BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF COLORADO 2003 JU

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IN THE MATTER OF THE APPLICATION OF PUBLIC SERVICE COMPANY OF COLORADO FOR AN ORDER APPROVING EXPENSES INCURRED FOR THE PERIOD JANUARY 2001 THROUGH DECEMBER 2001 THAT ARE RECOVERED THROUGH THE INCENTIVE COST ADJUSTMENT	)	DOCKET NO. 02A-541E

Exhibit No. 18
Appl. No. 02A-541E
Witness
Date 7/21/03

STIPULATION AND SETTLEMENT AGREEMENT

Public Service Company of Colorado ("Public Service" or the "Company"), the Colorado Office of Consumer Counsel ("OCC"), the Colorado Energy Consumers ("CEC") and the Staff of the Public Utilities Commission ("Staff"), (collectively, the "Parties"), hereby enter into this Stipulation and Settlement Agreement ("Stipulation") with respect to all issues disputed in this Docket.

Public Service filed the Direct Testimony of Mr. Stoffel and Mr. Wolaver, setting forth the Company's calculation of the 2001 ICA-recoverable costs and the 2001 ICA Deferred Cost Balance (Exhibit DAW-2). Answer Testimony and Exhibits were filed by four Staff witnesses: Ms. Pederson, Mr. Shiao, Ms. Podein, and Mr. Dominguez. Answer Testimony and Exhibits were also filed by CEC witness Ms. Iverson. The OCC filed no testimony. Public Service filed Rebuttal Testimony and Exhibits of seven witnesses: Mr. Eves, Mr. Haeger, Mr. Gonzales, Mr. Imbler, Mr. Keyser, Mr. Anderson and Mr. Wolaver. The Company conceded certain errors in its 2001 ICA-recoverable cost calculation and set forth the results of these concessions in Exhibit DAW-4. After the filing of its Rebuttal Testimony, the Company determined that certain minor corrections would be necessary to both Exhibits DAW-2 and DAW-4. These two exhibits have been corrected and are denominated in the record as Revised Exhibit DAW-2 and Revised Exhibit DAW-4.

As support for this Stipulation, the Parties agree that all pre-filed Testimony and Exhibits, as corrected, should be admitted into the record without cross examination. The Parties further agree that a full discussion of the disputed issues in the various testimonies need not be set forth in this Stipulation and that the corrected pre-filed testimonies and exhibits speak for themselves. In lieu of cross-examination and briefing of the issues raised by the pre-filed testimony and exhibits, the Parties respectfully request that the Commission accept this Stipulation as full settlement of all disputed issues.

This Stipulation addresses the resolution of the issues raised by each witness.

1. <u>Issues raised by Ms. Pederson</u>

A. Updating of Electric System Loss Analysis. An analysis of the Company's average energy losses on the four sections of the Company's delivery system (transmission, distribution substations, primary distribution, and secondary distribution) was last completed in January 1996. The 1996 Electric System Loss Analysis was based on electric system data for the calendar year 1994. Ms. Pederson requested that the Company update this study before the Company filed Phase 2 of its electric rate case and thereafter every three years. Company rebuttal witness Mr. Keyser objected to the time frames requested by Ms. Pederson for the updating of this analysis and to the need for a triennial study.

In resolution of this issue, the Parties agree that the Company shall complete an updated Electric System Loss Analysis by December 2004. The Parties further agree that the Company shall complete another Electric System Loss Analysis by December 2009. After the results of the 2009 study are reviewed, the Parties will each reassess the appropriate interval for conducting further Electric System Loss Analyses.

B. Accounting issues raised by Ms. Pederson. Ms. Pederson also raised a number of accounting and reporting issues, which are summarized in Recommendations 2-7 on page 31 of her Answer Testimony. Company rebuttal witness Mr. Anderson agreed to Ms. Pederson's Recommendation No. 5 to add account numbers to the Company's STES trading activity report beginning the month following the ruling in this ICA docket. The Company objected to the other five recommendations of Ms. Pederson, explaining that there was overlap between Ms. Pederson's accounting recommendations in this docket and the Settlement Agreement reached in the Company's general rate case, Docket No. 02S-315EG (the "Rate Case Settlement Agreement").

Staff agrees that the remaining accounting concerns expressed by Ms. Pederson in her Answer Testimony have been adequately resolved on a going forward basis by the Rate Case Settlement Agreement. The Rate Case Settlement Agreement has been approved by the Commission, with modifications, by Decision No. C03-0670 (June 26, 2003).

2. <u>Issues raised by Mr. Shiao</u>

A. Concern that $67.7 million of reported ICA costs were costs of short-term sales and not costs incurred to serve native load. Mr. Shiao recommended in his Answer Testimony that $67.7 million of Company purchased power expense should be considered to be a cost of the Company's short-term sales and not a cost that should be allocated to native load customers. Mr. Shiao acknowledged in this Answer Testimony that his recommended $67.7 million disallowance may have already been included in the Company's Short Term Sales Cost credit on line 21 of Exhibit DAW-4. Mr. Shiao indicated that he would adjust his recommendation if the Company provided data and justification why the additional credit proposed by Staff would be duplicative. The Company responded to Mr. Shiao's recommended disallowance of native load cost through the Rebuttal Testimony of Mr. Anderson.

Upon review of the Company's Rebuttal Testimony and the responses given to Staff discovery on the Company's Rebuttal Testimony, Staff now agrees that the $67.7 million of concern to Mr. Shiao is already included in line 21 of Exhibit DAW-4 and is already allocated to short-term sales in the Company's exhibits. Consequently, Mr. Shiao withdraws his request for an additional $67.7 million credit with respect to short-term sales cost.

Further, Staff agrees that for all 2001 costs that this Stipulation states should be allocated to short-term sales instead of to native load customers, such cost shifts would be reflected on Exhibits DAW-2, DAW-4 and LYS-2 and LYS-9 (all of which are spreadsheets calculating 2001 ICA Recoverable and Deferred Cost) both as an increase to Short Term Sales Cost (line 21) and as a decrease to Gross Trading Sales Margin (line 39). Several other line items on these spread sheets would be mathematically adjusted by these changes to lines 21 and 39. For clarification, Revised Exhibit DAW-4 is attached as Attachment 1.

B. Reports generated by the Company with respect to short term sales.

Mr. Shiao raised several concerns about the difficulty Staff encountered in auditing the Company's costs incurred for off-system short-term sales. Staff agrees that some of these concerns are addressed by the Rate Case Settlement Agreement. However, other concerns raised by Mr. Shiao were not specifically addressed in the Rate Case Settlement Agreement. To settle Mr. Shiao's issues, the Company agrees to the following tasks in addition to the tasks in the Rate Case Settlement Agreement:

1. Public Service agrees to provide, at the time it submits all future ICA and ECA applications, internal trade data for each month in a format similar to the information provided by Mr. Anderson in this Docket as his work papers 37-46. A sample of this format, for the month of April 2001, is attached as Attachment 2.

2. Public Service agrees to conduct an accounting workshop for Staff and the other parties to this Docket prior to September 30, 2003 to explain how it records all transmission-related costs that are recovered through the ICA and will be recovered through the ECA. Public Service agrees to work with Staff in developing the agenda for the workshop.

3. Public Service agrees to provide, at the time it submits future ICA applications, a breakdown of the Short-Term Sales Cost (that were totaled as a credit on line 21 of Revised Exhibit DAW-4) in the same format as Mr. Anderson's Exhibit CEA-3. For clarification, Exhibit CEA-3 is attached as Attachment 3.

4. Public Service agrees to provide to Staff, upon request, hourly short-term generation book purchase data in an electronic format. This data will include the hourly short-term generation book purchases used to serve native load. Public Service further agrees to provide, upon request, the hourly cost calculator reports in their current form in an electronic format and allow Staff and a Public Service analyst to work together to generate reports from the cost calculator in any manner the cost calculator is capable. Staff will need to designate the time period for the requested data. Staff will need to perform its own analyses with respect to the data contained within the requested reports. The Company reserves the right to change software programs and database reporting structures in the future and these changes may create different report formats. The Company will notify the Staff of such changes within 60 days of implementation. The Company will assure that the reports discussed in this paragraph can still be provided to Staff in a form that is compatible with industry standard analysis tools such as the Microsoft Excel spreadsheet. Staff acknowledges that hourly cost information is highly confidential information. Staff members reviewing this information will sign non-disclosure agreements and agree to protect this information in accord with the Commission's rules protecting Confidential Information.

3. <u>Issues raised by Ms. Podein</u>

Inaccurate heat rate curves for Fort St. Vrain. Ms. Podein filed Answer Testimony and Exhibits addressing the heat rate curves that were used by the Company in 2001 in its Cost Calculator to assign incremental fuel cost of Fort St. Vrain

("FSV") to short-term sales. Public Service witnesses Eves, Gonzales and Imbler filed Rebuttal Testimony and Exhibits to Ms. Podein's contentions. Public Service acknowledges that Ms. Podein is correct that during 2001 the Company's Cost Calculator failed to closely capture the actual operation of Fort St. Vrain. Public Service also acknowledges that the inaccuracies in the heat rates in the 2001 Cost Calculator model may have adversely affected the Company's native load customers in some hours.

Public Service further acknowledges the importance of ensuring that the heat rate curves included in the Cost Calculator are regularly updated to reflect the actual operation at Fort St. Vrain and other plants. While Public Service does not necessarily agree with the remaining arguments raised by Ms. Podein in her Answer Testimony, the Company agrees with Staff that, given the records and FSV data available during 2001, this issue is difficult to quantify with precision and therefore should be settled. Public Service and Staff agree to settle the issue by allocating $808,782 away from native load to short-term sales. This will have the effect of increasing the Short-term Sales Cost credit by $808,782 (line 21 of Revised Exhibit DAW-4), reducing by $808,782 the Total Actual Energy Cost for 2001 (line 24 of Revised Exhibit DAW-4), and also reducing the Gross Trading Sales Margin (line 39 of Revised Exhibit DAW-4) by $808,782. The Parties agree this adjustment is a reasonable resolution and compromise of the issues raised by Ms. Podein in her Answer Testimony.

As Company witness Mr. Stoffel testified, under the Settlement Agreement approved by Commission Decision No. C02-609 (May 24, 2002) in Docket No. 02A-158E (the "2002 ICA Stipulation") (Exhibit FCS-1), any changes to the 2001 ICA-recoverable costs resulting from this Docket No. 02A-541E will be reflected in customer rates in April 1, 2004.

4. Issues raised by Mr. Dominguez

Mr. Dominguez raised concerns about fuel reporting and the amount of gas hedges for which the Company contracted in 2001. Mr. Dominguez requested that $37.3 million of 2001 gas hedging cost be allocated away from native load customers and instead be allocated to 2001 short term sales.

Staff agrees that Mr. Dominguez's concerns with respect to fuel reporting are addressed by the provisions in the Rate Case Settlement Agreement. Staff agrees that Mr. Dominguez's concerns with respect to gas hedging costs are addressed by the settlement of the gas hedging cost issue discussed below in connection with the issues raised by Ms. Iverson.

5. Issues raised by Ms. Iverson

A. **Improper recovery of capacity payments.** Ms. Iverson testified that Public Service improperly recovered through the 2001 ICA capacity payments made to Otter Tail Power Company. She also claimed the electric hedge payments made by the Company in July 2001 to cover the delay in the commercial operation of the Fountain Valley units were capacity payments that should be excluded from the ICA. In a transaction approved by the Commission in the Company's 1999 Integrated Resource Plan, the Fountain Valley facility was constructed by an independent power producer and the output is being sold to Public Service under a power purchase agreement.

In Rebuttal, the Company agreed with Ms. Iverson that it had improperly booked capacity payments to Otter Tail Power as energy payments. The Company adjusted its ICA-recoverable costs to reflect this error in Exhibit DAW-4.

However, Company witness Eves filed Rebuttal Testimony and Exhibits contesting the adjustments requested by Ms. Iverson for the Fountain Valley electric hedges. Mr. Eves explained that these electric hedges were in the form of contracts for energy, not capacity, and that as such these payments were fully recoverable as "all-in-one" energy purchases through the ICA under the Stipulation and Agreement approved by the Commission in Docket No. 99A-557E in Decision No. R00-830 (August 1, 2000) (the "2000 Trading Stipulation") (Exhibit DLE-5). Mr. Eves also testified that the Company recovered delay damages from Fountain Valley for the failure to meet contractual commercial operation dates and that these delay damages were credited back to customers through the ICA.

The Parties agree that the cost incurred for this particular replacement power purchase for the delay in the commercial operation of Fountain Valley was an unusual occurrence, that the Company realized benefits of avoiding some capacity payments to Fountain Valley, and that an adjustment to the 2001 ICA-recoverable costs is warranted. By agreeing to this adjustment for Fountain Valley, Public Service is not agreeing that other all-in-one energy payments should be excluded in whole or in part from the ICA. Further, Public Service is not agreeing that future replacement power costs should be treated in a manner inconsistent with the 2000 Trading Stipulation. However, Public Service acknowledges that it may not recover capacity costs through the ICA mechanism. The Parties acknowledge that the 2000 Trading Stipulation remains in full force and effect and is not amended in any way by this Stipulation in Docket No. 02A-541E.

With respect to the Fountain Valley replacement power electric hedge, the Parties agree that the following adjustments should be made to the 2001 ICA:

1. Based upon the capacity payment that would have been made to Fountain Valley during July 2001, and the capacity factor of the replacement power purchased due to the delay in the in-service date, Public Service agrees to remove $688,500 from purchased energy on Revised Exhibit DAW-4, line 17 and re-state this amount as a purchased capacity expense. Public Service agrees that purchased capacity is not an ICA-recoverable cost.

2. Public Service agrees to allocate to short-term sales cost $188,585 more than reflected on the Company's books for the Fountain Valley energy that was supplied to Public Service in July 2001 and used to supply short term sales. This reallocation increases the 2001 short-term sales cost credit on Revised Exhibit DAW-4, line 21 by $188,585 and reduces the Gross Trading Sales Margin (Revised Exhibit DAW-4, line 39) by the same amount. This additional incremental cost to sales better reflects the hedged cost of the Fountain Valley energy supplied to short-term sales during July 2001.

These two reductions to the 2001 ICA-recoverable costs automatically reduce the 2002 ICA Base Cost. Again, pursuant to the 2002 ICA Stipulation, these changes to the 2001 ICA-recoverable costs will be reflected in retail rates on April 1, 2004.

B. Concerns about purchases made to serve native load for January through March 2001. Ms. Iverson testified that the Company was unable to supply her with information relative to purchases for native load for the months of January through March of 2001, before the implementation by the Company of the Altra system and the Cost Calculator in April 2001. Ms. Iverson offered an extrapolation of this value based upon relationships between native load costs and total purchases power costs from the nine months of April through December 2001. The Company disputed Ms. Iverson's extrapolation through the Rebuttal Testimonies of Mr. Imbler and Mr. Anderson.

In settlement of this issue, CEC agrees that Ms. Iverson has been provided the opportunity to review the available Company records on this matter and that for the purposes of settlement CEC no longer requires the adjustment set forth in Ms. Iverson's testimony and exhibits.

C. December 2001 payment to Pacificorp. Ms. Iverson argued that a $197,515 entry for payment to Pacificorp in December 2001 was subsequently reversed but that the Company failed to remove this amount from its 2001 ICA-recoverable costs. The Company agreed with Ms. Iverson that this cost should be removed from the 2001 ICA-recoverable costs. The effect of this removal was set forth in Revised Exhibit DAW-4. The Parties agree that this payment is a cost that the Company booked in 2002.

D. Gas hedging expense. Both Ms. Iverson and Mr. Dominguez argued that the Company's 2001 gas hedging expense was not properly recoverable through the ICA without prior Commission approval of a gas hedging plan. Company witness Mr. Haeger testified in rebuttal that the volatility in the fall 2000 and spring 2001 gas commodity market demanded that Public Service fix the price of gas through both physical and financial hedges to avoid exposure to the unusually large gas price volatility and the risk of having to pay even higher gas prices. Mr. Haeger testified that prior Commission approval was not required to enter into gas hedging agreements and that the Commission had indicated a reluctance to pre-approve gas hedging plans for the Company's gas department.

Ms. Iverson and Mr. Dominguez both argued that even if gas hedging expenses were not disallowed for the 2001 ICA, that an adjustment should be made for the 2002 ICA Base Cost due to the anomaly of the level of 2001 gas hedging expense. Company witnesses filed Rebuttal Testimony arguing that there was no evidence of imprudence on the part of the Company in contracting for the 2001 gas hedges and that under the Merger Stipulation Public Service was entitled to include these costs in the calculation of the 2002 ICA Base Cost.

In order to avoid disrupting the Merger Stipulation, the Parties agree to resolve this issue by an agreed prospective modification to the Price Volatility Mitigation ("PVM") factor in the 2004 Electric Commodity Adjustment ("ECA") that will take effect on January 1, 2004 in accord with the Rate Case Settlement Agreement. This will result in an adjustment to retail rates three months earlier than will occur for the other adjustments that are discussed in this Stipulation.

This issue shall be resolved as follows:

1. The Parties agree that the Company will make no adjustment to 2001 ICA-recoverable costs to disallow any gas hedging expense. The 2002 ICA Base Cost shall not be adjusted as a result of the gas hedging issues raised in this Docket.

2. The Parties agree not to argue any issue with respect to the recoverability of prudently-incurred gas hedging expenses through the 2002 ICA. The Parties also agree that in the prudence review of the 2002 ICA, consistent with the procedures approved by the Commission at page 64 of the Rate Case Settlement Agreement relating to gas hedging plans, Public Service will:

a. Separately identify its financial gas hedging costs booked to FERC Account Numbers 501, 547 and 555. The Company will also identify physical hedging costs in the aggregate by month.

b. Provide with its Application a Price Volatility Mitigation Report for 2002 that contains the following information: the volume of gas hedged; the timing of the hedges; a description of the types of hedging instruments that the Company used in implementing its 2002 hedging plan; and a discussion of the Company's 2002 hedging strategy. For each hedge transaction, the Company shall also provide the following information: contract date; counter party; transaction number; strike month; contract volume; contract price; settlement amount; NYMEX natural gas contract price for the month of delivery at the time of entering into the hedge; basis at the time of entering into the hedge; and relevant remarks/exceptions.

3. The Company agrees to a one-time prospective revenue adjustment for hedging costs that would be a part of the PVM factor in the 2004 Electric Commodity Adjustment Clause ("ECA"). The adjustment to prospective 2004

retail rates shall be a 30.62% reduction to the maximum annual hedging level in the Rate Case Settlement Agreement.

6. **<u>Issue raised by the OCC during settlement negotiations</u>**

Recently, Public Service affiliate e prime inc. fired certain gas traders for code of conduct violations associated with information provided to national industry trade publications with respect to gas trades they conducted. At this time, it is not known whether the conduct of these employees had any impact on gas prices paid by Public Service in 2001. The Company agrees that nothing in this Stipulation shall preclude any Party from later seeking a remedy for retail customers if retail customers suffered an adverse impact through the rates paid in 2001 as a result of the conduct of the e prime traders. Within two weeks of the completion of any investigation of this matter by any government agency, Public Service agrees to advise the Commission and the OCC of the results, so long as the information is public information.

7. **<u>Impact of this Stipulation</u>**

Attached as Attachment 4 is Exhibit DAW-5, which reflects the impact of this Stipulation on 2001 ICA-recoverable costs and the 2001 ICA Deferred Balance. Attached as Attachment 5 is Exhibit DAW-6 which reflects the impact of this Stipulation on the 2002 ICA-recoverable costs. Attached as Attachment 6 is a Summary that sets forth the impact of this Stipulation on both the Company's ICA and ECA. According to the 2002 ICA Stipulation, both the changes to the 2001 ICA-recoverable costs and the 2002 ICA-recoverable costs resulting from this Stipulation will be reflected in the rates filed by the Company in March 2004 to take effect April 1, 2004. The changes to the ECA will be reflected in rates filed by the Company in December 2003 to take effect

January 1, 2004. Except as provided by this Stipulation in Docket No. 02A-541E, the Parties are not waiving their rights to challenge the 2002 ICA-recoverable costs in a subsequent review action.

GENERAL TERMS AND CONDITIONS

This Stipulation reflects compromise and settlement of all issues raised or that could have been raised in this Docket. This Stipulation shall be filed as soon as possible with the Commission for Commission approval.

This Stipulation shall not become effective until the issuance of a final Commission Order approving the Stipulation, which Order does not contain any modification of the terms and conditions of this Stipulation, which is unacceptable to any of the Parties. In the event the Commission modifies this Stipulation in a manner unacceptable to any Party, that Party shall have the right to withdraw from this Stipulation and proceed to hearing on the issues that may be appropriately raised by that Party in this docket. The withdrawing Party shall notify the Commission and the Parties to this Agreement by e-mail within three business days of the Commission modification that the Party is withdrawing from the Stipulation and that the Party is ready to proceed to hearing; the e-mail notice shall designate the precise issue or issues on which the Party desires to proceed to hearing (the "Hearing Notice"). The withdrawal of a Party shall not automatically terminate this Stipulation as to the withdrawing Party or any other Party. However, within three business days of the date of the Hearing Notice from the first withdrawing Party, all Parties shall confer to arrive at a comprehensive list of issues that shall proceed to hearing and a list of issues that remain settled as a result of the first Party's withdrawal from this Stipulation. Within five business days of the date of the Hearing Notice, the Parties shall file with the Commission a formal notice containing the list of issues that shall proceed to hearing and those issues that remain settled. The Parties who proceed to hearing shall have and be entitled to exercise all rights with respect to the issues that are heard that they would have had in the absence of this Stipulation.

Hearing shall be scheduled on all of the issues designated in the formal notice filed with the Commission as soon as practicable. In the event that this Stipulation is not approved, or is approved with conditions that are unacceptable to any Party who subsequently withdraws, the negotiations or discussions undertaken in conjunction with the Stipulation shall not be admissible into evidence in this or any other proceeding, except as may be necessary in any proceeding to enforce this Stipulation.

Approval by the Commission of this Stipulation shall constitute a determination that the Stipulation represents a just, equitable and reasonable resolution of all issues that were or could have been contested among the Parties in this proceeding. The Parties to this Stipulation state that reaching agreement in this docket as set forth in this Stipulation by means of a negotiated settlement is in the public interest and that the results of the compromises and settlements reflected by this Stipulation are just, reasonable and in the public interest.

This Stipulation may be executed in counterparts, all of which when taken together shall constitute the entire agreement with respect to the issues addressed by this Stipulation.

Dated this 10th day of July, 2003.

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Attachment 1

EXHIBIT DAW-4
REVISED

ic Service Company of Colorado
Recoverable and Deferred Cost

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	January 01	February 01	March 01	April 01	May 01	June 01	July 01	August 01	September 01	October 01	November 01	December 01		
m Production Fuel Cost														
l 501-10	15,055,541.20	13,666,030.70	13,702,056.40	13,063,353.26	14,804,561.50	14,790,778.67	15,797,002.25	16,763,215.36	13,754,647.09	11,934,269.66	14,699,572.24	15,147,470.69	173,179,379.02	
s 501-20	546,330.98	(620,267.93)	1,504,077.83	1,968,064.03	1,614,659.37	2,759,092.03	2,913,212.63	2,677,492.56	3,581,845.91	5,889,610.73	2,946,578.41	1,807,729.01	27,588,445.56	
501-30	247.69	2,648.88	35.28	16.77	16,153.00	13,494.27	6,435.76	-	-	-	-	-	39,031.65	
s RTP Sales Cost	(85,857.93)	(87,187.56)	(3,286.66)	(6,190.55)	(4,039.02)	(1,871.03)	(3,285.52)	(4,468.57)	(1,533.76)	(1,386.50)	(1,747.49)	(4,991.01)	(205,845.60)	
ubtotal	15,516,261.94	12,961,224.09	15,202,882.85	15,025,263.51	16,431,334.85	17,561,493.94	18,714,245.12	19,436,239.35	17,334,959.24	17,822,493.89	17,644,403.16	16,950,208.69	200,601,010.63	
bustion Turbine Fuel Cost														
s 547-10	4,150,906.66	3,141,638.05	2,551,204.21	2,535,903.72	1,708,182.84	1,278,834.34	1,454,680.07	1,382,188.92	389,816.42	214,711.46	330,842.66	568,357.17	19,707,266.52	
547-20	15,693.75	103,217.92	7,064.01	51,281.10	7,349.97	72,072.99	10,843.12	133.52	-	-	4,067.28	6,834.68	278,558.34	
/ Gas 547-50	13,814,262.70	9,619,141.38	7,418,195.27	10,425,666.41	10,445,064.67	13,385,979.60	12,995,439.64	11,310,074.12	12,410,987.39	7,837,005.84	9,560,000.24	11,654,558.00	130,878,375.26	
s Denver Water Board Sales Cost	(56,863.75)	(49,042.51)	(21,703.19)	(20,736.61)	(28,738.81)	(53,865.89)	(67,414.17)	(50,068.40)	(52,732.03)	(42,330.72)	(61,203.65)	(61,492.59)	(568,282.32)	
ubtotal	17,923,999.36	12,814,954.84	9,954,760.30	12,992,114.62	12,131,858.67	14,683,021.04	14,393,548.68	12,842,328.16	12,748,071.78	8,009,386.58	9,833,818.53	12,168,257.28	150,205,917.80	
hased Energy Cost														
555-11	26,837,753.78	27,742,513.86	30,645,038.71	24,249,734.79	22,472,426.85	18,961,849.97	19,935,742.13	12,815,991.15	18,232,059.89	13,475,187.00	9,042,474.24	16,061,326.83	241,372,089.29	
ss: Otter Tail		(107,400.00)	(107,400.00)	(107,400.00)	(107,400.00)								(429,600.00)	
ss: PacifiCorp												(197,515.00)	(197,515.00)	
: Basin Contract 7900572633	(1,026,420.00)	(1,056,540.00)	(969,840.00)	(1,086,660.00)	(1,228,800.00)	(1,086,660.00)	32,130.00	(1,551,421.50)	(669,864.60)	(405,531.00)	(438,005.40)	(380,940.00)	(9,868,552.50)	
nomy 555-20	87,281,102.75	97,816,191.23	128,791,081.04	167,494,255.46	192,171,661.83	140,850,226.63	151,364,269.11	153,367,016.28	136,975,164.74	74,274,919.07	90,169,416.93	128,966,949.28	1,549,522,254.35	
l Facil 555-31	2,232,025.15	3,817,210.29	2,549,016.93	2,861,634.15	4,917,976.85	5,578,688.91	4,262,765.21	4,862,233.39	4,203,408.59	3,596,207.02	2,820,348.92	2,425,404.88	44,126,920.29	
chg 555-40	-	-	-	-	-	-	-	-	-	-	-	-	-	
eling 565-35	151,092.53	175,804.82	175,730.09	173,818.12	61,379.11	175,950.80	181,685.17	153,563.09	137,217.52	125,361.27	116,606.18	150,919.11	1,779,207.81	
Short-term Sales Cost	(105,908,473.00)	(111,617,967.00)	(137,656,953.00)	(172,877,697.00)	(203,320,283.00)	(141,387,699.00)	(135,038,980.00)	(150,461,315.00)	(137,745,431.00)	(77,976,395.00)	(89,919,529.00)	(132,402,648.00)	(1,596,313,370.00)	
otal	9,567,081.21	16,769,813.20	23,426,673.77	20,707,685.52	14,966,961.64	23,092,357.31	40,737,611.62	19,186,067.41	21,132,555.14	13,089,748.45	11,791,391.87	15,523,497.10	229,991,444.24	
Actual Energy Cost	43,007,342.51	42,545,992.13	48,584,316.92	48,725,063.65	43,530,155.16	55,336,872.29	73,845,405.40	51,264,634.92	51,215,586.16	38,921,828.92	39,269,411.56	44,641,963.05	580,888,372.67	
Allocator - Chged 3/2001	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823218	0.823216	0.823216	0.823216		
l Actual Energy Cost	35,404,332.00	35,024,541.00	39,995,387.00	40,111,252.00	35,834,720.00	45,554,199.00	60,790,719.00	42,201,868.00	42,161,490.00	32,040,908.00	32,327,208.00	36,749,978.00	478,196,602.00	
age Actual Energy Cost	0.01587	0.01674	0.01941	0.02076	0.01883	0.02300	0.02725	0.01802	0.01884	0.01569	0.01635	0.01694	0.01898	
Energy Sales KWH (Proforma)	2,230,744,740	2,092,031,615	2,060,125,691	1,931,921,518	1,902,834,559	1,980,797,742	2,230,624,492	2,342,346,343	2,237,634,632	2,042,094,019	1,976,932,974	2,168,818,933	25,196,907,258	
se Unit Cost - $/kWh	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	
l Base Energy Cost	28,508,918.00	26,736,164.00	26,328,406.00	24,689,957.00	24,318,226.00	25,314,595.00	28,507,381.00	29,935,186.00	28,596,971.00	26,097,962.00	25,265,203.00	27,717,506.00	322,016,474.76	
Excess Energy Cost (Actual less Base)	6,895,414.00	8,288,377.00	13,666,981.00	15,421,295.00	11,516,494.00	20,239,604.00	32,283,338.00	12,266,682.00	13,564,519.00	5,942,946.00	7,082,005.00	9,032,472.00	156,180,127.24	
Recoverable through ICA	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	
erable Energy Cost	3,447,707.00	4,144,189.00	6,833,491.00	7,710,648.00	5,758,247.00	10,119,802.00	16,141,669.00	6,133,341.00	6,782,260.00	2,971,473.00	3,531,003.00	4,516,236.00	78,090,063.62	
0% of RTP Sales Margin @ 82.3216%	(6,148.94)	(8,519.09)	3,443.99	(4,983.49)	(5,521.33)	(1,282.17)	1,674.50	(1,150.81)	(225.73)	(616.84)	(377.63)	(161.38)	(23,868.91)	
ading Sales Margin	(37,171,035.00)	(41,705,115.00)	(48,693,832.00)	(32,228,756.00)	(36,111,320.00)	(10,110,129.00)	(8,065,138.00)	(10,433,745.00)	(8,534,478.00)	(10,286,033.00)	(9,556,048.00)	(6,714,546.00)	(259,612,075.00)	
Premiums Sold & Purchased	-	(936,672.73)	513,000.00	(1,135,000.00)	(1,213,000.00)	(2,156,672.00)	(1,226,973.00)	103,527.00	(203,553.00)	(1,422,086.00)	(659,006.00)	(1,506,503.34)	(9,842,939.07)	
lary Sales Trading Margin JOA	7,885,148.11	8,803,260.14	5,780,013.05	7,343,553.85	7,090,540.59	1,011,365.68	(1,431,020.01)	223,727.92	300,149.51	1,431,149.66	222,839.65	4,803,207.01	43,463,995.98	
Gross Sharing of Trading Margins fc	(29,285,886.89)	(33,838,527.59)	(42,400,818.95)	(26,021,202.15)	(30,233,779.41)	(11,255,435.32)	(10,723,131.01)	(10,106,490.08)	(8,437,911.49)	(10,276,969.34)	(9,993,114.45)	(3,417,751.43)	(225,991,018.09)	
: 50% of Trading Sales Margin @ 82.3216%	(12,054,305.33)	(13,920,208.66)	(17,452,516.29)	(10,710,534.97)	(12,444,465.48)	(4,632,827.22)	(4,413,726.51)	(4,159,912.17)	(3,473,111.87)	(4,230,082.79)	(4,113,245.05)	(1,406,773.83)	(93,019,710.07)	
terruptible Fuel Cost & Econ Interrupt Credit														
ergy Cost Recoverable through ICA	(8,612,747.27)	(9,792,538.75)	(10,615,581.30)	(3,004,870.47)	(6,691,739.80)	5,485,692.61	11,729,616.99	1,972,278.03	3,308,922.40	(1,259,226.64)	(582,620.48)	3,109,300.80	(14,929,647.35)	
ICA Deferred Cost Balance	(7,865,999.06)	(13,963,077.58)	(21,371,756.60)	(31,739,746.23)	(32,674,485.55)	(37,660,853.96)	(15,165,918.61)	(1,449,906.00)	2,606,893.05	7,907,473.48	8,466,190.76	9,642,670.08	(133,268,518.22)	
Cost Recoverable through ICA	(8,612,747.27)	(9,792,538.75)	(10,615,581.30)	(3,004,870.47)	(6,691,739.80)	5,485,692.61	11,729,616.99	1,972,278.03	3,308,922.40	(1,259,226.64)	(582,620.48)	3,109,300.80	(14,953,513.89)	
ly ICA Deferred Cost Adjustment	2,515,660.75	2,383,859.73	2,349,514.94	2,070,131.15	1,705,371.39	1,768,948.74	1,986,395.62	2,084,521.02	1,991,658.03	1,817,943.92	1,759,099.80	1,973,011.85	24,406,924.94	
enue from ICA Rider Report												(123,192.00)		NSP Sharing
nth adjustment							-	-						
prior test period			(2,101,923.27)	-	-	15,240,294.00			-	-	-	-		
A Deferred Cost Balance	(13,963,077.58)	(21,371,756.60)	(31,739,746.23)	(32,674,485.55)	(37,660,853.96)	(15,165,918.61)	(1,449,906.00)	2,606,893.05	7,907,473.48	8,466,190.76	9,642,670.08	14,602,590.73		GL Year End

Attachment 2

MonthYear	04/2001
ScheduledWithCompanyName	PSCO (XCEL Marketer)

Sum of SumOfPrice	ScheduledProvisionTypeName		
ScheduledProvisionName	Sale	Grand Total	
From Gen (for Prop) (PSCO Book Transfers Sale)	$4,390,654	$4,390,654	$4,390,654
From Prop (for Gen) (PSCO Book Transfers Sale)	$929,662	$929,662	$939,287
From Prop (for Gen) (R/T PSCO Book Transfers Sale)	$9,625	$9,625	
From Prop (for Prop) (PSCO Book Transfers Sale)	$4,067,700	$4,067,700	$4,067,700
Losses (OAT-Gen Sale)	$0	$0	
Losses (OAT-Prop Sale)	$0	$0	
Grand Total	$9,397,641	$9,397,641	

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bit CEA-3
2001

No.	Cost Type	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01
	Generation Fuel Costs	$ 2,921,714	$ 2,637,335	$ 2,939,895	$ 1,706,843	$ 1,278,363	$ 1,567,933	$ 1,223,433	$ 1,178,821
	Long-Term PPA & Tolling Agreements Costs				$ 7,326,103	$ 3,012,418	$ 1,000,179	$ 1,281,079	$ 1,284,430
	Hourly Short-term Purchases for Resale Costs				$ 13,602,087	$ 8,340,992	$ 1,508,705	$ 1,806,154	$ 966,267
	Sub-Total Shadow Purchases	**$ 16,189,396**	**$ 14,610,600**	**$ 15,715,648**	**$ 20,928,190**	**$ 11,353,410**	**$ 2,508,884**	**$ 3,087,233**	**$ 2,250,696**
	Gen Book Prescheduled Short-term Energy Purchases for Resale Costs	$ 10,365,061	$ 18,734,005	$ 17,102,503	$ 16,467,976	$ 20,072,092	$ 27,557,405	$ 35,362,808	$ 38,652,330
	Sub-Total Gen Book Short-term Energy Cost	**$ 29,476,171**	**$ 35,981,940**	**$ 35,758,046**	**$ 39,103,009**	**$ 32,703,865**	**$ 31,634,222**	**$ 39,673,475**	**$ 42,081,847**
	Prop Book Short-term Energy Costs	$ 76,432,303	$ 75,636,027	$ 101,898,907	$ 133,774,688	$ 170,616,418	$ 109,753,476	$ 95,365,505	$ 108,379,468
	Total Costs	$105,908,474	$ 111,617,967	$ 137,656,953	$ 172,877,697	$ 203,320,283	$ 141,387,698	$ 135,038,980	$ 150,461,315
	Short-term Sales Cost (DAW-2 Line 21)	$105,908,475	$ 111,617,968	$ 137,656,955	$ 172,877,697	$ 203,320,284	$ 141,387,698	$ 135,038,980	$ 150,461,314

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r 2001

e No.	Cost Type	Sep-01	Oct-01	Nov-01	Dec-01	Total
1	**Generation Fuel Costs**	$ 581,276	$ 597,282	$ 383,139	$ 352,014	**$ 17,368,048**
2						
3	Long-Term PPA & Tolling Agreements Costs	$ 841,003	$ 1,967,980	$ 1,357,841	$ 1,144,269	
	Hourly Short-term Purchases for Resale Costs	$ 987,849	$ 2,184,029	$ 778,831	$ 1,145,678	
	Sub-Total Shadow Purchases	**$ 1,828,852**	**$ 4,152,009**	**$ 2,136,671**	**$ 2,289,946**	**$ 97,051,535**
	Gen Book Prescheduled Short-term Energy Purchases for Resale Costs	$ 33,753,988	$ 9,433,054	$ 9,945,530	$ 8,896,024	
	Sub-Total Gen Book Short-term Energy Cost	**$ 36,164,116**	**$ 14,182,344**	**$12,465,340**	**$ 11,537,984**	**$ 360,762,359**
	Prop Book Short-term Energy Costs	$ 101,581,314	$ 63,794,051	$77,454,188	$120,864,663	$1,235,551,008
	Total Costs	$ 137,745,430	$ 77,976,395	$89,919,528	$132,402,647	$1,596,313,367
	Short-term Sales Cost (DAW-2 Line 21)	$ 137,745,431	$ 77,976,394	$89,919,527	$132,402,648	$1,596,313,371

	January 01	February 01	March 01	April 01	May 01	June 01	July 01	August 01	September 01	October 01	November 01	December 01	Total
eam Production Fuel Cost													
Coal 501-10	15,055,541.20	13,666,030.70	13,702,056.40	13,063,353.26	14,604,561.50	14,790,778.67	15,797,882.25	16,763,215.36	13,754,647.09	11,934,269.66	14,699,572.24	15,147,470.69	173,179,379.02
Gas 501-20	546,330.98	(620,267.93)	1,504,077.63	1,968,084.03	1,614,659.37	2,759,092.03	2,913,212.63	2,677,492.56	3,581,645.91	5,889,610.73	2,946,578.41	1,807,729.01	27,588,445.56
Oil 501-30	247.69	2,640.00	35.28	16.77	16,153.00	13,494.27	6,435.76	-	-	-	-	-	39,031.65
Less RTP Sales Cost	(85,857.93)	(87,187.56)	(3,286.66)	(6,190.55)	(4,039.02)	(1,871.03)	(3,285.52)	(4,468.57)	(1,533.76)	(1,386.50)	(1,747.49)	(4,991.01)	(205,845.60)
Subtotal	15,516,261.94	12,961,224.09	15,202,882.85	15,025,263.51	18,431,334.85	17,561,493.94	18,714,245.12	19,436,239.35	17,334,959.24	17,822,493.89	17,644,403.16	16,950,208.69	200,601,010.63
ombustion Turbine Fuel Cost													
Gas 547-10	4,150,906.66	3,141,638.05	2,551,204.21	2,535,903.72	1,708,182.84	1,278,834.34	1,454,680.07	1,382,168.92	389,816.42	214,711.46	330,842.66	568,357.17	19,707,266.52
Oil 547-20	15,693.75	103,217.92	7,064.01	51,281.10	7,349.97	72,072.99	10,843.12	133.52	-	-	4,067.28	6,834.60	278,558.34
FSV Gas 547-50	13,814,262.70	9,619,141.38	7,418,195.27	10,425,666.41	10,445,064.67	13,385,979.60	12,995,439.64	11,310,074.12	12,410,987.39	7,837,005.84	9,560,000.24	11,654,558.00	130,876,375.26
Less Denver Water Board Sales Cost	(56,863.75)	(49,042.51)	(21,703.19)	(20,736.61)	(28,738.81)	(53,865.89)	(67,414.17)	(50,069.40)	(52,732.03)	(42,330.72)	(61,293.65)	(61,492.59)	(566,282.32)
Subtotal	17,923,999.36	12,814,954.84	9,954,760.30	12,992,114.62	12,131,858.67	14,683,021.04	14,393,548.66	12,642,328.16	12,748,071.78	8,009,386.58	9,833,616.53	12,168,257.26	150,295,917.80
rchased Energy Cost													
Firm 555-11	26,037,753.78	27,742,513.86	30,645,038.71	24,249,734.79	22,472,426.85	10,961,849.97	10,935,742.13	12,815,991.15	18,232,059.89	13,475,107.00	9,042,474.24	16,061,326.83	241,372,099.29
Less: Otter Tail		(107,400.00)	(107,400.00)	(107,400.00)	(107,400.00)								(429,600.00)
Less: PacifiCorp												(197,515.00)	(197,515.00)
Less: Basin Contract 7900572633	(1,026,420.00)	(1,056,540.00)	(969,840.00)	(1,086,660.00)	(1,228,800.00)	(1,086,660.00)	32,130.00	(1,551,421.50)	(669,864.60)	(405,531.00)	(438,005.40)	(380,940.00)	(9,868,552.50)
Economy 555-20	87,281,102.75	97,816,191.23	128,791,081.04	167,494,255.46	192,171,661.83	140,850,226.63	151,364,269.11	153,367,016.28	136,975,164.74	74,274,919.07	90,169,416.93	128,966,949.28	1,549,522,254.35
Less: Fountain Valley Capacity Cost							(688,500.00)						(688,500.00)
ual Facil 555-31	2,232,025.15	3,817,210.29	2,549,016.93	2,861,634.15	4,917,976.85	5,578,688.91	4,262,765.21	4,862,233.39	4,203,408.59	3,596,207.02	2,820,340.92	2,425,404.88	44,126,920.29
Merchg 555-40	-	-	-	-	-	-	-	-	-	-	-	-	-
Wheeling 565-35	151,092.53	175,804.82	175,730.09	173,818.12	61,379.11	175,050.80	181,665.17	153,563.09	137,217.52	125,361.27	116,686.18	150,919.11	1,779,207.81
ss Short-term Sales Cost	(105,908,473.00)	(111,617,967.00)	(137,656,953.00)	(172,877,697.00)	(203,320,283.00)	(141,387,699.00)	(135,038,980.00)	(150,461,315.00)	(137,745,431.00)	(77,976,395.00)	(89,919,529.00)	(132,402,648.00)	(1,596,313,370.00)
Fountain Valley & FSV cost shift							(188,000.00)					(808,782.00)	(996,782.00)
Subtotal	9,567,081.21	16,769,813.20	23,426,673.77	20,707,685.52	14,966,961.84	23,092,357.31	39,861,111.62	19,186,087.41	21,132,555.14	13,089,748.45	11,791,391.87	14,714,715.10	228,306,162.24
al Actual Energy Cost	43,007,342.51	42,545,992.13	48,584,316.92	48,725,063.65	43,530,155.16	55,336,872.29	72,968,905.40	51,264,834.92	51,215,586.16	38,921,628.92	39,269,411.56	43,833,181.05	579,203,090.87
rgy Allocator - Chged 3/2001	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	0.823216	
tail Actual Energy Cost	35,404,332.00	35,024,541.00	39,995,387.00	40,111,252.00	35,834,720.00	45,554,199.00	60,069,170.00	42,201,868.00	42,161,490.00	32,040,908.00	32,327,208.00	36,084,176.00	478,809,251.00
verage Actual Energy Cost	0.01587	0.01674	0.01941	0.02076	0.01883	0.02300	0.02693	0.01802	0.01884	0.01569	0.01635	0.01664	0.01892
ail Energy Sales KWH (Proforma)	2,230,744,740	2,092,031,615	2,060,125,691	1,931,921,518	1,902,834,559	1,980,797,742	2,230,624,492	2,342,346,343	2,237,634,632	2,042,094,019	1,976,932,974	2,168,818,933	25,196,907,258
Base Unit Cost - $/kWh	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278	0.01278
tail Base Energy Cost	28,508,918.00	26,736,164.00	26,328,406.00	24,689,957.00	24,318,226.00	25,314,595.00	28,507,381.00	29,935,186.00	28,596,971.00	26,097,962.00	25,265,203.00	27,717,506.00	322,016,474.78
il Excess Energy Cost (Actual less Base)	6,895,414.00	8,288,377.00	13,666,981.00	15,421,295.00	11,516,494.00	20,239,604.00	31,561,789.00	12,266,682.00	13,564,519.00	5,942,946.00	7,062,005.00	8,366,670.00	154,792,776.24
ent Recoverable through ICA	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
coverable Energy Cost	3,447,707.00	4,144,189.00	6,833,491.00	7,710,648.00	5,758,247.00	10,119,802.00	15,780,895.00	6,133,341.00	6,782,260.00	2,971,473.00	3,531,003.00	4,183,335.00	77,396,388.12
: 50% of RTP Sales Margin @ 82.3216%	(6,148.94)	(8,519.09)	3,443.99	(4,983.49)	(5,521.33)	(1,282.17)	1,874.50	(1,150.61)	(225.73)	(616.84)	(377.63)	(161.38)	(23,868.91)
Trading Sales Margin	(37,171,035.00)	(41,705,115.00)	(48,693,832.00)	(32,229,756.00)	(36,111,320.00)	(10,110,129.00)	(8,065,138.00)	(10,433,745.00)	(8,534,478.00)	(10,286,033.00)	(9,556,948.00)	(8,714,546.00)	(259,812,075.00)
educed Margins from line 21a							188,000.00					808,782.00	996,782.00
ion Premiums Sold & Purchased	-	(936,672.73)	513,000.00	(1,135,000.00)	(1,213,000.00)	(2,156,672.00)	(1,220,073.00)	103,527.00	(203,553.00)	(1,422,000.00)	(650,000.00)	(1,506,503.34)	(9,842,939.07)
prietary Sales Trading Margin JOA	7,805,148.11	8,603,200.14	5,780,013.05	7,343,553.85	7,090,540.59	1,011,365.68	(1,431,020.01)	223,727.02	300,119.51	1,431,149.66	222,039.55	4,803,207.01	43,463,995.08
Gross Sharing of Trading Margins fc	(29,205,886.89)	(33,838,527.59)	(42,400,818.95)	(26,021,202.15)	(30,233,779.41)	(11,255,435.32)	(10,535,131.01)	(10,106,490.08)	(8,437,911.49)	(10,276,969.34)	(9,993,114.45)	(2,608,969.43)	(224,994,236.09)
ess: 50% of Trading Sales Margin @ 82.3216%	(12,054,305.33)	(13,928,208.66)	(17,452,516.29)	(10,710,534.97)	(12,444,465.48)	(4,632,827.22)	(4,336,344.20)	(4,159,912.17)	(3,473,111.87)	(4,230,082.79)	(4,113,245.85)	(1,073,872.69)	(92,609,427.53)
Interruptible Fuel Cost & Econ Interrupt Credit													
Energy Cost Recoverable through ICA	(8,612,747.27)	(9,792,538.75)	(10,615,581.30)	(3,004,870.47)	(6,691,739.80)	5,485,692.61	11,446,225.30	1,972,278.03	3,308,922.40	(1,259,226.64)	(582,620.48)	3,109,300.94	(15,213,039.41)
ning ICA Deferred Cost Balance	(7,865,999.06)	(13,963,077.58)	(21,371,756.60)	(31,739,746.23)	(32,674,485.55)	(37,660,853.96)	(15,165,918.61)	(1,733,297.69)	2,323,501.36	7,624,081.79	8,182,799.07	9,359,278.39	(134,685,474.67)
gy Cost Recoverable through ICA	(8,612,747.27)	(9,792,538.75)	(10,615,581.30)	(3,004,870.47)	(6,691,739.80)	5,485,692.61	11,446,225.30	1,972,278.03	3,308,922.40	(1,259,226.64)	(582,620.48)	3,109,300.94	(15,236,905.44)
onthly ICA Deferred Cost Adjustment	2,515,668.75	2,383,059.73	2,349,514.94	2,070,131.15	1,705,371.39	1,760,948.74	1,906,395.62	2,004,521.02	1,991,658.03	1,817,943.92	1,759,099.80	1,973,811.85	24,406,924.94
Revenue from ICA Rider Report													
month adjustment							-	-				(123,192.00)	NSP Sharing
-up prior test period			(2,101,923.27)	-	-	15,240,294.00	-	-	-	-	-	-	
g ICA Deferred Cost Balance	(13,963,077.58)	(21,371,756.60)	(31,739,746.23)	(32,674,485.55)	(37,660,853.96)	(15,165,918.61)	(1,733,297.69)	2,323,501.36	7,624,081.79	8,182,799.07	9,359,278.39	14,319,199.18	GL Year End

DAW-6

Service Company of Colorado
CA Recoverable and Deferred Cost
Beginning October 1, 1996
PROFORMA

CA Recoverable Costs	January 02	February 02	March 02	April 02	May 02	June 02	July 02	August 02	September 02	October 02	November 02	December 02	Total
Actual Energy Cost													
Steam Production Fuel Cost													
Coal 501-10 614000	16,218,192.28	13,546,916.80	11,326,003.82	12,915,976.51	15,527,168.22	16,348,951.93	16,791,760.42	14,977,330.51	13,395,369.07	14,707,262.93	16,690,908.39	15,602,422.15	178,048,263
Gas 501-20 611000	1,648,108.66	1,008,987.80	3,203,603.36	1,537,505.61	961,104.48	497,298.84	1,031,353.87	633,701.99	553,520.86	974,677.52	228,234.97	62,524.13	12,940,712
Oil 501-30 612000	-	560.92	3,455.81	6,347.57	(23.24)	389.35	7,964.88	2,162.95	106.05	86.00	269.01	10,629.29	31,969
Less Economy and RTP Sales Cost	(175,574.00)	(129,637.00)	(186,498.00)	(393,982.00)	(497,120.00)	(381,986.00)	(325,210.00)	(751,501.00)	(896,768.00)	(2,598,289.00)	(3,285,840.00)	(2,788,183.00)	(12,410,797)
Subtotal	17,690,726.94	14,426,648.52	14,346,564.99	14,065,847.69	15,991,219.46	16,464,654.12	18,105,860.17	14,861,694.45	13,052,227.98	13,083,737.53	13,633,572.37	12,887,392.57	178,610,147
Combustion Turbine Fuel Cost													
Gas 547-10 611100	212,945.82	257,587.06	387,633.15	104,530.57	86,523.78	459,404.81	941,411.69	179,915.85	(9,195.38)	67,424.24	70,636.38	(10,087.38)	2,756,831
Oil 547-20 612100	100,897.60	7,076.50	-	176,878.51	273.28	74.74	40,022.41	106.90	-			15,196.75	341,407
FSV Gas 547-50 611100	9,702,778.72	10,693,591.20	10,671,773.06	7,859,974.06	7,026,487.58	7,085,856.25	6,331,329.38	7,266,051.99	6,961,955.65	6,584,249.75	8,847,193.50	11,099,240.97	100,130,482
Less Economy and RTP Sales Cost	-	-	-	-	-	-	-	-	-	-	-	-	-
Subtotal	10,016,622.14	10,959,054.76	11,059,406.21	8,141,383.14	7,113,284.64	7,545,335.80	7,312,763.48	7,446,154.74	6,952,760.27	6,651,673.99	8,928,829.88	11,103,450.34	103,228,719
Purchased Energy Cost													
Firm 555-11 632000	11,971,617.67	14,136,268.53	16,361,165.36	12,771,368.35	8,752,117.69	17,085,237.47	14,704,558.95	14,509,489.94	13,614,456.00	13,330,178.11	12,823,908.71	10,268,072.42	170,229,449
Less: Basin Contract 7900572633	(375,644.40)	(346,088.60)	(509,298.60)	(441,251.10)	(430,221.60)	(431,730.00)	(480,191.40)	(437,330.80)	(441,993.60)	(405,213.30)	(489,540.00)	(577,320.00)	(5,455,832)
Economy 555-20 632100	87,110,824.43	107,207,212.88	138,472,468.87	188,248,257.79	154,862,984.31	160,800,733.78	233,291,775.19	219,311,943.14	113,828,446.02	70,398,253.51	66,109,797.32	74,060,022.25	1,613,702,719
Qual Facil 555-31 632200	2,412,840.19	2,457,056.73	2,348,640.08	2,625,533.62	2,029,624.44	2,577,024.22	2,429,022.00	2,492,487.02	2,672,284.86	1,178,321.60	1,191,981.00	1,345,031.00	26,881,249
Interchg 555-40	-	-	-	-	-	-	-	-	-	-	-	-	-
Wheeling 565-35 638100	97,332.18	150,409.30	149,977.83	186,803.36	73,807.91	196,418.87	170,751.62	237,897.28	202,699.63	142,695.74	206,011.19	156,006.68	1,970,812
Less Economy Sales Cost	(78,727,872.00)	(102,856,214.00)	(135,568,393.00)	(186,136,736.00)	(154,000,409.00)	(158,877,554.00)	(228,999,579.00)	(216,737,204.00)	(108,034,541.00)	(67,266,311.00)	(61,475,403.00)	(68,650,544.00)	(1,587,330,910)
Subtotal	22,489,098.07	20,748,643.84	21,254,560.54	17,253,996.22	12,188,043.95	22,250,730.34	21,116,937.96	19,377,274.58	21,841,351.91	17,287,924.68	18,366,756.12	25,602,169.34	239,777,488
Total Actual Energy Cost	50,196,447.15	46,134,347.12	46,660,531.74	39,461,227.05	35,292,548.05	46,260,720.26	46,535,561.61	41,685,123.77	41,846,340.16	37,023,336.16	40,927,158.37	49,593,012.25	521,616,354
Energy Allocator	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713	0.830713
Retail Actual Energy Cost	41,698,841.00	38,324,402.00	38,761,510.00	32,780,954.00	29,317,978.00	38,429,382.00	38,657,696.00	34,628,374.00	34,762,299.00	30,755,767.00	33,998,723.00	41,197,560.00	433,313,486
Average Actual Energy Cost	0.01875	0.01826	0.01851	0.01664	0.01532	0.01887	0.01630	0.01416	0.01514	0.01512	0.01709	0.01302	0.01627
Base Energy Cost													
Retail Energy Sales KWH	2,223,352,812	2,099,089,842	2,094,140,164	1,969,849,090	1,914,284,093	2,036,406,121	2,372,050,108	2,446,027,407	2,296,221,333	2,034,246,786	1,989,800,189	3,164,368,257	26,639,936,202
ICA Base Unit Cost - $/kWh	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892	0.01892
Retail Base Energy Cost	42,065,835.00	39,714,780.00	39,621,132.00	37,271,437.00	36,218,255.00	38,528,804.00	44,879,188.00	48,278,839.00	43,444,508.00	38,487,949.00	37,647,020.00	59,869,847.00	504,027,594
Energy Cost Recoverable through ICA													
Retail Excess Energy Cost (Actual less Base)	(366,994.00)	(1,390,378.00)	(859,622.00)	(4,490,483.00)	(6,900,277.00)	(99,422.00)	(6,221,492.00)	(11,650,465.00)	(8,682,209.00)	(7,732,182.00)	(3,648,297.00)	(18,672,287.00)	(70,714,108)
Percent Recoverable through ICA	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50	0.50
Recoverable Energy Cost	(183,497.00)	(695,189.00)	(429,811.00)	(2,245,242.00)	(3,450,139.00)	(49,711.00)	(3,110,746.00)	(5,825,233.00)	(4,341,105.00)	(3,866,091.00)	(1,824,149.00)	(9,336,144.00)	(35,357,057)
Retail Energy Sales KWH	2,223,352,812	2,099,089,842	2,094,140,164	1,969,849,090	1,914,284,093	2,036,406,121	2,372,050,108	2,446,027,407	2,296,221,333	2,034,246,786	1,989,800,189	3,164,368,257	26,639,936,202
ICA Base Unit Cost Adjustment - $/KWH 0.01892-0.0127	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.00614	0.0614
	13,651,386.00	12,888,412.00	12,858,021.00	12,095,487.00	11,753,704.00	12,503,534.00	14,564,388.00	15,018,608.00	14,098,799.00	12,490,275.00	12,217,373.00	19,428,221.00	163,569,208
Less: 50% of RTP Sales Margin @ Retail Allocator	(458.55)	(685.75)	(875.37)	(14,561.57)	(13,529.41)	(9,822.15)	(8,438.38)	(8,174.27)	(7,479.74)	(3,149.23)	(2,890.88)	(5,392.16)	(70,855)
Gross Trading Sales Margin	(550,327.00)	(487,710.00)	(964,915.00)	2,248,354.00	1,096,720.00	1,171,004.00	3,346,934.00	3,127,609.00	309,096.00	(2,805,084.00)	(1,315,603.00)	(2,142,081.00)	3,034,206
Option Premiums Sold & Purchased	(530,246.00)	(406,374.00)	(234,180.00)	(599,100.00)	(324,520.00)	(1,258,680.00)	(557,560.00)	(605,000.00)	(446,600.00)	-	-	-	(4,962,260)
Joint Operating Agreement, Proprietary Sales Trading Marg	(112,300.71)	(66,464.33)	(121,920.72)	(113,359.04)	(80,535.18)	(250,571.72)	(209,040.24)	(80,549.12)	(79,051.61)	(100,743.08)	(76,662.71)	(110,099.20)	(1,401,808)
Proprietary Sales Trading Margin JOA	2,022,177.53	1,062,290.29	1,605,738.93	(1,967,922.29)	(178,155.59)	(176,270.44)	(1,664,105.70)	(748,119.82)	(433,214.90)	(165,781.89)	(88,487.28)	432,502.53	(299,238)
Gross Sharing of Trading Margins for I	829,503.82	101,741.96	284,723.21	(432,027.33)	513,518.23	(514,518.16)	915,530.06	1,694,140.06	(649,770.51)	(3,071,608.77)	(1,480,752.07)	(1,819,077.67)	(3,829,190)
Less 50% of Trading Sales Margin @ Retail Allocator	344,535.80	42,256.18	116,261.64	(179,445.36)	213,293.13	(213,708.40)	380,274.68	703,672.09	(269,886.40)	(1,275,812.67)	(615,040.37)	(755,814.95)	(1,507,408)
Plus: Interruptible Fuel Cost & Econ Interrupt Credit													
Total Energy Cost Recoverable through ICA	13,811,970.25	12,234,796.43	12,545,796.27	9,656,238.07	8,503,328.73	12,230,492.39	11,827,480.32	9,890,872.81	9,460,327.86	7,345,222.10	9,775,492.95	9,331,869.89	126,833,888
ICA Deferred Cost													
Beginning ICA Deferred Cost Balance	14,319,198.97	30,103,142.21	44,325,632.64	58,731,340.31	70,051,750.66	78,999,398.10	90,095,979.39	97,121,171.69	101,895,346.15	106,566,067.38	109,648,721.61	115,263,720.17	
Energy Cost Recoverable through ICA	13,811,970.25	12,234,796.43	12,545,796.27	9,656,238.07	8,503,328.73	12,230,492.39	11,827,480.32	9,890,872.81	9,460,327.86	7,345,222.10	9,775,492.95	9,331,869.89	
ICA Revenue from ICA Rider Report	1,971,972.99	1,866,568.21	1,859,911.40	1,664,172.28	444,318.71	(1,133,911.10)	(4,802,288.02)	(5,116,698.35)	(4,809,606.63)	(4,262,567.87)	(4,160,494.39)	(4,617,746.07)	
Monthly Rate Revenue Refund for ICA Rider 0	1,971,972.99	1,866,568.21	1,859,911.40	1,664,172.28	444,318.71	(1,133,911.10)	(4,802,288.02)	(5,116,698.35)	(4,809,606.63)	(4,262,567.87)	(4,160,494.39)	(4,617,746.07)	
Purchase Power Percentage 055720 (Entry 13	883,486.71	839,477.77	847,217.08	727,641.39	153,442.48	(545,384.67)	(2,179,185.44)	(2,378,490.45)	(2,510,334.49)	(1,990,392.00)	(1,867,092.39)	(2,383,890.62)	
Generation Fuel Percentage 055730 (Entry 13	1,088,486.28	1,027,090.44	1,012,694.32	936,530.89	290,876.23	(588,516.43)	(2,623,102.58)	(2,738,207.90)	(2,299,272.14)	(2,272,175.87)	(2,293,402.00)	(2,233,855.45)	
Prior period adjustment	-	-	-	-	-	-	-	-	-	-	-	-	
Monthly ICA Deferred Cost 018540	13,811,970.25	12,234,796.43	12,545,796.27	9,656,238.07	8,503,328.73	12,230,492.39	11,827,480.32	9,890,872.81	9,460,327.86	7,345,222.10	9,775,492.95	9,331,869.89	
Purchase Power Percentage 055720 (Entry 13	6,188,062.52	5,502,525.76	5,714,795.27	4,222,086.02	2,936,567.35	5,882,688.09	5,367,081.85	4,597,759.13	4,948,178.89	3,429,827.22	4,386,918.18	4,817,535.83	
Generation Fuel Percentage 055730 (Entry 13	7,623,907.73	6,732,270.67	6,831,000.99	5,434,152.05	5,566,761.38	6,347,804.30	6,460,398.47	5,293,113.68	4,532,148.97	3,915,394.88	5,388,574.77	4,514,334.07	
Prior month adjustment													
True-up prior test period		121,125.79	-	-	-		-	-	-	-	-	-	
Ending ICA Deferred Cost Balance	30,103,142.21	44,325,632.64	58,731,340.31	70,051,750.66	78,999,398.10	90,095,979.39	97,121,171.69	101,895,346.15	106,566,067.38	109,648,721.61	115,263,720.17	119,977,843.99	

SUMMARY of IMPACT of
STIPULATION AND SETTLEMENT AGREEMENT

2001 ICA Impact	Adjustments	Jurisdictional	Sharing	Total Energy Cost Recoverable Through ICA	Difference
DAW-2 Revised				$ (14,671,521)	
Adjustments:					
Otter Tail	$ (429,600)	82.32%	50.00%	$ (176,827)	
PacifiCorp	$ (197,515)	82.32%	50.00%	$ (81,299)	
DAW-4 Revised				$ (14,929,647)	$ 258,126
Adjustments:					
Fountain Valley Capacity	$ (688,500)	82.32%	50.00%	$ (283,392)	
DAW-5 Revised				$ (15,213,039)	$ 283,392
)02 ICA Impact					
2002 - As Filed	@ $19.00 / MWH			$ 127,699,486	
Adjustments:					
Fountain Valley Sales Shift					
Fort St. Vrain Sales Shift					
DAW-6	@ $18.92 / MWH			$ 126,633,888	$ 1,065,598
)tal ICA Impact					$ 1,607,116
ıtal ECA Impact					
PVM Discount	$15,000,000	30.62%			$ 4,592,690
tal Impact					$ 6,199,806

CERTIFICATE OF SERVICE

I hereby certify that on this, the 10th day of July, 2003, the original and five (5) copies of the foregoing **STIPULATION AND SETTLEMENT AGREEMENT** were served via hand delivery on:

Bruce Smith, Director
Colorado Public Utilities Commission
1580 Logan, OL-2
Denver, CO 80203

and copies were e-mailed, faxed, hand delivered, or placed in the United States Mail, addressed to:

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