an *ad hoc* methodology utilizing an "In-Kind Energy" payment. *See* PX 6 at DA31-33, DA35 (Consolidated Contract at §§ 13,14, 21); *see also* TR 139. This surrogate rate for regulating services was to be determined as follows: AEPCO, on North Star's behalf, would pre-schedule non-firm energy for delivery to WAPA's transmission system, including such amounts as WAPA advised were necessary to service its own load. *See* PX 6 at DA31-33 (Consolidated Contract at §§ 14.1-14.7). The amount of non-firm energy provided to WAPA was equal to the five minute hourly peak demand expected for the hour or hours during on-peak hours. *See* Court Ex. 2 at 9; *see also* TR 911. This allowed WAPA to "back down" generation from Hoover Dam, in the same amount that was pre-scheduled by AEPCO, while still being able to dedicate capacity to all of WAPA's preference customers. *See* TR 61-65, 175-76, 507; *see also* Court Ex. 2 at 9-10. In other words, "In-Kind Energy" in megawatt ("MW") hours was transferred from AEPCO to WAPA to compensate WAPA for the displacement and use of otherwise committed, but not always used, firm power that was then used to meet North Star's load. *See* PX 6 at 31-33 (Consolidated Contract at §§ 14.1-14.3); *see also* TR 61-65, 175-78. At WAPA's discretion, any excess "In-Kind Energy" could be used by WAPA to service its own load or re-sold on the open market. *Id*.

Nevertheless, WAPA was concerned that this arrangement might not allow it to recover costs. *See* 43 U.S.C. § 617d; *see also* TR 52-55, 220. And, as discussed at trial, WAPA had technical concerns about being able to provide regulating services to meet North Star's load requirements:

> MR. MONTOYA [An Assistant Regional Manager for WAPA's Power Systems Operations]: The concerns that we had at the time were related to -- there were two concerns. One was related to the general melt cycle that the arc furnace goes through, so the arc furnace is not running 100 percent of the time. It basically will go through a melt cycle where it's operating. It will discharge the melt and at that point, it's not operating. So we had a situation where we would go from a minimal load to a maximum load and cycle through that on a repeated basis, perhaps as much as an hour. I'm not exactly sure, but it would cycle in that fashion, so you'd go between not melting to a melt period and an increase of 60 megawatts is what we were given as design criteria for that step. The other concern was when we were melting, then you'd have the arc that was striking and that would look like almost a short circuit on the system for us, so we were concerned about the rapid fluctuations when the arc was striking. Then we were concerned about the large fluctuations during the melt cycle.
>
> GOVERNMENT'S COUNSEL: And how does that relate to regulation?

00308. Such services maintain a balance between power supply and demand on a moment-by-moment basis through special equipment that monitors power supply and demand. *Id.*; *see also* TR 176, 209-210.

> MR. MONTOYA: Well, the way it relates to regulation is when you connect the load meters to your EMS system and to your control system, your generators will see those fluctuations and will respond to the fluctuations. And one of the things that we were very concerned about was the fact that we had hydrounits that we were using to regulate with and hydrounits have a very fast response time compared to traditional thermal units. So we were very concerned that this increased variability would create wear and tear on the hydrounits that may be atypical when compared with utilities that had thermal units.

TR 456-57; *see also* TR 368-449, 454.

Arguably, for this reason, WAPA insisted that the Consolidated Contract include several provisions to protect WAPA's interests. First, WAPA retained the right to interrupt the transmission of electricity to North Star or automatically "shed" North Star's load for any reason. *See* PX 6 at DX35 (Consolidated Contract at § 17).

Second, North Star was required to pay, not only the standard FERC-approved transmission rate, but also an additional charge specifically designed to recover whatever other costs WAPA may incur. *Id.* (Consolidated Contract at § 14.3).[11] In addition, if North Star's load exceeded pre-scheduled demand by more than 5 MW and WAPA did not exercise its right to interrupt transmission, WAPA had authority to impose a penalty on the excess demand. *Id.* (Consolidated Contract at § 14.4).

Third, non-firm energy was to be provided to WAPA, by AEPCO, in an amount that would enable WAPA to provide regulation service for North Star. *Id.* (Consolidated Contract § 6). WAPA proposed a methodology to calculate an "In-Kind Energy" payment for regulating service based on load information: the product replacement cost of procuring regulating service via "In-Kind Energy" from an alternative provider suggested by North Star and an internal WAPA study that examined similar experiences of other power providers. *See* PX 118 (Iliff Ex. 2); *see also* TR 52, 361, 365-69, 457. This equated to an "In-Kind Energy" payment of 20%, the "actual" metered non-firm energy to serve the Harris Substation's hourly metered load in MWh. *See* PX 6 at DA32-33 (Consolidated Contract at § 14.3); *see also* TR 55, 60-61. WAPA, AEPCO, and North Star agreed, however, that after one year of normal operation, the 20% formula would be adjusted upward or downward to reflect a consensus methodology. *See* PX 6 at DA 36-37 (Consolidated Contract at § 21) ("Prior to the conclusion of the first year of normal operation of the North Star plant, the parties shall *jointly establish an appropriate cost-based methodology* to review, evaluate[,] and periodically, if

---

[11] Apparently, WAPA was aware that North Star also had discussions with representatives of the Arizona Public Service System, wherein the later anticipated annual costs to be $1.3 million. *See* PX 118 (Iliff Ex. 5); DX 8; *see also* TR 95-99, 108, 365-67 (WAPA "looked at some of the projected load profiles of the particular operating characteristic of a steel-mill-type, arc-furnace plant[.]"), 448-49, 454-55, 479-80, 1096; *compare with* PX 60 at 1-00013 (referencing a "50 MW regulation purchase offer from APS for $1 M[illion.]").

necessary, *adjust* the percentage associated with the In-Kind Energy payment. After one (1) year of normal operation, the percentage may be adjusted in accordance with said methodology.") (emphasis added); *see also* PX 29 (North Star "repeatedly made ovations that [WAPA] will have to deal with a consultant a year after operations commence to justify and probably adjust downward the 20 percent in[-]kind regulation charge[.]"); TR 57-62, 71, 182-84, 373 ("[WAPA] would be able to have an opportunity to go back with the customer and actually review the methodology in a joint process[.]").

3. October 23, 1997-July 28, 1999 -- The Western Area Power Administration Failed To Establish "An Appropriate Cost-Based Methodology" For The "In-Kind Energy" Payment.

a. October 23, 1997-June 19, 1998 -- Post Consolidated Contract Negotiations.

On July 1, 1997, North Star's mill began commercial operation. *See* PX 35 at 1-00308; *see also* TR 69. From October 23, 1997 to July 28, 1999, WAPA, AEPCO, and North Star engaged in negotiations under to Section 21 of the Consolidated Contract to ascertain "an appropriate cost-based methodology" for the "In-Kind Energy" payment. *See, e.g.*, PX 33-35; PX 38; PX 40-51; PX 53-57; PX 60-63; PX 65; PX 68-69; *see also* TR 73, 117, 402, 640-41. As the following chronology of these negotiations details, no such agreement was reached.

The first meeting took place on October 23, 1997. *See* PX 35; *see also* TR 402, 641-42. According to WAPA, the discussion concerned two topics: "replacement costs" and "incremental costs." *See* TR 374, 402-04, 642. It is clear from WAPA internal documents that WAPA believed the Consolidated Contract was commercially advantageous: "We have not committed fully committed generation resources; due to the non-firm & interruptible nature of the Contract, we have not committed firm transmission resources; and we have developed a process which has promise of benefits beyond just monetary . . . . We can't wait till it gets here, [and] the Contract is signed." PX 118 (Iliff Ex. 2 at 00211-12); *see also* PX 13 at DA141; PX 14; PX 17 at 00233; PX 19 at 00040; PX 28 at 00149.

Aware of this situation, Mike Sarafoleum, former Financial Manager of North Star, suggested a methodology to calculate charges associated with regulating service. *See* TR 640-41. Ms. Clark, a former WAPA Power Operations Specialist in Dispatch, presented a counter-methodology, although she did not believe that this proposal would be acceptable, because WAPA "is a wholesale service provider, regulation services for North Star are not directly comparable to regulations provided on a systemwide basis. In addition, deriving the incremental costs of the system of regulation provided for North Star may be undeterminable." TR 642; *see also* PX 35. Nevertheless, Ms. Clark testified that she tried to capture "replacement cost," *i.e.*, "the cost of replacing the capital equipment of the installed capacity." TR 643. That effort was not productive.

Subsequently, WAPA attempted to obtain "replacement costs" from the Bureau of Reclamation, *i.e.*, "unit specific costs that could be directly associated with regulating the North Star load." TR 643-45; *see also* TR 405-06, 408, 467-68. WAPA claimed that the Bureau of Reclamation advised that there was no useful data available to determine a methodology based on incremental cost and that such a task was "impossible." TR 406; *see also* TR 263, 643-45. Therefore, WAPA determined that an incremental cost-based methodology was no longer feasible and a "proxy for replacement costs" was created based on the costs of another unidentified "provider." *See* TR 408-09, 640, 645.

On January 7, 1998, WAPA advised AEPCO and North Star that it intended to offer "regulating and load following services" to preference customers, including "frequency response, voltage control, capacity, ramping and associated energy, scheduling and dispatch, and power accounting." PX 35 at 1-00308. To provide these services, WAPA was required to evaluate: resource availability, generator control, and response to its customer's moment-to-moment changes; generator control and response to variations in loads to maintain sixty hertz frequency; and factors to prevent generation and transmission system contingencies. *Id.*; TR 683, 742.

At a January 13, 1998 meeting, WAPA provided AEPCO/North Star with a methodology for the "In-Kind Energy" payment that was based on "identifying relevant cost components for services provided to AEPCO for North Star and distinguishing these costs from [WAPA's] Open Access Tariff for ancillary services." PX 38 at 1-00258. North Star was advised, however, that the charge for regulating services may include unspecified WAPA "cost components," reflecting load variations that are not identified in the Open Access Tariff. *Id.*; *see also* TR 74 (citing PX 35). On January 15, 1998, another meeting was held to discuss WAPA's regulating and load-following services for use by North Star. *See* TR 78-80.

On February 3, 1998, WAPA provided AEPCO/North Star with a revised proposal that compared regulating service for a "typical" WAPA wholesale customer with an average 6 MW load to North Star's 85 MW load. *See* PX 38 at 1-00260. WAPA represented that this methodology did not include any "incremental costs" associated with possible fluctuations in North Star's load and any additional stress that such fluctuations may have imposed on WAPA's equipment and system, despite the fact that WAPA previously concluded that "deriving the incremental costs to the system of regulation provided specific to North Star loads may be indeterminable." *Id.* at 1-00261.

On March 6, 1998, another meeting was held, where WAPA's position was that it received no direct benefits when AEPCO over-schedules power for North Star.

> Instead, AEPCO benefits from the dynamic ancillary service provided by [WAPA]. In addition, a comparison of [WAPA's] Open Access Tariff to services provided to AEPCO for North Star reveals that the nature of the service provided to AEPCO for North Star is unique and is not comparable to standard services provided by [WAPA].

PX 40 at 1-00251. Again, no agreement was reached. On March 15, 1998, another meeting was held, but WAPA did not provide cost data requested by AEPCO/North Star. *See* PX 40; *see also* PX 43.

In early April 1998, WAPA proposed to perform a comparison of certain limited data of North Star's load characteristics with a specific WAPA district load. *See* PX 42. A consultant for North Star observed, however, that:

> [the] sample appears much too simplistic to yield representative information of value in determining North Star's overall impact on [WAPA's] regulation service . . . . [Instead] all selected load data must be analyzed along with [WAPA's] total control area load[,] including dynamically scheduled loads. In addition, the data sampling must be very extensive.

See PX 43 at 1-00458; *see also* PX 60 (referencing an April 27, 1999 meeting attended by a consultant of North Star's parent company).

On April 30, 1998, WAPA proposed an "In-Kind Energy" payment consisting of the costs of scheduling, system control, and dispatch service, divided by the expected annual energy requirement. *See* PX 44 at 2. North Star's counsel responded that WAPA's proposed "Rate Schedule" was not based on any "technical justification" and was an attempt to recover "certain 'costs' that [WAPA] claims to have incurred but that are beyond the adjustment mechanism of Section 21 [of the Consolidated Contract]." PX 45 at 1-00239.

On May 27, 1998, WAPA proposed still another payment methodology for North Star's consideration. *See* PX 46; *see also* PX 47. This methodology utilized the regulating service rate schedules of unidentified regional utilities and applied a volatility factor, based on North Star's actual load fluctuation. *See* PX 46. WAPA claimed that this methodology would decrease North Star's "In-Kind Energy" payment percentage to 18.46%. *See* DX 3 at 6; *see also* TR 651.

On June 2, 1998, WAPA prepared a revised set of calculations, using the same methodologies proposed and rejected on May 27, 1998. *See* PX 50.[12] On this occasion, WAPA informed North Star that "[i]f there is no agreement on a revised methodology by July 1, 1998, the in-kind payment of 20 percent, as currently provided for in the Contract, will remain in effect." *Id.* at DA195.

---

[12] In June 1998, Ms. Gray, WAPA's Resource Manager, assumed responsibility for the "transmission of power scheduling in the operations arena," replacing Mr. Iliff. *See* TR 506-7. At trial, Ms. Gray testified that "with industry restructuring, it became quite a bit more important to insure that [WAPA] had . . . energy accounting correct . . . all of [the] control systems in place. And . . . [WAPA's] preference power customers were questioning and wanting to have an assurance that they were not being adversely impacted." TR 504.

On June 5, 1998, North Star's counsel advised WAPA that:

> [W]e continue to believe that the proposed charges for Scheduling, System Control and Dispatch Service, for Retroactive Supply and Voltage Control, and for Energy Banking Service are not within the purview of Section 21 and are, therefore, neither contractually nor technically justified. We also believe that [WAPA's] calculation of cost for the one cost component that is appropriate under the contract–Regulation and Frequency Response–remains grossly excessive.

PX 48 at 1-00604. On June 17, 1998, North Star proposed a counter-proposal that was rejected by WAPA in a June 19, 1998 letter that offered to further reduce the "In-Kind Energy" payment to 17.5 percent, but threatened if this proposal was rejected the 20 percent rate would remain in effect. *See* PX 48 at 1-00605-06; PX 49; PX 50. North Star also rejected the June 17, 1998 proposal. *See* TR 505-06.

b. December 7, 1998 -- The Western Area Power Administration Files An Open Access Transmission Tariff With The Federal Energy Regulatory Commission.

On January 6, 1998, WAPA's voluntary proposed Open Access Tariff was published. *See* PX 77 (Open Access Transmission Service Tariff, 63 FED. REG. 521 (Jan. 6, 1998)); *see also* TR 1190-92.[13] On February 4, 1998, February 19, 1998, and March 9, 1998, Ancillary Service Work Group meetings were held to discuss WAPA's proposed long-term rate methodologies for providing ancillary services. *See* PX 78; *see also* PX 79. On April 30, 1998, WAPA prepared a draft rate schedule for regulation and load following service. *See* Court Ex. 2 at 14.

On June 16, 1998, a notice to preference customers was issued to announce that WAPA was offering "long-term open access transmission and ancillary service rate methodologies" on an interim basis, beginning on November 1, 1998. *See* PX 81.[14] WAPA also advised preference customers that WAPA's marketing arm intended to file rates with FERC for six ancillary services, including "Regulation and Frequency Response Service" that, prior to this time, were not offered at an "unbundled rate." *Id.* (June 16, 1998 WAPA Brochure) at 3.

---

[13] On December 1, 1997, DSW had proposed an interim methodology for short term sales of "Regulation and Frequency Response Services" to be offered to existing customers at a rate of $0.34 per kilowatt per month. *See* PX 110. This rate was to be utilized until the formal rate process was concluded, within a year. *Id.*; *see also* TR 1187-88.

[14] On December 10, 1997, WAPA forwarded revised short-term Ancillary Service Rates, to be effective for one year until the public comment process was completed. *See* PX 76; *see also* PX 110 (rate proposed for Regulation and Frequency Response was $.034 per kW-hour); TR 1046, 1187-88.

On December 7, 1998, following a public comment period, WAPA voluntarily filed an Open Access Transmission Tariff ("OATT") with FERC, utilizing a formula methodology for short-term sales of network integration transmission services to be final on January 20, 2000. *See* Order Confirming and Approving Rate Schedules on a Final Basis, 90 FERC ¶ 62,032, 64,048-50 (Jan. 20, 2000). On December 7, 1998, WAPA also filed Rate Schedule DSW-FR1 for ancillary services with FERC, including "regulation and frequency response service[.]" PX 83 (Desert Southwest Customer Service Region Network Integration Transmission and Ancillary Services, Rate Order No. WAPA-84, 64 FED. REG. 25,323, 25,323 (May 11, 1999)); *see also* TR 1193. The rate for regulation was 08¢ per kWm, effective from April 1, 1999 through March 31, 2004. *See* PX 83. Specifically, "[r]egulation and frequency response service" was to be provided, if available, at a charge reflecting "the firm capacity rate of the project providing the regulation." *Id.* (Desert Southwest Customer Service Region Network Integration Transmission and Ancillary Services, Rate Order No. WAPA-84, 64 FED. REG. at 25,327). If transmission or ancillary services, such as regulating service, were not available, they were to be obtained in the open market and sold at a "pass through" rate– the cost of the service, plus a ten percent (10%) administrative charge. *Id.*; *see also* PX 60 (WAPA "does not intend to charge any preferential customers more than market value (10%)."); TR 1193-95.

c. December 8, 1998-September 15, 1999 -- The Western Area Power Administration And North Star Steel Co. Continue To Negotiate Until The Unilateral Imposition Of Amendment No. 3 On September 15, 1999.

On December 8, 1998, WAPA solicited approximately 65 other potential suppliers to provide bids for service to regulate North Star's load. *See* PX 53; *see also* TR 140. No responses were received because none of the regional utilities standard tariff rates offered regulating services that met North Star's requirements. *See* TR 140.

On February 8, 1999, representatives of North Star and AEPCO met. *See* PX 55 at 00633; *see also* TR 246-49, 508-13. At trial, Ms. Gray explained that:

> [T]he primary discussion at that time was that [WAPA] really had an opportunity to realize quite a bit of benefit from this contract. But because of the way it was being scheduled, both in terms of penalties as well as scheduling to the five-minute peak, the return energies provisions, most of the provisions in the contract were being implemented in a way that was most beneficial to North Star Steel.

TR 510. In addition, the requirement to return energy during the off peak times, as determined by WAPA, was not being enforced. *Id.* at 510-11. WAPA explained that if it held North Star accountable under the Consolidated Contract, it would have earned additional revenue from "penalties," due as a result of North Star failing to schedule a five-minute peak demand, and by not returning energy to North Star during off-peak hours. *See* TR 250, 511. North Star faulted WAPA for not adhering to a strict scheduling, which caused any surcharges. *See* TR 513.

On March 8, 1999, WAPA requested that AEPCO comment on another methodology for calculating the "In-Kind Energy Charge," admitting that:

> *[WAPA] agrees with you that this contract has not been implemented as it is written*. If [WAPA], AEPCO and [North Star] take action to change the current scheduling practices so that the contract is implemented as written, *then [WAPA] will realize some benefits*. As a result, [WAPA] would be willing to implement the calculation methodology shown[, reducing the rate to 11.45 percent, if North Star would change its scheduling practices and in the future, and comply with the Consolidated Contract penalties for North Star under scheduling power needs].

PX 56 at 00630 (emphasis added); *see also* TR 518-20, 654-55. AEPCO and North Star did not agree to WAPA's proposal. A March 15, 1999 internal WAPA memo indicated that North Star's position was that scheduling, system control, and dispatch were part of the bundled transmission tariff and, therefore, North Star objected to paying for the same service twice. *See* PX 57. In addition, since North Star scheduled all of the energy "up front," any deviation from North Star's regulating services provided WAPA with benefits, for which there needs to be consideration in the methodology. *Id.*

An April 6, 1999 internal document confirmed that WAPA "should basically develop [WAPA's offer] and negotiating position, *instead of continuing to walk down the road of trying to come to a meeting of the minds on benefits*." PX 58 at 1-00626 (emphasis added). Therefore, WAPA advised North Star that it wanted an immediate meeting to discuss the results of WAPA's discussions with other potential power suppliers and explore the option of allowing North Star to purchase blocks of energy to use during on-peak hours. *Id.* In April 1999, other negotiating meetings were held between WAPA, AEPCO, and North Star "regarding regulating services." *Id.* WAPA's position was that since it was not negotiating a contract change, the 20% initial contract rate would remain in place until WAPA determined whether that rate would be reduced. *See* PX 59 at 00592. WAPA also continued to assert that "wear & tear" on the generating units should be included in any "cost-based" methodology, but an internal document evidenced that WAPA perceived that it was in a position to "drive the cost where ever . . . it [needed]." *Id.* at 00593.

At a meeting held on April 28, 1999, WAPA advised North Star that "[n]o one currently at [WAPA was] involved in [the] original contract negotiations" and the methodology, which "[l]ast revisited [a] 20% charge in June [1998,]" was dropped. PX 60 at 1-00013. North Star also was told that WAPA was "open to discussion on methodology changes as long as the end result ([*i.e.*,] bottom line) is the same." *Id.* At an April 29, 1999 meeting, WAPA presented the "bottom line" as $750,000, while admitting to North Star that amount was not based on WAPA's "own costs." *Id.* at 1-00015.

It is also significant that an internal WAPA document, dated April 29, 1999, confirmed that WAPA was no longer "negotiating a *contract change*." *See* PX 59 at 00592 (emphasis added). Instead, WAPA unilaterally decided to establish a methodology based on "replacement costs" plus

10% as published in WAPA's Ancillary Service Tariff. *Id.* The "10% tariff filed with FERC," however, was to "cover the real time operations cost" and was not "cost-based." PX 60 at 1-00015. As of April 27, 1999, however, another WAPA document evidenced that WAPA had not determined the cost of the so-called "wear & tear" imposed by North Star, but nevertheless insisted "[t]his should be part of the methodology and will also help defend [WAPA's] position." PX 59 at 00593. It appears that WAPA's *modus operadi* was to "drive the cost where ever [WAPA] needed it," recognizing that WAPA was receiving substantial benefits from the current contract "by the difference between what [WAPA] could have sold at the off-peak price compared to the on-peak price." *Id.* This document further identified three proposed actions that could mitigate the impact of having North Star provide most of the energy during non-peak hours. *Id.*

On May 11, 1999, North Star's counsel provided WAPA with comments on the discussions held on April 28-29, 1999. *See* PX 63 at 00609-11. Therein, North Star also presented two alternative fee schedules: a Fixed Annual Fee, based on the "current OATT of the Salt River Project or of the California ISO" or a "proxy used to determine an appropriate market value for the 'In-Kind Percent.'" PX 63 at 00609-10; *see also* TR 522-26. A condition to either proposal included a "true-up" of In-Kind payments retroactive to the date of North Star's operations. *See* PX 63 at 00611; *see also* TR 527-28. North Star's proposals, however, were rejected by WAPA. *See* PX 64; PX 65; PX 66; PX 67; *see also* TR 522-28.

On May 27, 1999, WAPA proposed a new methodology, using the standard FERC tariff rate of the Salt River Project and a volatility factor "to fix the In-Kind percent from July 1, 1999, through June 30, 2000." PX 65. WAPA also represented that it was "willing to consider options and alternatives that can be implemented within the provisions of the existing contract with [AEPCO] through modifications to operating procedures." *Id*. at 00595; *see also* TR 522-25.

On June 3, 1999, a meeting took place to explain WAPA's proposal to add an Amendment No. 3 to the Consolidated Contract, incorporating Exhibit H. *See* TR 250-53, 528-30. This so-called "cost-based methodology" was touted as compensating WAPA for the value of "In-Kind Energy" payments provided by AEPCO up to $1.5 million annually, *i.e.,* an estimated "In-Kind" percentage of 19.67%. *See* PX 10; *see also* PX 73; PX 74. Amendment No. 3 also provided that, under certain specified conditions, WAPA or AEPCO could invoke an alternative methodology to compensate WAPA for the value of "In-Kind Energy" up to $750,000 annually, or an estimated "In-Kind" percentage of 9.83%. *See* PX 10; *see also* PX 73. In addition, Amendment No. 3 provided that WAPA had the unilateral right, with notice, to "review, evaluate and adjust the value of the In-Kind Energy payment" under certain circumstances, such as where the spot market price increased above a specified level. PX 73.

On June 4, 1999, WAPA presented North Star with the "final version" of a proposed methodology: "Frankly, . . . it is time to bring this issue to closure." *See* PX 68 at 00576; *see also* TR 530. This rate included three components: 1) scheduling system control and dispatch data, derived from WAPA operations documents; 2) regulation and frequency response, derived from "historical data" from North Star operations, including a comparison of North Star's load to that of

other WAPA customers; 3) the sum of component 1 and component 2 above. *Id.*; *see also* TR 659-64. These proposed rates were the same as those set forth in Amendment No. 3. *See* PX 10; *see also* TR 664-65. Ms. Gray testified that the terms of Amendment No. 3 were accepted by North Star's counsel during private discussions that took place on June 27, 1999 between North Star's counsel and Ms. Gray. *See* TR 531-36. Mr. Gray perceived that North Star's counsel agreed that the dollar value of the regulating services charge would be either $750,000 per year at a five minute interval or $1.5 million per year at a 30 minute scheduling interval. *See* TR 532-34. According to North Star's counsel, WAPA claimed to agree that North Star should not pay twice for the same service and agreed to look at what "In-Kind Energy" charge should be used regarding "assumed changes in preschedules and real-time operations[.]" PX 55 at 00634.

On July 28, 1999, WAPA informed AEPCO/North Star that negotiations had ended and presented a take-it-or-leave-it offer, based on a revenue stream that WAPA projected would be produced by the Consolidated Contract, and that had been provided to WAPA's preference customers for their approval. *See* PX 69; *see also* TR 82, 207-08, 487-88, 531-34.

On July 29, 1999, North Star authorized AEPCO to accept Amendment No. 3 and amend the Consolidated Contract under protest. *See* PX 69; DX 9 at 9 (Sarafolean Aff. ¶ 19) ("North Star . . . was in effect coerced . . . to accept WAPA's 'bottom line' offer[.]"); *see also* TR 89-91, 126, 129-30, 251-54. North Star's counsel, however, sent AEPCO a letter on that date to memorialize "North Star's view that none of the proposals put forth by [WAPA] are truly cost-based and that all are unreasonable. The current charge is so excessive, however, that even an unreasonable lesser charge is preferable to the continuation of the charge at the existing level." PX 69 at DA207. On September 15, 1999, WAPA and AEPCO, on North Star's behalf, signed Amendment No. 3, effective retroactively to August 1, 1999. *See* PX 10; *see also* TR 534. North Star admitted that Amendment No. 3 "had the effect of reducing the economic value of North Star's In-Kind Energy Payment from approximately $2.1 million to $1.5 million. . . . North Star continued [however] to be responsible for tariff transmission charges that amount to $1.2 million per year . . . charges[North Star asserts were] sufficient to compensate WAPA for Control Area and Regulating Services[.]" DX 9 at 9 (Sarafolean Aff. ¶ 20). Amendment No. 3 did not provide for a retroactive "true-up" post-cost disputes. *See* TR 131. Instead, Amendment No. 3 changed only a percentage of future costs for regulating services. *Id.*

d. During 2000, The Western Area Power Administration And North Star Steel Co. Resumed Negotiations Until North Star Steel Co. Rejected Revision 1 On October 17, 2001.

By March 2000, North Star began to reduce operations, because of increased electric costs and falling demand for steel. *See* PX 70; *see also* DX 1; TR 93, 207, 536-37.

On April 27, 2000, North Star filed a Complaint in the United States Court of Federal Claims for breach of the Consolidated Contract and other claims seeking, among other relief, monetary

damages in the form of a refund for WAPA's overcharges concerning the methodologies used to determine the "In-Kind Energy" payments. *See* Compl. ¶¶ 7-8 at 2-3.

On August 1, 2000, WAPA notified AEPCO and North Star that WAPA was invoking the right to re-evaluate the "In-Kind Energy" payment, because the spot market price of electricity had risen above the levels specified in Amendment No. 3. *See* PX 70; *see also* TR 536-37. Discussions commenced in November 2000 and continued into January 2001 to determine if an alternative "cost-based methodology," agreeable to WAPA and North Star, could be applied retroactively to October 1, 2000 to provide North Star financial relief, since the business was beginning to fail. *See* PX 71; PX 72; PX 73; PX 74; *see also* TR 92, 538. Those efforts were unsuccessful. *See* PX 74; *see also* TR 539-40.

In December 2000, North Star stopped melting steel, because "energy prices got too severe," although rolling operations continued with a substantially reduced load of 20-25 MWh. *See* TR 93-94.

On February 14, 2001, WAPA forwarded North Star Metering and Scheduling Instructions for the Consolidated Contract. *See* PX 73; TR 1095-98. On June 29, 2001, WAPA again unilaterally modified the Consolidated Contract to impose another payment methodology for "In-Kind Energy," retroactive to October 1, 2000. *See* TR 92-93; *see also* PX 73. This methodology, described as REVISION No. 1 or REV 1, provided that:

> AEPCO will pre- and post-schedule Non-Firm Energy to [WAPA] to provide for the metered North Star load plus In-Kind Energy, based upon the anticipated metered North Star load. Effective October 1, 2000, In-Kind Energy will be scheduled in an amount such that the total value of the In-Kind Energy equals an amount calculated in accordance with the methodology set forth in Attachment H-1, REVISION No. 1, hereto and the hourly peak demand for pre-scheduling and accounting shall be interpreted in accordance with MSI3 as measured, determined, and reported by [WAPA].

Id.

On August 7, 2001, WAPA forwarded REVISION No. 1 to Amendment No. 3 to AEPCO/North Star for execution. *See* PX 73. On October 16, 2001, WAPA and North Star discussed the substance of the proposed revision. *See* PX 74. On October 17, 2001, North Star responded with a counterproposal that substantially departed from the previous methodology, in that AEPCO would no longer pre-schedule "In-Kind Energy" with WAPA. *See* Def. App. at 253. North Star's proposal was rejected and WAPA's proposed REVISION No. 1 was not authorized. *See* TR 93, 539.

In March 2003, North Star closed the mill and exited the market. *See* TR 93.

Despite their disagreement over the methodology for determining the "In-Kind Energy" payment for regulating services, the parties agree that WAPA provided North Star with transmission and regulating services from August 17, 1994 to August 1, 1999 for which AEPCO/North Star paid WAPA, pursuant to Section 21 of the Consolidated Contract. *See* DX 9 at 10 (Sarafolean Aff. ¶ 21). From August 1, 1999 to October 1, 2000, AEPCO/North Star paid WAPA, pursuant to Amendment No. 3. *Id*. And, from October 1, 2000 until March 2003, AEPCO/North Star paid WAPA, pursuant to REVISION No. 1 to Amendment No. 3. *Id*. North Star asserts, however, that all of the aforementioned methodologies violated and continue to violate the Consolidated Contract. *Id*.

C. Procedural Background.

On April 18, 2001, North Star filed a First Amended Complaint in the United States Court of Federal Claims seeking a declaration that the amount North Star was required to pay for WAPA control area and regulating services from the date of initial operation on July 1, 1997 to March 2003 violates the Consolidated Contract, a violation of various federal statutes and is arbitrary, capricious, an abuse of discretion, and otherwise not in accordance with applicable law. *See* First Amend. Compl. ¶¶ 7-9 at 2-3. In addition, the First Amended Complaint requested entry of an order, requiring WAPA to refund the full value of the "In-Kind Energy" payments made by North Star from the beginning of operation on July 1, 1997 to the date of judgment or, in the alternative, to refund the difference between what North Star paid for services for the period between July 1, 1997 and August 1, 1999, and the amount North Star would have paid under the methodology set forth in Amendment No. 3. *See* First Amend. Compl. at 8 (Prayer for Relief). This case originally was assigned to the Honorable Lynn J. Bush.

On December 7, 2001, WAPA moved for summary judgment. Briefing was completed on February 5, 2002. On January 22, 2002, North Star filed a Motion to Strike Portions of the Government's Motion for Summary Judgment. On August 15, 2003, this case was transferred to the undersigned judge.

* * *

On November 26, 2003, the court issued a Memorandum Opinion, in which WAPA's December 7, 2001 Motion for Summary Judgment was granted in part, *i.e.*, the court agreed with WAPA that neither the Consolidated Contract, nor any of the four federal statutes cited, required that WAPA charge only "actual costs" for regulating services under the Consolidated Contract. *See United States* v. *North Star Steel Co*., 58 Fed. Cl. 720, 735-38 (Fed. Cl. 2003). Accordingly, as a matter of law, Paragraphs 31, 33(a) and (b) of North Star's April 18, 2001 First Amended Complaint were dismissed, together with Paragraph 1 (a) and (b) of the Prayer for Relief. *Id.* at 741. In addition, Paragraph 33 (c) that stated a claim under the Administrative Procedure Act, 5 U.S.C. §§702, *et seq*., and Paragraph 1(c) of the Prayer for Relief were dismissed. *Id.* North Star, however, was granted leave to file a Second Amended Complaint to state precisely the nature of the breach of contract claim regarding the Consolidated Contract. *Id*. Since material facts were at issue as to whether the parties agreed that any refunds for WAPA's regulating services would be applied

retroactively and the effect of North Star's rejection of REVISION No. 1, WAPA's December 7, 2001 Motion for Summary Judgment was denied. *Id.*

On December 10, 2003, the court entered a Scheduling Order: establishing dates for the submission of post-opinion briefs; requiring North Star to proffer, under seal, a copy of the Asset and Purchase Agreement regarding the sale of North Star; and setting a telephone conference for February 19, 2004. On January 9, 2004, North Star filed a Second Amended Complaint. On January 20, 2004, WAPA filed an Answer to the Second Amended Complaint. On February 17, 2004, WAPA filed a Post-Opinion Brief. On February 19, 2004, a telephone status conference was held with the parties. On February 20, 2004, North Star filed a Post-Opinion Brief, and the requested copy of the Asset Purchase Agreement. The Asset Purchase Agreement was placed and remains under seal.

On March 5, 2004, the court entered another Scheduling Order, wherein the date for the exchange of expert reports, additional memorandum, witness lists, exhibit lists, and any remaining motions was set, together with a Pre-Trial Conference for November 8, 2004. A trial also was set for November 15-19, 2004. On March 23, 2004, the court entered an Order that North Star's January 22, 2002 Motion to Strike Portions of the Government's Motion for Summary Judgment was moot, in light of the court's November 26, 2003 Memorandum Opinion. On May 27, 2004, June 16, 2004, and August 24, 2004, the court convened a telephone conferences to discuss and resolve other pre-trial matters.

On September 29 , 2004, the court entered an Order approving the parties' retention of Dr. Barbara Barkovich for the limited purposed of serving as a factual and technical witness for the court, pursuant to Fed. R. Evid. 706. This Order is set forth below in its entirety, because it recites the process by which Dr. Barkovich was identified, retained, and the specific scope of her assignment, in which the parties and the court agreed:

> On December 10, 2003, the court issued an order indicating that the advice of a technical expert in utility rate-making would advance an appropriate resolution in this case. Thereafter, the American Association for the Advancement of Science's Directorate for Science and Policy Programs–Court Appointed Scientific Experts ("CASE") was contacted by the court and later provided the court with a list of three suggested experts. Of the three experts, Dr. Barbara Barkovich was acceptable to both parties . . . for the limited purpose of serving as a factual and technical expert to the court, pursuant to Fed. R. Evid. 706. Dr. Barkovich will prepare a written report that:
>
> 1. Identifies all of the cost-based elements that the Federal Energy Regulatory Commission would allow in calculating WAPA's revenue requirement for the regulation service for which North Star was assessed the "In-Kind Energy Payment."

2. Provides a statement and references to support why each of the cost-based elements listed in response to Item 1 is reasonable.

3. Calculates, using practices employed by the Federal Energy Regulatory Commission, within a zone of reasonableness, for each of the following periods, the amount that North Star should have been assessed for the regulation service for which North Star was assessed the "In-Kind Energy Payment."

   a. July 1, 1998 through July 31, 1999;
   b. August 1, 1999 through September 30, 2000; and
   c. October 1, 2000 through March 17, 2003 (or the last date services were provided).

4. Calculates, for each period identified in Item 3, the difference between the amount(s) that North Star should have paid and the amount North Star did pay for regulation services.

In connection with this assignment, counsel for plaintiff promptly will provide Dr. Barkovich with a copy of the Second Amended Complaint; Answer to Second Amended Complaint; the Court's November 26, 2003 decision; a copy of its expert report, together with a list of other suggested discovery (documents and deposition testimony) that Dr. Barkovich may elect to review. Simultaneously, counsel for the Government will provide Dr. Barkovich with a copy of its expert report, together with a list of suggested discovery (documents and deposition testimony) that Dr. Barkovich may elect to review. Any correspondence to Dr. Barkovich by counsel for the parties will be copied to all parties and the court. Likewise, any correspondence from Dr. Barkovich to counsel for the parties will be copied to all parties and the court. All such communications should be in writing.

Dr. Barkovich's report will be provided to the parties by October 18, 2004. Dr. Barkovich will be available for deposition during the period October 18, 2004 through November 4, 2004. Following deposition(s), Dr. Barkovich will be permitted to amend and/or supplement her report, which will be filed as direct testimony with the court and counsel for the parties on November 8, 2004. The court anticipates that Dr. Barkovich would be available for cross-examination at a date to be determined at trial during the week of November 15-19, 2004.

Both parties have agreed to share equally in Dr. Barkovich's fees and expenses. The parties are ordered to immediately issue a retainer check in the amount of $10,000 to Dr. Barkovich. Dr. Barkovich will be required to maintain a detailed time log and expense record to be provided to the court and counsel for the

> parties for review on or before December 1, 2004. The court will issue a second order regarding payment of the balance due after receipt of Dr. Barkovich's time log and expense record.

See North Star Steel Co. v. *United States*, No. 00-238C (Fed. Cl. Dec. 10, 2003) (Order).

On September 27, 2004, North Star filed a Memorandum of Contentions of Fact and Law. On October 7, 2004, North Star filed a Motion in Limine to Preclude the court and Dr. Barkovich from admitting the Government's Proposed Exhibit 8, "NSS Regulation Fee" into evidence.[15] On October 8, 2004, the court convened a telephone conference to discuss Dr. Barkovich's schedule and entered an Order setting the date of her deposition.

On October 25, 2004, the Government filed: an Exhibit List, consisting of 21 exhibits; a Witness List; a Pre-Trial Memorandum of Contentions of Fact and Law; a Response to North Star's October 7, 2004 Motion in Limine; and a Motion in Limine to preclude the deposition testimony of Mr. James Rein, as hearsay.

On November 1, 2004, North Star filed an Exhibit List, consisting of 128 exhibits; a Witness List; and a Reply to the Government's October 25, 2004 Response to North Star's October 7, 2004 Motion in Limine. On November 3 and 5, 2004, the court convened telephone conferences, following which an Order was entered on November 8, 2004, denying North Star's October 7, 2004 Motion in Limine, and rendering the Government's October 25, 2004 Motion in Limine moot. On November 9, 2004, North Star filed an Exhibit List and a Witness List.

On November 9, 2004, Dr. Barkovich was provided with WAPA's response to North Star's Exhibit 111, hourly transaction data provided by AEPCO in electronic format. On November 11, 2004, Dr. Barkovich was provided with a spreadsheet assembled by WAPA to reflect the returned energy.

On November 11, 2004, Dr. Barkovich requested other detailed information from the parties:

> 1. Attorneys for both parties have sent me data tables that are referred to as for "Replacement Energy." I do not see this term in the CAC. I would appreciate it if each party could define this term for me and explain how it relates to the contract and amendments.
>
> 2. Please provide the source of the data for each of the tables referred to as for "Replacement Energy."
>
> 3. What is the source of the data in the table entitled "NSS. Actual.Regulation(clean).xls"? Please explain what is meant by "Dollar Value per

[15] The court has admitted DX 8 into evidence.

MWh" and the source of those figures. Also, please explain what is meant by "Total Energy for Regulation Fee" and provide the source of those data. Are they metered data? If so, from whose meter and where?

4. Is there a document that contains metered kWh data for NSS? Have those data been provided?

5. Please provide an explanation of what is contained in each column in Exhibit 111 and the source of the data.

6. Please provide an explanation of what is contained in each column of Exhibit 112 (aka Clements Exh. 6) and the source of the data.

7. Please provide an explanation of what is contained in each column of Exhibit 113 (aka Clements Exh. 7) and the source of the data.

8. Please provide an explanation of what is contained in each column of Exhibit 114 (aka Clements Exh. 9) and the source of the data.

9. Please identify the source of the North Star Minute Loads for Wednesday, September 24, 1997 that is relied upon by Dr. Gegax in his Expert Report at Exhibit B. Was a real time meter installed to record NSS's loads? Has this meter continued to operate during the tenure of the contract between Western and AEPCO/NSS? If so, are these data available to me?

E-mail from Barbara R. Barkovich to Jonathan Reid Prouty and Philip L. Chabot, Jr. (Nov. 11, 2004, 4:58 p.m. EST).

On November 12, 2004, North Star advised Dr. Barkovich that Section 14.5 of the Consolidated Contract defines "Returned Energy" as "Scheduled Energy (minus) Metered Energy (minus) In-Kind Energy (minus) transmission tariff payments.

On November 13, 2004, WAPA advised Dr. Barkovich that:

Section 14.3, 14.5 and 14.6 of the CAC provide references in the contract [regarding "Replacement Energy"];

Also referred to in Section 4.2 of the Metering and Scheduling Instructions. MSI3 is attached for your reference.

Also, NSS Exhibit 61, titled Parker Davis Project Rates Committee Meeting Presentation of May 5, 1999 (we have attached this exhibit) gives a good tutorial on how the energy deviation accounting worked under the CAC. Page 5 of that exhibit

> presentation has the NSS Daily Deviation Accounting spreadsheet. You will see that Column 1 of that spreadsheet is titled "Replace." The explanation for that column provided on page 7 of the presentation states "Western determines Return Energy to be supplied by Western."

E-mail from Jonathan Reid Prouty to Dr. Barbara R. Barkovich and Philip L. Chabot, Jr. (Nov. 13, 2004, 1:59 p.m. EST).

A trial was conducted on November 15-19, 2004, during which the court heard testimony from six North Star witnesses and four Government witnesses, and the court's expert. In addition, the court reviewed documentary evidence proffered by the parties, and considered argument by the parties' counsel.

On December 9, 2004, the court issued a Scheduling Order for the submission of post-trial briefs and post-trial exhibits.

On December 22, 2005, Dr. Barkovich advised the court and the parties that:

> 1. Having reviewed the WAPA web site it is clear that there are varying types of annual report information about Boulder Canyon but nothing useful for the year 1998. Therefore I would like to see either a Statistical Appendix or an Operations Summary for the year 1998, in particular all data related to the Boulder Canyon plant.
>
> 2. Please provide data regarding the control area providing ancillary services to North Star Steel (NSS). Please provide the monthly hourly peak control area native load for the years July 1996 through March 2003. Please describe the control area providing ancillary services to NSS for each of those years. Please explain the impact of the consolidation discussed in the November 19, 2004 transcript and how it affected the control area and the control area load for the control area serving North Star Steel.
>
> 3. Please also provide information as to what percentage of regulation for NSS was provided by Hoover/Boulder Canyon each year from 1996 through 2003, or whether WAPA has concluded that all regulation for NSS was provided by that facility.

E-mail from Barbara R. Barkovich to Ms. Elizabeth Clements, Law Clerk to the undersigned judge, Philip L. Chabot, Jr., and Jonathan Reid Prouty (Dec. 22, 2004, 2:09 p.m. EST).

On January 27, 2005, North Star filed a Motion to Take Post-Trial Discovery. On February 7, 2005, the Government opposed that motion.

On February 9, 2005, the court entered an Order extending the dates for the submission of Dr. Barkovich's Supplemental Testimony and for final post-trial briefs, responding to Dr.

Barkovich's Supplemental Report. On February 11, 2005, North Star filed a Reply to the Government's February, 7, 2005 Opposition to North Star's January 27, 2005 request for post-trial discovery. On February 15, 2005, North Star also filed the Expert Sur-Rebuttal Report of R. Mark Clements, without objection by the Government. On February 18, 2005, the court entered an Order denying North Star's request for post-trial discovery. On March 1, 2005, North Star and the Government filed Post-Trial Briefs and North Star filed Proposed Findings of Fact and Conclusions of Law. On March 22, 2005, North Star filed a Post-Trial Reply Brief. On March 23, 2005, the Government filed a Reply.

On September 30, 2005, the court entered an Order requesting additional information from Dr. Barkovich, including comment on the February 15, 2005 Sur-Rebuttal Report of North Star's expert, R. Mark Clements. On November 7, 2005, Dr. Barkovich provided the court with that Response.

DISCUSSION

A. Jurisdiction.

The Second Amended Complaint alleges that the court has subject matter jurisdiction to adjudicate Plaintiff's breach of contract claims for monetary relief against the United States, pursuant to 28 U.S.C. §1491(a). *See* Second Amend. Compl. ¶ 1 at 1; *see also Martinez* v. *United States*, 333 F.3d 1295, 1302-03 (Fed. Cir. 2003) (the United States Court of Federal Claims has jurisdiction to adjudicate actions, including "contracts with the United States, actions to recover illegal exactions of money by the United States, and actions brought pursuant to money-mandating constitutional provisions, statutes, regulations or executive orders."). The court's jurisdiction, however, is not so easily resolved in this case, because a determinative issue is whether the explicit waiver of sovereign immunity and grant of jurisdiction under the Tucker Act of 1887 was trumped when Congress enacted the DOE Organization Act in 1977.[16] *See Palmer Molnar* v. *Barran*, 184 F.3d 1373, 1377

[16] The court has identified four cases in which the contractual rates for power sold by PMAs have been contested in the United States Court of Federal Claims, however, none of them confronted the jurisdictional issues discussed herein. *See, e.g., S. Cal. Edison* v. *United States,* 58 Fed. Cl. 313, 319 (Fed. Cl. 2003) (holding that the court's jurisdiction under the Tucker Act was not "ousted nor supplanted by the Ninth Circuit under 16 U.S.C.§839 f(e)(5.)"; *City of Burbank* v. *United States*, 47 Fed. Cl. 261, 269 (Fed. Cl. 2000) (dismissing contract claim for lack of subject matter jurisdiction under the Northwest Power Act), *rev'd*, 273 F.3d1370 (Fed. Cir. 2001) (holding the court had jurisdiction); *S. Cal. Edison Co.* v. *United States*, 43 Fed. Cl. 107,118-21(Fed. Cl. 1999) (determining, where subject matter jurisdiction was not challenged, the methodology WAPA used to calculate refunds due under a longer term contract for the purchase of electricity generated at Hoover Dam was contrary to applicable regulations), *aff'd in part and rev'd in part,* 226 F.3d 1349 (Fed. Cir. 2000) (finding WAPA's method of allocating a contractual surplus for pre-FERC contracts entered between 1941 and 1960 to be reasonable without considering subject matter jurisdiction); *Puget Sound Power & Light Co.* v. *United States*, 23 Cl. Ct. 46 (1991) (holding challenge to extra

(Fed. Cir. 1999) ("Although the government did not move to dismiss, it is always the duty of the court to determine its jurisdiction[.]").

When Congress enacted the DOE Organization Act, transferring jurisdiction from FPC to FERC for all final rates of the PMAs, including WAPA, no provision was included that specifically provided for judicial review of such determinations. Since that time, some federal appellate courts have held that a district court may review FERC final action, but only under the Administrative Procedure Act, 5 U.S.C. §§ 701-02 (2000) ("APA"). *See Central Lincoln Peoples' Util. Dist.* v. *Johnson*, 735 F.2d 1101, 1109 (9th Cir. 1984) ("Since there are no special provisions for judicial review of . . . [final FEC] rate determinations, challenges to other PMA rates are brought in district court under the [APA].") (citing FERC Supplemental Status Report 1 n.1 (June 3, 1983);[17] *see also Nader* v. *Volpe*, 466 F.2d 261, 266-67 (D.C. Cir. 1972) (denying an injunction under the APA where the regulation at issue was not final and observing: "The implicit legislative concept of separateness in the functioning of agencies and courts is ill served by improvident judicial interference in agency administrative proceedings.").

In *Overton Power Dist. No. 5* v. *O'Leary*, 73 F.3d 253, 255-258 (9th Cir. 1996), the United States Court of Appeals for the Ninth Circuit went further, dismissing an action brought by two power suppliers challenging final FERC approval of WAPA rates for power generated at Hoover Dam, holding that the presumption of reviewability under the APA was overcome "whenever the congressional intent to preclude judicial review is 'fairly discernable in the statutory scheme.'" *Id.* at 255 (citations omitted). In reaching this determination, that federal appellate court relied on *Block* v. *Cmty. Nutrition Inst.*, 467 U.S. 340 (1984), in which consumers were held not to have standing to seek judicial review of milk marketing orders because *"the congressional intent to preclude* is fairly discernible in the statutory scheme . . . consumer suits might themselves frustrate achievement of the statutory purposes [by disrupting the] cooperative venture among the Secretary [of Agriculture], producers, and handlers . . . [and] undermin[ing] the congressional preference for administrative remedies[.]" *Id.* at 351-52 (internal quotations omitted) (emphasis added); *see also Clarke* v. *Securities Indus. Ass'n*, 479 U.S. 388, 400 (1987) ("In *Community Nutrition Inst.*, . . . the Court found that. . . the *reviewability question turns on congressional intent*[.]" *Id.* at 400 (quotations omitted) (emphasis added).

---

regional sales of surplus power by the Bonneville Power Administration was dismissed because the Ninth Circuit had exclusive jurisdiction under the Northwest Power Act), *aff'd on other grounds*, 944 F. 2d 912 (Fed. Cir. 1991) (holding that an immediate review by the Ninth Circuit of its jurisdiction was required and/or a motion to transfer in light of the collateral order doctrine).

[17] Judicial review of certain final actions of the Bonneville Power Administration has been committed to the exclusive jurisdiction of the United States Court of Appeals for the Ninth Circuit. *See* 16 U.S.C. § 839 f(e)(1); *see also S. Cal. Edison* v. *United States,* No. 03-2869C, ___ Fed. Cl. ___, 2005 WL 3046539, 2005 U.S. Claims LEXIS 341 (Fed. Cl. Nov. 10, 2005); *S. Cal. Edison* v. *United States*, 58 Fed. Cl. 313, 319-20 (Fed. Cl. 2003).

A related piece of legislation, the Public Utility Regulatory Policies Act of 1978, Pub. L. No. 95-617, 92 Stat. 3117 (codified at 16 U.S.C. §§ 2601, *et seq.*) ("PURPA"), was enacted to encourage the conservation of fossil fuels and promote the development of new generating facilities with "equitable rates." By that time, significant technological advances made it possible to transmit electric power over long distances at a lower and lower cost by "wheeling power," *i.e.,* the "transfer by direct transmission or displacement electric power from one utility to another over the facilities of an intermediate utility." *Otter Tail Power Co.*, 410 U.S. at 368. Larger utilities, however, had control over most of the nation's transmission lines and were reluctant to purchase power from nontraditional facilities. *See New York*, 535 U.S. at 9. Therefore, Congress directed FERC to promulgate rules under PURPA to require utilities to purchase electricity from "qualifying" cogeneration and smaller power production facilities.[18] *See* 16 U.S.C. § 824a-3; *see also id.* These rules increased the "wheeling" of power across the country and allowed consumers to shop for the lowest available power rates. More importantly, FERC also was given exclusive jurisdiction over PMAs to "confirm, approve, and place in effect on a final basis, to remand, or to disapprove" all final rates under the following standard:

> (a) Whether the rates are the lowest possible to customers consistent with sound business principles; (b) whether the revenue levels generated by the rates are sufficient to recover the costs of producing and transmitting electric energy . . . ; and (c) the assumptions and projections used in developing the rate components that are subject to [FERC] review.

48 FED. REG. at 55664-65. PMAs, like WAPA, however, were allowed to continue to set their own rates, approved only by DOE and subject to FERC "confirmation and approval," but not FERC's adjudicatory review. *Id.* Therefore, although FERC nominally can approve, reject, or request further consideration of a PMA rate, it appears that from 1983 to date, FERC has taken no action, other than to approve a rate.

On August 17, 1994, the date that the Consolidated Contract was executed, WAPA had final wholesale transmission power rates on file with FERC, *i.e.*, rates determined to be reasonable and in the public interest. Accordingly, if North Star's Complaint had challenged those rates, the court would have no jurisdiction, in light of clear congressional intent to delegate and commit final rate reviewability to FERC's expertise and discretion. At *that* time, however, WAPA did not have a separate rate for regulating services filed with FERC. Therefore, and only for this reason, the court has determined that it has jurisdiction over North Star's breach of contract claim in this case. The parties concur that the court has jurisdiction over North Star's claims in this case. *See* TR 628-30.

---

[18] Congress recently amended PURPA to eliminate the requirement that a utility enter into a new contract to purchase energy from a "qualifying cogeneration facility or a qualifying small power production facility" under certain circumstances. *See* Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594, 967-71 (Aug. 8, 2005).

The Tucker Act also provides that "[t]he [United States] Court of Federal Claims shall have jurisdiction to render judgment upon any claim by or against, or dispute with, a contractor arising under section 10(a)(1) of the Contract Disputes Act of 1978 [("CDA")]." 28 U.S.C. § 1491. Section 605 of the CDA, however, contains a jurisdictional prerequisite to the court's jurisdiction:

> (a) All claims by a contractor against the government relating to a contract shall be in writing and shall be submitted to the contracting officer for a decision. All claims by the government against a contractor relating to a contract shall be the subject of a decision by the contracting officer[.]
>
> (b) The contracting officer's decision on the claim shall be final and conclusive and not subject to review by any forum, tribunal, or Government agency, unless an appeal or suit is timely commenced as authorized by this chapter.

41 U.S.C. § 605. The United States Court of Appeals for the Federal Circuit has held that a "request for a final decision can be implied from the context of the submission." *James M. Ellett Const. Co., Inc.* v. *United States*, 93 F.3d 1537, 1543 (Fed. Cir.1996). Under such circumstances, the court must ascertain whether the contracting officer issued a final decision. *Id.*; *see also Transamerica Ins. Corp., Inc.* v. *United States,* 973 F.2d 1572, 1576-77 (Fed. Cir. 1992) ("[I]n order to establish that a 'claim' has been submitted to a contracting officer *the relief requested must include an expression of interest in a final decision by the contracting officer.*" (emphasis in original)), *overruled in part on other grounds by Reflectone* v. *Dalton*, 60 F.3d 1572, 1579 & n. 10 (Fed. Cir. 1995). Since North Star seeks damages as a result of WAPA's breach of the Consolidated Contract in this case, North Star also must comply with the CDA's jurisdictional prerequisite that a contracting officer received a claim and issued a final decision.

On June 5, 1998, North Star sent a proposal to WAPA seeking a final determination that the methodology, pursuant to which North Star was receiving regulating services, was "cost-based." *See* PX 48 at 1-00606 ("If an agreement is not reached, then we propose that on July 1, 1998, [WAPA] unilaterally implement its calculation of cost as set forth on June 2, 1998[.] . . . We will then take the necessary steps to resolve our disagreement over the propriety of these charges by other means."). On July 17, 1998, North Star sent a letter to WAPA stating that the time period specified in the proposal had elapsed without any response. *See* PX 49 ("Having not heard from [WAPA] by that date, we interpret your silence as a rejection of that proposal. . . . While we remain hopeful, we believe the possibility of reaching a mutually agreeable adjustment of prior to the contract deadline of July 1, 1998, is limited."). On June 19, 1998, WAPA responded indicating that it "does not accept either of the two proposals submitted for our consideration." *See* PX 50 ("If there is no agreement on a revised methodology by July 1, 1998, the in-kind payment of 20 percent, as currently provided for in the Contract, will remain in effect."). On April 27, 2000, North Star filed a Complaint in the United Stated Court of Federal Claims.

Although WAPA had no formally designated contracting officer, the court has determined from the conduct of the parties that North Star complied with CDA's requirement that it submit a

written claim for a decision and an appropriate WAPA official issued a final decision denying North Star's claim.

B. North Star Steel Co. Has Standing As A Third-Party Beneficiary To The August 17, 1994 Consolidated Contract For Regulating Services.

The court previously determined that North Star has standing to enforce the Consolidated Contract as a third-party beneficiary thereunder. *See North Star Steel Co.* v. *United States*, 58 Fed. Cl. 720, 734-35 (Fed. Cl. 2003).

C. The Court's Resolution Of The Remaining Substantive Issues.

In *United States* v. *North Star Steel Co.*, 58 Fed. Cl. 720 (Fed. Cl. 2003), the court granted, in part, WAPA's motion for summary judgment that the Consolidated Contract did not require that WAPA charge only "actual costs" for regulating service and that none of the four federal statutes,[19] cited by North Star, required that WAPA charge only "actual costs" for regulating services. *Id.* at 735-38. On the other hand, the court denied WAPA's motion for summary judgment that the Consolidated Contract was amended by the parties' conduct to require that WAPA retroactively refund North Star for regulating service payments that exceeded a "cost-based methodology," because material facts were at issue. *Id.* at 738-39. The court also denied WAPA's motion for summary judgment that, as a matter of law, North Star's rejection of REVISION No. 1 necessarily reinstated Exhibit H, as the methodology under which WAPA's payments for regulating services should be calculated as of October 1, 2000. *Id.* at 739-40. For the same reason, the court also denied WAPA's motion for summary dismissal of North Star's Complaint, because whether terms of the "In-Kind Energy" payment complied with the Consolidated Contract or otherwise was "reasonable" remained at issue. *Id.* at 740.

Since the record now is fully developed by trial and submission of expert opinions, the unresolved substantive issues can be adjudicated.

1. The Western Area Power Administration Had No Contractual Obligation To North Star Steel Co. To "True Up" Over Or Under Payments Of "In-Kind Energy" On An Annual Basis And No Duty To Refund Retroactively Any Overpayment For Regulating Services.

Neither the Principles Agreement (PX 4) nor the Consolidated Contract (PX 6) contain any language requiring that WAPA engage in a retroactive adjustment or a "truing up" of the amounts

---

[19] The four statutes relied on by North Star were: the Reclamation Act of 1902, 32 Stat. 388, 389 (codified at 43 U.S.C. § 461); the Reclamation Project Act of 1939, 53 Stat. 1187, 1193 (codified at 43 U.S.C. § 485h(c)); 68 Stat. 143 (codified at 43 U.S.C. Ch. 12A); the Department of Energy Organization Act, 91 Stat. 565 (codified at 42 U.S.C. §§ 7101, *et seq*).

paid by North Star for regulating service. *See* TR 101-07, 225-27. Since the Consolidated Contract did not contain an Integration Clause and there was evidence in documents submitted in support of summary judgment that WAPA may have agreed that any refunds for regulating services would be applied retroactively, the court allowed the parties to adduce further evidence on this issue at trial. *See North Star Steel Co.*, 58 Fed. Cl. at 739 (citing Def. App. at 252 (Oct. 16, 2001 Letter from Jean Gray regarding North Star Steel Contract No. 10590, Proposed Revision to Exhibit H. (PX 74) ("We [WAPA] agreed to a retroactive application of the new methodology back to October 2000.”))).

At trial, North Star's witnesses continued to testify that there was an explicit, if not implicit, understanding that WAPA assured North Star there would be an annual "true-up" of "In-Kind Energy" payments. *See* TR 226, 234, 1086-87; 1092-93. Not surprising, WAPA witnesses denied that there was any agreement to adjust regulating services to North Star retroactively. *See* PX 64, *see also* TR 226, 234, 374-76, 457-58, 465-66, 483-84, 491-94, 1240-44, 1263-66.

For the court, the determinative testimony was that of Mr. Sarafolean, North Star's former Financial Manager, Cost Accounting Manager, and Energy Specialist and currently Secretary of the Texas Industrial Energy Group, who explained that a separate metering and scheduling instructions agreement included an "annual consolidated charge adjustment" by November 30th of each year, at which time WAPA "would determine the current fiscal year consolidated transmission value to be applied in the monthly billing." TR 1095-97. This procedure, however, was agreed to in a different contract after the Consolidated Contract was executed. *Id.* at 1098; *see also* PX 73. And, as Mr. Sarafolean testified: "I guess, in my mind, I envisioned something like this as we would establish a methodology and ongoing criteria for the [I]n-[K]ind [E]nergy numbers as well." *Id.* at 1097. Although the court does not doubt that Mr. Sarafolean may have "envisioned" that the Consolidated Contract included a "truing up," North Star failed to establish at trial by a preponderance of evidence that the parties conduct amended the Consolidated Contract in that regard. *See, e.g.,* TR 1265-66. Moreover, although it appears that WAPA eventually agreed to such an amendment in October 2001, North Star rejected related terms and no amendment was made. *See* TR 93, 539.

Accordingly, the court has determined that WAPA did not have an obligation under the Consolidated Contract to "true up" over or under payments of the "In-Kind Energy" on an annual basis.

2. The Terms Of The Consolidated Contract Evidence Sufficient Certainty To Determine: The Intent Of The Parties To Enter a Contract; Whether And When A Breach Occurred; And An Appropriate Remedy For Breach.

The United States Court of Appeals for the Federal Circuit has discussed the rationale for requiring certainty in contracts, *i.e.*, "the need to determine whether the parties in fact intended to contract at all, and . . . the ability of a court to determine when a breach has occurred and to formulate an appropriate remedy." *Aviation Contractor Employees, Inc.* v. *United States*, 945 F.2d 1568, 1572 (Fed. Cir. 1991) (citing RESTATEMENT (SECOND) CONTRACT (1981) ("RESTATEMENT") at § 33) (selected citations omitted).

In the Consolidated Contract, WAPA and North Star "agreed to agree" to establish an "appropriate cost-based methodology to review, evaluate and periodically, if necessary, adjust the percentage associated with the In-Kind Energy payment" after "one (1) year of normal operation[.]" PX 6 at DA36-37 (Consolidated Contract at § 21). The court has determined that this language and the conduct of the parties thereafter evidences an intent to contract and the requirement of establishing a "cost-based methodology" provides a clear demarcation by which the court can determine whether and when a breach occurred. In addition, in this case both parties agreed to jointly negotiate, which "impliedly place[d] an obligation on the parties to negotiate in good faith." *Aviation Contractor Employees*, 945 F.2d at 1572; *see also id.*; TR at 57-62, 71, 182-84, 373. Accordingly, the Consolidated Contract could be breached if a "cost-based methodology" was not utilized by WAPA or if one of the parties failed to negotiate in good faith. If either occurred, the court could ascertain an appropriate remedy by determining a reasonable price for WAPA's regulating services. *See Aviation Contractor Employees*, 945 F.2d at 1573 ("[A] court can enforce the contract by determining a 'reasonable' price."); *see also* WILLISTON ON CONTRACTS § 4.28 (4th ed.) ("[I]f the contract cannot be performed without resolution of the undetermined point, but the parties have intended to contract, and a *reasonable term can be inferred* to have been intended, each party will be bound to a *reasonable determination* of the unsettled point in order that the main promise may be enforced.") (emphasis added); RESTATEMENT § 33, cmt. e ("Where they intend to conclude a contract for the sale of goods, however, and the price is not settled, the price is a reasonable price at the time of delivery if (a) nothing is said as to price, or (b) the price is left to be agreed by the parties and they fail to agree, or (c) the price is to be fixed in terms of some agreed market or other standard as set or recorded by a third person or agency and it is not so set or recorded.").

3. The Western Area Power Administration Breached The Consolidated Contract By Failing To Establish A "Cost-Based Methodology" For Regulating Services On July 1, 1998 Or Thereafter.

a. In Discovery And At Trial, The Western Area Power Administration Claimed That No Data Existed To Evidence Annual Operations And Maintenance Costs For The Regulating Services Provided To North Star Steel Co.

The Reclamation Project Act of 1939 mandates that WAPA, as a Power Marketing Administration, establish rates at a level sufficient to recover the full costs of producing, transmitting, and selling Bureau of Reclamation-generated power. *See* 43 U.S.C. § 485h(c). To recover full costs:

> Any sale of electric power[,] . . . made by the Secretary [of Energy] in connection with the operation of any project or division of a project, shall be . . . at such rates as in [the Secretary's] judgment will produce power revenues at least sufficient to cover an *appropriate share of the annual operation and maintenance cost*, interest on an

> appropriate share of the construction investment at not less than 3 per centum per annum, and such other fixed charges as the Secretary deems proper.

Id.

During the negotiations, discovery, and at trial, however, WAPA claimed that the Bureau of Reclamation did not have data to evidence whether the terms of WAPA's sale of regulating services to North Star were sufficient to cover "an appropriate share of the annual operation and maintenance cost."[20]

At trial, the court explored this problematic situation with both counsel:[21]

> THE COURT: The cost structure of [WAPA], I gather the cost data has never been provided, is that correct?
>
> NORTH STAR'S EXPERT: That's correct, Your Honor.
>
> THE COURT: [To the Government's Counsel] So inherently, the experts are not going to be able to give . . . certain answers because of [the Government's] own conduct. I'm not sure why [the Government] haven't provided cost data. Perhaps you can give me an explanation for that?
>
> GOVERNMENT'S COUNSEL: Well, Your Honor, the witnesses will explain the data that was provided, of course.
>
> THE COURT: Right, but if you're looking to decide what a rate should be, they need to know costs.
>
> GOVERNMENT'S COUNSEL: Yes, Your Honor.

---

[20] WAPA claimed that North Star had access during discovery to "much of the data needed for negotiations, such as expected power purchase costs, expected spot costs, and pre-scheduled hourly loads." WAPA Post-Trial Reply Brief at 10 (citing TR 238-39). In fact, most of the relevant cost data was not produced by WAPA in this litigation either to WAPA's expert, North Star's expert, or the court-appointed expert. *See* PX 40; PX 43; *see also, e.g.,* TR 76, 78, 80-81, 119, 262-63, 406, 643-45, 912 ("[W]hen I requested WAPA data on a minute-by-minute basis comparable to North Star Steel, I was told it was no longer available."), 1252-53, 1260.

[21] The court's skepticism about WAPA's inability to document costs was shared by Dr. Barkovich. *See, e.g.*, Court Ex. 3 ¶¶ 5, 6 at 2; E-mail from Barbara K. Barkovich (Nov. 11, 2004, 4:58 p.m., EST); E-mail from Barbara K. Barkovich to counsel (Dec. 22, 2004. 2:09 p.m., EST).

THE COURT: So why is it the [G]overnment has not provided that information all this time?

GOVERNMENT'S COUNSEL: Well, Your Honor, the witnesses will testify that we did provide some costs and that *some of the costs that were sought from the Bureau of Reclamation were not in a format or not available in such a way that they could be used to calculate the costs*. So therefore, there just was no data that could be used to support costs from one particular direction in determining what the costs were. Now the [G]overnment actually will, and I don't wish to testify, but I'll give you a preview of what the testimony is going to be, though. They're going to basically suggest that because of the limitations on the Bureau of Reclamation data, they had to approach a cost basis methodology from a different direction, because they just frankly could not do it in another way. And that's essentially what the [G]overnment did.

TR 322-23 (emphasis added).

* * *

THE COURT: Then I want to get back to what type of cost data [WAPA] provide[d] FERC so that FERC can make this initial evaluation at least that the costs have been covered. Do we have the same data that FERC has in this case? Is the cost data that's given to FERC, has that been provided to the Plaintiff in this case?

GOVERNMENT'S COUNSEL: My understanding is the data, the filings that are provided to FERC are quite voluminous.

THE COURT: I understand that. That's not the issue.

GOVERNMENT'S COUNSEL: I believe they're actually available publicly. I don't believe there's any suggestion or concern that Mr. Chabot didn't have access to it or his expert didn't have access to it. I believe it's the kind of thing that is in the domain that's accessible.

THE COURT: The first cost data [North Star] received from [WAPA] was when?

GOVERNMENT'S COUNSEL: I guess I'm confused by your question, Your Honor. If your question is --

THE COURT: My understanding is [WAPA] didn't file with FERC until May 11, 1999, is that correct?

GOVERNMENT'S COUNSEL: This filing --

THE COURT: Or did they file before that?

GOVERNMENT'S COUNSEL: For this transmission power. For this regulation.

THE COURT: This regulating service, that's the first time they filed for that particular service?

GOVERNMENT'S COUNSEL: I believe that's so. Certainly I think Ms. Gray might know better than I do, but the reason of course is because it was not in bundles until in 1988.

THE COURT: Right. At that time they provided some type of cost data?

GOVERNMENT'S COUNSEL: Yes, Your Honor.

THE COURT: FERC. My question is: Is whatever that data is, has that been provided to the Plaintiff in this case?

GOVERNMENT'S COUNSEL: Your Honor, I don't know if it's been specifically provided as a discovery response as opposed to that being simply available, which area would have got themselves.

TR 619-20.

* * *

THE COURT: That was [not] my question: Did you have the cost data? Whatever cost information was provided to FERC you have?

NORTH STAR'S COUNSEL: Yes. The problem with that, Your Honor, it has the same problem that Mr. Iliff testified about yesterday. It is generic, high-level. It does not give sufficient detail to do the kinds of calculations that are necessary to determine the specific cost elements here. You cannot --

THE COURT: Why was it sufficient for FERC then? That's what I'm trying to figure out.

NORTH STAR'S COUNSEL: It wasn't. Absent an intervenor and all that FERC is doing is saying, as Ms. Gray said, for a general regulation service this is a reasonable rate. There is sufficient cost justification for it.

THE COURT: It's kind of like a prima facie showing?

> NORTH STAR'S COUNSEL: Well not as a prima facie. They're looking at the entire rate for the Desert Southwest. There was sufficient data to determine that for a rate, what we're trying to call regulation service applicable to customers of the Desert Southwest region, there was sufficient cost justification. That's precisely why Mr. Clements and you'll see Dr. Barkovich say for all intents and purposes that ought to be the rate case. The basis of this rate. There is some cost justification. The problem is if you try to determine the price components for an individual customer from that data, it cannot be done. You need different sets of data and it's that different data set that has never been provided here. Again, that's the problem that Mr. Iliff testified about yesterday as to why at some point they had to determine that they couldn't go down the road that they initially started out and had to change the methodology.

TR 624-25.

b. Substantial Expert Testimony Confirmed That The Western Area Power Administration Did Not Establish A "Cost-Based" Methodology With North Star Steel Co.

Since it would not have been cost-effective for the court to have ordered an independent audit of the Bureau of Reclamation and/or WAPA's accounting records to ascertain whether cost data existed, the court suggested, and the parties agreed, to appoint an independent expert in utility ratemaking to identify and support the reasonableness of cost-based elements that FERC would allow, if it had jurisdiction to review WAPA's proposed rates. An examination of the parties and court-appointed experts' testimony confirmed that WAPA did not establish a "cost-based methodology" for the regulating services sold to North Star, but instead ignored that contractual obligation and proceeded in "another way." TR 323.

(1) June 22, 2004 Direct Testimony Of North Star Steel Co.'s Expert -- Dr. Carl Pechman.

(a) Qualifications.

Dr. Carl Pechman holds B.A., M.A., and Ph.D. degrees from Cornell University. *See* PX 128 at 1. Dr. Pechman's doctorate is in the field of Resource Economics. *Id.* Dr. Pechman currently is President of Power Economics, Inc., a consulting firm specializing in the economics of electricity. *Id.*

From 1979 through 1997, Dr. Pechman was an economist and ultimately Supervisor of Energy and Environmental Economics in the New York Public Service Commission ("NYPSC"). *Id.* During his tenure at the NYPSC, Dr. Pechman was involved in: analysis of the need for energy infra-structure plants; the design of rates, such as performance-based regulation; development of avoided costs; and creation of an Independent System Operator for the State of New York. *Id.* A

principal concern in these positions was the "efficient design, planning and operation of an environmentally compatible power system that was reliable." *Id.* Dr. Pechman also had experience in calculating marginal cost of transmission in the context of utility rate cases and investigating alternative methods of costing transmission services. *Id.*

In 1997, Dr. Pechman joined the LEGC consulting firm as a Director, where he worked on client issues, involving competitive structure in the electric utility industry. *Id.* at 1-2. In 1999, Dr. Pechman formed Power Economics, Inc. *Id.* at 2. In this capacity, Dr. Pechman has served as a consultant to the Speaker of the California Legislature about the California Power Crisis. *Id.* In addition, Dr. Pechman has served in a variety of government appointed and private industry contexts. *Id.*

(b) Expertise.

Dr. Pechman was proffered by North Star to render an expert opinion as to: 1) whether WAPA's transmission charges [to AEPCO/North Star] were "just and reasonable;" and 2) whether WAPA's "pricing behavior" was an improper exercise of market power. *Id.* at 2. The court accepted Dr. Pechman as an expert in the proffered areas.

(c) Opinion.

Dr. Pechman advised the court that the aforementioned issues are "inter-related[, as the] exercise of market power raises prices above those that would be found a competitive, efficient market. [Therefore,] [p]rice affected by market power, by definition, are not just and reasonable." *Id.* at 3. Because WAPA's ownership and control over the 230KW transmission line that provided electric power to North Star was an "essential facility," an appropriate method for evaluating cost was never developed and because WAPA "is the only entity that has access to information necessary to develop an appropriate method, [WAPA had] an advantage from asymmetric information." *Id.* at 4-5. Therefore, Dr. Pechman concluded that WAPA had market power, *i.e.*, control of information and control of facilities, and exercised it. *Id.* at 3-5.

The court also was advised by Dr. Pechman that the "ability to price prices above cost is an exercise of market power." *Id.* As to determining whether market power was exercised, Dr. Pechman found the practice of basing hourly regulation requirements on the maximum five-minute demand to be significant. *Id.* Because the five-minute peak "ratchets requirements for the entire hour," WAPA was able to "over-collect" "In-Kind Energy." *Id.*

(2) July 27, 2004 Direct Testimony Of North Star Steel Co.'s Expert -- R. Mark Clements.[22]

(a) Qualifications.

R. Mark Clements is a Senior Consultant at the Energy & Resource Consulting Group, LLC, with "thirty-two years of experience with domestic and foreign utilities in the long-range planning of generation and the planning and operations of bulk power and regional transmission systems, with special assignments in all aspects of mergers and acquisitions, power contracts and control area operation and planning." PX 126 at Tab 1. Prior to his service as a consultant, Mr. Clements "directed and [has] been extensively involved in production cost modeling, fuel procurement studies, management audits of production and system operations, generation expansion plans, load management studies, energy audits of industrial facilities[,] and the performance of cost allocation studies." *Id.* Mr. Clements also has testified before FERC, the Colorado Public Utilities Commission, and the Kentucky Public Service Commission. *Id.* at 2. In addition, Mr. Clements has served as a member of the Regional Policy Planning Committee and the Planning and Coordinating Committee of the Western Systems Coordinating Council and was a member of the Board of Directors and Secretary/Treasurer of the Western Regional Transmission Association. *Id.*

(b) Expertise.

R. Mark Clements was proffered by North Star as an expert on: electric transmission planning and operation; electric control area design, planning, and operation; and electric system planning and costing. *See* TR 310-11. The court accepted Mr. Clements as an expert in the proffered areas.

(c) Opinion.

Mr. Clements testified that the following were the "components of costs . . . attributable to regulation service:

- Generation capacity costs;
- The cost of automatic generation control ("AGC") and communications equipment installed at power production facilities required to instruct turbine governors to control real power output from generators;

[22] Mr. Clements testified that in preparing his Direct Testimony, he primarily relied on PX 16; PX 26; PX 51; PX 58; PX 59, PX 81; PX 82; PX 83; PX 84; PX 90; PX 91; PX 92; PX 93; PX 94; PX 95; PX 96; PX 97; PX 98; PX 103; PX 104; PX 105; PX 106, PX 122; PX 123; PX 124; PX 125. *See* TR 314.

- Variable O&M expenses; and

- Opportunity costs.

See PX 126 at 21-22.

Mr. Clements then analyzed the "theory" and "practice" of the four above-referenced cost components in this case. *Id.* at 23-32.

(i) Generation Capacity Costs.

Mr. Clements advised the court that, in theory, regulating services only can be provided in physical response to two main signals into the AGC system: errors in the Interconnection frequency and errors in the scheduled interchange control area. *Id.* at 23. Accordingly, the aggregate control area load, and variations of that load from minute to minute, cause generation to increase or decrease within a control area. *Id.* Therefore, transmission customers that have "intra-hour" load variations should be required to pay for generation capacity costs, since they are a "component of the aggregate load." *Id.* at 23-24. Generation capacity is needed to provide for random increases in load, but not for "load magnitude decreases," resulting from random variation. *Id.* In sum, the components of generation capacity are the same as those "associated with the revenue requirements of a fixed plant," *i.e.*, depreciation, taxes, return on investments, and fixed, but not variable, O&M expenses. *Id*. at 24.

In practice, the Consolidated Contract required that AEPCO provide non-firm energy for the "entire scheduling period equal to North Star's maximum five minute demand." *Id.* As a result, except for the five minute peak load, more capacity was available during the remainder of the load cycle than North Star consumed. *Id.* To substantiate this proposition, Mr. Clements prepared the following table to illustrate that, except during the five minute peak demand interval, WAPA's generators actually decreased output. *Id.* at 25-26.

Table 1

Western Area Lower Colorado ("WALC") Control Area Generation And North Star Schedules (MW)

No North Star Load				With the North Star Load				
\ WALC /				\ WALC /		\ North Star /		
A	**B**	**C**		**D**	**E**	**F**	**G**	**H**
Minutes	Load	Generation		Load	Generation	Actual Load	Schedule	"Extra" Capacity
1-5	1000	1000		1000	960	30	70	40
5-10	1000	1000		1000	975	45	70	25
10-15	1000	1000		1000	1000	70	70	0
15-20	1000	1000		1000	950	20	70	50

Id. at 26.

Mr. Clements concluded WAPA's generation capacity costs were zero because WAPA actually decreased generation output with the North Star load. *Id.* at 27; *see also* WAPA Resp. to Pl. First Request for the Production of Documents No. 1-7.[23]

(ii) Automatic Generation And Communications Costs.

In theory, Mr. Clements assumed that automatic generation and communications costs were assigned by WAPA to "generation function," because the Bureau of Reclamation and Army Corps of Engineers "own" these facilities. PX 126 at 27. If that is so, then the "costs of the AGC and communications equipment associated with sending signals to the governor controls has been paid for by wholesale customers of [WAPA]." *Id.* at 27. Mr. Clements also testified that since transmission customers need this same equipment, WAPA's transmission rates also covered these costs. *Id.* at 27-28.

[23] Dr. Pechman reviewed Mr. Clements' analysis and concurred that "because North Star self provided regulation through its scheduling services, it did not impose regulation costs on [WAPA] . . . and should, therefore, be viewed as having zero cost and any changes associated with regulation are in excess of its cost basis." PX 128 at 5. The fact that "WAPA would collect an amount in excess of its cost basis of zero is an exercise of market power." *Id.* at 5-6.

Mr. Clements did not dispute that North Star, through AEPCO, should pay for the automatic generation and communications equipment costs. *Id.* at 28. In this case, however, WAPA provided no data or information as to these costs. *Id.* Therefore, Mr. Clements concluded that WAPA's costs were zero. *Id.*

(iii) Variable Operating And Maintenance Costs.

Mr. Clements assumed that WALC Control Area regulating capacity was provided from hydroelectric resources. *Id.* If so, variable operating and maintenance costs are "applicable costs that should be [included] in cost-based rates, since cycling hydroelectric units either up or down produces such variable O&M costs." *Id.* In theory, typical variable operating and maintenance costs incurred to provide regulating services would include: water used by increased generation; water used by transitioning output from one level to another, assuming "the turbine control system optimizes the consumption of water relative to output at constant loads, but that during transitions between load levels the control system produces less efficient use of water[;]" "damage" that may occur, because "allegedly, some hydro units experience vibrations in transitioning to new operating levels[;]" the cost of energy to supply hearing energy losses, because "as generator output increases, the armature current (in Amps) increase[;]" "stresses produced by magnetic fields [in] 'current flow;'" and other maintenance "attributable to larger torques and forces" on the turbine and seals, as water is released. *Id.* at 28-29.

In this case, Mr. Clements testified that North Star's load "cycles up and down and impacted variable O&M expenses." *Id.* at 30. Because North Star's load largely was in "intra-hour" cycles, WAPA's generation output was reduced and saved water. *Id.* Although in the off-peak period WAPA scheduled back return energy to AEPCO, Mr. Clements advised the court that "this is not regulation service," because the energy WAPA returned was caused by an "energy in balance service" that reflected differences between "scheduled energy . . . and the actual metered load." *Id.*

Mr. Clements agreed, however, that North Star's load caused "all of the cyclic components of variable O&M costs. As such, the regulation charge assessed by [WAPA] should reflect those expenses." *Id.* Therefore, Mr. Clements stated that the variable operating and maintenance costs attributed to regulating service would be "extremely difficult" to quantify in the abstract. *Id.* Since WAPA did not quantify those costs in discovery, Mr. Clements advised the court that WAPA's variable operating and maintenance costs should be considered as zero. *Id.*

(iv) Opportunity Costs.

Mr. Clements acknowledged, but did not accept the economic theory of opportunity costs, *i.e.*, that WAPA's generation capacity could have been sold at market rates but for being obligated for "intra-hour"fluctuations supplied by regulation service." *Id.* at 31. In this case, however, since WAPA stated that it had no excess capacity for regulating services, Mr. Clements reasoned that WAPA could not have had any opportunity costs. *Id.* at 32.

(v) Conclusion.

Mr. Clements concluded that no costs were "associated" with WAPA's provision of regulating services for North Star. *See* PX 126 at 32. Therefore, for each period identified in the court's September 29, 2003 Order, Mr. Clements determined that the "entire cost of the In-Kind Energy furnished by AEPCO to [WAPA] exceeded the costs [that WAPA] incurred to provide regulation service." *Id.* Accordingly, Mr. Clements' expert opinion was that WAPA's charges to North Star for regulating services were "unjust and unreasonable, and should be fully refunded to North Star." *Id.*

(d) Cross Examination.

On cross-examination, Mr. Clements conceded that his analysis did not compare the "variability" of North Star's load to WAPA's other customers, because one would have to add North Star's load to all other loads in the control area to determine variability, and that exercise was not done because WAPA's cost structure data was never provided to North Star. *See* TR 322-26.

> GOVERNMENT'S COUNSEL: Now essentially, you did not look at the variability of the load upon the [WAPA] system, did you?
>
> MR. CLEMENTS–NORTH STAR'S EXPERT: No, and actually, I wouldn't have wanted to, because it's not my belief that this load was nonconforming or nonstandard to an extent that would have caused costs to be calculated in a manner based on their standard deviation, as opposed to standard practice, which is to charge upon the maximum integrated hourly demand for a period. So I wouldn't have been interested in making that calculation, even if you had given me the hour-to-minute load variations. . . .
>
> GOVERNMENT'S COUNSEL: . . . [P]lease restate what you said.
>
> MR. CLEMENTS–NORTH STAR'S EXPERT: . . . First, in order to make a calculation of the cost of regulation service, it's necessary to know the minute-to-minute standard deviation for the entire system. And then what FERC does is it takes that entire cost and it allocates it among the customers, based upon their maximum period scheduling demand. And all I'm saying is that North Star Steel deserved no other treatment than that.
>
> GOVERNMENT'S COUNSEL: But my question to you is not what FERC did. My question to you is what regulation costs were imposed upon the system by North Star Steel? And to determine what regulations were imposed upon the system by North Star Steel, would it not be helpful to know how much variation the addition of North Star Steel's load imposed upon that system?

MR. CLEMENTS–NORTH STAR'S EXPERT: To know the change in cost? Yes.

GOVERNMENT'S COUNSEL: And you did not do that analysis?

MR. CLEMENTS–NORTH STAR'S EXPERT: I didn't have the data.

GOVERNMENT'S COUNSEL: You also just testified a few minutes ago that in your belief system that would not be something that would be helpful, or am I mischaracterizing your testimony?

MR. CLEMENTS–NORTH STAR'S EXPERT: Yes, that's FERC policy, to assign regulation expenses to customers based on their maximum demand, not upon the standard deviation of the load. And we could talk about that for a long time.

GOVERNMENT'S COUNSEL: And right now, I'm not interested in FERC policy, I'm interested in what you did, okay? And it sounds like, and you'll correct me if I'm wrong, that what you're saying is that you would not have wanted to do that because your belief system was such that you match up with what FERC does, is that right?

MR. CLEMENTS–NORTH STAR'S EXPERT: Right.

TR 324-26.

Mr. Clements also agreed that if there was greater variability in WAPA's load due to North Star's load variability, it would lead to greater "wear and tear." *See* TR 329-31.

GOVERNMENT'S COUNSEL: If one wanted to figure out the costs, though, there'd be nothing wrong with taking . . . a look at how much variability the addition a particular customer added to a load[, even if FERC does not do it], isn't that true?

MR. CLEMENTS–NORTH STAR'S EXPERT: The particular variability that the customer added to the control area, probably. Yes, you could make that calculation, yes. . . .

GOVERNMENT'S COUNSEL: And greater variability, of course, leads to greater wear and tear?

MR. CLEMENTS–NORTH STAR'S EXPERT: Yes. . . .

GOVERNMENT'S COUNSEL: And despite the increased wear and tear, you still believe that North Star should not be charged more than any other customer?

MR. CLEMENTS–NORTH STAR'S EXPERT: Yes, that's true.

TR 329-31.

(3) July 2, 2004 Direct Testimony Of The Western Area Power Administration's Expert -- Dr. Douglas A. Gegax.

(a) Qualifications.

Dr. Douglas A. Gegax is currently a Professor of Economics at the New Mexico State University, where he has served in various academic positions since 1984. *See* DX 7, Ex. D. at 1. Prior to that time, he served from 1980-1984 as an Instructor of Economics and Research/Teaching Assistant at the University of Wyoming. *Id.* Dr. Gegax graduated from San Diego State University in 1980, obtaining a B.A., *summa cum laude*, in Economics and a Ph.D. in Economics in January 1985 from the University of Wyoming. *Id.* Since 1986, Dr. Gegax also served as Director for the Center for Public Utilities, which is affiliated with the College of Business Administration, and Economics. *Id.* at 2. In addition, Dr. Gegax has published articles, participated in the presentation of academic papers, made other public presentations, and proffered testimony concerning electricity deregulation and market power in the Southwest, and related costs. *Id.* at 3-4. Dr. Gegax also has served as a professional consultant on projects concerning cost-of-service price and the electric utility industry. *Id.* at 7.

(b) Expertise.

Dr. Gegax was profferred by WAPA as an expert in electrical power cost allocation, bundled and unbundled rate design, and electrical industry restructuring. *See* TR 719. The court accepted Dr. Gegax as an expert in the proffered areas.

(c) Opinion.[24]

Dr. Gegax's July 2, 2004 Direct Testimony advised the court that in light of the "non-standard characteristics" of North Star's electric arc furnaces "moment-to-moment demands for power loads, WAPA's estimated charges to North Star . . . to obtain regulation and frequency response services were within a reasonable cost-based range." DX 7 at 2. Dr. Gegax represented that the "market value" of the "In-Kind Energy" transferred to WAPA "equated the charges to [North Star] for regulation services" and criticized North Star for not disclosing what it *actually paid* to AEPCO for this energy. *Id.* (emphasis in original). Accordingly, Dr. Gegax used market value of the "In-Kind Energy," as the upper bound of the payment that North Star should make for WAPA's regulating services, and concluded that the estimated payments fell within a "reasonable cost-based range." *Id.* Accordingly, Dr. Gegax concluded that all of WAPA's proposals for determining such payments resulted from a "good faith" effort to establish an appropriate cost-based methodology, as required by Section 21 of the Consolidated Contract. *Id.*

---

[24] At trial, Dr. Gegax made several corrections and clarifications regarding certain calculations. *See* TR 720-24, 1246-48.

Dr. Gegax testified that "two main points . . . guide my analysis." *Id.* First, the "characteristics of an individual customer's load must be examined to determine the customer's *fair share* of the total regulation costs." *Id.* (emphasis added). Accordingly, Dr. Gegax concluded that "since [North Star's] load characteristics were non-standard . . . *based on* cost, [North Star's] regulation charges were not, and should not have been standard." *Id.* (emphasis in original). Second, since no new generation was built in response to North Star's operations, "*existing regulating capacity was used*[.]" *Id.* at 3 (emphasis in original). Accordingly, Dr. Gegax advised that the "comparison of how generation capacity was used shifted towards a greater share being used for regulation . . . as a result of adding [North Star] to the system." *Id.* Therefore, Dr. Gegax concluded that "additional regulation capacity was required . . . [and] with this capacity [there was] a "real significant cost." *Id.*; *see also* TR 769-70. For example, the "hourly scheduled non-firm energy paid for by [North Star] and delivered by AEPCO–of which WAPA received a portion for providing regulation service–did not have the characteristics required to regulate any load, let alone [North Star's]." DX 7 at 3.

Dr. Gegax characterized the OATT methodology of calculating costs associated with regulation and frequency response services as a benchmark, and then suggested the following alternative methodology to calculate "regulation capacity costs:"

> Step 1–Establish the per-unit costs of generation suited for regulation.
>
> Step 2–Establish an appropriate amount of required capacity, usually measured as a percentage of peak-load.
>
> Step 3–Multiply the first two [steps] in order to obtain "regulation capacity costs."

Id. at 12.

Dr. Gegax stated that Step 1 determines the per-unit cost of generation capacity, either as the cost of existing capacity, the installed cost of replacement capacity,[25] or the cost of purchasing capacity in the market, *i.e.*, a cost-based "as billed" rate component. *Id.* at 13. Step 2 establishes capacity costs associated with regulation services, *i.e.*, an appropriate amount of regulation capacity. *Id.* at 14. Dr. Gegax advised the court that the OATT currently measured this amount as a customer's peak load or average system moment-to-moment fluctuations in load or the standard deviation of the moment-to-moment loads. *Id.* at 14-15.

---

[25] Dr. Gegax explained that two cost methodologies are used to determine the cost of existing capacity: "embedded-cost studies" that look at historical installed cost and "marginal-cost studies," such as replacement costs. *Id.* at 13. When installed costs are determined, they are then spread over the useful life of an asset to determine an annualized capacity cost by two methods: rate-base rate of return or levelized carrying charge.

Dr. Gegax also testified that WAPA's actual rate for regulation and frequency response filed with FERC in 1999 establishes that the rate for a standard customer either as: 1) the market (replacement) rate plus 10% or 2) the capacity rate of the project supplying generation, if available. *Id.* at 15. Therefore, if North Star's load was "standard," then the rate should be based at a market replacement plus 10%. *See* PX 7 at 15; *see also id.* at 10-11 (explaining arc furnaces are "non-standard" loads).

In the alternative, to determine a "reasonable cost range" for WAPA regulating services, Dr. Gegax asked: "[W]hat would the [North Star] charges have been if they were currently FERC-accepted OATT of utilities[,] in proximity to WAPA[?]" and, if appropriate, what adjustments should be made for non-standard loads. DX 7 at 16 (emphasis omitted). To calculate that amount, Dr. Gegax used an average rate of a regulation and frequency response from three unidentified "neighboring" WAPA utilities–$7.25 per kW-month. This amount represents the generation capacity element in Step 1. *Id.* at 17. Of the utilities surveyed, Dr. Gegax determined that the percentage requirement applied to the customer's peak load averaged "just over 1%." *Id.* Dr. Gegax cautioned, however, that this percentage was for a standard customer. For a customer with a "non-standard moment-to-moment load variations significantly increases the system regulation standard deviation, [so] the customer . . . should be charged an additional fee since [t]his fundamental cost concept is consistent with [the] 'volatility factor' and 'excess regulation charges' that WAPA incorporated into their cost-based methodology proposals to [North Star] and to what was developed in the Amendment 3 of the [Consolidated Contract]." *Id.* at 18.

Next, Dr. Gegax selected one day in North Star's first year of operation, *i.e.*, September 24, 1997,[26] and determined that North Star had a one minute peak load of 86.08 MW and a standard deviation that equals 23.68 MW or 27.5% of North Star's peak load. *Id.*; *see also id.* at Ex. B at 13 (North Star Minute Loads-Wednesday, Sept. 24, 1997). Utilizing the OATT methodology, North Star's regulation capacity would be 27.5% or 23,680 KW. Then, multiplying the $7.25 per W month generation capacity element derived from the average rate of three undisclosed neighboring utilities, Dr. Gegax determined that North Star should pay WAPA $171,680 per month for "regulation and frequency response services," or approximately $2.1 million per year. *Id.* at 18-19. Dr. Gegax characterized $2.1 million annual payment to be an "upper-bound value," but one that also is "conservatively low" in that it did not take in account the magnitude of the servicing on WAPA's generation." *Id.* at 19; *see also id.* at 8-10 (discussing "market value" of "In-Kind Energy" to WAPA). Dr. Gegax contended that since WAPA would have to ramp generation in response to this swing, the annualized costs of regulation capacity, "fully attributable," should be based on North Star's maximum moment-to-moment swing, or 63,130 KW. *See* DX 7, Ex. B at 13. Under this scenario, North Star's annualized cost for regulation capacity would have been $5.5 million, or 63,130/kW X $7.25 per W month X 12, if based on September 24, 1997 data. *See* DX 7 at 19.

---

[26] *See* TR 752 (Ms. Clark, WAPA's Power Operations Specialist, suggested September 24, 1997 as the "representative day" utilized by Dr. Gegax.).

Dr. Gegax challenged Mr. Clements' statement that North Star did not "significantly alter" WAPA's moment-to-moment standard deviation because: the system was large enough to absorb North Star's load and North Star was small, compared to the total control-area load that would be offset in the event of North Star's "extreme load variations." *Id.* at 19. Dr. Gegax asserted that the total load comparisons "mask" the "true" amount of regulation required, *i.e.*, moment-to-moment standard deviations. *Id.* Even if the allowance was made for "average offsets," the addition of North Star's load, with "extreme swings" increased the system regulation "standard deviation." *Id.* In support, Dr. Gegax cited HIRST AND KIRLY (Dec. 1999) for the proposition that "typically the regulation standard deviation is 1.3% of total load." *Id.*

Dr. Gegax also suggested an alternative methodology by first determining that the Western Area Lower Colorado Control Area had an average monthly system peak of 1,700 MW, of which approximately 580 MW are attributed to WAPA's native or peak load, without North Star. *Id.* at 20; *see also id.* at 20 n.16; TR 1246. Applying the HIRST & KIRLY 1.3% standard deviation, regulation should be 7.5 MW. DX 7 at 20; corrected at TR 720-28. Assuming North Star's moment-to-moment load's standard deviation was 24 MW, when North Star added to the system the deviation increased to 25 MW. *Id.* The average level of regulation capacity attributed to North Star then is 7.5 MW, *i.e.*, the difference between 25 MW (North Star's standard deviation) and the 7.5 MW system regulation standard deviation. *Id.* Under this scenario, North Star would owe WAPA approximately $1.4 million per year for regulating and frequency response services or 17,500 KW X $7.25/per kW-month (average of their surrogate rates). *Id.* Dr. Gegax considered $1.4 million per year to be the "lower bound" of a "reasonable cost range." *Id.*[27] North Star's average annual fair share of regulation capacity would be "a value in between the upper bound (23,680 KW or $2.1 million) and the lower bound (17.5 KW or approximately $1.4 million)." *Id.* at 21. Dr. Gegax suggested that two further adjustments also should be made. First, the difference between these two value estimates "depends on what percent of the year North Star fell into each of these two scenarios." Second, based on a marginal analysis for one day, North Star's regulating service would be equal to 63 MW or an annual cost of approximately $5.5 million. *Id.* Therefore, Dr. Gegax estimated "[u]sing FERC-approved regulation rates for standard loads, North Star should be charged between $1.4 million to $2.1 million per year. *Id.*

Dr. Gegax observed that since the proposed annual regulation charge of $701,340 in Attachment H-2 was well below the $2.1 million upper boundary and less than the $1.4 million of the lower bound, *ipso facto*, WAPA negotiated in "good faith." *Id.* at 23. If North Star had selected the other option to pay WAPA $1.2 million annual for regulating services and that amount also fell

---

[27] *Compare* DX 7 at 19 n.14 (noting the Arizona Power Systems 1993 estimate that North Star regulating services would cost $1.3 million) *with* TR 197 (As Mr. Rein testified "The Hoover costs were never produced. The bottom line was . . . [WAPA] simply said that . . . wanted to have $1.5 million for the regulation services, and that's the bottom line. And so anything that [AEPCO] would suggest to try to come through there, mysteriously enough, the bottom line always came back at $1.5 million.").

within the $1.4 million to $2.1 million per year range, Dr. Gegax concluded that the $1.2 million amount also was reasonable. *Id.*

(4) July 27, 2004 Rebuttal Of North Star Steel Co.'s Expert -- R. Mark Clements To The Western Area Power Administration's Expert -- Dr. Gegax.

Mr. Clements' rebuttal included: (a) a critique of WAPA's expert Dr. Gegax; (b) a calculation of the price North Star paid for "In-Kind Energy" to WAPA; (c) a calculation of North Star's costs for regulating services; and (d) a comparison of costs incurred by North Star with WAPA's "capacity costs" for the Boulder Canyon and Parker-Davis projects, as filed with and approved by FERC. *See* PX 127 at 1.[28]

(a) Summary Critique Of Dr. Gegax's Report.[29]

Mr. Clements agreed with Dr. Gegax that three types of costs are relevant in determining the cost of regulating services: generation capacity costs; System Control and Data Acquisition ("SCADA") costs; and variable O&M costs, including fuel or water used or saved. *Id.* at 1-2 (citing DX 7 at 12); *see also* TR 316. Because WAPA did not provide any data in this case of SCADA or O&M costs, Mr. Clements attributed no value for these costs. *See* PX 127 at 2; *see also* TR 318-19. In addition, since AEPCO provided North Star with energy in an amount equal to North Star's maximum scheduled load, as a matter of physics, North Star "itself" provided the energy used by WAPA to provide regulation services for North Star. *Id.* at 2, 6-8. Mr. Clements also contested the validity of Dr. Gegax's conclusions, because they were not based on analyzing any of WAPA's "generating capacity costs, SCADA costs, or variable O&M costs," but relied only on so-called "market-based comparisons," in concluding that the "In-Kind Energy" payments North Star made to WAPA were "reasonable." *Id.* at 2.

Mr. Clements further challenged Dr. Gegax's conclusion that the energy provided by AEPCO to WAPA on behalf of North Star was not "equivalent" to generation capacity and could not provide regulating service. *Id.* Mr. Clements countered that "energy" is "energy." *Id.* at 2-4. Mr. Clements also took issue with Dr. Gegax's conclusion that the "In-Kind Energy" payments were reasonable because North Star's "non-standard" load imposed "non-standard" costs on WAPA and that the "range of market-based cost" to regulate North Star's maximum moment-to-moment swing was

---

[28] At trial, Mr. Clements testified that in preparing the Rebuttal Report, he relied on PX 107; PX 108; PX 109; PX 110; PX 111; PX 112; PX 113; PX 114. *See* TR 314. Mr. Clements also corrected several typographical errors in this Report. *See* TR 313-14.

[29] The court has attempted herein to state the highlights of Mr. Clements' critique of Dr. Gegax's Report as set forth in PX 127 at 1-5. Mr. Clements provided further detail and support for this critique in PX 127 at 5-20.

63.12 MW. *Id.* at 4. Mr. Clements argued that merely calling North Star's load "non-standard" or WAPA costs "non-standard" did not address the issue of what were WAPA's costs for serving a "non-standard" load. *Id.*; *see also* TR 333-35.

Finally, Mr. Clements found Dr. Gegax's Report to be deficient for not utilizing the 10% regulating services fee that WAPA filed with FERC as part of OATT. PX 127 at 4-5. Mr. Clements suggested that if the court rejected his argument that North Star owed WAPA no charge for regulating services, the court should view WAPA's OATT as a "reasonable" rate, because FERC does not permit regulating services to be based on special load qualities. *Id.* at 5 & n.11.

(b) Calculation Of Actual Costs For Regulating Services Provided To North Star Steel Co. For The Period July 1997–March 2003.

Mr. Clements advised the court that North Star's "costs" for regulating services, based on monthly data provided by AEPCO for the period July 1997 through March 2003, were:

1. Non-firm energy purchased by AEPCO for North Star;

2. Energy AEPCO might have generated for North Star;

3. Wheeling "expenses" paid to WAPA by AEPCO for North Star;

4. Penalty fees paid to WAPA for under-delivery of energy by AEPCO for North Star;

5. A "mark-up" fee AEPCO charged to North Star;

6. AEPCO's O&M expenses for generation;

7. AEPCO's generation start-up costs to supply energy to North Star; and

8. Any AEPCO wheeling expenses incurred by AEPCO for transmission services for North Star.

Id. at 21.

Mr. Clements then calculated the amount North Star overpaid for regulating services as:

1.	July 1, 1997 through June 30, 1998	$1,362,532
2.	July 1, 1998 through July 31, 1999	$1,952,594
3.	August 1, 1999 through September 30, 2000	$2,526,936
4.	October 1, 2000 through March 31, 2003	$ 751,972
Total From July 1, 1998 through March 31, 2003		$5,231,502
Total From July 1, 1997 through March 31, 2003		$6,534,034

Id.

(5) October 25, 2004 Direct Testimony Of The Court's Expert -- Dr. Barbara R. Barkovich.

(a) Qualifications.

Dr. Barkovich has a B.A. (highest honors) in Physics from the University of California at San Diego; a M.S. in Urban and Policy Sciences from the State University of New York at Stony Brook; and a Ph.D. in Energy and Resources from the University of California at Berkeley. *See* Court Ex. 1; *see also* TR 907. Dr. Barkovich's Ph.D. dissertation was on regulatory decision-making with emphasis on energy utility regulation. *See* Court Ex. 1 at 2. Dr. Barkovich has been a consultant in the energy regulatory area for over 19 years. *Id.* at 1. Her clients have included: private and public electric utilities; large industrial firms with substantial energy or reliability requirements; and independent power producers. *Id.* She has negotiated rate and service matters, including interruptible rates, with electric utilities and large industrial customers and developed electric industry restructuring proposals in California. *Id.* Dr. Barkovich has represented large consumers on the WEPEX Steering Committee and served as a Member of the Technical Advisory Exchange in California. *Id.* In addition, she has been a member of the California ISO Governing Board and currently is Chairman of the Board of Directors of the Reorganized California Power Exchange, responsible for implementing refunds arising from FERC's review of the 2000-2001 California Energy Crisis. *Id.* Dr. Barkovich also served eight years on the staff of the California Public Utilities Commission, where she became the Director of the Policy and Planning Division. *Id.* She has testified before state and federal regulatory agencies, legislative bodies, and has served as an expert witness regarding cost-of-service requirements, cost allocation, and rate design for electric utilities. *Id.*

(b) Expertise.

Pursuant to Fed. R. Ev. 706, Dr. Barkovich was retained by the parties as a court-appointed factual and technical witness on utility rate-making. *See North Star Steel Co.* v. *United States*, No. 00-238 (Fed. Cl. Sept. 29, 2004) (Order).

(c) Opinion.

Dr. Barkovich explained that, in the electric power business, ancillary services, such as regulation, are "provided by generation facilities to support the transmission system." *See* Court Ex. 2 at 7. Generation facilities, however, also supply electricity to customers. *Id.* Therefore, the kWh produced for regulating service is "essentially secondary" and generally should "net out over time." *Id.*

(i) Comparison Of Alternative Cost Models.

A "cost-of-service" model is one way "to *analyze the fixed and variable costs* associated with reserving a part of the capacity of the generating plant for [r]egulation and the incremental costs associated with moving it up and down to meet load." *Id.* (emphasis added); *see also* TR 962. Dr. Barkovich testified that "under a traditional cost-of-service contract, it is most likely that any revenues received by WAPA for sales of excess power from the [Consolidated Contract] in excess of its own costs of providing the service would have been credited back to AEPCO/NSS." Court Ex. 2 at 13. Since that did not occur, Dr. Barkovich concluded that the price for regulating services under the Consolidated Contract was not based on a cost-of-service model. *Id.*

An alternative to determine "fixed and variable costs" is a "competitive market" model. *Id.* In a "competitive market," there must be a "substitute for a cost of service analysis." *Id.* at 7; *see also* TR 962. Therefore, there must be a standardized service being sold, *e.g.*, capacity reserved for regulation for a fixed period of time in a location. *See* Court Ex. 2 at 7. Under these circumstances, the highest bid for an ancillary service will set the price for a time period. *Id.* If the market is not competitive, or the service being provided is not standardized, then a "competitive market" should not be utilized to determine costs. Dr. Barkovich advised the court that the price WAPA charged for regulation under the Consolidated Contract was not set competitively, because WAPA has not solicited another regulation customer since 1996 nor ascertained a price at which regulation otherwise could be purchased. *Id.* at 13.

A third alternative to determine "fixed and variable costs" is an "opportunity-cost pricing model," *i.e.*, where "one entity will sell a service to another at a price that reflects a higher price than the seller could otherwise have received for that service . . . [if] it had been sold competitively." *Id.* Dr. Barkovich cautioned, however, that "opportunity-cost pricing" is not easy to ascertain, because a legitimate sale under exact same terms and conditions must occur or be possible in order to measure the alternative "opportunity." *Id.* Dr. Barkovich did not ascertain "any opportunity cost issue here because WAPA had indicated that it did not have capacity to provide any firm service

elsewhere." *Id.* at 13. In fact, the "In-Kind Energy" WAPA received from North Star/AEPCO "did not reduce WAPA's ability to sell non-firm power elsewhere and probably increased it." *Id.*

(ii) The Western Area Power Administration's Regulating Services Were Not Provided To North Star Steel Co. On A "Cost-Of-Service" Basis.

Dr. Barkovich used WAPA's proposed April 30, 1998 rate schedule for "regulation and load following" to AEPCO/North Star as an example of what WAPA considered as a "cost-of-service" rate. *Id.* at 14-15. Dr. Barkovich explained, however, that WAPA assumed that North Star's "average percentage change in load is 32%, which is 10.67 times the three percentage bandwidth (*i.e.*, North Star's load variation was within 3%), [North Star] should pay more than ten times the tariffed Regulation charge for a fraction of the time (cited as 82%) that North Star exceeds a load variation of three percent. This results, on an annual basis, in an excess Regulation charge of roughly fifty times the standard Regulation charge for the 18% of the load whose deviations fall within the three percent bandwidth." *Id.* at 15. Therefore, Dr. Barkovich concluded that this rate was "not remotely cost-based." *Id.*

Dr. Barkovich observed that WAPA's workpapers for the OATT filing,[30] included a "weighted average calculation cost-based on the generating capacity used to provide Regulation and the associated revenue requirements of those facilities, divided by the control area 1 CP load."[31] *Id.* at 16. This resulted in a charge of $0.20/kW-month. *Id.* Multiplying that charge by a factor of over ten is "to say that [North Star] must pay ten times more than the revenue requirement for the portion of the capacity providing the Regulation. This makes no sense." *Id.* Noting that WAPA provided no cost-of-service analysis for any increased "wear and tear,"[32] Dr. Barkovich posited that using "a maximum figure of a ten percent increase in the revenue requirement associated with increased

---

[30] WAPA's OATT provided that if regulation could not be provided from generation capacity, it would be obtained at an "open market" price plus a 10 percent administration charge. *See* Court Ex. 2 at 11. WAPA's OATT also required transmission customers to pay a proportion of the capacity reserved for regulation. *Id.* at 12. Dr. Barkovich estimated that this amount was about 0.7%–1.5% between $4-$8 kW-month. *Id.*

[31] The term "1CP" refers to the demand of each customer on the day of highest coincident peak of the system during a year.

[32] Dr. Barkovich noted that even if there was excess "wear and tear" on WAPA's equipment and increased O&M, only a fraction of the equipment was covered, for which costs were recovered. *Id.* Instead, WAPA's regulating services charge to North Star was based on allocating the entire revenue requirement corresponding to the [portion of] generation (providing the regulation). *Id.* This allocation share was determined as the MW "devoted to Regulation divided by the total loads served by the Regulation." *Id.* at 15-16.

depreciation and O&M expense," would mean that North Star "would be charged an additional $.02/kW-month for 82% of its load, or $.22/kW-month." *Id.* This was only a "small fraction" of the amount imposed under WAPA's proposed April 30, 1998 methodology. *Id.*

Dr. Barkovich, however, agreed with WAPA that under a cost-of-service rate, North Star should pay for its share of the fixed and variable costs. *Id.* Dr. Barkovich also opined that the fixed costs of generation from Hoover Dam required that North Star should pay an amount larger than a standard tariff, because of the "non-standard" nature of North Star's load. *Id.* Dr. Barkovich expected, however, that this charge would only be a fraction of WAPA's revenue requirements for the generating units providing regulating service. *Id.* Although WAPA did not provide a "cost basis" in this case, Dr. Barkovich estimated that amount would be "no more than ten percent of the revenue requirement associated with the facilities providing the generation service." *Id.* Therefore, the increase of the cost of the revenue requirement providing for regulating services would be increased by a factor of 1.1. *Id.*

WAPA's FERC-filed Rate Order-84 for Parker-Davis and Boulder Canyon stated that the revenue requirement was $23.88/kW and 60 MW of the Desert Southwest Customer Service Region ("DSW") and Colorado River Storage Project (Post Consolidation) and was used to support a 582 MW load. *Id.* at 17. Based on this data, WAPA's regulation capacity represented 10.3% of the load, an amount that Dr. Barkovich observed was "high" compared to other control areas, which was closer to 1% of the load. *Id.* For example, if WAPA's fixed cost of generation was $23.88/kW multiplied by the cost of revenue requirement X .103 for incurred fuel costs X 1.1 for O&M expenses, the result would be $2.71/kW-year, or 0.226/kW-month. *Id.* This amount would then be multiplied by North Star's peak demand to determine the charge for regulation. *Id.*

Under the Consolidated Contract, North Star purchased and scheduled a block of non-firm energy at its hourly peak demand. *Id.* Since North Star's load typically was less than the energy available, this allowed WAPA to utilize or re-sell that excess energy. *Id.* From July 1, 1998 until July 1, 1999, North Star paid 20% for "In-Kind Energy," and thereafter at 10%, when the H-2 pricing proposal went into effect. The "In-Kind Energy" sent to WAPA allowed it to "back-off" generation making regulation available to the entire load, including meeting North Star's requirements. *Id.* Dr. Barkovich, however, noted that without this energy, no regulation would have been available for North Star. *Id.*

Dr. Barkovich advised that from a cost-of-service perspective, what North Star paid for "In-Kind Energy" was of lesser importance than the effect on WAPA's generation capacity. *Id.*

(iii) Dr. Barkovich's Initial "Cost-Of-Service" Calculations.

Dr. Barkovich recommended that North Star should pay a "non-standard, but cost-based rate" for regulation service. *Id.* Since WAPA did not have capacity to provide regulation, but for the "In-Kind Energy" payment, Dr. Barkovich made the following calculation of the amount of "In-Kind Energy" that North Star should have paid WAPA for regulation service. *Id.*

First, Dr. Barkovich utilized a 3% average of deviation load from schedule for WAPA's preference customers, set forth in WAPA's OATT Regulation and Frequency Response Ancillary Service. *Id.* at 19.

Second, WAPA's average total energy sales from the Boulder Canyon project (Hoover Dam) was determined to be 5.046 billion kWh for the period 2000 and 2001. *Id.* Dividing this amount by 8,760 hours per year yielded an average annual demand of 576 MW. *Id.*; *see also* TR 1043-44.[33]

Next, utilizing a 3% average deviation load, discussed above, Dr. Barkovich calculated that there was a 17.3 MW (17.46 MW) deviation for WAPA's system. *See* Court Ex. 2 at 19; *see also* TR 1037, 1043-44. From April 1998 through February 2000, North Star's deviation was 40 MW, within the first year. *Id.; see also* Table 1 (attached).[34] Stated differently, North Star's load was 2.3 times "more variable" (40 MW/17.3 MW) than WAPA's entire system load. *See* Court Ex. 2 at 19; *see also* TR 1039. For this reason, Dr. Barkovich concluded that North Star should pay for 2.3 times the tariffed cost of regulation "to support regulation [than] that . . . paid by standard customers." Court Ex. 2 at 19.[35]

Dr. Barkovich advised the court that most IOU OATTs-based regulation charges were approximately 1.5% of the customer maximum load, reflecting their system deviations. *Id.* WAPA, however, based its charges on a system load within a 3% deviation. *Id.* at 20. Therefore, since North Star's load deviation was 2.3 times the system load deviation, the percentage of the cost to serve a load with a 3% deviation, would be "the regulation charge times 6.9% of its maximum demand during the month." *Id.*;[36] *see also* TR 1033.

---

[33] At trial, Dr. Barkovich recalculated the average annual demand figure from 576 MW to 582 MW. *See* TR 1043-44.

[34] Dr. Barkovich did not believe that data derived during the "start-up period" of the first year of operations should be considered in determining an average deviation load because data from one day during this period would not be representative or "a good basis for drawing any conclusions." *See* Court Ex. 2 at 19 & n.6. Therefore, Dr. Barkovich "question[ed]" Dr. Gegax's use of load data, as of September 1997, shortly after the North Star plant came on line. *Id*.

[35] Dr. Barkovich agreed with Mr. Clements and Dr. Gegax, however, that calculating regulation should not be based on the generation revenue requirement, but on the annualized cost of the generating capacity, plus "necessary" AGC and SCADA equipment. *See* Court Ex. 2 at 19. For this reason, Dr. Barkovich used the revenue requirement-based figure developed by WAPA as a "proxy." *Id*.

[36] Dr. Barkovich calculated North Star's "maximum demand," in any given month, as 80 MW; therefore, its regulation requirement would be 5.52 MW. *See* Court Ex. 2 at 20.

Dr. Barkovich noted that Hoover Dam had an approximate capacity factor of 25%. *See* Court Ex. 2 at 25 (citing 2001 WAPA Statistical Appendix); *see also* TR 1059-60. Accordingly, "In-Kind Energy" was 5.52 MW X (0.25) X 720 hours/month = 994 MWh of capacity for regulation. *See* Court Ex. 2 at 20 (citing Table 2, *infra*).[37] Dr. Barkovich further noted that a "non-standard" regulation tariff should be added times North Star's maximum demand to the "In-Kind Energy" payment, because of the characteristics of North Star's load, *i.e.*,"[t]his non-standard regulation rate would be increased ten percent to generously approximate the higher cost associated with WAPA's allegation of increased wear and tear on its facilities." *Id*. at 20. Table 2 states the "sum of what [North Star] should have paid in "In-Kind Energy" plus the non-standard regulation charge on a monthly basis. *Id.*

Table 3 represented the difference between the cost of actual "In-Kind Energy" minus Returned Energy and the non-standard tariff rate, plus the "In-Kind Energy" payment, which yielded an amount of $3,872,729 due North Star for the period October 2000 to March 2003. *See* Court Ex. 2, Table 3 at 8.[38]

Dr. Barkovich explained, however, that:

> [D]espite the voluminous information presented to me by the parties, I have not received all of the data needed to fully perform the ordered calculations. I require a monthly accounting by the parties as to what energy, if any, was returned by WAPA under the [Consolidated Contract] to [North Star] and AEPCO.

Court Ex. 2 at 2; *see also id.* at 20; TR 908, 961-62, 968-69.

(6) November 16, 2004 Supplemental Report Of The Court's Expert -- Dr. Barbara R. Barkovich.

Prior to trial, Dr. Barkovich issued a Supplemental Report responding to the Direct Testimony of WAPA's expert, Dr. Gegax, that was not available at the time of her deposition. *See* Court Ex. 3 at 1. Dr. Gegax stated that "the market value of this [I]n-[K]ind [E]nergy transferred to WAPA has been equated to the charge to NSS for regulation service." DX 7 at 2. Dr. Barkovich responded that "only [WAPA . . . has never] attempted to associate 'market value' with the [I]n-[K]ind [E]nergy under the [Consolidated Contract.]" Court Ex. 3 ¶ 1 at 1. Dr. Barkovich also

---

[37] Dr. Gegax testified on rebuttal that "instead of using a 25 percent capacity factor across the entire time period in her analysis, [Dr. Barkovich] should have used capacity factors for each of the particular years." TR 1251; *see also* TR 1246-49.

[38] On November 17, 2004, Dr. Barkovich provided the court and parties with revised tables. *See* Court Ex. 2-A. Table 3 therein reported that the amount that should be refunded to North Star under a cost-based rate for the period October 2000 to March 2003 was $3,875,153. *Id.* at 11.

countered that there is no reason why market value should mark the upper bound of what North Star paid for "In-Kind Energy." *Id.* ¶ 2 at 1.

Dr. Gegax also advised the court that "one must examine the characteristics of an individual customer's load in order to determine that customer's fair share of the total regulation costs." DX 7 at 2. Dr. Barkovich agreed that this general statement was accurate, but qualified that "it is not true that a customer's load can be analyzed without reference to the overall load on the system." Court Ex. 3 ¶ 3 at 1.

In addition, Dr. Gegax stated that: "[r]egulation is the use of on-line generation capacity units[;] energy is not the same as generation capacity;" and regulation "is a function of capacity, not energy." *See* DX 7 at 12. As a result, regulation costs should be "based on the cost of capacity to provide regulation service, not the entire revenue requirement." *Id.* Dr. Barkovich observed that this is an issue about which there was agreement among all of the experts. *See* Court Ex. 3 ¶ 4 at 1-2.

Dr. Barkovich, however, disagreed with Dr. Gegax's statement "that cost-based methodology developed by WAPA took regulation costs for [North Star's] non-standard load and divided these costs by the market price for non-firm energy in order to obtain the in-kind percentage." *Id.* ¶ 5 at 2 (citing DX 7 at 9). First, Dr. Barkovich stated the obvious, *i.e.*, that WAPA provided "no information" as to the cost of using facilities to provide regulation service. *Id.* ¶ 6 at 2. Second, the system-wide tariff filed by WAPA with FERC in 1999 represented that regulating services would be made available at $0.20/kW-minute, based on "the revenue requirement associated with capacity used to provide that service." *Id.* Dr. Barkovich, however, disagreed that the "appropriate regulation rate" for North Star should be based on the replacement rate, since WAPA's cost of providing regulating services was not a market rate. *Id.* Although, "In-Kind Energy" freed up capacity at the Hoover Dam and enabled WAPA to use that capacity to provide regulating services to North Star, Dr. Barkovich was not satisfied with the manner in which WAPA assigned revenue requirement to capacity. *Id.*

Dr. Barkovich advised the court that it was entirely appropriate for WAPA to include relevant capacity costs in determining the terms for regulation, however, Dr. Gegax utilized capacity costs from other utilities that were not used to provide regulation services to North Star. *Id.* Therefore, Dr. Barkovich concluded that Dr. Gegax's $7.25/kW-month was "inappropriate," since WAPA used revenue requirement figures, not capacity costs, that include O & M. *Id.* Consequently, Dr. Gegax's $7.25/kW-month rate was not "conservatively low," particularly when compared to WAPA's filed tariff at $0.20/kW-month. *Id.*

In addition, Dr. Barkovich criticized Dr. Gegax's use of North Star's standard deviation on a minute-to-minute basis only for one day early in North Star's operation and only for North Star, rather than North Star's load in the context of WAPA's overall system load. *Id.* ¶ 7 at 2-3 (citing DX 7 at 2). Dr. Barkovich found Dr. Gegax's entire approach to be problematic because WAPA claimed that it had no minute-by-minute data and therefore no comparison could be made from actual variation in WAPA's system and North Star. *Id.* ¶ 8 at 3. Since WAPA's documents indicate

standard regulation was available for loads with a deviation of 3% , Dr. Barkovich challenged the relevancy of Dr. Gegax's use of a "typical standard deviation of 1.3% of the total load," which yielded an estimated "typical average level of regulation capacity of 22 MW." *Id.* ¶ 9 at 3. If Dr. Gegax had used 3%, the standard regulation service deviation reflected in WAPA's documents, it would have yielded a regulation capacity of 51 MW. *Id.*

At trial, Dr. Barkovich explained that using a variability analysis, as Dr. Gegax did, is relevant to determining "In-Kind Energy," but "doesn't correspond to anything in [WAPA's] tariff because [WAPA] never calculated a cost-of-service for regulation." TR 1005.

At trial, Dr. Gegax responded:

> DR. GEGAX: Conceptually I believe that Dr. Barkovich and myself were on the same page. I really do. I believe that what she–her two components in her measurement of cost, the second component that she had she was trying to get at the notion that because of North Star Steel there were -- there was additional regulation capacity that was required to regulate the WALC. Okay. And I agree with her on that. The other term she had was she also tried to measure the additional wear and tear on the generation capacity, due to the North Star Steel load.
>
> THE COURT: Without having any documentation at all --
>
> DR. GEGAX: That's right.
>
> THE COURT: -- that that --
>
> DR. GEGAX: And I applaud her for that effort. I did not attempt to do that. I think that's a legitimate cost and I -- because of the lack of data, I was not able to do that and she approached it I think in a very sound way. So we have these two components of cost, wear and tear on the equipment and additional capacity that's required because of the North Star Steel. Additional regulation capacity. The difference is that we got to that problem through two different routes and I think that's very reasonable. As Your Honor yourself said, that there is a -- this -- there's -- this is an art to a large degree in terms of rate making. You have a concept and there are many different routes you can take to get there. The route that she took to come up with that additional --
>
> THE COURT: Many legitimate routes?
>
> DR. GEGAX: Legitimate routes. Absolutely. The route that she took to capture the additional capacity and I really believe that the crux of this is the additional capacity. Those are significant costs. And then the route that she took to get to that additional capacity owed to North Star Steel -- additional regulation capacity was she took a --

the ratio of these loads to see how much more variable North Star Steel was as opposed to the WALC. She took that multiplier, multiplied it by the standard percentage, which was the three percent and then came up with the 6.9 percent and then multiplied that by North Star Steel's peak load to come up with what she felt was a good measure of how much additional capacity -- regulation capacity was required.

THE COURT: Your fault is relying on the peak?

DR. GEGAX: And the -- in doing that, taking that route at measuring that, in order to be consistent I would just argue that she might have wanted to look at using the average internal control area load that's --

THE COURT: Did she have enough data to do that?

DR. GEGAX: I'm not sure if she did or not, Your Honor.

THE COURT: Okay. Thank you.

DR. GEGAX: And whereas in my report, I took a little more direct routes. Again in a capacity cost part of her cost, she looked at the ratios of those loads to come up with a multiplier, used a multiplier times the standard percent of three percent, to come up with the 6.9 percent and those -- that was therefore a step to come up with in the end, which was very important the amount of additional regulation capacity that was required due to North Star Steel's load, given her calculations and assuming a peak load, because she did that month-to-month. That was another nice feature of her analysis also. She did that month-to-month and assuming an 80 megawatt load, then she came up with a number about five, five and a half megawatts that were attributable to North Star Steel. So in the end, it's that -- how much additional regulation capacity owed to North Star Steel. I just took a more direct route, but I had to impute the minute-to-minute variation for WALC, prior to North Star Steel. Again, because neither of us had access to those data. Those would be very valuable data to have in this proceeding.

THE COURT: Yes. Well there are probably many pieces of documents that would be valuable, but for whatever reasons, they don't exist or haven't been proffered or whatever. So here we are.

DR. GEGAX: I agree.

TR 1256-60.

(7) February 1, 2005 Post-Trial Additional Report Of The Court's Expert -- Dr. Barbara R. Barkovich.

At trial, Dr. Barkovich learned of additional information that she wished to consider. *See* TR 1260-62. After receiving that data, Dr. Barkovich submitted a Post-Trial Additional Report and Revised Tables on February 1, 2005. *See* Court Ex. 4. Therein, Dr. Barkovich accommodated WAPA's critique of her analysis of the deviation of North Star's load by making adjustments to compare deviation based on the 1 CP annual maximum demand of North Star and WAPA when compared to their respective average demands. *Id.* at 1. Dr. Barkovich also updated Hoover Dam capacity factors to reflect "yearly variations." *Id.* The results of this additional work appear in revised tables to reflect "an improvement in the cost of analysis . . . originally presented, although the dollar amount is not that large." *Id.*

Dr. Barkovich, however, continued to disagree with WAPA's proposal to substitute the 1997 Interim Rate of $.034/kW-month as the basis for the non-standard tariff, but agreed that North Star should have paid a "non-standard, but cost-based rate" for regulating services. *Id.* To make that determination, Dr. Barkovich first utilized the $23.88/kW-per year revenue requirement that WAPA reported in the 1998 OATT Data Sheet. *Id.*[39] WAPA's 1998 OATT Data Sheet also indicated that 60 MW of generation was used to provide regulation for a 582 MW control area load, *i.e.*, a 1 CP peak, the highest annual peak. *Id.*; *see also* TR 923. In this case, regulation capacity represented 10.3% of the maximum load, which Dr. Barkovich characterized as a "high percentage" of capacity for regulation than other control areas. *See* Court Ex. 4 at 2; *see also* TR 920-23 ("[F]or the purpose of acknowledging [WAPA's claim of] wear and tear [on the turbines], although it has not been quantified, I simply took a figure of 10 percent and added it on[.] . . . [T]he statement has been made by [WAPA] that there were incremental costs associated with the operation of the generation for the purpose of providing regulation for NSS. I indicated that . . . was not quantified, and indeed, what I have done is to basically develop what I think is a generous proxy for that extra wear and tear."); TR 923-24 (explanation of how 11% was calculated and substituted for a 10% "wear and tear" factor). To determine the cost of facilities used for generation, Dr. Barkovich multiplied: $23.88/kW-per year, WAPA's 1998 OATT "revenue requirement" times .103, the cost of "capacity for regulation" times a 1.1 factor for "wear and tear," claimed but not verified by WAPA, to yield an annual $2.71/kW or a monthly charge of $.226/kW. *See* Court Ex. 4 at 2; *see also* TR 924-35.[40]

---

[39] Dr. Barkovich declined to use WAPA's "short term" 1997 OATT, finding that the "data and their development [are] unclear and do not meet the test of being based on cost of service." Court Ex. 4 at 2. Dr. Barkovich observed there is "too much here that does not make sense." *Id.*

[40] At trial, however, WAPA's Assistant Regional Power Marketing Manager testified that he had never seen any data to verify "wear and tear:"

> NORTH STAR'S COUNSEL: Now, you expressed that there was a concern over wear and tear. What, if any, regime was put in place to determine or measure the

This charge was then multiplied by North Star's monthly peak demand to determine a cost-based methodology for the regulating services WAPA provided North Star. *Id.*

Dr. Barkovich also re-determined the amount of "In-Kind Energy" that North Star owed WAPA for regulating services. *Id.* at 3. First, the monthly maximum and average demand for 1997-2003 was utilized to determine the variability of this control area load by using a 1 CP methodology. *Id.* Next, three percent of the maximum annual demand was utilized, based on WAPA's representation in the standard tariff. *Id.* The result was compared to the variability of the North Star

---

> wear and tear that was to be experienced in connection with the services provided under the contract?
>
> MR. MONTOYA: The generators that we used to provide regulating service are owned and operated by the United States Bureau of Reclamation [("USBR")]. We had contacted the USBR . . . and told them what we were doing, discussed the issue of wear and tear, and asked them to provide incremental cost data for us. They were going to look into it, but I recall them saying that it would be difficult data to provide, because some of the concern was a long-term incremental effect and they were concerned about loss of life, which would be difficult to measure.
>
> NORTH STAR'S COUNSEL: Loss of life being in loss of life of the units?
>
> MR. MONTOYA: Loss of life of the units, lining of the tail races, the steel -- one of the issues that we were concerned with was when you use a hydrounit to perform a high percentage of regulation, it operates in an inefficient zone. They refer to it as the rough zone and there's a lot of water turbulence that goes through the entire hydrogenerating system and that creates something called cavitation, which is a pinpoint bubble that kind of eroded things.
>
> NORTH STAR'S COUNSEL: But apart from this concern, was anything done to actually attempt to measure that?
>
> MR. MONTOYA: I don't know. We contacted Reclamation. We talked to them about it later when we went to get the data. I don't recall ever seeing it.
>
> NORTH STAR'S COUNSEL: You don't recall ever having seen the data with respect to measurement of wear and tear on the generated units used to support generation?
>
> MR. MONTOYA: I don't recall seeing it.

TR 471-72.

load, calculated by subtracting "the average of the overage" North Star load each year from the 1 CP maximum North Star load for the corresponding year, resulting in a different ratio for each year, 1997–2003. *See* Court Ex. 4 (Revised Table 1). The maximum WAPA demand was presented in Table A-2 and ratios in Table A-3. *Id.* at 3-4. Then, the ratio was multiplied times three percent to obtain an annual "In-Kind Energy" Percentage applicable to North Star, presented in the fifth column of Table A-3. *Id.* In Revised Table 3, Dr. Barkovich presented the actual monthly charge provided by North Star to WAPA and the difference between the cost of "In-Kind Energy," minus Returned Energy, and the non-standard tariff rate. *Id.* at 4.

In Table A-1, Dr. Barkovich provided the average capacity factor of the Hoover Dam, since WAPA represented that facility was used for regulation. *Id.* At Revised Table 2, Dr. Barkovich calculated the number of kWh that North Star provided to free up capacity equivalent to North Star's "In-Kind Energy" factor in MW. *Id.* The sum of what North Star should have paid in "In-Kind Energy," plus a non-standard regulation charge on a monthly basis is also presented in Revised Table 2. *Id.* In Revised Table 3, the monthly amount of "In-Kind Energy" that actually was provided by North Star to WAPA under the Consolidated Contract is calculated and the difference between the cost of actual "In-Kind Energy," minus Returned Energy and the non-standard tariff rate plus correct "In-Kind Energy" payment yield the amount of refund due North Star. *Id.*

For the period July 1997 to June 1998, Dr. Barkovich advised the court that $407,181 was due to be refunded North Star under a cost-based rate; $1,005,205 for the period July 1998 to July 1999; $1,413,142 for the period August 1999 to September 30, 2000; and $108,484 for the period October 1, 2000 to March 17, 2003; or a total of $2,934,012 for the entire period that North Star was operational. *Id.* (Revised Table 3).

(8) February 15, 2005 Post-Trial Sur-Rebuttal Report Of North Star Steel Co.'s Expert -- R. Mark Clements.

On February 15, 2005, Mr. Clements filed a Sur-Rebuttal Report. *See* PX 202 at 1.[41]

---

[41] At trial, the court suggested that all expert rebuttal be submitted in writing after the transcripts were examined. *See* TR 1074-1085. The Government objected and demanded the opportunity to conduct rebuttal orally. *Id.* The court allowed the Government to proceed as requested. *Id.* After the Government concluded oral rebuttal, it changed position.

> THE COURT: The Court has indicated that in light of the rebuttal that was proffered today by the [G]overnment, including the attempt to introduce summary documents in evidence for which there was no backup in the record and documents which have been proffered to them, which was not provided to the Plaintiff so that they could properly cross-examine, the Court has not decided what to do with that examination. However, the Court is going to provide Dr. Barkovich an opportunity to respond to the specific critiques about her report. Dr. Barkovich has been given as much time as she needs. She indicates she will probably have her report done at the beginning, her response, at the beginning of the month of January. Now, the [G]overnment was given an opportunity to decide how they wished to conduct the rebuttal process and the Court suggested, indeed the Court encouraged, the use of rebuttal by the experts in written form, because they would have an opportunity to look at the transcript and an opportunity basically to reflect. The [G]overnment objected, I do believe the words were, strenuously yesterday to that procedure, because they felt it should be done orally. Now after having engaged in the exercise, the [G]overnment's lawyer has informed me that he objects to not having a second opportunity to conduct rebuttal now in writing. The Court is not inclined to allow any additional rebuttal from the [G]overnment. They had a choice about what they wanted to do. They chose it. They got precisely what they asked for. Dr. Barkovich will respond in writing and the Plaintiff's counsel will be given an opportunity to provide anything their expert needs to rebut in writing and it will be short. It's possible, after reading Dr. Barkovich's report, that they may not have anything to put in writing. That they are content with Dr. Barkovich's report. Her response. The [G]overnment now would like to make a formal I suppose objection for the record, which is fine with the Court.
>
> MR. PROUTY: Yes. Your Honor, the objection yesterday was based upon the idea that not only would orally be better, but it would provide cross-examination for both sides, because the proposed procedure before was that both experts would simultaneously submit written rebuttal reports with no opportunity for examination or --
>
> THE COURT: You proffered evidence from your folks basically on which the Plaintiff couldn't possibly cross-examine, because they testified about documents that are not in the record and in fact aren't here and aren't physically available in the

Therein, Mr. Clements concurred with the definition of "regulation" proffered by Dr. Gegax and Dr. Barkovich, *i.e.*, "the response by generating units under AGC control . . . necessary to supply the minute to minute fluctuations in the control area load." *Id.* In addition, Mr. Clements agreed that "WAPA supplied regulation service to meet the WALC control area minute to minute load fluctuations, that included North Star's load" and that the "cost components" of "supplying regulation" are: 1) "generation capacity," 2) "capital costs of AGC equipment at the generating station," and 3) "generation variable O&M expenses." *Id.*

Mr. Clements, however, disagreed with Dr. Gegax's rebuttal testimony and the February 1, 2005 Post-Trial Additional Report of Dr. Barkovich that WAPA incurred any generation capacity costs in serving North Star's load, because WAPA did not document capacity costs during discovery. *Id.* at 1-3. Mr. Clements stated there are three ways to incur capacity costs: 1) purchasing capacity; 2) reserving capacity for a customer's exclusive use; or 3) supplying capacity to serve customer load from generation. *Id.* at 2. Mr. Clements contended that there is no evidence in the record that

---

> city of Washington now. You really attempted to sandbag the Plaintiff's lawyer and you had your opportunity. You got what you wanted.
>
> MR. PROUTY: Nevertheless, Your Honor, we continue to object because what will happen as a result is that Plaintiff's expert will submit a report, which would not be subject to cross-examination.
>
> THE COURT: We don't know what they're going to do.
>
> MR. PROUTY: I assume we'll have the opportunity to present a report, which would not be subject to cross-examination or any probing whatsoever or rebuttal. Likewise from the Court's expert.
>
> THE COURT: Well, that could go on forever, couldn't it?
>
> MR. PROUTY: It could, Your Honor, but I think it probably suggested -- and of course when it's done orally through testimony, it narrows and narrows and narrows until it's completed. We'll not have the opportunity to do that in the Court's proposed methods.
>
> THE COURT: You asked for the way you wanted the rebuttal and you got it.
>
> MR. PROUTY: Your Honor, we asked for it to apply to both sides.
>
> THE COURT: You asked for what you wanted and you got it.

TR 1271-74.

WAPA purchased any capacity. *Id.* at 2 (citing TR 668). Mr. Clements also argued there is no evidence in the record that WAPA reserved capacity for North Star, since WAPA's capacity already was committed to other customers, which is why transmission service to North Star was non-firm. *Id.* (citing TR 160); *see also* PX 30 at 004701 (WAPA recognized "[T]here was a rather significant revenue potential for serving [North Star] on a non-firm and interruptible basis without direct cost or intrusion upon fully committed resources."). Likewise, Mr. Clements asserted that there is no evidence that WAPA served North Star from WAPA's generation facilities. *See* PX 202 at 2. In fact, the excess capacity for regulation was provided by AEPCO purchased power "92% of the time during peak periods." *Id.* WAPA did not increase generation output. *Id.* For that reason, WAPA was able to reduce generation MW output below native load 92% of the time since AEPCO's schedule matched North Star's five-minute load. *Id.* Accordingly, WAPA provided regulation from AEPCO's imported capacity. *Id.* Therefore, Mr. Clements continued to assert that at no time did WAPA increase capacity costs to provide regulation to North Star. *Id.* at 2-3.

Mr. Clements also argued that FERC required unbundled ancillary services, such as regulation, be based only on that portion of time that transmission generators increased output. *Id.* at 3 (citing, *e.g.*, *Entergy Servs., Inc.*, 109 FERC ¶ 61,095 (2004); *Allegheny Power Serv. Corp.*, 85 FERC ¶ 61, 275 (1998), *Ky. Utilities Co.*, 85 FERC ¶ 61, 274 (1998)). Mr. Clements argued that FERC precedent support his contention that WAPA incurred no capacity cost as a regulation expense, because no capacity cost is incurred by any utility that receives a block schedule of capacity that "exceeds the load 92 percent of the time and is equal to the load the other 8 percent of the time." *Id*. Therefore, Mr. Clements disagreed with Dr. Barkovich's conclusion that simply because WAPA provided regulating services that it was entitled to charge North Star for that service: WAPA "was not and is not entitled to charge for capacity costs under a cost of service standard." *Id.*

After hearing WAPA's witnesses at the November 15-19, 2004 trial, Mr. Clements apparently decided to investigate "new" allegations made at trial regarding the location and amount of Bureau of Reclamation capacity devoted to regulation. *Id.* at 3-4. Mr. Clements located a Bureau of Reclamation document, "A Method for Calculating Production Costs For Ancillary Generation Service," Bureau of Reclamation's Ancillary Services Team, presented Power Operations and Maintenance Workshop: Denver, Colorado (May 19-21, 1998). *See* PX 203. Therein, Mr. Clements learned that capacity costs were recognized as incurred, only when capacity is consumed and:

> *only increases in capacity–not decreases–produced costs* that should be charged to the customer:
>
> > The actual regulation signal will swing the unit loading above and below the calculated average capacity. . . . The capacity for regulation which swings the unit above the average capacity is one half of the total regulation. The regulation capacity reduces the amount of capacity available for spinning reserve. The reduction of the spinning reserve by regulation must be calculated in order to

> account fully for capacity utilization while the unit is operating. The capacity for regulation is the product of one half the percent regulation (expressed in decimal form) multiplied by the average capacity while on line.

PX 202 at 4 (citing PX 203 at 5) (emphasis in original). This additional information confirmed Mr. Clements' position that North Star's regulation never occurred in the peak period, "except for under schedule which are paid for by the Penalty Payment." *Id.* Instead, scheduled energy in excess of North Star's load was provided at no charge to WAPA and in an amount "so large" that the Return Energy exceeded the "In-Kind Energy" payment by a factor of 4 to 1. *Id.* (citing PX 204); *see also* PX 26 (WAPA referring to the excess energy from AEPCO/North Star as "dispositive of the spoils.").

Therefore, Mr. Clements concluded that the excess capacity AEPCO provided WAPA was costly for North Star in the end, because North Star paid both AEPCO and WAPA for the power providing regulating services. *See* PX 202 at 4. It was, however, profitable to WAPA since WAPA earned profits from "charging [North Star] for costs fully allocated to [other] customers." *Id.*

Mr. Clements then proceeded to analyze the methodology utilized by Dr. Barkovich to determine a "cost-based" price, *i.e.*, non-standard rate and capacity reserved at Hoover. *Id.* at 6. First, Dr. Barkovich determined the "non-standard rate" component by multiplying:

The cost of regulation service @	$23.88/kW-per year[42]
X (times) regulation capacity @	.103[43]
X (times) est. variable O&M expenses, because of variations in North Star's load	1.10[44]
	_____
	Sub-total
÷ (divided by) 12 months	_____
	NON-STANDARD RATE COMPONENT

Mr. Clements argued that the third element, *i.e.*, variable O&M expenses estimated at 1.10, . . . should be eliminated or reduced to .10, because both Dr. Gegax and Dr. Barkovich agree that a .10 "adder" appropriately captures the magnitude of variable O&M expenses and should not

[42] *See* Court Ex. 4 at 1; *see also* PX 202 at 6 (Eq. 1).

[43] *See* Court Ex. 4 at 1; *see also* PX 202 at 6 (Eq. 1).

[44] *See* TR 920, 923-24; *compare* PX 202 at 6 (Eq. 1) *with* PX 202 at 6 (Eq. 5).

include "capacity costs at both Hoover or Parker-Davis, because only Hoover is relevant and such "costs" were already were being paid to WAPA via 'In-Kind Energy.'" *Id.* at 7-8.

Second, Dr. Barkovich constructed a "cost-based" price was to capture capacity reserved at Hoover. For example, in the month of July 1977 that amount would be:

The annual "In-Kind Energy" % for North Star @	.1151[45]
X (times) North Star's monthly peak @	83.203 MW[46]
X (times) annual capacity factor at Hoover @	.261
X (times) hours in the month (July 1997) @	744
	_____
	Energy Per Month
X (times) North Star average cost per MWH	_____
	CAPACITY COSTS AT HOOVER COMPONENT

The total monthly costs that North Star owed WAPA was the sum of the Non-Standard Rate Component and the Capacity Costs at Hoover Component. *Id.* at 7.

Mr. Clements objected to the use of the second cost component, because "[North Star] has to free up Hoover capacity to create capacity for regulation. At first, this seems a logical proposition. However, when examined critically, the second component is not required at all." *Id.* at 8.

Mr. Clements conceded that WAPA incurred variable O&M costs and annualized costs of AGC equipment at the generating stations. Mr. Clements, however, calculated the amount that WAPA owes North Star as the cost of energy that North Star purchased for "In-Kind Energy" minus the sum of variable O&M and annualized cost of AGC equipment, or $6,465,588.65 for the period July 1997-March 2003. *Id.* at 11-12 (citing PX 205 at 1-3).

(9) November 7, 2005 Post-Trial Response Of The Court's Expert -- Dr. Barkovich To February 15, 2005 Post-Trial Sur-Rebuttal Report Of North Star Steel Co.'s Expert -- R. Mark Clements.

In the course of writing this Memorandum Opinion, the court realized that Dr. Barkovich was not provided with a copy of the February 15, 2005 Sur-Rebuttal Report of North Star's expert, R. Mark Clements. Accordingly, on September 30, 2005, the court issued an Order, requesting Dr. Barkovich's views. On November 7, 2005, Dr. Barkovich filed a Response, in which she did not contest Mr. Clements' assertion that AEPCO provided more energy to North Star than was required

---

[45] *See* Court Ex. 4 at 3; *see also* PX 202 at 7 (Eq. 3).

[46] *See* Court Ex. 4 at 3; *see also* PX 202 at 7 (Eq. 4).

by the Consolidated Contract, because of fluctuations in North Star's load. *See* Court Ex. 5 at 1. That fact, however, did not relieve North Star from paying WAPA for regulation capacity, but instead was relevant to whether North Star overpaid WAPA in "In-Kind Energy." *Id.* Dr. Barkovich observed "there are costs inherent in owning and operating [generation and transmission] . . . facilities. This is a separate matter from how [North Star] paid for the regulation service. The issue then is "whether . . . the payment made by [North Star] was appropriate compensation for the costs incurred by WAPA." *Id.* at 2.

* * *

In light of the fact that WAPA did not produce or introduce WAPA cost data to establish whether the regulating services provided to North Star, in fact, were "cost-based" and expert testimony confirmed that WAPA did not establish a rate for regulating services that was "cost-based" on July 1, 1998 or thereafter, the court has determined that there is substantial evidence in the record in this case that WAPA, in fact, breached the Consolidated Contract.

4. The Western Area Power Administration's Unilateral Imposition Of Amendment No. 3 On September 15, 1999 Was An Act Of "Economic Duress" And A Breach Of The Obligation To Negotiate In Good Faith.

It is well established that an implied covenant of good faith is inherent in all contracts. *See Bradley* v. *Chiron Corp*., 136 F.3d 1317, 1326 (Fed. Cir. 1998) (reaffirming that "implied covenants of good faith and fair dealing are limited to assuring compliance with express terms of the contract[.]") (citation omitted); *see also* RESTATEMENT § 205 ("Good faith performance . . . of a contract emphasizes faithfulness to an agreed common purpose and consistency with the justified expectations of the other party.").

The United States Court of Appeals for the Federal Circuit has held that the Government, like all contracting parties, is bound by the obligation of good faith and fair dealing. *See Centex Corp.* v. *United States,* 395 F.3d 1283, 1304 (Fed. Cir. 2005) (explaining that the covenant of good faith and fair dealing "applies to the government just as it does to private parties"). As a matter of law, however, the Government enjoys a presumption of good faith in contractual dealings requiring a private party to prove by "clear and convincing" evidence that the Government acted otherwise. *See Am-Pro Protective Agency, Inc*. v. *United States*, 281 F.3d 1234, 1240 (Fed. Cir. 2002). Where such allegations are raised, the court looks for evidence of misconduct or specific intent to injure the plaintiff, such as economic duress. The United States Court of Appeals for the Federal Circuit requires that a party asserting economic duress[47] establish that: "(1) [the party alleging duress]

[47] Duress is a well-recognized ground for avoidance of a contract. *See* RESTATEMENT § 7 at 20; *see also id*. § 7 at 20, cmt. b. A contract is voidable for duress "[i]f a party's manifestation of assent is induced by an improper threat of the other party that leaves the victim *no reasonable alternative*[.]" RESTATEMENT § 175(1) at 475 (emphasis added).

involuntarily accepted [another party's] terms, (2) [the] circumstances permitted no other alternative, and (3) such circumstances were the result of [another party's] coercive actions." *Rumsfeld* v. *Freedom NY, Inc*., 329 F.3d 1320, 1329 (Fed. Cir. 2003); *see also Sys. Tech. Assocs. Inc.* v. *United States*, 699 F.2d 1383, 1387-88 (Fed. Cir. 1983) ("the coercive nature of the act [is] dispositive of its 'wrongfulness.' The standard now looks more closely at the defeat of the will of the party coerced. *An act* that the Government is empowered to undertake under law, regulation, or contract *may nonetheless support a claim of duress if the act violates notions of fair dealing* by virtue of its coercive effect.") (emphasis added). In *Rumsfeld*, the United States Court of Appeals for the Federal Circuit further required that "government coercion must have been the cause of the contractor's agreement." *Rumsfeld*, 329 F.3d at 1329. Therefore, coercion requires a showing that the Government's action was wrongful, *i.e.*, "(1) illegal, (2) a breach of an express provision of the contract without a good-faith belief that the action was permissible under the contract, or (3) a breach of the implied covenant of good faith and fair dealing." *Id.* at 1330.

a. North Star Steel Co. "Involuntarily Accepted" Amendment No. 3.

Applying the first *Rumsfeld* test, there is clear and convincing evidence in this record that North Star "involuntarily accepted" Amendment No. 3 on September 15, 1999. *See* PX 10; PX 68 at 00576; PX 69 at DA207; DX 9 at 9; *see also* TR 82, 89-91, 126, 129-32, 251-54, 487-88, 531-34.

b. The "Circumstances Permitted" North Star Steel Co. "No Other Alternative," Than To Accept Amendment No. 3.

Second, there also is clear and convincing evidence in this record that the "circumstances permitted [North Star] no other alternative" than to accept the unilateral imposition of Amendment No. 3. *Rumsfeld*, 329 F.3d at 1329. The negotiations surrounding Amendment No. 3 were not conducted at arms length between two parties with equal bargaining power. WAPA owned and controlled the sole transmission line to North Star, without which North Star could not receive electric power and operate. *See* DX 9 at 3; *see also* TR 30. In addition, no other regional utilities offered regulation services at that time that met WAPA's technical requirements. *See* TR 140; *see also* Court Ex. 2 at 13. Moreover, North Star had incurred approximately $5 million of embedded costs from building a switching station for WAPA. *See* TR 132-33. Another factor making it difficult for North Star to switch to an alternative provider for regulating services was the necessity of having a reliable source of power. As Mr. Sarafolean, North Star's former Financial Manager, Cost Accounting Manager, and Energy Specialist, testified, WAPA "is a reliable entity . . . electric agreements like this aren't something you change every time somebody shows up with a lower price." TR 132; *see also* TR 486, 668. Finally, central to the court's determination that the circumstances permitted North Star with no alternative, but to accept Amendment No. 3, is the fact that WAPA did not produce or introduce WAPA cost data to establish whether the regulating services provided to North Star, in fact, were "cost-based." *See, e.g.,* TR 322-23, 619-20, 624-25, 1256-60; *see also supra* note 20 and accompanying text.

c. Amendment No. 3 Was Not "Cost-Based."

As previously discussed, the parties' experts and the court-appointed expert provided clear and convincing, indeed substantial evidence, at trial and subsequent filings that Amendment No. 3 was not "cost-based." *See, e.g.,* Court Ex. 2, 3, 4, 5.

* * *

For these reasons, the court has determined that the record in this case evidences that WAPA's unilateral imposition of Amendment No. 3 on North Star on September 15, 1999 was an act of "economic duress" and a breach of the obligation to negotiate in good faith.

D. North Star Steel Co. Is Entitled To Damages In The Amount Of $1,521,626.

North Star paid WAPA the voluntarily negotiated "first year" rate set forth in the Consolidated Contract until August 1, 1999, the effective date of Amendment No. 3. *See* DX 9 at 10. Therefore, no injury occurred until August 1, 1999. For the period August 1, 1999 until North Star ceased operations, North Star is entitled to damages in the amount of $1,521,626. *See* Court Ex. 4 (Table 3 Revised).

* * *

Dr. Barkovich's Initial Report advised the court that a "cost-based price," and inherently the elements thereof, are not easily defined "in the abstract . . . . [t]here is no perfect way to do this." *See* Court Ex. 2 at 6; *see also* TR 975. Both North Star's and WAPA's experts concurred. *See* TR 337 (North Star's expert conceded that there is more than one way of calculating an appropriate cost-based methodology, depending on the "data available."); *see also* TR 1256-60 (WAPA's expert stated that rate-making "is an art to a large degree[.] . . . You have a concept and there are many different routes you can take to get there.").

The court has attempted to take a "route," with the guidance of Dr. Barkovich,[48] to achieve a result that, while not perfect, achieves a measure of justice for the injury North Star incurred as a result of WAPA's breach of the Consolidated Contract and breach of the obligation to negotiate in good faith.

---

[48] The court acknowledges the critical contribution of the American Association for the Advancement of Science (http://www.aaas.org) in helping the court and parties identify Dr. Barkovich and providing source materials on the proper use of court-appointed experts. A special note of appreciation is due Dr. Mark S. Frankel, Project Director, and Ms. Deborah Runkle, Project Manager, for their assistance to the court in this case and continuing support of the judiciary and work with the Federal Judicial Center.

CONCLUSION

For the reasons discussed herein, North Star is awarded $1,521,626. The Clerk of the Court is hereby ordered to enter judgment in accordance with this Memorandum Opinion and Final Order.

IT IS SO ORDERED.

_____
SUSAN G. BRADEN
Judge