electric utility industry[363] that, Tesoro asserts, show that when interest rates *increase* by 100 basis points, the equity risk premium will *decrease* by 37 basis points. Similarly, when interest rates *decrease* by 100 basis points, the equity risk premium above those riskless investments will *increase* by 37 basis points.[364]

Like Tesoro, Williams backcasts only equity rates of return. Williams thus also avoids relying on the Modigliani-Miller hypothesis. Williams' backcast analysis, however, differs from both the Carriers' and Tesoro's. Williams relies on data for rates of return for comparable pipelines beyond the 1997-1998 time frame. Williams uses three different methods to backcast equity returns and then uses the average of the results produced by the three different methods. Williams multiplies the average of the three methods by 1.05 to reflect a five percent common equity flotation.[365] We discuss Williams' three methods separately.

The first method starts by using publicly available data for the pipelines in the petroleum pipeline proxy group to perform a traditional discounted cash flow (DCF) analysis of required investor returns. In a DCF analysis, the most critical parameter is the expected rate of growth in stock dividends. Williams relies upon Institutional Brokers Estimate System (I/B/E/S) data for the expected growth rate.[366] Because the I/B/E/S data on which Williams relies is generally only available for the proxy sample companies as far back as 1990,[367] yearly DCF estimates of equity returns can be determined only for some of the many years at issue. To determine DCF-based returns

[363] *See* WBT-52, Panel C. All of the parameter estimates in that paper are statistically significant. *Id.,* at 6.

[364] FJH-T (E-2) 67.

[365] *See* JSG-2 Schedule 8.

[366] JSG-T (W-2) 32. I/B/E/S publishes a survey of financial analysts' predictions for future performance.

[367] *Id*.

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for earlier years, Williams estimates the *average* risk premium over the long-term U.S. Treasury bond yields for the five earliest years for which I/B/E/S data are available.[368] Williams then adds this average risk premium to the actual yield on Long-Term U.S. Treasury bonds for each of the earlier years for which data were unavailable to produce a backcast estimate for the annual return on equity for each company.[369] The annual median return of the group is then adopted as the petroleum pipeline proxy equity return.[370]

Williams' second method is similar to the first, with the difference being that Williams calculates DCF returns for each of the TAPS Carrier parent companies. Williams uses historical data to calculate DCF required equity returns. Where I/B/E/S growth rate forecasts are available for a given company, Williams uses them.[371] For a number of years before 1981, Williams uses Value Line data to calculate a retention growth rate.[372] The moving three year average growth rate of retained earnings is then used as an estimate of future rates of growth within a DCF framework. When retention growth rate data are not available, Williams backcasts equity rates of return in similar fashion to the approach used for the petroleum pipeline proxy companies.[373] Where results of this analysis fail to yield results of return on equity that are reasonable in light

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[368] *Id.*

[369] JSG-2 Schedule 11 at 2-7.

[370] JSG-2 Schedule 11 at 1. Gaske explained that his use of the median of the data, rather than the mean, was informed by recent FERC practice and the fact that the mean is more likely to be skewed by outliers in the data. Tr. 4386 (JSG).

[371] JSG-2 Schedule 12. Gaske reports that I/B/E/S data were available for most TAPS parent companies as far back as 1981. JSG-T (W-2) 33.

[372] JSG-T (W-2) 33.

[373] JSG-T (W-2) 33-34.

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of the prevailing costs of debt, Williams "pragmatically" adjusts results[374] and uses the median of the different estimates to determine annual return on equity.

Williams' third method relies on past Alaskan pipeline cases to determine the appropriate return on equity. From 1981-1984, Williams relies on a FERC pipeline decision[375] that established required returns to equity for the Kuparuk pipeline, an oil pipeline carrying crude oil from the Kuparuk field on the North Slope to the beginning point of the TAPS.[376] For 1985-1992, Williams uses the APUC decisions[377] for return on equity for the Kenai pipeline.[378] For years before 1981, Williams backcasts by assuming that the risk premium difference between a corporate bond yield in 1981 and the FERC's equity return finding remains constant, at 4.89 percent.[379] For years after 1992, Williams also assumes that the premium difference between a corporate bond yield and the APUC's equity return finding remains constant, at 5.95 percent. Williams contends that the disparity in the "constant" premium differences was due to changes in capital markets. Williams agrees with Tesoro's general contention that the size of the premium above a riskless investment varies inversely with interest rates.[380]

[374]JSG-T (W-2) 33.

[375]*Kuparuk Transportation Co.*, 55 F.E.R.C. ¶ 61,122, 61,379 (1991).

[376]JSG-T (W-2) 35.

[377]*Re Kenai Pipe Line Co.*, 12 APUC 425 1992 WL 696192 (Alaska P.U.C., 1992); *Re Kenai Pipe Line Co.*, 13 APUC 29 (1993).

[378]JSG-T (W-2) 34.

[379]*See* JSG-2 Revised Schedule 6. In his written testimony Gaske says that he backcasts the *Kuparuk* decision data by using average yields on long-term United States Treasury bonds. JSG-T (W-2) 36. A comparison of figures in JSG-2 Revised Schedule 6 with the Treasury bond data contained in JSG-2 Schedule 11 reveals that the JSG-2 Revised Schedule 6 data are not Treasury bond data. We infer, therefore, that they are properly labeled and represent some sort of corporate bond data.

[380]Tr. 4374 (JSG).

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None of the backcast methods offer the same degree of rigor as normally seen for rate of return recommendations. As Williams stresses, backcasting results are "not as reliable as a detailed analysis of every company for each year."[381] We decide the annual equity rate of return based on the evidence on this record.

We find the Carriers' backcast method too speculative. Their recommendations presume a capital structure and cost of debt that are inconsistent with our findings on the appropriate capital structure and cost of debt for TAPS. Further, while the Carrier's approach might be applied to our findings on appropriate capital structure and cost of debt, doing so requires complete reliance upon the validity of the Modigliani-Miller hypothesis. The record suggests that as a theoretical construct, and as a contribution to financial theory, the Modigliani-Miller theorem is of considerable importance.[382] However, the record also demonstrates considerable controversy over the extent to which the Modigliani-Miller theorem should be applied to public utility finance and regulation.[383] Because there are reasonable alternative approaches that do not rely on the theorem, we pick an alternative approach.

The Carriers' approach is unreliable for additional reasons. The Carriers assert that "[o]ver longer time periods, the better approach is to hold constant the differences between equity return and bond yields."[384] However, they do not provide

[381]JSG-T (W-2) 32-33.

[382]Tr. 2751-52 (WBT).

[383]The Modigliani-Miller theorem's applicability is affected by taxes, the threat of bankruptcy, and the cost of enforcing complex debt contracts. Tr. 2755 (WBT). *See also* 75-WBT-W, and Tr. 2757 (WBT). The degree to which the theorem importantly deviates from real-world conditions was subject to considerable dispute at hearing. *See, e.g.,* Tr. 4984 (FJH) and Tr. 2758 (WBT).

[384]T-10 (WBT) 61. Tye urges that his view reflects "overall consensus;" he does not, however, offer evidence. Tye advocates adopting the constant risk premium hypothesis in the absence of strong evidence to the contrary. Tr. 2601 (WBT).

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empirical or theoretical support for that assertion. The Carriers' approach to calculating return on equity hinges on the assumption that a constant risk premium adequately approximates reality. Both Williams[385] and Tesoro[386] challenge this proposition. The record suggests that, rather than holding constant, there is an inverse relationship between an equity risk premium and a riskless investment broadly throughout the economy.[387] We, therefore, do not assume a constant risk premium.

Finally, even if over longer time periods the difference between equity return and bond yields were relatively stable, there is significant annual variation. For example, the Carriers' recommendation for what equity investors in an average pipeline require is 13.3 percent for both 1997 and 1998, and 16.0 percent for 1999;[388] the long term United States Treasury bond yield was 6.60 percent, 5.66 percent and 6.11 percent for 1997, 1998, and 1999, respectively.[389] The difference between bond yields and recommended return on equity therefore ranges from 6.70 percent in 1997 to 9.89 percent in 1999. A swing of 319 basis points over three years raises the issue of whether the choice of the "anchor year" (in this case, 1997) is appropriate for backcasting purposes.[390] The Carriers assert that using 1997 is conservative. To achieve just and reasonable rates we must use a reasonable rather than "conservative" approach. Relying on a single year, in light of the very significant annual variation, is

[385]Tr. 4374 (JSG).

[386]Tr. 5056 (FJH); FJH-T (E-2) 67-68.

[387]223-FJH-C Workpaper 3. The record indicates that this inverse relationship also appears to hold for electric utilities. 223-FJH-C Workpaper 2.

[388]T-10 (WBT) 13.

[389]JSG-2 Schedule 12 at 10.

[390]As noted in Part IV Section B.2, we had similar concerns with Tesoro's approach to backcasting the cost of debt.

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not reasonable. Therefore, we reject the Carriers' approach to determining return on equity.

Tesoro's approach is also inappropriate. Although Tesoro's method does not require use of the Modigliani-Miller hypothesis, like the Carriers, Tesoro relies on a single year for backcasting annual rates of return to 1968 and a theory about how petroleum pipeline equity interest rates move with United States Treasury bond. Above, we discussed the problem of relying on only a single year from which to backcast all subsequent equity returns: if the single year is unrepresentative, then reliable return on equity calculations are undermined.

We also find Tesoro's *method* of backcasting rates of return on equity too speculative. Tesoro relies on parameter estimates from the electric utility industry that the Carriers point out are not clearly applicable to petroleum pipelines.[391] Tesoro misapplies the Maddox, Pippert and Harris results in its return on equity calculations. Although Tesoro's misapplication of the Maddox *et al.* results can be partially corrected,[392] corrections create significant out-of-sample projection problems.[393] These errors make Tesoro's proposed rate of return on equity calculations unreasonable.

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[391]T-10 (WBT) 60.

[392]WBT-52, Panel B.

[393]While Maddox *et al.* detect an inverse relationship between the equity risk premium and the interest rate on risk-free securities, this analysis assumes and finds statistically significant a number of constant terms that capture the average difference between equity costs and government bond yields during different time periods. Tesoro ignores these constant terms. They are, however, integral to the overall projection of equity rates based on bond yields. T-10 (WBT) 60. Data for the Maddox *et al.* paper come from 1980 through 1993. WBT-52 Panel C at 3. Separate dummy variables, crucial to the prediction of risk premium given bond yield, are calculated for the following periods: 1984-1993, 1987-1993, 1991-1993, 1992-1993. *Id.,* at 4. Thus, these variables change substantially from period to period, and new variables are introduced every few years. Considering that Maddox *et al.* relied on four dummy variables for a ten-year period, using the study results for periods 15 years earlier and 5 years later is problematic. It is unlikely that the reliability of the Tesoro results would hold for such extrapolations.

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Williams' approach to backcasting the return on equity has several strengths. First Williams relies, whenever feasible, on available data from comparable companies. Williams constructs conventional DCF estimates of investor-required returns for the petroleum pipeline sample when possible. Second, when forced to backcast results from the petroleum pipeline sample, Williams adopts the most-recent 5-year average of the difference between the DCF equity results and riskless United States Treasury yields. Use of the 5-year average smoothes out some of the volatility that plagues the Carriers' and Tesoro's analyses. Third, Williams calibrates its recommendation by ensuring conformity to past regulatory decisions concerning appropriate equity return for Alaska oil pipelines.[394] Fourth, the calibration seems to reflect an inverse relationship between risk premiums and interest rates over broad periods, a relationship that the record supports.[395] Finally, Williams' approach of combining several methods for backcasting minimizes some of the effects of projection errors.[396]

Although the other parties do not directly criticize Williams' approach,[397] we note several faults. Williams' backcast and forecast of the Alaska oil pipeline results

[394]The Alaska pipeline decisions were based on much richer equity positions than the capital structure adopted here. Accordingly, one could argue that the applicable rate of return should be adjusted to reflect this richer capitalization. *See, e.g.,* Tr. 2948-49 (WBT). However, the Kuparuk pipeline decision adopted a return on equity based on "average petroleum pipeline" risk, without reference to the capital structure and return to debt that they adopted (which reflected parent company financials). Thus, the FERC's findings were expressly inconsistent with Modigliani-Miller. We find mechanical reliance on Modigliani-Miller both speculative and unnecessary.

[395]223-FJH-C Workpapers 2 and 3; Tr. 4374.

[396]Tr. 4382 (JSG).

[397]The Carriers argue that Gaske should have provided an increased risk premium in his backcast results. T-10 (WBT) 54. In this section of the order, however, we establish rates of return for an "average" petroleum pipeline before considering special TAPS risks. Special TAPS risks are considered in Part IV,B.4 and Endnote 8.

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is somewhat problematic. First, Williams uses a single "anchor year" to backcast and forecast these results.[398] Second, Williams' use of corporate bond yields for forecasting and backcasting purposes is inconsistent with its use of United States Treasuries to backcast DCF results. A theory regarding the risk premium between "risk free" United States Treasuries and equity returns was articulated but no corresponding theory was presented for a similar relationship between corporate bonds and equity returns.[399] To produce more reasonable results, we modify Williams' recommendation to rely on the most recent five-year average of the risk premium between United States Treasuries and the Alaska Pipeline decisions.

Finally, when determining appropriate return on equity based on Alaska oil pipeline decisions, Williams reported but did not use return on equity numbers for 1985-1988 from the *Kuparuk* decision.[400] The 1985-1988 years, however, overlap with the APUC's *Kenai* pipeline decisions (which spanned 1985-1992). By ignoring the overlap and relying only on *Kuparuk*, Williams consistently chose the higher return on equity number for those three years. When given multiple choices, but no theoretical grounds for choosing, the more reasonable approach is to average the overlapping numbers.[401] We thus modify Williams' Alaska oil pipeline decision analysis.

The result of modifying Williams' Alaska oil pipeline decision analysis is an increase to the backcast risk premium for years before 1981 from 4.89 percent to 4.98

[398]Gaske argued for using the "most recent" year for backcasts by saying that he relied on the number that was as close to the projected or backcast period as possible. Tr. 4373 (JSG).

[399]Again, Gaske's prefiled testimony refers to United States Treasury yields, while his JSG-2 Revised Schedule 6 appears to use some unspecified grade of corporate bond yields.

[400]*See* JSG-2 Revised Schedule 6; JSG-T (W-2) 35; *Kuparuk Transp. Co.*, 55 F.E.R.C. ¶ 61,122, 61,379 (1991).

[401]Tr. 5027-78 (FJH).

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percent, and the "forecast" risk premium for years after 1992 from 5.95 percent to 6.21 percent. We apply these back- and forecast risk premiums to U.S. Treasury Yields rather than to corporate bond yields. The results of these modifications to Williams' approach for determining return on equity are found in Exhibit 17.

Finally, we modify Williams' backcast rate of return because the required rates of return on equity of the TAPS parent companies bear no clear and systematic relationship to the required rates of returns on equity of petroleum pipeline companies. Accordingly, Williams' reliance on the TAPS Carrier parent company DCF results to derive its recommended 1968-1996 equity rates of return is not reasonable. We instead average across the proxy pipeline DCF and the modified Alaska oil pipeline decision results.[402] These adjustments to Williams' analysis are shown on Exhibit 18 and yield annual cost of equity for 1968-1996, not including any special TAPS risk premium. We adopt the annual rates of return on equity contained in Exhibit 18 for years 1968-1996.[403]

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[402]Gaske urged that averaging across methods would help to smooth out "random glitches" in the data. Tr. 4382 (JSG). Averaging is a reasonable approach given acceptable and complementary methods.

[403]The resulting annual rates of return on equity are comparable to the rates awarded in other Alaska oil pipeline decisions. The APC allowed a 13.00 percent return on equity for the Nikiski pipeline in 1976; the backcast return calculated above for the average petroleum pipeline company in 1976 is 13.06 percent. In *Re Exxon Pipeline Company* the APC provided for a 15 percent return; however, this appears to reflect a one percent risk premium to account for special TAPS risks. *See* 66-WBT-E at 91-92 and 1 APUC 580, 601 (1980). Removing the 1 percent risk premium is appropriate because we are reviewing the appropriate rate of return on equity for TAPS, to which a risk premium may be later added. The backcast calculated above for 1978 is 14.67 percent. The APUC allowed a 17.00 percent return on equity for the Cook Inlet pipeline in 1980; the backcast calculated above for 1980 is 17.50 percent. *See* 68-WBT-E for Alaska oil pipeline decision benchmark data.

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4. Risk Premium to Reflect Special Risks of TAPS

If the business risks of TAPS are greater than those of an average pipeline project, then TAPS investors require a premium above the rate of return granted to the average pipeline. The parties agree that risks for ongoing TAPS operations are roughly comparable to the average risk faced by other pipelines.[404] The parties also agree that during its early planning and construction phase, TAPS faced greater risks than those faced by an average pipeline.[405] To determine an appropriate risk premium for 1968-1996, we resolve three questions. First, how much compensation is necessary to compensate for unusual risks? Second, should the risk premium be applied to debt, equity, or both? Finally, how long should investors collect this risk premium?

The Carriers urge that a risk premium of two to five percent[406] be applied to the entire TAPS investment. They assert that a risk premium should be applied to the entire cost of capital, rather than just equity capital because the entire pipeline asset

[404] T-3 (WBT) 39; FJH-T (E-2) 65; Tr. 4944-45 (FJH); JSG-T (W-2) 39. There is agreement that current risks on TAPS are either slightly more, slightly less, or equal to those of the average pipeline. None of the parties proposed making an adjustment to the rate of return compared with the comparative pipeline sample groups to compensate for extraordinary on-going risks.

[405] T-3 (WBT) 48; FJH-T (E-2) 55; JSG-T (W-2) 39.

[406] T-3 (WBT) 48.

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was at risk.[407] The Carriers also argue that this risk premium should be applied throughout the stipulated 34.5-year economic life of the line.[408]

Williams advocates that a risk premium of 0.50 percent[409] be applied to equity investment in TAPS.[410] During the hearing, Williams's expert witness testified that only equity investment, rather than the entire pipeline, was put at risk. Thus only equity capital was deserving of a risk premium.[411] The Williams analysis allows for a risk premium on initial project capital expenditures until such capital is recovered.[412]

Tesoro urges that a risk premium ranging from 0.33 to 0.87 percent,[413] and averaging 0.48 percent,[414] should be applied to the entire TAPS investment.[415] While Tesoro agrees that the risk premium should be applied to the entire cost of

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[407]T-3 (WBT) 51-52. Although Carriers attribute a risk premium to the entire rate base, in calculating AFUDC and annual revenue requirements they apply the entire weight of this risk premium only to the return on equity. This considerably boosts the equity risk premium; *see* JSG-T (W-2) 45. For example, given their recommended capital structure, during 1997-2000 the Carriers' 3.5 percent midpoint risk premium on all capital converts to a 4.5 to 4.7 percent equity risk premium. 71-WBT-W.

[408]T-3 (WBT) 42.

[409]JSG-T (W-2) 44.

[410]Williams witness Gaske's recommended overall return does not include a risk premium on debt; *see* JSG-2 Schedule 10.

[411]Although the Carriers urged that Dr. Gaske had admitted in prefiled testimony that during the construction era the entire pipeline was at risk and thus deserving of a risk premium (*see* T-10 (WBT) 39), during oral testimony Dr. Gaske reiterated his opinion that only equity investment, and not the entire pipeline, was put at risk. *See* 4376-77 (JSG). Thus, his use of the phrase "entire investment" in his prefiled testimony presumably refers only to "equity investment." *See* JSG-T (W-2) 42.

[412]JSG-T (W-2) 44. It is not clear the duration for which Williams believes a risk premium is appropriate, but oral testimony at the hearing suggests that Williams advocates the risk premium applying through 2030 on construction era investment (*see* Tr. 4376 (JSG)), given its view that TAPS will last through 2030. *See* BEW-T (W-3) 23.

[413]FJH-12 at 1-2.

[414]T-10 (WBT) 37.

[415]FJH-12.

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capital, it does so only through 1981.[416] Tesoro asserts earlier-period risks have passed, and investors require compensation only for prospective risks.[417]

The parties' positions on the appropriate risk premium vary because of differences in their assessment of a) the magnitude of the special TAPS risks; b) the type of capital exposed to extraordinary risks; and c) the proper method for translating the assessed risk into a rate of return premium that investors in a stand-alone TAPS would have required. The parties' introduced record from Phase I of the original TAPS litigation to evaluate the magnitude of special TAPS risks and the amount of capital exposed to those risks.[418] The discussion of early-period TAPS risks in the Phase I exhibits is much more extensive than the direct discussion by the parties' expert witnesses in these dockets. We therefore consider those portions of the Phase I record that were introduced in the record in these consolidated dockets along with the testimony of current expert witnesses.

Considering a risk premium on a "backwards" looking basis is extremely unusual. It is challenging because we are removed from the events that informed investor perceptions of TAPS risks. Nonetheless, based on the record, we review and carefully evaluate special TAPS risks as they would have been perceived from the perspective of a rational, well-informed, prudent investor at the time of investment.[419]

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[416]FJH-12 at 1-2.

[417]FJH-T (E-2) 55-56.

[418]*See* Endnote 1 at 2-3.

[419]We must be particularly careful not to diminish the rates of return that construction era investors would have demanded, particularly now that we are looking at TAPS after more than twenty years of successful operation.

Relevant investor risk in TAPS can be divided into three time periods: 1) before May 1974, 2) between May 1974 and June 1977, and 3) after June 1977.[420] The first was the pipeline planning phase ending with State and Federal issuance of right-of-way permits. The second period was pipeline construction. The third period is pipeline operation.

Investors faced various types of risks: non-completion, economic, litigation, and regulatory. Non-completion risk is the risk that technological, regulatory, or other factors could stop the project before completion. For an investor, project non-completion would be catastrophic because much of the money invested would not be recovered and no return earned.[421] Economic risk is the risk that cash flow will be insufficient to provide adequate return on or of capital. Litigation risk consists of the risk that shippers could challenge as imprudent costs that Carriers attempt to recover in rates. Regulatory risk is that risk that regulators would regulate TAPS in an unusual manner that would deny investors an adequate return. We analyze each of these risks in detail in Endnote 8 subparts (a) through (d). Based on that analysis, we find that there was significant risk to investor capital before May 1, 1974 and some risk thereafter. Below we summarize our analysis of the risks facing investors.

[420]Carrier witness Tye also suggests that risks should be considered in terms of three periods. His demarcation of relevant periods, planning and construction (1968-1977), post-construction cost recovery (1977-1985), and ongoing operation-phase risks, differs from ours. The difference in relevant temporal periods is due to our findings regarding relevant risks.

[421]Non-completion need not entail total loss of all investment to date, given the possibility of positive salvage value as well as possible tax benefits.

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a. Risk of Non-completion	Non-completion risk premium awarded due to legal and regulatory uncertainty prior to May 1, 1974, but none awarded post-May 1, 1974
b. Economic Risk	
i. Risk of inadequate physical supply	Less risk than the average pipeline
ii. Risk of inadequate throughput due to competition	Less risk than the average pipeline
iii. Risk of throughput interruption	No significant additional risk compared to average pipeline
iv. Risk that shipping oil is uneconomic for producers	Risk premium added for risk that post-1974 costs might be greater than those associated with an average pipeline
c. Post-construction regulatory risks	Policy reasons dictate no risk premium for post-construction regulatory risk
d. Post-construction litigation risks	Policy reasons dictate no risk premium for post-construction litigation risk

The specific factors listed above and analyzed in Endnote 8, suggest that investors in a stand-alone TAPS would have faced greater risk than investors in an average pipeline. Accordingly, we award a risk premium. We determine an appropriate risk premium by translating risks that investors faced into a premium to the cost of capital that investors would have required.

Tesoro asserts that differences between construction risk for TAPS and TAPS' operation risk can be captured by differences in utility bonds ratings of Baa (for TAPS during 1968-1981) and A (for TAPS at present).[422] However, as the Carriers note, Tesoro fails to fully explain the basis for this conclusion.[423] Specifically, Tesoro fails to clearly explain why the difference between Baa and A bond ratings is analogous

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[422]FJH-T (E-2) 56.

[423]T-10 (WBT) 32.

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to the risk differentials between TAPS and an average pipeline. Accordingly, we find that the Tesoro analysis is too speculative to rely upon for awarding a risk premium.

Williams calculates a special TAPS risk premium by postulating an additional 10 percent probability of losing the entire equity investment, above and beyond those faced during construction by average pipelines prior to operation.[424] Williams' urges that this would be a very high additional probability, and is probably unrealistic.[425] Nevertheless, based on this assumed probability, Williams considers the added rate of return that would be needed to make investors "whole." Williams notes that the required return on common equity for sample pipelines was roughly 14.5 percent. Williams then assumes a hypothetical dividend yield ($4.50), a hypothetical share value ($100), and a hypothetical expected growth rate (10 percent) that under a DCF analysis produces the 14.5 percent rate of return.[426] Williams reasons that an additional risk of losing 10 percent of the entire investment would reduce share value to $90, so that within a DCF framework the resulting return on equity would be 15 percent. Accordingly, Williams proposes a risk premium of 50 basis points.[427]

This analysis is not reliable for two reasons. First, based on a thorough reading of the evidence in the record, we do not agree with the assessment that rational equity investors perceived a risk of as much as 10 percent of losing their entire investment. Second, as Williams witness Gaske readily admits, the entire calculation -- the stock price, the dividend rate, and the growth rate -- is hypothetical.[428] If one

[424]JSG-T (W-2) 42.

[425]JSG-T (W-2) 42.

[426]JSG-T (W-2) 43-44.

[427]JSG-T (W-2) 43-44.

[428]Tr. 4378 (JSG). The hypothetical nature of all the terms in Dr. Gaske's calculation further underscores the tenuous nature of the assumption that an additional 10 percent probability of losing the entire equity investment existed.

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chooses parameters other than those chosen but consistent with the 14.5 percent average equity rate, then an entirely different risk premium emerges. Given the lack of actual data on stock price, dividend rate, and growth rate of a stock compared to TAPS, we find Williams' method too speculative.

The Carriers present two complimentary approaches to deriving an appropriate TAPS risk premium. First, the Carriers appeal to market data which reveal that investors demand greater returns for risky projects. The market data are intended to indicate a lower bound on the level of acceptable risk premiums.[429] Second, the Carriers then present a specific method for translating extraordinary TAPS risks into required return premiums. We review the Carriers' approaches below.

Carriers present three types of market evidence to indicate what they regard as minimum risk premiums for TAPS. First, the Carriers point to an academic study that shows that third-party guarantees reduce the costs of project finance loans by an average of nearly 43 basis points.[430] The Carriers assert that, because TAPS was substantially larger than the projects sampled in the study, the risk premium demanded by TAPS investors will be "well in excess" of this amount.[431]

Second, the Carriers cite academic authority that indicates that investors in BB-rated rated bonds demanded an average rate of return premium of 2.1 percent over AA-rated bonds.[432] The Carriers then point to the cumulative default rate on the lower grade bonds (6.64 percent) and the ultimate average recovery of original investment (36 percent) once default has occurred.[433] They reason that, because the

[429]T-10 (WBT) 50.
[430]T-10 (WBT) 46.
[431]T-10 (WBT) 46.
[432]T-10 (WBT) 49.
[433]T-10 (WBT) 50.

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TAPS early-period risks of losing the entire investment were greater than the risks faced by holders of BB-rated bonds, the required risk premium for TAPS should be at least 2 percent.[434]

Finally, the Carriers cite an academic study that shows that "large engineering projects," projects with an average value of $1 billion, often turn out to be bad investments.[435] A significant portion of the projects fail.[436] TAPS was an especially large project. The Carriers conclude, therefore, that the assumption of a 10 percent risk of losing the entire investment should be considered a lower bound of the early-period risks faced by TAPS.[437]

The academic studies of market data to which the Carriers appeal show that investors demand compensation for investing in riskier projects. They also show that large projects can generate large risks. However, the Carriers fail to provide good evidence that the studies cited are relevant to the comparative risks between TAPS and the average pipeline.

For example, the Carriers do not explain why the TAPS was akin to the sample of projects considered in the first study that they cite. The Carriers assert that because TAPS was a bigger project than those studied its parent company loan guarantees would "surely" require a greater risk premium. However, the record is silent on the nature of the businesses and thus on baseline risks of projects considered by the study. Without knowing this baseline, how TAPS risks compare to this baseline, and how the value of third party guarantees change as baseline risk changes, we cannot

[434]T-10 (WBT) 50.
[435]T-10 (WBT) 47-48.
[436]T-10 (WBT) 47-48.
[437]T-10 (WBT) 48-49.

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meaningfully draw conclusions about the risk premium that TAPS investors would demand. Similarly, with reference to the second study, the Carriers fail to adequately explain why the risk of TAPS compared to an average pipeline company is analogous to the risk of projects financed with BB compared to projects financed with AA grade bonds. Finally, although it is clear that TAPS was a large engineering project, the Carriers do not adequately explain why investing in TAPS was "certainly" more risky than investing in tunnels, subways, airports, toll roads and power plants[438] (large projects that sometimes fail). The record does not provide information on the risks that these other projects confront. In conclusion, we find that the studies cited by the Carriers do not provide convincing evidence of a lower bound on the risk premium that TAPS investors would demand.

The Carriers present a method for specifically quantifying a rate of return premium to reflect special TAPS risks. The method is based on an assessment of an investor's perceived probability of losing their entire investment. The Carriers' approach is designed to determine how much of an extra return is required to allow an investment with extra risks of losing the entire investment to yield the same expected value of future returns as an investment without these additional risks.[439] The method requires assessing the probability of capital loss, estimating the cost of capital without the risk premium, and making an assumption about the economic life of the line that investors perceived when they made their investment.[440] Different assessments of these three variables will generate different required risk premiums. Such flexibility and transparency is certainly a virtue.

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[438]T-10 (WBT) 48.

[439]T-3 (WBT) 48-49.

[440]*See* WBT-49, Panels B-E.

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This method, however, also implicitly assumes that a risk premium needs to be recovered into the future, even when the risks for which compensation is awarded have passed.[441] The parties present divergent views on whether we should award a risk premium prospectively. Accordingly, if the Carriers' method is to be used to assess the required risk premium demanded by TAPS investors, we must resolve the question of whether a risk premium can properly be included in rates after the risk has passed.

The Carriers assert that special risks during development, construction, and post-construction can only be compensated through higher expected earnings during project operation.[442] Therefore, a risk premium must necessarily be awarded after risks have passed. The Carriers assert that unless investors can reasonably expect this compensation, projects will not be able to attract capital.[443] The higher expected earnings are achieved by awarding a risk premium into the future. The Carriers cite the pharmaceutical industry, wildcat oil wells, and telecommunications satellites as examples of efforts where the occasional success must "pay for" the many failures.[444]

Although these examples are not from industries with similar business risks as to TAPS, in each case the compensation for the risk of project failure is recovered after the risk is resolved.[445] In the first two cases the risk of the endeavor is usually covered by a business undertaking many such endeavors and "self insuring." In

[441]This point is clear from an examination of the underlying calculations in WBT-49.

[442]T-3 (WBT) 42; T-10 (WBT) 34.

[443]T-10 (WBT) 34.

[444]T-3 (WBT) 44-45.

[445]T-3 (WBT) 45.

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the latter case insurance premiums to cover the risk of failed satellite launches are directly included in the costs consumers pay.[446]

Tesoro asserts that there should be no risk premium in current rates for any extraordinary past risks associated with TAPS.[447] Tesoro reasons that because ratemaking is prospective, compensating TAPS investors for past risks would be retroactive ratemaking.[448] While some risk premium was necessary in the past, investors would or should have received acknowledgment of them through appropriate rates of return in the past. Tesoro reasons that the rates for 1997-2000 should therefore not include a risk premium.[449]

Williams asserts that we need not provide an additional return premium to maintain the value of existing capital or to attract additional capital prospectively.[450] Williams reasons that the rate of return used to establish rates must reflect current risks; if it does so the company will be able to attract future capital.[451] Williams explains that the value of capital already committed will be maintained so long as there is a reasonable expectation that the allowed return will be achieved.[452] Nevertheless, Williams asserts that "it would be reasonable to provide a premium in the current TAPS rate of return to recognize" the early-year special TAPS risks.[453]

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[446]T-3 (WBT) 45.

[447]FJH-T (E-2) 64.

[448]FJH-T (E-2) 64. *See also* Endnote 6.

[449]Tr. 4935 (FJH).

[450]JSG-T (W-2) 39.

[451]JSG-T (W-2) 38-39.

[452]JSG-T (W-2) 39.

[453]JSG-T (W-2) 39.

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We find that it is appropriate to award a risk premium after the relevant risks have passed. Considering TAPS on a stand-alone basis suggests recognizing that TAPS was a unique all-or-nothing gamble. If investors need to be compensated for an all-or-nothing gamble for only a short period, then the risk premium during that time will be larger. It is more equitable to have later-year ratepayers shoulder some of these extraordinary capital costs because they receive benefits from the pipeline's construction.

Moreover, we are persuaded by the Carriers' arguments that markets sometimes continue to reward risk taking investors after the risks have passed. Bonds continue to pay a return premium if extraordinary risks were present at bond issuance.[454] Further, if the Carriers could have obtained insurance for construction-era risks, the cost of that insurance would have been included in rates and recovered long after the risks passed.[455] Finally, in competitive markets, the value of a stock once a risk is favorably resolved is greater than when the risk is still present. If initial investors are confident that regulators will mimic this dynamic and allow them this greater value then the enterprise will have an easier time attracting capital at reasonable rates.[456]

Having resolved protestants' objections, we find that the Carriers' method[457] of translating risk into a rate of return premium is reasonable.[458] We disagree, however, with the Carriers' assessment of the relevant inputs. We do not

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[454]T-10 (WBT) 49.

[455]Tr. 2950-51 (WBT).

[456]*See* Tr. 2951-52 (WBT).

[457]*See* WBT-49.

[458]We also recognize that it is imperfect. The Carriers' method fails to address the sum of risks to partial, rather than complete, capital loss. To capture risk of partial loss, we adjust upward the risk of "total loss" used in our calculation of the appropriate risk premium.

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accept the Carriers' estimate of the risk of principal loss, nor their base line, non risk-adjusted rate of return to which the risk premium is applied, nor their assessment of the period over which the risk premium is recovered. Instead, our findings regarding relevant inputs and their application to the Carriers' method are discussed below.

Based on the record and our analysis at Endnote 8, we find that, before May 1, 1974, investors may have perceived a roughly 50 percent likelihood that the project would not be completed. Accordingly, investors in a stand-alone pipeline before this date faced a significant chance of failing to receive, not only an adequate return on, but also the return of their principal investment. The return on capital expended before May 1, 1974, should therefore be adjusted to reflect this extraordinary risk. This adjustment should only be applied to equity capital because we have found that a stand-alone pipeline would have been financed with only equity during this period.[459]

Investors provided $514 million towards TAPS construction before May 1, 1974.[460] However, not all of this money was at risk. During Phase I of the original TAPS litigation, State witness Parcell pointed out that a significant portion could have been recouped. "[A]t the beginning of 1974 only about $451 million had been committed to the TAPS project. When allowances for salvage values and tax savings effects are taken into consideration, the net commitment falls to $137 million."[461] The first $514 million (rather than the $451 million to which Parcell refers) was exposed to significant non-completion risk. Parcell's ratio of capital at risk to total capital expended

[459]Our earlier finding that the pipeline would have been capitalized with 100 percent equity until May 1, 1974, was also based upon the considerable risks of non-completion that investors in a stand-alone pipeline would have faced.

[460]143-RGV-C, Workpaper TAPS-RGV WP3.xls, Schedule 3.

[461]WBT-67-E (Parcell) 44.

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is roughly 30.38 percent.[462] It is reasonable to expect that a similar ratio applied to the incremental $63 million in expenditures made from January through April of 1974. Accordingly, we find that $156.138 million[463] of original investor capital was subject to extraordinary risk associated with legal and other institutional hurdles.[464] When compared to total equity expenditures of roughly $3.909 billion during the construction phase (based on our finding of a 50.5 percent equity structure), this amounts to four percent of total equity capital. Our finding that there was a 50 percent chance of total capital loss before construction began thus translates to a two percent chance (50 percent of 4 percent) of total project equity capital loss.[465]

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[462]Parcell suggested that true capital exposure was $137 million, while total capital expenditures were $451 million. The ratio of capital exposure to total expenditure is thus 137/451, or 30.38 percent.

[463]$156.138 million results from multiplying $514 million by 30.38 percent.

[464]In the Phase I litigation, Carrier witness Patton suggested that the planning and pre-construction era risk needs to be applied to all subsequent construction capital. He explains:

> [A]t least by the late Fall of 1973, the Owners were for all intents and purposes obligated, as a matter of political reality and economic fact, to undertaking the Project, notwithstanding the risks and unresolved uncertainties that still existed regarding negotiation of the PLA, securing design criteria approvals and the like.

WBT-16 (Patton) 95.

We find Patton's assessment incorrect. Taken literally, it suggests that the Carriers would have been willingly derelict in their duties to shareholders and would have refused to stop construction if doing so was appropriate.

Patton's view is contradicted by his claim that he had advised the TAPS owners that Alyeska was considering a complete shutdown if progress was not made with the Teamsters Local by the first week of April, 1974. WBT-16 (Patton) 8. The stated willingness to stop capital expenditures on the project illustrates the willingness of the Carriers to act rationally in the face of future threats and demonstrates that a risk of total construction capital loss did exist. Although the Carriers make theoretical arguments as to how investors' funds can become irreversibly committed even in the face of foreseeable loss, the record does not suggest that investors were indeed in such a position after April, 1974. WBT-29 (Arrow) 27-29; Tr. 2641-42 (WBT).

[465]*See* T-3 (WBT) 48-49 for a similar style of calculation, although with different inputs.

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In addition to the extraordinary risks during the planning phase, we find that during the entire construction period equity investors faced some additional risk of capital recovery, both on and of investment, from economic risks. Roseman's testimony that TAPS could be expected to generate funds sufficient to cover debt service under almost any scenario is persuasive.[466] However, equity investors did face additional risks, "because stockholders' claims are subordinated to those of lenders when the firm issues debt, the risks faced by stockholders are magnified."[467] Although equity investors' total exposure was comparatively modest, we find that it was nevertheless present. After a complete review and analysis of the record, we find that construction-era equity investors faced an additional five-percent probability[468] on top of risks borne by the average pipeline of losing half of their investment. To use the Carriers' method for calculating a risk premium, this five-percent probability is translated into a 2.5 percent probability of losing the entire equity investment.[469] We add this risk premium to all equity investment made until the pipeline became operational. The Carriers[470] and Williams[471] adopt an operational date for TAPS of July 1, 1977; Tesoro does not sponsor a date for when the pipeline began operations. Because the date of initial operations are uncontested, we use July 1, 1977 as the start of operations.

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[466]*See* 66-WBT-E (Roseman) 68-75.

[467]WBT-60 at 2.

[468]The early construction period generated risks somewhat greater than this for equity investors, while the later construction periods generated somewhat lower risks. Given that these risks cannot be measured with precision (T-3 (WBT) 50), we find determining an average risk premium over the entire pre-operational period reasonable.

[469]*See* T-3 (WBT) 48-49 for example of translating a risk of partial loss to a smaller risk of total loss.

[470]*See* 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls, Schedule 3, l. 106.

[471]*See* 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedule 3, l. 106.

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Having determined the extraordinary risk to which planning and construction era equity capital were exposed, we must determine the baseline, non-risk adjusted return required for such capital investments. Given our findings from Part IV Section B.3, from 1968 through 1974, the non risk-adjusted cost of equity capital averaged 12.31 percent.[472] Similarly, our findings from Part IV Section B.3 indicate that the non risk-adjusted cost of equity capital from 1968 through 1977 averaged 12.63 percent.[473]

Finally, we must decide to what capital and for what length of time the risk premium should be applied. Although the Carriers posit a horizon of 34.5 years, investors were aware at the time of investment that TAPS rates were initially set using a 25-year depreciation schedule.[474] We therefore adopt a 25-year time over which to apply risk factor to equity capital.

We use the Carriers' methodology with adjusted inputs to determine a risk premium. That risk premium is 33 basis points for the original TAPS investors who provided capital from 1968 through May 1, 1974.[475] It is applied to *all* equity capital for the 25-year period 1977 through the middle of 2002. We add an *additional* 42 basis

[472]Based on the arithmetic average of our findings for appropriate return on equity for 1968-1974; *see* Exhibit 19, Schedule 1.

[473]Based on the arithmetic average of our findings for appropriate return on equity for 1968-1977; *see* Exhibit 19, Schedule 2.

[474]*See* 106-RGV-E. We attempt to provide a premium that makes equity investors whole with regard to risks experienced during the planning and construction eras. Accordingly, it is appropriate to adopt the time horizon that these initial equity investors expected because that is the time period over which they might have hoped to recover such a premium. Neither Tesoro nor Williams proposed time horizons that met this requirement. *See* n.412 and n.416, *supra.*

[475]Exhibit 19, Schedule 1. The 33 basis points is adjusted from 36 basis points to recognize that roughly 90 percent of the equity capital expended to date comes from the original construction period. T-3 (WBT) 50. The rationale for such leveling was detailed during cross-examination. Tr. 2935-36 (WBT).

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point risk premium to correspond to the risk faced by original TAPS investors who provided equity capital from 1968 through July 1, 1977.[476] This risk premium is also applied to all equity capital for the 25-year period 1977 through the middle of 2002. Thus, the total risk premium to be added to return on equity is 75 basis points.[477] The full, appropriate return on equity that combines the special TAPS risk premium with the non risk-adjusted equity rate of return is calculated at Exhibit 20. The overall weighted rate of return on rate base is calculated at Exhibit 2.

5. *Allowance for Funds Used During Construction*

Allowance for Funds Used During Construction (AFUDC) is allowed in modern ratemaking to compensate investors for funds expended to construct pipeline facilities before the facilities are used to deliver services.[478] To calculate AFUDC for the

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[476]Exhibit 19, Schedule 2. Again, the 42 basis points reflects adjustment from 46 basis points in recognition that on a leveled basis roughly 90 percent of the equity capital expended to date comes from the original construction period. T-3 (WBT) 50.

[477]Without adjusting for a leveled rate base that also contains new, less risky capital, these calculations suggest an overall risk premium on original capital expenditures of 82 basis points. This conforms closely to the equity risk premium of one percent, provided by the APC. *See Re Exxon Pipeline Co.*, 1 APUC 580, 601 (1980). The Alaska superior court, in its remand of *Re Exxon Pipeline Company* asserted that risks associated with construction cost overruns were fully subsumed within the rate base. *State of Alaska v. Alaska Pub. Util. Comm'n,* 3AN 80-7163 CI (Alaska Super.) Nov. 28, 1983, vacated by *Amerada Hess Pipeline Corp. v. Alaska Pub. Util. Comm'n,* No. S-195, slip op. (Alaska Nov. 20, 1985) at parties' request due to settlement. The Alaska Superior court may not have recognized that cost-overruns were only part of the risks facing TAPS. Moreover, while actual cost overruns were included in rate base, the threat of cost over-runs served to create some small but non-zero uncertainty for equity investors as to whether the economics of the pipeline might prevent full equity capital recovery.

[478]AFUDC allows for recovery of interest on both debt and equity funds used during construction. In *Re Exxon Pipeline Company,* the APC awarded the TAPS Carriers actual booked original cost including Interest During Construction (IDC). 1 APUC 580, 591 (1980). IDC allows only for recovery of interest on debt costs. In doing so, the APC followed the old Interstate Commerce Commission approach that provided only IDC for oil pipelines. The use of AFUDC instead of IDC is now well settled and we calculate it for the TAPS.

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TAPS, we determine the AFUDC balances to be used and the schedule for compounding.[479] The parties present different methodologies for determining AFUDC.

Tesoro uses end-of-year Construction Work in Progress balances against which AFUDC is calculated, as well as annual compounding, but provides little reasoning for doing so.[480] The Carriers calculate AFUDC against year-average Construction Work in Progress balances, and compound AFUDC balances semi-annually. They assert that this is consistent with FPC Order 561.[481] Williams agrees with the Carriers.

The APUC directed in *Cook Inlet* that "AFUDC should be calculated in accordance with the formula set out in FPC Order No. 561."[482] The FPC approach permits AFUDC to be calculated against average year Construction Work in Progress balances. FPC Order 561 also directs that compounding should be done no more frequently than semi-annually.[483] By directing that AFUDC should be calculated pursuant to Order 561, the APUC in *Cook Inlet* allowed for semi-annual compounding. We see no reason to deviate from that precedent. We adopt the average year balance

[479]The size of AFUDC balances will be larger the more frequently it is compounded.

[480]Tesoro adopts the TSM's AFUDC amounts at the beginning of pipeline operations. *See* 225-JFB-T. That balance was calculated using end of year Construction Work in Progress balances. *See* 31-BWF-E. Tesoro also suggests that we should use ADIT as an offset when we calculate AFUDC. While this approach may be theoretically more accurate than the one we adopt, we lack a record sufficient to allow us to make that calculation.

[481]Tr. 3609 (RGV).

[482]*Re Cook Inlet Pipe Line Co.,* 6 APUC 527, 543 (1985).

[483]226-JFB-T.

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and semi-annual compounding previously adopted by the APUC. We adopt the resulting amounts for AFUDC as calculated at Exhibit 21.[484]

C. Depreciation

We found that the Carriers' use of straight-line depreciation was inappropriate in Part III, *supra*. Our goal is to set cost-based rates. We found in Part III Section C that the TSM depreciation schedule provides the Carriers with an opportunity to recover their capital investment and safeguards shippers from paying twice for the Carriers' investment. In this section, we refine our finding on the use of TSM depreciation to determine the remaining rate base at year-end 1996, and calculate the depreciation charges that result for each year. We then describe how we calculate retirements from accumulated depreciation. Finally, we explain how the AFUDC balances are amortized.

1. TSM Depreciation Charges Should Be Adopted

There are several issues that are addressed in this subsection. First, we determine whether TSM depreciation charges or factors should be used. Second, we explain the use of TSM-6 depreciation for the years 1977-1984. Third, we explain how we included TSM's amortization of excluded costs to calculate investment recovery.

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[484]Tesoro urges that we incorporate accumulated deferred income taxes (ADIT) as a source of cost-free capital in our calculation of AFUDC. JFB-T (E-3) 48; *Tesoro Alaska Company's Posthearing Reply Brief* at 31-32. We do not do so for two reasons. First, most of the AFUDC is accumulated before the pipeline went into operation and there is no ADIT during that period. Tr. 5355-56 (JFB). Second, including ADIT in the AFUDC calculations from 1977-1996 only makes a difference to shippers to the extent that AFUDC is booked by compounding semi-annually, because using ADIT to fund AFUDC reduces the AFUDC balance but increases the return on rate base. Witnesses agreed that the size of AFUDC had a *de minimus* impact on the revenue requirements and rates during the protested years. JFB-T (E-3) 50. Administrative simplicity does not support Tesoro's approach.

Tesoro suggested that the rate base against which we test 1997-2000 filed rates should be calculated with reference to historical TSM depreciation *charges*.[485] Williams urged that the rate base be determined with reference to TSM depreciation *factors*.[486] The depreciation charges that Williams derives from these factors differ from the TSM depreciation charges. Thus, protestants raise the issue of which "TSM based" depreciation figures should be used.

The TSM charges are more appropriate to use as a measure of the opportunity that Carriers have historically enjoyed to recover their investment. The depreciation factors upon which Williams relies have never been used to set rates, were not used to reconcile the TSM starting rate base, and were never presented to any regulatory body. The TSM depreciation charges, however, meet all these criteria and were recognized by the settling parties as a vehicle for investment recovery. We find TSM depreciation charges more reasonable.

The Carriers have urged that using TSM depreciation charges to set rate base for 1997-2000 is inappropriate, because TSM itself contained no depreciation charges for 1977-1983.[487] Instead, the Settlement Agreement set a starting rate base for 1983 year-end,[488] and determined depreciation charges for 1984 through the present.[489] The depreciation charges upon which Tesoro relies are contained in an illustrative exhibit, known as TSM-6.[490]

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[485]*See* 225-JFB-T.

[486]*See* 189A-BEW-T.

[487]*See* Tr. 4518-21 (BEW).

[488]*See* BWF-2 at 14; BWF-3 at 59.

[489]*See* BWF-3 at 55. The Settlement specifies depreciation *factors* through 2011.

[490]31-BWF-E.

We acknowledge that the TSM-6 depreciation charges were not directly used to set tariffed rates for 1977-1983. Rather, until the Settlement was brokered, rates were still being charged according to the originally filed and suspended rates from 1977.[491] However, the question concerning TSM-6 depreciation charges is not whether they were used as a means of revenue collection, but whether they provided the Carriers with a reasonable opportunity to recover their investment.

The TSM-6 depreciation charges are the same as those presented by ARCO witness Baden to the APUC in support of the Settlement.[492] In explaining his schedule, which reconciles FERC Form 6 data to the 1984 starting values in the TSM, Mr. Baden explained that "the TSM numbers do have real numbers behind them,"[493] and that his purpose was "to show the trail from the Form 6 data or the TAPS record to the TSM stipulated number."[494] The State of Alaska and the U.S. Department of Justice represented that refunds under the Settlement were determined according to the TSM-6 revenue requirements for 1977-1984.[495] Thus, the record shows that the Carriers and the APUC relied on the TSM-6 depreciation charges to arrive at and accept the Settlement's starting rate base.

Because the Carriers and the APUC relied on the TSM-6 depreciation charges, they fairly represent the Carriers' opportunity for investment recovery. When the APUC approved the Settlement Agreement, they made 1977-1985 rates

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[491] *See* Tr. 4518-19 (BEW).

[492] *See* 235-JFB-T; 31-BWF-E.

[493] *See* 236-JFB-T at 699.

[494] *See* 236-JFB-T at 699.

[495] *See* BWF-4 at 70.

permanent.[496] Although they did not assert that those rates were just and reasonable, in making those rates permanent and in relying upon the reconciliation of FERC Form 6 to TSM-6 data to do so, the APUC closed the book on considering any other depreciation charges for those years. As a witness for Williams noted, the depreciation contained in TSM-6 was "analogous to setting a rate based on a suspension rate. In other words, the Carriers had made a tentative filing under one rate methodology, and the actual depreciation rates to be used were not established until later."[497] To accept straight-line depreciation for 1977-1983 instead of the TSM-6 depreciation charges may run afoul of the doctrine of retroactive ratemaking.[498]

We turn now to the issue of TSM's amortization of excluded costs. The Settlement excluded $450 million of Carrier property from TSM's rate base. However, the Settlement Agreement amortized these excluded costs from 1978 through 1984.[499] The TSM disks show that more than $72 million was amortized in 1984.[500] The full amortization schedule is included in TSM-6.[501] Thus, the Settlement Agreement allowed no return *on* the $450 million, but did permit a return *of* the $450 million.[502]

To set depreciation charges for 1977-1996, we determine the opportunity that the Carriers have enjoyed to recover their investment. We found that the TSM and TSM-6 depreciation amounts better represent this opportunity than the Carriers' FERC Form 6 books and records. To be consistent, we add the $450 million rate base

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[496] *Re Amerada Hess Pipeline Corp.,* 8 APUC 168, 170 (Alaska P.U.C. May 30, 1987).

[497] Tr. 4519 (BEW).

[498] *Tesoro Alaska Company's Initial Posthearing Brief* at 30-31.

[499] BWF-3 at 14.

[500] 31-BWF-E.

[501] 31-BWF-E.

[502] 29-ABJ-W at 10.

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exclusion to the TSM and TSM-6 depreciation charges for 1978-1984.[503] The yearly amounts that we adopt for depreciation and accumulated depreciation used to determine the year-end 1996 rate base are set forth in Exhibit 22.

2. Retirements From Accumulated Depreciation

When property is retired from service, generally the accumulated depreciation associated with that property to date is removed from the total accumulated depreciation account.[504] The Carriers' data for retirements from accumulated depreciation reflect FERC Form 6 depreciation.[505] It thus reflects straight-line depreciation for plant of different vintages and with different expected lives. Williams assumes that accumulated depreciation amounts are unaffected by retirements[506] and makes no deductions from accumulated depreciation, even though they take retirements from gross depreciable property. Tesoro adopts the TSM approach and reports only net retirements.[507]

We find the various data presented on retirements from accumulated depreciation to be inconsistent with our finding that TSM depreciation should be used to calculate the 1996 rate base. The Carriers' data reflect straight-line depreciation,[508] while the TSM depreciation amounts imply a more accelerated depreciation schedule. With an accelerated depreciation schedule, accumulated depreciation balances should

[503]In Part IV Section A(1), we found that the Settlement's $450 million should not be disallowed from rate base. By adding add the $450 million rate base exclusion to the TSM and TSM-6 depreciation charges for 1978-1984, we provide for both the return on and of this investment.

[504]Tr. 5137 (JFB).

[505]*See* 143-RGV-C. Workpaper TAPS RGV-WP3.xls, Schedule 12, l. 12.

[506]189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedule 12.

[507]*See* 225-JFB-T.

[508]143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls, Schedule 2, l. 19.

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be reduced more than suggested by the Carriers' data. Williams' approach is not appropriate because accumulated depreciation should reflect retirements of Carrier property. Tesoro's data cannot be used, given our finding that the FERC Form 6 retirements data are more appropriate.[509]

The more rapid depreciation schedule that we adopt needs to be imposed on property that has a shorter life than 34.5 years (the stipulated life of the TAPS). Because the record does not provide adequate information on the vintage of the retired property, we referred to individual Carriers' annual reports filed with us. Supplemental pages to the FERC Form 6, added after the Settlement, contain information on retirements by vintage year, as well as charges to accumulated depreciation that reflect those retirements.[510]

For 1977 through 1996, for each retirement from vintage year, we determine the expected life of property retired by dividing the number of years of service by the ratio of FERC Form 6 charges to accumulated depreciation to retirements. For retirements prior to 1986 there are no supplemental pages. Having no information regarding vintage year, we treat retirements from accumulated depreciation in the aggregate. For all retirements from all years, we then use TSM depreciation charges to impose the implied depreciation profile on shorter-lived assets. This allows us to derive retirements from accumulated depreciation that are adjusted for the more rapid depreciation schedule that we adopt.[511]

[509]Part IV Section A.4.

[510]Although the Carriers are not always consistent in their numbering of the Supplemental pages, in general the vintage year data on retirements are contained on Supplemental page 9. Aggregate retirements data are contained on Supplemental pages 1-3.

[511]Exhibit 23.

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3. *Amortization of AFUDC*

AFUDC balances are traditionally amortized consistently with the depreciation schedule because both depreciation and amortization of AFUDC are methods for recovery of capital. Williams[512] and Tesoro[513] amortize AFUDC using the TSM depreciation factors. The Carriers amortize AFUDC based on the relationship between depreciation expense and net carrier depreciable property.[514]

The rate at which AFUDC is amortized should match the rate at which Carrier property is depreciated. Accordingly, we follow the Carriers' approach, and derive amortization factors for AFUDC based on the relationship between the appropriate depreciation expense and net carrier property. The amortization factors were used to calculate the amortization of AFUDC, both debt and equity portions.[515] Exhibit 24 shows the derivation of the amortization factors, and Exhibit 25 illustrates the amortization of AFUDC.

D. Accumulated Deferred Income Taxes

ADIT is used by regulators to adjust rates for the difference in timing of depreciation for ratemaking and tax purposes. We use TSM depreciation charges for ratemaking, see Part IV, *supra.* For tax depreciation, we follow the approach taken by the parties[516] and assume the most accelerated methods of tax depreciation allowed,

[512]189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls.

[513]225-JFB-T.

[514]T-4 (RGV) 10.

[515]The Carriers (143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls), Williams (189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls), and Tesoro (compare 225-JFB-T and 31-BWF-E) amortize additions to AFUDC balances on a beginning-of-year basis; that is, the amortization factors are applied additions to AFUDC in the year in which additions are made. We follow this approach.

[516]*See*, e.g., T-7 (RGV) 12; 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedules 6-7; 225-JFB-T, Workpaper 2.

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i.e., that maximum depreciation charges allowed by state and federal tax law are taken.[517] Consistent with a stand-alone income tax calculation, we follow the parties and assume that income is sufficient to be taxed at the highest statutory rate,[518] recognizing relevant changes in income tax rates[519] and laws.[520] Finally, we follow the approach used by all of the parties and do not reduce outstanding ADIT balance to reflect changes in deferred taxes associated with property retirements.[521] We calculate an ADIT balance for 1977-1996 at Exhibit 28.

E. <u>Having Established All Necessary Inputs, We Calculate Reasonable Annual Rate Bases for 1977-1996</u>

We can now calculate a reasonable rate base for year-end 1996. The value of original carrier property in service at commencement of service (July 1, 1977) is determined in Part IV Section A (Exhibit 8). That balance includes both depreciable and non-depreciable property. To provide AFUDC rather than just interest during construction (IDC), IDC is subtracted from FERC Form 6 figures for gross Carrier property.[522] The working capital balance (Exhibit 9) is added to obtain the value of

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[517]Exhibit 26, Schedules 1 and 2 show the State and Federal tax depreciation, respectively, used to calculate ADIT balances.

[518]*See*, e.g., T-7 (RGV) 11.

[519]*See*, *e.g.*, T-7 (RGV) 12.

[520]Exhibit 27 shows the calculation of an adjustment to tax depreciation caused by the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA, Pub.L. 97-248, Sept. 3, 1982, 96 Stat. 324). The TAPS Carriers and Williams recognize a TEFRA Adjustment to tax depreciation (*see* 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls and 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, respectively), while Tesoro does not (*see* 225-JFB-T). The parties did not explain why a TEFRA adjustment should or should not be made. We include the TEFRA adjustment as it better conforms to Federal statute.

[521]*See, e.g.,* T-7 (RGV) 12. Carriers note that this tends to result in the highest ADIT balance possible, and thus the largest reduction in rate base.

[522]We follow the Carriers' and Williams' (e.g. 189A-BEW-T) approach in this regard. *See, e.g.,* T-7 (RGV) 11; 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls

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original carrier property in service. The AFUDC as of commencement of service is determined in Part IV Section B (Exhibit 21). To compute a rate base for year-end 1977, the 1977 additions to Carrier property are added and the 1977 retirements of Carrier property (Exhibit 8) are subtracted. The amount of depreciation charged for 1977 is subtracted from the value of Carrier property and AFUDC. AFUDC is amortized (Exhibit 25) according to an annual depreciation factor (Exhibit 24) that is based on the relationship between depreciation expenses and net Carrier property. Finally, in accordance with standard ratemaking practice, we deduct the ADIT balance for 1977 as determined in Part IV Section D (Exhibit 28). The rate base for year-end 1977 is $9.533 billion, shown at Exhibit 29, line 18.

Rate base at year-end for each of the years following is calculated by beginning with the balances at the end of the previous year, adding additions to Carrier property, subtracting retirements of Carrier property, annual TSM depreciation charges, and ADIT. The calculation of rate base at each year-end is depicted in Exhibit 29.[523] We find that the year-end 1996 rate base is $669 million, shown at Exhibit 29, line 18.

V. WE USE A COMPARATIVE REVENUE REQUIREMENT ANALYSIS TO CONFIRM THAT THE $669 MILLION YEAR-END 1996 RATE BASE DOES NOT CONFISCATE CARRIER PROPERTY

In *Kenai*, the APUC found that if a switch in ratemaking methodologies imposed a regulatorily enforced return deficiency[524] then an upward adjustment to rate

[523]Normally, the Commission requires the use of a 13-month average rate base. However, the record does not contain precise monthly rate base information. Because the effort costs required to calculate monthly rate base balances for TAPS would be much greater than the benefits conferred, we calculate both year-end and average-year rate bases, where the "average-year" rate base is calculated as the average of the rate base as of the beginning and the end of a given year. *See*, *e.g.*, T-7 (RGV) 12.

[524]*Re Kenai Pipe Line Co.*, 12 APUC 425, 438, 1992 WL 696192 (Alaska P.U.C., 1992).

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base might be made.[525] Such an adjustment is known as a "transition rate base." Transition rate bases ensure that no regulatory taking occurs and that carriers are provided an opportunity to recover their investment.[526]

The APUC explained in *Kenai*[527] how to determine the amount, if any, of a regulatorily enforced return deficiency.

> If, cumulatively, KPL had been entitled to earn less under the valuation methodology than it would have been allowed under DOC, it could argue for a transition rate base in excess of original cost.

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[525]Equity suggests that if a switch in methodologies granted an excessive return opportunity to recover investment, then a downward adjustment to rate base might be made to ensure that shippers do not face the same opportunity for carriers to recover costs twice. *See* T-10 (WBT) 84.

[526]Such adjustments do not run afoul of the rule against retroactive ratemaking. They are not made on the basis of past rates but on the basis of allowable revenue requirements.

[527]*Re Kenai Pipe Line Co.*, 12 APUC 425, 439-40, 1992 WL 696192 (Alaska P.U.C., 1992).

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Under this approach, we compare the revenue requirements used to set the filed rates generated by TSM[528] with the revenue requirements produced by a DOC analysis applied with reasonable inputs consistently from the beginning of pipeline operation. A transition rate base might be awarded if, cumulatively, the two methodologies yield significantly different revenue requirements.

[528]The Settlement did not specify a revenue requirement for the years 1977-1984. Rather, it set rates. Specifically, the Settlement made the originally-filed 1977 rates permanent for 1977-1981; refunds were made for rates from 1982-1985. Nevertheless, in explaining the Settlement to regulatory bodies when seeking its approval, the Carriers relied upon the TSM-6 spreadsheet model, which illustrated TSM contained annual revenue requirements for those years. *See* 236-JFB-T at 697; 30-BWF-E. Those revenue requirements reflect property balances that were reconciled to FERC Form 6 books and records. *See* 235-JFB-T and 236 JFB-T. Close questioning by Commissioners suggests that the APUC at the time relied upon that reconciliation, at least in part, in allowing filed rates for 1977-1984 to go into effect on a permanent basis. Moreover, refunds were made on the basis of the TSM-6 model. BWF-4 at 67. Accordingly, because the TSM-6 revenue requirements appear to have been relied upon in the acceptance of the Settlement, refunds, and making filed rates permanent, they are the appropriate benchmark against which to assess our appropriate DOC revenue requirements for any return deficiency. We note that the Carriers themselves evaluate the revenue requirements produced by their benchmark DOC against TSM and TSM-6 revenues. *See* ABJ-19.

Assessing cumulative DOC revenue requirements against the TSM-6 revenue requirements rather than actual revenues, as do the Carriers, modestly sways the analysis in the Carriers' favor. Actual revenues generated by originally filed rates for 1977-1981 were cumulatively $169 million more than the TSM-6 revenue requirements, while revenues for 1982-1984 were cumulatively $137 million more. *Compare* 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls *with* 31-BWF-E. Accordingly, DOC revenue requirements are more likely to cumulatively exceed TSM-6 revenue requirements in this period than cumulative historical revenues. Thus, we use the TSM-6 revenue requirement to insure that a regulatory taking does not occur when we adopt a $669 million rate base for year-end 1996. Reliance on TSM-6 revenue requirements protects Carriers against the possibility of regulatory taking better than looking to actual revenues.

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> Returns in excess of allowed DOC returns in some years offset return deficiencies in other years. In order to be able to argue for a rate base adjustment a net deficiency over the entire period during which the previous methodology was in effect must be demonstrated.

Kenai.[529] We perform a comparative yearly revenue requirement analysis to determine whether the $669 million rate base established for year-end 1996 is reasonable or needs adjustment.

A. <u>We Calculate Past Annual Revenue Requirements Using a DOC Methodology</u>

An annual comparative revenue requirement analysis requires determining the appropriate past annual revenue requirements. The revenue requirement is expressed as: RR= [r(V-D)] +[OE +d+ t] where

RR = revenue requirement

r = after-tax return

V = sum of prudently incurred capital expenditures, allowance for funds used during construction (AFUDC), and working capital

D = accumulated depreciation

OE = operating and maintenance expenses

d = annual depreciation charges

t = taxes.

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[529] *Kenai Pipe Line Co.*, 12 APUC 425, 472 at n.26, 1992 WL 696192 (Alaska P.U.C., 1992). In *Kenai* the APUC was careful to explain that actual revenues under the previous methodology were not an appropriate benchmark; rather, the benchmark was maximum revenues that might be achieved under the prevailing rate setting mechanism. The reasoning was that "if higher rates were permitted under the prevailing methodology but the company chose not to raise its rates at that time for whatever reason[,] [t]he company should not now be permitted to add its voluntary return deficiency (as distinguished from a regulatorily enforced return deficiency) to rate base for recovery in present rates." *Id.*

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In Part IV we found all the necessary elements for calculating a DOC methodology revenue requirement except annual operating expenses (OE), return on rate base, and a tax allowance.

1. Operating Expenses

The parties dispute the actual allowable past operating expenses.[530] The Carriers' adopt as operating expenses those expenses described in the Carriers' books and records, including FERC Form 6.[531] Tesoro, however, relies on the operating expenses filed with the TSM[532] which have been used to set rates from 1984-2000.[533] On a cumulative basis from 1977 through 1996, the FERC Form 6 operating expenses exceed the TSM operating expenses by $149.209 million.

There is no evidence in this record to reconcile the TSM and FERC Form 6 operating expenses. Carrier witness Folmar agreed that TSM operating expenses represent "real operating expenses" and differ from the FERC Form 6 data (exclusive of capitalized interest and DR&R) only in terms of an IRS imputed management fee, and "one small stipulated amount by one of the Carriers." [534] The IRS management fee adjustment came to $385,000 in 1997,[535] the record does not indicate the size of the adjustment in other years. The other "small stipulated amount" appears to refer to a

[530]*See* Exhibit 30 for a summary of the parties' positions on operating expenses.

[531]*See* T-7 (RGV) 14. Williams adopts the same operating expenses as the Carriers.

[532]For 1977 to 1983, Tesoro relies on operating expense data from TSM-6. BWF-6 at 5-12.

[533]*See* 30-BWF-E and BWF-6 at 5-12 which provide operating expenses from 1977-1983 (*see* 31-BWF-E).

[534]Tr. 2154 (BWF).

[535]*See* 99-RGV-E at 1-3.

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management fee associated with ARCO Transportation Alaska.[536] In 1997 this amount was $1.518 million.[537] The record does not indicate the size of this adjustment to FERC Form 6 operating expenses in other years.

Tesoro's cross-examination of the Carriers' expert witness suggests two additional differences between the operating expense data sets. The FERC Form 6 data in 1994 may include the costs of two separate settlements related to the Exxon Valdez oil spill litigation: one with the State and Federal governments for $31.7 million, the other with a class of private plaintiffs for $98 million.[538] It is also unclear whether the FERC Form 6 operating expense data reflects the post-employment benefits other than pensions (PBOP) settlement with the State and the public relations expenses challenged in Docket P-94-1.[539]

We analyze these five differences in operating expenses. The record does not indicate whether the IRS imputed management fee or the ARCO Transportation Alaska adjustment are costs that were imprudently incurred or are not properly included in rates. The record also does not suggest that these costs are not properly ascribed to the operating expense category. Accordingly, we cannot conclude that the Carriers erred by including these costs. We find that for purposes of our comparative revenue requirement analysis these costs are properly included in operating expenses.

With respect to the $31.7 million that reflects the settlement with State and Federal governments concerning the Exxon Valdez oil spill, the Carriers' 1994 operating

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[536]Tr. 3248-49 (RGV); *see* 99-RGV-E at 1-2.

[537]99-RGV-E at 1.

[538]Tr. 3257 (RGV).

[539]*Id.*

expense data probably should be adjusted. Under the terms of that settlement, the $31.7 million payment could not be included in TAPS rates.[540] However, the record is ambiguous as to whether the FERC Form 6 data include this payment.[541] Accordingly, we do not adjust the Carriers' operating expenses as being improper.

It is also unclear whether the Carriers' operating expenses for 1994 should be adjusted to reflect the $98 million settlement with private plaintiffs. Tesoro asserts that the FERC and ultimately the District of Columbia Circuit Court of Appeals ruled that the $98 million was not includable in rates under the terms of the Settlement. However, this decision had to do with the construction of the Settlement and not ratemaking.[542] Tesoro has not presented evidence of imprudence regarding the private Exxon Valdez settlement costs. We, therefore, do not exclude these costs from 1994 operating expenses.

Finally, it is unclear whether the Carriers should have adjusted their FERC Form 6 operating expense data to reflect the settlement agreement between the State and the TAPS Carriers concerning PBOP.[543] The protestants provided no substantive rationale to explain why this settlement agreement should be binding on the Carriers for the purpose of calculating operating expenses. In fact, in Order 52 the Commission held: "The Settlement Agreement should be and is, by this Order, accepted by the Commission, subject to the express condition that no issue shall be considered to have been finally determined or adjudicated by virtue of Commission acceptance of the

[540] *See* P-94-1 (9), p. 3.

[541] *See* Tr. 3257 (RGV).

[542] *Re Amerada Hess Pipeline Corp.*, 117 F.3d 596 (1997).

[543] Tr. 3248, 3254 (RGV).

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agreement."[544] Accordingly, the FERC Form 6 data need not be adjusted to reflect adjustments due to PBOP.

For these reasons, despite these five issues we find that the Carriers' sponsored operating expenses are reliable for determining appropriate operating expenses for 1977-1996.

2. <u>Return on Rate Base</u>

Return on rate base is the product of rate of return (r) and rate base (V-D). We establish return on rate base using our findings from Part IV. Exhibit 31 shows the appropriate annual return using these inputs.

3. <u>Tax Obligations</u>

To determine income tax obligations, we follow the approach of the parties and assume that the Carriers pay maximum statutory federal and state tax rates.[545] Exhibit 32 shows our finding of the appropriate annual income tax allowance.

Having made all the necessary findings for the required inputs to calculate the annual revenue requirements for the TAPS using a DOC methodology consistently from the beginning of pipeline operations. We calculate the annual revenue requirement for 1977-1996 at Exhibit 33.[546]

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[544]*Re Exxon Valdez Litigation and Settlement Costs* 1998 WL 1035074 *2 (Alaska P.U.C. Nov. 17, 1998).

[545]This was the approach adopted by all parties. *See*, *e.g.*, T-7 (RGV) 13; 189A-BEW-T Workpaper BEW_R_RGV6RE.xls, Schedule Income Tax Expense; 225-JFB-T, Workpaper 1.

[546]We make no finding about the appropriate amount that should have been collected in rates for DR&R. However, we find that the Carriers have collected the DR&R amounts specified in the Settlement. *Initial Post-hearing Brief of the Indicated TAPS Carriers* at 28. So that we can make a valid comparison between the appropriate annual cost of service under a DOC methodology and the TSM, we do not include any DR&R amount in the DOC revenue requirement and remove TSM's DR&R allowance from the TSM revenue requirement.

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B. Comparing From the Beginning of Pipeline Operation, the Annual Past Revenue Requirements of a DOC Methodology With the Annual Past Revenue Requirements of TSM, Demonstrates That the Year-end 1996 Rate Base of $669 Million Is Reasonable

We now compare the past annual DOC revenue requirements shown at Exhibit 33 with the past annual TSM revenue requirements. Exhibit 7, Schedule 2 reveals that TSM has, on a cumulative basis,[547] provided the Carriers with an opportunity to recover $9.9 billion more than their costs as determined by the DOC revenue requirements.[548] In 1997 dollars, the net present value[549] of the cumulative stream of revenue requirement differences is $13.5 billion, far in excess of the $669 million year-end 1996 DOC rate base.

Because the revenue requirements determined under TSM have been higher than costs as determined under a DOC methodology applied consistently from the beginning of pipeline operations, we find that the Carriers have had ample opportunity to recover costs and no taking of Carrier property occurs if we adopt a $669

[547]Our finding regarding the appropriateness of TSM depreciation and the year-end 1996 rate base is properly tested with reference to the Carriers' *cumulative* historical opportunity to recover their full costs of service. In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(79), April 10, 2000, we directed the Carriers to show that 1997-2000 rates reflect costs. We found that evidence that rates are just and reasonable over the life of the line is not sufficient to prove that the rates for specific years are just and reasonable. *Id.,* at 11. The Carriers' "life of the line" argument requires, among other things, a projection of costs of service into the future. Moreover, it fails to address whether 1997-2000 costs are reflected in 1997-2000 filed rates. We evaluate *historical* costs; we do so to determine whether 1997-2000 rates reflect the costs of providing service for the years in question.

[548]Exhibit 7, Schedule 2, Line 1.

[549]Exhibit 7, Schedule 2, Line 2. The net present value calculation uses interest rates equal to the Commission's overall weighted rate of return in each year. *See* Exhibit 7, Schedule 1, Line 6. We note that the present value comparative revenue requirement analysis indexes 1997 dollars, because those are the dollars with which the remaining rate base is measured.

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million year-end 1996 rate base.[550] Therefore, we find that the $669 million year-end 1996 rate base calculated consistent with *Cook Inlet* and confirmed using the comparative revenue requirement analysis suggested by *Kenai* is just and reasonable. In the following part we calculate 1997-2000 rates using the $669 million rate base.

VI. WE COMPUTE 1997-2000 INTRASTATE TAPS RATES USING THE $669 MILLION YEAR-END 1996 RATE BASE

We establish a TAPS revenue requirement for each year 1997-2000, using the formula RR = [r (V-D)] + [OE + d + t]. From the revenue requirement, we calculate a rate to each delivery point on TAPS.

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[550]The logic of *Kenai* suggests an alternative approach for determining rate base in the middle of a pipeline's life. *Kenai* discusses the possibility of a pipeline company advocating an upwards adjustment to rate base if the cumulative opportunity for investment recovery were insufficient. A symmetric reading suggests that a downward adjustment to rate base might be advocated if the cumulative opportunity for investment recovery was excessive. Extending *Kenai*'s logic thus suggests that rate base might be established by determining the cumulative net opportunity for investment recovery that the Carriers have enjoyed. The Carriers appear to endorse such a view. *See Initial Post-hearing Brief of the Indicated TAPS Carriers* at 14; T-10 (WBT) 84.

As Exhibit 7 shows, opportunities for investment recovery were much greater than remaining investment as of year-end 1996. This holds true *even if a straight-line depreciation schedule were adopted*. Exhibit 4 shows a comparative revenue requirement analysis using the Carriers' FERC Form 6 straight-line depreciation charges and the other Commission-adjudicated inputs of Part IV and Part V Section A. It demonstrates that the Carriers' opportunity to recover their investment as of year-end 1996 was $7.4 billion greater than the costs of providing service even under this alternative set of assumptions. In 1997 dollars, the net present value (calculated as per Exhibit 7) of these over-collections is $12.6 billion. The result shows that the Carriers' exhibit ABJ-19 is incorrect, largely because the capital structure and rate of return inputs chosen for the DOC methodology are inappropriate.

Exhibits 7 and 4 show that, under the logic of *Kenai,* rate base could be set to reflect only the new investment that Carriers have made during 1997-2000. We decline to apply this rationale to set rate base. None of the protestants sponsored such an analysis. Moreover, the *Cook Inlet* approach has been upheld by the Alaska Supreme Court. *Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n*, 836 P.2d 343 (Alaska, 1992)

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To establish the revenue requirements for 1997-2000, we determine each individual element. We adopt historical test years for 1997-1999 and a mixed historical/projected test year for 2000 consistent with the information that was available to the parties at the hearing. Below, we establish in Section A the appropriate rate of return (r), and in Section B the rate base (V-D). Because we must set rates for four years, in the discussion of rate base we also determine yearly depreciation charges (d). In Section C, we then determine the appropriate return on rate base, and associated income tax allowance. In Section D we establish appropriate operating expenses. In Section E we calculate the resulting total annual revenue requirement. Having determined the total revenue requirement, we finally determine rates.

A. Rate of Return

We establish an overall rate of return for each of the years from 1997 to 2000. The overall rate of return is determined by the embedded cost of debt and the market return on equity. To determine these elements, we establish: (1) capital structure, (2) cost of debt, (3) return on equity and (4) rate of return adjustment necessary to compensate for any special risks associated with TAPS.

1. The Appropriate Capital Structure for 1997-2000

In Part IV Section B.1, *supra*, we discussed appropriate capital structure for the TAPS Carriers. Our general practice is to use the actual capital structure of a regulated entity unless there is a good reason to believe that the actual capital structure does not properly reflect the risks of the enterprise. For the reasons discussed in Part IV Section B.1, we found that the actual capital structure of the TAPS Carriers in the years 1977-1996 should not be used.[551] Instead, we used a hypothetical capital

[551]We previously determined that all Carriers face the same risks in owning TAPS. Based on the principle that capital structure should thus be the same for each Carrier, we do not use the actual capital structure of each TAPS Carrier.

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structure based upon the capital structure that we determined could be supported by a stand-alone TAPS. A hypothetical capital structure is also appropriate for 1997-2000 for the same reasons that it was appropriate for 1977-1996.

Normally, a single capital structure is proposed to support a filed rate. The TAPS Carriers, however, rely on one set of capital structures to generate an overall rate of return recommendation. Once this overall rate of return is established, the Carriers then rely on the Miller-Modigliani theorem, and sponsor a different capital structure to allocate that rate of return into debt and equity components.[552]

To derive an overall rate of return recommendation, the Carriers' consider both petroleum and gas pipeline proxy samples.[553] The Carriers measure capital structure using the equity stock's market, rather than book value.[554] They argue that market value yields a more appropriate measure of capital structure because the required return on equity is a market-determined value that depends on market perception of financial risk.[555] Although the Carriers recognize that the petroleum pipeline companies in their sample issue preferred stock, for purposes of deriving an overall rate of return the Carriers assume that the cost of preferred stock is the same as the cost of debt.[556] In effect, then, the Carriers consider only debt and common equity in the capitalization of pipelines in their proxy samples.

Having calculated an overall rate of return, the Carriers then use the TAPS parent company capital structure and return on debt to "back out" the required return on

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[552] *See* Tr. 2972-76 (WBT) and 87-WBT-T for a detailed explanation.

[553] T-3 (WBT) 55.

[554] T-3 (WBT) A-9.

[555] *Id.,* T-10 (WBT) Appendix A at 8.

[556] T-3 (WBT), A-10.

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equity.[557] Exhibit 34 shows the actual capital structures of the parent company of each TAPS Carrier for each of the years 1997 through 1999.[558] The Carriers' arguments for using the parent company capital structures for 1997-2000 are the same as those offered for 1968-1996. Their proposed debt/equity structures range from 60.68/39.42 to 10.3/89.7.[559]

For 1997-2000, Williams advocates a capital structure based on the average of the petroleum pipelines in its proxy sample. Williams explained that lower-48 petroleum pipeline operations are substantially similar to TAPS; therefore, the petroleum pipeline proxy group provided a good reference for the appropriate capitalization of a stand-alone TAPS. Williams argued that the book value of proxy group debt and equity, rather than market value, should be used to measure capital structure. Williams' recommended capital structure is the average capital structure of the pipelines in its sample.[560] It reflects the average contribution of preferred stock,[561] as well as common stock and debt. For 1997-2000, Williams recommends the following debt percentages: 53.10 percent, 51.28 percent, 52.55 percent, and 51.28 percent.

Like the Carriers, Tesoro recommends a capital structure that is based upon analysis of both petroleum and gas pipeline proxy samples. Tesoro relies upon the subsidiary company data from the gas pipeline group, rather than the holding

[557]T-3 (WBT) 59-60.

[558]Data for 2000 was not available during the hearing.

[559]*See* Exhibit 34.

[560]*See* JSG-T (W-2) 28.

[561]Williams' recommended contribution of preferred stock to the overall capital structure for 1997-2000 is 0.3 percent, 0.43 percent, .34 percent, and .35 percent, respectively. JSG-T (W-2) 29.

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company gas pipeline data (upon which the Carriers rely).[562] Tesoro's expert witness urges that the holding company data is not representative for how pipeline companies should be financed. They are over-leveraged as a result of acquisitions and mergers in recent years accomplished largely through the use of debt capital.[563] Tesoro urges, as does Williams, that the book value of its proxy sample pipelines should be used as a guide to capital structure, rather than market value.[564] After calculating the average capital structure of the pipelines in its samples, Tesoro makes a minor adjustment to account for bond ratings in arriving at its recommendation of 49.5 percent debt for all four years in question.[565] Tesoro does not include preferred stock within its derivation of an appropriate hypothetical capital structure.

For the same reasons as articulated in Part IV Section B.1, *supra*, we reject the use of Carrier parent company capital structures. It largely reflects the risk and business decisions of integrated petroleum companies, rather than pipeline companies.[566] We, therefore, do not use the capital structure of each parent company for its subsidiary TAPS Carrier. Using the weighted average capital structure of the TAPS parent companies[567] makes no more sense than using the individual parent

[562]FJH-T (E-2) 16.

[563]*Id.*

[564]FJH-T (E-2) 19.

[565]FJH-T (E-2) 21-22; Tr. 5037-38 (FJH).

[566]The Carriers' expert witness acknowledged that the TAPS parent company capital structure was not particularly appropriate for a stand-alone TAPS. *See* T-3 (WBT) 58. Although he suggested that parent company capital structures have a greater percentage of debt than a stand-alone company would support -- a position we rejected in Part IV.B.1 -- he maintained that his approach was consistent with a traditional regulatory practice. *See* Tr. 2791, 2797 (WBT).

[567]That weighted average for the years 1997, 1998, and 1999 is shown in Exhibit 10.

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capital structures. In consequence, we find no compelling reason to use the Carriers' circuitous approach of first finding the appropriate overall rate of return and then "backing out" the return on equity through the use of some other hypothetical capital structure. The traditional approach of constructing the overall rate of return from the ground up has stood the test of time[568] and does not rely upon the Miller-Modigliani theorem. We adopt it here.

We determine the appropriate capital structure for a stand-alone TAPS with reference to the capitalization of a pipeline sample. The record presents three issues. First, whether appropriate capitalization should be determined in reference to both oil and gas pipelines, or to oil pipelines only. Second, whether to adopt book or market values in determining capital structure. Third, whether to include preferred stock in the capitalization of a hypothetical stand-alone TAPS.

We rely on the gas and oil pipeline sample data, rather than oil pipeline data alone. As the Carriers' expert witness notes, the number of publicly traded petroleum pipeline companies is quite small.[569] Gas pipelines share many of the same business risks as oil pipelines,[570] and can therefore provide a useful reference point.[571] We find that it is reasonable to expect that investors would look to other publicly traded companies, engaged in similar affairs, for guidance.

Second, we use book value to determine benchmark capitalization of the proxy pipeline companies. We acknowledge that academic theory provides some

[568]On cross examination, the Carriers' expert witness could not provide any clear examples where his suggested approach had been applied. *See* Tr. 2563-64 (WBT).

[569]T-3 (WBT) A-10.

[570]We acknowledge that the business risks of the two types of pipelines are distinct, but there appear also to be many similarities. *See* Tr. 4384 (JSG).

[571]T-3 (WBT) A-10.

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support for the Carriers' approach of using market values,[572] however, it is standard regulatory practice to rely on book value.[573] Book value measures the capital that has been actually provided to support utility operations.[574] This is the necessary information for regulators.[575] Moreover, book values are relied upon by analysts, bond rating agencies, and financial publication firms.[576] Standards & Poor's target financial ratios for utilities are based on book values.[577] SEC Form 10-K's also rely on book values.[578] All of these sources are readily available, and thus likely to affect investor-decisions.[579] We find that book values are more likely to be the data upon which investors rely.

Finally, we do not ascribe a contribution of preferred stock in our finding regarding a hypothetical capital structure for a stand-alone TAPS. As a practical matter, preferred stock represents an extremely small portion of the average capitalization of the proxy group pipelines.[580] Therefore, it will have little effect on the overall rate of return. The record provides little rationale for why we should adopt a contribution of preferred stock to the overall hypothetical capitalization of a stand-alone TAPS. Consistency with our hypothetical capitalization for 1968-1996 suggests that we avoid imputing a contribution of preferred stock.

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[572]*See* T-10 (WBT) Appendix A at 8.

[573]JSG-T (W-2) 28.

[574]*Id.*

[575]Tr. 4382-83 (JSG).

[576]FJH-T (E-2) 19.

[577]FJH-T (E-2) 60.

[578]*See, e.g.,* FJH-T (E-2) 60.

[579]FJH-T (E-2) 61.

[580]FJH-3 at 1; JSG-2 Schedule 9 at 1. *See* n.561, *supra*.

Based on these findings we adopt Tesoro's recommended capital structure of 49.5 percent debt. Further, we adopt a single capital structure for the four years in question because nothing in the record suggests that it varied significantly enough to affect the cost of debt.[581] This capitalization is very close to that recommended by Williams. Moreover, it is consistent with our approach to back-casting the hypothetical TAPS capital structure for 1977-1996.

2. *Appropriate Cost of Debt*

We generally use a regulated entity's actual embedded cost of debt to calculate revenue requirement. In this case, no party suggested using the Carriers' cost of debt. What little debt is carried by the TAPS Carriers is guaranteed by their parent companies. Thus, we do not use that cost of debt.

Williams advocated using the Carriers' parent companies' embedded cost of debt.[582] The Carriers also advocated using the parent company embedded cost of debt in constructing a revenue requirement, but they do so only after determining an overall rate of return of proxy companies, and then adding a TAPS specific risk premium.[583] In arriving at the overall return required by the sample pipelines, the Carriers used a current market cost of debt, BBB-rated electric utility bonds, rather than the embedded cost of debt of the sample pipelines.[584]

The record provides no clear economic rationale for adopting the parent company cost of debt when the parent company's activities fail to approximate those of

[581]Tr. 5043 (FJH).

[582]JSG-T (W-2) 31.

[583]T-3 (WBT) A-13 - A-14.

[584]*See* WBT-12.

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a pipeline subsidiary. Moreover, the parent company cost of debt is not appropriate given that we do not adopt the parent company capital structure.

Instead of a current cost of debt, we look to the actual embedded proxy company cost of debt. The hypothetical cost of debt should not be the current market cost of debt because we strive to set rates that reimburse the Carriers' costs. The book rate, rather than the market rate, reflects these costs.

In the context of its recommended 49.5 percent debt capital structure, Tesoro advocated hypothetical debt costs of 8.00 percent for 1997, 7.75 percent for 1998, 7.50 percent for 1999, and 7.40 percent for 2000. Tesoro's rate of return witness bases his recommendations on the weighted average cost of debt of three separate proxy groups. On a composite basis, the TAPS Carriers' parent companies have costs of debt of 7.75 percent, 7.44 percent, 6.78 percent, and 6.99 percent for 1997-2000, respectively; the parent companies have lower debt/equity ratios than the capital structure we have adopted. The proxy group of oil pipeline companies have an embedded cost of debt of 8.81 percent, 8.18 percent, 7.24 percent, 7.17 percent for 1997-2000, respectively. The operating subsidiaries of proxy gas pipeline holding companies have an average embedded cost of debt of 8.14 percent, 7.83 percent, 7.72 percent, and 7.59 percent for 1997-2000, respectively; their debt equity ratios are greater than the capital structure we have adopted.

We use the arithmetic average of the average embedded cost of debt of Tesoro's proxy oil pipeline companies and the average embedded cost of debt of Tesoro's proxy gas pipeline companies for each of the years 1997-2000. We cannot determine the actual numbers with greater precision. Using an average takes into account the range of different rates.

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1997	8.475%
1998	8.005%
1999	7.48%
2000	7.38%
Average	7.805%

We adopt the average of the four yearly averages as the hypothetical cost of debt used to calculate revenue requirements for 1997-2000. Because the actual embedded pipeline cost of debt changes slowly, if at all, from year to year, we adopt the same hypothetical cost of debt for all four years to more closely track our preferred cost of debt.[585]

3. *Appropriate Return on Equity*

The appropriate return on equity should reflect the compensation that investors require based on their perceptions of prospective project risks.[586] All parties agree that current period TAPS risks are essentially comparable to those of the average pipeline.[587] Thus, the parties' methods are designed to determine equity investor requirements given average pipeline risk. After mechanical application of their favored methods, the parties' expert witnesses apply their judgment to select between estimates. Some then add a risk premium to accommodate special TAPS risks.

The Carriers base their return on equity recommendation on DCF analyses of publicly traded petroleum and gas pipeline companies.[588] They present

[585]We note a substantial drop in our findings regarding the back-cast cost of debt in 1996 (9.24 percent) to 1997 (7.84 percent). We assume that a stand-alone TAPS would have taken advantage of the lower interest rates of recent years and refinanced its long-term debt.

[586]FJH-T (E-2) 7.

[587]*See* n.404, *supra*.

[588]The Carriers select their recommended return on equity from the petroleum pipeline estimates, but use the gas pipeline sample as a reference. T-6 (WBT) 38.

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both simple[589] and two-stage[590] DCF analyses calculated for two periods, 1997-98 and 1999-2000. On a composite basis the Carriers add equity risk premiums of 4.53 percent, 4.63 percent, 4.65 percent, and 4.65 percent for 1997-2000,[591] respectively, to reflect extraordinary TAPS-specific risks.

Williams bases its return on equity recommendation on DCF analyses of publicly traded petroleum pipeline companies and of the TAPS parent companies. It presents both simple[592] and two-stage[593] DCF analyses for 1997-2000. In addition, Williams projects forward the return on equity established by the APUC in *Kenai*, in the same manner in which it had back-cast those results.[594] Williams adds a construction-period risk premium of 50 basis points to its proxy-based recommendations. Finally, as

[589]The Carriers project dividend growth rates using the I/B/E/S 5-year earnings forecasts. WBT-37 at 2.

[590]The Carriers' two-stage DCF analysis estimates future dividend growth as a weighted average of company growth forecasts (2/3) and gross domestic product (GDP) growth forecasts. For 1997-1998, future GDP growth is estimated using the ten-year consensus forecast of nominal GDP growth (2000-2009) provided by Blue Chip Economic Indicators for long-term GDP growth forecasts. T-3 (WBT) A-6. For 1999-2000, future GDP growth is taken as the average of estimates made by the Energy Information Administration and Social Security Administration (WBT-37 at 3) -- as is consistent with FERC's. *See, e.g., Trunkline Gas Co.*, 90 F.E.R.C. ¶ 61,017, 61,116-17 (2000); *Williston Basin Interstate Pipeline Co.*, 91 F.E.R.C. ¶ 63,005, 65,085 (2000).

[591]The equity premiums result from applying a constant 3.5 percent premium to the entire cost of capital, but placing the entire weight of this premium to only the return on equity. The equity premiums are not reported by the Carriers, but were derived from the composite Carrier capital structure, cost of debt, and overall rate of return data as contained in 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls; *see* Input ll. 6, 5, and 4, respectively.

[592]Williams projects dividend growth rates, as do the Carriers, using I/B/E/S estimates. JSG-T (W-2) 15.

[593]Williams estimates future dividend growth as a weighted average of I/B/E/S growth rate projections (weighted 2/3) and historical retention growth rates (weighted 1/3). JSG-T (W-2) 16, 19.

[594]JSG-T (W-2) 22.

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an adjustment to reflect the costs of issuing common stock, Williams multiplies its preliminary recommendation by 1.05.

Tesoro bases its return on equity recommendation on multiple methods applied to publicly traded petroleum and gas pipeline companies, as well as the TAPS parent companies.[595] It presents simple[596] and two-stage[597] DCF analyses, traditional and empirical capital asset pricing models (CAPM and ECAPM),[598] a comparable earnings model (CEM), and a risk premium model (RPM). Tesoro's expert witness applied his judgment to choose among the various estimates. The result is generally within 10 basis points of the mean of results across all methods and both proxy groups. Tesoro makes separate recommendations for each of the four years at issue and asserts that no risk premium need be awarded.

The returns on equity recommended by each party, exclusive of any special TAPS risk premium are:

[595]Tesoro's expert witness relies principally upon the two proxy groups of five oil and four gas pipeline companies. *See* FJH-T (E-2) 52. He does not consider the TAPS Carriers' parent companies to be indicative of how a pipeline company should be financed. FJH-T (E-2) 16.

[596]Tesoro estimates future dividend growth as the average of the I/B/E/S and Value Line projections of growth rates in earnings per share for each company in each group. FJH-T (E-2) 31.

[597]Tesoro provides two, two-stage DCF analyses. Like the Carriers and Williams, it performs a FERC-style two-stage DCF, with an estimate of future dividend growth as the weighted average of I/B/E/S growth rate projections (weighted 2/3) and GDP growth forecasts (weighted 1/3). Future GDP growth is taken as the average of estimates made by the Energy Information Administration and Social Security Administration. FJH-T (E-2) 34. Tesoro also presents a two-stage compound growth analysis. Its two-stage recommendation is the average of both two-stage results.

[598]Tesoro's CAPM recommendation is the average of the results produced by its traditional CAPM and ECAPM analyses. FJH-T (E-2) 47.

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	Carriers	Williams	Tesoro
1997	13.30 percent	14.17 percent	12.50 percent
1998	13.30 percent	12.82 percent	12.25 percent
1999	16.00 percent	14.75 percent	13.25 percent
2000	16.00 percent	14.75 percent	14.00 percent

The parties largely failed to successfully rebut each other's various approaches to determining return on equity.[599] For the most part, the record fails to provide a theoretical or empirical basis for deciding whether any particular method is more appropriate than another.[600] The record also fails to suggest that any of the expert witnesses have applied their chosen methods inappropriately, or have chosen inappropriate data or parameters.

We find Tesoro's expert witness to be the most credible. We base our rate of return findings primarily upon Tesoro's witnesses' recommendation. Tesoro sponsors multiple methods because it believes investors rely on the widest possible

[599]The Carriers urge that Tesoro's expert witness used non-DCF approaches to "water down" the higher returns generated by the DCF method. The Carriers also suggest that we adopt the DCF approach because this is the method generally preferred by the FERC for oil pipelines. *See* T-10 (WBT) 15. However, no empirical or theoretical evidence was offered in this case to support the contention that the DCF method is a superior guide to investor perceptions and expectations. Thus, Carriers' charges that Tesoro "watered down" its results carry no more weight than the contrary position that the Carriers artificially boosted their own results. Further, no reasons were provided for why FERC practice is either particularly accurate or appropriate for use by this commission. Indeed, the record only suggests theoretical reasons for *not* adopting the FERC approach. *See* n.600.

[600]Tesoro's expert witness urges that the FERC's two-stage DCF methodology is inappropriate because it is inconsistent with the theory underlying the DCF approach. FJH-T (E-2) 33. Nevertheless he presents and relies upon the FERC's approach to the two-stage DCF because he lacks any empirical evidence to suggest that investors do not rely upon it. Tr. 5028 (FJH).

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information available.[601] We agree with Tesoro that investors are aware of all the various traditional cost of common equity models discussed in financial literature. Absent good reason for believing that investors weight the results of one method more heavily than another in their assessment of an appropriate rate of return, it is reasonable to hold that investors ascribe weight to them all. We note that the APUC has relied on a variety of methods when those methods were reliable given the specific facts at hand.[602]

In addition, we find Tesoro's DCF analysis the most reliable. Tesoro relies on I/B/E/S and Value Line estimates of future dividend growth, rather than just the I/B/E/S data. In the absence of a good rationale for why investors would be more likely to rely on one data source than another, we find Tesoro's agnostic approach preferable. In a similar vein, Tesoro relies equally upon the single and two-stage results, rather than choosing a result based on "expert judgment". Absent good motivation for why an investor would make the same judgments as did the competing expert witnesses,[603] we

[601]FJH-T (E-2) 14-15.

[602]The APUC has relied on comparable earnings and risk premium methods as benchmarks in their determination of return on equity, although they gave primary weight in that case to the DCF method. *Re Alascom, Inc.*, 7 APUC 665 (1986); *Re Enstar Natural Gas Co.*, 7 APUC 375 (1986). In the current proceeding the expert witnesses' methods were largely unrebutted.

[603]The Carriers' witness, "after taking into consideration" the results from the natural gas pipeline sample, relies on the FERC DCF result for his 1999-2000 recommendation, while taking the average of the two approaches for his 1997-1998 recommendation. T-6 (WBT) 38. No theoretical reason is given for why such consideration should emulate the process that investors go through.

Williams' witness essentially selects the single stage petroleum pipeline DCF results in 1997 and 1999, eschews the DCF results altogether for 1998, and then adopts an average across his results for 2000. Tr. 4381 (JSG). He provides no reason for his primary reliance upon the single stage DCF. Tr. 4380 (JSG). While he explains that his choices for 1998 and 2000 based on "smoothing variability" (Tr. 4380-81 (JSG)), there are numerous ways to smooth such variability. Indeed, the substantial variability to which he points is arguably a product of his substantial reliance on the single-stage results.

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find such equal weighting reasonable. Tesoro's DCF recommendation is also favored because, unlike Williams' DCF recommendation, it is integrally based on the same proxy companies as were used to determine appropriate capital structure and cost of debt. Finally, Tesoro sponsors separate return on equity figures for each of the years in question, rather than using a single figure for two years, as do the Carriers.

Although we primarily rely upon Tesoro's recommendation, we are concerned, however, about Tesoro's CAPM analysis. Tesoro averaged the results it obtained from CAPM and ECAPM while at the same time providing empirical testimony[604] that the ECAPM results are more accurate then traditional CAPM results. The reasonable investor would be aware of these empirical results. Therefore, we adjust Tesoro's recommendation to reflect only the ECAPM result.

We adopt returns on equity for each of the years 1997-2000, based on Tesoro's DCF, ECAPM, CEM and RPM results for each of the companies (both petroleum and gas pipelines) in its sample groups. We find that those returns, which do not include any risk premium, are:

1997	12.71 percent
1998	12.26 percent
1999	13.61 percent
2000	14.00 percent

Williams contended that we should add flotation costs to ensure that the return is sufficient to attract new common equity capital on reasonable terms without diluting the value of existing investment. The Carriers, however, are wholly owned subsidiaries that do not offer stock to the public; no dilution of shareholder value could therefore occur. Further, the APUC has consistently rejected the addition of flotation

[604]FJH-T (E-2) 43.

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costs when the regulated entity did not contemplate issuance of stock.[605] The parties have not presented any sound reason to deviate from that precedent in this case. Therefore, we do not award a flotation cost adjustment.

4. Rate of Return Adjustment to Compensate for Any Special Risks Associated With TAPS Between 1997 and 2000

The parties agree that during the period 1997-2000 TAPS was no more risky than the average petroleum pipeline.[606] Therefore, we add no risk premium to our adopted returns on equity to account for present risk.

In Part IV Section B.4., *supra*, however, we determined that a risk premium of 75 basis points should be added to return on equity through the middle of 2002, in consideration of early period risk. The returns on equity we use to calculate rates for 1997-2000 consist of the adopted returns on equity and this early period risk premium. We find that those returns are:

1997	13.46 percent
1998	13.01 percent
1999	14.36 percent
2000	14.75 percent

5. Overall Rate of Return

The overall rate of return is calculated as the weighted average of the cost of debt and equity. Given the foregoing findings on capital structure, cost of debt, and return on equity, we find that the resulting returns on rate base are:

1997	10.68%
1998	10.45%
1999	11.13%
2000	11.33%

[605]*Re Enstar Natural Gas Co.*, 7 APUC 375, 400 (1986); *Re Kenai Pipe Line Co.*, 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992).

[606]T-3 (WBT) 39; T-10 (WBT) 9-10; FJH-T (E-2) 6; JSG (W-2) 39:10-11.

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B. Rate Base

In Part IV Section E, we established that the year-end rate base for 1996 was $669 million, as shown at Exhibit 29, line 18. The rate base for 1997, 1998, 1999, and 2000 is affected by subsequent additions to gross Carrier property, changes in working capital, and additions due to AFUDC. Rate base is also a function of subtractions that come from yearly depreciation charges, property retirements, and the amortization of AFUDC. Finally, we adjust rate base to reflect ADIT, the "cost free" capital provided by shippers that results from differences between depreciation schedules used for tax and rate making purposes.

1. Carrier Property Balances and Working Capital

Although the TAPS pipeline was constructed from 1968 to 1977, property additions are still being made. We must determine capital additions and retirements for 1997-2000. We generally adopt the Carrier-sponsored data, rather than Tesoro's data, for the same reasons as articulated in Part IV Section A.1.[607] Similarly, we adopt the Carriers' sponsored Working Capital allowances, rather than Tesoro's, for the same reasons as articulated in Part IV Section A.3.These amounts are shown, below.

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[607]For the same reasons articulated at n.229, we use the FERC Form 6 data on retirements filed with the Commission, rather than the Carrier-sponsored retirements data. The differences are not material.

Line No.	Account	1997	1998	1999	2000
1	Land - New Construction Exp.	$0	$0	$0	$0
2	Grand Total - New Construction Exp.	$61	$30	$95	$45
3	Grand Total - Acquired Property	$0	$0	$0	$0
4	Grand Total - Credits for Retirements	($3)	($6)	($47)	($1)
5	Grand Total - Other Adjustments	($0)	($0)	($0)	$0
6	Land - EOY Balance	$19	$19	$19	$19
7	CWIP – EOY Balance	$30	$39	$43	$30
8	Grand Total - EOY Balance	$10,214	$10,238	$10,286	$10,330
9	Capitalized Interest - EOY Balance	$1,205	$1,205	$1,205	$1,205
10	Working Capital	$44	$43	$47	$24

2. *AFUDC*

For the reasons given and in the manner articulated in Part IV Section B.5, we permit AFUDC for capital expenditures made during 1997-2000. We adopt the AFUDC additions depicted at Exhibit 35.

3. *Appropriate Depreciation*

We must determine the appropriate depreciation charges to include in the 1997-2000 revenue requirements. To determine those amounts we must decide the remaining economic life of TAPS, as well as the depreciation profile appropriate for ratemaking purposes.

a) Life of the Line

TSM assumes a 34-1/2-year life of TAPS, ending in 2011. TSM's stipulated life of the line is the same as that contained in an earlier stipulation, signed by

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all parties, as a part of Phase II of the original litigation.[608] Neither the APUC, the FERC, nor this Commission have found that 2011 is the appropriate end date for TAPS operations.

In this proceeding, Williams contends that TAPS will operate beyond 2011. This contention is not seriously challenged. Williams prefiled confidential testimony and exhibits, and submitted confidential evidence at the hearing to support its contention that TSM will operate beyond 2011.[609]

Further, public information supports a substantial extension of the life of TAPS for ratemaking purposes. We recently accepted a settlement of Alpine Pipeline rates.[610] The Alpine Pipeline connects to TAPS through the Kuparuk Pipeline. The parties to the settlement of Alpine Pipeline rates[611] agreed to an economic life for the Alpine Pipeline extending through 2026. Alpine Pipeline has no reason to operate if TAPS is not in operation. Accordingly, the parties to the Alpine Pipeline Settlement represented that TAPS will operate at least through the year 2026. In accepting the settlement, we accepted that projection.

Based on the Alpine settlement and the confidential testimony and exhibits in this docket, we find that the appropriate life of TAPS for ratemaking purposes extends through the year 2026, fifteen years beyond the current assumed 2011 end of TAPS life. Accordingly, for ratemaking purposes we find that the remaining economic life of TAPS as of January 1, 1997 extends for 30 years to December 31, 2026.

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[608] *Re Construction of the Trans Alaska Pipeline*, 4 APUC 338, 341 (1982).

[609] 14-ABJ-W.

[610] *Re Alpine Transp. Co.*, Order P-00-15(11), dated December 5, 2001.

[611] The parties to the Alpine Settlement are the State and Alpine Transportation Company, which is largely owned by Phillips Petroleum Company, a major producer of North Slope oil and a TAPS parent company.

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b) Depreciation Profile

The depreciation profile determines the rate at which the Carriers may recover their remaining investment. In their benchmark DOC methodology the Carriers use straight-line depreciation but assume a life ending in 2011.[612] Williams[613] and Tesoro[614] advocate using TSM depreciation. We use TSM depreciation charges to calculate our year-end 1996 rate base. To calculate depreciate depreciation for 1997-2000 we must choose either TSM's accelerated depreciation schedule or a straight-line depreciation schedule.

TSM depreciation assumes a useful life ending in 2011. We do not use TSM depreciation because we have determined that TAPS' useful life extends to 2026. Use of TSM depreciation would unfairly burden shippers who transport oil in the first 15 years of the 30-year remaining life of TAPS. We thus use straight-line depreciation to calculate 1997-2000 rates.[615]

We do not have continuing property records or comparable information in the record that allows us to determine depreciation in the usual way, i.e., based on classes of depreciable property with differing useful lives.[616] Instead, we establish depreciation in a way similar to TSM. We assume all depreciable property has a useful

[612]T-7 (RGV) 10.

[613]189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls.

[614]225-JFB-T.

[615]As the APUC stated, in pipelines with declining throughput, unit of throughput depreciation may be desirable. *Re Kenai Pipe Line Co.,* 12 APUC 425, 437, 1992 WL 696192 (Alaska P.U.C., 1992). Unit of throughput depreciation attempts to apportion an equal amount of capital costs to each barrel transported on the pipeline. We do not have a record upon which to determine an appropriate unit of throughput depreciation schedule. No party has yet argued for unit of throughput depreciation on TAPS.

[616]Typically, a carrier provides evidence showing the various classes of depreciable property. In this case the Carriers did not.

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life equal to the life we have determined for TAPS. We include in the 1997 revenue requirement 1/30th of the sum of the year-end 1996 net depreciable property and the 1997 depreciable property additions.[617] We determine depreciation charges for 1998, 1999, and 2000 similarly, using composite depreciation factors of 1/29, 1/28, and 1/27, respectively. We find annual amounts for depreciation are:[618]

1997	$ 23,732,829
1998	$ 24,350,726
1999	$ 27,370,118
2000	$ 27,674,341.

c) Amortization of AFUDC

We amortize AFUDC according to the same depreciation factors we adopt above. This approach to AFUDC amortization is different than that adopted for rate base development purposes in Part IV Section C.3, because in that analysis we had historical data to use.[619] It is, nevertheless, consistent in the principle applied: the rate at which AFUDC is amortized should match the rate at which Carrier property is depreciated. We find annual amounts for amortization of AFUDC are:[620]

[617]Williams' uses depreciation factors to calculate yearly depreciation charges and depreciation additions to property in service on an end-of-year basis. 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedule 2 line 30. The TSM determines yearly depreciation charges in a similar manner. 31-BEW-T, line 14. However, we depreciate additions to depreciable property in service on a beginning-of-year basis to mirror our treatment of AFUDC amortization. *See* Exhibit 37. We are guided by the principle that AFUDC amortization should proceed at the same rate as depreciation of Carrier property. *See* Part IV Section C.3, *infra*.

[618]*See* Exhibit 36 for calculations.

[619]For 1977-1996, we adopted AFUDC amortization factors that reflect net depreciation factors. The derivation of net depreciation factors begins with depreciation charges, and is influenced by retirements from accumulated depreciation. Here we start with depreciation factors, and derive depreciation charges. Thus, retirements from accumulated depreciation do not affect AFUDC retirements. As before, depreciation proceeds at the same rate as AFUDC amortization.

[620]*See* Exhibit 37 for calculation.

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1997	$ 3,673,787
1998	$ 3,788,596
1999	$ 4,009,653
2000	$ 4,281,328.

d) Retirements from Accumulated Depreciation

We explain how adopting TSM depreciation charges affect the appropriate calculation of retirements from accumulated depreciation in Part IV Section C.2. We impose the shape of depreciation profile implicit in the appropriate depreciation charges on charges to accumulated depreciation due to retirements. However, for property placed in service after 1996 and retired during 1997-2000, we make adjustments because a straight-line depreciation profile is adopted for 1997-2000. Exhibit 38 shows the adjustments to accumulated depreciation to reflect property retirements.

4. *Accumulated Deferred Income Taxes*

ADIT is a function of the difference in timing of depreciation for ratemaking and tax purposes. For ratemaking for 1997-2000, we use the depreciation charges shown in Exhibit 36.[621] For tax depreciation, we follow the approach taken by all parties and assume the most accelerated methods of tax depreciation allowed,[622] i.e., that maximum depreciation charges allowed by state and federal tax law are taken.[623] Consistent with a stand-alone income tax calculation, we follow the parties and assume that income is sufficient to be taxed at the highest statutory rate,[624] recognizing relevant

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[621] *See infra* Part VI Section B.3.b.

[622] *See*, e.g., T-7 (RGV) 12; 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedules 6-7; 225-JFB-T, Workpaper 2.

[623] Exhibit 39, Schedules 1 and 2 show the State and Federal tax depreciation, respectively, used to calculate ADIT balances.

[624] *See*, e.g., T-7 (RGV) 11; 189A-BEW-T Workpaper BEW_R_RGV6RE.xls, Schedule Income Tax Expense; 225-JFB-T, Workpaper 1.

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changes in income tax rates[625] and laws.[626] Finally, we follow the approach used by the parties and do not reduce outstanding ADIT balance to reflect changes in deferred taxes associated with property retirements.[627] We find that ADIT balances for 1997-2000 are:[628]

1997	$ 98,112,934
1998	$ 108,152,461
1999	$ 117,233,293
2000	$ 127,327,563.

5. *Appropriate Rate Base for Year End 1997, 1998, and 1999.*

Having calculated the necessary elements for V -- the sum of prudently incurred capital expenditures, allowance for funds used during construction, and working capital, adjusted for accumulated deferred income tax and retirements -- we now calculate (V-D) of the DOC formula. We add 1997 additions to property and working capital to year-end 1996 rate base calculated at the end of Part V, subtract retirements, and subtract the depreciation amount described in Part VI Section C, *supra*, and the amount of ADIT calculated above in Part VI, Section D, *supra*. We use this year-end 1997 rate base to calculate the 1998 revenue requirement. Rate base for year-end 1998 and year-end 1999, calculated in the same way, are used to determine the rate bases for 1999 and 2000, respectively. The calculation of average year rate

[625]*See*, e.g., T-7 (RGV) 12.

[626]Exhibit 40 shows the calculation of an adjustment to tax depreciation caused by TEFRA. Pub.L. 97-248, Sept. 3, 1982, 96 Stat. 324. As in Part IV Section D, we include the TEFRA adjustment as it better conforms to Federal statute.

[627]*See* T-7 (RGV) 12; 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedules 6-7; 225-JFB-T, Workpaper 2. Carriers note that this tends to result in the highest ADIT balance possible, and thus the largest reduction in rate base.

[628]*See* Exhibit 41 for calculation.

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base for 1997, 1998, 1999 and 2000 is shown in Exhibit 42. We find the resulting rate bases are:

year-end 1997	$714,306,826
year-end 1998	$752,575,116
year-end 1999	$752,555,251
year-end 2000	$740, 267,853

C. Appropriate Return and Income Tax Allowance

1. Appropriate Return on Rate Base

Using the overall rate of return, that we find at Part VI Section A.5, we calculate return on rate base to be included in revenue requirements for 1997, 1998, 1999, and 2000. Return is calculated against 1997, 1998, 1999 and 2000 average-year rate bases. The average-year rate base is determined as the average of the beginning of year and end of year rate base figures.[629] We find the resulting returns on rate base are:[630]

1997	$ 76,287,969
1998	$ 78,644,100
1999	$ 83,759,399
2000	$ 83,872,343

2. Income Tax Allowance

We calculate the income tax allowance in the standard way based on our calculated return on equity amounts and assuming maximum statutory federal and state

[629]*See* n.523.

[630]*See* Exhibit 43 for calculation.

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income tax rates.[631] Doing so, we find the income tax allowances included in the 1997-2000 revenue requirements are:[632]

1997	$ 35,032,772
1998	$ 35,691,153
1999	$ 39,361,114
2000	$ 39,895,903

D. Appropriate Operating Expenses.

As discussed in Part IV, *supra*, there are two sets of operating expense data in the record, TSM (sponsored by Tesoro) and FERC Form 6 (sponsored by the Carriers and Williams). For the same reasons articulated in Part V Section A, we adopt the FERC Form 6 data for the purpose of calculating 1997-2000 rates. The record does not contain complete FERC Form 6 data for 2000. We accept the Carrier-sponsored operating costs for 2000, which are based on a mix of Carrier actual and projected operating expenses. Tesoro also urges that we disallow "those costs associated with the unique ownership structure the TAPS Carriers have put in place . . . ."[633] Tesoro asserts that because TAPS' joint undivided interest ownership allows each Carrier to file separate tariffs, costs are higher than they would be under more conventional ownership. Tesoro argues that such costs are necessarily inefficient, and therefore imprudently incurred.[634] Tesoro urges removing roughly $27 million[635] from the General and Administrative overhead account.[636]

[631]This was the approach adopted by the parties. *See*, *e.g.*, T-7 (RGV) 13; 189A-BEW-T Workpaper BEW_R_RGV6RE.xls, Schedule Income Tax Expense; 225-JFB-T, Workpaper 1.

[632]*See* Exhibit 44 for calculation.

[633]JFB-T (E-3) 33.

[634]Tr. 5216 (JFB).

[635]Tr. 5226 (JFB).

[636]Tr. 5223 (JFB).

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Tesoro's claims of imprudence are unsupported by the record. Tesoro fails to detail which operating expenses result from "duplicative ownership." Accordingly, we do not reduce the FERC Form 6 data by the amounts that Tesoro suggests.

We find that the Carriers reasonable operating expenses for each year are:[637]

1997	$ 603,775,000
1998	$ 565,598,000
1999	$ 567,658,000
2000	$ 553,280,000

E. Other Rate Elements

In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(118)/P-97-7(78), we ruled that if 1997-2000 TAPS rates were found to be unjust and unreasonable, then "the Commission will need to hear evidence on additional issues, including the appropriate amount and management of DR&R".[638] Based on this record, we find that the Carriers have collected $1,552,743,000 from 1977-1996 to cover their costs of eventual DR&R.[639] To determine the appropriate amounts for DR&R for 1997-2000 and for subsequent years we must consider the issues of the earnings on funds already collected, the cost of ultimate DR&R obligations and whether the DR&R funds should be maintained in a separate account. Because many years remain in the life of TAPS during which we can adjust the amounts to be collected for DR&R, because DR&R

[637] 143-RGV-C, Workpaper TAPS-RGV WP3.xls, Schedule 13.

[638] *Re Amerada Hess Pipeline Corp.,* Order P-97-4(118)/P-97-7(78) at 11 (February 16, 2001).

[639] *See* Exhibit 7, Schedule 1, line 3; *Initial Post-hearing Brief of the Indicated TAPS Carriers* at 28. Although this figure contains DR&R amounts from TSM-6, we adopt those amounts as having been collected for the same reasons that we found TSM-6 depreciation amounts to be appropriate. *See* Part IV Section C.1.

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issues are complex and costly, and because we do not have a sufficient record to rule on appropriate DR&R charges for 1997-2000 we do not award DR&R in this order.[640]

In Phase II of this docket we will investigate these issues and determine if any additional funds should be paid by 1997-2000 shippers for DR&R or whether there should be a negative allowance in future rates to refund overcollections. Determining the Carriers' ultimate obligation will be a challenge at this stage of the pipeline's operation. In Phase II of this case we intend to determine the size of the existing fund, the rate at which it will continue to grow and clarify if there will be a process for refunds or additional collections at the end of the pipeline's life.

1. Total Revenue Requirement for 1997, 1998, 1999, 2000

Having determined all the inputs for the DOC revenue requirement formula for the period 1997-2000, we now calculate the 1997-2000 revenue requirements exclusive of DR&R. We find that the annual revenue requirements are:[641]

[640]The PAS has consistently maintained that the TAPS Carriers have not accounted for earnings on accumulated DR&R collection. P-1 (RAF) 15, 22-24. The Carriers failed to provide DR&R evidence. They did not include a DR&R allowance in their benchmark rates. They also disavowed TSM's DR&R allowance as representing the appropriate amounts that should be collected in rates to cover eventual DR&R costs. We have no record upon which to award DR&R amounts for 1997-2000 rates.

In *Re Amerada Hess Pipeline Corporation*, dated February 16, 2001, we tried to draw a distinction between the DR&R amount includable in 1997-2000 rates from the overall amount of the DR&R obligation and the current size of the DR&R internal fund established by the Settlement. We consolidated Docket P 97-7 and Docket P-97-4 with hopes of being able to award, if appropriate, a DR&R allowance. *Re Amerada Hess Pipeline Corp.*, Order P-97-4(118)/P-97-7(78) at 12 (February 16, 2001). To reasonably determine the includable amount of DR&R obligation in 1997-2000 rates, however, we must determine the appropriate amount of the overall DR&R obligation as well as the size of the current DR&R internal fund. This record does not provide sufficient information to make these findings.

[641]*See* Exhibit 45 for calculation.

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1997	$742,502,356
1998	$708,072,574
1999	$722,158,284
2000	$709,003,915

F. Just and Reasonable Rates for 1997, 1998, 1999, and 2000

The Carriers' tariffs provide for three different rates for the transportation of oil on the TAPS, reflecting the three different distances of the off-take points along the pipeline from Pump Station #1. These off-take points are at the Golden Valley Electrical Authority (GVEA) interconnection facility (469.06 miles), the Petro Star interconnection facility (796 miles), and the Valdez marine terminal (800.32 miles).[642]

The parties adopt a rolled-in barrel mile methodology for calculating intrastate rates to these three destinations, given a revenue requirement.[643] Most costs are deemed to be "distance related"; these are apportioned according to a destination's barrel-mile share of total (both intrastate and interstate) barrel-mile deliveries. Total non-distance related costs are apportioned on a per-barrel (both intrastate and interstate) basis. This rate design follows APC's decision in *Re Amerada Hess Pipeline Corporation* as modified by the Quality Bank Agreement accepted by the APUC.[644] The connection costs specific to the GVEA connection facility are apportioned to the GVEA tariff. The parties do not dispute the magnitude of GVEA connection costs, nor of non-distance related costs, nor of deliveries to any given destination.

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[642]T-2 (BWF) 13.

[643]*See* RGV-14 Schedule 1; 225-JFB-T, Workpaper 5; BEW-T (W-3) 48.

[644]*Re Amerada Hess,* 1 APUC 606, 611 (1980); 6 APUC 401, 405 (1984).

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We therefore adopt the Carriers' undisputed approach to rate design. Accordingly, we make the necessary calculations and fnd that the following rates are just and reasonable:

	GVEA	Petro Star	Valdez
1997	$1.02	$1.55	$1.56
1998	$1.03	$1.62	$1.63
1999	$1.19	$1.88	$ N/A[645]
2000	$1.25	$1.96	$ N/A.

On average the Carriers' filed rates for 1997-2000 exceed cost-based rates by 57 percent. *See* Exhibit 1 Schedule 3. Fifty-seven percent above cost-based rates is well outside the zone of reasonableness. This further confirms our finding that the 1997-2000 filed rates are unjust and unreasonable.

We adopt the above rates as satisfying the requirements of AS 42.06.410 (b) for the years 1997-2000. These rates are single rates for all Carriers for each year.[646] Consistent with this order, we allow each Carrier to file individual rates supported by individual actual, historical Carrier costs that justify individual revenue requirements if the sum of the individual annual revenue requirements does not exceed the composite revenue requirement found in this order. If the Carriers do not elect to file separate rates, we will be able to bring our investigation of the capacity settlement

[645]*See* Exhibit 46 for calculation. The tariffs to the Valdez Marine Terminal, for 1999 and 2000, are not calculated because during those years no intrastate shipments were made to Valdez.

[646]Endnote 9 discusses the appropriateness of a single rate for the TAPS.

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agreement and whether there is competition on this pipeline to a close.[647] TSM was structured based on the assumption that there would be competition amongst the TAPS carriers. Until recent years, the tariffs have been uniform.[648] If the Carriers elect to file separate rates, they must do so by January 27, 2003.

These rates are different than the Carriers' filed rates. The Carriers shall refund the difference between their filed rates and our calculated rates by January 13, 2003.[649] If adjustments are necessary because the Carriers file and we approve individual Carrier rates, those will be made within thirty days of our final order approving individual rates.

Carriers have had the use of shippers' money since it was paid, and an award of interest is appropriate. We do not have a record sufficient to determine the interest due, and require the parties to address that issue in Phase II.

[647]Docket P-97-6 is titled *In the Matter of the Cancellation of Allocation of Capacity Rules by AMERADA HESS PIPELINE CORPORATION; ARCO TRANSPORTATION ALASKA, INC.; BP PIPELINES (ALASKA) INC.; EXXON PIPELINE COMPANY; MOBIL ALASKA PIPELINE COMPANY; PHILLIPS ALASKA PIPELINE CORPORATION; and UNOCAL PIPELINE COMPANY and the Matter of the Complaint of the STATE OF ALASKA Concerning Allocation of Trans Alaska Pipeline System Capacity and the Petition of TESORO ALASKA PETROLEUM COMPANY for an Investigation into Capacity Allocation and the Discontinuance of Use of Certain Pump Stations on the Trans Alaska Pipeline System*.

[648]Amerada Hess sold its interest in the pipeline after concluding that existing agreements amongst the carriers made it uneconomic for any carrier who was not also a producer to retain an interest in the TAPS. 33 BWF-E, 51 HIGHLY CONFIDENTIAL Absent separate rates for the Carriers, we will have no cause to investigate these issues further.

[649]*See* Endnote 10.

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G. Post-2000 Intrastate TAPS Rates

Post-2000 intrastate TAPS rates will be determined based on the Carriers' tariff filings and supporting documentation. To determine rates for 2001 and subsequent years we require the Carriers to file tariff revisions including the information required by AS 42.06.350(a) and 3 AAC 48.275(a).[650] We will review those filings for consistency with the depreciated original cost methodology described in Part IV of this order. We require the Carriers to make supporting documentation available for review by Commission staff. Because these filings are likely to be suspended at the end of the 45-day review period, we set a prehearing conference in this order.

H. Rate Case Expense

Tesoro protested allocation of rate case expenses and we ordered the Carriers to file quarterly reports of the costs they have incurred litigating this case. The most recently filed reports show that the Carriers have incurred $14.83 million in legal costs.[651]

Rate case expense is ordinarily a fairly uncontroversial component of revenue requirement. The actual or estimated cost of the rate case is supplied by the regulated entity. The Commission then looks at the entity's rate case history and applies its own judgment to decide how many years it will be before a new rate case. Typically, rate case expense would be amortized over a three to five-year period. Because we are setting rates for a four-year period it would be reasonable, if this were

[650] AS 42.06.440.

[651] *Indicated TAPS Carriers' Eighteenth Litigation Cost Report*, filed August 29, 2002; *Seventh Cost Report of Williams Alaska Pipeline Company, L.L.C*, filed August 30, 2002.

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an ordinary case, to simply take the total rate case expense, divide it by four, and include that amount in the revenue requirement for each of the years 1997-2000.

This case is not an ordinary case. Rate case expense is extremely high. If we assume intrastate shipments over the four-year period of 146,000,000 (100,000 barrels per day) and rate case expense of $15,000,000, each intrastate barrel would pay approximately ten cents in rate case expense.

The very high expenditure in this case may be partially justified by the issues, which reach far beyond those in the usual rate case and include issues of first impression before the Commission. To decide this case we considered evidence that spanned a twenty-five year period. The decision in this case will affect future TAPS rates. We, therefore, may treat the rate case expenses incurred in this case differently.

The Alaska Pipeline Act requires us to exclude all direct and indirect costs of any unreasonable practices from tariffed rates.[652] We have found that TSM did not produce just and reasonable rates for 1997-2000. Carriers' costs incurred in defending TSM are arguably costs associated with an unreasonable practice. However, we have no record to determine what portion of the Carriers' litigation expenses is reasonable. We also lack a record on whether the reported legal expenses have already been collected in rates. If any party still believes that we should open a proceeding to examine the reasonableness of the Carriers' rate case expenses and determine an appropriate schedule for recovery of those expenses, it may file a request within forty-five days of this order and we will address that issue in Phase II of this case.[653]

[652]"Following such a determination, the commission shall take appropriate action to ensure that neither the direct nor indirect costs of any unreasonable practices or imprudent expenditures are included in any tariff or rate of a pipeline carrier or are borne by the public of the state." AS 42.06.450.

[653]AS 42.06.410(b).

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VII. FURTHER PROCEEDINGS

Tesoro raises two additional issues. Tesoro request that we 1) audit TSM inputs for 1997-2000[654] and 2) determine whether duplicative management of TAPS exists making rates excessive.[655] Tesoro also requested, in the initial filing that began this docket, an opportunity to raise additional issues after it had access to the data supporting TSM rates.

We did not use TSM inputs to set rates for 1997-2000. Therefore, there is no need to audit them. Tesoro may still believe that the operating costs used to set rates are imprudent.[656] The record, however, does not contain sufficient evidence of 1997-2000 operating cost imprudence. Therefore, we do not order an audit.

The Carriers responded to the allegation that their ownership structure produces duplicative management costs by asserting that their ownership structure is common in the pipeline industry and that they have valid business reasons for maintaining such an ownership structure.[657]

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[654]Tr. 5251 (JFB).

[655]JFB-T (E-3) 16-17.

[656]The issue of the reasonableness of TSM inputs and the correct calculation of rates under TSM for 1986-1996 is not resolved by this decision and remains open in Docket P-86-2. *Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993); *Re Amerada Hess Pipeline Corp.*, Order P-86-2(56)/P-90-1(26)/P-92-2(23)/P-94-1(28)/P-95-1(7), dated November 30, 1995; *Re Amerada Hess Pipeline Corp.*, Order P-86-2(55)/P-90-1(25)/P-92-2(22)/P-94-1(27)/P-95-1(6), dated June 30, 1996; *Re Amerada Hess Pipeline Corp.*, Order P-86-2(58)/P-90-1(29)/P-92-2(25)/P-94-1(30)/P-95-1(9), dated March 29, 1996; *Re Amerada Hess Pipeline Corp.*, Order P-86-2(57)/P-90-1(27)/P-92-2(24)/P-94-1(29)/P-95-1(8)7, dated January 31, 1996; *Re Amerada Hess Pipeline Corp.*, Order P-86-2(60)/P-90-1(30)/P-92-2(28)/P-94-1(32)/P-95-1(11), dated June 28, 1996; *Re Amerada Hess Pipeline Corp.*, Order P-86-2(62)/P-92-2(31)/P-94-1(37)/P-95-1(17)/P-97-4(2)/P-97-5(2)/P-97-6(2)/P-97-7(2), dated June 30, 1997. Further the issue of public relations expenditures in the 1994 rates remains open in Docket P-94-1. Order P-94-1(1) (Exxon Valdez litigation and settlement costs and post-employment benefits other than pension have been settled. *See Re Exxon Valdez Litigation and Settlement Costs* 1998 WL 1035074 (Alaska P.U.C. Nov. 17, 1998).

[657]T-12 (BWF) 6-10.

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We do not have a record that would enable us to evaluate expenses associated with TAPS ownership structure. This kind of issue is usually addressed by ordering a management audit. The testimony submitted by Tesoro is not sufficient to justify ordering such an audit for 1997-2000. However, the costs of the TAPS management structure will be at issue when we set rates for 2001 and subsequent years. If any party can demonstrate that a further investigation of this issue for 1997-2000 is justified based on evidence gleaned during this phase of the case they may request a further investigation within 60 days of the date of this order.

VIII. ORDER

THE COMMISSION FURTHER ORDERS:

1. The following filed rates for 1997-2000 calculated pursuant to the Intrastate Settlement Agreement are not just and reasonable:

a. Amerada Hess (1997) TL50-300, TL52-300 (changed only to Valdez and Petro Star, not North Pole), TL55-300; (1998) TL58-300; (1999) TL63-300, TL64-300, TL66-300, TL68-300; (2000) TL-70-300, TL71-300.

b. ARCO (1997) TL56-301, TL59-301; (1998) TL61-301; (1999) TL 66-301, TL68-301; (2000) TL71-301.

c. BP (1997) TL56-311, TL60-311; (1998) TL61-311; (1999) TL67-311, TL69-311; (2000) TL73-311, TL75-311.

d. Exxon (1997) TL69-304, TL72-304; (1998) TL74-304; (1999) TL80-304, TL81-304, TL83-304; (2000) TL87-304.

e. Unocal (1997) TL52-312, TL55-312; (1998) TL56-312; (1999) TL60-312; (2000) TL64-312.

f. Mobil (1997) TL52-308, TL55-308; (1998) TL58-308, TL63-308; (1999) TL64-308, TL66-308, TL68-308; (2000) TL70-308.

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g. Phillips (1997) TL53-310, TL55-310, TL58-310, TL59-310; (1998) TL62-310; (1999) TL67-310, TL69-310, TL71-310, TL73-310; (2000) TL77-310, TL78-310, TL79-310.

2. The rates for calendar years 1997, 1998, 1999, and 2000 shown on Exhibit 1, Schedule 3 to this order are the Phase I rates for those years, replacing the 1997, 1998, 1999, and 2000 filed rates found by this order to be unjust and unreasonable.

3. The issue of whether filed 1997-2000 rates are correctly calculated under TSM is moot.

4. The rates calculated above are in all cases different than the Carriers' maximum filed rates; *see* Exhibit 1, Schedule 3. By 4:00 p.m., January 13, 2003, the Carriers shall refund the difference between their filed rates and our calculated rates.

5. Consistent with this order, each Carrier may file individual rates supported by individual Carrier actual, historical costs that justify individual revenue requirements if the sum of the individual revenue requirements does not exceed the composite annual revenue requirements found in this order. If the Carriers elect to file separate rates, they must do so by 4:00 p.m., January 27, 2003.

6. If the Carriers file and we approve individual Carrier rates, we will order appropriate adjustments to the refund amounts within thirty days of our final order approving individual rates.

7. The request made by Tesoro Alaska Company for a Commission audit of 1997-2000 operating expenses is denied.

8. The request made by Tesoro Alaska Company to investigate duplicative management costs incurred in 1997-2000 is denied without prejudice.

9. By 4:00 p.m., January 13, 2003, Tesoro Alaska Company or any other party may request an investigation into duplicative management costs and must provide

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sufficient evidence that those management costs were imprudent to justify an investigation.

10. By 4:00 p.m., January 13, 2003, any part may request investigation into rate case expense.

11. A prehearing conference to set the schedule Phase II of this docket shall convene at 10 a.m. March 4, 2003, in the East Hearing Room of the Regulatory Commission of Alaska, 710 West Eighth Avenue, Suite 300, Anchorage, Alaska. The parties should be prepared to submit a proposed procedural schedule at the prehearing conference.[658] The parties should be prepared to discuss a schedule for resolving the issues identified in Ordering Paragraph Nos. 9 and 10 above and the issue of interest owing on Carriers' refunds.

12. A prehearing conference to set the schedule for the 2001 rate case shall convene immediately following the prehearing conference scheduled in Ordering Paragraph No. 11, in the East Hearing Room of the Regulatory Commission of Alaska, 710 West Eighth Avenue, Suite 300, Anchorage, Alaska. The parties should be prepared to submit a proposed procedural schedule at the prehearing conference.[659]

13. Using the depreciated original cost methodology of Part IV of this order to set rates for 1997, 1998, 1999, and 2000 and the information required by AS 42.06.350(a) and 3 AAC 48.275(a) the Carriers shall either together or individually calculate revenue requirements and rates for 2001 and subsequent years. By 4:00 p.m., January 13, 2003, the Carriers shall either together or individually file tariff

[658]If you are a person with a disability who may need a special accommodation, auxiliary aid, or service or alternative communication format in order to participate in this prehearing conference, please contact Jennifer Guigley at 1-907-276-6222 or TTY 1-907-276-4533 to make the necessary arrangements.

[659]*See* n.658.

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revisions including the information required by AS 42.06.350(a) and 3 AAC 48.275(a). The 2001 test year will be used to set rates for 2001 and subsequent years.

DATED AND EFFECTIVE at Anchorage, Alaska, this 27th day of November, 2002.

BY DIRECTION OF THE COMMISSION
(Commissioners Bernie Smith and
Will Abbott, not participating)

(S E A L)

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X. ENDNOTES

ENDNOTE 1 CITATIONS TO THE RECORD AND ORDER EXHIBITS

Prefiled testimony for the Carriers, the State, and the Public Advocacy Section (PAS) are designated with a one-letter prefix, T for Carriers (TAPS Carriers), S for State, and P for PAS, followed by a hyphen and then a number indicating the position of the testimony in that party's list of prefiled testimony. Those official designations of testimony are followed in this Order by a parenthesis containing the initials of the witness to whose testimony we refer. For example, T-1 is the official designation of the prefiled testimony of Carriers' witness Adam B. Jaffe. We cite to that testimony as T-1 (ABJ).

Prefiled testimony for Tesoro and Williams are designated with a three-letter prefix followed by a hyphen and then the letter T. The three letters are the initials of the witness testifying. The letter T in this context means testimony, not TAPS Carriers. The initials and letter T are followed by a parenthesis which contains the single letter designation of the party sponsoring the testimony, E for Tesoro and W for Williams, followed by a number indicating the position of the testimony in that party's list of prefiled testimony. For example, KAW-T (E-1) is the prefiled testimony of Tesoro witness Kenneth A. Williams. These are the official record designations for Tesoro and Williams prefiled testimony and also the way we cite them in this order.

Prefiled exhibits for all parties begin with a three-letter prefix followed by a number. The three letters are the initials of the witness sponsoring the exhibit. For example, ABJ-1 is the first prefiled exhibit of the witness Adam B. Jaffe. These are the official record designations of the exhibits and the ones we use in this order. It is unnecessary to add a designation of the party sponsoring the exhibit because prefiled exhibits are sponsored by the party for whom the sponsoring witness is testifying.

Hearing exhibits are numbered sequentially 1 through 259, followed by a hyphen and the initials of the witness during whose testimony the exhibit was marked, then followed by another hyphen and the one-letter designation of the party who asked that the exhibit be marked. For example, 1-ABJ-E is a hearing exhibit marked by Tesoro during its examination of Adam B. Jaffe. A hearing exhibit containing the party designation R was marked by Williams Alaska Pipeline Company, L.L.C. Hearing exhibits requested by the Commission at the hearing contain the designation C following the number and initials of the witness testifying at the time.

Both prefiled exhibits and hearing exhibits are cited by their exhibit designation only. The word Exhibit does not appear in front of the exhibit designation. The word Exhibit followed by a number in this order refers to exhibits appended to this order, rather than to exhibits in the underlying record.

The transcript is cited first by the designation Tr. and the page or pages of the transcript being cited. (Transcript volume numbers are not included in the citation and line numbers on a page are not cited.) The transcript cite is followed by a parenthesis containing the initials of the witness testifying. For example, a portion of the examination of Adam B. Jaffe at the hearing would be cited as Tr. 1605 (ABJ). The hearing transcript in this case begins at Tr. 1524 and ends at Tr. 5673.

The letter designation of each witness and the party sponsoring that witness are listed below in alphabetical order of their initials.

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ABJ	Adam B. Jaffe	Carriers
BEW	Bruce E. Warner	Williams
BWF	Billy W. Folmar	Carriers
FJH	Frank J. Hanley	Tesoro
JEH	Jerome E. Haas	State
JFB	John F. Brown	Tesoro
JSG	J. Stephen Gaske	Williams
KAW	Kenneth A. Williams	Tesoro
KBJ	Kenneth B. Johnston	Williams
LPS	Leon P. Smith	Carriers
RAF	Richard A. Fineberg	PAS
RGV	Robert G. Van Hoecke	Carriers
WBT	William B. Tye	Carriers
WDVD	William Van Dyke	State

The record also contains testimony and exhibits of certain witnesses in Phase I of the original TAPS litigation. The Phase I testimony and exhibits which were entered into our record were written and filed in the late 1970s. The witnesses who compiled the testimony and exhibits were cross-examined at the Phase I hearing in 1978-79, but that hearing testimony has not been entered into our record. The Carriers' witness Tye attached the prefiled testimony and exhibits of certain Phase I witnesses for the Carriers to his testimony in this proceeding. During Tye's cross-examination Tesoro and Williams introduced the prefiled testimony and exhibits of other parties from Phase I.

When an exhibit containing Phase I prefiled testimony is cited, the exhibit designation will be followed by a parenthesis containing the last name of the Phase I witness. The full names of each Phase I witness whose testimony is contained in this record, alphabetized by last name; the Phase I party for whom the witness testified; and the exhibit in which that witness's testimony appears in this record are:

WITNESS	PHASE I PARTY	P-97-4 EXHIBIT
Arrow, Kenneth J.	Exxon Pipeline	WBT-29
Carter, Jared	BP Pipelines	WBT-18
Cooper, Joe L.	Mobil Alaska Pipeline	WBT-20
Donaldson, Richard M .	Standard Oil etc.	WBT-17
Dunn, John C.	State of Alaska	83-WBT-W
Foster, J. Rhodes	ARCO Pipeline	WBT-31
Gary, Raymond B.	Exxon Pipeline etc.	WBT-26, WBT-27
Hall, William J.	Mobil Alaska Pipeline	WBT-21
Moolin, Frank P., Jr.	Mobil Alaska Pipeline	WBT-19
Nathan, Robert R.	BP Pipelines	WBT-28
Olson, Charles E.	Amerada Hess Pipeline	WBT-56
Parcell, David	State of Alaska	67-WBT-E
Patton, Edward L.	Mobil Alaska	WBT-15, WBT-16
Price, Harold C.	Mobil Alaska Pipeline	WBT-22
Roseman, Herman G.	U.S. Dept. of Justice	66-WBT-E
Ryan, John	Exxon Pipeline	WBT-32
Solomon, Ezra	Exxon Pipeline	WBT-33
Spahr, Charles E.	Standard Oil	WBT-23
Stich, Robert S.	Union Alaska Pipeline	WBT-34

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Whitehouse, Alton W., Jr.	Standard Oil	WBT-24
Wilson, John W.	Arctic Slope Regional Corp.	65-WBT-E
Woody, L. Dale	Exxon Pipeline	WBT-25

The Exhibits prepared by this Commission and appended to the order fall into several groupings. They are summarized below.

- Exhibit 1 summarizes and compares just and reasonable rates to the Carriers' filed rates. Exhibits 3 and 4 use other tests to find the Carriers' filed rates unjust and unreasonable.
- Exhibits 4 and 7 confirm that the rate base that we adopt in Part IV Section E is reasonable.
- Exhibit 5 and 6 show that the Carriers' unrecovered investment analysis fails to support their benchmark rates.
- Exhibits 9, 10, 12, and 16 summarize positions by the parties on various inputs necessary to determine a reasonable 1996 year-end rate base.
- Exhibits 2, 8, 11, 13-15, and 17-28 consist of findings that allow us to determine a reasonable year-end 1996 rate base, which we do at Exhibit 29.
- Exhibit 30 summarizes the parties' positions on operating expenses for 1977-1996.
- Exhibit 31 and 32 consist of findings that allow us to determine reasonable revenue requirements for 1977-1996, which we do at Exhibit 33. This allows us to confirm in Exhibit 7 the rate base that we adopt.
- Exhibit 34 shows the Carriers' position on capital structure for 1997-1999.
- Exhibits 35-45 consist of findings that allow us to calculate just and reasonable rates, which we do following the practice of the parties at Exhibit 46.

Exhibits concerned with establishing and testing the year-end 1996 rate base are displayed to the nearest million. However, exhibits make use of the exact figures submitted electronically.

ENDNOTE 2 BRIEF DESCRIPTION OF TAPS RATE LITIGATION

Following is a brief description of the TAPS litigation history in general and the litigation history of these consolidated dockets.

A. <u>TAPS Litigation History</u>

Rates for transportation of oil on TAPS have been the subject of litigation almost without interruption since 1977, when the Carriers filed their initial rates.[660] However, the issues we address here have never been decided. Rates filed under TSM have never been reviewed to determine if they are just and reasonable.

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[660]In past litigation the parties have spent millions of dollars and ten years trying to resolve what the appropriate rates should be for shipping oil on TAPS. In this docket alone litigation costs for the Indicated TAPS Carriers have exceeded $14.83 million. *Indicated TAPS Carriers Eighteenth Cost Report,* filed August 29, 2002; *Williams Alaska Pipeline Company, L.L.C.'s Seventh Cost Report,* filed August 30, 2002.

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The original TAPS rate litigation occurred in two phases. Phase I, conducted in 1978 and 1979, examined rate base/rate of return methodology, including treatment of taxes. Phase II, conducted from 1982 through 1985, was divided into two portions: cost of construction and all other costs. The cost of construction portion involved the prudence of certain TAPS construction expenditures. The non-cost of construction portion addressed depreciation charges, AFUDC, DR&R costs, and all other issues not decided in Phase I.[661]

Federal and state regulators conducted the two phases concurrently. The federal agencies were the Interstate Commerce Commission and later the FERC. The state agencies were our predecessor agencies: first, the APC, and later, the APUC.

Administrative Law Judge Max L. Kane, who presided over the Phase I hearings for the FERC, issued his initial decision in February 1980.[662] Parties took exception to that decision and it remained before the FERC until 1982, when the FERC, without opinion, remanded the case for further evidence to determine whether a FERC decision establishing a ratemaking methodology for oil pipelines generally, should be applied to TAPS.[663] The agencies compiled a record in the Phase I remand but the parties settled the federal rate proceeding before the FERC decided the matter.

The APC, however, issued its Phase I decision on September 17, 1980. The decision consisted of two orders, Order 25oth[664] and Order 26.[665] In Order 25, the APC established a ratemaking methodology for TAPS. In Order 26 the APC used the Order 25 methodology to set rates to the GVEA connection for four of the Carriers. The parties appealed Orders 25 and 26 to the Alaska superior and Supreme courts.

While Orders 25 and 26 were on appeal, from 1982 through 1984, the parties continued Phase II proceedings before the FERC and the APUC. In 1982, as a part of Phase II, the parties stipulated to the life of the line for depreciation purposes as well as to a straight-line depreciation schedule.

In July 1984, MAPCO Alaska Petroleum Inc. (the predecessor of Williams Alaska Petroleum Inc. (Williams)), an intrastate shipper, settled the Order 26 issues with the Carriers. As part of the settlement, the parties moved to dismiss the appeal of Order 26. In November 1985, the Supreme Court dismissed the appeal of Order 26. The

[661]The record in Phases I and II is massive. Eighty-two witnesses testified in Phase I. Nine hundred and fifty exhibits were introduced. The Phase I transcript, including pre-filed testimony and cross-examination, is 24,000 pages long. One hundred and thirty six witnesses testified in the cost of construction portion of Phase II. The transcript, which includes cross-examination only, is 26,000 pages long. More than 8,000 Phase II cost of construction exhibits, including the pre-filed testimonies of the witnesses, exist. The Phase II non-cost of construction record includes the testimony of 45 witnesses. There are 5,300 pages of cross-examination transcript and 1125 exhibits, including the pre-filed testimonies of the witnesses.

[662]*Trans-Alaska Pipeline Sys.,* 10 F.E.R.C. ¶ 63,026.

[663]*Trans Alaska Pipeline Sys.*, 21 F.E.R.C. ¶ 61,092.

[664]*Re Exxon Pipeline Co.,* 1 APUC 580 (1980).

[665]*Re Amerada Hess Pipeline Corp.,* 1 APUC 606 (1980).

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Supreme Court also dismissed Order 25 because it no longer contained rates requiring review.

Meanwhile, in June 1985, the State and five of the eight TAPS Carriers agreed to settle the federal TAPS rate litigation. A sixth Carrier later joined the settlement. In October 1985, the FERC accepted the Interstate Settlement Agreement. The Interstate Settlement relied on TSM as the method for calculating interstate maximum ceiling rates for those six carriers. The remaining two carriers joined the settlement in February 1986, and the FERC accepted the final settlement in June 1986.[666]

The State and all eight TAPS Carriers reached a similar settlement of intrastate rates in April 1986.[667] The Settlement purported to resolve all issues then pending including the pre-1985 contested rates. The Settlement agreed to TSM as the method for calculating a maximum intrastate ceiling rate for future years.[668]

On May 30, 1986, the APUC opened Docket P-86-2 to consider the Intrastate TAPS Settlement concerning past and future intrastate TAPS rates. One year later on May 30, 1987, the Commission issued Order P-86-2(14) accepting settlement rates for periods before July 11, 1986, ordering refunds to intrastate shippers based on those accepted rates, and terminating the Commission's investigation into rates for shipments before July 11, 1986.[669] The APUC required as a condition of accepting the Settlement that the Carriers in the future file intrastate rates no higher than those calculated under TSM.[670] The Commission accepted the Settlement because all economically impacted parties had expressly or presumedly consented to the imposition of the settlement rates for the period before July 17, 1986.[671]

However, on July 10, 1986, Petro Star Inc. (Petro Star), an economically impacted party, challenged the filed rates. Because of Petro Star's protest, the APUC found that it must determine whether rates for periods after July 10, 1986, were just and reasonable under the Alaska Pipeline Act, not just whether the Settlement was in the public interest.[672]

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[666]*Trans Alaska Pipeline Sys.,* 33 F.E.R.C. ¶61,064 (1985); *Trans-Alaska Pipeline Sys.,*35 F.E.R.C. ¶61,425 (1986). Arctic Slope Regional Corporation appealed the approval of the Interstate TAPS Settlement Agreement but in October 1987, the United States Court of Appeals for the District of Columbia Circuit affirmed FERC's approval. The United States Supreme Court denied *certiorari* in October 1988. *Arctic Slope Reg'l Corp. v. F.E.R.C.*, 832 F.2d 158 (D.C. Cir., 1987), *cert. denied*, 488 U.S. 868 (1988). The federal portion of the TAPS rate litigation lasted eleven years from beginning to end.

[667]BWF-2.

[668]For a brief explanation of TSM, *see* Endnote 3, *infra*.

[669]*Re Amerada Hess Pipeline Corp.*, 8 APUC 168, 169 (1987).

[670]*Re Amerada Hess Pipeline Corp.,* 8 APUC 168, 171 (1987).

[671]*See Re Amerada Hess Pipeline Corp.,* 8 APUC 168, 169 (1987).

[672]*Re Amerada Hess Pipeline Corp.,* 8 APUC 168, 169 (1987).

Petro Star later settled with the Carriers.[673] In October 1993, the APUC accepted the Settlement for the calculation of rates after July 11, 1986, but did not vacate the suspension of those rates. The APUC specifically did not find that the 1986 filed rates were just and reasonable. Instead, with two dissenting Commissioners,[674] the APUC accepted the Settlement as in the public interest because no economically interested party protested.[675] The APUC stated that any future challenge to the rates would be evaluated as if the APUC had not accepted the Settlement, i.e., without giving any weight to the finding that the Settlement was in the public interest when it was

[673]*Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 452 (1993).

[674]In dissenting, Commissioner Foster explained,

> Among the most egregious departures is the violation of the basic principle that rates should be based on actual costs and that the carrier is entitled to earn a reasonable return on its investment. The 35cent/barrel (in 1983 dollars) "incentive" provision which took affect in 1990 has no basis in cost and clearly goes beyond a reasonable return on <u>actual</u> investment. . . . This Settlement provides a windfall return to carriers with its so-called "incentive " return component. Shippers are in essence being asked to pay more than once for an investment. This is not a fair balance of the interests of shippers and carriers.

Re Amerada Hess Pipeline Corp., 13 APUC 448, 462-63 (1993). Commissioner Knowles concurred with Commissioner Foster regarding the allowance per barrel. Both Commissioners also found the approach to DR&R inappropriate. Commissioner Knowles explained,

> Two other objectionable features to TSM concern DR&R. The DR&R amounts to be collected each year are fixed and cannot be changed under TSM. There is no mechanism to adjust collections for DR&R to reflect known and measurable changes which may occur during the remaining life of the pipeline. The result may be overcollection or undercollection, both of which are undesirable. . . I cannot endorse a method which permits the TAPS Carriers knowingly to under collect or over collect their cost of service. The other unacceptable feature of the DR&R provisions of TSM is the fact that there is no mechanism by which excess DR&R funds can be refunded to ratepayers in the event that some or all of the currently anticipated DR&R work is ultimately unnecessary for whatever reason. The pipeline is not scheduled to be shut down for another 18 years. Circumstances could change significantly in that time period. The TAPS Carriers should not be allowed to retain monies collected for DR&R which are not used for that purpose. Those monies belong to the ratepayers.

Re Amerada Hess Pipeline Corp., 13 APUC 448, 460 (1993), Commissioner Foster agreed, "the Settlement proposes a DR&R fund that is not consistent with Commission policy and creates a windfall for carriers at the expense of shippers." *Id.* at 464.

[675]*Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993).

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uncontested.[676] The APUC made the entire prior record from Phases I and II available for any future rate challenges.[677]

After accepting the Settlement, the APUC continued to suspend annual rates, pending review of whether the rates were correctly calculated under TSM and contained acceptable input data.[678] The APUC never ruled on the post-1986 rates. Therefore, the correct calculation of TAPS rates using TSM and acceptable input data are issues still before us.[679]

B. <u>History of P-97-4</u>

The Carriers continued to file TAPS rates under Order 41 and the ongoing review described above. The Commission continued to accept those rates until December 23, 1996. On that date Tesoro protested the 1997 filed rates. MAPCO Alaska Petroleum Inc. intervened and the APUC designated Staff (whose successor is Public Advocacy Section of the Regulatory Commission of Alaska (PAS)) as a party. Therefore, the correct calculation under TSM and the acceptability of input data are issues for all intrastate rates filed after the 1985 Settlement and are being investigated in Docket P-86-02. We opened Docket P-97-4 to review post-1996 rates to determine if they are just and reasonable under AS 42.06.370. We opened Docket P-97-7 to address issues of appropriate DR&R collection and allowances.

On January 12, 1998, the Carriers moved to terminate the investigation in Dockets P-97-4 and P-97-7, observing that Tesoro's protest was a direct assault on TSM, DR&R and the Allowance Per Barrel return elements of TSM. They asserted that these issues could not be re-examined without reopening the full array of TAPS rate

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[676] *Id.*

[677] *Re Amerada Hess Pipeline Corp.*, 8 APUC 168, 171 (1987). The parties in Docket P-97-4 have in fact introduced extensive portions of the Phase I record into evidence in this proceeding. Although the entire record for the Phase I and Phase II of the joint federal/state proceedings was available for use in this docket, the record for this docket now consists only of those matters that were specifically introduced into this docket's record during the proceedings held for this docket.

[678] *Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993).

[679] In this proceeding, we combined the issue of the correct calculation and use of acceptable input date for the 1997-2000 rates with determining whether the 1997-2000 rates are just and reasonable. *Re Amerada Hess Pipeline Corp.,* Order P-86-2(61)/P-92-2(30)/P-94-1(36)/P-95-1(16)/P-97-4(1)/P-97-5(1)/ P-97-6(1)/P-97-7(1), dated June 27, 1997; *Re Exxon Valdez* Litigation *and Settlement Costs*, Order P-94-1(46)/P-95-1(26)/P-97-4(12)/P-97-6(11)/P-97-7(11)/P97-9(5), dated December 26, 1997; *Re Exxon Valdez Litigation and Settlement Costs*, Order P-94-1(54)/P-95-1(33)/P-97-4(35)/P-97-6(20)/P-97-7(21) dated December 28, 1988; *Re Exxon Valdez Litigation and Settlement Costs* Order P-94-1(75)/P-97-4(64)/P-97-6(41)/P-97-7(46), dated December 20, 1999. We have not determined whether the input data for 1986-1996 is reasonable, although we opened Docket P-86-2 when a protest was filed. We have not closed that docket because until this case was resolved, the significance of adjustments to those years was unknown. The issue is now ripe and we encourage the parties to include an appropriate resolution of those issues in any settlement discussions they may have.

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issues that the Settlement resolved.[680] The Carriers asked the Commission to use its discretion to decline to reopen TAPS rate issues because these burdens outweighed any Tesoro interest in rates. They also asserted that if intrastate rates were lowered, there would be an immediate, off setting increase in interstate rates, resulting in detriment to interstate shippers and State revenues.[681] They further asserted that a disparity between intrastate rates and interstate rates could lead to a FERC proceeding under Section 13(4) of the Interstate Commerce Act wherein FERC could invalidate RCA rates and set its own intrastate rates.[682]

In response, the APUC explained that "where no economically impacted party contests the rates, the public interest may tilt toward allowing unproven rates to be charged in lieu of conducting costly proceedings . . . ."[683] However, when a rate payer challenges unproven rates that it is paying, the Commission should not refuse to investigate those rates unless the party challenging rates is somehow precluded from challenging them.[684] Although the Settlement precludes the State from challenging rates filed in accordance with the Settlement, Tesoro is not similarly restricted.[685] The APUC concluded that to terminate the investigation and require an economically impacted party to pay, over its objection, rates that have not been fully justified as required by AS 42.06 would constitute de facto deregulation of TAPS.[686] The APUC, therefore, denied the Carriers' motion to terminate.[687] This history explains why this is the first time that the rates filed pursuant to TSM have been reviewed to determine if they are just and reasonable.

The Carriers filed their case-in-chief with the APUC on October 8, 1998, stating that "the principal question presented is whether the TAPS Settlement Methodology will continue to govern the TAPS Carriers' maximum intrastate rates."[688] On March 15,

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[680]*TAPS Carriers' Motion to Terminate Investigation* at 22.

[681]*Id.* at 20.

[682]*Id.,* at 20-21; *TAPS Carriers' Reply in Support of Motion to Terminate Investigation* at 24. We disagree. *See* Endnote 7 for a discussion of the Carrier assertion that Section13(4) of the Interstate Commerce Act gives the FERC the authority to order an increase in intrastate rates to avoid an undue burden on interstate shippers.

[683]*Re Amerada Hess Pipeline Corp.*, P-97-4(21)/P-97-7(16) at 14 (May 5, 1998).

[684]*Id.* at 14-17.

[685]*Id.* at 14. The Settlement does not limit the rights of future shippers to protest future rates. However, it limits the State of Alaska's protest right to only those tariffs which are inconsistent with the terms of the Settlement. BWF-2. Therefore, the State of Alaska is precluded from challenging the rates at issue in this docket. The Intrastate TAPS Settlement Agreement is only binding upon signatory parties and not upon third parties. *Id.* at 17, 19.

[686]*Id.* at 15.

[687]Further, failing to investigate rates places a chilling effect on non-Carrier shippers desire to ship. It also arguably reduces the incentive for non-pipeline owners to explore for additional oil on the North Slope.

[688]*TAPS Carriers' Covering Brief* at 2.

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1999, Tesoro moved for summary disposition because it contended that the Carriers failed to prove that the filed rates were just and reasonable.

The Carriers' described their initial filing as showing that:

> (a) TSM must be evaluated as an integrated whole and from the perspective of the 1985-86 time period in which the TAPS Settlement Agreement came into being;
>
> (b) from that perspective, TSM was expected to produce reasonable rates and returns and has performed as the parties intended;
>
> (c) TSM is a reasonable, cost-based ratemaking methodology that was designed to serve, and has served, important public policy goals benefiting the State of Alaska ("State") and TAPS shippers;
>
> (d) if TSM had not been adopted, rates derived under more traditional ratemaking methodologies would have been significantly higher during 1997 and 1998 than the TSM derived rates actually being charged; and
>
> (e) the public interest benefits that strongly supported the Commission's approval *(sic-acceptance)* of TSM have been realized and continue to justify its retention.[689]

After reviewing extensive briefing, we granted Tesoro's motion, finding that

> despite the inordinate amount of briefing and expert testimony on TSM, the Commission is not determining whether TSM is a just and reasonable methodology over the life of the pipeline. Rather, the Commission must address whether the resulting rates in 1997 and 1998 are just and reasonable.[690]

Further, we found that to the extent that non-cost based factors of TSM were included in the filed rates, the Carriers failed to provide a reasoned explanation. We instructed that once rates are challenged, at issue is whether the filed rates are just and reasonable under AS 42.06, not whether a settlement methodology will continue to be used to set the maximum rate level. We reiterated the direction of the APUC in originally allowing TSM rates. The APUC clearly stated TSM rates "would be subject to the same *standards* and *procedures* to which [they] would have been subject if the

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[689]*Id.,* at 2.

[690]*Re Amerada Hess Pipeline Corp.*, P-97-4(79) at 8-9 (April 10, 2000). We also suspended and address in these dockets whether the 1999 and 2000 rates are just and reasonable. Even if the reasonableness of a methodology over the life of the line could be a sole test for meeting the requirements of AS 42.06, our analysis in Section V demonstrates that in this case the filed rates produced by TSM over the life of the line produce an excessive opportunity to recover costs. *See* Part V, B. *supra*.

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Intrastate Settlement Agreement had not been accepted."[691] We explained that determining whether rates are just and reasonable begins with costs.[692] Non-cost factors may be considered if specifically justified.[693]

Although we granted Tesoro's motion for summary judgment, we did not decide whether the filed rates were just and reasonable. Instead, we provided the Carriers a second opportunity either to file a case supporting their 1997-2000 filed rates as just and reasonable under the AS 42.06 or to file different rates with support showing that the new rates were just and reasonable. We established a procedural schedule allowing the Carriers to file a new case-in-chief, the protestants to file answering testimony and the Carriers to file rebuttal testimony. We also scheduled a hearing and ordered pre- and post-hearing briefing.[694]

On January 26, 2001, the Carriers moved to strike portions of the protestants' testimony that addressed the issue of DR&R. They asserted that they were unaware that DR&R issues were a part of Docket P-97-4 and had presumed DR&R issues would be addressed only in Docket P-97-7.[695]

In 1985, as a part of the Settlement, the parties stipulated to the size of the ultimate DR&R obligation, the method for calculating the funds necessary to meet those obligations, and the role that DR&R obligations play in the overall settlement methodology established to calculate TAPS rates.[696] Once Tesoro challenged the 1997 rates, however, the Carriers were on notice that they would need to support the DR&R element of their rate calculation along with all other elements involved in a rate calculation.[697]

We therefore denied the Carrier motion to strike, consolidated the two dockets, and granted the Carriers an extension of time to file rebuttal testimony in the consolidated P-97-4 and P-97-7 proceeding.[698] We explained,

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[691] *Re Amerada Hess Pipeline Corp.,* 13 APUC 448, 456 (1993) *(emphasis added)* and n.28,*supra.*

[692] *Re Amerada Hess Pipeline Corp.*, Order P-97-4(79) at 9, 11 (April 10, 2000.

[693] *Id.*, at 10.

[694] *Re Amerada Hess Pipeline Corp.*, P-97-4(79) at 15 (April 10, 2000).

[695] *Indicated TAPS Carriers' Motion to Strike Testimony Relating to Dismantling, Removal and Restoration, or, In the Alternative, For an Extension of Time to File Rebuttal Testimony*, filed January 26, 2001.

[696] 29-ABJ-W at 11-13.

[697] The Carriers were on notice as early as February 28, 1998. *Tesoro's Opposition to Motion to Terminate* at 30 n.5.

[698] *Re Amerada Hess Pipeline Corp.*, Order P-97-4(118)/P-97-7(78), dated February 16, 2001.

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> issues of whether the appropriate amount and management of DR&R can be separated from the issues of whether, as part of a filed rate, DR&R amounts collected in 1997-2000 produce just and reasonable rates.[699]

We further explained that we would rule on whether the 1997 filed TAPS rates are just and reasonable after the April 2001 hearing if we could.[700]

Based on the record before us, we can determine whether the 1997 filed rates are just and reasonable but without reference to DR&R costs and revenue. We determine rates and refunds for 1997-2000 and address the DR&R issues in Phase II of this proceeding, after a full opportunity for discovery, pre-filed testimony and hearing. In that proceeding we will decide whether additional DR&R funds need to be collected or refunds issued post-1996.

After we consolidated P-97-4 and P-97-7, the parties filed cross motions for summary disposition, which we denied.[701] Based on the extensive record in these consolidated dockets, we determine whether the 1997-2000 filed rates absent consideration of DR&R expenses and revenues are just and reasonable under the Alaska Pipeline Act.

ENDNOTE 3 THE TAPS SETTLEMENT METHODOLOGY

Re Amerada *Hess Corporation*[702] contains a brief description of the TAPS Settlement Methodology (TSM).

> TSM is a formula for calculating tariffs of the seven TAPS Carriers beginning in the year 1977 and continuing through the year 2011. Although development of rates under TSM is complicated by several elements such as net carryover, calculation of rates for different types of petroleum (Sadlerochit, Kuparuk, etc.), calculation of rates to the intermediate points, and separation of rate base into 'original' and 'new' for purposes of providing a different basis for calculating rate of return after 1990, the underlying methodology itself is relatively straightforward.
>
> The methodology embodied in TSM is basically a trended original cost methodology (TOC or TOC methodology). TOC differs from the depreciated original cost methodology (DOC or DOC methodology), the method normally used by the Commission, in the manner in which investors are compensated for inflation. Under DOC, investors receive a nominal rate of return on the original cost of plant net of accrued depreciation. The nominal rate of return includes a premium to compensate investors for expected inflation. Under TOC, investors are compensated for inflation through rate base write-ups equal to expected inflation.

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[699] *Id.*, at 12.

[700] *Id.*

[701] Order P-97-4(130)/P-97-7(89), dated April 3, 2002.

[702] *Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 458-59 (1993).

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Under TSM a real return on total rate base of 6.4 percent is included in the revenue requirement each year (until 1990), and the rate base (except for land and working capital) is written up each year for inflation as measured by the Consumer Price Index for All Urban Consumers. That writeup is included in an account called Deferred Return which is added to carrier property to arrive at total rate base which is then used to compute returns in succeeding years.

Although application of a TOC methodology usually results in fairly level rates over time, TSM results in declining rates over time because of its depreciation profile. Under TSM, property is depreciated and Deferred Return is recovered under a schedule which is more accelerated than straight-line and which apparently has no particular rationale other than that the parties agreed to it. Rate base declines very rapidly under this depreciation schedule as does return on rate base.

In order to give the TAPS Carriers an incentive to continue to operate the line, TSM provides for a profit element of 35 cents per barrel (adjusted for inflation since 1983) to be collected in lieu of a return on rate base after 1990 (35-cent provision). In order to give the TAPS Carriers an incentive to make appropriate investments after 1990, the rate base is divided into 'original' and 'new' portions. In addition to the 35 cents per barrel adjusted for inflation, the TAPS Carriers continue to earn the 6.4 percent return on 'new' rate base in 1990 and thereafter.

Under the provisions of the settlement each Carrier calculates its own tariff but that tariff is based on a common revenue requirement for the entire TAPS operation. The revenue requirement consists of the sum of the following elements: operating expenses; dismantling, removal, and restoration (DR&R) allowance; depreciation; recovery of deferred return; after-tax margin (6.4 percent return on total rate base prior to 1990 and 35 cents per barrel plus 6.4 percent return on new rate base in 1990 and thereafter); and income tax allowance. Any nontransportation revenues collected by the Carriers are subtracted from the revenue requirement.

Under TSM, the TAPS Carriers collect a fixed dollar amount for DR&R each year. These amounts do not change based on any change in either the obligation to perform DR&R or the cost of performing it. If the Carriers are not required to perform DR&R or it costs them less to perform it than the amount collected under TSM, the Carriers presumably retain the leftover DR&R amounts. Conversely, if DR&R is more expensive than originally contemplated, the Carriers and their parent companies are responsible for making up the difference and performing the DR&R.

Income tax allowance is calculated under the assumption that the entire amounts of those TSM elements entitled Recovery of Deferred Return and After- Tax Margin are fully taxable. Thus, the tax allowance is calculated as though the TAPS Carriers had a 100 percent equity capital structure. The difference between book and tax depreciation is calculated under TSM and results in an amount of deferred taxes. Deferred taxes are deducted from the rate base under TSM.

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> An allowance for funds used during construction (AFUDC) is included in TSM based on the yearly balance of construction work in progress (CWIP). When a portion of CWIP is transferred to carrier property, the AFUDC attributable to that portion of CWIP is transferred to the Deferred Return account and recovered on the same accelerated basis as the other element of Deferred Return, the annual rate base writeup. Consistent with the rest of TSM, AFUDC is assumed to be composed of all equity funds.
>
> Rates under TSM are calculated based on estimates of the various components of revenue requirement. If those estimates are incorrect and more or less than the actual revenue needed is collected during the year, that over or under collection is carried over to the next year and reduces or increases the following year's rates. This mechanism assures both shippers and carriers that the carriers collect neither more nor less than the exact amount needed to operate TAPS and to provide the TAPS Carriers with the return specified in TSM.

(Footnotes omitted.)

ENDNOTE 4 WILLIAMS' PROPOSED MANAGEMENT FEE

Williams' testimony is confusing. On the one hand, Williams asserts that the appropriate rate base for determining rates is the TSM rate base,[703] which consists of "original" rate base plus "new" rate base, including deferred return.[704] The TSM rate base on which TSM return may be earned was $284 million at year-end 1996. In 1997 that rate base consists of over $284 million.[705] Williams provides little rationale beyond that of the Carriers for why TSM produces just and reasonable rates and should therefore be retained.

On the other hand, Williams also asserts that by 2000 the original rate base is 99 percent depreciated and that we should therefore award a management fee.[706] Williams urges that as much of TSM's framework as possible should be retained but that a management fee should be substituted for the current TSM allowance per barrel provision.[707] Williams' proposal is based on a series of FERC decisions regarding project financed gas pipelines.[708]

The purpose behind a management fee according to Williams is to compensate pipeline owners after their original investment is fully depreciated.[709] Based on the FERC line of cases cited above, Williams urges that a management fee of 10 percent of

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703 *Williams Alaska Petroleum Inc.'s Post-hearing Initial Brief* at 43-44.

704 *See* T-2 (BWF) A-3 to A-6.

705 31-BWF-E.

706 KBJ-T (W-1) 28-29.

707 Tr. 4159-60 (KBJ); KBJ-T (W-1) 30; Tr. 4091-92 (KBJ).

708 KBJ-T (W-1) 30; Tr. 4091 (KBJ).

709 Tr. 4092 (KBJ).

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the average pre-tax return, i.e. operating income of the pipeline over its proceeding life, should be awarded for TAPS beginning 1997.[710]

In response to Williams' argument, we note first that the analysis concluded in Part IV demonstrates that the TAPS is far from being fully depreciated; the year-end 1996 rate base on which return may be earned consists of $669 million.[711] Furthermore, new rate base is continually being added to TAPS.[712]

Even if rate base were fully depreciated, a parallel line of FERC cases calls into question the logic of providing a management fee once rate base is fully depreciated. In *High Island Offshore System,* the FERC explained, "although the Commission has accepted proposals to impose a management fee, HIOS's proposal results in a substantial rate of return level that must be explored at the hearing to determine appropriateness."[713] Further, Commissioner Langdon dissented, stating

> I would vote to reject HIOS' management fee proposal as being contrary to established Commission policy. When a pipeline is fully depreciated, it has been paid for, and there is no logical reason for a company to receive "in lieu" payments for its fully recovered return on equity. Shareholders who provided the equity for the pipeline have been fully repaid for their investment. Period.
>
> Adoption of a management fee would require the Commission to depart significantly from its historic view of depreciation. While, on the surface, the fee is derived from a formula based on the cost of the pipeline, down deep, its adoption is a recognition that we have to pay companies to stay in business. Until the Commission formally eliminates its cost-based form of regulation over monopoly pipelines, I view such hybrids as the management fee proposed here to be unjust and unreasonable.[714]

AS 42.06 requires that Alaska's intrastate rates be just and reasonable. To be just and reasonable, rates should be cost based and, if not, a specific public policy rational should be provided. Commissioner Langdon's dissent raises serious question as to whether the management fee as proposed by Williams would be cost based and, if it is not, whether a policy rationale could exist that would support it.

In *Stingray*, the FERC explained that although it had provided Stingray the opportunity to argue for the inclusion of a management fee, the burden of proving the need for a management fee was upon Stingray.[715] Further, the FERC explained,

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[710]Tr. 4092-93 (KBJ).

[711]Exhibit 29.

[712]*See* Part IV, B.1, *supra.*

[713]*High Island Offshore Sys.*, 57 F.E.R.C. ¶ 61,420, 62,372 (1991).

[714]*Id.* at 62, 374.

[715]*Stingray Pipeline Co.,* 98 F.E.R.C. ¶ 63,004, 65,023 (2002).

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> . . . in order to demonstrate a need for the management fee over and above the substantial allotments for depreciation, return and associated taxes, a company (especially one not fully depreciated) would need to show significant detrimental financial circumstances, through no fault of its own, inhibiting the company's ability to manage its operations.[716]

Williams has made no such showing. Further, the rate base for TAPS is not fully depreciated and new rate base is being added.[717] Therefore, we do not adopt Williams' proposed management fee for TAPS.

ENDNOTE 5 BURDEN OF PROOF

The Carriers have repeatedly suggested that they do not carry the burden of proof.[718] We have therefore repeatedly instructed the Carriers that they carry the burden of proving that 1997-2000 rates are just and reasonable.[719] In *Cook Inlet Pipe Line*, the Alaska Supreme Court held that an uncontested settlement does not establish the rates are reasonable.[720] The Alaska Supreme Court relied on the United States Court of Appeals for the District of Columbia decision that involved TAPS[721] and a FERC decision involving TAPS,[722] noting that the "justness of rates cannot be implied from an approved settlement" because the settlement rates were never adjudicated to be just and reasonable.[723] In Order 50 in this docket, the APUC carefully acknowledged the Carrier position regarding the standard for determining if rates just and reasonable and rejected it.

> The TAPS Carriers stated that the Commission has determined that in the absence of a protest by an interested party, rates calculated consistently with TSM should be accepted and allowed to become final rates, citing 3 AAC 48.090(d), Order P-86-2(41) at pp. 20-21, Order P-86-2(14) at pp. 3-4. The provisions of 3 AAC 48.090(d) addresses the withdrawal of applications/petitions, the termination of Commission proceedings prior to full

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[716]*Id.*

[717]Exhibit 42, line 2.

[718]*Initial Post-hearing Brief of the Indicated TAPS Carriers* at 54; and *see Indicated TAPS Carriers Notice of Pertinent Additional Authority*.

[719]*Re* Amerada *Hess Pipeline Corp.*, Order P-97-4(79) at 3-4 (April 10, 2000); Prehearing Conference Transcript at 66 (May 5, 1998).

[720]*Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n*, 836 P.2d 343, 353 (Alaska, 1992).

[721]*Arctic* Slope *Reg'l Corp. v. F.E.R.C.*, 832 F.2d 158, 164 n.12 (D.C. Cir., 1987), *cert. denied*, 488 U.S. 868 (1988).

[722]*Trans-*Alaska *Pipeline Sys.,* 35 F.E.R.C. P 61,425, 61,983 n.17 (1986).

[723]*Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n*, 836 P.2d 343, 353 (Alaska, 1992).

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> adjudication, and the amendment of pleadings in the event of changed circumstances. That regulation does not provide any justification for the TAPS Carriers' assertion that TSM should be assumed to produce just and reasonable rates in the absence of a protest.[724]

The APUC further explained,

> As previously noted, Order P-86-2(14) addressed the TAPS Settlement and the protest filed by an intrastate TAPS shipper (Petro Star) on July 11, 1986. The Commission was required to determine just and reasonable rates for periods after the date of Petro Star's protest. *See* P-86-2(14) at pp.4-5, *Amerada Hess,* 8 APUC at 169. In that Order the Commission stated:
>
> > The Commission will first complete its investigation of the acceptability of using TSM to derive present and future rates. . . . If the Commission determines that TSM does not produce just and reasonable results or is otherwise an appropriate methodology to be used in calculation of intrastate TAPS rates, the Commission will proceed to fully adjudicate rates from July 11, 1986, forward. With respect to that adjudication, the Commission is free to set just and reasonable rates according to whatever methodology the Commission finds to be appropriate for the regulation of TAPS.
>
> Order P-86-2(14), p. 5. That proceeding was subsequently terminated prior to adjudication as to whether TSM produced just and reasonable rates by Petro Star's withdrawal of its protest pursuant to a settlement with the TAPS Carriers (Petro Star Settlement).
>
> Order P-86-2(41) accepted the Petro Star and TAPS Settlement and terminated the rate proceeding. Contrary to the TAPS Carriers' assertion, that Order did not state that rates calculated in accordance with TSM would be accepted as final rates in the absence of a protest. Instead the Commission reserved the right to review TSM rates for justness and reasonableness, stating:
>
> > Each new rate filed by the TAPS Carriers under the [TAPS Settlement] is considered to be a revised tariff filing under AS 42.06.400. The filing is subject to the same standards and procedures to which it would have been subject if the [TAPS Settlement] had not been accepted. However, in the absence of a protest, the TAPS Carriers need not file the supporting material required by 3 AAC 48.275(a). Instead, the TAPS Carriers should file the TSM computer disk used in calculating the rate filed and a hard-copy printout of the rate calculation.

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[724]*Re Exxon Valdez Litigation and Settlement Costs*, Order P-94-1(63)/P-95-1(43)/P-97-4(50)/P-97-6(29)/P-97-7(30) at 18 (May 27, 1999).

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Order P-86-2(41), p. 21.

The TAPS Carriers' misconception regarding the Commission's ability to investigate TAPS rates may be based on the statement that the TAPS Carriers would not have to file supporting documentation typically required for rate revisions in the absence of a protest. The waiver of a revenue requirement filing indicates the Commission's willingness to waive the burdensome requirement of an annual showing of just and reasonable rates, but is not indicative of Commission intent to render itself unable to investigate TAPS rates in the absence of a protest. Such an interpretation of the Commission's language in Order P-86-2(41) is irrational and would require the Commission to abdicate its statutory mandate to ensure that rates charged by the TAPS Carriers are just and reasonable.

Tesoro and MAPCO contended that AS 42.06.400(a) authorizes the Commission to investigate the 1999 TAPS rates under its own motion. The pertinent provision of AS 42.06.400 states "[w]hen a tariff filing is made containing an initial or revised rate . . . the commission may, either upon written complaint or upon its own motion, after reasonable notice, conduct a hearing to determine the reasonableness and propriety of the filing." The Commission believes that statute clearly establishes its authority to institute an investigation into the TAPS rates regardless of whether a protest has been filed. The Commission concludes it can and should, under the authority provided by AS 42.06.400, institute an investigation into the 1999 TAPS rates to determine if TSM produces just and reasonable rates.

P-94-1(63)/P-95-1(43)/P-97-4(50)/P-97-6(29)/P-97-7(30), dated May 27, 1999, at 18-21. (*Footnotes omitted.*)

The record in this docket clearly reflects that the 1997-2000 rates were suspended before they came into effect. The APUC suspended the 1997 and 1999 rates based on Tesoro's protest and suspended the 1998 and 2000 rates on its own motion.[725] Because the 1997-2000 rates are suspended and have never been final rates, the burden lies with the Carriers to prove that each annual rate is just and reasonable.

ENDNOTE 6 THE RULE AGAINST RETROACTIVE RATEMAKING

The general statement of the rule against retroactive ratemaking is "that when determining each of the terms of the revenue requirement formula, when calculating the amount of the revenue to be collected under proposed rates, or when allocating rates between or within a class, the commission cannot adjust for past losses or gains to

[725] *Re Amerada Hess Pipeline Corp.,* Order P-86-2(61)/P-92-2(30)/P-94-1(36)/P-95-1(16)/P-97-4(1)/P-97-5(1)/ P-97-6(1)/P-97-7(1), dated June 27, 1997; *Re Exxon Valdez* Litigation *and Settlement Costs*, Order P-94-1(46)/P-95-1(26)/P-97-4(12)/P-97-6(11)/P-97-7(11)/P97-9(5), dated December 26, 1997; *Re Exxon Valdez Litigation and Settlement Costs*, Order P-94-1(54)/P-95-1(33)/P-97-4(35)/P-97-6(20)/P-97-7(21) dated December 28, 1988; *Re Exxon Valdez Litigation and Settlement Costs* Order P-94-1(75)/P-97-4(64)/P-97-6(41)/P-97-7(46), dated December 20, 1999.

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either the utility, consumers, or particular classes of consumers."[726] The rule against retroactive ratemaking thus precludes adjusting future rates based on commission review of past recovery.

Because of this doctrine we do not conduct an unrecovered investment analysis which requires looking at past collections to judge current rates. Instead, we follow the instructions of *Kenai*[727] and look to the past *opportunity* of the Carriers to collect. Doing so does not violate the rule against retroactive ratemaking because we rely on past opportunity to recover. We do not run afoul of the doctrine of retroactive rate making because the rates that we set in this order do not reflect past gains or losses.

Looking backward at past opportunity to recover is not prohibited. The rule against retroactive ratemaking was not intended to prevent commissions from looking backward. The use of a historical test year by its very nature requires examination of the past experience of the company. Even the use of a future test year generally involves consideration of historical data adjusted for a future period. Accordingly, the rule against retroactive ratemaking does not bar examination of the past experience of a company.

The rule against retroactive ratemaking is often not strictly applied.[728] It can also be overcome by notice to the parties that approved rates are subject to retroactive alteration. The U.S. Supreme Court has upheld such a notice procedure.[729] The APUC gave notice to the Carriers when it accepted the Intrastate Settlement Agreement subject to the caveat that the rights of future shippers would not be infringed and that any determination of just and reasonable rates in the future would be subject to the same standards and procedures as if TSM had not been accepted.[730] In light of this

[726]Stefan H. Kreiger, *The Ghost of Regulation Past: Current Application of the Rule Against* Retroactive *Ratemaking in Public Utility Proceedings,* 4 ILL. L.REV. 983, 997 (1991) cited by the Alaska Supreme Court in *Matanuska Electric Association, Inc. v. Chugach Electric Association*, Inc., S-9839, No. 5611, August 23, 2002.

[727]*Re Kenai* Pipe *Line Co.,* 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992).

[728]*See* Kreiger, *supra* note 718, at 999-1002, 1030-31. For example, the Florida Public Service Commission approved an equipment depreciation increase for a utility that adversely affected the amount of refunds. *Citizens of the State v. Florida Pub. Serv. Comm'n*, 415 So.2d 1268 (Fla. 1982) On appeal, the Public Counsel argued that the depreciation represcription was not merely a bookkeeping entry but a retroactive change in rate base. The court rejected the argument, holding that the commission "was not (engaged in) rate-making but, rather considering depreciation represcription. We acknowledge, as did the commission, that new depreciation allowance does have an effect on the stipulation and refund." The commission determined, however, that a depreciation represcription was a factor that all parties should have known would affect the refund.

[729]*See Great N. Ry. v. Sunburst Oil & Ref. Co.,* 287 U.S. 358, 361-63 (1932). The state supreme court in a previous decision had held that shipper could challenge previously approved rates and recover retroactively excess charges because a notice of the possibility of recalculation was in the tariff.

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notice, the Carriers do not now have a legitimate reliance on Settlement rates. A reliance rationale is relevant only when the party invoking it has rational and legitimate expectations that the past rates will remain in effect for purposes of determining future rates.[731] The APUC decision accepting TSM subject to the possibility of future challenges[732] combined with our suspension of 1997-2000 rates[733] clearly precludes the Carriers from such a reliance.

Therefore, although a strict interpretation of the rule against retroactive ratemaking might preclude adjusting future rates based on past revenues, the facts of this case, i.e., prior notice, rate suspension, and use of recovery opportunity rather than post collections to determine whether filed rates are just and reasonable insure that our findings do not violate the rule against retroactive ratemaking.

ENDNOTE 7 CARRIER ALLEGATION THAT AN INTERSTATE SHIPPER MAY FILE AN INTERSTATE COMMERCE ACT SECTION 13(4) CLAIM WITH THE FEDERAL ENERGY REGULATORY COMMISSION

Carriers' assert that "if Tesoro were successful in the short run in lowering intrastate rates, the net result [under TSM] would be immediate, offsetting increase in interstate rates."[734] This is based on the provision of the TAPS Settlement that provides "if the Intrastate revenues are reduced, the interstate rates will be based on a larger Total Revenue Requirement and will therefore be higher than they otherwise would be."[735]

(. . . continued)

[730]*Re Amerada Hess Pipeline Corp.,* 13 APUC 448 (1993). The APUC stated in its October 29, 1993, order accepting the Settlement "Each new rate . . . is subject to the same standards and procedures to which it would have been subject if the Intrastate Settlement Agreement had not been accepted." *Id.,* at 456. This finding has been reiterated often during the history of this case. The APUC was quite clear at a May 5, 1995, prehearing conference when it stated "The Commission wishes to make it clear that the TAPS Carriers are the ones who need to justify their rates as though TSM had not been approved." Prehearing Conference Transcript at 66 (May 5, 1998)].

[731]Kreiger, *supra* note 718, at 1041.

[732]*Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993).

[733]724A *Re Amerada Hess Pipeline Corp.,* Order P-86-2(61)/P-92-2(30)/P-94-1(36)/P-95-1(16)/P-97-4(1)/P-97-5(1)/P-97-6(1)/P-97-7(1), dated June 27, 1997; *Re Exxon Valdez* Litigation *and Settlement Costs*, Order P-94-1(46)/P-95-1(26)/P-97-4(12)/P-97-6(11)/P-97-7(11)/P97-9(5), dated December 26, 1997; *Re Exxon Valdez Litigation and Settlement Costs*, Order P-94-1(54)/P-95-1(33)/P-97-4(35)/P-97-6(20)/P-97-7(21) dated December 28, 1988; *Re Exxon Valdez Litigation and Settlement Costs* Order P-94-1(75)/P-97-4(64)/P-97-6(41)/P-97-7(46), dated December 20, 1999; *Re Amerada Hess Pipeline Corp.*, Order P-94-1(101)/P-97-4(105)/P-97-6(66)/P-97-7(72), dated December 29, 2000; *Re Amerada Hess Pipeline Corp.*, Order P-94-1(111)/P-97-4(144)/P-97-6(78)/P-97-7(103), dated December 20, 2001.

[734]*TAPS Carriers' Motion to Terminate Investigation* at 20.

[735]*Id.* at 5 n.8.

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