

**UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION**

**BIG WEST OIL CO. v. FRONTIER PIPELINE CO. and EXPRESS PIPELINE PARTNERSHIP
DOCKET No. OR01-2-000, et al.**

**CHEVRON PRODUCTS CO. v. FRONTIER PIPELINE CO. and EXPRESS PIPELINE PARTNERSHIP
DOCKET No. OR01-4-000, et al.
(Consolidated)**

**PREPARED DIRECT TESTIMONY
OF
PATRICK R. CROWLEY
WITNESS FOR THE STAFF OF
THE FEDERAL ENERGY REGULATORY COMMISSION**

COST OF SERVICE & RATE DESIGN

REDACTED PUBLIC VERSION



**Washington, D.C.
December 4, 2001**

Federal Energy Regulatory Commission
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Summary of the Prepared Direct Testimony of Patrick R. Crowley

Exhibit No. S-7

Mr. Crowley addresses the just and reasonableness of the Frontier Pipeline Company's Local Tariff FERC No. 21 (formerly FERC No. 20). He examines the tariffs at issue, calculates the cost of service for Frontier for the relevant years, estimates the appropriate volumes for the test year, and, finally, calculates rates for transportation services provided under Frontier's local tariffs FERC Nos. 19 and 21.

Mr. Crowley recommends three rates for Frontier: \$0.1075 per barrel for sour condensate transportation under tariff FERC No. 19; \$0.5250 for the movement of crude oil from Casper, Wyoming, to Ranch Pipeline, Utah, under Frontier's local tariff FERC No. 21; and \$0.4941 for the movement of crude oil from Casper, Wyoming, to Divide Junction, Wyoming, under Frontier local tariff FERC No.21.

Exhibit No. S-8

Exhibit No. S-8 contains the Staff Cost of Service model for Frontier Pipeline Company. The model develops the annual cost components for operating expenses, depreciation expenses, the amortization of deferred earnings on the trended equity rate base, and the allowance for return on capital. Mr. Crowley makes numerous adjustments to Frontier's cost components. Mr. Crowley's cost of service model results in substantial reductions in the total cost of service for the years 1999, 2000, and for the 12 month period ending June 30, 2001.

Exhibit No. S-9

Exhibit No. S-9 contains the Frontier Cost of Service Model as reflected in the electronic workpapers provided in response to data requests. The Frontier cost of service model demonstrates that Frontier's revenues far exceed their own costs of service calculations for the years 1998, 1999, and 2000.

Exhibit No. S-10

Exhibit No. S-10 contains various workpapers in support of Mr. Crowley's cost of service analysis and rate design.

**Prepared Direct Testimony of
Patrick R. Crowley
Witness for the Staff of the
Federal Energy Regulatory Commission**

Q. Please state your name and business address.

A. My name is Patrick R. Crowley. My business address is 888 First Street, N.E., Washington, D.C. 20426.

Q. By whom are you employed and in what capacity?

A. I am employed by the Federal Energy Regulatory Commission (FERC or Commission) as an Economist in the Division of Litigation, Office of Markets, Tariffs, and Rates.

Q. Please state your educational background and professional qualifications.

A. I graduated from DePaul University in Chicago, Illinois, in 1976 with a Bachelor of Arts degree in Economics. In 1978, I received a Master of Arts degree in Economics from DePaul University. I began work at the Commission in 1979 as an Industry Economist in the Pipeline Rates Division of the Office of Pipeline Rates. As an expert witness with the Staff litigation team from 1979 to 1992, I prepared pipeline depreciation studies, long-term forecasts of natural gas reserves and production, mortality studies of plant investment and retirements, cost behavior studies for pipeline facilities, and Mcf/mile studies. From 1992 through 1994, I worked on two teams shepherding the restructuring of two major gas pipeline companies. From 1994 through 1998, I worked on the advisory side of the Commission where I prepared reports for Commission orders regarding proposals for revised tariff terms; new services, rate designs, and tariff rates; and a wide

variety of utility reports and cost studies. In 1998, I returned to the litigation side of the Commission where I now work on electric utility, natural gas pipeline, and oil pipeline rate cases and complaint cases.

Q. Have you previously filed testimony before the Commission?

A. Yes, I filed testimony in the following rate cases:

Black Marlin Pipeline Company, Docket No. RP81-67-000;

Tarpon Transmission Company, Docket No. RP84-82-000;

National Fuel Gas Supply Corporation, Docket No. RP86-136-000;

Pacific Gas Transmission Company, Docket No. RP87-62-000;

Sea Robin Pipeline Company, Docket No. RP88-181-000;

Natural Gas Pipeline Company of America, Docket No. RP88-209-000;

Paiute Pipeline Company, Docket No. RP88-227-000;

Southwest Gas Storage Company, Docket No. RP89-60-000;

Montana Power Company, Docket No. ER98-2382-000.

San Diego Gas & Electric Company, Docket Nos. ER97-54-002 & EL99-21-000.

Boston Edison Company, Docket No. ER01-890-000.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to examine the just and reasonableness of the rates incorporated into Frontier Pipe Line Company's (Frontier) local tariff FERC No. 20 governing the transportation of crude oil from Casper, Wyoming, to Divide Junction, Wyoming and Ranch Pipeline, Utah. I shall also examine whether reparations are in order due to any difference in the rates charged under tariff FERC No. 20 in 1999 and 2000 versus my recommended rates for those years.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes, in addition to this direct testimony, Exhibit No. S-7, I am sponsoring: Exhibit No. S-8, which is the Staff Cost of Service Model for Frontier,

Exhibit No. S-9, which is Frontier's Cost of Service Model for Frontier, and Exhibit No. S-10, which is a set of workpapers supporting my cost of service analysis and rate design.

Tariffs

Joint Rate Tariffs & Local Rate Tariffs

- Q. What crude oil movements are involved in this case?
- A. Big West Oil Company (Big West) owns and operates a refinery in Salt Lake City, Utah. Chevron Products Company (Chevron) also owns and operates a refinery in Salt Lake City, Utah. Both Big West and Chevron supply their refineries with crude oil transported, in part, through a chain of pipelines originating in both the Rocky Mountains of Wyoming and Alberta, Canada. This transportation service is provided to Big West and Chevron by Frontier using three tariffs, two of which are joint tariffs with the connecting pipelines, one is solely a Frontier tariff. The connecting pipeline companies are Express Pipeline Partnership (Express), Frontier, Anschutz Ranch East Pipeline Inc, and Chevron Pipeline Company. The Frontier pipeline is also used by BPAmoco to supply its Salt Lake City refinery with crude oil from Canada. The BPAmoco crude moves over Glacier Pipeline Company from the Canadian border to Billings, Montana, where it meets Bear Tooth Pipeline, which brings the crude to the Big Horn Pipeline Company, which brings the crude down to Casper, Wyoming. Then the crude moves on through Frontier, Anschutz, and Chevron to Salt Lake City.
- Q. What tariffs are involved with this case?
- A. Frontier's local interstate tariff FERC No. 20 provides for transportation of crude oil over Frontier's line from Casper, Wyoming to Divide Junction, Wyoming, and Ranch Pipeline, Utah. Express Pipeline Partnership offers two joint interstate tariffs that governs the transportation of crude petroleum across all four oil

pipelines. The Express FERC No. 21, Supplement No. 3, is a term rate tariff that provides for 5, 10, and 15 year terms. The Express FERC No. 22, Supplement No. 2, is an uncommitted rate tariff that does not specify the term of agreement. The tariff numbers here relate to the particular pipeline companies' tariffs and can get confusing. (Oil pipeline companies periodically adjust their rates through an indexing formula and then re-number the tariff. For example, Frontier's sour condensate tariff was inaugurated as FERC No. 8, but through successive adjustments is now numbered FERC No. 22. It is not the same FERC No. 22 as the Express FERC No. 22.)

Q. What tariffs are you examining in this testimony?

A. Joint rate tariffs cover transportation services over more than one pipeline. Rather than subject its customers to several separate tariffs, scheduling orders, and the like, the joining pipelines offer one tariff, in essence a one-stop service for the whole transportation movement. The division of the revenues among the pipeline companies providing the service is governed by agreement between or among the pipeline companies. Local tariffs provide for service over only one pipeline. Although the complaints filed by Big West Oil and Chevron against Frontier and Express reference the two joint rate tariffs, it is the rates in the local tariff with which they take issue. The Commission established a hearing in this proceeding to examine the local interstate rates of Frontier and Anschutz, and determine whether those rates are just and reasonable. 94 FERC ¶ 61,339 at 62,260.

Q. Why do the Complainants take issue only with the Frontier local tariff FERC No. 20?

A. The Commission's policy regarding the justness and reasonableness of joint rates is simply that the joint rates must be less than or equal to the sum of the local rates. 72 FERC ¶ 61,313 Big West's complaint alleges that Frontier's local rate is unjust

and unreasonable, and, if so, the joint rates are by definition unjust and unreasonable. The Commission's mandate in this proceeding, as noted above, is to examine only the local interstate rates.

Q. What are the current local and joint rates of the adjoining pipelines?

A. Frontier's local tariff No. 20 currently imposes a rate of \$1.5106 per barrel for the transportation of crude oil from Casper, Wyoming, to Ranch Pipeline, Utah. A shipper wishing to bring crude oil from Canada to Salt Lake City via the local tariffs of the adjoining pipelines would have to pay the rates in Table 1 on the following page. Express offers joint rate tariffs covering the entire movement over Express, Frontier, Anschutz, and Chevron, from the Canadian border to Salt Lake. As shown on Table 1, the sum of the local rates for "Medium Salt Lake" crude oil transported from the Canadian border to Salt Lake City is \$3.1380 per barrel, whereas the Express joint rate for Tariff No. 22 is \$2.8820 per barrel. Thus, the under the current rates, the joint rate is \$0.2560 less than the sum of the local rates.

Q. Has the rate you derived for Frontier's local tariff FERC No. 20 significantly altered the relationship of the local and joint rates?

A. Yes, it has. My cost of service calculations suggest a rate for Frontier's local tariff FERC No. 20 of approximately \$0.5246 per barrel. Consequently, the sum of the appropriate local rates is no longer less than the joint rate, as can be seen on the table below. The joint rate is now \$0.7406 per barrel higher than the sum of the local rates.

	<u>Light</u>	<u>Salt Lake Medium</u>	<u>Salt Lake Heavy</u>
Express Pipeline			
FERC No.29 (local)	1.0490	1.1330	1.2590
Frontier Pipeline			
FERC No. 20 (local)	1.5106	1.5106	1.5106
Anschutz Ranch East PL			
FERC No.7 (local)	0.3735	0.3735	0.3735
Chevron Pipeline			
FERC No.628 (local)	<u>0.1209</u>	<u>0.1209</u>	<u>0.1209</u>
Total of Local Rates	3.0540	3.1380	3.2640
Express Joint Rate			
FERC No. 22	2.5091	2.8820	3.0827
Differential	0.5449	0.2560	0.1813

	<u>Light</u>	<u>Salt Lake Medium</u>	<u>Salt Lake Heavy</u>
Express Pipeline			
FERC No.29 (Local)	1.0490	1.1330	1.2590
Frontier Pipeline			
FERC No. 20 (local)	0.5250	0.5250	0.5250
Anschutz Ranch East PL			
FERC No.7 (local)	0.3735	0.3735	0.3735
Chevron Pipeline			
FERC No.628 (local)	<u>0.1209</u>	<u>0.1209</u>	<u>0.1209</u>
Total of Local Rates	2.0684	2.1414	2.2784
Express Joint Rate			
FERC No. 22	2.5091	2.8820	3.0827
Differential	(0.4411)	(0.7406)	(0.8056)

Cost of Service

Frontier's FERC Form 6 Cost of Service Model

Q. Have you examined Frontier's FERC Form 6 Cost of Service Analysis?

A. Yes, I have. The FERC Form 6 is an annual report filed by oil pipeline companies that includes a snapshot of the pipeline's cost of service, throughput, and revenues. This snapshot, referred to as Page 700, appears on the last page of the Form 6. Frontier's FERC Form 6 for the years 1990 through 2000 have been submitted by Big West and Chevron as Exhibit Nos. BWC-69 through BWC-79. The underlying calculations for the Page 700 cost of service were provided by Frontier in response to Big West and Chevron's data request 2(c). The hard copies of Frontier's workpapers, submitted by Big West and Chevron as Exhibit Nos. BWC-54 and BWC-55 do not include much of the data for the year 2000 cost of service. However, the electronic versions of those workpapers do. For comparison purposes, I have reproduced Frontier's year 2000 Page 700 cost of service as Exhibit No. S-9.

Q. What does the Page 700 cost of service indicate?

A. The Page 700 cost of service, as prepared by Frontier and unmodified by Staff or the complainants, reveals that Frontier has been a very profitable operation over the last several years. The cost of service calculations underlying the Page 700 analysis incorporate all the major cost elements that the pipeline faces, including an allowance for a return on capital component. Frontier provided these cost of service workpapers in response to Big West and Chevron's data request question 2(c), which have been reproduced in Big West and Chevron's Exhibit Nos. BWC-54, BWC-55, BWC-90, BWC-91, and BWC-92. As can be seen by the figures shown below, copied from Frontier's FERC Form 6, as filed, for the last four years,

the annual revenues realized by Frontier have increased dramatically while its cost have remained fairly stable.

Table 3

(\$000)	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
Annual Cost of Service	\$9,309	9,680	8,570	9,267
Operating Revenues	\$9,011	11,391	14,028	14,965

Q. Does Page 700 include a return on capital component?

A. Yes, it does. The first page of each set of calculations clearly show that return is included in the total cost of service and that Frontier's revenues have far outstripped their costs. The excess revenues in 1998, 1999, and 2000 reflect a return over and above the 10.73% allowance for the cost of capital incorporated into Frontier's workpapers. What this tells us is that the tariff rates for the movement of crude oil on Frontier's line are significantly higher than necessary to recover Frontier's annual cost of service.

Q. What were the realized returns on capital for those years?

A. Frontier's realized returns on capital for the each of the last four years significantly exceed the 10.73% return on capital that Frontier incorporated into its cost of service calculations. If you add the return on capital component, which is already in the cost of service, to the excess or loss shown in Table 3, you see the substantial realized returns, even using Frontier's own numbers. The full calculations are shown in Exhibit No S-10, Page 1 of 10. In the table below I have converted the return dollars into percentage returns on rate base and equity rate base.

Table 4

(\$000)	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
Total Return on Rate Base	10.19%	15.34%	25.59%	25.02%
Return on Equity Rate Base	13.72%	20.65%	34.14%	34.88%

As can be seen in the table above, Frontier's total returns on capital have far exceeded Frontier's 10.73% return on capital targets reflected in the costs of services calculated for those years.

The Staff Cost of Service Model

Q. How have you analyzed Frontier's cost of service?

A. I have produced a cost of service model reflecting my recommendations as to the various cost of service elements that produce just and reasonable tariff rates for transportation of crude oil on Frontier's pipeline. My calculation of Frontier's cost of service, labeled "Staff Frontier Model" can be examined in Exhibit No. S-8.

Q. Please describe your model.

A. Rather than run a separate model for each year, my model in Exhibit No. S-8 provides the cost of service analysis for every year from 1984 through June 30, 2001. Each year builds upon the data from the previous year. The model derives a rate for Frontier's local interstate tariffs for the calendar years 1999 and 2000, and for the twelve month period ending June 30, 2001, which for convenience I have referred to as the "test year." The Staff Frontier Model incorporates the following schedules:

"Index" presents the schedules included in Exhibit No. S-8,

"Input" presents the variables that go into the model for 1984 through 2001,

"SCH 1" summarizes the cost of service for 1984 through 2001,

"SCH 2A" summarizes the real return on capital for 1996 through 2001,

"SCH 2B" summarizes the operating expenses for 1996 through 2001,

"SCH 3" summarizes the interest expense and return allowances for 1984 to 2001,

"SCH 4" summarizes the income tax allowance for 1984 through 2001,

"SCH 5A" summarizes the equity rate base return allowances for 1984 to 2001,

"SCH 5B" summarizes the debt rate base for 1984 through 2001,

"SCH 6" summarizes the carrier property for each year for 1984 through 2001,
"SCH 7A" summarizes the annual and accrued depreciation for 1984 to 2001,
"SCH 7B" summarizes the AFUDC calculations for 1984 through 2001.

Schedule 6 - Carrier Property

- Q. Please describe Schedule No. 6.
- A. Schedule No. 6 contains the carrier property valued at the original cost.
- Q. How did you arrive at the carrier property amount for the test year 2001?
- A. To adjust the carrier property for the June 30, 2001 test year, I included plant additions of \$10,000. This information was provided by Frontier in response to Staff Data Request WHG-1Fr, Question13. (See Exhibit No. S-10, Page 2.)

Schedule 7A - Accumulated Reserve for Depreciation & Depreciation Expense

- Q. Please describe Schedule 7A.
- A. Schedule 7A is the accumulated reserve for depreciation and the annual depreciation expense. The starting balance for the accumulated reserve for depreciation should reflect a beginning year balance of approximately \$121,000 as shown in the FERC Form 6 for 1984. (See Staff Workpapers, Exhibit No. S-10, Page 3.) The balance should also incorporate retirements in the years 1984 and 1985, and other debits and credits in 1986 as shown in the respective FERC Form No. 6s. (See Staff Workpapers, Exhibit No. S-10, Pages 4 and 5.) The corrections referred to above are incorporated into the 1999, 2000, and test year 2001 calculations in my Exhibit No. S-8, SCH 7A, Page 47.
- Q. What depreciation rate did you use in your cost of service models?
- A. I am relying on the recommendation of Staff Witness Kevin Pewterbaugh, who has conducted a study of the crude oil reserves in Alberta, Canada, which is the source

of virtually all of Frontier's throughput. His analysis, Exhibit No. S-4, indicates that the proper depreciable remaining life for Frontier's facilities is 35 years from December 31, 1999. (See Exhibit No. S-4, Pages 25 and 39.) Hence, the proper rate to calculate the depreciation expense to be included in Frontier's cost of service is 1.55%. (Exhibit No. S-4, Page 39.) Mr. Pewterbaugh provided the depreciation expense figures for 1999 and 2000 that I have incorporated into the Staff Frontier Model on Exhibit No. S-8, "Input," Page 6 of 54, and "SCH 1," Page 11.

- Q. What depreciation expenses have you used for the 1999 and 2000 cost of service models?
- A. As shown on Exhibit No. S-8, SCH-1, Page 12, I have incorporated depreciation expenses of \$848,000 for the 1999 model and \$823,000 for the 2000 model.
- Q. What depreciation expense have you used for the test year 2001 cost of service model?
- A. For the test year ending June 30, 2001, I have estimated the depreciation expense as being half of the year 2000 expense and half of the year 2001 expense. The resulting estimate is \$898,000.
- Q. Have you made any other adjustments to the depreciation accounts?
- A. Yes, I have. Because Frontier suspended operations for a time from April, 1988 to May 1990, I have suspended the accrual of the depreciation for those years as Frontier did in its workpapers, Exhibit No. S-9, SCH 7.
- Q. Are you recommending that the Frontier's book depreciation accruals for the years 1999 and 2000 be adjusted to reflect Staff's depreciation expenses for those years?
- A. No, I am not. Frontier's book depreciation expenses, like its other cost of service components, were what they were for those years. What we are endeavoring to determine in this case is what Frontier's customers should have paid, just and

reasonably, for the transportation services they received. Consequently, for ratemaking purposes, I have incorporated depreciation expenses for 1999 and 2000 that more accurately reflect what the expenses should have been for those years rather than what Frontier actually booked for those years. If the underlying cost elements were not just and reasonable, the customers should not be required to reimburse the pipeline for them. Staff is recommending that Frontier's future booked depreciation rates be adjusted to reflect the longer remaining life developed by Mr. Pewterbaugh.

Schedule 7B - AFUDC

- Q. Please describe Schedule 7B.
- A. Schedule 7B is the AFUDC calculation. This calculation incorporates various elements for which Staff witnesses are recommending different figures from those reflected in Frontier's workpapers as shown on Exhibit No. S-10, SCH 7B. Specifically, they include the depreciation component, the capital structure component, and the nominal return on capital. These corrections to the AFUDC calculations are reflected in my Exhibit No. S-8, SCH 7B, page 54 of 54.
- Q. Why did you change Frontier's depreciation component in the AFUDC calculation?
- A. Frontier's AFUDC schedule, as reflected on Page 2 of 29 in Exhibit No. S-9, includes a depreciation component of 3.33%. As noted above, Mr. Pewterbaugh's depreciation study indicates a remaining life of 34 years, which translates into a depreciation rate of 1.55%. Therefore I have adjusted the AFUDC to reflect Mr. Pewterbaugh's recommended depreciation rate of 1.55%.
- Q. Why did you change Frontier's capital structure component in the AFUDC calculation?

- A. Frontier's AFUDC calculation includes components for capital structure which are inappropriate. Frontier has used a generic equity/debt ratio of 65% equity/35% debt for its rate base components. Staff witness Douglas Green has conducted a financial analysis of Frontier and recommends the following capital structures: 54.05% equity/45.95% debt for 1999, 53.33% equity/46.67% debt for 2000, and 53.33% equity/46.67% debt for 2001. These capital structures are supported by Mr. Green's Exhibit No. S-2, Schedule Nos. 1A, 1B, and 1C.
- Q. Why did you change Frontier's nominal return on capital component in the AFUDC calculation?
- A. The nominal return on capital component used in the derivation of the AFUDC is the sum of the real return on equity and the inflation factor. I have used the figures shown in Mr Green's financial analysis.
- Q. What AFUDC allowance did you use for the 1999 and 2000 cost of service models?
- A. As shown on Exhibit No. S-8, SCH-1, Page 12, I have incorporated an AFUDC allowance in the 1999 and 2000 cost of service models of \$9,000 for both years.
- Q. What AFUDC allowance did you use for the test year 2001 cost of service model?
- A. The AFUDC allowance for the 2001 test year cost of service model is \$10,000. This figure is based on the year 2000 construction work in progress (CWIP), which is comparable to the confidential 2001 CWIP figures shown in the various Frontier Income Statements (See Exhibit Nos. BWC-53 for 6/30/01 and BWC-16 for 7/31/01).

Schedule 2B - Operating Expenses

- Q. Please describe Schedule 2B.

- A. Schedule 2B contains Frontier's operating expenses. I have used the figures for operating expenses as shown on Frontier's FERC Form No. 6, page 302, for the year 1999, provided in Exhibit No. BWC-78, Page 48.
- Q. Does your operating expenses schedule adjust for the difference in depreciation rates which Staff is recommending?
- A. Yes, it does. My Exhibit No. S-8, SCH 2B, Page 18, incorporates the revised depreciation rates developed by Mr. Pewterbaugh.
- Q. Why have you incorporated revised depreciation figures into past period operating expenses?
- A. I have incorporated Mr. Pewterbaugh's revised depreciation figures into the past period operating expenses for 1999 and 2000 to calculate a cost of service for the two years preceding the date of the filing of the complaint for the purposes of preparing a calculation of reparations.
- Q. Have you accepted all of the operating expense figures from Frontier's FERC Form No. 6?
- A. No, I have not. Account No. 520, Outside Services, for the year 2000 is three times higher than the previous years and not representative of normal operating expenses. Consequently, I have, instead, taken the average of the three preceding years as a representative level for outside services.
- Q. What operating expense did you use for the 1999 and 2000 cost of service models?
- A. As shown on Exhibit No. S-8, SCH-1, Page 12, I have incorporated operating expenses for the 1999 and 2000 cost of service models of \$1,152,000 and \$1,138,000 respectively.
- Q. What operating expense did you use for the test year 2001 cost of service model?
- A. I have incorporated an operating expense figure for use in the 2001 test year cost of service model of \$1,135,000. This figure is based on the year 2000 operating

expenses, as adjusted, which are comparable to the confidential operating expenses shown in the various Frontier Income Statements. (See Exhibit Nos. BWC-53 for 6/30/01 and BWC-16 for 7/31/01.) The two adjustments are for outside services and the depreciation expenses.

Schedule 3 -Interest Expense and Return

Q. Please describe Schedule No. 3.

A. Schedule 3 is the calculation of Frontier's interest expense and return on capital allowance. The return on capital allowance incorporates (1) an interest expense for the cost of debt, (2) a return on the original cost rate base, and (3) a return on the trended equity rate base.

Q. How is the interest expense calculated?

A. The interest expense is calculated by multiplying the rate base from Schedule 5B times the weighted cost of debt. The weighted cost of debt is calculated by multiplying the cost of debt (an interest expense) on line 12 times the debt ratio for Frontier on line 11.

Q. Why is the equity/debt ratio on Schedule 3 different from the debt ratio on Schedules 5A and 5B?

A. The equity/debt ratio used on Schedules 5A and 5B are used to derive the trended equity rate base. The trended portion of the equity rate base becomes a deferred income asset for ratemaking purposes, which I will explain later in my testimony. When the deferred income is added to the equity portion of the original cost rate base, a new equity ratio is created to reflect the higher value of the equity portion of the total rate base. The new equity/debt ratio is used on Schedule 3 to derive the appropriate returns on capital.

- Q. How are the return on the original cost rate base and trended equity rate base calculated?
- A. The original cost rate base (essentially the original cost less accrued depreciation) and trended equity rate base (which I will explain later in my testimony) are added together and multiplied by the weighted cost of capital. The equity rate base amount on line 5 of Exhibit No S-8, Schedule 3, incorporates deferred income, which is an inflation write-up for the equity portion of the total rate base (I will explain this derivation later in my testimony). This deferred income, shown on line 6, is stripped out of the equity rate base, shown on line 5, for the derivation of the total original cost rate base, line 7. The total original cost rate base is multiplied by the weighted cost of capital from line 17 to derive the return on the total original cost rate base, shown on line 8. The return on the deferred income portion of the equity rate base is calculated separately on line 9 by multiplying the deferred income by the real return on equity from line 15.
- Q. What changes have you made to the return on capital allowance calculations?
- A. Schedule No. 3 incorporates elements for which Staff witnesses are recommending different figures from those reflected in Frontier's workpapers as shown on Exhibit No. S-9, SCH 3. These elements include the debt rate base, the equity rate base, the weighted cost of debt, and the capital structures. The correct figures for both 1999 and 2000 are provided in my Exhibit No. S-8, SCH 3, Page 24.
- Q. Why are your equity rate base figures different from Frontier's equity rate base figures?
- A. Frontier's equity rate base figures, shown on Exhibit No. S-9, SCH 3, are drawn from SCH 5A, which calculates the trended equity rate base. The derivation of the equity rate base on Frontier's SCH 5A contains a number of errors that flow

through to every year's rate base calculation. I will explain these errors later in my testimony.

- Q. Why are your capital structure figures different from Frontier's capital structure figures?
- A. As noted earlier, Frontier has incorporated an across the board hypothetical equity ratio of 65%. As noted above, Mr. Green's recommended correct capital structure are: 54.05% equity/45.95% debt for 1999, 53.33% equity/46.67% debt for 2000, and 53.33% equity/46.67% debt for 2001.
- Q. What return on capital allowances have you included in the 1999, 2000, and test year 2001 cost of service models?
- A. As shown on Exhibit No. S-8, SCH-1, Page 12, I have incorporated a return on capital component of \$3,249,000 for the 1999 model, \$3,817,000 for the 2000 model, and \$3,476,000 for the test year 2001 model.

Schedule 4 -Income Tax Allowance

- Q. Please describe Schedule No. 4.
- A. Schedule No. 4 is the calculation of Frontier's allowance for income taxes. The calculation of Frontier's income tax allowance **should take into consideration the tax status of one of** the owners of Frontier, Ranch Pipeline, Inc. As explained by Staff witness John McClland, the tax factor should be reduced to reflect Ranch Pipeline's tax status for the years 1999, 2000, and 2001. Furthermore, the amounts used in Schedule No. 4's calculation are drawn from other schedules for which I and other Staff witnesses are recommending various changes as discussed below or in other Staff witnesses testimony.

Schedule 5A -Equity Rate Base Calculations

Q. Please describe Schedule No. 5A.

A. Schedule No. 5A contains the derivation of the equity rate base, which is used to derive the deferred income component of the cost of service. The basic purpose of Schedule 5A is to build up the rate base to reflect the increase in value of the equity portion of the rate base over time.

Q. What is the purpose for deriving a trended equity rate base?

A. As explained more fully in the Commission's Opinion No. 154-B, the intent is to account for the increased value of the pipeline's assets over time by writing-up the rate base. This write-up is passed on to the equity holders through deferred income. Because the deferred income is an asset, the equity holders are entitled to both a return of the asset and a return on the asset. The return of the deferred income as an asset is accomplished through an amortization over the life of the facilities, which shows up on line 19 of SCH5A. The sum of the annual amortizations of the deferred income shows up on line 20 of SCH 5A, which is carried over to the cost of service on SCH 1. The return on the pipeline's asset is accomplished through a return computed based on both the original cost of the assets and the unamortized portion, line 34, of the deferred income, which shows up on SCH 3.

Q. What is the Commission's methodology for deriving the equity rate base?

A. The Commission's Opinion No. 154-B established the methodology for developing jurisdictional rates for oil pipeline companies. Among other elements, Opinion No. 154-B established the mechanics of calculating the trended equity rate base in the cost of service. The Opinion states:

We have chosen to trend only the equity portion of the rate base. We have done this in order to ensure that the equity holder will not benefit from a write-up of the rate base with

respect to assets financed by debt. The equity holder will only be compensated for the inflation to the extent that assets are financed by equity. 31 FERC ¶ 61,377 at 61835 (1985)

In other words, the deferred income, which represents the return of the increased value of the assets to the equity holders, should be based only on the proportion of the assets financed by the equity holders. In practice the rate base is written up by applying an inflation factor to the rate base to reflect the increase in value of the facilities. However, the inflation factor is not applied to the whole rate base, only the equity portion of the rate base.

Q. Would you walk us through that calculation?

A. Yes. The methodology requires that the 1983 starting rate base is written-up according to a formula. The 1983 rate base on SCH 5A, line 22, in the first column, (which is the sum of the gross plant in service less the total deductions, plus the working capital) is multiplied by the equity ratio on line 23, then multiplied by the inflation factor on line 28. The product of that computation is found on line 19 in the next column, which is the adjustment for the following year's rate base to reflect the write-up of that equity rate base. It is referred to as "deferred income" to represent the value of the assets that ultimately should be recovered by the equity holders.

Q. What happens to this deferred income?

A. This deferred income is amortized over the remaining life of the pipeline and each year's amortization is added to the prior years' amortizations and included in the cost of service on SCH 1.

Q. How does your Schedule 5A differ from Frontier's model?

A. Frontier's derivation of the trended equity rate base, which is a key element in the cost of service for oil pipelines, reflects a significant misunderstanding of the

Commission's oil pipeline ratemaking methodology. The Frontier model and Staff's model differ in two significant aspects. The first difference is that Frontier improperly calculated a rate base that cumulatively over-inflates the base upon which the return is calculated. I have used the Commission's correct methodology. The second difference is that Frontier's model assumes a non-representative constant equity ratio of 65% across all the years. I have used equity ratios that are based on actual equity ratios provided by Frontier or ratios calculated by Mr. Green for 1999, 2000, and 2001 using equity ratios of a representative proxy group.

Q. How has Frontier calculated the equity rate base?

A. Frontier erroneously calculated a trended "equity" rate base on SCH 5A, line 19, by applying the inflation factor to the whole rate base. Thus, the figure on Frontier's line 19 is not really an inflated equity rate base but an inflated total rate base.

Q. How has Frontier calculated the amortization of the deferred income?

A. Frontier's cost of service model calculates the amortization of deferred income by dividing its inappropriately inflated total rate base by the remaining life.

Q. How has Frontier incorporated the amortization of the deferred income into the cost of service?

A. Frontier has reduced the annual amortization by multiplying the annual amortization on line 20 of SCH 5A by the equity ratio from SCH 3. The product of this calculation shows up on SCH 1 as part of the cost of service allowance for the amortization of deferred income.

Q. What's wrong with Frontier's calculation?

A. The problem with Frontier's calculation is that its calculation of the amortized deferred income is based on an over-inflated rate base figure in every year. In other words, Frontier first calculates an inflation-enhanced rate base for every year by multiplying the entire rate base by the inflation factor. Frontier then amortizes

this rate base adjustment over the life of the pipeline. Finally, Frontier takes this over-inflated rate base adjustment and multiplies it by the equity ratio before it's added to the cost of service. Frontier has applied the equity ratio at the back end of the calculation instead of the front end, leaving the total rate base over-inflated so that the application of the equity ratio does not capture only the equity portion of the rate base. The correct methodology is to apply the equity ratio to the rate base every year, and then apply the inflation factor and divide by the remaining life.

Q. What is the significance between the two methodologies?

A. Over time, the over-inflating of the rate base will lead to over-inflated deferred income and over-inflated allowances for the amortization of that deferred income. In the tables on the following page, I have constructed an example of the impact of these methodologies over even a short time frame. The first case is Frontier's method of adjusting rate base by only an inflation factor. The second case is the correct method of adjusting rate base by both the inflation factor and the equity ratio. Although we have calculated the actual allowance differently for the cost of service, the calculation is the same mathematically. It is the rate base to which the calculation is applied that makes the difference. In the second year, the difference in the calculating the equity rate base results in an increase of \$1.12 in the amortized deferred income. By the fifth year the difference in methodologies produces an increase of \$5.28, which results in a cost allowance for deferred income approximately ten percent higher than appropriate. Although the difference in the rate base derivation methodologies may appear somewhat arcane, the cost to consumers is clearly substantial.

Table 5

Frontier's Method : Rate Base + (Rate Base *Inflation Factor)					
Year	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Rate Base	\$10,000	10,700	11,499	12,250	13,108
Inflation Factor	7.00%	7.00%	7.00%	7.00%	7.00%
Remaining Life	10	10	10	10	10
Equity Ratio	65%	65%	65%	65%	65%
Amortized Def Inc	\$45.50	48.69	52.09	55.74	59.64
<u>((Rate Base * Inflation Factor)/Life)*Equity Ratio</u>					

Table 6

Correct Method : Rate Base + (Rate Base *Inflation Factor*Equity Ratio)					
Year	<u>1</u>	<u>2</u>	<u>3</u>	<u>4</u>	<u>5</u>
Rate Base	\$10,000	10,455	10,931	11,428	11,948
Inflation Factor	7.00%	7.00%	7.00%	7.00%	7.00%
Remaining Life	10	10	10	10	10
Equity Ratio	65%	65%	65%	65%	65%
Amortized Def Inc	\$45.50	47.57	49.73	52.00	54.36
<u>((Rate Base * Equity Ratio)*Inflation Factor)/Life</u>					

- Q. You noted that Frontier used a single equity ratio across all the years, what equity ratios have you incorporated into your cost of service analysis?
- A. To build the appropriate equity rate base over time, I have used the equity ratios shown in Exhibit No. BWC-30 for the year's 1984 through 1998. Because Frontier is a partnership, I have looked to the weighted average equity ratios of its parent companies. This information was provided by Frontier in response to Big West and Chevron's data request Interrogatory #5, and submitted by Big West and Chevron in Exhibit No. BWC-30, Page 1 and 2. (Pages 3 and 4 of Exhibit No. BWC-30 are marked "confidential" but pages 1 and 2 are not.)

- Q. Why not use the across-the-board estimate of 65% as Frontier has done?
- A. Frontier's cost of service model incorporates an equity ratio of 65% across all years. However, the only years in which the weighted average equity ratio of Frontier's parent companies reached this high was back in 1983 and 1984. The result is that Frontier's presumed equity ratio would over-inflate the equity rate base every year by the difference between the actual weighted average equity ratio and the presumed 65% equity ratio used by Frontier. Opinion No. 154-B instructs us to inflate only the equity portion of the rate base. As can be seen in Exhibit No. BWC-30, the difference between the two estimates of equity ratio has been as high as 15.5 percentage points, which would lead to a significant build-up in the trended equity rate base above what it ought to be. While Opinion No. 154-B provides for the inflating of the equity rate base for return purposes, it does not instruct us to over-inflate the rate base by presuming a higher equity ratio than actually existed over the years.
- Q. What equity ratios have you used for the years 1999, 2000, and 2001?
- A. I have incorporated Mr. Green's hypothetical capital structures and rates of return into the cost of service model to derive the transportation rates for the years 1999 and 2000 in order to calculate potential reparations and for the 2001 test year to establish rates for the future.
- Q. How do these capital structures differ from those you used for the years 1984 through 1998?
- A. The capital structures used for the years 1984 through 1998 reflect the weighted average equity ratios of the ultimate parent companies of the owners of Frontier as provided by Frontier. Ideally, the capital structure used for the derivation of the deferred income should be that of the pipeline company itself. But, because Frontier is a partnership, we must look to the equity ratios of its parent companies.

Big West and Chevron attempted to ascertain this information in its Interrogatory #5. (See Exhibit No. S-10, Page 7 and 8.) However, the response by Frontier (Bates number FR01278, reproduced in Exhibit No. BWC-30) reflects the equity ratios of the ultimate parents, not the immediate parents of Frontier. The further up the corporate ladder we go, the less representative is the capital structure of the pipeline company in question. In the absence of actual capital structures for the derivation of the equity rate base and return for all those years, I would prefer a hypothetically derived set of capital structures. However, the task of deriving those hypothetical capital structures for appropriate proxy groups for the period 1984 through 1998 is beyond the resources of our staff at this time. Consequently, I turned to the only data available, which was supplied by Frontier, to construct the equity rate bases for each of those years.

- Q. Have you used revised figures for other cost of service elements that appear in the equity rate base calculations?
- A. Yes, I have. The equity rate base spreadsheets contain a great deal of information carried over from other spreadsheets for which I and other Staff witnesses are recommending changes. The 1999, 2000, and 2001 Staff cost of service model incorporates the revised depreciation rates, the revised accrued depreciation balances, and 2001 carrier property additions as discussed earlier in my testimony, and revised inflation factors as discussed below.
- Q. What inflation factors have you used to calculate the write-up or trending of the equity rate base?
- A. I have used the Bureau of Labor Statistic's Consumer Price Index for All Urban Consumers (CPI-U), see Exhibit No. S-10, Page 6. The inflation factors used by Frontier in its workpapers differ from those I used. It is not clear what index Frontier used.

Q. Why did you use the CPI-U instead of some other inflation index?

A. Oil pipeline rates are derived using two inflation indexes. In between cost of service analyses, oil pipelines are permitted to adjust their transportation rates by the Producer Price Index (PPI) to reflect the changes in industrial prices over time. In a cost of service analysis, however, Opinion 154-B permits the analysis to use whatever inflation index appears most appropriate - as long as the index used to write up the equity portion of the rate base is the same index used to deflate the return components in the cost of service. In other words, it does not matter what inflation index is used, as long as it is the same index, because the inflationary component of the return on equity that is stripped out of the nominal return on equity gets built back into write-up of the equity rate base. The CPI-U is the same index as used by Mr. Green to deflate the return on capital component. Thus my use of the CPI-U is consistent with the requirements of Opinion No. 154-B.

Q. Have you made any other adjustments to the equity rate base calculation?

A. Yes, I have. Because Frontier suspended operations from April 1988 to May 1990, and was not performing services for the ratepayers, I have suspended the accrual of the deferred income for those years. Frontier's derivation of the equity rate base, as reflected on its workpapers shown in Exhibit No. S-9, SCH 5A, did include a continued buildup in the equity rate base for the years it has suspended operations. To be consistent with the suspension of depreciation expenses, I have also suspended the equity rate base write up for that period.

Schedule 5B -Debt Rate Base Calculations

Q. Please describe Schedule No. 5B.

A. Schedule No. 5B is the calculation of the debt rate base. Sch 5B is almost identical to SCH 5A in that it derives the total rate base for Frontier pipeline. SCH 5B stops

where SCH 5A continues on to derive the equity rate base and deferred income.

The debt rate base derivation is used on Schedule 3 for the derivation of the allowance for total return on capital.

Q. Where have you reflected the revised debt rate base amounts in your cost of service model?

A. The revised debt rate base is shown on Exhibit No. S-8, SCH 5B and SCH 3.

Schedule 1 -Cost of Service

Q. Please describe Schedule No. 1

A. Schedule No. 1 is the summation of the cost of service elements from all the other schedules. The table below summarizes the difference between Frontier's Page 700 cost of service reports and my Staff Frontier Model.

(\$000)	<u>1997</u>	<u>1998</u>	<u>1999</u>	<u>2000</u>
Frontier's Page 700 Model	\$9,203	\$9,680	\$8,579	\$9,267
Staff Frontier Model	\$8,332	\$9,276	\$6,830	\$7,593

A comparison of Frontier's Schedule No.1 and Staff Schedule No. 1 reveals significant differences between the cost of service components. Staff's recommendation for depreciation expense allowances is approximately one million less than the current expense reflected in the FERC Form 6. The difference in the calculation of the equity rate base resulted in a difference of about \$300,000 in the allowance for deferred income amortization. Staff's 1999 allowance for return on capital is approximately \$475,000 less than Frontier's calculated allowance. My estimate of the cost of service for the test year ending June 30, 2001 is \$7,178,000.

Grandfathered Rates

Sour Condensate Service & Changed Circumstances

Q. Will you briefly review the history of Frontier's current sour condensate tariffs?

A. Yes. Frontier had three tariffs, FERC Nos. 6, 7, and 8, governing the transportation of sour condensate that went into effect on May 25, 1990, all of which have been superceded or canceled. Oil pipeline tariffs are stamped "canceled" when they are superceded by a new tariff that amends the language of the provisions or adjusts the rates applicable under the service. The new tariff generally will reference the superceded tariff. The rates change but the terms and conditions of the superceded tariff remain in effect unless specifically noted in the new tariff. Hence, a "canceled" tariff doesn't necessarily mean that service under that tariff has been halted.

Frontier initiated its sour condensate transportation with its FERC No. 6 tariff on May 25, 1990, to reestablish its transportation service after the hiatus from 1988 to 1990. FERC No. 6 does not specify a direction of flow. Frontier's FERC No. 6 was superceded by FERC No. 9, which went into effect May 1, 1993. FERC No. 9 is still in effect. FERC No. 9 does not specify a direction of flow.

Frontier's FERC No. 7 tariff provided for transportation of sour condensate eastward from Divide Junction, Wyoming, to Casper, Wyoming. FERC No. 7 was canceled on May 11, 1993, when the direction of flow on the line was reversed.

Frontier's FERC No. 8 tariff provided for transportation of sour condensate westward from Divide Junction, Wyoming, to Ranch Pipeline, Utah. FERC No. 8 has seen a succession of replacements occasioned by the indexing of the rates over time. FERC No. 8 was canceled by FERC No. 14, which went into effect July 1, 1996. FERC No. 14 was canceled by FERC No. 16 on July 1, 1998, which was canceled by FERC No. 19 on July 1, 1999, which was canceled by FERC No. 21

on July 1, 2000, which was canceled by FERC No. 22 on December 22, 2000.
FERC No. 22 is still in effect.

Q. The current Frontier local tariff governing sour condensate transportation from Divide Junction, Wyoming, to Ranch Pipeline, was made effective May 25, 1990. Explain whether the sour condensate tariff rate is "grandfathered" and whether it is subject to change in this proceeding?

A. The Energy Policy Act of 1992 (EPACT) provided that any oil pipeline rates in effect as of October 24, 1992, were deemed just and reasonable. Hence, Frontier's local tariff FERC No. 8 contains a grandfathered rate. The EPACT also provided that "grandfathered" rates could be challenged if parties could show substantial changes had occurred in the economic circumstances that were the basis of the rates or the nature of the service provided after the date of the enactment of EPACT. **Importantly, however, in a recent order in ARCO v. Calnev Pipe Line, L.L.C., 97 FERC 61,057 (2001), under circumstances very similar to the situation here, the Commission found that the complainant did not have to demonstrate a substantial change in economic circumstances. The Commission said (mimeo, at 4):**

Calnev has changed its rate a number of times since October 24, 1992. Most of those changes were made pursuant to the Commission's indexing methodology. Therefore, Calnev's current rates are the product of indexing and thus are not grandfathered rates per se. As the Commission stated in Order No. 561, "the Commission is mindful of the need to avoid indexed rates that increase substantially above a pipeline's actual costs...Complaints against rates that have been indexed will continue to be governed by the procedures set forth in section 13(1) of the ICA." (Footnote omitted)

Therefore, I do not believe it is necessary to demonstrate that there has been a substantial change in the economic circumstances that were the basis of the rate.

As my testimony indicates, there *are* reasonable grounds for believing that the discrepancy between the actual costs experienced by Frontier and the existing rates at issue is so substantial that the existing rates are not just and reasonable. However, even if the test did apply, there is more than enough evidence to pass it. In this case there have been changes in (1) the source markets, (2) the destination markets, (3) the direction of flow, (4) the proportions of crude type transported, (5) the cancellation of the tariff itself, and (6) the life expectancy of the pipeline.

Q. Can you elaborate on these changes?

A. Yes. When Frontier resumed operations in 1990, it reopened as a sour condensate pipeline transporting sour condensate eastward from the Salt Lake City to the Casper, Wyoming, refineries. In 1993, Frontier canceled its existing sour condensate tariff to begin transporting sour condensate and crude petroleum in a westerly direction from the Rocky Mountain production areas to the Salt Lake City refineries. Currently Frontier transports almost exclusively crude petroleum from Canada and almost no sour condensate. Thus Frontier's principal source market has shifted from Salt Lake City, to the Rocky Mountains to Canada. Similarly, its destination market has shifted from Casper Wyoming to Salt Lake City. The direction of flow obviously is 180° different than when the sour condensate tariff went into effect in May 1990. In addition, the proportions of product transported has shifted from 100% sour condensate to approximately 0.5% (one half of one percent) sour condensate. Finally, the building of the Express pipeline in 1997 enabled Salt Lake City refineries to contract for Canadian crude and synthetic oil supplies in Alberta. These Alberta oil fields in Western Canada have extended the economic life of Frontier's facilities substantially. Canadian reserves now account for over 90% of Frontier's throughput. These issues are more thoroughly examined in Mr. Garner's testimony at Exhibit BWC-104.

Rate Design

Volumes

- Q. Earlier in your testimony you provided, in Table 2 of this Exhibit No. S-7, Staff's recommended revised rates for the transportation of crude and sour condensate over Frontier's pipeline. What volumes did use to derive those rates?
- A. I used actual annual volumes by tariff segment for 1999 and 2000. For the 2001 test year I used volumes for the last half of 2000 and the first half of 2001. The annual volumes for 1999 and 2000 were provided by Frontier in response to Staff's data request WHG - 1Fr, question 2, which I have reproduced in Exhibit No. S-10, page 9 and 10. Volumes for the first half of 2001 were provided in response to a Big West and Chevron data request which has been reproduced in Exhibit No. BWC-20, page 33. This sheet was marked Highly Confidential. The volume figures for all three periods are shown in Exhibit No. S-9, "Rates," Page 56.
- Q. Your volumes schedule references different tariff numbers than you discussed earlier. Would you explain that difference?
- A. Yes. Oil pipeline tariffs are periodically adjusted to allow the indexing of the rates by the Producer Price Index. The revised rates are given a new tariff number designation and the older tariff number is then canceled. Hence, the tariff numbers in the complaint and Commission order differ from the tariff numbers on the volume sheets.

The tariff labeled FERC No. 18 on Exhibit No. S-10, page 9 and 10 of 10 is the successor tariff to Frontier's local crude tariff FERC Nos. 10, 11, 12, 13, 15, and 17. FERC No.18 has, in turn, been replaced by Frontier local tariff FERC Nos. 20 and 23. The designations "A" and "B" refer, I believe, to the two destinations listed on the tariff sheet, Divide Junction, Wyoming, and Ranch Pipeline, Utah.

The tariff labeled FERC No. 19 on Exhibit No. S-10, page 9 and 10 is Frontier's local sour condensate tariff, which is the successor tariff to Frontier tariff FERC Nos. 8, 14, and 16, and is now succeeded by Frontier's local tariff FERC Nos. 21 and 22.

The tariff labeled FERC No. 2318 on Exhibit No. S-10, page 9 and 10 is Amoco's joint rate tariff that transports over Amoco Pipe Line Company, Frontier, and Anschutz pipelines.

The tariff labeled FERC No. 21 on Exhibit No. S-10, page 9 and 10 is the Express joint rate tariff, not the Frontier local sour condensate tariff.

Rate Design

Q. How did you design the rates for Frontier?

A. The essential model for the rate design is simply dividing the costs by the barrels moved. However, two important aspects must be factored in: one, because some movements on Frontier traverse significantly different distances, the rate design has to include a barrel-mile component; and, two, some cost elements are not distance related, so the barrel-mile component is not applied to them.

Q. What are the mileages for the various movements?

A. Frontier's tariff FERC No. 22 (formerly FERC Nos. 8, 14, 16, 19, and 21) provides for the transportation of sour condensate over a short 19.5 mile stretch of pipe from Divide Junction, Wyoming, to Ranch Pipeline, Utah. Frontier's local FERC No. 23 (formerly FERC Nos. 10, 11, 12, 13, 15, 17, 18 and 20) provides for transportation approximately 270 miles from Casper, Wyoming to Divide Junction, Wyoming, and approximately 290 miles from Casper to Ranch Pipeline, Utah. Frontier's portion of the joint tariffs Express' FERC No. 21 and Amoco's FERC No. 2318 provide for crude oil transportation approximately 290 miles from Casper to Ranch Pipeline.

Consequently, the distance related cost components must be allocated among three distance categories; 19.5 miles, 270 miles, and 290 miles.

Q. What did you do with these mileage categories?

A. To derive the barrel-mile allocations, I multiplied the annual volumes, by tariff segment, times the corresponding mileages. I then calculated a barrel-mile share for each segment and multiplied the shares by the total distance-related cost components. I then divided the dollar-shares by the volumes transported to get the distance-related rate per barrel. See Exhibit No. S-8, page 56, columns labeled "Distance Related Costs."

Q. What cost components are not distance related?

A. The Administrative and General (A&G) cost components are generally not considered distance-related. Consequently, these costs are simply divided by the total barrels transported. The A&G costs from Exhibit No S-8, SCH 2B, line 18, less the pipeline taxes from line 17, are used for the non-distance-related rates. See Exhibit No. S-8, page 56, columns labeled "Non-Distance-Related Costs."

Q. How is the total rate derived?

A. The total rate is the sum of the non-distance-related rates and the distance-related rates.

Q. What rates are you recommending for Frontier for the future?

A. I am recommending three rates for Frontier:

-- \$0.1075 per barrel for the movement of sour condensate from Divide Junction, Wyoming, to Ranch Pipeline, Utah, under Frontier local tariff FERC No. 19 (formerly FERC No. 8),

-- \$0.5250 for the movement of crude oil from Casper, Wyoming, to Divide Junction, Utah, under Frontier local tariff FERC No. 21 (formerly FERC No. 20),

-- \$0.4941 for the movement of crude oil from Casper, Wyoming, to Ranch Pipeline, Utah, under Frontier local tariff FERC No.21 (formerly FERC no. 20).

Q. Your calculation includes rates associated with the joint Amoco and Express tariffs. Are you recommending changes in those rates are well?

A. No, I am not. The inclusion of the volumes associated with those tariff movements is done solely to properly calculate a cost per barrel on Frontier's pipeline.

Reparations

Q. What is your estimate of the maximum potential reparations due from Frontier for the differential between the current local tariff rates and your recommended local tariff rates?

A. Staff's analysis indicates that Frontier's revenues have substantially over-collected its just and reasonable cost of service. I have calculated the difference between the current Frontier local tariff rates and those I have recommended for 1999 and 2000. These rates and charges are shown on Exhibit No. S-8, Page 57. My calculations indicate that the maximum potential reparations for the local tariff shipments would be \$2,058,000 for 1999 overcharges and \$1,415,000 for 2000 overcharges. These amounts should also be adjusted for accrued interest on the reparation.

Q. Do these reparations include potential reparations for the joint tariffs?

A. No, they do not.

Q. How would you calculate potential reparations due Big West and Chevron?

A. Reparation due to individual shippers on Frontier would be calculated by multiplying the volumes transported for those shippers the difference between the charges assessed upon those shippers under the current rates and the charges assessed under my recommended rates for the relevant periods. I have not made a specific calculation for the amounts that may be owed to Big West or Chevron.

Close

Q. Does this conclude your testimony?

A. Yes, it does.

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

**BIG WEST OIL CO. v. FRONTIER PIPELINE CO. and EXPRESS PIPELINE PARTNERSHIP
DOCKET No. OR01-2-000, et al.**

**CHEVRON PRODUCTS CO. v. FRONTIER PIPELINE CO. and EXPRESS PIPELINE PARTNERSHIP
DOCKET No. OR01-4-000, et al.
(Consolidated)**

AFFIDAVIT

City of Washington)
) **SS:**
District of Columbia)

Patrick R. Crowley, being first duly sworn, deposes and says that he is the same Patrick R. Crowley whose Prepared Direct Testimony accompanies this affidavit; that such testimony was prepared by him; that he is familiar with the contents thereof; that the facts set forth herein are true and correct to the best of his knowledge, information, and belief; and that he does adopt the same as his sworn testimony in this proceeding.

Subscribed and sworn to before me,
the undersigned notary public, this ___ day of _____, 2001.

Notary Public

My Commission expires:

Big West Oil Company v. Frontier Pipeline Company
Docket No. OR01-02-000, et al. & OR01-04-000, et al.

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