for energy utilities.[17] The next section looks at a second approach that goes beyond the CAPM to estimate the equity risk premium.

5. Equity Risk Premium with the Adjusted CAPM

This section considers two empirical adjustments to the CAPM estimates proposed in the academic literature to account for their deficiencies. We call the CAPM with the addition of the two modifications the "Adjusted CAPM". Unlike the CAPM and the Fama-French model, the Adjusted CAPM is not an equilibrium model of expected returns. It contains adjustments to the CAPM that are empirically justified in a context where the known difficulties of a theoretical model need to be lessened for improved estimation. We first introduce the Adjusted CAPM. Then we implement it to estimate the risk premium of energy utilities. We finally offer a brief discussion of our findings.

5.1. Model and Literature

The Adjusted CAPM is based on the CAPM but provides more realistic estimates of the rate of return by considering the empirical problems of the CAPM. More specifically, the Adjusted CAPM is a model in which the expected equity return of a gas utility is arrived at by

$$E(R_{GAS}) = R_f + \alpha_{GAS} \times \left(1 - \beta^{Adj}\right) + \beta^{Adj} \times \lambda_m .$$

Compared to the CAPM, this equation incorporates a modification to take into account that estimated betas can be adjusted for better predictive power and a modification to take account of the fact the alpha (risk premium error) is high for low-beta value-oriented firms in the CAPM.

The first modification originates from the works of Blume (1971, 1975). Blume (1971) examines historical portfolio betas over two consecutive periods and finds that the historical betas, from one period to another, regress towards one, the average of the market. He also shows that the historical betas adjusted towards one predict future betas better than unadjusted betas. Blume (1975) builds a historical beta adjustment model to capture the tendency to regress towards one. He discovers that the best adjustment is to use a beta equal to $0.343 + 0.677 \times \beta^{His}$, a finding that led to the concept of "adjusted beta". Merrill Lynch, which popularized the use of adjusted betas based on Blume (1975)'s results, advocates the adjustment $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. Merrill Lynch's adjusted beta, now widely used in practice, represents a weighted-average between the beta of the market and the historical beta, with a two-thirds weighting on the historical beta.

The second adjustment is initially proposed by Litzenberger, Ramaswamy and Sosin (1980), who consider solutions to the problem that the CAPM gives a cost of equity capital with a downward bias for low beta firms, as discussed in section 3.1. They note that one way of remedying the problem is to add a bias correction to the CAPM risk premium. To be effective, the correction must take account of the

[17] Some of the documented effects, like momentum, are short-lived. Hence, their related factor might be irrelevant for estimates of the cost of equity capital.

importance of the risk premium error and the level of the firm's beta because these two elements influence the magnitude of the problem. To do this for low beta securities, Litzenberger, Ramaswamy and Sosin (1980) propose the bias correction $\alpha_{GAS} \times (1-\beta)$. As desired, the correction increases with the risk premium error of the CAPM, and decreases with the beta. The correction is nil for a firm for which the CAPM already works well (when $\alpha_{GAS} = 0$) or for a firm having a beta of one, two cases where the CAPM produces a fair rate of return on average. Morin (2006, Section 6.3) presents an application of this adjustment in regulatory finance through a model he calls the empirical CAPM.

In summary, the two modifications incorporated in the Adjusted CAPM involve first using the adjusted beta instead of the historical beta and second including the bias correction in the risk premium calculation. Considering the documented usefulness of the two adjustments, the Adjusted CAPM has the potential to estimate a reasonable risk premium for the energy utilities.

5.2. Risk Premium Estimates

To compute the Adjusted CAPM estimates for our utilities, the starting point is the estimates of the CAPM of Section 3.2, given in Table 2. The beta estimates are now understood as the unadjusted historical betas β^{His}. The gas utility risk premium with the Adjusted CAPM can then be expressed as

$$\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right),$$

where $\beta^{Adj} = 0.333 + 0.667 \times \beta^{His}$. The Adjusted CAPM risk premium error is arrived at by

$$\alpha_{GAS}^{Adj} = E\left(R_{GAS,t} - R_{f,t}\right) - \left[\alpha_{GAS} \times \left(1-\beta^{Adj}\right) + \beta^{Adj} \times E\left(\lambda_{m,t}\right)\right].$$

Table 4 shows the Adjusted CAPM estimates using the four gas distribution reference portfolios. The estimates of the risk premium error α_{GAS}^{Adj}, the adjusted beta β^{Adj}, the bias correction $\alpha_{GAS} \times \left(1-\beta^{Adj}\right)$ and the risk premium are shown in Panels A, B, C and D, respectively. The risk premium errors are still positive for the four portfolios, with values ranging from 1.39% (for CAindex) to 2.89% (for USindex), but the underestimation is only significant for USindex. The reduction in errors comes from the use of adjusted betas, which are 0.56 on average, and the bias corrections, which are 2.96% on average. Lastly, the risk premiums vary between 4.88% and 8.27%, findings comparable to the estimates obtained with the Fama-French model.

TABLE 4
Adjusted CAPM Risk Premium Estimates for the Gas Distribution Reference Portfolios

Portfolio	Estimate	SE	t-stat	Prob > |t|
Panel A: Risk Premium Error (Alpha)				
DJ_GasDi	1.82	2.00	0.91	0.365
CAindex	1.39	1.54	0.9	0.366
DJ_GasUS	2.68	1.97	1.36	0.176
USindex	2.89	1.37	2.11	0.035
Panel B: Adjusted Beta				
DJ_GasDi	0.47	0.07	6.69	<.0001
CAindex	0.56	0.05	11.38	<.0001
DJ_GasUS	0.58	0.06	9.84	<.0001
USindex	0.64	0.04	15.44	<.0001
Panel C: Bias Correction				
DJ_GasDi	4.46	2.28	1.96	0.052
CAindex	1.99	1.10	1.81	0.071
DJ_GasUS	3.12	1.61	1.94	0.054
USindex	2.26	0.77	2.94	0.004
Panel D: Risk Premium				
DJ_GasDi	8.27	2.71	3.05	0.003
CAindex	4.88	2.11	2.31	0.021
DJ_GasUS	7.45	2.52	2.96	0.004
USindex	6.05	1.89	3.21	0.002

NOTES: This table reports the results of the estimation of the Adjusted CAPM for the gas distribution reference portfolios. Panels A to D look at the annualized risk premium error or alpha (in percent), the adjusted market beta, the bias correction and the annualized risk premium (in percent), respectively. The columns labelled Estimate, SE, t-stat and Prob > |t| give respectively the estimates, their standard errors, their t-statistics and their p-values. The four gas distribution reference portfolios and their sample are described in section 2 and table 1. The annualized mean market risk premiums for their corresponding sample period are 8.1% for DJ_GasDi, 5.2% for CAindex, 7.5% for DJ_GasUS and 6.0% for USindex.

Figure 5 shows the risk premium errors for the utilities that make up the CAindex portfolios (Figure 5a), the gas distributors in the USindex portfolios (Figure 5b) and the four utilities reference portfolios (Figure 5c). The errors are generally insignificant and a comparison with Figure 1 indicates that they have decreased considerably for all portfolios. For example, for the TSX_Util portfolio, the error is down from 5.0% with the CAPM to 0.9% with the Adjusted CAPM.

FIGURE 5
Risk Premium Errors with the Adjusted CAPM for Various Utilities

Figure 5a: Firms in the CAindex Portfolio

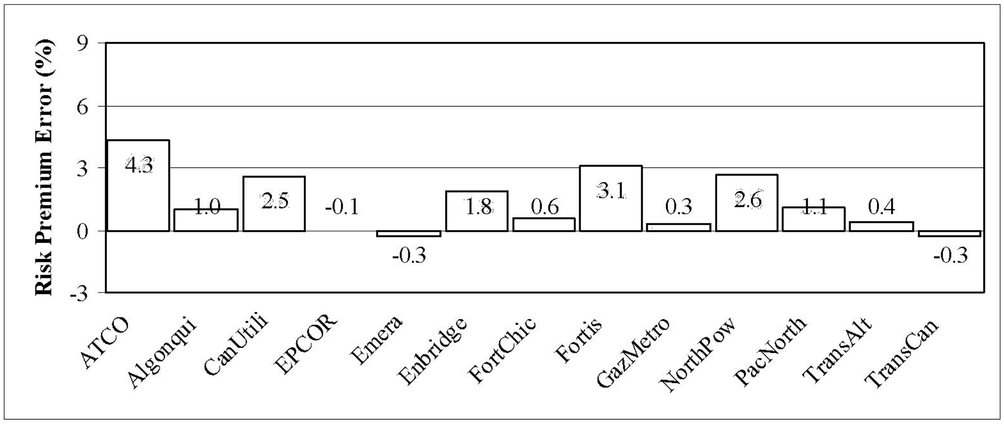


Figure 5b: Firms in the USindex Portfolio

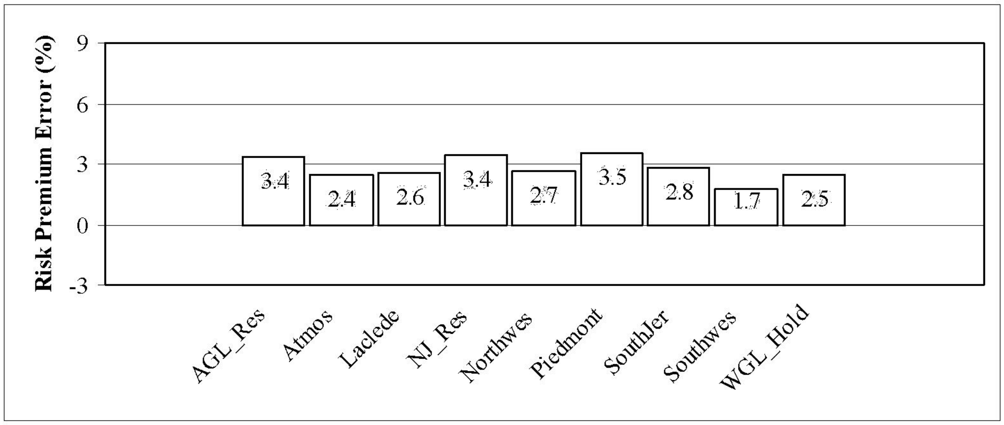
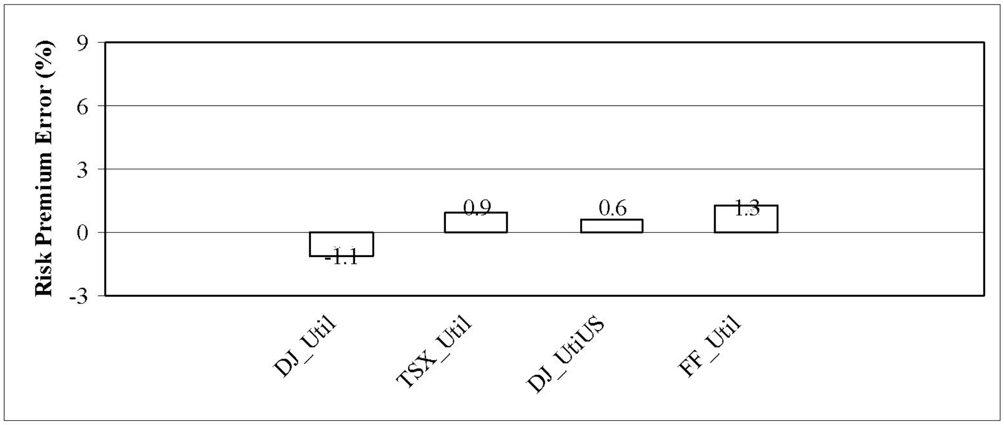


Figure 5c: Utilities Reference Portfolios



NOTES: This figure shows the annualized risk premium errors (or alphas) with the Adjusted CAPM for the Canadian utilities in the CAindex portfolio (Figure 5a), the U.S. gas distributors in the USindex portfolio (Figure 5b) and the utilities reference portfolios (Figure 5c).

5.3. Discussion

Our results support the validity of the Adjusted CAPM for determining the rate of return on energy utilities. While its risk premium estimates are in the same range as the Fama-French estimates, it arrives at its results from a different perspective. The Fama-French model advocates the use of additional risk factors to reduce the CAPM risk premium errors. The Adjusted CAPM, through its bias correction, effectively estimates the risk premium as a weighted-average of the CAPM risk premium and the realized historical risk premium, with a weighting of beta on the former.

The Adjusted CAPM thus recognizes that the CAPM is an imperfect model that can be improved with the information contained in the historical returns. Pastor and Stambaugh (1999) propose a similar strategy by demonstrating how to estimate the cost of equity by using Bayesian econometrics to incorporate the CAPM risk premium error (or alpha) in an optimal manner based on the priors of the evaluator. Consistent with our results, they also show evidence of higher costs of equity for energy utilities using their technique than using the CAPM alone.[18] As the Adjusted CAPM does not require additional risk factors like size and value, the model might be easier to interpret for regulators already familiar with the standard CAPM in their decisions.

6. Conclusion

It is difficult to overstate the importance of the evaluation of the expected rate of return in finance. For a firm's management group, the expected rate of return on equity (or the equity cost of capital) is central to its overall cost of capital, i.e. the rate used to determine which projects will be undertaken. For portfolio managers, the expected rate of return on equity is an essential ingredient in portfolio decisions. For regulatory bodies, the expected return on equity is the basis for determining the fair and reasonable rate of return of a regulated enterprise. This paper is interested in evaluating the rate of return in the context of regulated energy utilities.

The academic literature contains numerous theories for determining the expected rate of return on equity. As those theories are based on simplified assumptions of the complex world in which we live, they cannot be perfect. Even if the theoretical merit of the different models can be debated, the determination of the most valid approach to explain the financial markets really becomes an empirical question – it is necessary to answer the question "which theory best explains the information about actual returns?" This paper empirically examines the validity of the model the most often used in the rate adjustment formula of regulatory bodies, the CAPM, one of the most prominent academic alternatives, the Fama-French model, and a version of the CAPM modified to account for some of its empirical deficiencies, the Adjusted CAPM.

Our empirical results show that the risk premiums for energy utilities estimated with the CAPM are rejected as too low compared to the historical risk premiums.

[18] Pastor and Stambaugh (1999) obtain risk premiums that vary between the CAPM estimates, when they assume that there is zero prior uncertainty on the CAPM, and the historical estimates, when they assume that there is infinite prior uncertainty on the CAPM. Our bias correction corresponds approximately to a prior uncertainty on the CAPM between 3% and 6% in their setup.

The rejections are related to the well-documented CAPM underestimation of the average returns of low-beta firms and value firms. The Fama-French model and the Adjusted CAPM appear statistically better specified, as we cannot reject the hypothesis that their risk premium errors are equal to zero. They suggest equity risk premiums for gas distribution utilities between 4% and 8%. Overall, our findings demonstrate that models that go beyond the CAPM have the potential to improve the estimation of the cost of equity capital of energy utilities. They are thus interesting avenues for regulators looking to set fair and reasonable equity rates of return.

ACKNOWLEDGEMENTS

We would like to thank Mark Lowenstein and Jacques St-Pierre for helpful discussions. We gratefully acknowledge financial support from the *Institut de Finance Mathématique de Montréal*, the Investors Group Chair in Financial Planning (Chrétien), the Faculty of Business Administration at Laval University (Chrétien) and the *Faculté d'administration, Université de Sherbrooke* (Coggins). Stéphane Chrétien is also grateful to Kalok Chan (Department Head) and the Department of Finance at the Hong Kong University of Science and Technology, where part of this research was conducted while he was a Visiting Associate Professor of Finance.

REFERENCES

Ang, A., R.J. Hodrick, Y. Xing and X. Zhang (2006) 'The Cross-Section of Volatility and Expected Returns,' Journal of Finance 51:259-299.

Ang, A., R.J. Hodrick, Y. Xing and X. Zhang (2009) 'High Idiosyncratic Volatility and Low Returns: International Evidence and Further U.S. Evidence,' Journal of Financial Economics 91:1-23.

Banz, R. (1981) 'The Relation between Return and Market Value of Common Stocks,' Journal of Financial *Economics* 9:3–18.

Bartholdy, J. (1993) 'Testing for a Price-Earnings Effect on the Toronto Stock Exchange,' *Canadian Journal of Administrative Sciences* 10:60–67.

Basu, S. (1977) 'The Investment Performance of Common Stocks in Relation to Their Price to Earnings Ratios: A Test of the Efficient Market Hypothesis,' *Journal of Finance* 32:663–682.

Berk, J., R.C. Green and V. Naik (1999) 'Optimal Investment, Growth Options, and Security Returns,' *Journal of Finance* 54:1553–1607.

Black, F., M.C. Jensen and M. Scholes (1972) 'The Capital Asset Pricing Model: Some Empirical Tests' in M.C. Jensen (ed.) *Studies in the Theory of Capital Markets* (New York:Praeger Press) pp.79–121.

Blume, M. (1971) 'On the Assessment of Risk,' *Journal of Finance* 26:1–10.

Blume, M. (1975) 'Betas and their Regression Tendencies,' *Journal of Finance* 30:785–895.

Blume, M. and I. Friend (1973) 'A New Look at the Capital Asset Pricing Model,' *Journal of Finance* 28:19–33.

Bonbright, J.C., A.L. Danielsen and D.R. Kamerschen (1988) *Principles of Public Utility Rates.* (Arlington:Public Utilities Reports Inc.)

Bourgeois, J. and J. Lussier (1994) 'P/Es and Performance in the Canadian Market,' *Canadian Investment Review* Spring:33–39.

Carhart, M.M. (1997) 'On Persistence in Mutual Fund Performance,' *Journal of Finance* 52:57–82.

Carlson, M., A. Fisher and R. Giammarino (2004) 'Corporate Investment and Asset Price Dynamics: Implications for the Cross-Section of Returns,' *Journal of Finance* 59:2577–2603.

Cochrane, J.H. (1999) 'New Facts in Finance,' *Economic Perspectives Federal Reserve Bank of Chicago* 23:36–58.

Cochrane, J.H. (2001) *Asset Pricing* (Princeton:Princeton University Press)

Davis, J. (2006) 'Reviewing the CAPM,' *Canadian Investment Review* Winter:21.

Elfakhani, S., L.J. Lockwood and T.S. Zaher (1998) 'Small Firm and Value Effects in the Canadian Stock Market,' *Journal of Financial Research* 21:277–291.

Fama, E.F. and K.R. French (1992) 'The Cross-Section of Expected Stock Returns,' *Journal of Finance* 47:427–465.

Fama, E.F. and K.R. French (1993) 'Common Risk Factors in the Returns on Stocks and Bonds,' *Journal of Financial Economics* 33:3–56.

Fama, E.F. and K.R. French (1996a) 'Multifactor Explanations of Asset Pricing Anomalies,' *Journal of Finance* 51:55–84.

Fama, E.F. and K.R. French (1996b) 'The CAPM is Wanted, Dead or Alive,' *Journal of Finance* 51:1947–1958.

Fama, E.F. and K.R. French (1997) 'Industry Cost of Equity,' *Journal of Financial Economics* 43:153–193.

Fama, E.F. and K.R. French (1998) 'Value Versus Growth: The International Evidence,' *Journal of Finance* 53:1975–1999.

Fama, E.F. and K.R. French (2004) 'The Capital Asset Pricing Model: Theory and Evidence,' *The Journal of Economic Perspectives* 18:3:25–46.

Fama, E.F. and J. MacBeth (1973) 'Risk, Return, and Equilibrium: Empirical Tests,' *Journal of Political Economy* 71:607–636.

Fowler, D.J., C.H. Rorke and V. Jog (1979) 'Heteroscedasticity, R^2 and Thin Trading on the Toronto Stock Exchange,' *Journal of Finance* 34:5:1201–1210.

Fowler, D.J., C.H. Rorke and V. Jog (1980) 'Thin Trading and Beta Estimation Problems on the Toronto Stock Exchange,' *Journal of Business Administration* Fall:77–90.

Friend, I. and M. Blume (1970) 'Measurement of Portfolio Performance under Uncertainty,' *American Economic Review* 60:607–636.

Gomez, J., L. Kogan and L. Zhang (2003) 'Equilibrium Cross-Section of Returns,' *Journal of Political Economy* 111:693–732.

Hansen, L.P. (1982) 'Large Sample Properties of Generalized Method of Moments Estimators,' *Econometrica* 50:1029–1054.

Jagannathan, R. and Z. Wang (1996) 'The Conditional CAPM and the Cross-Section of Expected Returns,' *Journal of Finance* 51:3–53.

Jegadeesh, N. and S. Titman (1993) 'Returns to Buying Winners and Selling Losers: Implications for Stock Market Efficiency,' *Journal of Finance* 48:65–91.

Kothari, S.P., J. Shanken and R.G. Sloan (1995) 'Another Look at the Cross-Section of Expected Stock Returns,' *Journal of Finance* 50:185–224.

L'Her, J.-F., T. Masmoudi and J.-M. Suret (2002) 'Effets taille et book-to-market au Canada,' *Canadian Investment Review* Summer:6–10.

L'Her, J.-F., T. Masmoudi and J.-M. Suret (2004) 'Evidence to Support the Four-Factor Pricing Model from the Canadian Stock Market,' *Journal of International Financial Markets, Institutions & Money* 14:313–328.

Lakonishok, J., A. Shleifer and R. Vishny (1994) 'Contrarian Investment, Extrapolation, and Risk,' *Journal of Finance* 49:1541–1578.

Lintner, J. (1965) 'The Valuation of Risky Assets and the Selection of Risky Investments in Stock Portfolios and Capital Budgets,' *Review of Economics and Statistics* 47:13–37.

Litzenberger, R., K. Ramaswamy and H. Sosin (1980) 'On the CAPM Approach to the Estimation of A Public Utility's Cost of Equity Capital,' *Journal of Finance* 35:369–383.

Lo, A. and A.C. MacKinlay (1990) 'Data-Snooping Biases in Tests of Financial Asset Pricing Models,' *Review of Financial Studies* 3:431–468.

Merton, R. (1973) 'An Intertemporal Capital Asset Pricing Model,' *Econometrica* 41:867–887.

Morin, R.A. (1980) 'Market Line Theory and the Canadian Equity Market,' *Journal of Business Administration* Fall:57–76.

Morin, R.A. (2006) *New Regulatory Finance* (Vienna:Public Utilities Reports Inc.)

Newey, W. and K. West (1987) 'A Simple, Positive Semi-Definite, Heteroscedasticity and Autocorrelation Consistent Covariance Matrix,' *Econometrica* 55:703–708.

Pastor, L. and R.F. Stambaugh (1999) 'Costs of Equity Capital and Model Mispricing,' *Journal of Finance* 54:67–121.

Pastor, L. and R.F. Stambaugh (2003) 'Liquidity Risk and Expected Stock Returns,' *Journal of Political Economy* 111:642–685.

Ross, S.A. (1976) 'The Arbitrage Theory of Capital Asset Pricing,' *Journal of Economic Theory* 13:341–360.

Schink, G.R. and R.S. Bower (1994) 'Application of the Fama-French Model to Utility Stocks,' *Financial Markets, Institutions and Instruments* 3:74–96.

Sharpe, W.F. (1964) 'Capital Asset Prices: A Theory of Market Equilibrium under Conditions of Risk,' *Journal of Finance* 19:425–442.

Stein, J. (1996) 'Rational Capital Budgeting in an Irrational World,' *Journal of Business* 69:429–455.

SOAH DOCKET NO. 473-21-2606
PUC DOCKET NO. 52195

APPLICATION OF EL PASO ELECTRIC COMPANY TO CHANGE RATES	§ § §	BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS

EL PASO ELECTRIC COMPANY'S RESPONSE TO
CITY OF EL PASO'S SEVENTEENTH REQUEST FOR INFORMATION
QUESTION NOS. CEP 17-1 THROUGH CEP 17-23

CEP 17-13:

Reference the Rebuttal testimony of Jennifer E. Nelson at 45, footnote 132 and footnote 133 please provide a copy of each of the orders referenced.

RESPONSE:

Please see CEP 17-13, Attachments 1-7.

Preparer: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

Sponsor: Jennifer E. Nelson Title: Assistant Vice President – Concentric Energy Advisers

STATE OF ALASKA

THE REGULATORY COMMISSION OF ALASKA

Before Commissioners: G. Nanette Thompson, Chair
Bernie Smith
Patricia M. DeMarco
Will Abbott
James S. Strandberg

In the Matter of the Correct Calculation and Use of Acceptable Input Data To Calculate the 1997, 1998, 1999, 2000, 2001, and 2002 Tariff Rates for the Intrastate Transportation of Petroleum over the Trans Alaska Pipeline System Filed by AMERADA HESS PIPELINE CORPORATION; ARCO TRANSPORTATION ALASKA, INC.; BP PIPELINES (ALASKA) INC.; EXXON PIPELINE COMPANY; MOBIL ALASKA PIPELINE COMPANY; EXXONMOBIL PIPELINE COMPANY; PHILLIPS ALASKA PIPELINE CORPORATION; UNOCAL PIPELINE COMPANY; PHILLIPS TRANSPORTATION ALASKA, INC.; and WILLIAMS ALASKA PIPELINE COMPANY, L.L.C., and the Protest by TESORO ALASKA PETROLEUM COMPANY of the 1997 and 1999 Tariff Rates	P-97-4 ORDER NO. 151
In the Matter of the Petition of TESORO ALASKA PETROLEUM COMPANY for an Investigation into the Amounts Collected 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 for Dismantling, Removal, and Restoration of the Trans Alaska Pipeline System	P-97-7 ORDER NO. 110

ORDER REJECTING 1997,1998,1999 AND 2000 FILED TAPS RATES; SETTING JUST AND REASONABLE RATES; REQUIRING REFUNDS AND FILINGS; AND OUTLINING PHASE II ISSUES

BY THE COMMISSION:

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

ORDER REJECTING 1997,1998,1999 AND 2000 TAPS RATES; SETTING JUST AND REASONABLE RATES; REQUIRING REFUNDS AND FILINGS; AND OUTLINING PHASE II ISSUES

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

I. DECISION SUMMARY

Two petroleum companies operating in Alaska, Tesoro[1] and Williams,[2] assert that the 1997 rates for transporting North Slope oil to their Alaska refineries over the Trans Alaska Pipeline System (TAPS) exceed the reasonable costs of transportation. To investigate their allegations, we suspended all post-1997 intrastate TAPS rates[3] filed by the TAPS Carriers,[4] and held an evidentiary hearing.

The Alaska Pipeline Act requires that oil pipelines operate as common carriers and gives this Commission the responsibility of setting just and reasonable rates for intrastate transportation.[5] After careful review of the record we conclude in this order that the 1997-2000 filed intrastate TAPS rates do not satisfy the AS 42.06

---

[1]Tesoro Alaska Company.

[2]Williams Alaska Petroleum Company.

[3]*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.

[4]The TAPS Carriers are Amerada Hess Pipeline Corporation, BP Pipelines (Alaska) Inc., ExxonMobil Pipeline Company, Phillips Transportation Alaska, Inc. and Unocal Pipeline Company (collectively the Indicated Taps Carriers). Williams Alaska Pipeline Company, L.L.C. acquired the pipeline interest of Mobil Alaska Pipeline Company in TAPS effective July 1, 2000. Although Williams Alaska Pipeline Company, L.L.C. is a TAPS Carrier closely aligned with the Indicated TAPS Carriers and has adopted the testimony and exhibits of the Indicated TAPS Carriers for the purposes of this proceeding, Williams Alaska Pipeline Company, L.L.C. has carefully maintained its individual party status throughout this proceeding. Therefore, we refer to all of the TAPS Carriers except Williams Alaska Pipeline Company, L.L.C. as the Indicated Carriers and to all of the TAPS Carriers as the Carriers. Each of the Carriers holds separate certificates of public convenience and necessity. As a result, each Carrier files separate rates for transportation on TAPS for each year. The Carriers are subsidiary corporations of most of the producers who ship oil on the TAPS.

[5]AS 42.06.140, AS 42.06.410(a).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

requirement that pipeline rates be just and reasonable, set new 1997-2000 rates and order filings so that we can set rates for 2001 and subsequent years.

The Trans Alaska Pipeline System carries oil from the largest oil field on the North American continent, Prudhoe Bay, on the North Slope of Alaska over 800 miles across tundra, mountains and rivers to the freshwater port of Valdez, Alaska. During Prudhoe Bay's peak production years, the pipeline carried two billion barrels each day. Constructing TAPS was and remains the most ambitious pipeline construction project in United States history. Planning and construction began in 1968 and the first oil flowed through the pipeline in 1977.

Over ninety percent of the oil produced in Alaska is carried by tankers to markets on the west coast of the United States. The Federal Energy Regulatory Commission (FERC) is responsible for approving rates for interstate shipments. Throughout the pipeline's history, some oil has been removed from the pipeline in Alaska and processed for sale in local markets.[6] The Regulatory Commission of Alaska sets just and reasonable rates for intrastate transportation based on the costs reasonably incurred in transporting oil from the North Slope to destinations in Alaska. Just and reasonable intrastate transportation rates are important for insuring continuing

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[6]Some oil is delivered to intermediate points along the pipeline route within Alaska: 1) to the Golden Valley interconnection outside of Fairbanks, Alaska for further transportation to the Williams and Petro Star refineries in North Pole and 2) to Petro Star refinery outside of Valdez. We have jurisdiction over the tariffed rates charged for intrastate shipments. AS 42.06. Therefore, rather than determining the rate for 1,151,000 barrels per day our decision affects the rate applied to only 87,000 barrels per day of the TAPS oil. RGV-14 Schedule 1.

development of the state's oil resources and insuring that Alaskans have the opportunity to benefit from development of their natural resources.[7]

After prolonged litigation about the appropriate rates for shipments on the TAPS, the TAPS Carriers signed interstate and intrastate settlements with the State of Alaska. Our predecessor agency[8] accepted[9] the Intrastate Settlement[10] (the Settlement) because all affected parties supported it; the Commission did not decide that the Settlement produced just and reasonable rates. Since 1986, the TAPS Carriers calculated intrastate rates using the TAPS Settlement Methodology (TSM).[11] The Alaska Public Utilities Commission (APUC) deferred the issue of whether TSM produced just and reasonable rates until a shipper protested the rates. The 1997 Tesoro and Williams protests put that issue before us for the first time in this pipeline's twenty-year history. Under the Alaska Pipeline Act, the Carriers have the burden of proving that the rates calculated and filed using TSM are just and reasonable.

The Carriers did not support their rates with evidence showing that they reflect the costs of providing service. Instead, they assert that because the rates set by TSM are below a benchmark, the filed rates are just and reasonable. The Carriers do

[7]Alaska Const. art. VIII. The Carriers argue that a decrease in intrastate rates will result in an increase in interstate rates and the effect on the State of Alaska will be a net loss. We note that the TSM Settlement provision allowing Carriers to collect their revenue requirement from the combination of interstate and intrastate rates affords Carriers the *option* of raising interstate rates if intrastate rates decrease. The TSM Settlement agreement does not require Carriers to recover costs disallowed as unjust and unreasonable by state regulators from the federal jurisdiction.

[8]The Regulatory Commission of Alaska assumed the duties of the Alaska Public Utilities Commission on July 1, 1999. Ch. 25 SLA 1999.

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

[10]BWF-2, *Intrastate Settlement Agreement* (the Settlement). Endnote 1 describes record designations. A review of TAPS litigation history can be found at Endnote 2.

[11]*See* Endnote 3 for a detailed description of TSM.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

not ask us to adopt their benchmark ratemaking methodology to set rates. Instead, they contend that this method demonstrates what rates would have been absent the Settlement and as such provide a good measure of whether the filed rates calculated using TSM are just and reasonable.[12]

To calculate benchmark rates, the Carriers use a rate base that assumes straight-line depreciation from pipeline startup. They use rates of return that include a premium over the average oil pipeline company's cost of capital to compensate investors for substantial early period risks of the TAPS project. They assume that the life of TAPS is no longer than the life predicted at the time of the Settlement. Using these inputs, the Carriers calculate a year-end 1996 rate base to establish 1997-2000 benchmark rates. The Carriers assert because the filed rates are below benchmark rates, the filed rates are reasonable.

To verify the accuracy of the year-end 1996 benchmark rate base, the Carriers calculate the amount of their original investment that they believe they had recovered by the end of 1996. They apply annual revenues for 1977 to 1996 first to operating costs other than depreciation, then to return on rate base and taxes, and finally to depreciation. Their analysis concludes that unrecovered investment as of January 1997 significantly exceeds the year-end 1996 benchmark rate base. The Carriers assert that this verifies that the TSM filed rates are reasonable because it

[12]The Carriers assert that they were directed to file a comparison between TSM rates and those that would have been set by a regulator using traditional ratemaking methodologies. The Carriers misinterpret the language in *Re Amerada Hess Pipeline Corp.*, 13 APUC 448 (1993) and *Re Amerada Hess Pipeline Corp.*, Order P-97-4(79), dated April 10, 2000, to suggest that filed rates should be reviewed as if the past twenty years of rates have not been filed and collected. We disagree. The APUC stated "the filing 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 (e*mphasis added*). We did not direct that the history of rates filed and collected should be ignored.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

demonstrates that the Carriers have recovered less of their original investment under the Settlement than they would have under the methodology that they assert would have been used had the Settlement not occurred.

The Carriers' urge us to permanently approve the filed 1997-2000 rates and to continue the Settlement's effect. The Carriers also contend that the filed rates calculated using TSM are just and reasonable over the life of the Settlement and that allowing rates to be set using TSM furthers important public policy goals.

The State of Alaska (the State) supports the Carriers' position. The State asserts that public policy concerns also support preserving the Settlement. The State describes its position as (1) ensuring that this case does not affect the validity or enforceability of the Settlement,[13] (2) protecting the State's ability to continue making oil pipeline settlements within the jurisdiction of the Regulatory Commission of Alaska, and (3) protecting its economic interests.

Tesoro disagrees with the Carriers and the State. Tesoro contends that the filed rates for 1997-2000 are not just and reasonable and that AS 42.06 requires us to set just and reasonable rates. Tesoro calculates a year-end 1996 rate base that is much lower than the Carriers'. Tesoro calculates its rate base using the depreciation amounts used to calculate TSM ceiling rates. Tesoro's rate base is lower than the TAPS Carriers' benchmark analysis rate base because Tesoro relies on the depreciation schedule used in TSM which is much more accelerated than the straight-line depreciation the Carriers adopt in their benchmark analysis.

Williams also asserts that the filed rates calculated under TSM are not just and reasonable and that the Carriers' year-end 1996 benchmark rate base is too high.

[13]The Settlement terms require the State to defend against any litigation affecting the validity and enforceability of the Settlement. BWF-2, Section I-3.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Williams contends that TAPS is nearly fully depreciated but proposes that the basic framework of the Settlement should continue to be used to calculate rates. Williams asks, however, that we change certain elements of the TSM, including adding a management fee.[14] Williams proposes that we require the Carriers to use this adjusted methodology to calculate intrastate rates from 1997 forward.

The Public Advocacy Section (PAS)[15] supports Tesoro's and Williams' arguments. It asserts that the filed rates are not just and reasonable and that we should set new rates using the accelerated depreciation schedule employed in TSM rates, a longer TAPS life, and an adjustment for over collection for dismantling, removal and restoration (DR&R).

During most of the operational history of the TAPS, Carriers have charged the maximum rates allowed by TSM. Carriers filed the cost information used to calculate TAPS rates confidentially under the terms of TSM. Requiring shippers to pay rates based on cost data to which they do not have access is unusual. The policy concerns favoring settlements do not outweigh our statutory obligation to set just and reasonable rates or the policy favoring shipper and public access to the cost data used to calculate those rates.

Alaska statutes[16] require pipeline rates to be just and reasonable. Just and reasonable rates allow pipeline owners an opportunity to recover their investment, a

---

[14]*See* Endnote 4 for an analysis of Williams' proposed management fee.

[15]The Public Advocacy Section was established in 1999 by the Legislature to operate independently from the Commission and represent the public interest. Ch. 25 SLA 1999. The Commission assigns cases to the Public Advocacy Section when a public interest perspective would add to the full development of the record.

[16]AS 42.06, Pipeline Act.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

return on that investment and their reasonable operational costs.[17] As the Carriers note, the most important element of the cost of service for years 1997-2000 is the amount of the Carriers' investment which they have not yet had an opportunity to recover, their "rate base" at year-end 1996.[18] Because our regulatory predecessors did not decide whether TSM produced just and reasonable rates there is no approved rate base for year-end 1996. To determine the starting point, the year-end 1996 rate base, we must determine the amount of Carrier investment and the amount that they have previously had the opportunity to recover by year-end 1996.

This requires that we use cost information that is outside the 1997-2000 years. We rely on the voluminous historical record to determine an appropriate year-end 1996 rate base. We apply a depreciated original cost (DOC) methodology from the beginning of pipeline operations.[19] We adopt an appropriate capital structure of 49.5 debt/50.5 equity, adopt TSM depreciation charges and set overall annual rates of return ranging from 11 to 15 percent.[20] We generally accept the Carriers' inputs for all other elements of the rate calculation. We find the year-end 1996 rate base is $669 million.[21] We compare our year-end 1996 rate base to the Carriers'. The Carriers calculate a benchmark rate and argue that if filed rates are below the benchmark we should find them just and reasonable. We find that even if the Carriers' benchmark and supporting

[17]*See* Federal *Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944).*

[18]"The critical issue in determining the reasonableness of the 1997-2000 rates is the appropriate rate base against which to measure the returns achieved." *Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 40.

[19]*Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n*, 836 P.2d 343, 350 (Alaska, 1992) (affirming rate base computed by taking original cost minus accumulated depreciation).

[20]Exhibit 2, Column g.

[21]*See* Part IV, infra.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

unrecovered investment analyses are logical and legally sufficient to prove that rates are just and reasonable, the Carriers' methodology and choice of inputs to the benchmark analysis and unrecovered investment analyses are unreasonable. As a result, in addition to being insufficient to support filed rates, the benchmark and unrecovered investment analyses fail.

To verify the reasonableness of the $669 million year-end 1996 rate base, we compare TSM revenue requirements for past years with the revenue requirements we calculate using our consistently applied DOC methodology. If TSM's cumulative revenue requirement provided an opportunity to earn less than would have been allowed under an appropriate consistently applied depreciated original cost methodology the Carriers may be entitled to an upward adjustment to the year-end 1996 rate base.[22] However, no adjustment is necessary because we find that by 1997 TSM provided the Carriers an opportunity to earn over $9.9 billion more than the cost of providing service.

We calculate just and reasonable rates for 1997-2000 starting from the $669 million rate base. To calculate the TAPS 1997-2000 revenue requirements, we determine the rate base in each year. We determine an appropriate capital structure, cost of debt, and return on equity for each protested year. The return on equity for this period includes a premium for the early period risk to TAPS. To determine the appropriate depreciation amounts for 1997-2000 rates, we use straight-line depreciation and the now-expected longer life of TAPS. Using these inputs, we calculate the appropriate return on rate base and associated income tax allowance for each year. We use the resulting revenue requirements and the $669 million year-end 1996 rate

[22]*Re* Kenai *Pipe Line Co.,* 12 APUC 425, 438-40, 472 nn.25-26,1992 WL 696192 (Alaska P.U.C., 1992).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

base to compute just and reasonable TAPS rates for 1997, 1998, 1999 and 2000. Those rates are shown below and discussed in Part VI Section F, *infra*.

	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
2000	$1.25	$1.96	N/A

Finally, we compare these cost-based rates with the TSM filed rates. The Carriers' filed rates for 1997-2000 exceed these rates by an average of 57 percent.[23] Fifty-seven percent above costs is well outside the zone of reasonableness standard that reviewing courts apply. We, therefore, find that the 1997-2000 filed rates are not just and reasonable. We set the above rates[24] that we calculate as the permanent TAPS rates for 1997, 1998, 1999 and 2000. We order the Carriers to calculate and pay appropriate refunds.

II. LEGAL AND POLICY STANDARDS

The threshold issues in these dockets are the appropriate standard of review for filed rates and the method for determining what are "just and reasonable" rates under the Alaska Pipeline Act.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[23]In any given year, the Carriers' filed rates exceed the cost of providing service by 19 to 88 percent. *See* Exhibit 1. Cost based rates, determined in Part.VI Section F, are shown at Schedule 1. The Carriers' average yearly filed rates are shown at Schedule 2. The percentage by which each filed rate exceeds cost-based rates, and the average excess, is calculated at Schedule 3.

[24]AS 42.06.410(a) allows the Commission to fix rates when "after an investigation and hearing, [the commission], finds that a rate demanded, observed, charged, or collected by a pipeline carrier for a service . . . is unjust, unreasonable, unduly discriminatory, or preferential, ..."

A. Standard of Review for Filed Rates

In 1997, 1998, 1999, and 2000 each Carrier revised its existing tariffs and filed new rates.[25] Under AS 42.06.400(d), "[o]ne who initiates a change in existing tariffs bears the burden of proving the reasonableness of the change." The APUC held that "[e]ach new rate filed by the TAPS Carriers under the Intrastate Settlement Agreement is considered to be a revised tariff filing under AS 42.06.400."[26] The Carriers therefore carry the burden of proving that the filed rates are just and reasonable.[27]

The Settlement does not shift the burden of proof. When the APUC accepted the Settlement, it found that if the Settlement was challenged, the Commission would evaluate the filed rates using the same standards and procedures as if the Settlement had never been accepted.[28] The Carriers therefore carry the burden of proving that the filed rates are just and reasonable.

[25]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. ARCO (1997) TL56-301, TL59-301; (1998) TL61-301; (1999) TL 66-301, TL68-301; (2000) TL71-301. BP (1997) TL56-311, TL60-311; (1998) TL61-311; (1999) TL67-311, TL69-311; (2000) TL73-311, TL75-311. Exxon (1997) TL69-304, TL72-304; (1998) TL74-304; (1999) TL80-304, TL81-304; TL83-304; (2000) TL87-304. Unocal (1997) TL52-312, TL55-312; (1998) TL56-312; (1999) TL60-312; (2000) TL64-312. Mobil (1997) TL52-308, TL55-308; (1998) TL58-308; TL63-308; (1999) TL64-308, TL66-308; TL68-308; (2000) TL70-308. 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.

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

[27]*See* Endnote 5 for a more detailed discussion of burden of proof.

[28]*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).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

B. Just and Reasonable Rates

Whether the filed intrastate 1997-2002 TAPS rates are just and reasonable turns on the following five issues. First, how are just and reasonable rates determined? Second, what is a reasonable methodology for establishing just and reasonable rates? Third, what methodology is appropriate for establishing a year-end 1996 rate base for TAPS? Fourth, how does one determine the reasonable inputs for a DOC methodology? Fifth, does a change in ratemaking methodology in the middle of the operating life of a pipeline result in a return deficiency? We discuss each in turn.

1. What Are Just and Reasonable Rates?

Alaska Statute 42.06.370(a) states that "[a]ll rates demanded or received by a pipeline carrier, or by any two or more pipeline carriers jointly, for a service furnished or to be furnished shall be just and reasonable." Courts have developed various criteria for "just and reasonable" rates. Rate orders that fall within a "zone of reasonableness" are neither "less than compensatory" nor "excessive."[29] The "zone of reasonableness" is delineated by striking a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[30] The balance is struck by affording the owners of the pipeline a fair opportunity to earn a return commensurate with the risk of their capital investment[31] under tariffs that are fair and nondiscriminatory toward shippers and other members of the relevant public.

[29]*Farmers* Union *Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[30]*In re* Permian *Basin Area Rate Cases,* 390 U.S. 747, 792, (1968); *In re Trans Alaska Pipeline Rate Cases,* 436 U.S. 631, 653, 98 S.Ct. 2053, (U.S.Tex., 1978).

[31]*See, e.g.* Federal *Power Comm'n v. Hope Natural Gas Co,* 320 U.S. 591, 603, (1944) (*Hope*).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

We have some latitude in determining just and reasonable rates. In arriving at a just and reasonable rate "no single method need be followed."[32] "Under the statutory standard of 'just and reasonable' it is the result reached not the method employed which is controlling. . . . It is not theory but the impact of the rate order which counts."[33]

We have held that "[r]ates that are just and reasonable generate enough revenue to pay the costs actually and prudently incurred by the regulated entity in providing service (including depreciation and taxes) plus a reasonable return to the entity on the original cost of its property in service."[34] If non-cost based factors are to be considered they must be specifically supported.[35] The most useful and reliable starting point for rate regulation is an inquiry into costs.[36] We apply this standard to the filed 1997-2000 TAPS rates.

2. *What Is a Reasonable Methodology for Determining Rates?*

To determine rates, we assess the prudent cost of providing pipeline service.[37] A pipeline's costs include the cost of operation and maintenance and a

[32]*Wisconsin v. Fed. Power Comm'n,* 373 U.S. 294, 309, 48 P.U.R.3d 273, 83 S.Ct. 1266 (U.S.Dist.Col., 1963); *see also, Hope,* 320 U.S. at 602.

[33]*Hope,* 320 U.S. at 602.

[34]*Re Kenai Pipeline Co.,* 12 APUC 425, 433, 1992 WL 696192 (Alaska P.U.C., 1992).

[35]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984). Non-cost factors may justify a departure from a rigid cost-based approach. *F.E.R.C. v. Pennzoil Producing Co.,* 439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979).

[36]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984); *see, e.g., Mobil Oil Corp. v. Federal Power Comm'n*, 417 U.S. 283, 305-06, 316, 5 P.U.R.4th 1, 94 S.Ct. 2328 (U.S.La., 1974); *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 602-03 (1944).

[37]*See* BONBRIGHT, JAMES C. ET AL., PRINCIPLES OF PUBLIC UTILITY RATES 237-38 (1988).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

reasonable return of and on capital. The term "rate base" is used to describe the balance of prudently incurred capital investment which the Carriers have not yet had an opportunity to recover in rates and on which Carriers may earn a return. Rate base is a regulatory concept; it is not property.[38]

A pipeline's rate base is increased over time by additional prudent carrier capital expenditures and is decreased by depreciation. Depreciation is included in rates to allow carriers an opportunity to recover their investment principle. As a pipeline recovers its capital investment over time, the rate base declines so that the entire capital investment is recovered by the end of the asset's useful life.

As the Carriers note, "The critical issue in determining the reasonableness of the 1997-2000 rates is the appropriate rate base against which to measure the returns achieved."[39] The Carriers assert that had the TSM not been approved, the rate base at year-end 1996 would be $3.26 billion.[40] The Carriers assert that we should not use the TSM rate base to evaluate filed rates because it reflects compromises made to achieve the Settlement. They further contend that the true value of unrecovered Carrier property is even greater.[41] Williams asserts that the year-end 1996 rate base is $855 million[42] and Tesoro asserts it is $394 million.[43] The PAS suggests that the Carriers' investment has been completely recovered and that the rate base is zero.

---

[38]*Cook Inlet* Pipe *Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343, 350 (Alaska 1992).

[39]*Indicated TAPS* Carriers *Initial Post-Hearing Brief*, filed July 16, 2001, at 40.

[40]T-7 20.

[41]T-7 20.

[42]189A-BEW-T, Schedule 5, Line 16. This is the rate base sponsored by Williams as an alternative to the Carriers' benchmark analysis.

[43]JFB 1 Schedule B.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Throughout the life of the TAPS, tariffs have been calculated using TSM. In accepting TSM, the APUC agreed to allow TAPS rates to be calculated using the methodology in the Settlement until such time as TAPS rates were challenged, but the APUC did not establish or approve a rate base.[44]

We set the year-end 1996 rate base in Part IV, *infra*. To do so we determine the original 1977 rate base and then account for all additions to and subtractions from rate base from 1977 through year-end 1996. In Part V, we verify that the year-end 1996 rate base so established does not deny Carriers a reasonable opportunity to recover their investment.

3. What Methodology Is Appropriate for Establishing Rate Base at Year-End 1996?

In *Cook Inlet,*[45] the Alaska Supreme Court approved a method for determining the appropriate rate base in the middle of a pipeline's operating life. The APUC found that a rate base may be established using a DOC methodology applied as if that methodology had been used from the beginning of pipeline operations.[46]

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

---

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

[45]*Cook Inlet* Pipe *Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343 (Alaska 1992).

[46]*Re Cook Inlet Pipe Line Company,* 6 APUC 527 (1985); *see generally, Re Kenai Pipe Line* Company, 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992).

The parties do not dispute that this approach is reasonable.[47] The Carriers use a DOC analysis from the beginning of pipeline operations to generate benchmark rates.[48] Tesoro and Williams also use DOC analyses to support their respective cases. We find that a DOC methodology applied from the beginning of pipeline operations should be used in this case to determine rates.

4. <u>How Should Reasonable Inputs for a DOC Methodology Be Determined?</u>

Disputes over appropriate inputs into a methodology are normal in ratemaking. This proceeding is different from a normal rate case because throughout TAPS' history, no agency or court has approved a depreciation schedule or rate of return that has been used to set just and reasonable rates. The parties disagree about

[47]*Initial Post-Hearing Brief of the Indicated TAPS Carriers,* filed July 16, 2001, at 40-41; *Initial Brief* of *Williams Alaska Pipeline Company LLC*, filed July 16, 2001, at 14; *Tesoro Alaska Company's Initial Posthearing Brief*, filed July 18, 2001, at 26; *Williams Alaska Petroleum Post-hearing* Brief at 18 (if a DOC comparison is to be used TSM's accelerated depreciation schedule should be employed); Public *Advocacy Section Initial Post-Hearing Brief*, filed July 16, 2001, at 11. The parties, however, dispute what the inputs into a DOC methodology should be. The Carriers suggest that a straight-line depreciation should be used. *Initial Post-Hearing Brief of the Indicated TAPS Carriers* at 11-12**;** *Initial Brief of Williams Alaska Pipeline Company* at 16. Tesoro, PAS and Williams contend a consistent DOC methodology from the beginning of pipeline operation should use the TSM depreciation schedule. *Tesoro Alaska Company's Initial Posthearing Brief*, at 28-29; Williams agrees but asserts that the TSM depreciation factors should be used. *Williams Alaska Petroleum Inc.'s Post-hearing Reply Brief*, filed August 1, 2001, at 5, 16-18; *Public Advocacy Section Initial Post-Hearing Brief*, at 9. They argue we should use the depreciation underlying historical filed rates. We agree with Williams, Tesoro and PAS. *See* Parts III, C.2, IV, C.2 and VI B.3.

[48]We did not direct that benchmark rates be calculated. In *Re Amerada Hess Pipeline Corporation*, we instructed the Carriers that, although we believe the most useful and reliable point for rate regulation inquiry is costs, no single method need be followed. *Re Amerada Hess Pipeline Corp.,* Order P-97-4(79) at 8 (April 10, 2000). 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 Intrastate Settlement Agreement had not been accepted." *Re Amerada Hess Pipeline Corp.*, 13 APUC 448, 456 (1993) (e*mphasis added)* and n.28. We explained that determining whether rates are just and reasonable begins with costs. *Re Amerada Hess Pipeline Corp.*, Order P-97-4(79) at 9, 11 (April 10, 2000). Non-cost factors may be considered if specifically justified. *Id.*, at 10.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

the appropriate accumulated depreciation and rates of return that should be used to calculate the TAPS year-end 1996 rate base.

a) <u>A Depreciation Schedule for the TAPS Rate Base Has Never Been Approved</u>

The amount of accumulated depreciation by year-end 1996 affects the rate base and resulting rates. Carriers urge that we calculate the amount of accumulated depreciation at year-end 1996 using a straight-line approach. By doing so, the Carriers conclude that accumulated depreciation is $4.982 billion by year-end 1996.[49]

Past rates for TAPS, however, have been calculated using the TSM accelerated depreciation schedule, not a straight-line depreciation schedule. TSM uses an accelerated depreciation schedule that allows expedited recovery of the Carriers' capital investment.[50] Thus, the depreciation amount charged annually in rates was much larger in the early years of TAPS operation than in later years.

To evaluate the 1997-2000 filed rates, Williams argues that accumulated depreciation through year-end 1996 should reflect the past depreciation *factors*[51] used to set tariffs and collect rates under TSM, and that doing so results in accumulated depreciation of $9.2 billion by year-end 1996.[52] Tesoro[53] and the PAS[54] urge that accumulated depreciation should reflect the actual TSM annual *charges* included in rates, and that the total is $8.1 billion by year-end 1996.

---

[49]143-RGV-C, Workpaper TAPS-RGV WP3.xls, Schedule 5, Line 9.

[50]BWF-4 at 31.

[51]TSM sets depreciation *factors* for each Carrier that are used to calculate annual depreciation charges.

[52]189A-BEW-T, Schedule 2, Line 2.

[53]JFB 1 Schedule B.

[54]RAF-4, Schedule 1, Column 3.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Depreciation schedules are established for a variety of purposes. The Federal Energy Regulatory Commission (FERC) generally requires Carriers to use straight-line depreciation when filing FERC Form 6.[55] The Form 6 filings allow FERC to compare pipeline costs.[56] For tax purposes, entities often choose accelerated depreciation.

Regulatory bodies establish a depreciation schedule for ratemaking. The depreciation schedule determines the amount of annual depreciation allowed in the revenue requirement, thereby providing carriers an opportunity to recover their investment over time. In this case, because a depreciation schedule for TAPS has never been approved, we determine both the historical depreciation charges through year-end 1996 and the current depreciation charges for 1997-2000.

The Settlement sets a depreciation schedule. By accepting the Settlement for post-July 11, 1986 rates, the Commission did not find that the TSM depreciation schedule produced just and reasonable rates.[57] The parties contest whether the annual TSM depreciation schedule gave the Carriers adequate opportunity to recover their investment.

Carriers contend that if we adopt TSM depreciation[58] to calculate past recovery of investment they will be deprived of the opportunity to recover their investment.[59] To set cost-based rates we must use a depreciation schedule that provides Carriers with the opportunity to recover their investment from 1997 through

---

[55]Tr. 3147 (RGV); Tr. 4865 (KAW).

[56]*See* Tr. 2386-87 (LPS);Tr. 2411-12 (LPS).

[57]*Re Amerada Hess*, 13 APUC 448 (1993).

[58]*See* Part III,C.2. for an analysis of the Carriers' choice of straight-line depreciation.

[59]T-6 (WBT) 26.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

2000, yet does not require shippers to pay costs twice.[60] We determine the appropriate accumulated depreciation and the future annual deprecation schedule in Part IV Section C.2 and Part VI Section B.3, *infra*.

b) The Rate of Return Should Be Based on the Return Required by a Stand-alone Pipeline

The rate of return compensates investors for the use of their capital. As with depreciation, we determine not just rate of return for the years with disputed rates but also rate of return for previous years. The appropriate rate of return determines the size of allowance for funds used during construction (AFUDC), an important component of rate base. Regulators use AFUDC to compensate pipeline owners for construction costs. The capital costs incurred during construction are not includable in the rate base until those costs can be linked to an asset that is used and useful in providing service. Carriers account for construction costs and add the cost of financing the capital investment during construction. This total AFUDC is added to the rate base when the asset goes into service.

Because the financing costs are included in AFUDC, a larger rate of return results in a larger AFUDC balance and a smaller rate of return results in a smaller AFUDC balance. Carriers suggest that starting AFUDC balances in 1977 were \$2.562 billion;[61] Williams suggests that starting AFUDC balances in 1977 were \$2.006 billion;[62] Tesoro suggests that AFUDC in 1977 was \$1.246 billion.[63]

[60] *Re Cook* Inlet *Pipe Line Co.*, 2001 WL 1850233 (RCA Oct. 29, 2001).

[61] 143-RGV-C. Workpaper TAPS RGV-WP3.xls, Schedule 4, ll. 6, 9.

[62] 189A-BEW-T Workpaper BEW_R_RGV WP! DR 22RE.xls, Schedule 4 ll. 7, 11.

[63] 225-JFB-T, Workpaper 2 JFB-1 page 1 l. 4.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

In this case, determining the appropriate rate of return is complicated in two ways. First, it is highly unusual to determine an appropriate rate of return for years before rates are at issue. The rate of return is generally determined prospectively. The compensation that investors require for the risks to which they expose their capital is based on investors' prospective reading of those risks. In this case, the rate of return in distant *past* years must be determined from the vantage point of investors' prospective expectations at that time. The parties approach this task by using their analyses of 1997-2000 rates of return to backcast[64] the cost of capital in prior years.

Second, to determine rate of return we must consider the business and financial structure of the TAPS for ratemaking purposes. We must decide whether to treat the TAPS as a separate entity or as an amalgam of its owners. TAPS is still owned by seven individual pipeline companies; six are subsidiaries of North Slope producers. The TAPS does not exist as a separate entity in which investors actually can invest. Instead, each share of TAPS is generally owned by producer parent companies. The parent companies are generally large integrated petroleum companies. The risks faced by integrated petroleum companies do not reflect the risks for which a pipeline company would need to be compensated.

The parties agree that the rate of return allowed in rates should be based on the business risk of TAPS.[65] As one witness explained:

> [W]e're trying to determine what business risks are associated with that stand-alone enterprise so that we can compensate investors and ask rate payers to pay a rate of return which is commensurate with that risk and not other risks.[66]

---

[64]The word "backcast" is the opposite of "forecast"; it is used to describe the method of extrapolating results from the current period to earlier periods.

[65]T-3 (WBT), p. 60; Tr. 2743 (WBT); FJH-T (E-2) at 18; WBT-59.

[66]Tr. 2937 (WBT).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

This is consistent with controlling legal authority on TAPS. In response to an appeal from Alaska Pipeline Commission's (APC) 1983 decision setting the first tariff for intrastate transportation of oil on the TAPS, the Alaska superior court reversed a contrary APC finding and described the TAPS as follows:

> TAPS is, in fact, a single pipeline and not eight individual pipelines of varying capacities. There is no basis for taking the capitalization of eight oil companies who are the owners or parent companies of the owners and imputing their individual capitalization to TAPS. The pipeline should have been considered to be an entity and capitalization, costs, rates of return on both debt and equity capital, and other financial information should have been imputed to it.[67]

Although the superior court's decision was vacated by the Alaska Supreme Court[68] because the parties settled their appeal, the Alaska superior court's description of the TAPS is still relevant. It suggests that we should view the TAPS as a single, stand-alone enterprise.

A "stand-alone" enterprise is one that can attract capital on its own. It provides a good lens for determining what investors would require for a return in light of TAPS' business risks. We prefer the stand-alone model because it is more likely to reflect the reasonable costs of capital. We do not use the actual cost of capital used to finance the TAPS construction because it is complicated by financial arrangements between parents and subsidiaries that make it difficult to determine the prudent cost of capital for a stand-alone TAPS. For example, if a carrier were to choose an unwise method of financing, its costs would be unreasonably high. As regulators we do not

---

[67]*State of* Alaska *v. Alaska Public Utilities Comm'n*, 3AN 80-7163 CI (Alaska Super.) Nov. 28, 1983.

[68]*Amerada Hess Pipeline Corp. v. Alaska Public Utilities Comm'n*, No. S-195, slip op. (Alaska Nov. 20, 1985).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

allow recovery of imprudent costs.[69] Accordingly, we determine rate of return based on the cost of capital of a "stand alone" TAPS.

The return demanded by a stand-alone TAPS consists of the weighted average of the cost of debt and the return on equity. The relative weights are determined by the relative amounts of capital used to finance debt and equity. The relative amounts of debt and equity are known as the capital structure.

To determine what portion of return compensates for the cost of debt and what portion provides for return on equity, we rely either on the regulated entity's actual capital structure or choose a hypothetical capital structure if the actual capital structure is inappropriate. Consistent with the need to determine rate of return based on a stand-alone model, we determine the capital structure for TAPS based on a stand-alone model.[70]

5. Does a Change in Ratemaking Methodology in the Middle of the Operating Life of the Pipeline Result in a Return Deficiency?

Because we are applying a ratemaking methodology in the middle of the operating life of TAPS that is different than TSM, we must confirm that the year-end 1996 rate base so calculated is reasonable and will not deprive the Carriers of the opportunity to earn a reasonable return. The Carriers,[71] perform an unrecovered investment analysis to verify that their proposed rate bases are reasonable. Tesoro and Williams perform an unrecovered investment analysis to show that the Carriers' benchmark rate base is unreasonable and that investment has been mostly recovered.

[69]*Re Cook Inlet Pipe Line* Company, 2001 WL 1850233 (RCA Oct. 29, 2001).

[70]Using a stand-alone model is consistent with the Alaska Superior Court holding in *State of Alaska v.* Alaska *Public Utilities Comm'n*, 3AN 80-7163 CI, (the APC erred in setting rates based on a model that reflects the capitalization and capital costs of the multiple owners of TAPS).

[71]RGV-15.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

We analyze and reject the unrecovered investment analyses because they are unreliable. In some situations they may also violate the rule against retroactive ratemaking.[72]

Instead, we use the annual comparative revenue requirement analysis described in *Kenai*[73] to confirm that the year-end 1996 DOC rate base calculated in the middle of the operating life of the pipeline is reasonable. In *Kenai*, the APUC held that a new rate base established midstream may be adjusted if a regulatorily enforced return deficiency results from a switch in ratemaking methodology. The APUC explained

> The Commission does not believe that it is legally or constitutionally required to recognize such a return deficiency. However, if one were demonstrated, then the Commission would consider whether, in fairness, an adjustment ought to be made for it.[74]

Neither this Commission, nor our predecessor agencies, the APUC and the APC, have ordered a rate base adjustment for this reason. However, if the Carriers are denied an opportunity to recover and earn a reasonable return on their investment due to a switch in ratemaking methodology an adjustment may be appropriate.[75]

A regulatory agency must provide an opportunity to earn a return;[76] but, it does not guarantee a return. In this case, the Carriers negotiated a future opportunity to earn a return when they entered into the Settlement. They assumed the risk that at some time during the life of the Intrastate TAPS Settlement Agreement a shipper might

---

[72]*See* Endnote 6 for a discussion of retroactive ratemaking.

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

[74]*Id.*, at 439.

[75]*Id.,* at 438. Similarly, if through past rates carriers have enjoyed excessive opportunity to recover costs, a downward adjustment to rate base may be appropriate. *See* T-10 (WBT), 84:3-14; *Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 18.

[76]*Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

protest and a commission would determine that rates filed pursuant to the Settlement are not just and reasonable. The Carriers were never guaranteed their *future* negotiated returns.[77]

The year-end 1996 rate base should provide an opportunity to earn a reasonable return but need not guarantee the future negotiated return allowed in the Settlement. We, therefore, compare TSM's annual revenue requirements with cost-based DOC revenue requirements to ensure that the Carriers will not be denied an opportunity to recover their costs. By doing so we verify that the rate base we calculate for year-end 1996 does not result in the Carriers losing their opportunity to earn a return.

III. THE CARRIERS FAIL TO SHOW THAT FILED RATES ARE JUST AND REASONABLE

In a typical rate case, the regulated entity proposes a rate base and we determine whether the proposed rate base is correct for ratemaking purposes. We also review the other elements of the proposed ratemaking methodology to determine whether they are reasonable.

The Carriers present an unconventional case. They compute two different rate bases, one in the benchmark analysis and one in their unrecovered investment analysis. They do not support either as the rate base that we should adopt for ratemaking purposes.[78] Further, they do not propose that the labeled components of

[77]When the APUC considered the Settlement in 1987, it indicated that when rates filed pursuant to the Settlement are challenged, the Commission will determine whether those rates are just and reasonable and if not, will calculate just and reasonable rates. *See Re Amerada Hess Pipeline Corp.*, 8 APUC 168, 169 (1987). Therefore, the Carriers were on notice that the APUC acceptance of the Settlement did not guarantee the return contemplated in the Settlement.

[78]Tr.1726-27 (ABJ); Tr. 1846 (ABJ); Tr. 3324 (RGV).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

"rate base" in the TSM model be adopted as a DOC rate base for TAPS. They claim that they cannot file a typical rate case because the filed rates are not determined by a conventional rate base rate of return methodology. They assert that the building blocks of the TSM filed rates cannot be converted directly into standard ratemaking elements.[79]

Instead, the Carriers make three arguments in support of filed rates. In Section A below, we address the Carriers' argument that over the life of the line TSM rates are just and reasonable and therefore are just and reasonable for 1997 through 2000. In Section B we address the argument that the filed rates are just and reasonable based on public policy grounds.[80] In Section C we address the argument that if filed rates are below benchmark rates then filed rates are just and reasonable.

A. <u>The Carriers Fail to Prove That TSM Rates Are Just and Reasonable Over the Life of the Line</u>

The Carriers suggest we should determine whether the filed rates are just and reasonable by calculating an internal rate of return (IRR) on their investment in TAPS and comparing that IRR to the average required rate of return over the life of the line.[81] If the IRR does not exceed the required rate of return on capital at the time of settlement, the Carriers assert that the rates in all years must be just and reasonable.

In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(79), dated April 10, 2000, we assumed for the purposes of argument that the Carriers had shown that TSM rates were just and reasonable over the life of the line. We found that, even if the Carriers proved that rates were just and reasonable over the life of the line, that proof is not sufficient under AS 42.06 to establish that rates in any particular year were just and

---

[79]*See* T-5 (ABJ) 24.

[80]The State also asserts that filed rates are just and reasonable based on public policy grounds. *State of Alaska's Prehearing Brief*, filed April 5, 2001, at 7; *State of Alaska's Initial Post-hearing Brief* at 2, filed July 16, 2001.

[81]T-1 (ABJ) 15.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

reasonable. We instructed the Carriers to submit proof that each of the filed rates at issue in this proceeding was just and reasonable for the year in which it was filed.[82] The Carriers subsequently submitted evidence relating to individual years, as instructed, but continue to assert that the filed rates are just and reasonable because the IRR they calculate under TSM is no higher than the rate of return required at the time of the Settlement.

The Carriers calculate IRRs for each of three different sets of data, performing two separate IRRs for each set of data.[83] The IRR on a project varies depending upon whether and to what extent the investor can utilize tax benefits generated by interest deductions associated with the investment. The Carriers calculate one IRR on each set of data assuming no tax benefit from interest deductions and another assuming full tax benefit.[84] All three sets of data yield IRRs that are in the low range or are lower than the required overall rates of return recommended by the Carriers' rate of return witness.[85]

The use of IRRs in a ratemaking context is novel. Businesses use IRRs to analyze current investments or investment opportunities. To calculate an IRR, a business must project expected future cash flows of the project being analyzed. An IRR requires speculative assumptions about future data. Large differences in the amount of future cash flows make little difference in an IRR because future cash flow amounts

---

[82]*Re Amerada Hess Pipeline Corp.*, Order P-97-4(79), dated April 10, 2000 (Order 79) at 11, 15.

[83]*See* ABJ-3. The three sets of data reflect different assumptions about TAPS throughput.

[84]T-1(ABJ) 19.

[85]T-1 (ABJ) 21.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

may be heavily discounted. Mathematically, the further into the future a difference in cash flow occurs, the less impact that difference has on the IRR.

We find the IRR analysis is an unreliable tool in this case for determining if rates are just and reasonable. The Carriers' IRR analysis is based on speculative assumptions about future throughput, operating expenses and capital costs. Even if an IRR analysis was appropriate, when we compare the overall rates of return found reasonable in this order[86] to the Carriers' IRRs, the Carriers' IRRs on all three sets of data are significantly in excess of appropriate rate of return during the settlement period.[87]

B. <u>The Carriers' and the State's Public Policy Arguments Are Insufficient to Approve Filed Rates</u>

The Carriers and the State make a public policy argument that the Settlement is in the best long-term interests of Alaska. They argue that TSM provides a declining tariff profile, rate stability and avoids expensive, repetitive rate litigation. Further, the State claims that TSM's net carryover provision reduces Carrier incentive to "game" the normal rate-setting process, i.e., it reduces carrier incentive to inflate test-year costs above those likely to prevail in future years. TSM also allows the State to annually review and audit tariffs before rates are filed. Finally, the State suggests that the Settlement encourages development on the State's oil-bearing lands, and positively

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

---

[86]*See* Exhibit 2 for summary of appropriate rates of return for 1977-1996; these findings are made in Part IV Section B.

[87]The Carriers' numerical case regarding appropriate rates of return for 1968-1998 did not change between their first and second prefiled cases. *See* T-3 (WBT) and T-6 (WBT).

affects State revenues. The State concludes that these public policy benefits are so great that we should not invalidate or modify the Settlement.[88] The Carriers concur.[89]

The Settlement does not set rates.[90] Instead, the Settlement requires the Carriers to file rates at or below a ceiling. It also prevents the State from protesting any rate so filed.[91] The terms of the Settlement do not provide that the Settlement is voided if we set just and reasonable rates below the TSM maximum ceiling rates. The results in this case therefore do not invalidate or modify the Settlement.[92] AS 42.06 requires that we consider whether filed rates are just and reasonable The settling parties nonetheless may choose to modify the terms of the Settlement as the result of this order in this case, but our order regarding whether the 1997-2000 filed rates are just and reasonable does not require them to do so.

The State and the Carriers assert that if we find 1997-2000 filed rates do not satisfy AS 42.06 we will create a chilling effect on future settlements. We disagree. The parties to the Settlement have been on notice that the APUC conditioned its acceptance of the Settlement on allowing nonsettling parties to protest rates in the future. The APUC cautioned that rates set by TSM were "subject to the same standards and procedures to which [rates] would have been subject if the Intrastate Settlement Agreement had not been accepted."[93] We must decide whether filed rates are just and

[88]*State of Alaska's Prehearing Brief* at 7, filed April 5, 2001.

[89]*TAPS Carriers' Covering Brief*, October 8, 1998, at 2, 12, 13.

[90]*State of Alaska's Initial Post-hearing Brief* at 2, filed July 16, 2001.

[91]BWF-2, Sections I-3 and I-4(c); *State of Alaska's Initial Post-hearing Brief* at 3.

[92]Professor Jaffe testified that a commission ordered rate reduction based on a finding that TSM rates exceeded cost-based rates would not be inconsistent with the Settlement. Tr. 1643-1644 (ABJ).

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

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

reasonable when a third party challenges rates.[94] The Carriers and the State therefore cannot now and could not at the time of settlement reasonably expect that rates calculated under the Settlement will always be accepted without review.

We recognize that when parties enter into rate settlements they have hopes of future revenue opportunities and tariff limitations. However, the role of regulating agencies is not to guarantee any particular revenue opportunity or rate. In the regulatory arena, settlements are always at some risk because at any time they may be subject to a test of whether they satisfy AS 42.06. If we are unwilling to review rates when challenged, we abdicate our responsibility under the Alaska Pipeline Act to ensure that rates are just and reasonable.[95] In the context of rate regulation, settlements are always subject to future challenge by third parties. We therefore find that our review of rates in this case does not produce any special chilling effect.

The State and Carriers also assert that the Settlement provides a declining tariff profile, rate stability, and avoids expensive, repetitive rate litigation. We agree that tariffs should be appropriate and the cost of maintaining such rates

[94]AS 42.06.

[95]Settlements regarding future regulated rates are different from settlements that involve past unregulated behavior. In the regulation arena, future intrastate rates are subject to AS 42.06. Therefore, settling parties in the regulatory arena are always at risk that settlement-produced rates can be challenged and found to violate AS 42.06.

Settlements, however, can be drafted to provide some certainty regarding future rates. For example, in approving the Cook Inlet Pipe Line Company settlement, we required as a condition of approval that the parties stipulate that the depreciation component of the settlement would be "used for ratemaking purposes for [Cook Inlet Pipe Line Company], so long as [it] continues to be regulated under a depreciated original cost methodology." Doing so "allows us to keep track of investment recovery and removes a number of potentially troublesome issues from a future rate case, in the unlikely event one should occur." *Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 at 3 (RCA Oct. 29, 2001). This type of condition for approving a settlement may constrain the negotiable elements of a settlement, but it also provides certainty about the reliability of certain settlement elements in the event of a challenge that filed rates do not satisfy AS 42.06.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

reasonable. Although settlement can accomplish these goals, the 1997-2000 intrastate rates produced by the Settlement do not. Rate case costs are a necessary part of regulation and are appropriate to confirm that rates are just and reasonable. This case resulted in extraordinary expenses because no regulatory agency has determined the appropriate methodology and inputs for calculating rates for this pipeline. The result of this order should be stable rates and lower litigation expenses in the future. We agree with Tesoro witness Williams who testified:

> In my view, when a regulatory agency, this Commission or any commission, clearly delineates what its standards are and what it's procedures are, and what its approach is for developing rates, once that occurs, the parties understand that's -- those are the criteria, those are the approach, that generally greatly reduces the amount of litigation. It's only uncertainty that encourages litigation.[96]

Finally, the State and Carriers allege that if we find filed intrastate rates not just and reasonable and order intrastate rates that differ from interstate rates, then state royalties, tax revenues, bidding, exploration, and development of State oil-bearing lands will be negatively affected.[97] We find that these contentions are not adequately supported.

The ultimate effect of intrastate TAPS tariffs on the State's revenue position is not as transparent as the State and the Carriers indicate. We agree with PAS witness Fineberg who testified:

> The fact that the State gave up any potential State revenue gains from reduced TAPS tariffs in intrastate commerce in the settlement that established TSM does not diminish or dismiss this Commission's responsibility to protect shippers within its jurisdiction by assuring just and reasonable intra-state tariffs.[98]

---

[96]Tr. 4915 (KAW).

[97]*State of Alaska's Initial Post-hearing Brief,* July 16, 2001, at 4-6, 11; *State of Alaska's Post Hearing Reply* Brief, 22-25, 31-32; *TAPS Carriers' Covering Brief,* October 8, 1998 at 2, 12, 13.

[98]P-1 (RAF) 8.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

We must consider both the immediate and long-term consequences for setting intrastate rates that are based on costs and may differ from interstate rates.[99] We must strike a fair balance between the financial interests of the regulated company and the relevant public interests, both existing and foreseeable.[100]

The Interstate TAPS Settlement Agreement has a net crediting provision regarding intrastate TAPS revenues. If intrastate revenues decrease, then the TSM interstate revenue requirement *may* increase.[101] The Carriers may choose to take advantage of this crediting provision in setting interstate rates. Given the terms of the State's royalty agreements with producers, the value of North Slope oil and hence State royalty payments will decline with an increase in interstate TAPS tariffs.[102] The PAS suggests that revenues to the State from 1997 through 2000 would decrease by no more than $10 million per year.[103]

However, although the Carriers may apply revenue "shortfalls" from intrastate to interstate tariffs, nothing in the Interstate Settlement Agreement requires them to do so. If the Carriers take advantage of the Settlement's crediting provision, future interstate tariffs for the same transportation service will rise above the cost-based intrastate rates that we determine in this order to be just and reasonable. Although the

---

[99]In addition to the public policy arguments the Carriers assert that an interstate shipper could file an Interstate Commerce Act Section 13(4) claim with the Federal Energy Regulatory Commission if interstate rates to Valdez, Alaska are different than intrastate rates to the same destination. The Alaska Supreme Court has already rejected this contention. *Cook Inlet Pipe Line Co. v. Alaska Pub. Util. Comm'n,* 836 P.2d 343, 351-53 (Alaska, 1992) *citing Simpson v. Shepard*, 230 U.S. 352, 417, 33 S.Ct. 729, 748 (1913). For a more complete discussion *see* Endnote 7.

[100]*In re Permian Basin Area Rate Cases,* 390 U.S. 747, 797 (1968).

[101]Tr. 3855 (WDVD); *State of Alaska's Initial Post-hearing Brief* at 11, filed July 16, 2001; 258-RAF-S.

[102] S-1 (WDVD) 3-4.

[103]Tr. 5623 (RAF).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Carriers certainly have incentive to raise rates, they also have an incentive to treat the State and intrastate shippers fairly.

From a long-term perspective, the effect on State revenues of setting cost-based intrastate rates is likely to be beneficial. First, in light of this order, an independent interstate shipper may protest interstate TAPS rates. If such a protest were successful, the State's royalty and severance tax position will improve. Second, even if a protest of interstate rates were not made or was not successful, lower intrastate tariffs provide increased incentives for exploration[104] and in-state downstream processing. Were this to occur the State's revenue and resource development position would improve.[105]

The State nonetheless asserts that establishing intrastate rates that are different from interstate rates will have a detrimental effect on bidding, exploration and development of State oil-bearing lands. That assertion is not supported by the record. As noted above, near-term royalties will be lost to the State only if Carriers take advantage of the crediting provision. If the Carriers do not take advantage of the crediting provision, the lower royalties to the State would then provide an exploration incentive and an economic incentive for bidding, exploration and development of oil-bearing lands. Therefore, the State's argument that our finding intrastate rates different from interstate rates is harmful to the State is not persuasive.

The United States Supreme Court has held that a regulatory commission is "obliged at each step of its regulating process to assess the requirements of broad public interests." [106] Non-cost factors may legitimize a departure from a rigid cost-based

[104]Tr. 3881 (WDVD).

[105]Tr. 5598 (RAF).

[106]*In re Permian Basin Area Rate Cases*. 390 U.S. 747, 790 (1968).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

approach.[107] The mere invocation of them however is not sufficient.[108] Each non-cost factor must be made to justify the resulting rate for the specific years in question.[109]

Further, the United States Supreme Court decision in *F.E.R.C. v. Pennzoil Producing Company*[110] held that rates must lie within a zone of reasonableness. That zone is found by striking a balance between the financial interests of the regulated company and the relevant interests both existing and foreseeable.[111] As shown in Exhibit 1, Schedule 3 the 1997-2000 filed rates exceed cost-based rates by an average of 57 percent, with the excess ranging from 19 to 88 percent. This range is in such excess of cost-based rates that the rates are driven outside the zone of reasonableness even when considering non-cost factors.

In *Farmers Union* the D.C. Circuit required a reasoned explanation of non-cost factors to justify the resulting rates.[112] As Tesoro has noted, in the past commissions have made only small adjustments to cost-based rates to accommodate non-cost based factors and never in petroleum or petroleum product pipelines.[113] Although the Carriers and State have provided some rationale for including non-cost factors, they have failed to provide sufficient justification for rates exceeding costs by 19 to 88 percent. These percentages are outside the zone of reasonable and fail the basic

[107]439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979); *Mobil Oil Corp. v. Federal Power Comm'n*, 417 U.S. 283, 305-06, 316, 5 P.U.R.4th 1, 94 S.Ct. 2328 (U.S.La., 1974).

[108]*Id.*

[109]*See Farmers Union Cent. Exchange, Inc. v. F.E.R.C.,* 734 F.2d 1486, 1502-03, 1530 (D.C. Cir., 1984).

[110]*F.E.R.C. v. Pennzoil Producing Co.,* 439 U.S. 508, 517, 27 P.U.R.4th 473, 99 S.Ct. 765 (U.S.Tex., 1979); *In re Permian Basin Area Rate Cases,* 390 U.S. at 797.

[111]*Re Permian Basin,* 390 U.S. at 797.

[112]*Farmers Union Cent. Exchange, Inc. v. F.E.R.C.,* 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[113]*Tesoro Alaska Company's Initial Posthearing Brief* at 34-36.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

test of *Farmers Union*, which does not permit profits that are "too huge to be reconcilable with the legislative command" to produce just and reasonable rates.[114]

C. <u>The Carriers' Benchmark Analysis Fails to Satisfy the Burden of Proof for Two Reasons</u>

We turn to the Carriers' final argument that filed rates must be just and reasonable because they are lower then benchmark rates calculated using a DOC methodology consistently applied from the beginning of pipeline operations. That analysis fails to satisfy AS 42.06. The Carriers' benchmark analysis is neither reasonable nor legally sufficient, and even if it were, the factual inputs the Carriers choose for the benchmark rate base are untenable. Moreover, the unrecovered investment analysis presented as a check on the reasonableness of the benchmark rate base is unreliable.

1. *<u>A Benchmark Analysis Is Neither Reasonable Nor Legally Sufficient</u>*

The Carriers' benchmark analysis presumes that rates falling below a specified benchmark are necessarily just and reasonable. AS 42.06.370 requires that we find that rates are just and reasonable, not simply that they are below a just and reasonable threshold. The proposition that if filed rates are below a benchmark they are necessarily just and reasonable may not always be true. The goal of regulation is to balance the needs of both carrier and shipper. To do so requires that we establish, to the best of our ability, based on the record before us, rates that achieve that balance. If we endorse rates because they fall below a ceiling of reasonable rates, then carriers may not receive the return that they are due. Rates would then be confiscatory and not just and reasonable.

[114]*Farmer's Union*, 734 F.2d 1486, 1502-1503, quoting *Pub. Serv. Comm'n v. F.E.R.C.*, 589 F.2d 542, 550 (D.C. Cir., 1978).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

The D.C. Circuit Court of Appeals explained to the FERC quite clearly that approving rates that fall below a cap is not an acceptable way to set just and reasonable rates. The D.C. Court stated that setting a ceiling in that case only served as a cap on egregious price exploitation by regulated pipelines; it did not properly set just and reasonable rates.[115]

This same rationale applies to the Carriers' use of a benchmark to determine whether the filed rates in this case are just and reasonable. When faced with a protest, we are obligated under AS 42.06.370 to determine whether filed rates are just and reasonable, not just whether they fall below a benchmark.

2. <u>*The Carriers' Benchmark and Unrecovered Investment Analyses Are Unreasonable Because the Depreciation Schedule Used Is Unreasonable*</u>

The TAPS Carriers assert that we should use a benchmark to assess the justness and reasonableness of 1997-2000 rates. The Carriers calculate benchmark rates and the year-end 1996 rate base by applying a straight-line depreciation schedule from the beginning of TAPS operations.[116] They suggest that both economic reality[117] and Commission precedent[118] require adopting a straight-line schedule. Williams,[119] Tesoro,[120] and the PAS[121] assert instead that the TSM's depreciation schedule or TSM

[115] *Farmers Union Cent. Exchange, Inc. v. F.E.R.C.*, 734 F.2d 1486, 1502 (D.C. Cir., 1984).

[116] *Post-Hearing Reply Brief of the Indicated Taps Carriers* at 13.

[117] *See* T-9 (ABJ) 22; *Initial Post-hearing Brief of the Indicated TAPS Carriers*, at 4-5, 14, 40-41.

[118] *Initial Post-hearing Brief of the Indicated TAPS Carriers,* at 9.

[119] 189-A-BEW-T. *See also Williams Alaska Petroleum Inc.'s Post-Hearing Initial Brief* at 11.

[120] *Tesoro Alaska Company's Initial Posthearing Brief* at 28-29.

[121] *Public Advocacy Section Initial Post-hearing Brief* at 9

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

depreciation factors should be used to establish the rate base for 1997-2000. They cite both economic arguments [122] and legal precedent[123] to support this position.

The correct depreciation schedule is critical for deciding whether 1997-2000 TAPS tariffs are just and reasonable. The Carriers' proposed straight-line schedule applied from 1977-1996 suggests that roughly 46 percent of the Carriers' initial investment in TAPS remains unrecovered.[124] The TSM depreciation schedule, applied from 1977-1996, suggests that roughly 3 percent of the Carriers' initial investment remains to be recovered.[125] These different depreciation schedules imply vast differences in remaining unrecovered investment, and thus in rate base. If the Carriers' choice of all other inputs into the benchmark DOC were appropriate for 1997-2000 but TSM depreciation charges are used, then filed rates fail the Carriers' benchmark test.[126] Conversely if protestants' choices of all other inputs into their respective benchmark DOCs were appropriate for 1997-2000, but straight-line depreciation charges are used, then the filed rates may pass the Carriers' benchmark

[122]BEW-T (W-3) 12; JFB-T, 45; *see Tesoro Alaska Company's Initial Posthearing Brief* at 19.

[123]Tr. 4910 (KAW).

[124]This figure assumes that the TAPS has an economic life of 34.5 years.

[125]Figure is derived from TSM depreciation factors contained in 29 ABJ-W. 29 ABJ-W Exhibit Alaska __(TOH-1) shows that the TSM depreciation schedule would result in over 90 percent recovery of the Carriers' initial TAPS investment by 1990.

[126]*See* Exhibit 3, Schedule 1.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

test.[127] Thus, the choice of depreciation schedule is critical to the evaluation of filed rates.[128]

We must use a depreciation schedule that when applied from 1977 through 1996 both provides the Carriers with an opportunity to recover their capital investment and also does not force shippers to pay for that investment twice.[129] We find that the depreciation schedule that has actually been used, i.e., the TSM depreciation schedule -- best meets these twin objectives.[130] Below, we address economic and then regulatory arguments about which depreciation schedule is appropriate for determining year-end 1996 rate base.

a) The Carriers' Economic Arguments For Using Straight-line Depreciation Are Unpersuasive

As the Carriers note, a depreciation schedule "can be viewed as 'neutral' in terms of [its] impact on rates overall. This is because [it] affect[s] the timing and not the ultimate value of the rates."[131] Nonetheless, the Carriers assert that using TSM

[127]T-9 (ABJ) 16; T-10 (WBT) 6-7.

[128]The appropriate choice of depreciation schedule, however, is not necessarily determinative of whether filed rates are just and reasonable. A comparative revenue requirement analysis as directed by *Kenai* shows that even if we assume straight-line depreciation the Carriers have had ample opportunity to recover their investment. *Re Kenai Pipe Line Co.*, 12 APUC 425, 440, 1992 WL 696192 (Alaska P.U.C., 1992). *See* n.550 and Exhibit 4, Schedule 1, lines 9-10 for 1996.

[129]*Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001). We are restricted to looking only at the opportunity that the Carriers have had to recover, not what they actually recovered. To look at what they actually recovered may violate the rule against retroactive ratemaking. *See* Endnote 6. We note, however, that in this case because of TSM's true-up mechanism the Carriers' have actually recovered what they had the opportunity to recover. *See* Endnote 3 for an explanation of TSM's true-up mechanism.

[130]We find that the 1997-2000 filed rates are not just and reasonable even when measured against benchmark rates calculated using all of the Carriers' inputs except straight-line depreciation. *See* Exhibit 3, Schedule 1.

[131]T-9 (ABJ) 32.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

depreciation to establish rate base would deny them an opportunity to recover their costs. The Carriers' argument turns on whether TSM's revenue requirement has historically been insufficient to cover TSM's stated amounts of "depreciation" while also giving the Carriers a fair opportunity to earn their contemporaneous required return.[132] If TSM generated inadequate allowed rates of return, then TSM's depreciation schedule should arguably not be used in isolation to determine year-end 1996 rate base. Doing so might deprive the Carriers of the opportunity to recover their investment. However, if the revenue requirement under TSM provided the Carriers with a fair opportunity to contemporaneously recover their investment according to the TSM depreciation schedule and earn an appropriate return, then it would be inappropriate to use anything other than the TSM's depreciation schedule to determine rate base for 1997-2000 rates. Doing otherwise could require shippers to pay for the same costs twice.

When the Settlement Agreement was approved, the Carriers represented that depreciation in TSM was investment recovery. In their 1987 brief to the APUC in support of the Settlement Agreement, the Carriers argued that:

> The so-called factored unit-of-throughput *depreciation* profile is an integral element of the overall settlement arrangement. This mechanism permits the TAPS Carriers to *recover* a major portion of their capital investment in the early years of the pipeline's life, when there is clearly sufficient throughput to support *recovery* of the *depreciation charges*.[133]

Other parties to the Settlement Agreement also suggested that the "depreciation" term within TSM was intended for investment recovery. The United States Department of Justice and the State, in support of the Settlement, explained that:

> Four of the eight elements of the Total Revenue Requirement are associated with the *recovery* of a TAPS Carrier's costs: Operating Expenses; the Dismantling, Removal, and Restoration (DR&R) Allowance; *Depreciation*; and the Income Tax Allowance. Two elements, After-Tax

[132] T-6 (WBT) 26.

[133] 7-ABJ-E *(emphasis added)*.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

> Margin and Recovery of Deferred Return, provide for a return on unrecovered capital . . . .[134]

As the PAS urged, "If the amount attributed to a tariff element in the TSM ceiling formula in any given year does not represent the amount for that specific tariff element that can be collected through TSM, what does that number represent and what is it doing in the TSM model?"[135] The plain language of the Settlement suggests that the depreciation schedule in TSM was intended to and has been used to recover investment. We also find based on our review of confidential documents produced during the hearing that the TAPS Carriers themselves viewed TSM depreciation as investment recovery.[136]

There is no reason for us to use the depreciation schedule that might have been adopted had TAPS rates been approved from 1977-1996, rather than the schedule that was used to recover investment. The Carriers must make a persuasive case that the TSM depreciation amounts do *not* represent their opportunity to recover their investment.

(i) <u>The Carriers fail to support the contention that using TSM depreciation charges for calculating rate base is "cherry picking" and denies a reasonable return</u>

The Carriers' use of straight-line depreciation hinges on their contention in this case that the depreciation term within TSM was not really intended to provide the Carriers with an opportunity to recover investment. The Carriers contend that the TSM can be considered only as a package, and that none of its elements has meaning

---

[134]BWF-4 at 27 (*emphasis added*); *see also* 29-ABJ-W at 16, 19, 21.

[135]P-1 (RAF) at 26-27.

[136]*See*, e.g., 110-RGV-E at RTSXPA 221761, RTSXPA 221768; 116-RGV-E, Bates number RTSXBP 325202 and 325203.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

outside the context of the Settlement.[137] They assert that TSM depreciation is not depreciation;[138] it is only one of the many components of TSM. Carriers contend that only the complete *package* of TSM elements, rather than any individual element, provides the Carriers with an opportunity to recover their investment.[139] The Carriers contend that using the TSM depreciation schedule to determine year-end 1996 rate base thus amounts to "cherry picking." We disagree.

"Cherry picking" is choosing what is desirable for a certain outcome and leaving the undesirable elements. Our role is to choose the most appropriate depreciation schedule based on the record before us.[140] There is no dispute in the record about the amount of depreciation that has been charged for the last twenty years under the rates calculated using TSM. Principles of equity and fairness require us to base our finding on the amount of depreciation that the shippers have been charged to date when we are determining the year-end 1996 rate base. In setting rates for 1997 through 2000, we must insure that shippers do not pay twice for the same Carrier investment. As the PAS suggested, "It is fundamental that historical depreciation taken

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[137] *Initial Post-hearing Brief of the Indicated TAPS Carriers*, July 16, 2001, at 54; T-9 (ABJ) at 36.

[138] *See* T-5 (ABJ) 24-25.

[139] The Carriers admit that both "operating expenses" (Tr. (BWF) 2154) and "DR&R" (*see Initial Post-hearing Brief of the Indicated TAPS Carriers, dated July 16, 2001,* at 28-29) as used within TSM have their usual meaning. Accordingly, their claim is really that the remaining elements of the "TSM package" must cover return of investment, return on investment, and income taxes.

[140] Carriers' citation to *Lopez v. Public Employees*, 20 P.3d 568 (Alaska 2001), is not on point. It addresses the probative value of settlements. The court in *Lopez* held that it was not error for the Public Employees Retirement Board to exclude evidence of a settlement agreement from the record. The plaintiff sought to introduce it as evidence of an admission by the defendant and the Board properly excluded it as hearsay. There are no allegations in this case that the Intrastate Settlement Agreement is hearsay.

by the Carriers to justify tariffs actually collected since the beginning of the pipeline be used in the rates for 1997-2000 no matter what methodology is used."[141]

The Carriers suggest not only that the Settlement must be allowed to continue through 2011 to receive the benefit of their bargain but also that the Settlement fails to fully compensate the Carriers for costs.[142] The Carriers assert that if the TSM depreciation schedule is used in a consistent DOC to set year-end 1996 rate base,[143] then they will be deprived of an opportunity to recover capital costs (which include both return on and of capital investment). The Carriers point out that through 1989, the Original Rate Base portion of TSM earned a 6.4 percent *real* return; New Rate Base continues to earn this 6.4 percent real return.[144] This figure, the Carriers suggest, is far too low given the risks associated with TAPS.[145] The Carriers contend that TSM was designed to "make up" for this underrecovery in the later years of operation through its Deferred Return and Allowance Per Barrel components.[146] Accordingly, the Carriers assert that the TSM must be allowed to run its course so that they can earn an adequate return on their investment.[147]

---

[141]PAS Initial Post-hearing Brief at 9.

[142]T-9 (ABJ) 57.

[143]The Carriers acknowledge that a DOC may be "consistent" under virtually any depreciation schedule, (Tr. 1670-71 (ABJ), although they generally use the term "consistent DOC" to refer to their DOC methodology that employs straight-line depreciation.

[144]T-6 (WBT) 26. Dr. Haas, testifying for the State of Alaska, urged that due to details in its application the real return was actually only 5.5 percent overall. The Carriers' reliance on the TSM rates of return as a basis for indicating an actual rate of return is inconsistent with their contention that labels within TSM cannot be relied upon to reflect economic reality.

[145]T-6 (WBT) 26-28.

[146]T-5 (ABJ) 40; T-6 (WBT) 26.

[147]*See* T-1.(ABJ) 4; T-5 (ABJ) 41, 43.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Tesoro, Williams and the PAS urge, however, that the rate of return provided by TSM is actually far greater than 6.4 percent.[148] The PAS argues, for example, that because the TSM presumes a 100 percent equity capital structure, while its true equity position has been considerably less, TSM actually generates a rate of return that is far greater than 6.4 percent.[149] Further, Williams, Tesoro, and the PAS all argue that the TSM's allowance per barrel (ABP) generates returns on Original Rate Base that are far in excess of what capital markets require.[150] These parties conclude that no "off book" deferred return is required to compensate the Carriers for "underrecovery" in the early years of operation.

As we note in Part IV Section C.4.f, a 6.4 percent real rate of return would often be inadequate to provide TAPS investors with appropriate compensation for the risk that they incur. However, as we discuss in Part IV Section B.1, a 100 percent equity capital structure is also not appropriate in a ratemaking context in which rates must reflect prudently incurred costs. Those conflicting elements, without further analysis, make the Carriers' actual returns indiscernible. The Carriers have failed to provide direct evidence of what they believe their past return to be.[151] Therefore, we

[148]BEW-44; RAF-3 (Revised); *see* JFB-9, line 12.

[149]The concerns about capital structure are two-fold. On the one hand, the actual fact of debt financing and the tax advantages conferred by debt mean that TSM provides an excessive income tax allowance relative to its putative 6.4 percent return. *See* BEW-44. On the other hand, the PAS contends that providing a deferred return to the inflation component of this return for debt-financed capital is inappropriate. *See* P-1 (RAF) 13-14; RAF-5 (Rev.) Schedule 2.

[150]P-1 (RAF) 14; RAF-3; RAF-4; JFB-2 Schedule F; *Williams Alaska Petroleum Inc.'s Post-hearing Initial Brief* at 27; BEW-34; BEW-44.

[151]Tr. 3493-94 (RGV).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

find the Carriers fail to provide sufficient evidence to support a finding that the TSM depreciation schedule has not allowed a sufficient opportunity for them to recover investment.

To verify that we do not deny the Carriers a fair opportunity to recover their investment, in Part V, *infra*, we compare the Carriers' costs of providing service, as measured by a DOC methodology using TSM depreciation charges, with the TSM's annual revenue requirement. We conclude that the Carriers have had an adequate opportunity to recover their investment and earn an appropriate return. Carriers have had the opportunity to earn $9.9 billion in excess of the reasonable and prudent costs of providing service.

(ii) <u>The Carriers' unrecovered investment analysis fails</u>

The Carriers do not provide evidence of the annual opportunity that TSM has provided for earning a rate of return from 1977-1996. Nor do the Carriers provide evidence of the annual achieved returns under the TSM for 1977-1996.[152] Neither do they suggest what returns will be in future years.[153] Instead, the Carriers present a method for determining their "actual" unrecovered investment to date.[154] They assert that this analysis shows that "actual" unrecovered investment is considerably greater

[152]The Carriers admit that they do not provide evidence on achieved returns under TSM. Tr. 3493-94 (RGV).

[153]The Carriers' assertion that achieved returns during 1977-1981 were too low appears inconsistent with their assertion that the internal rate of return generated by the TAPS is relatively insensitive to deviations in throughput from levels expected at the time of the Settlement (ABJ-3), even though from 1990 through 2000 these throughput differences provided Carriers with $760,487 million (nominal dollars) more than anticipated. *See* RAF-6 (Rev.). On its face, this suggests that revenue streams before 1990 are more important to providing the Carriers an adequate return than revenue streams in later years. This appears to conflict with the Carriers' current contention that future-year TSM rates are required to compensate for past inadequate returns.

[154]T-5 (ABJ) 26; RGV-15.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

than the rate base that would result from applying straight-line depreciation from 1977 through 1996.[155] Accordingly, Carriers assert that we should use straight-line depreciation to determine rate base for 1997-2000 to evaluation filed rates. [156]

The Carriers' unrecovered investment analysis, however, is unsuitable for checking the appropriateness of a straight-line DOC rate base. Although it attempts to depict actual investment recovery, actual investment recovery is irrelevant. We provide Carriers only with a reasonable *opportunity* to recover their investment. We do not look to their actual investment recovery. Determining rate base according to actual investment recovery can run afoul of the doctrine against retroactive ratemaking.[157]

Moreover, even if we were to look to "actual" investment recovery the Carriers' method of determining "actual" unrecovered investment is not reliable. The method measures unrecovered investment by subtracting the Carriers' operating expenses, return on remaining investment, and a tax allowance for that return from pipeline revenues. The remaining monies are finally applied to investment recovery. This approach is inadequate for the following three reasons: the Carriers' choice of conservative assumptions are not appropriate for determining actual investment recovery, the Carriers' unrecovered investment analysis produces an implausible result, and the Carriers choice of inputs is flawed.

<u>(aa) The Carriers' conservative assumptions are inappropriate for setting cost-based rates</u>

[155]T-6 (WBT) at 23; T-11 (RGV) 22.

[156]T-10 (WBT) 77. The Carriers seek to determine rate base only for purposes of establishing an appropriate comparative benchmark.

[157]The Carriers appear to agree. *Initial Post-hearing Brief of the Indicated TAPS Carriers,* dated July 16, 2001, at 6-21. The doctrine against retroactive ratemaking prohibits adjusting future rates to make up for past gains or losses. *See* Endnote 6.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

The Carriers assert that their measurement of unrecovered investment is conservative.[158] This "conservativeness" comes from two elements of their method. First, the Carriers state that as a matter of economic theory,[159] under-recovery of return *on* investment should be capitalized and added to rate base,[160] much like AFUDC. The Carriers, however, do not make these capitalizations despite their representation that return was inadequate from 1977 through 1981. Second, the Carriers point out that they include DR&R *revenues*, as provided by TSM, but do not include eventual DR&R *expenses*. The Carriers properly note that this also understates the amount of unrecovered investment.[161]

The Carriers assert that their analysis is intended to measure the "actual" level of unrecovered investment.[162] If so, it should not be a "conservative" measure, but rather an economically appropriate measure. One test of the Carriers' approach, from an economic perspective, is whether it produces credible results when "conservative" assumptions are removed and appropriate ones are employed.

We tested the Carriers' unrecovered investment analysis by removing the "conservative" assumptions.[163] Using the Carriers' suggestions for how inadequate return on investment might be capitalized,[164] and reducing pipeline revenues available

---

[158]T-9 (ABJ) 26, 66-68.

[159]"From a theoretical perspective, the appropriate treatment of such an event would be to capitalize the cost-of-service shortfall, and add that amount to rate base, in order to allow the Carriers an opportunity to recover those costs in the future." T-11 (RGV) at 25.

[160]T-5 (ABJ) 20; T-11 (RGV) 29.

[161]T-9 (ABJ) 34, 66.

[162]T-5 (ABJ) 26; RGV-15.

[163]Williams sponsored exhibits during the hearing that attempted this analysis. *See, e.g.,* 139-RGV-W. During cross-examination, the weaknesses in Williams' attempts were revealed. *See, e.g.,* Tr. 3587-90 (RGV).

[164]141-RGV-T; Tr. 3612-16 (RGV).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

to pay for investment recovery by TSM's DR&R allowance, we calculate the resulting purported level of unrecovered investment. Exhibit 5 shows that, according to the Carrier's framework, there has been *no* recovery of investment by the end of 1996.[165] Using the Carriers' unrecovered investment analysis, capitalized under-recovery continues to grow and Carrier rate base at the end of 1996 is more than 60 percent greater than the rate base at the beginning of pipeline operations.[166] This result is implausible.

It is not plausible that the Carriers would agree to a settlement that would not allow investment recovery. The TAPS generated over $50 billion in revenue from 1977-1996; operating expenses for that period were roughly $10.7 billion.[167] We cannot accept that the Carriers have nevertheless managed to recover *none* of the original investment. Although the Carriers and the State represent that significant amounts of unrecovered investment represent a good deal for the State (and, by extension, shippers),[168] we do not believe that the Carriers' shareholders would tolerate such a settlement.

(bb) The Carriers' unrecovered investment analysis is conceptually flawed

The Carriers' methodology inconsistently mixes regulatory and non-regulatory concepts and approaches. The Carriers incorporate accumulated deferred income taxes (ADIT) in their analysis of actual unrecovered investment. Doing so

[165]Exhibit 5, Schedule 1, Line 15.

[166]Exhibit 5, Schedule 6, Line 13.

[167]11-ABJ-E.

[168]Tr. 3789-90 (JEH); *see* Tr. 2032-33 (ABJ).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

reduces the amount of unrecovered investment in 1996 by nearly $3 billion.[169] ADIT is a regulatory construct. It reflects money that Carriers may collect in rates to pay for taxes that are not yet owed. ADIT exists because of differences between regulatory and tax depreciation schedules.[170] Therefore, ADIT can exist only when a firm has a regulatorily approved depreciation schedule. The TAPS had none. Therefore, it did not generate such tax timing differences.[171] As an economic matter, ADIT cannot *actually* exist in the way that the Carriers have presumed because there have not been tax timing differences of the sort that they model. The Carriers' reliance on this regulatory concept is inconsistent with their failure to adopt the fundamental regulatory practice that return of investment is recovered before return on investment.

The Carriers' unrecovered investment analysis also creates contradictions. If the Carriers' unrecovered investment analysis[172] is meant to describe "actual" unrecovered investment, then the use of a rate of return that the Carriers believe they *should* have earned is inappropriate because as demonstrated in Exhibit 5 this leads to the result that not all investment is recovered. Investors would not tolerate that. On the other hand, if the Carriers' unrecovered investment analysis[173] is meant to describe the investment that *would* have been recovered had an appropriate regulatory regime been in place, then the methodology of taking return *on* investment (profit) before return *of* investment (depreciation) is inappropriate. Therefore, the Carriers'

---

[169]*See* BEW-T (W-3) 7-8; 143-RGV-C, RGV WP6.xls, Schedule 5 l. 15 wherein ADIT affects the return on investment that Carriers allege they should receive in any given year.

[170]BEW-T (W-3) 7.

[171]Firms that are not economically regulated generate no ADIT because no timing differences exist between regulatory and tax depreciation schedules.

[172]RGV-15.

[173]*Id.*

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

unrecovered investment analysis fails. It should not be used to check the reasonableness of a DOC rate base.

(cc) The Carriers' inputs are flawed

We also find that the inputs that the Carriers use in their methodology are inappropriate. As explained in Part IV Section B.1 and B.3, (*infra*) respectively, the Carriers' choices for capital structure and rate of return are inappropriate. If appropriate inputs are chosen, then the Carriers' approach to measuring unrecovered investment, even when the Carriers' "conservative" assumptions are corrected, suggests that the Carriers had already completely recovered their investment by 1989[174] and by 1996 had earned an additional $8.4 billion in excess of costs.[175] Hence, the Carriers' unrecovered investment analysis fails to prove that using the TSM depreciation schedule to determine year-end 1996 rate base would deprive the Carriers of a reasonable opportunity to recover investment.

b) The Carriers' Additional Arguments for Using Straight-line Depreciation Are Unpersuasive

We now consider three additional Carrier arguments to support the use of straight-line depreciation for determining year-end 1996 rate base. The Carriers assert that straight-line depreciation is appropriate because: 1) the Uniform System of

[174] *See* Exhibit 6, Schedule 1, line 19.

[175] *See* Exhibit 6 Schedule 1, line 17. A comparison of Exhibit 6 with 143-RGV-C, RGV Workpaper 6, Schedule 10 reveals a failing in the Carriers' methodology and helps explain the widely differing results concerning unrecovered investment. By presuming that revenues go to return on investment before return of investment, the methodology effectively maximizes the tax payments purportedly made to Federal and State governments. Thus, the Commission's finding on appropriate capital structure and rate of return, when coupled with a Carrier-style unrecovered investment analysis, suggests a cumulative income tax allowance of something over $9 billion. *See* Exhibit 6 Schedule 1, Line 14. The Carriers' capital structure and rate of return, however, produces a cumulative tax allowance of over $17 billion. *See* RGV Workpaper 6 Schedule "Imputed Depr Rates," Line 9.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Accounts requires using it; 2) the APUC used it in *Cook Inlet* and *Kenai,* and 3) the APUC accepted straight-line depreciation for TAPS when it accepted the 1982 depreciation stipulation. As further explained below, none of these rationales justifies using straight-line depreciation.

(i) The use of straight-line depreciation in FERC's Form 6 does not make straight-line depreciation appropriate for ratemaking on TAPS

The Carriers urge that benchmark rates should use straight-line depreciation because the FERC's Form 6 records straight-line depreciation. We disagree. The FERC requires all pipeline companies to file a FERC Form 6 so that FERC can compare the costs of different pipelines.[176] The FERC also requires pipeline companies filing FERC Form 6 to use the Uniform System of Accounts. The Uniform System of Accounts requires pipeline companies to use straight-line depreciation unless an alternative is approved.

Carrier witnesses admit that they do not use the straight-line depreciation shown in FERC Form 6 ratemaking purposes. Carrier witness Smith explained that "[t]he Form 6 was not intended as it was created to be a ratemaking document . . . ."[177] When asked whether the FERC would use FERC Form 6 to determine the components of a methodology, witness Smith responded, "No, the FERC Form 6 is—is an accounting and regulatory document. It is not a—a manual on how to develop a rate base."[178] When Carrier Witness Folmar was asked specifically if the numbers reported on the FERC Form 6 could be used for rate purposes, he responded, "With the

[176]Tr. 2411-12(LPS).
[177]Tr. 2370 (LPS).
[178]Tr. 2473 (LPS); *see also* Tr. 2371(LPS).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

approval—or with the acceptance of TSM agreements, no."[179] He stated that the numbers used in the Uniform System of Accounts were regulatorily reported numbers but were not used in setting rates.[180] Finally, Carrier witness Van Hoecke encouraged us to rely on ratemaking numbers and not on accounting requirements.[181]

Therefore, although the FERC Form 6 may provide helpful information to the FERC for indexing pipeline companies' costs and perhaps for measuring changes in pipeline rates, we find that it is not a compelling reason to choose straight-line depreciation as the appropriate depreciation schedule for ratemaking on TAPS.

(ii) *Cook Inlet* and *Kenai* do not require us to adopt straight-line depreciation

The Carriers assert that the APUC holdings in *Cook Inlet* and *Kenai* also support use of straight-line depreciation to compute a TAPS rate base against which to measure the rates under investigation. In both *Cook Inlet* and *Kenai* a rate base had to be established in the middle of the life of the line. In *Cook Inlet,* Cook Inlet Pipe Line Company's rates were calculated under the ICC valuation methodology. The ICC valuation methodology allowed companies to include depreciation charges as an element of rates. Depreciation charges were designed to recover the cost of the property over time and were calculated on a straight-line basis. Under the ICC valuation methodology, rate base was not calculated solely by deducting those same depreciation charges from the original cost of the property. Because straight-line depreciation is included in both ICC valuation and DOC rates, the amount of accumulated depreciation under both methodologies is the same.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[179]Tr. 2174 (BWF).
[180]Tr. 2301 (BWF).
[181]Tr. 3146 (RGV).

When the APUC established a DOC rate base in the middle of the life of the Cook Inlet line, it used the actual straight-line depreciation charges included under the ICC valuation methodology to calculate the new DOC rate base.[182] Therefore, rather than providing precedent for use of straight-line depreciation when establishing a rate base in the middle of the life of the line, *Cook Inlet* more precisely stands for the proposition that the actual depreciation charges should be used for calculating future rates.

In *Kenai,* the APUC could not determine which methodology the Kenai Pipe Line Company (KPL) had used to calculate prior intrastate rates. The APUC presumed that prior intrastate rates were calculated under the ICC valuation methodology and under those facts, the APUC concluded that the same straight-line depreciation that was included or was includable in rates computed under the ICC valuation methodology should be used in calculating the new rates. The APUC stated:

> Under the valuation methodology depreciation was included in revenue requirement to the same extent it would have been under DOC. Thus, amounts that have been deducted from the DOC rate base through depreciation have actually been recovered by KPL.[183]

The APUC ordered the use of straight-line depreciation in *Kenai* and *Cook Inlet* because straight–line depreciation was the depreciation actually used to calculate prior rates. *Kenai* and *Cook Inlet*, therefore, stand for the proposition that when establishing a DOC rate base for an existing pipeline in the middle of the operating life we should apply the depreciation actually used to establish prior rates rather than the depreciation that would or should have been used. Therefore, the Carriers' citations to

---

[182]*Re Cook Inlet Pipe Line Company*, 6 APUC 527, 536 (1985).

[183]*Re Kenai Pipe Line Co.*, 12 APUC 425, 440, 1992 WL 696192 (Alaska P.U.C., 1992) *(footnote omitted)*.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Cook Inlet and *Kenai* as precedent for using straight-line depreciation in this case to calculate a DOC rate base are not persuasive. Instead *Cook Inlet* and *Kenai* support using TSM depreciation charges to calculate a mid-stream rate base because that depreciation schedule was used to establish the past rates charged to shippers.

(iii) The APUC's acceptance of a depreciation stipulation for TAPS in an uncontested settlement is not binding once a subsequent settlement supersedes it and a non-stipulating shipper contests rates

The Carriers assert a third rationale for using straight-line depreciation to calculate a rate base against which to test filed rates: the FERC and the APUC accepted a 1982 Depreciation Stipulation that adopted a straight-line depreciation schedule for TAPS.[184] The straight-line depreciation schedule was approved subject to conditions by the FERC and the APUC as an uncontested stipulation;[185] it was not altered or withdrawn.[186]

The APUC accepted the depreciation stipulation in 1982 in the context of the then pending (original) TAPS litigation. The unresolved depreciation issue at that time was the life of the line, not the depreciation rate.[187] Although the APUC accepted the depreciation stipulation as in the public interest, it did not adjudicate rates and never approved the depreciation stipulation as producing just and reasonable TAPS rates under AS 42.06.370(a).[188]

---

184 *Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 12-14.

185 *Re Construction of the Trans Alaska Pipeline*, 4 APUC 338 (1982) at 339.

186 BWF-2, Sec. III-5.

187 *Re Construction of the Trans Alaska Pipeline*, 4 APUC 338 (1982) at 339.

188 *Cook Inlet Pipe Line Co. v. Alaska Public Utilities Comm'n,* 836 P.2d 343, 353 (Alaska 1992).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

The 1982 Depreciation Stipulation might support the Carriers' position if this case were concerned with whether current shippers are "disadvantaged by the rate pattern established by TSM,"[189] or would have paid rates less favorable "than those they would have paid in the absence of TSM."[190] However, we are not engaged in a hypothetical exercise to determine what the rate base would have been if TSM had never been used to set rates.[191] Rather, we choose the depreciation schedule that -- when applied from 1977 through 1996 – actually provided the Carriers with an opportunity to recover their capital investment and yet will not force shippers to pay for that investment twice.[192]

The record reveals unequivocally that the Carriers have filed tariffs using the TSM depreciation schedule. When asked if Tesoro's rates have been calculated under TSM, Carrier witness Adam B. Jaffe responded, "That is my understanding, yes."[193] Similarly, when Carrier witness Billy W. Folmar was asked what depreciation schedule the Carriers used to set rates, he responded "TSM Depreciation."[194]

---

[189] *TAPS Carriers' Prehearing Brief*, April 5, 2001, at 3.

[190] *Initial Post-hearing Brief of the Indicated TAPS Carriers*, July 16, 2001, at 40.

[191] In *Re Amerada Hess Pipeline Corporation*, Order P-97-4(79) (Order 79), dated April 10, 2000, we reiterated the APUC's warning when it originally allowed TSM rates that TSM rates would be subject to the same standards and procedures as if the Settlement had not been accepted. *Id.*, at 4. In saying this we did not imply that the Carriers should support their filed rates as if actual history had not transpired. In the context of Order 79, our meaning was clear: No presumption should be made that filed rates were just and reasonable simply because the Settlement had been accepted. In Order 79, we made clear that we intended to review the TAPS filed rates using the same standards and procedures that we use to review any filed rate.

[192] *Re Cook Inlet Pipe Line Company*, 2001 WL 1850233 (RCA Oct. 29, 2001).

[193] Tr. 1717 (ABJ).

[194] Tr. 2302 (BWF).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

The filings that the Carriers have made confirm that they have used an accelerated depreciation schedule for calculating intrastate rates.[195] The Carriers and the State represented at the time of the Settlement that TSM depreciation was investment recovery. Internal company documents also strongly suggest that the Carriers have viewed TSM depreciation as investment recovery.[196]

The Carriers nonetheless assert that the rates charged under the Settlement are consistent with the 1982 Depreciation Stipulation because the accelerated depreciation schedule in the Settlement only calculates depreciation for TSM ceiling rates.[197] They reason that if we are looking at rates as "if the Intrastate Settlement Agreement had not been accepted" then the only depreciation schedule truly accepted by the APUC is the 1982 Depreciation Stipulation.

We find this argument unpersuasive. TSM has been used to establish rates for more than twenty years. Tesoro witness Williams testified that "I am not aware of any instance where any one has been able to go back and change depreciation that has already been collected in rates."[198] Williams went on to testify that he could not think of any circumstances where FERC would not consider the depreciation already included in rates to be recovered investment for the purposes of rate setting.[199] When Tesoro witness Brown was asked if he had ever seen "an instance in which the

[195]*See* 30 BWF-E.

[196]*See*, e.g., 110-RGV-E at RTSXPA 221761, RTSXPA 221768; 116-RGV-E at RTSXBP 325202-03.

[197]However, the Settlement that incorporated TSM for use in setting maximum rates provides in Section II-5 that an earlier stipulation can continue to be used only if it is not inconsistent with TSM. *See* BWF-2 III-5. Williams witness Johnstone testified that the 1982 Depreciation Stipulation was inconsistent with TSM because it has a different depreciation schedule than was used to set rates on the TAPS and calculate refunds. Tr. 4207-08 (WBJ).

[198]Tr. 4910 (KAW).

[199]Tr. 4911 (KAW).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

accumulated depreciation was based on something other than the amounts actually collected in rates," he testified: "I began my career in the industry in ratemaking in 1957, and I have never seen anything like what is being proposed by the TAPS Carriers and I really feel that if it were proposed to the FERC the first thing they would do would be to disallow that proposal."[200] PAS witness Fineberg explained

> In the Carriers' hypothetical DOC tariff for 1997-2000, the replacement of the actual, hyper-accelerated collections under the TSM with hypothetical, Form 6 depreciation reduces the historical capital actually recovered, thereby artificially increasing the remaining rate base. This is an inappropriate substitution based on illusory data. TAPS Carriers in fact had already recouped the vast majority of the their original investment by 1997 through TSM's hyper-accelerated depreciation schedule. For this reason, the comparison [of the Carriers' filed rates to benchmark rates] proposed by the Carriers cannot be considered valid.[201]

The 1982 Depreciation Stipulation is therefore not relevant to establishing a year-end 1996 rate base. It was superceded and has never been used to calculate either ceiling or filed TAPS rates.

We note that the depreciation amounts that yield TSM maximum ceiling rates provided the Carriers with the opportunity to fully recover their investment.[202] If the Carriers have voluntarily chosen to file rates that are less than TSM ceiling rates and thereby curtail their opportunity, the Carriers nevertheless have had an opportunity to recover and we cannot require shippers to pay for that opportunity twice. Therefore, the only depreciation schedule that can be applied and meet the twin goals of providing Carriers the opportunity to recover their investment and also does not force shippers to

---

[200]Tr. 5389 (JFB).

[201]P-1 (RAF) at 30.

[202]*See* n.550. We have also determined that the Carriers have had ample opportunity to both recover their investment and earn a reasonable contemporaneous return. *See* Part V Section B. and Exhibit 7.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

face paying for that investment twice is the depreciation schedule used in calculating past tariffs, *i.e.*, the TSM depreciation schedule.

In addition to the legal and logical arguments discussed above, the Carriers use of straight-line depreciation to calculate their benchmark rates and to perform an unrecovered investment analysis is untenable. Doing so provides the Carriers with overrecovery of investment and potentially forces shippers to pay for that investment twice. We therefore find that the Carriers have failed to adequately support the filed rates as just and reasonable.

To confirm this finding, in the next section we apply a DOC methodology from the beginning of TAPS operation to year-end 1996 to establish a year-end 1996 rate base from which to calculate 1997-2000 rates as required by *Cook Inlet*[203]. In doing so, we confirm that the Carriers rates are 57 percent higher than just and reasonable rates.

IV. WE COMPUTE A $669 MILLION YEAR-END 1996 RATE BASE USING DOC METHODOLOGY CONSISTENTLY APPLIED FROM THE BEGINNING OF TAPS OPERATIONS

A DOC methodology applied from the beginning of the life of the line is the most reliable method for establishing a rate base in the middle of the operating life of a line.[204] No party in this proceeding disagrees. We review the record to determine the appropriate inputs for calculating the year-end 1996 intrastate TAPS rate base using a DOC methodology.

The DOC methodology formula is RR = [r (V-D)] + [OE + d + t] where

RR = revenue requirement

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

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

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

r = after-tax return

V = sum of prudently incurred capital expenditures, allowance for funds used during construction (AFUDC), and working capital adjusted for Accumulated Deferred Income Tax (ADIT) and retirements

D = accumulated depreciation, adjusted for retirements

OE = operating and maintenance expenses

d = annual depreciation charges

t = taxes.

If an oil pipeline must be dismantled at the end of its useful life, a pipeline carrier is also entitled to recover the reasonable dismantling, restoration and removal (DR&R) costs.[205]

In the formula above, the rate base equals V-D. In the following sections, we establish the elements necessary to calculate rate base: A) The total amount of prudent investment (Carrier property balances) including capital and retirements, B) AFUDC amounts when the associated property is first brought into service; C) ADIT, and D) the depreciation schedule used to determine accumulated depreciation from 1977-1996.

A. <u>Carrier Property Balances</u>

Rate base consists of both depreciable and non-depreciable property in service. In this case non-depreciable property consists of Working Capital and Land.[206]

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

---

[205]TSM includes DR&R. For purpose of this analysis, DR&R is not considered because this analysis establishes rate base. DR&R, however, is relevant when discussing rates. *See* Part VI, Section E.

[206]*See, e.g.,* 143-RGV-C, RGV-14 WP 3, TAPS-RGV WP3.xls, Schedule 2; Line 13; 225-JFB-T, Workpaper 2, Line 13; 30-BWF-E ('77-'83) Lines 82 and 83; 31-BWF-E ('84-'00) Lines 82-83.

Carrier property balances that may earn AFUDC[207] include both depreciable property and land. An allowance for AFUDC is a reasonable element to include in rates because it is appropriate to compensate for the capital costs incurred constructing the pipeline before it is placed into service.

We first determine initial Carrier property balance. The record presents four Carrier property issues: 1) what the actual level of capital expenditures in any given year should be; 2) whether a significant portion of Carrier expenditures during construction, $450 million, should be removed from rate base because of imprudence; 3) what the appropriate allowance for Working Capital should be, and 4) how to calculate property retirements. We address each in turn.

1. Capital Expenditure Amounts

The parties do not agree on the actual level of capital expenditures in any given year. Tesoro relies upon the capital expenditure data contained in the TSM spreadsheet filings for 1984-2000. For the years before 1984, Tesoro relies on data[208] contained in the TSM-6 illustrative model.[209] The Carriers and Williams use the

---

[207]AFUDC is Allowance for Funds Used During Construction. The amount of accumulated AFUDC for a particular item under construction is added to rate base at the same time the CWIP (Construction Work in Progress) balance attributable to that item is transferred to rate base, i.e., when the property is placed in service. BONBRIGHT, JAMES C., PRINCIPLES OF PUBLIC UTILITY RATES 246-253 (1988).

[208]Tr. 5129 (JFB).

[209]31-BWF-E; *see also* BWF-6 at 5-12; T-8 (BWF) 2. The TSM-6 model was attached to the *Explanatory Statement of the State of Alaska and the United States Department of Justice in Support of Settlement Offer* (BWF-4). TSM-6 shows the derivation of various rate base balances that were embodied within TSM as of 1984, by tracing various Carrier property balances back to 1968. The illustrative model for how TSM was intended to operate (BWF-3 at 56) agrees with TSM-6 for 1984 and 1985 (the years of overlap). BWF-3 at 34.

TSM-6 shows, among other things, the derivation of TSM's 1984 starting AFUDC balance (BWF-3 at 38), the annual depreciation taken during 1977-1983 to derive the Settlement's starting rate base in 1984 (BWF-3 at 19), and the amortization schedule of the $450 million in excluded costs (BWF-3 at 14).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

property balance data entered into the record in earlier TAPS proceedings for years before 1977, where no annual records were available.[210] The Carriers and Williams rely on the property balances that the Carriers filed in their annual reports with this Commission and the FERC for years after 1977.

The difference between the two sets of capital expenditure data in any given year is occasionally substantial. For example, in the first half of 1977, the Carrier-sponsored property additions data are $39.8 million more than the figure sponsored by Tesoro.[211] In 1978, the Carrier-sponsored property addition figure is $56.1 million less than the one sponsored by Tesoro. However, for twenty-three out of thirty-three years, the difference is less than $1 million.[212]

On a cumulative basis, the Carrier-sponsored property addition data exceed Tesoro's during 1973-1977, reaching a peak surplus level of $56.4 million mid-way through 1977. A sizeable cumulative deficit is then accrued from 1978-1982, reaching a peak cumulative deficit of $21.5 million in 1979. From 1983-1996 the cumulative difference between the two sponsored data sets remains below $1 million.[213] The total property balances are thus cumulatively essentially the same. The choice of one set of property additions over another primarily affects the size of the AFUDC balance. Because the Carrier property addition data is greater in the earliest years,

[210]T-7 (RGV):4. As indicated below, Williams follows TSM and makes a downward adjustment of $450 million to the Carrier property balances; the Carriers do not.

[211]212-FJH-T.

[212]*See* 212-FJH-T.

[213]212-FJH-T.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

using the Carriers' sponsored property addition data produces somewhat greater AFUDC balances than the data sponsored by Tesoro.[214]

The record provides no guidance for why the Carriers' representation of additions to Carrier property are less reliable than those sponsored by Tesoro. It is not clear how additions to Carrier property are determined within the context of TSM; however, the amounts reported in FERC Form 6 and the Carriers' annual reports must comply with the Uniform System of Accounts for oil pipelines. We, therefore, adopt the Carrier property balances because they are more reliably based on books and records that conform to the Uniform System of Accounts for oil pipelines.[215]

2. *Alleged Imprudent Expenditures*

The voluminous Phase II record of the original TAPS litigation which is not part of the record in this case addresses whether some of the capital expenditures on the TAPS were prudently incurred. The parties agreed in the Settlement to reduce the original Carrier rate base by $450 million.[216] The Settlement states that this "reduction in investment base is amortized based on petroleum delivered during the years 1978 through 1984."[217]

[214]For purposes of establishing just and reasonable rates under the Alaska Pipeline Act, we recognize that this may result in slightly higher rates than if we chose the capital expenditure inputs utilized by Tesoro.

[215]A schedule of these property balances can be found at Exhibit 8.

[216]The State asserts that if we fail to approve the TSM filed rates then we open the issue of whether all of the original capital expenditures on the TAPS were prudently incurred. To the extent this assertion may be accurate, no party offered evidence in these consolidated dockets to support a finding of imprudent original expenditures. Therefore, we do not address this issue.

[217]BWF-3 at 14.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Williams and Tesoro, in sponsoring inputs for their respective DOC methodologies, both reduce the original Carrier capital expenditures by this $450 million.[218] The Carriers object.[219]

We find that the original capital expenditures should not be reduced by $450 million. To do so unfairly confers benefits of the Settlement outside the context of the Settlement. Neither Tesoro nor Williams have put forward a substantive case in this docket to show that $450 million in construction expenditures were imprudently incurred. The record is insufficient to support a finding on this issue. Therefore, we include all Carrier capital expenses in rate base.

3. *Working Capital*

Working capital is generally provided in rate making to allow the utility to pay its bills in advance of receiving revenues because the utility must "front" the money for its bills before it gets paid. This "fronting" has a cost, the time value of money. A working capital allowance is therefore included in rate base for purposes of determining the overall return. Working capital does not earn AFUDC, nor is it considered depreciable property.

The Carriers' working capital figures come from their FERC Form 6 filings. Carriers explain that, pursuant to a stipulation in the original TAPS rate case, no cash working capital component is included.[220] Instead, their working capital figures reflect "the sum of balances for Oil Inventory, Materials and Supplies, and Prepayments."[221]

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[218]Tr. 4551 (BEW); ABJ-20.
[219]*See* 225-JFB-T; 189A-BEW-T.
[220]T-7 (RGV):11.
[221]T-7 (RGV):11.

Williams adopts the Carriers' working capital figures.[222] Tesoro includes the TSM figures for working capital within their determination of the appropriate level of non-depreciable plant.[223]

No clear pattern exists showing one set of numbers being consistently higher or lower than the other. On a cumulative basis, Tesoro's working capital figures are $53.96 million more than the Carriers through 2000.[224] The record contains no rationale for why one set of working capital figures is more appropriate than another. Because no party protested the Carriers' inclusion of a working capital allowance in rate base, we permit its inclusion. Further, we adopt the Carriers' working capital figures, as no rationale for why the TSM figures might be more accurate was provided.

4. Property Retirements

When property is retired, or taken out of service before being fully depreciated, it is removed from rate base because it is no longer used and useful in providing service. The Carriers and Williams sponsor property retirements data based on the Carriers' FERC Form 6 annual filings.[225] Tesoro relies on retirements data from the TSM spreadsheet filings for 1984-2000. For years before 1984, Tesoro relies on data contained in the TSM-6 illustrative model.[226] Neither party contests the others' figures.

---

[222]189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedule 5, Line 14.

[223]225-JFB-T, Workpaper 2, l. 13; 30-BWF-E ('77-'83) ll. 82-83; 31-BWF-E ('84-'00) ll. 82-83.

[224]A schedule of the parties' positions can be found at Exhibit 9.

[225]143-RGV-C, Workpaper TAPS-RGV WP3.xls, Schedule 12 and 189A-BEW-T Workpaper BEW_R_RGV WP1 DR 22RE.xls, Schedule 12, respectively.

[226]225-JFB-T.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

The TSM property retirements data shows only "net proceeds" from retired property.[227] The record fails to explain how these net proceeds were calculated or how they reconcile with the FERC Form 6 data. TSM treats property retirements in a non-standard manner.[228] Without understanding this approach, we cannot rely on it. We therefore use the FERC Form 6 property retirements data because it is better supported and more transparent.[229]

B. AFUDC

Determining unamortized AFUDC to be included in year-end 1996 rate base requires establishing an appropriate overall rate of return for each prior year of pipeline construction and planning. The overall rate of return is determined by the embedded (or weighted average) cost of debt and the then-current market required return on equity. To determine these elements, we establish the historical: 1) capital structure, 2) cost of debt, 3) return on equity, and 4) rate of return adjustments necessary to compensate for any special risks associated with TAPS. These historical factors are rarely determined in a rate case.[230] Nonetheless, because no rate base has been previously established for TAPS we must make these determinations based on the record in order to correctly set the necessary AFUDC and rate base to determine just and reasonable rates for the protest period.

[227] 236-JFB-T, 697.

[228] 236-JFB-T, 698.

[229] These data are shown at line 5 of Exhibit 8. As explained in Part IV Section C.2, for 1986-2000 we relied on the Carriers' annual reports to obtain details on the vintage year of property retired. In doing so we found minor discrepancies between the Carriers' sponsored retirements data and those contained within their annual reports. We adopt the annual report data, noting that on a cumulative basis the differences with the Carriers' sponsored data are not material.

[230] As Tesoro's witness stated: "Yes, it is unusual and frankly I've never been in a backcasting mode before. But then again this is a very unusual proceeding." Tr. 5080 (FJH).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

1. Capital Structure

A regulated firm's capital structure affects overall rates. Investors pay income taxes for return on equity, but not for cost of debt. Shippers therefore pay a tax allowance as part of the tariff to "cover" return on equity so that equity investors are made whole after taxes are paid. As a witness for the TAPS Carriers explained during the Phase I litigation: "Under regulation an initial judgment would be made concerning the reasonableness of the capital structure. This judgment would be necessary because of tax advantages on debt capital."[231]

In general, the greater the proportion of equity, the greater the tax allowance that shippers pay. Because a regulated firm is allowed to recover its cost of service, it may have little incentive to choose a capital structure that minimizes costs. Accordingly, regulated entities, especially those not owned by the customers it serves, are not provided a free hand with which to determine capitalization for purposes of ratemaking. We determine the appropriate capital structure for ratemaking by applying a stand-alone model to TAPS.[232]

In the early years, TAPS was heavily financed with debt.[233] TAPS debt financing was guaranteed by parent companies.[234] The actual market response to the capital structure of the subsidiaries is thus not a good guide to how capital markets would view the risks associated with the TAPS as a stand-alone enterprise; indeed,

[231]WBT-56 (Olson) 3.

[232]*See supra* Part III Section B(4)(6).

[233]In the 1978 test year of the original Phase I litigation, the actual capital structure of the pipeline subsidiaries ranged from 74 percent to 96 percent debt. 67-WBT-E (Parcell) RTSTXX 75023.

[234]Tr. 4408 (JSG).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

markets would not have permitted a stand-alone pipeline to be financed with over 98 percent debt.[235]

In more recent years, the TAPS pipeline subsidiaries have been almost entirely financed with equity capital from their parents.[236] A 100 percent equity capital structure is also inappropriate for a regulated pipeline that is many years from the end of its life.[237] We find that the actual capital structures of the TAPS pipeline companies therefore should not be used to set rates.

The TAPS Carriers propose using instead the respective parent company capital structures.[238] On a composite basis, the parent capital structure ranges from 55

---

[235]In the original Phase I litigation this point was disputed. State witness Parcell urged that "[f]rom an economic standpoint, the Consent Decree and its effects do not create an incentive to finance predominantly with debt." *Quoted in* WBT-27 (Gary) at 25. Parcell then argued that therefore actual financing could be used as a guide to what financial markets would support. Carrier witness Gary, however asserted that the actual financing of the TAPS reflected the incentives that the ICC's Valuation Methodology and the Elkins Decree created. The Valuation Method provided very large returns to equity if the pipeline company was heavily leveraged. Gary went on to urge that capital markets would not support such quantities of debt in a stand-alone enterprise. WBT-27 (Gary) 24-26.

We agree with the APC's prior finding in *Re Exxon Pipeline Company,* 1 APUC 580, 1980 WL 100772 (Alaska P.U.C., 1980) that the actual financing of the pipeline was indeed a function of the Elkins consent decree and so should not be taken as a guide to how a prudently managed stand-alone pipeline w*ould* be financed, nor to what financial markets would support.

[236]Tr. 2765 (WBT).

[237]None of the parties sponsor a 100 percent equity capital structure for the later years of the pipeline's life. *See* FJH-T (E-2) 22; JSG-T (W-2) 9; WBT-38. Gary, however, suggests that a truly stand-alone TAPS without parent guarantees could only have been financed with 100 percent equity. WBT-26 (Gary) 19. We consider the arguments for this proposition, and found otherwise in Section IV, B.1.b and c.

[238]Exhibit 10 contains a summary of the Carriers' position relying on data from WBT-38.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

to 78 percent equity between 1968 and 2000;[239] the average capital structure over that period is 68 percent equity. The Carriers assert that the parent company capital structure should be adopted because it is consistent with past APUC[240] and FERC precedent;[241] it is more than fair to shippers because TAPS could not have been financed with anything other than 100 percent equity on a stand-alone basis;[242] it is within a zone of reasonableness; and adopting a different capital structure denies the Carriers needed managerial discretion.[243]

Williams also proposes using the parent company capital structure for 1968-1996. Williams explains that, for purposes of calculating AFUDC during 1968-1996, it is the only capital structure that was available during those years.[244] Nevertheless, Williams suggests that TAPS could have been financed on a stand-alone basis with something like a throughput guarantee.[245]

Tesoro asserts that the TAPS could have been financed on a stand-alone basis with considerably less than 100 percent equity if the owners of the pipeline secured long-term contracts with shippers.[246] Tesoro urges adopting a hypothetical

---

[239]*Initial Post-hearing Brief of the Indicated TAPS Carriers,* dated July 16, 2001, at 43.

[240]*Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 42-43.

[241]*Id*.

[242]67-WBT-E (Parcell) RTSTXX 75023

[243]*Initial Post-hearing Brief of the Indicated TAPS Carriers*, dated July 16, 2001, at 43.

[244]*See* Tr. 4385 (JSG) and JSG-T at 37.

[245]*See* Tr. 2833-35 (WBT). (Williams' counsel suggests in hypothetical questioning to Carrier witness Tye that the TAPS could have been financed on a stand-alone basis with something like a throughput guarantee.)

[246]Tr. 5045-5046 (FJH).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

capital structure that reflects a stand-alone pipeline and industry norms.[247] Tesoro proposes a capital structure of 50.5 percent equity based on the average capitalization of publicly traded oil and gas pipeline companies.[248] Tesoro provides evidence that this is consistent with a) historical data on how oil pipelines were financed from 1966-1975,[249] b) the capital structure adopted by the APC in *Re Exxon Pipeline Company*,[250] and c) the actual average capitalization of pipeline companies today.[251] Tesoro concludes that a stand-alone pipeline could have been financed with 49.5 percent debt and 50.5 percent equity.[252]

In determining capital structure for ratemaking, regulators should set a capital structure that reflects the riskiness of the project and allows the company to attract new investors. "The capital structure ratios employed should be consistent with the prospective level of business risk of the enterprise and with similar risk companies whose capital structure ratios have found acceptance in the marketplace."[253] Regulators most often approve a regulated pipeline's actual capital financing, because it generally reflects the market determination that investors have found the actual capital structure acceptable. However, in cases such as this one where the actual financing may be inappropriate, regulators approve a capital structure that produces a reasonable revenue requirement, consistent with the goal of allowing the regulated entity to

[247]*Tesoro Alaska Company's Initial Posthearing Brief*, filed July 18, 2001, at 29.

[248]Tr. 5044 (FJH).

[249]183-JSG-W.

[250]*Re Exxon Pipeline Co.*, 1 APUC 580 (1980); Tr. 5035-5036 (FJH).

[251]FJH-3 at 1. Williams also suggests that the TAPS could have been financed on a stand-alone basis with at least 50 percent debt (*see* Tr. 4423 (JSG)), as did the United States Department of Justice during the original TAPS litigation. 66-WBT-E (Roseman) 52.

[252]Tr. 5044-46 (FJH).

[253]FJH-T (E-2) at 3.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

continue to attract new funds.[254] The parties agree that the TAPS' actual capital structure is inappropriate and a hypothetical capital structure should be adopted.[255]

a) <u>Parent Capital Structure Is Not the Appropriate Capital Structure for Regulating TAPS</u>

The Carriers assert that APUC and FERC precedents direct us to adopt the parent company capitalization. The Carriers note that our predecessor agencies have historically used parent company capital structures for pipeline regulation, citing decisions in *Kenai*, *Cook Inlet* and *Re Exxon Pipeline Company*.[256] Further, the FERC's general practice is to adopt the parent company capital structure when that of the subsidiary is inappropriate. These precedents, however, are distinguishable and are not applicable to this case.

First, in *Kenai*, the APUC approved a parent company capital structure because all of the parties before it agreed that such a structure was appropriate. The record did not support any other finding. In this case, the parties do not agree that parent company capital structure is appropriate and the record supports a finding that the parent capital structure is not appropriate.

Second, the Carriers note that in *Cook Inlet* the APUC adopted a 75 percent equity position, a hypothetical capitalization that produces a result that is broadly consistent with the Carriers' recommendation. The APUC found that a 75

[254]*Re Cook Inlet Pipe Line Co.*, 6 APUC 527 (1985); *Re Enstar Natural Gas Co.*, 7 APUC 375 at 402 (1986); Tr. 5042 (FJH).

[255]The TAPS is owned by pipeline companies that are wholly owned by the TAPS parent companies. The only actual capitalization of the TAPS is the capitalization of these pipeline companies. All parties agree that that capitalization is inappropriate for ratemaking, and that a hypothetical capital structure should be adopted. The Carriers assert that the hypothetical structure should be the actual capitalization of the parent companies.

[256]*Re Kenai Pipe Line Co.,* 12 APUC 425, 1992 WL 696192 (Alaska P.U.C., 1992)*; Re Cook Inlet Pipe Line Co.,* 6 APUC 527 (1985)*; Re Exxon Pipeline Co.*, 1 APUC 580 (1980).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

percent hypothetical capital structure was appropriate in that case because the pipeline was nearing the end of its life. As a wasting asset, the APUC found that the Cook Inlet pipeline needed to revert to 100 percent equity by the end of its life.[257] The record in this case indicates that TAPS will continue to operate for at least another twenty-five years.[258] Therefore, the issue of reverting to 100 percent equity is not yet ripe.

Finally, when the issue was before the APC in 1980, the APC adopted parent company capital structure.[259] The APC noted that "[w]here the pipeline company is a wholly owned subsidiary. . . the parent company can create an artificial capital structure for the subsidiary to maximize the profits and benefits of the parent company's stockholders."[260] Accordingly, it rejected the use of the actual capitalization of the pipeline subsidiaries. The superior court reversed the APC. The superior court explained that "[t]here is no basis for taking the capitalization of eight oil companies who are the owners or parent companies of the owners and imputing their individual capitalization to TAPS."[261] We agree with the court's finding and adopt a hypothetical composite capital structure.

Our predecessor agencies have adopted hypothetical capital structures when parent capitalization is inappropriate. In *Alascom,*[262] the APUC constructed a

[257]Tr. 4258-59 (JSG).

[258]14-ABJ-W.

[259]*Re Exxon* Pipeline *Company*, 1 APUC 580 (1980). We note, however, that in adopting the parent company capital structure on a composite basis the APC approved a capital structure of 51.3 percent equity, very close to the capital structure of 50.5 percent equity, which we adopt, *infra*.

[260]*Id.,* at 596.

[261]*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.

[262]*Re Alascom, Inc.*, 7 APUC 665, 708-09 (1986).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

hypothetical capital structure, rather than adopt that of the subsidiary or parent, precisely because it better approximated the industry norm. Without a reasonable matching of business activities between the parent and subsidiary, if the parent's capital structure is used in rate making it reflects the business costs of the parent, rather than those of a prudently managed and regulated pipeline company. Thus, *Alascom* suggests that an important test of whether the parent company capital structure is appropriate is whether the TAPS parent company capital structures reflect those of a stand-alone TAPS.

The Carriers also assert that the FERC typically applies the actual capital structure of a subsidiary unless the subsidiary issues none of its own debt or its debt is guaranteed by the parent company. In such instances, the FERC generally adopts the parent company capitalization.[263] The FERC, however, adopts the parent capital structure in part because the parent company's enterprise approximates that of the carrier.[264]

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

---

[263]*See* 169-JST at WIL 06196.

[264]In *Re Iroquois Gas Transmission System, L.P.*, the F.E.R.C. explained the rationale for using a particular capital structure:

> These proposals are contrary to the general Commission policy first set forth in *Arkansas Louisiana Gas Company*. There, the Commission held that, as a general matter, to establish an allowed rate of return it would use the actual capital structure of the entity that does the borrowing in the market place rather than a hypothetical capital structure. Because of the difficulty of selecting a representative capital structure for a company, the Commission decided to rely on the amount of debt and equity selected by the entity that actually does the financing *because it is likely to be more representative of what the market requires for a company of that particular risk*.

Iroquois Gas Transmission Sys., L.P., 53 F.E.R.C. ¶ 61,194 at 61,708 (1990) (emphasis added) (footnote omitted).

In this case the spirit of FERC precedent suggests that adopting a hypothetical capital structure is appropriate.[265] The TAPS parent companies' primary businesses are outside of the pipeline arena. The parent companies of the TAPS Carriers are integrated petroleum firms. They typically have substantial business interests overseas and are engaged in chemical manufacturing, oil and gas exploration and development, and refining.[266] Their primary business activity is not transporting petroleum products via pipeline. Accordingly, the parent company capitalization is not a good indicator of how a prudently managed pipeline company should be capitalized.[267]

b) <u>A Stand-alone Model With Less Than 100 Percent Equity Is Appropriate for TAPS</u>

The Carriers offer three arguments to support their position in this case that we should use a stand-alone model at 100 percent equity to determine capital structure. The Carriers first assert that a contract that guarantees shipment will shift risk from the pipeline carrier to the shipper. A pipeline enjoying such a guarantee is thus not truly "stand-alone."[268] Although the Carriers acknowledge that a pipeline might be financed with less than 100 percent equity with throughput guarantees, the Carriers contend that the notion of guarantees conflicts with the requirement to evaluate possible capital structures on a stand-alone basis.

Although a throughput guarantee shifts risk from the investor to the shipper, such shifts are a normal business occurrence.[269] The willingness of pipeline

[265]In *Transcontinental Gas Pipe Line Corporation,* 60 F.E.R.C. ¶ 61,246, ¶¶ 61,823-24 (1992), the F.E.R.C. based a hypothetical capital structure on industry averages in order to achieve the goal of selecting the debt equity ratio that best represents what the market would require for a company of the type that it is regulating.

[266]221-FJH-E, 222-FJH-E.

[267]Tr. 4385 (JSG); JSG-T, 28.

[268]Tr. 2995-96 (WBT); WBT-27 (Gary) 27.

[269]66-WBT-E (Roseman) 50.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

investors to provide funds is only indirectly related to the shippers' risks.[270] Rather, a pipeline investor's concern is with the business risk to the pipeline. If a pipeline company secures throughput guarantees, then the costs associated with acquiring capital are reduced. Investors know that an enterprise with throughput guarantees is less risky.[271] The throughput guarantees thus reduce the costs associated with risk. They do not interfere with the enterprise's ability to attract capital on its own; rather they enhance it. The assertion that a stand-alone TAPS would need to be financed with 100 percent equity if it were truly stand-alone is thus not compelling.

The Carriers' second argument is that a pipeline that enjoys throughput guarantees would perform contract rather than common carriage.[272] Common carriers are required to pro-rate capacity if nominations exceed capacity. As a common carriage pipeline, TAPS cannot enter into contract carriage. The Carriers therefore assert that a stand-alone model based on anything less than 100 percent equity is not representative of how TAPS actually could have been financed because throughput guarantees are not actually allowed on the TAPS.[273]

Here too we disagree. The record contains no evidence of a contractual relationship between shippers and Carriers guaranteeing throughput. However, TAPS is the only way to move North Slope reserves to market.[274] The value of North Slope reserves assures that throughput will be adequate to generate revenues for the

---

[270]Shipper risk matters to the extent that there is a risk of shipper default.

[271]Tr. 2833-35 (WBT).

[272]WBT-27 (Gary) 29-30.

[273]WBT-27 (Gary) 29.

[274]The Carriers assert that other methods of transportation off the North Slope were contemplated as competitive to TAPS. The record suggests that those other methods were not contemplated as competitive to TAPS but rather as alternatives to TAPS. *See* 66-WBT-E (Roseman) 59.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

pipeline.[275] This assurance reduces investor risk. The regulatory environment for TAPS differs distinctly from the competitive environment of pipeline companies in the contiguous 48 states because shippers have no alternatives. TAPS' common carriage requirement does not preclude us from using a stand-alone model.

Finally, the Carriers' suggest that TAPS on a stand-alone basis would need to be financed at close to 100 percent equity because the risks for TAPS were so great that the assurance of throughput was not adequate for lenders to provide debt. The Carriers assert that, if TAPS were truly a stand-alone enterprise, then risks of throughput interruption, production curtailment, or non-completion were so large that lenders would be unwilling to invest in TAPS.[276] Tesoro and Williams dispute these assertions.[277]

For TAPS to attract debt financing on a stand-alone basis, lenders would have required assurance that they would be repaid. Because TAPS is a common carrier, such assurance could not come from contractual guarantees. Rather, assurance would come from investor expectations regarding the value of North Slope reserves. Sohio financed its participation in TAPS almost exclusively with debt. Had TAPS not been completed, Sohio would have been unable to meet its obligations. In effect, Sohio "bet the company" on the success of its North Slope venture.[278] To secure its debt Sohio pledged all of its assets to its creditors.[279] "Sohio's ability to finance its

[275] 66-WBT-E (Roseman) 48. No party asserts that the value of the reserves is a throughput guarantee. Rather, the existence of oil otherwise trapped on the North Slope provides security that operates somewhat like a throughput guarantee. *See* WBT-26 (Gary) 55-56; WBT-27 (Gary) 34-36.

[276] WBT-27 (Gary) 31.

[277] Tr. 5045-46 (FJH); *see* Tr. 4408-09 (JSG).

[278] Tr. 4408-09 (JSG); WBT-26 (Gary) 55.

[279] 66-WBT-E (Roseman) at 52.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

TAPS expenditures rested largely upon lenders' valuation of its reserves in the ground."[280]

Sohio's borrowing power thus depended upon expectations that TAPS would be completed.[281] Investors understood that the only way to move that oil to market was through the TAPS.[282] They therefore knew that Sohio could only realize the value of its reserves through the construction of the TAPS.

> Ultimately, then, it is the value of the reserves which stand as security to the creditors of the pipeline. That would be true whether or not there was an actual contractual obligation to that effect, so long as the pipeline tariff was designed to recover the costs of the pipeline plus at least a reasonable return.[283]

Without a functioning TAPS, Sohio's North Slope reserves would have no value. Thus, investors believed that the prospects for TAPS were as good as the prospects for success of the entire North Slope venture.[284] During the Phase I proceeding the United

---

[280]WBT-27 (Gary) at 36.

> I agree that during the production phase these reserves are a source of cash flow which creates borrowing power for Sohio. But the reserves also provided borrowing power during the construction phase of TAPS.

WBT-27 (Gary) 34.

[281]A certain portion (the record does not indicate how much) of Sohio's debt was backed not just by Sohio parent guarantees, but also a substantial contribution to the financing by BP. 66 WBT-E (Roseman) 55; Tr. 4412-13 (JSG). Accordingly, Sohio's borrowing power depended also upon BP's financial position, and not only on prospects for the North Slope as a whole.

[282]66-WBT-E at 48.

[283]66-WBT-E (Roseman) 48. Carriers point out that the Northwest Alaskan Pipeline Company (formally Alcan) found that loan guarantees or protective tariff conditions were required to obtain debt financing for the Alaskan gas pipeline. WBT-56 (Olson) 11. The fact that guarantees were needed, however, may reflect the comparatively smaller prospective margins that were then required for gas compared with oil. It is the prospective value of reserves combined with lack of competition that act like a guarantee.

[284]We agree with the Carriers that consideration of TAPS must be done independent of other developments on the North Slope. *Cite to Carrier Briefs*. However, it is unreasonable to think that investors would not consider the value of North Slope reserves when weighing whether to invest in TAPS.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

States Department of Justice's expert witness argued, on the basis of the Sohio experience, that a stand-alone TAPS could have been financed with a debt ratio of 40 to 60 percent.[285] This is comparable to the capital structures of average lower-48 pipelines at the time,[286] and with the composite capital structure approved for TAPS by the APC.[287]

Sohio's highly leveraged position made it akin to a "stand alone" company. Contrary to the Carriers' position that a stand-alone company would have required 100 percent equity capital structure, Sohio's actual financing experience suggests that investors in a stand-alone pipeline would have had sufficient confidence in the completion of TAPS to provide substantial amounts of debt.[288]

c) Determining the Appropriate Capital Structure

The record includes two proposals for the amount of debt that could have been raised. The Carriers' position is that we adopt the parent company capital

[285]66-WBT-E (Roseman) 48.

[286]WBT-34 (Stich) 250, 274, 282.

[287]*Re Exxon Pipeline Company*, 1 APUC 580 (1980).

[288]The Carriers raise two additional arguments to support their position that the capital structures of the parent companies should be used to calculate TAPS rates. The Carriers assert that the appropriate capital structure should lie "at the outer edge of the zone of reasonableness" to provide for managerial discretion in structuring capital. 169-JSG-T; WIL 06196. We disagree. Even if markets "support" richer equity positions, when attempting to establish reasonable cost-based rates, we adopt the least costly capital structure that financial markets will support and which would also provide owners of a stand-alone TAPS adequate ability to raise new capital. Tr. 4959-60 (FJH). To do otherwise is to impose an unnecessary burden on shippers.

The Carriers also assert that parent capital structure falls within a "zone of reasonableness" and therefore we should adopt it. *Initial Post-hearing Brief of the Indicated TAPS Carriers* at 43. The "zone of reasonableness" standard, however, is a judicial check on whether commission decisions are reasonable. *Farmers Union Cent. Exch., Inc. v. FERC,* 734 F.2d 1486, 1502 (D.C. Cir., 1984). It is not a justification for regulators to fail to make informed, reasoned choices in exercising their discretion when ratemaking. The results of agency discretion must lie *within* that zone of what is appropriate. The fact that one of the parties' positions may lie within that zone is not sufficient to allow us to adopt it.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

structure. We have rejected that proposal.[289] Tesoro's position is that we adopt a 50.5/49.5 percent equity-debt capitalization. We choose the capital structure that best represents the capital structure of a stand-alone TAPS.

Tesoro proposes a hypothetical capital structure of 50.5 percent equity and 49.5 percent debt[290] consistent with the standard regulatory benchmark of a 50-50 capital structure[291] and with the average historical capital structures of gas[292]and oil pipelines,[293] generally. Hypothetical capitalization for stand-alone pipelines should reflect what has been accepted in the marketplace for pipelines of roughly comparable risk.[294] Having reviewed the record and evaluated the relative risks of TAPS as compared with the average pipeline,[295] we find that a stand-alone TAPS could have been financed with a 50.5-49.5 equity/debt capital structure. To the extent that extraordinary risks existed for TAPS that exceeded an average pipeline's, those extraordinary risks should be accounted for in a risk premium and not the capital structure.[296]

We assume that capital structure is constant from 1977 through 1996 because this is consistent with the historical capitalization of average pipeline companies.[297] Further, the record suggests that capitalization would not have varied

[289]*See supra* Part IV Section B.1(a).

[290]FJH-T (E-2) 22.

[291]*See* WBT-34 (Stich) 283-84.

[292]WBT-34 (Stich) 282; FJH-3 at 1.

[293]WBT-34 (Stich) 244, 250; FJH-3 at 1.

[294]FJH-T (E-2) 3.

[295]*See* Part IV Section B.4 and Endnote 8.

[296]We consider risk premiums in Part IV Section B.4 and Endnote 8.

[297]WBT-34 (Stich) 244, 250, 282; FJH-3 at 1.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

enough to affect the cost of debt.[298] The record does not support a finer determination and holding capitalization constant is also administratively efficient.

During the early years of planning pipeline construction when risks to the pipeline's completion were highest, a stand-alone pipeline was much less likely to secure debt financing.[299] As Gaske explained, "[i]t seems quite appropriate to me that you'd have almost all equity in the very initial planning stages."[300] Accordingly, we find it is reasonable to assume full equity financing before May 1, 1974.[301] When construction began in May 1974, risks on TAPS reverted to those that are reasonably comparable to a stand-alone pipeline. We assume that expenditures after April 1974 were financed with something greater than[302] 49.5 percent debt so that by the beginning of pipeline operations, July 1, 1977, there was a composite 49.5 percent debt and 50.5 percent equity capital structure. Exhibit 11 depicts the capitalizations that we adopt from 1968 to June 30, 1977.

The record does not support finding separate capital structures for each of the pipeline companies. All the expert rate of return witnesses in this proceeding explained that risks to TAPS should be assessed irrespective of ownership.[303] If the

[298]Tr. 5043 (FJH).

[299]The rationale for this finding is explained in Part IV,B.4 and Endnote 8, *infra*, in the discussion of risk premiums to reflect special TAPS risks.

[300]Tr. 4262 (JSG).

[301]Tr. 4262 (JSG).

[302]The fractions of this "something greater" are determined as follows. We first take 49.5 percent of the cumulative balance of property spent prior to May 1, 1974. We then add fractions of this sum to the yearly debt balances for May-December, 1974, 1975, 1976, and January through June, 1977, according to the proportion of funds spent per period relative to the cumulative amount of funds spent during June, 1974 through June, 1977. This approach permits a "ramp up" in equity financing that seems more reasonable than a dramatic switch from one period to the next.

[303]T-10 (WBT) 8; WBT-61 at 2-3; FJH-T (E-2) 4.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

risk to the enterprise does not change based on ownership, there is no reason to adopt different capital structures for each of the TAPS owners.[304] When remanding *Re Exxon Pipeline Company,* 1 APUC 580 (1980), the Alaska Superior Court made a similar finding: "The pipeline should have been considered to be an entity . . . ."[305] We, therefore, find a 100 percent equity capital structure for 1968 to May 1, 1974, a gradual decrease to 49.5/50.5 debt equity capital structure for 1974 to 1977, and a 49.5/50.5 debt/equity capitalization for the TAPS Carriers for 1977 through 1996 appropriate.

2. Cost of Debt

In most cases, regulators set the cost of debt at the actual embedded cost of the debt of the regulated entity. In this case, however, the debt issued to build the TAPS was backed by parent company guarantees.[306] Thus, the Carriers' actual cost of debt does not reflect the true return on debt for a stand-alone pipeline that investors would require as compensation for providing capital.[307] Because the cost of borrowing

[304]Testimony makes clear that the individual ownership structure of TAPS is not something that should be reflected in rate of return. Tr. 2896 (WBT). However, the Carriers assert that the overall rate of return on capital is invariant to capitalization, and parent company capitalization and return on debt can be used to "back out" individual return on equity. They urge that this approach is consistent with traditional ratemaking. Tr. 2767 (WBT). Our goal as regulators is to set rates based on costs. The overall cost of capital is agreed by all parties to be invariant across ownership. T-10 (WBT) 8; WBT-61 at 2-3; FJH-T (E-2) 4*),* We find no reasoned basis nor does the record support a finding of different hypothetical capital structures for the different carriers.

[305]*State of Alaska v. Alaska Pub. Util. Comm'n*, 3AN 80-7163 CI, 2 (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.

[306]Tr. 2852 (WBT).

[307]The record does not clearly indicate the embedded cost of debt of the subsidiaries. However, even if it did, the subsidiary debt costs would not be appropriate given the parent company guarantees of that debt.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

changes through time, we determine the appropriate cost of project debt for each year from 1974-1996.[308]

The parties disagree about how to properly establish the cost of debt.[309] Both the Carriers and Williams adopt annual parent company embedded cost of debt for 1968-1996.[310] They use cost of debt, however, for different purposes. Williams uses the parent cost of debt, combined with its independent estimate of the cost of equity capital, to construct an overall rate of return for the TAPS.[311] The Carriers start with an independent estimate of the overall rate of return for TAPS, and use the parent cost of debt and capital structure to "back out" the cost of equity for each year.[312]

Neither the Carriers nor Williams claims that the embedded cost of debt of the parent companies bears any relationship to the cost of debt of a stand-alone TAPS.[313] The Carriers support their use of the parent company cost of debt because it is consistent with their reading of standard regulatory practice.[314] Williams supports its use of parent company cost of debt because "this is all that was available to the pipeline companies."[315]

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

[308]Finding that a stand-alone TAPS could only have attracted debt financing after April, 1974 means that a cost of debt need not be determined for years prior, even though capital expenditures were made as early as 1968.

[309]For a summary of the parties' positions on the cost of debt, *see* Exhibit 12.

[310]The Carriers adopt separate costs of debt for each of the parent companies to construct separate revenue requirement calculations for 1968-1996. RGV-14A through RGV-14G. Williams, however, adopts a composite cost of debt, based on the average of the parent companies' book cost of debt to construct a single revenue requirement for 1968-1996. JSG-T (W-2) 37.

[311]JSG-2 Schedule 10.

[312]Tr. 2972-73 (WBT); Tr. 2725-26 (WBT).

[313]Tr. 2592 (WBT); JSG-T 31.

[314]Tr. 2767 (WBT).

[315]Tr. 4385 (JSG).

Neither reason is persuasive for establishing cost of debt for a stand-alone enterprise. As we have found above, the record provides no compelling reason to use the Carrier parent company cost of debt. The parent companies in this case are generally large integrated petroleum companies[316] that have significantly richer equity positions than pipeline companies.[317]

A hypothetical cost of debt for a stand-alone pipeline more closely reflects costs.[318] Therefore, we look at a proxy group to determine an appropriate hypothetical cost of debt. We assess the cost of debt for a proxy group of pipelines that share risks similar to the TAPS. We assess annual costs of capital for 1974-1996 to help establish

[316]Tr. 5097-5101 (FJH); 221-FJH-E; 222-FJH-E.

[317]In 1997, the average equity position of the operating subsidiaries of the publicly traded gas pipeline holding companies was 49.41 percent. The average equity position of the publicly traded oil pipeline companies was 50.25 percent. In contrast, the arithmetic average equity position of the TAPS Carriers' parents was 66.46 percent, while the weighted average equity position was 73.21 percent. FJH-3 at 1.

[318]*State of Alaska v. Alaska Pub. Util. Comm'n*, 3AN 80-7163 CI, 2 (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.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

a rate base[319] for the TAPS as of year-end 1996.[320] The parties concur that after construction was started in 1974 the risks facing the TAPS are comparable to those of an average Lower 48 petroleum[321] or gas[322] pipeline. Therefore, we review the record to determine a cost of debt that reflects operations of a stand-alone pipeline company in the contiguous United States.

Tesoro advocates a hypothetical cost of debt based on three proxy groups of companies. The first two proxy groups consist of oil and gas pipelines that are publicly traded; the third proxy group consists of the TAPS parent companies. Tesoro uses data from the proxy groups, combined with expert judgment,[323] to arrive at an eight percent cost of debt for 1997.[324] Tesoro then assumes that the difference between the cost of debt for an appropriate pipeline company and the rate on long-term government

---

[319]Our findings on the cost of capital for 1968-1996 will also be used to analyze whether our determination of a rate base as of January 1, 1997, is reasonable in light of whether it constitutes a regulatorily enforced deficiency; *see* Section V.

[320]Even if we were to adopt the Carriers' recommended approach to setting an overall annual rate of return during 1968-1996, an appropriate cost of debt would nonetheless need to be established. Although the Carriers' sponsored approach does not, as a theoretical matter, affect the *overall* rate of return, (*see* Tr. 2972-76 (WBT), and 87-WBT-T), it nevertheless affects rate base. This is because ADIT, which affects rate base, is calculated with reference to the debt portion of AFUDC balance; *see, e.g.,* 143-RGV-C, TAPS-RGV WP3, Schedule 8, line 2 and Schedule 6 Column B). The debt portion of AFUDC is clearly affected by the choice of capital structure and the appropriate cost of debt.

In addition, the return to debt portion of a cost calculation does not receive an income tax allowance, while the return to equity portion does. Hence, the cost of debt affects the overall revenue requirement. Tr. 4964-66 (FJH). *See* Part IV,B.1. Therefore, determining the appropriate cost of debt is necessary for a fair determination of whether a regulatorily enforced deficiency, produced through a change in ratemaking methodologies, exists.

[321]T-10 (WBT) 10; JSG-T (W-2) 13.

[322]FJH-T (E-2) 4; T-6 (WBT) 37.

[323]Tr. 4978 (FJH).

[324]FJH-4 at 1.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

bonds will be constant.[325] Tesoro uses this assumed relationship to calculate the year-by-year cost of debt from 1996 back to 1968 by tracking changes in long-term Government bonds.[326] Tesoro's method for determining the cost of debt from 1968 to 1996 thus has two critical parts: a) the "anchor-year" cost of debt used for backcasting purpose; and b) the assumed constancy of the appropriate cost of debt for the TAPS and the annual return on United States Treasuries. Both of Tesoro's assumptions are problematic.

First, the 1997 anchor-year cost of debt is inappropriate. For 1997, Tesoro's gas pipeline proxy group had an average embedded cost of debt of 8.14 percent;[327] the average debt ratio was 52.39 percent.[328] Tesoro's sample oil pipeline companies had an average cost of debt of 8.81 percent in 1997;[329] the average debt ratio was 53.09 percent.[330]

Second, the spread between the cost of debt and United States Treasury bond yields that Tesoro relies on is not constant. Therefore, an analysis based on the spread for one year is not reliable.

In addition, Tesoro's approach fails to recognize that the cost of project debt does not change annually with capital markets.[331] It is not as volatile as Tesoro

[325]FJH-12 at 2. The "constancy" assumption is also made by the Carriers for the *overall* rate of return on capital and by Williams for the DCF analysis of the rate of return on equity to develop "backcast" costs of capital for 1968-1996. T-3 (WBT) 61-62; WBT-40; JSG-T (W-2) 32.

[326]*See* FJH-12 at 2.

[327]FJH-4 at 4. Tesoro bases its debt cost recommendation for 1997 on the proxy group debt costs for 1996.

[328]*See* FJH-3 at 4. The figure includes both short and long-term debt.

[329]FJH-4 at 3. Tesoro bases its debt cost recommendation for 1997 on the proxy group debt costs for 1996.

[330]FJH-3 at 3. The figure includes both short and long-term debt.

[331]Tr. 4953-54 (FJH).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

urges. The cost of debt for ratemaking purposes is generally the *embedded* cost of debt, *not* the current cost of debt.[332] As Williams witness Gaske explained:

> Now, with regard to debt holders and bond holders, as market conditions change, the yield changes, and the market value of the debt changes, *but the company's fixed obligations to pay the lenders does not change*, and so in a case like that, or when you're thinking in terms of the debt, you have to use the embedded cost of debt . . . .[333]

The cost of debt *issued* in any given year can match the cost of debt used to finance the TAPS only if the TAPS debt were fully refinanced each year. Such refinancing would produce unrealistic volatility in the debt return, be prohibitively expensive, and is contrary to prudent financial practice. The debt issued to originally construct the TAPS during 1974-1977 was less costly than debt issued during the late 1970s through the early 1990s because of the then existing market conditions. The bonds were often 20- to 30-year issues.[334] Therefore, Tesoro's proposal in effect would have the TAPS Carriers refinancing lower-cost debt with higher cost debt. This is unreasonable.

We modify Tesoro's approach to backcasting to determine the appropriate cost of debt capital. First, we designate a sample group from which to determine the appropriate cost of annual debt for a stand-alone TAPS. Second, we determine the appropriate cost of debt from which to backcast the annual cost of debt capital for the average pipeline in any given year. Finally, we determine the annual embedded cost of debt consistent with our findings on capital structure and annual debt costs. In developing rate of return recommendations, the Carriers and Tesoro rely on information

[332]The embedded cost of debt reflects the weighted average cost of debt for all bonds issued in prior years. The current cost of debt reflects what capital markets currently require.

[333]Tr. 4278 (JSG) (e*mphasis added)*.

[334]Tr. 4953 (FJH).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

from gas and oil pipelines. Our capital structure is based on both gas and oil pipeline proxy groups. Therefore, it is reasonable to base the appropriate cost of debt on the same two groups.[335]

Because the record contains multiple options for cost of debt data with no compelling grounds for weighting one data set more than another, the most reasonable approach is to average the different figures.[336] We average the cost of debt of the gas and oil pipeline groups to determine cost of debt to use in our backcast analysis.[337]

We next correct the problem of relying on a single "anchor year" for backcasting the annual cost of debt back to 1974. The record shows the annual spread between the cost of debt for an average pipeline and the yield on United States Treasuries for 1997, 1998, 1999 and 2000.[338] Therefore, we adopt the average pipeline sample's average premium during 1997-2000 above United States Treasuries.[339] The average premium is 1.86 percent.[340] We use this premium to derive reasonable figures for the cost of pipeline debt *issued* in prior years.

We make no adjustment in the cost of debt to accommodate risks particular to the TAPS. Before May 1974, risks faced by TAPS investors were especially high, but the record suggests little debt was issued.[341] We assumed 100 percent equity financing during this period.[342] From 1974 forward, as we discuss in

---

[335]Tr. 2949 (WBT). It requires a judgment. Tr. 4977 (FJH).

[336]Tr. 5027-5028 (FJH); Tr. 4959 (FJH).

[337]*See* Exhibit 13, line 3.

[338]JSG-2 Schedule 12; FJH-4.

[339]U.S. Treasury data are from JSG-2 Schedule 12.

[340]*See* Exhibit 13, line 6.

[341]*See* WBT-26 (Gary) 99.

[342]Part IV Section B.1.c.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

Part IV Section B.4, *infra*, the nature and extent of TAPS risks, although greater than those facing the average pipeline, confronted only equity and not debt investors. Therefore, we do not award a special TAPS risk premium on the cost of debt. Having made these modifications to Tesoro's analysis, we generate the *annual* cost of debt from 1974 to 1996 for debt *issued* at Exhibit 14.[343]

Next we calculate an appropriate *embedded* cost of debt to correct the flaw in Tesoro's analysis that low-cost debt is replaced with high-cost debt. The embedded cost of debt is the weighted average cost of debt for all outstanding debt balances. The hypothetical cost of debt needs to reflect the size and cost of the bonds issued, when the bonds were issued, and the length of time to bond maturity (because the rate of return on bonds stays constant).[344] The hypothetical embedded cost of debt in any given year also reflects assumptions about the rate at which payments are made into a sinking fund; the date of those payments; and the amount of "balloon payments" needed to compensate for sinking fund shortfalls at the date of maturity.

Carriers suggest that the typical bond issued to build the TAPS had a maturity of 20 to 30 years.[345] This evidence was not disputed by the other parties. Data contained in Carrier-sponsored exhibits show that major debt issuances by the TAPS Carriers' parents during November 1973 through October 1977 have a weighted average term to maturity of roughly 19 years.[346] We therefore adopt a 19-year term to maturity for all TAPS bonds to calculate the hypothetical embedded cost of debt.

---

[343]We add the 1.86 percent premium to the cost of U.S. Treasuries in any given year to derive the cost of debt issued in that year.

[344]*See* Tr. 4952- 54 (FJH).

[345]Tr. 4953 (FJH).

[346]*See* WBT-26 (Gary) 99-100. The weighted average figure of nineteen years does not include Valdez terminal debentures, which appear to generally have thirty-year maturities. *See* Exhibit 15, Schedule 1.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

We make reasonable assumptions to set the remaining variables needed to construct a yearly hypothetical embedded cost of debt. Our findings reflect the constant hypothetical structure that we adopt; the term to maturity of the hypothetical bonds we impute; the need to finance TAPS' yearly capital additions; and the regulatory depreciation schedule. *See* Exhibit 15, Schedule 2. Although these assumptions may not conform to the actual bonds used to finance the TAPS, they are reasonable and consistent.[347] We adopt the hypothetical embedded cost of debt for each year 1974 through 1996 calculated in Exhibit 15, Schedule 3.[348]

3. *Return on Equity*

Regulators determine the cost of equity by assessing the return that equity investors require given their perceptions of prospective project risks.[349] The parties assert that ongoing operational risks of TAPS are roughly equivalent to those faced by average pipeline companies.[350] We therefore assess the cost of equity based on what an average stand-alone pipeline would require. That cost is the baseline cost of TAPS equity from 1968-1996. To account for any special TAPS risks, we adjust the baseline after analyzing TAPS project risks in Part IV Section B.4, *infra*.

---

[347]The constant capital structure adopted for 1977-1996 plays a particularly important role in our derivation of the embedded cost of debt. Capital additions in any given year must be financed at a 49.5/50.5 percent ratio, and bond retirements must therefore track regulatory depreciation. Accordingly, the goal of relative transparency and simplicity provides relatively little room to make assumptions other than those adopted.

[348]The embedded cost of debt that we derive and award is a reasonable estimate based upon the record in this case. We note that it may be an overly generous award. The average embedded cost of debt for crude oil pipelines during 1974 and 1975, according to a Carrier witness during the original Phase I proceeding, is roughly 250 basis points less than the embedded cost of debt that we award for TAPS. *Cf.* WBT-34 (Stich) 276 *with* Exhibit 15, Schedule 3.

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

[350]T-3 (WBT) 39; FJH-T (E-2) 65; Tr. 4944-45 (FJH); JSG-T (W-2) 39.

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

In most rate cases, the cost of equity is determined for a single, or at most a few, years. In this case, however, the appropriate cost of equity capital must be determined on an annual basis for 1968-1996.[351] General economic conditions changed from 1968 to 1996. The cost of equity, therefore, also changed.[352] The parties evaluated investor expectations and what compensation they would require for each year over a nearly 30-year period. Exhibit 16 summarizes the parties' positions on the return on equity.

The parties combined the recent data on current costs of equity with past trends in equity markets to "backcast" or "project" the rate of return that investors required for past years. Tesoro's rate of return witness Hanley explained that "the backcasting approach is what I would call a vehicle of convenience in this proceeding."[353] Williams witness Gaske echoed the practical need to backcast given the many years at issue.[354] Based on the record, we decide the most appropriate "backcast" approach.

The Carriers' backcast return on equity for 1968-1996 is based on their expert witness's recommendation regarding the overall rate of return for TAPS for 1997-

[351]Tesoro's witness Hanley reiterated the need for determining the rate of return on equity for every year, from 1968-1996, to establish a rate base: "But in terms of backcasting the reason for it seems clear, is because there needs to be some determination of rate base. The rate of return is a portion of it." Tr. 5080 (FJH). The return on equity affects AFUDC balances, which in turn affect the size of rate base. Furthermore, to check the appropriateness of the rate base, comparative revenue requirement analyses require a rate of return determination so that a total annual revenue requirement can be calculated. *See also* T-10 (WBT) 53-54, where the need for obtaining earlier-year costs of equity to perform the parties' unrecovered investment analyses is explained.

[352]Tr. 4278-79 (JSG); FJH-T (E-2) 65.

[353]Tr. 5080 (FJH).

[354]Tr. 4382 (JSG).

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533

1998.[355] This approach relies on the theory that investors demand a constant premium for overall returns above the return on long-term government debt.[356] The Carriers use the difference between this recommendation for an overall rate of return and the "riskless" investment of 1997 U.S. Government bonds, combined with historical data on United States Government bonds, to "backcast" overall rates of return for each year in question.[357] The Carriers then determine the backcast rates of return on *equity* through application of the Modigliani-Miller theory. The Modigliani-Miller theory states that the overall rate of return is invariant to how an enterprise is financed. Thus, given recommendations on the annual capital structure and rate of return on debt, Modigliani-Miller allows one to "back out," or solve for, the rate of return on equity.[358]

Tesoro's expert witness also bases its backcast results on its determination of an appropriate return for 1997.[359] However, Tesoro's approach differs from the Carriers'. First, Tesoro backcasts the return on equity separately from the overall rate of return.[360] Tesoro thus avoids using the Modigliani-Miller hypothesis to derive backcast equity returns. Second, Tesoro disputes that the difference between the return on equity and the return on long-term government bonds is constant.[361] Tesoro's analysis is, instead, based on the theory that equity risk premiums change inversely with interest rate changes.[362] Tesoro relies on empirical findings for the

---

[355]Tye has a single recommended rate of return for this two-year period; T-3 (WBT) 59, Table 3.

[356]T-3 (WBT) 62.

[357]WBT-40; WBT-5.

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

[359]*See* FJH-12 at 2..

[360]*See* FJH-12 at 1.

[361]FJH-T (E-2) 67-68.

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

Regulatory Commission of Alaska
701 West Eighth Avenue, Suite 300
Anchorage, Alaska 99501
(907) 276-6222; TTY (907) 276-4533