Exhibit No. ______ (GRS-4T)
Docket No. TO-011472
Witness: George R. Schink

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

Washington Utilities and Transportation Commission,	)	DOCKET NO. TO-011472
	)	)
Complainant,	)	
	)	
v.	)	
	)	
Olympic Pipe Line Company, Inc.	)	
	)	
Respondent.	)	

REBUTTAL TESTIMONY OF
GEORGE R. SCHINK

OLYMPIC PIPE LINE COMPANY

June 11, 2002

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Exhibit No. ___ (GRS-4T)

OLYMPIC PIPE LINE COMPANY

REBUTTAL TESTIMONY OF DR. GEORGE R. SCHINK

I. Introduction

Q. Please state your name, business address, and business title for the record.

A. My name is George R. Schink. My business address is 1725 Eye Street, NW, Suite 800, Washington, D.C. 20006. I am a director of LECG, LLC, an international economic and financial consulting firm.

Q. Have you presented previous testimony in this matter?

A. Yes. My academic and professional backgrounds were provided in my direct testimony at Exhibit No. ___(GRS-1T).

II. Purpose and Organization of Testimony

Q. What is the purpose of your testimony?

A. I have been asked to update my cost of capital analysis for Olympic and to evaluate the testimony submitted by witnesses for Staff and Tesoro Refining and Marketing Company and Tosco Corporation (when used collectively, "Intervenors") addressing Olympic's cost of capital. In response to issues raised by other witnesses, I have been asked to address some regulatory policy and practice issues relevant to this matter. Finally, I have been asked to consider some issues raised by other witnesses related to Olympic's power cost and throughput.

Q. How is your testimony organized?

A. In the next section, Section III, I provide a summary of my testimony.

In Section IV, I discuss regulatory framework issues relevant to this proceeding. In this section, Hope Natural Gas, 320 U.S. 591 (1944), the "end result" test, and common sense are examined as guidelines for Washington Utilities and Transportation Commission ("Commission" or "WUTC") decisions on the appropriate rate of return. I also discuss regulatory consistency, the costs of regulatory change, and the need for compensation for regulatory change.

Section V of my testimony examines Olympic's riskiness relative to that of a typical oil pipeline company. The factors contributing to Olympic's higher-than-average risk are the extensive waterborne competition faced by Olympic and the asymmetric risk caused by Olympic's potential failure.

Section VI examines Olympic's capital structure and its historical dividend policy.

Section VII addresses Olympic's cost of capital. The discussion of the cost of capital is set within the framework of the Commission's recommended methodology. First, I update Olympic's cost of common equity capital. Next, I discuss the appropriate equity risk premium adder for Olympic, the appropriate cost of debt, and the appropriate capital structure to use for ratemaking. In addition, I examine the cost of capital issues raised by Staff and Intervenors and the methodologies they employ and results they produce.

Section VII of my testimony looks at the unconventional and inappropriate approaches to ratemaking employed by other parties to this proceeding.

Section VIII addresses concerns about retroactive ratemaking

Finally, Section X discusses issues related to Olympic's power cost and throughput.

III. Summary of Testimony

Q. Please summarize your testimony regarding the appropriate rate of return on common equity capital for Olympic.

A. Staff's and Intervenors' witnesses who have submitted cost of common equity capital testimony have based their analyses on more current data than were available when I submitted my direct testimony. Therefore, I have updated my calculations to incorporate the most recent information available. Based on the DCF-based approach adopted by the Federal Energy Regulatory Commission ("FERC") in other proceedings, my current estimate of the cost of common equity capital for a typical oil pipeline company, in real terms (i.e., not reflecting expected inflation)[1] is 13.20% and, in nominal terms (i.e., reflecting expected inflation) is 14.70%. Olympic, however, is not a typical pipeline in terms of risk. Olympic is a relatively high-risk pipeline due to the waterborne

[1] Two recent inflation expectation estimates are 1.55% and 1.48% with a midpoint value of 1.515%, or approximately 1.50%.

competition it faces and to its risk of financial failure. Based on these two factors, I have determined that a risk premium adder of 0.95% is appropriate for Olympic (i.e., Olympic's cost of common equity capital is 0.95% higher than that for a typical oil pipeline company). Therefore, based on the most current available data, my recommendation is that Olympic's cost of common equity capital in real terms be 14.15% and in nominal terms be 15.65%

Q. Please summarize your conclusions regarding the cost of common equity capital testimony submitted by other witnesses.

A. Mr. Hanley, on behalf of Tesoro Refining and Marketing Company ("Tesoro"), recommends a much lower cost of common equity capital for both a typical oil pipeline company and for Olympic. He obtains these low results for a typical oil pipeline company by simply averaging the results produced by several methods. If one only considers Mr. Hanley's DCF-based calculations the most closely approximate approach adopted by this Commission in earlier matters, Mr. Hanley's calculated cost of common equity capital in nominal terms is 15.65% versus my estimate of 14.70% for a typical oil pipeline company. Mr. Hanley's estimate of the inflation factor is inappropriate and unrealistically high thereby making his estimate of the cost of common equity capital in real terms unrealistically low.

Mr. Means, on behalf of Tosco Corporation ("Tosco"), uses a methodology very similar to mine in determining the cost of common equity capital. In fact, he relied on my earlier DCF-based calculations to develop his estimate. If he were to apply the same methodology to my updated calculations, his estimate of the cost of common equity for a typical oil pipeline company would be only slightly less than mine in both real and nominal terms.

Both Mr. Hanley and Dr. Means, however, argue that Olympic is no riskier than a typical oil pipeline. Therefore, they assert that no risk premium adder is necessary for Olympic and that Olympic's cost of common equity capital is no higher than that of a typical oil company. They offer no evidence to support their positions, however, and their attempts to refute my evidence are ineffective. Further, both Tesoro and Tosco refused to supply Olympic with their costs for waterborne transportation of light refined products. I believe this refusal should be viewed by the Commission as an implicit admission by Tesoro and Tosco that waterborne transportation is a cost-effective competitor to Olympic.

Dr. Wilson, on behalf of Staff, fails to employ any method consistent with the DCF-based approach accepted by the Commission in previous rate cases. Further, the methods he uses to estimate the cost of common equity capital for a typical oil pipeline company are seriously flawed. As a consequence, I urge the Commission to disregard his estimates of the cost of common equity capital. Dr. Wilson, like Mr. Hanley and Mr. Means, asserts that Olympic is no riskier than a typical oil pipeline company, but, also like Mr. Hanley and Dr. Means, Dr. Wilson offers no meaningful evidence to support his assertion.

Q. What are your recommendations regarding Olympic's cost of debt and capital structure?

A. I have updated my estimate of Olympic's cost of debt which, consistent with FERC precedent for a company like Olympic that is wholly-owned by other companies, is set equal to the ownership share weighted embedded debt costs of

Olympic's parents. Based on the most currently available data, Olympic's cost of debt is 5.26%.

Regarding Olympic's capital structure, again consistent with FERC precedent for a company like Olympic that is wholly-owned by other companies, I have assigned Olympic a hypothetical capital structure based on the capital structures of its parents. Olympic's equity share of capital is set equal to the ownership share weighted equity shares of capital for its parents. Based on the most current data, Olympic's equity share of capital is 86.85%.

Q. Please describe issues raised by witnesses for Staff and the Intervenors regarding Olympic's cost of debt and capital structure.

A. Mr. Hanley, on behalf of Tesoro, argues that Olympic's cost of debt and equity share of capital should be set equal to the average values of the companies in the oil pipeline proxy group. Dr. Means, on behalf of Tosco, agrees with me on how Olympic's debt cost should be defined and with Mr. Hanley on how Olympic's capital structure should be defined. Dr. Wilson, on behalf of Staff, assigns arbitrary values to both.

While I believe my approach to defining Olympic's debt cost is appropriate, the effect of the differences between the results produced by the different approaches are not that substantial. The differences regarding Olympic's capital structure, however, <u>are</u> substantial. Mr. Hanley's and Dr. Means's recommended equity shares in Olympic's capital structure are both below 50%. Dr. Wilson's recommendation ranges from a 20% to 50% equity share.

Intervenors' witnesses' equity share recommendations for Olympic are premised, at least implicitly, on the assumption that Olympic is no riskier than a typical oil pipeline company. Given that Olympic, in fact, is riskier than a typical oil pipeline company, it is appropriate for Olympic to have a higher equity share in its capital structure than would a typical oil pipeline company, which is what I recommended.

Q. Have you suggested some alternatives to the Commission if it decides that the equity share implied by Olympic's parents' capital structures is too high?

A. Yes. I have recommended, as a minimum, a 60% equity share for Olympic. This share is just below the upper end of the range of equity shares for the companies in the oil pipeline proxy group. However, Olympic is riskier than any of the companies in the oil pipeline proxy group. Therefore, I believe it would be more appropriate to set Olympic's equity share to a value halfway between the upper end of the range for the companies in the oil pipeline proxy group (60%) and the ownership share weighted average of Olympic's parents' equity shares (86.85%). This midpoint value is 73%.

Q Regarding issues other than Olympic's cost of capita, please briefly describe these issues and the conclusions you have reached.

A. First, I have examined the <u>Hope</u> case and have considered the implications of the so-called "end result" test for this matter. <u>Hope</u> and the "end result" test indicate that the specific circumstances of a company should be taken into account in determining its cost of capital. Given Olympic's very high risk situation, this suggests that Olympic's costs of capital are much higher than those of a typical oil pipeline company and also that it is appropriate for Olympic to have a higher equity share in its capital structure than would a typical oil pipeline company. Finally, it is also permissible, according to court precedent, for a regulatory commission to allow a regulated company a higher return on equity capital based solely on the desire of the commission to provide an incentive for the regulated company to invest in socially-desirable projects.

Second, witnesses for Tesoro pursue what I have characterized as a blame and punish approach to ratemaking, which is inappropriate. The Tesoro witnesses recommend that the Commission punish Olympic for alleged transgressions by reducing its cost of common equity, its cost of debt, its equity share of capital, its operating expense, and by increasing Olympic's throughput thereby producing ridiculously low tariff rates for Olympic.

Third, Tesoro's witnesses urge the Commission to engage in retroactive ratemaking, which is inappropriate.

Fourth, other witnesses have improperly reduced Olympic's power costs and have overstated Olympic's test year throughput.

Q. Are there some issues relevant only to the WUTC proceedings?

A. Yes.

Q. Please discuss your conclusions regarding these issues.

A. First, I believe that it would be unfair and unreasonable for the Commission to reject the FERC ratemaking methodology given that the Commission has accepted it in the past. Further, a switch from the FERC ratemaking approach to a DOC-based ratemaking methodology, properly implemented, provides no benefits to shippers or to society. Finally, if the Commission is to switch to a DOC-based methodology, then unless the Commission approves an appropriately defined transition mechanism, Olympic will be denied the opportunity to earn a fair return on its existing investment. I have developed an appropriate transition mechanism that I urge the Commission to adopt if it decides to use a DOC-based methodology in this matter.

Second, Staff is too quick to arbitrarily alter or replace Olympic's data to the detriment of Olympic. This practice is inappropriate.

IV. Regulatory Framework Issues

A. Hope, "End Result," and Common Sense

1. The Hope Natural Gas Case

Q. Does the Hope case give Commission the discretion to consider the unique circumstances of a regulated entity when determining its appropriate return on equity?

A. Yes. Prior to Hope, the regulatory process was governed by Smyth v. Ames, 169 U.S. 466 (1898), which required regulatory commissions to follow a court-specified process in determining a fair and reasonable return for a regulated entity. In Hope, the Supreme Court gave regulatory commissions a great deal of discretion as to how they were to determine the appropriate return on equity for a regulated entity.

2. The "End Result" Test

Q. Did the Hope decision foster the so-called "end result" test?

A. Yes.

Q. Please explain.

A. The "end result" test essentially states that the methodologies used by regulatory commissions to determine the rate of return for a regulated entity is essentially irrelevant so long as the outcome is just and reasonable. In other words, there needs to be a reasonable and defensible method for justifying the return for a regulated entity, which generally requires that a reasonable and defensible method be used to generate the end result. Courts have reversed commissions who used the end result defense to declare simply that the new rates were reasonable and old rates were not reasonable. See Commonwealth Telephone Company v. Wisconsin Public Service Commission, 71 P.U.R.(NS) 65, 69, 71 (1947), affirmed, 32 N.W.2d 247 (1948).

Conversely, regulatory commissions could not expect to successfully defend an unfair and unreasonable outcome just because it was produced following the same procedures it followed in other matters (e.g., used the same models in the same way). Put somewhat differently, procedural consistency, by itself, is not sufficient justification for a commission's return on equity decision. Instead, the Commission must be able to demonstrate that the end result is just and reasonable. In summary, under Hope, the critical factor is not the method used to determine the result but instead the critical factor is whether the result is just and reasonable.

The relevance of the "end result" test to this matter is that the oil pipeline industry is different from other regulated industries, and Olympic's circumstances are different from those of a typical oil pipeline company. The oil pipeline industry is much more competitive than the electricity or gas distribution industries and also more competitive than the natural gas pipeline industry. Olympic, because of its exposure to waterborne competition and to the severe negative financial impacts that have followed in the wake of the June 10, 1999, accident in Bellingham, Washington, has much higher risks than are faced by a typical oil pipeline company. I believe that it is essential for the Commission to take these factors into account in reaching its decision regarding Olympic's return on equity if the Commission is to satisfy Hope and the "end result" test.

3. Common Sense

Q. Please explain the relevance of the term "common sense" in the context of this proceeding.

A. The common sense aspect of evaluating Olympic's risk in determining an appropriate return on equity for Olympic is that an investment in Olympic is obviously much riskier than investment in any one of the companies in the oil pipeline proxy group used Staff's and Intervenors' witnesses' testimonies address Olympic's cost of common equity to determine the cost of common equity capital for a typical oil pipeline company.

If I were told that I could expect to earn about the same return on a $1 equity investment in Olympic as I could earn by investing $1 in the equity of any one or any combination of the oil pipeline proxy group companies, I would invest in the latter without a moment's hesitation. The reason for this decision is that the risk to my $1 equity investment in Olympic is much higher in the sense that Olympic has a much greater risk of failure (bankruptcy) where I could lose my entire investment. The risk of Olympic's failure is real given its current financial condition. The risk of Olympic's failure is an asymmetric risk in the sense there is a large downside risk (i.e., failure) and no corresponding upside opportunity (i.e., if Olympic survives, it can not earn a sufficient return to offset the downside risk). Olympic's investors must be compensated for this asymmetric risk by allowing Olympic a substantially higher return on equity than would be appropriate for the oil pipeline proxy group companies or, at minimum, at the upper end of the range of the cost of common equity calculated for these companies.

Q. Is it appropriate and defensible under the guidelines set by Hope and the "end result" test to allow Olympic an above-average return on equity as an incentive to produce Olympic's owners an economic incentive to make the large investments necessary to ensure the long-term reliability of the pipeline and to restore the pipeline to its full operating capacity?

A. Yes. The end result desired is that Olympic makes these investments. In Farmers Union Central Exchange, Inc. v. FERC, 734 F.2d 1486 (D.C. Cir. 1984 (Farmers Union II), the court stated that it would be appropriate for the FERC to set returns at the upper end of the reasonable range based solely on the desire of the Commission to encourage what it perceived to be useful investment. In Farmers Union II, the court stated that:

> We recognize, of course, that "noncost" factors may play a legitimate role in the setting of just and reasonable rates. In Williams, FERC invoked the need to stimulate additional oil pipeline capacity as one reason for setting maximum rates at such high levels. See supra at p. 9. As this court has observed before, "[r]eliance on noncost factors has been endorsed by the courts primarily in recognition of the need to stimulate new supplies." *Consumers Union of United State, Inc., v Federal Power Commission* (1974) 166 US App DC 276, 5 PUR4TH 500, 510 F2d 656, 660 (footnote omitted) (discussing Permian and Mobil

Oil).

This clearly gives the Commission the discretion to offer Olympic an incentive to make the large investments required to restore its operating pressure to 100% and to ensure the long-run reliability of the system. Finally, common sense suggests it is in the public interest for the Commission to provide such an incentive.

B. Other Regulatory Framework Issues

1. The Importance of Regulatory Consistency and the Cost of Regulatory Change

Q. What regulatory framework has Olympic operated under since 1985?

A. Olympic has been subject to the FERC regulatory framework as spelled out in Opinion 154-B since 1985. During this period, Olympic has kept its records, done its planning, and conducted its operations in the context of the current FERC regulatory framework. The Commission has accepted Olympic's FERC Form 6 filings as sufficient for its monitoring purposes since that time. All prior tariff rate increase submissions to the Commission have been developed and justified within the FERC's framework and have been accepted by the Commission. Staff's and Tesoro's witnesses' position that the Commission should reject the FERC framework at this juncture is unfair and unreasonable.

Q. What hardships would a rejection of the FERC methodology and acceptance of the proposed alternative by the Commission impose on Olympic?

A. Because no transition mechanism is proposed by the Staff or Tesoro's witnesses, Olympic would be denied the opportunity to earn a fair return on its existing investment if the Commission were to accept Staff's and Tesoro's witnesses' recommendation. Both Staff and Tesoro's witnesses propose an uncompensated shift from the trended original cost (TOC) ratemaking methodology used by the FERC to the depreciated original cost (DOC) framework of the sort that the Commission uses to regulate companies in the regulated industries.

A transition from a TOC to DOC framework has the effect of stranding investment, just as a transition from a regulated to market framework has stranded investment for electric utilities. However, there is a difference. There is no uncertainty regarding whether the switch from TOC to DOC will create stranded investment--it will. Furthermore, the dollar value of the lost return as a result of the switch from TOC to DOC can be calculated exactly, as I have done below.

If the Commission were to determine that it would require Olympic to justify its proposed rates in this proceeding within the DOC ratemaking framework, then a transition mechanism also must be approved by the Commission that would give Olympic the opportunity to earn a fair return on its existing investment. Otherwise, the resulting rates would not be just and reasonable. I have calculated below the dollar value that Olympic would be denied the opportunity to earn as the result of an uncompensated transition from TOC to DOC. I also have proposed a five-year transition mechanism that would give Olympic the opportunity to recover the return that would be stranded as a result of a switch from TOC to DOC.

Q. What benefits would the shippers and the public obtain as the result of a properly compensated switch from TOC to DOC?

A. None. As I demonstrate below, the return on investment and thereby the cost to shippers and the public is identical over the life of an asset under the TOC and DOC frameworks.

Therefore, I believe it would be appropriate for the Commission to accept the additional burden of working within the TOC framework used by the FERC just as the Commission and its Staff have done in the past.

The estimated cost to Olympic of such an uncompensated transition from TOC to DOC is calculated below.

2. The Need to Compensate Olympic If It Is Required to Switch From TOC to DOC

Q. Have you demonstrated that it would be unfair to require that Olympic be required to switch from TOC to DOC and not be compensated?

A. Yes.

Q. Please explain beginning with an explanation of the DOC and TOC ratemaking methodologies and the differences between them.

A. The DOC and TOC ratemaking approaches are two different approaches to setting rates that permit a regulated entity to earn the same fair return on the investment in an asset over its lifetime. The timing of when the fair return is earned over an asset's lifetime, however, differs between the two methods. Under DOC, the dollar earnings are higher early in an asset's life and lower late in an asset's life than is the case under TOC. The rationale for using a TOC approach is that it tends to levelize earnings over an asset's lifetime.

Q. Can you illustrate the differences between DOC and TOC in the context of a simple hypothetical example?

A. Yes. I will start with the simplest possible hypothetical example and then present a more complicated hypothetical to illustrate more clearly some additional points. Assume a hypothetical new pipeline with a cost of $100, a lifetime of two-years, depreciation of $50 per year, an annual throughput of fifty barrels, a nominal cost of common equity capital of 15%, an expected inflation rate of 3% and, thereby, a real cost of common equity capital of 12%. Under DOC, the annual earnings, the annual tariff per barrel, and the discounted present value of earnings for the hypothetical pipeline are as follows:

DOC Ratemaking Example

	Net Book Value	Realized Earnings	Annual Tariff ($/Bb1)	Discounted Realized Earnings (15%)
Year 1	$100	$15	$0.30	$13.04
Year 2	$50	$7.5	$0.15	$5.67
Discounted Present Value at 15%	___	___	___	$18.71

TOC ratemaking introduces the complication of deferred earnings. For the simple hypothetical example, deferred earnings would be $3 for the first year (i.e., the 3% inflation factor times the net book value of $100) and the first year realized earnings would be $12 (i.e., the 12% real cost of common equity capital times the net book value of $100). Total earnings in the first year are the same under DOC and TOC, but, under DOC, the total earnings are realized in the first year and there are no deferred earnings. In the second and last year of the hypothetical pipeline's life under TOC, deferred earnings on the rate base would be $1.50 (i.e. 3% of $50) and realized earnings on the rate base would be $6 (i.e. 12% of $50). In addition, there are deferred and realized earnings on the deferred earnings balance of $3 in the amounts of $0.09 (i.e., 3% of $3) and $0.36 (i.e., 12% of $3). Finally, realized earnings would also include recovery of deferred earnings. In the context of the simple pipeline with a two-year life, all the deferred earnings would be recovered in realized earnings in the second and last year of the asset's life: (1) the $3 deferred earnings balance from the first year and (2) the $1.50 deferred earnings component from the second year.

Total second year realized earnings under TOC are $10.95: $6 + $1.50 + $3 + $.09 + $0.36. The results of all the above TOC calculations are summarized below:

TOC Ratemaking Example

	Net Book Value	**Realized Annual Earnings**	**End of Year Deferred Earnings Balance**	**Annual Tariff Rate ($1/Bb1)**	**Discounted Realized Annual Earnings (15%)**
Year 1	$100	$12	$3	$0.240	$10.43
Year 2	$50	$10.95	$0	$0.219	$8.28
Discounted Present Value at 15%	___	___	___	___	$18.71

The discounted present value of the realized earnings under both DOC and TOC equals $18.71. The discount factor is 15%, which equals the nominal cost of common equity capital for the hypothetical pipeline. The pipeline's owners earn a 15% internal rate of return under both DOC and TOC. Therefore, so long as either DOC or TOC is used consistently over the life of an asset, the asset's owners are neither benefited nor harmed by the use of DOC or TOC. (i.e., the asset's owners would be indifferent between the consistent use of either DOC or TOC).

Conceptually, shippers might prefer a TOC approach because TOC tends to levelize realized earnings and, thereby, levelize the implied per barrel tariff rate over the life of the asset. Under DOC, the per barrel tariff rates in year 1 and 2 are $0.30 and $0.15, respectively. Under TOC, the corresponding per barrel tariff rates are $0.240 and $0.219. TOC reduces the initial rate shock that would result under DOC as a consequence of a major new investment.

Q. Have you used your simple hypothetical pipeline example to demonstrate the stranded investment problem that arises with an uncompensated transition from TOC to DOC?

A. Yes. The following illustrates the consequences of switching from TOC to DOC in the second and last year of the life of the hypothetical pipeline:

Uncompensated Switch From TOC to DOC Ratemaking Example

	Net Book Value	**Total Realized Earnings**	**End-of-year Deferred Earnings Balance**	**Annual Tariff Rate ($/Bbl)**	**Discounted Realized Annual Earnings (15%)**
Year 1	$100	$12	$3	$0.240	$10.43
Year 2	$50	$7.5	$3	$0.150	$5.67
Discounted Present Value at 15%	___	___	___	___	$16.10

The discounted present value, using a 15% discount rate, of total earnings is $16.10 with a TOC to DOC switch versus $18.71 under either just DOC and just TOC. The internal rate of return to the owners of the pipeline over its lifetime with a TOC to DOC switch is 12.9% instead of the 15% achieved with either just DOC or just TOC.

Q. In this simple hypothetical example, what is the appropriate transition payment that would provide the pipeline's owners with the opportunity to earn the 15% return implied by their nominal cost of common equity capital?

A. The answer is simple and obvious in this two-year life hypothetical. The transition mechanism must allow the pipeline to charge the same rates per barrel in the second year as would have been charged under TOC to give it the opportunity to earn a 15% return. That is, the second year tariff rate will have to be raised from $0.150 per barrel to $0.219 per barrel so that second year revenues on 50 barrels of throughput would be $10.95 instead of $7.50 implied by DOC.

It is interesting and useful for generalizing the results from this simple hypothetical to examine what makes up the difference between the $7.50 of revenues under the DOC–based tariff rate and the $10.95 of revenues under the TOC-based tariff rate. With the TOC to DOC switch, the $3 deferred earnings balance is stranded and never recovered so this is part of the difference. The other part of the difference is the return on the deferred earnings balance during the second year, which, in nominal terms under the DOC, would be 15% or $0.45. The sum of these two components, $3.45, is, in fact, the difference between $10.95 and $7.50.

To properly compensate the hypothetical pipeline for the investment that would be stranded as a result of the switch from TOC to DOC, the DOC-based tariff rate would have to be increased by $0.069 per barrel which is $3.45 divided by the 50 barrels of throughput.

The discounted present value of the $3.45 earned in the second year, using a 15%

discount rate, at the end of the first year is $3 which equals the deferred earnings balance at the end of the first year. The generalization of this result is that an appropriate transition mechanism must be expected to generate future revenues whose discounted present value as of the end-of-the-year before the transition from TOC to DOC equals the deferred earnings balance at the end-of-the year before the transition. In the context of the five-year transition developed below for Olympic, this involves determining a constant five-year surcharge to tariff rates that generates expected revenues, based on test year volume, whose discounted present value at the beginning of the test year equals the deferred earnings balance at the beginning of the test year.

Q. Have you evaluated the issue of a TOC to DOC transition in the context of a somewhat more complex hypothetical pipeline example?

A. Yes. I have maintained all the assumptions underlying the simple two-year life example above except that the hypothetical $100 pipeline now is assumed to have a four year life and the transition from TOC to DOC occurs between the second and the third year of the pipeline's life. The annual depreciation is $25, the annual throughput is fifty barrels, the nominal cost of common equity capital remains 15%, the inflation factor remains 3%, and the implied real cost of common equity capital remains 12%.

Exhibit GRS-5, page 1 shows the annual dollar returns on net book value (or, equivalently, net depreciated investment) over the four-year life of the pipeline under DOC (the black bars) and under TOC (the white bars). The dollar returns under TOC are lower than those under DOC in the first two years and the reverse is true in the last two years.

In the upper two panels on page 2 of the Exhibit GRS-5, the discounted present value of the annual dollar returns are calculated for DOC and TOC over the four-year life of the pipeline and both are $28.63 (i.e., the present value of returns to the pipeline's owners over the pipeline's life is 15% under both DOC and TOC).

In the third panel on page 2 of Exhibit GRS-5, the effect on the pipeline's returns of an uncompensated switch from TOC to DOC between the second and third year of the pipeline's life is calculated. Such a switch would reduce the discounted present value of the pipeline owner's revenue to $25.34 (from $28.63 under the just TOC or just DOC) and would reduce the internal rate of return of the pipeline owners to 13.30% (from 15% under either just TOC or just DOC).

In the fourth (bottom) panel on page 2 of Exhibit GRS-5, a fixed amount is added to the third and fourth year revenues implied by DOC. Including these increments generates the same return to the pipeline's owners over the pipeline's life as would have been generated under either just TOC or just DOC (i.e., a discounted present value for revenue of $28.63 or, equivalently, a 15% internal rate of return.) The implied annual increment to revenues in the third and fourth years under DOC after the switch from TOC is $2.67. The fixed per barrel tariff surcharge in years 3 and 4 to the DOC after the switch is $0.0534 per barrel. Page 3 of Exhibit GRS-5 illustrates the increment to DOC revenues in the year 3 and 4 after the switch from TOC that are needed to produce a 15% internal rate of return for the hypothetical pipeline's owners over its four-year lifetime.

Pages 4 and 5 of Exhibit GRS-5 provide the detailed calculations underlying the results presented on pages 1 to 3 of this exhibit.

Q. Have you developed a transition mechanism for Olympic that would provide it with the opportunity to recover its deferred earnings if the Commission were to decide to calculate Olympic's revenue requirement and rates based on DOC instead of TOC?

A. Yes. Olympic's deferred earnings balance as of the beginning of the test year is $23.7 million. I have calculated the increment to the revenue requirement generated under DOC that would allow Olympic to recover the present value of this deferred earnings balance over a five-year period.

As shown in Exhibit GRS-6, page 1, the constant annual increment to pre-tax revenue required over the next five years to allow Olympic to recover, after tax, the discounted present value of $23.7 million is $11.0 million for the next five years. Based on Olympic's test year throughput of 103.1 million barrels, the average per barrel tariff surcharge for the next five years that would be needed to generate this pretax increment to revenues is $0.1069 per barrel. See page 2 of Exhibit GRS-6 for the details of the calculations.

If the Commission were to require Olympic to switch to DOC from TOC, I recommend that a $0.1069 per barrel average surcharge be levied for five years to give Olympic the opportunity to recover its existing deferred earnings balance of $23.7 million.

Q. How would you propose to deal with the issue that Olympic's throughput might increase substantially some time during this five-year period?

A. I recommend that the surcharge be fixed at $0.1069 for five years or until the discounted present value of revenues generated by the surcharge reaches $23.7 million, whichever comes first. This would guarantee that the surcharge would not continue beyond five years and also that there would not be an over-recovery of Olympic's existing deferred earnings balance.

Olympic could calculate the discounted present value of the revenues received from the surcharge each month and eliminate the surcharge in the month after the discounted present value of the revenues generated by the surcharge reached $23.7 million. Any incidental over-recovery, if the Commission believes this to be a concern, could be refunded to the shippers via a discount to their bills.

3. It Is Appropriate To Allow Olympic To Also Earn a Return on the Remaining Balance of the Starting Rate Base Write-up

Q. What was is the rationale for the starting rate based write-up under Opinion No. 154-B?

A. Conceptually, the starting rate base write-up was designed to accomplish the same thing as the transition mechanism proposed above for a shift from a TOC to DOC; namely, without the starting rate base write-up mechanism, a pipeline would have had stranded investment problems in the sense that the transition from the Interstate Commerce Commission (ICC) to the FERC methodology would have caused oil pipelines to lose earnings on assets that they were due under the ICC mechanism.

Investments had been made by oil pipelines under the ICC regime with the expectation that returns would be calculated based on the ICC methodology. The starting rate base write-up is a transition mechanism, but one that extended over the remaining life of the assets in place at the time of the transition from ICC to FERC regulation.

Q. Could Opinion No. 154-B have devised an alternative transition mechanism along the lines you proposed above for the TOC to DOC switch that provided oil pipelines with the same net present value return as has been provided by the starting rate base write-up?

A. Yes, but I have not attempted to define such an alternative mechanism.

Q. If the Commission were to decide to disallow Olympic to recover the return on the remaining starting rate base write-up, would this be a form of retroactive ratemaking?

A. Yes. The oil pipeline companies were given the right to recover the return on the starting rate based write-up by the FERC in 1985 in Opinion No. 154-B. While the return on the starting rate base write-up is not formally labeled as a deferred return, it essentially is a deferred return designed to compensate pipelines on a long-term deferred basis for the transition from the ICC to FERC ratemaking paradigm.

Q. Were part of the historical returns on the starting rate base write-up deferred?

A. Yes. These historical deferred returns are part of the deferred return balance that would be recovered by the transition mechanism above for the TOC to DOC switch.

Q. If the Commission were to decide to not allow any further returns on the starting rate base write-up, would it be appropriate to remove the historical deferred earnings associated with the starting rate base write-up from the overall deferred earnings balance?

A. No. This would clearly be retroactive ratemaking.

Q. If the Commission were to allow Olympic to recover the return on the remaining starting rate base write-up, have you developed a transition mechanism to accomplish the recovery of these returns?

A. Yes. I propose that a five-year transition mechanism be used for the recovery of the return on the remaining starting rate base write-up. I propose that an average per barrel surcharge of $0.0095 per barrel be imposed for five years or until the present discounted value of the realized return on the remaining starting rate base write-up of $2.1 million is recovered. See Exhibit GRS-7, pages 1 and 2. This mechanism would eliminate the possibility of over-recovery and establish a maximum length of time that the surcharge would be in place.

V. Olympic's Relative Riskiness

A. Extensive Waterborne Competition

Q. What have Staff's or Intervenors' witnesses claimed regarding the effectiveness of waterborne transportation as a competitor to Olympic?

A. Witnesses for Tesoro and Tosco claim that waterborne transportation is not an effective competitor to Olympic. These claims are not based on either data or reasoned analysis. In my direct testimony and in Olympic's responses to data requests, it has been made clear that neither I nor Olympic have reliable data on the cost of the waterborne transportation alternatives to Olympic. More specifically, we do not know what it would cost high volume consistent shippers such as Tesoro and Tosco to use waterborne transportation instead of Olympic. Tesoro and Tosco could obtain the lowest possible rates for waterborne movements because each could make firm volume commitments which would allow waterborne transportation operators to devise least-cost strategies for providing the requested waterborne transportation service.

In addition, Tesoro and Tosco are known to use waterborne transportation services on a continuing basis. This was true before the June 1999 accident and federally-mandated throughput restrictions because of failures in longitudinal ERW-welds in September of 1999, and will be true after Olympic is able to resume operating at 100% pressure. As was documented in my direct testimony, in 1998, which is the last year of Olympic's operation at 100% pressure, waterborne transportation was used to transport 41,245,000 barrels of light refined products from the refineries served by Olympic. See Exhibit No. OPL-36 to my WUTC testimony. Those waterborne movements in 1998 amounted to 23.8% of the total light refined product output of the refineries served by Olympic. Olympic's test year throughput levels are about 13 million barrels less than its 1998 levels. If these volumes are moved by waterborne transportation instead of Olympic, waterborne transport volumes in the test year will be over 54 million barrels which would be over a 30% increase in the volumes transported by water relative to the 1998 volumes.

Further, as documented at length in my initial testimony, waterborne transportation was able to replace Olympic within months of the September 1999 restriction on throughput and wholesale gasoline prices in the areas served by Olympic returned to their pre-restriction relationship to prices in other West Coast and Gulf Coast markets.

The fact that waterborne transportation provides effective competition to refined product pipelines is well established. The U.S. Department of Justice (DOJ), in its study of pipeline competitiveness, included possible expansion of waterborne traffic as one of the factors indicating a competitive marketplace:

> The presence of port facilities in the market may also indicate a more competitive market than the HHI alone would suggest. The essential question is whether the concentrated market is served by a port that can easily expand its petroleum traffic. If so, the threat of expansion of water transport could be expected to check an increase in pipeline tariffs after deregulation.[2]

> [D]eregulation of pipelines in concentrated petroleum markets may be justified if competing water transportation can be expanded at constant unit cost. If that is the case, any effort to elevate the price of transportation will be checked by the ability of shippers to switch to water transportation.[3]

> If water traffic appears to be a currently viable source of competition, and water traffic could easily and efficiently expand from 1980 levels in response to an attempted exercise of pipeline market power, the Department adjusts the HHI downward.[4]

The FERC cited this portion of the DOJ study in its analysis of the importance of waterborne competition in Williams Pipe Line Company, 71 F.E.R.C. ¶61,291 (1995):

> [I]t is commonly viewed that the existence of waterborne traffic, coupled with expandable capacity for waterborne deliveries, makes an oil market competitive. The staff in the past has suggested a more conservative approach, holding that expandable waterborne capacity, coupled with waterborne deliveries that account for at least 10 percent of total deliveries into a market, create a presumption of competition in that market. We will adopt this

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[2] Department of Justice, *Oil Pipeline Deregulation,* May 1986, p. xii.

[3] Department of Justice, *Oil Pipeline Deregulation,* May 1986, p.8.

[4] Department of Justice, *Oil Pipeline Deregulation,* May 1986, p. 36.

more conservative approach.

Id. at ¶62,138. Olympic's situation is consistent with all of the key factors identified by the DOJ as being an important indicator that waterborne transportation was an effective competitor to refined products pipelines; namely, the ability of waterborne traffic to increase when pipeline supply is reduced.

The above evidence provides strong support for the position that waterborne transportation is an effective competitive alternative to Olympic.

Q. Has Olympic attempted to obtain information on waterborne transportation costs from shippers who can make long term substantial volume commitments?

A. Yes. Olympic submitted data requests to Tesoro and Tosco requesting detailed cost information for their waterborne shipments of light refined products. See Olympic's Request Nos. 509 and 510 to Tesoro and Request Nos. 609 and 610 to Tosco in Exhibit No. GRS-8. Both Tesoro and Tosco claim in their responses that waterborne transportation costs are not relevant to this proceeding and refuse to provide the requested information.

However, Tesoro's and Tosco's witnesses claim that, due to the lack of such waterborne transportation cost information, the Commission should presume that waterborne transportation is not a cost effective competitor to Olympic. For example, see pages 9-10 of Mr. Hanley's WUTC testimony and pages 16-17 of Dr. Means' WUTC testimony.

Presumably, if the waterborne transportation cost data requested from Tesoro and Tosco had shown that waterborne transportation was not a cost effective competitor to Olympic, Tesoro's and Tosco's own witnesses probably would have submitted it in support of their, otherwise, unsupported arguments that waterborne transportation does not provide cost-effective competition to Olympic. Additionally, if their waterborne transportation cost data documented their position, Tesoro and Tosco would have every reason to provide it to Olympic so as to undermine Olympic's position. The fact that Tesoro and Tosco have refused to provide the requested waterborne transportation cost data on the absurd grounds that these data are not relevant to this matter should be considered by the Commission as evidence that waterborne transportation is a cost effective competitor to Olympic.

B. The Asymmetric Risk of Olympic's Potential Failure

Q. Please explain the concept of asymmetric risk.

A. Asymmetric risk is when upside and downside risks are not balanced. In a fair coin toss game, everyone knows that a head and tail side of a coin are equally likely to appear. Suppose you were involved in a fair coin toss game and that you would win if a head came up and would lose if a tail came up. You would insist that the dollar value of the reward you received when you won was at least as large as the dollar value of loss you suffered when you lost. Your opponent would demand at least as large a reward when a tail came up as the penalty that would be suffered when a head came up. Therefore, the reward and loss amounts would be equal. Alternatively, if you were told you would win one dollar if a head came up and lose two dollars if a tail came up, you would not play because the game would be unfair to you. This unfair coin toss game is an example of asymmetric risk. Asymmetric risk arises when the expected outcomes are not balanced (i.e.. when the expected outcome is less than a fair outcome).

In a nonregulated context, companies with a significant risk of failure (i.e.. going into bankruptcy and losing all the equity investor's capital) also typically will have a high potential upside. If one invests in a high-risk unregulated firm, there is the potential of losing everything, but there also is the potential of a very high return. Therefore, the risks are balanced (i.e., there is no asymmetric risk).

In the context of a regulated entity with a similar high risk of failure, asymmetric risk arises because the expected outcome, under the conventional regulatory paradigm, is less than a fair return. A regulated entity, in theory, always has an open-ended downside risk in the sense that a regulated entity can fail (i.e., go bankrupt and lose all the equity investors' capital). Nonetheless, for most regulated entities, the downside risk is very small. Unlike its unregulated counterparts, however, there is no possibility of a big offsetting win if the entity does not fail. In such a situation, there is no need for the regulators to take the asymmetric nature of risk into account because of the very low risk of failure.

In Olympic's case, though, the risk of failure is not low and, in fact, is substantial. If not for Olympic's financially sound parents, Olympic almost certainly would be in bankruptcy today.

The solution to the asymmetrical risk problem is to define a risk-adder to the normally calculated cost of equity capital for a regulated entity such a risk-adder would compensate the regulated entity's shareholders for the asymmetric nature of the risk faced in situations where the risk of failure is real and substantial. The concept of a risk-adder to compensate a regulated entity for asymmetric risk was first analyzed in the context of Duquesne Light Co. v. Barasch, 488 U.S. 299 (1989).[5]

A similar conceptual approach has been proposed in the context of how to compensate electric utilities for stranded costs. A risk-adder can be developed to compensate electric utilities for stranded costs. Risks are asymmetric because an electric utility, in a competitive electricity generation market, could not expect to recover its investment and earn a fair return on the power plants it owned (i.e., the shift from a regulated to competitive environment made the game unfair for the regulated utilities).[6]

The events creating severe asymmetric risk for Olympic are the Bellingham accident, the September 1999 restriction on throughput due to flawed ERW-welds, and their aftermaths. It is not the costs directly related to the Bellingham accident, but the sustained loss in revenues due to having to operate below 100% pressure, the high costs of returning Olympic to 100% operating pressure, and the high cost of ensuring that Olympic will operate safely in the long-run.

VI. Olympic Pipeline's Capital Structure and Historical Dividend Policy

A. The Intervenors Incorrectly Allege Impropriety by Olympic Due to Its All-Debt Capital Structure

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[5] Duquesne Light Co. faced the risk of bankruptcy due to substantial investments in nuclear generation facilities that were never permitted to operate. For a disscussion of this case and asymmetric risks, see A. Lawrence, Kolbe and William B. Tye, "The Duquesne Opinion: How Much "Hope" is there For Investors in Deregulated Firms?" *Yale Journal of Regulation*, Winter, 1991.

[6] For example, see A. Lawrence Kolbe and William B. Tye, "It Ain't In There: The Cost of Capital Does Not Compensate for Stranded-Cost Risk," *Public Utilities Fortnightly*, May 15, 1995.

Q. Have Staff's and Intervenors' witnesses argued that Olympic's own capital structure is inappropriate?

A. Yes. Mr. Hanley, on behalf of Tesoro, argues that Olympic's essentially all-debt capital structure is inappropriate and urges the Commission to set Olympic's overall cost of capital equal to its parents' embedded debt cost (i.e., to punish Olympic due to its 100% debt capital structure) unless Olympic's parents make an equity infusion sufficient to raise Olympic's equity share to at least 46.40%. Mr. Brown, on behalf of Tesoro, claims that Olympic's 100% debt capital structure is evidence of financial imprudence. Mr. Brown concurs with Mr. Hanley's recommended remedy.

Dr. Wilson, on behalf of Staff, also argues that Olympic's owners should be punished if they do not inject more equity capital into Olympic. He argues that the regulatory capital structure for Olympic should, in some sense, reflect Olympic's own capital structure.

Q. Is there any reason for the Commission to be concerned with Olympic's actual capital structure?

A. No.

Q. Please explain.

A. The capital structure is irrelevant for a company such as Olympic that is wholly-owned by several large corporations (such as BP and Shell), that does not have publicly-traded stock, and that does not issue any debt without the guarantee of its parents. Potential lenders to Olympic would be concerned with the financial condition of Olympic's parents and would pay no attention to Olympic's capital structure because it is Olympic's parents, and not Olympic, that would be guaranteeing any loan that these lenders made to Olympic.

Q. Is it unusual for a pipeline like Olympic that is wholly-owned by several large integrated oil companies to have an almost all-debt capital structure?

A. No. As shown in Exhibit No. GRS-9, there were four other such pipelines during the 1999-2000 period. The four pipelines, other than Olympic, are financially healthy pipelines.

Q. What is of concern to potential lenders about a pipeline such as Olympic?

A. Potential lenders are concerned with Olympic's cash flow. As can be seen from Exhibit GRS-9, what dramatically distinguishes Olympic from the other financially strong pipelines wholly-owned by integrated oil companies is Olympic's cash flow crisis. Olympic's revenues in 2000 covered only 54.1% of its operating and maintenance expenses. The other four pipeline companies' revenues are 165.4% to 241.8% of their operating and maintenance expenses. Olympic's cash flow crisis is a post-June 1999 phenomenon. In 1998, its last year of full operation, Olympic's revenues were 185.5% of operating and maintenance expenses, and Olympic was a financially strong pipeline company.

Q. Is your view that cash flow is the critical concern to potential lenders supported by others?

A. Yes. The Standard & Poor's Corporate Ratings Criteria, which Mr. Hanley includes as Exhibit No. ___ (FJH-3) to his WUTC testimony, stresses the importance of cash flow from operations to a potential lender.

Q. What is needed to make Olympic a financially sound company again?

A. Olympic needs more revenues from operations which, given its regulatory constrained throughput, requires higher tariff rates for Olympic.

B. Olympic's Historical Practice of Paying Out All Its Profits As Dividends

Q. Do Tesoro's witnesses also claim that the fact that Olympic historically paid out all its profits to its owners as dividends is an indication that Olympic was financially imprudent?

A. Yes, but this claim is specious and, in any case, not relevant to this proceeding. This is yet another attempt by Tesoro's witnesses to engage the Commission in retroactive ratemaking:

Further, it is not unusual for pipelines, like Olympic, to routinely pay all their profits to their parents as dividends. The parents, as member of the pipeline's board, then determine which investment projects to pursue. These investment projects are funded by equity infusions, by guarantees in loans to the pipeline by others, or by direct loans from the parents to the pipeline.

Finally, the fact that a pipeline pays out all its profits as dividends does not make it financially unsound as Tesoro's witnesses allege. I assume that Mr. Hanley believes that the five oil pipeline companies in the oil pipeline proxy group are financially sound. The average dividend payout ratio for these companies in 2000 was 119.33%, and the average dividend payout ratio for these companies has been near or above 100% since 1997. See Exhibit No. GRS-10. The Commission should disregard Tesoro's witnesses' specious arguments regarding

Olympic's historic dividend payout practices.

VII. Olympic's Cost of Capital

A. Identification of Issues

Q. Please describe the issues that have been raised by the other parties to this matter regarding Olympic's cost of capital.

A. Issues have been raised regarding all the components of Olympic's cost of capital: (1) Olympic's cost of equity capital; (2) Olympic's cost of debt; and (3) Olympic's capital structure. The differences between the parties are substantial. I addressed Olympic's cost of capital in my direct testimony. The other witnesses who have addressed Olympic's cost of capital are Mr. Frank Hanley, on behalf of Tesoro, Dr. Robert Means, on behalf of Tosco, and Dr. John Wilson, on behalf of Staff.

B. Cost of Common Equity

1. Issues Regarding the Cost of Common Equity Capital.

Q. Are there methodological differences in the approaches you employed to determine the expected cost of common equity capital for Olympic and the approaches taken by the witnesses for Staff and Intervenors?

A. Yes.

Q. Please summarize these methodological differences.

A. I have followed the discounted cash flow (DCF) approach that the FERC has specified as appropriate for oil pipeline companies in recently litigated proceedings. However, I also have proposed two modifications to the calculations under the FERC specified approach and have proposed a risk-adder of 75 basis points to reflect Olympic's above average risk. Mr. Frank Hanley utilizes the DCF method in his analysis but he gives equal weight to the results produced by the DCF, risk premium model (RPM), capital asset pricing model (CAPM), and the comparable earnings model (CEM) approaches. For all but the CEM approach, Mr. Hanley conducts his analysis using the FERC's five-company oil pipeline proxy group. Further, there are non-trivial differences between the DCF-based approach used by Mr. Hanley and the FERC-specified DCF-based approach. The net result is Mr. Hanley proposes a much lower proposed cost of common equity capital than is implied by the unmodified FERC DCF-based approach. Mr. Hanley also rejects my risk-adder for Olympic claiming that Olympic does not face above average risk.

Dr. Robert Means accepts the DCF-based approach that the FERC has specified as appropriate and also my calculations of the DCF-based results under the FERC method. Dr. Means rejects one of my suggested modifications to the FERC approach and rejects my 75 basis point risk adder arguing that Olympic does not face above "normal" risk. The ultimate result is a substantially lower proposed cost of common equity capital for Olympic than I recommend.

Dr. John Wilson bases his cost of common equity capital on the DCF, CAPM, and CEM methods. Dr. Wilson employs two distinct DCF-based approaches so he presents four sets of results. Dr. Wilson applies these four approaches to three different proxy groups: (1) FERC's five-company oil pipeline proxy group; (2) a group of seven natural gas pipeline companies selected by Dr. Wilson; and (3) a group of fifteen integrated oil companies selected by Dr. Wilson. As a result of using four distinct calculation methods applied to three different proxy groups, Dr. Wilson produces twelve sets of estimates to which he assigns equal weight in arriving at his proposed cost of common equity capital for Olympic. The net result is a much lower proposed cost of common equity capital than is implied by the unmodified FERC DCF-based approach. Dr. Wilson also rejects my proposed risk-adder for Olympic arguing that Olympic does not face above average risk.

2. Discussion of the Commission Recommended Methodology For Oil Pipelines

a. The FERC'S Methodology

Q. Has the FERC selected a specific methodology that it uses to evaluate an oil pipeline's cost of common equity capital?

A Yes. The FERC has devoted substantial effort to evaluating alternative methodologies for determining an oil pipeline's cost of equity capital recently in the context of the SFPP, L.P. oil pipeline proceedings which began in 1992 and continues today.[7] As a result of this extensive litigation, the FERC has evaluated numerous options and has selected a detailed, specific DCF approach that it expects to be used in calculating the cost of common equity capital for an oil pipeline.

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[7] The FERC decision in this case that dealt in detail with the determination of the cost of common equity capital for an oil pipeline was 86 FERC ¶61,022 (1999) which is referred to as Opinion No. 435. (hereinafter Opinion No. 435). Opinion No. 435 affirms without discussion some of the decisions reached by Administrative Law Judge as set forth in "Initial Decision Concerning Rates, Terms, and Conditions of Service, and other Matters; Issued September 25, 1997, Docket Nos. OR92-8-000, OR93-5-000, OR 94-3-000, OR 94-4-000, OR 95-5-000, and OR 95-34-000 (hereinafter SFPP Initial Decision).

First, the FERC expects that the DCF analysis will be performed on the five companies in its oil pipeline proxy group, which is what I did in my direct testimony. I agree with the FERC's proxy group definition because it consists of all the almost "pure-play" oil pipeline companies. Further, it is a robust proxy group that the FERC can expect to rely on for the foreseeable future because the number of oil pipeline companies in this group is expanding.[8]

Second, the FERC has selected a specific methodology for calculating the three components of the DCF model for each of the proxy group companies: (1) base period dividends ("D_0"); (2) base period price ("P_0"); and (3) expected long run dividend growth ("g"). Under the FERC method, base period dividends for a given proxy group company are calculated as the average annualized dividend payments during the most recent six-month period, and the base period price is the average share price over the same six-month period. The expected long-run dividend growth is calculated using the expected growth rate in earnings per share over the next five year period as reported in the Institutional Brokers Estimate

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[8] Three oil pipeline new master limited partnerships have been formed recently: Valero, Plains All American Pipeline and Suncoco Logistics Partners. Valero L.P. (formerly Shamrock Logistics L.P.) had its initial public offering in April 2001. Valero L.P. owns and operates most of the crude oil and refined product pipelines serving three of Valero Energy's refineries located in Texas and Oklahoma. See Valero L.P. Form 10-K for fiscal year ended December 31, 2001 and Shamrock Logistics Form 10-Q for quarter ended March 31, 2001. Plains All American Pipeline L.P. was formed in September 1998 and effectively offered shares to the public in June 2001. Plains All American owns gathering and mainline crude oil pipelines in the United States and Canada and crude oil terminalling and storage. See Plains All American Pipeline L.P. Form 10-K for fiscal year ended December 31, 2001. Sunoco Logistics Partners L.P. was formed on October 15, 2001. Its assets are the Eastern Pipeline System, a refined pipeline system which serves the Northeast and Midwest, the Western Pipeline System, a crude oil gathering, purchasing, and transportation system in Oklahoma and Texas. See Sunoco Logistics Partners L.P. Form 10-K for fiscal year ended December 31, 2001. These new companies could be considered for inclusion in the oil pipeline proxy group after they have developed a sufficient price and dividend record and analyst coverage has increased.

System (IBES) publication (given a 2/3 weight) and the expected long-term growth rate of nominal U.S. gross domestic product (GDP) over the next 15 to 20 year period (given a 1/3 weight). I performed these calculations according to the FERC's specifications.

Third, the FERC specifies that the expected cost of common equity capital for a given oil pipeline company's proxy group ("k") shall be calculated using the following equation:

$$k = (D_1 / P_0) + g \qquad \text{Equation (1)}$$

where D_1 is the expected dividend payments per share to be paid during the immediately upcoming twelve-month period by the given oil pipeline company. D_1 is defined under the FERC method as follows:

$$D_1 = D_0 \ast (1 + 0.5\, g) \qquad \text{Equation (2)}$$

I calculated D_1, and k according to the above equations, and I also proposed a modification to equation (2) for D_1 which provides a more accurate measure of expected dividend payments per share during the upcoming twelve-month period based on actual dividend payments during the most recent six-month period and the long-run expected dividend growth rate.

Fourth, the FERC method uses the resulting expected cost of common equity capital for the five proxy group companies (k_i for i = 1, 2, 3, 4, 5) to determine a zone of reasonableness for the cost of common equity capital for an oil pipeline company and also to determine the cost of common equity capital for a typical or average oil pipeline company. The FERC method specifies that the zone of reasonableness ranges from the lowest to the highest individual proxy group company expected cost of common equity capital (i.e., from the minimum to the maximum value among the k_i for i =1, 2, 3, 4, 5). The FERC method specifies that the expected cost of common equity capital for the average or typical oil pipeline company equals the median ("middle") cost of common equity capital value for the oil pipeline proxy group companies (i.e., if the five k_i are arranged in ascending order, it would be the third value such that two values are higher and two values are lower). I have followed the FERC method, but I also have proposed a modification concerning how the expected cost of common equity capital for the average or typical oil pipeline company is determined which I believe provides a more accurate estimate than the FERC approach.

Fifth, the FERC assigns an expected cost of common equity capital to the oil pipeline company based on the FERC's assessment of the relative risk of the oil pipeline. If the FERC determines that the oil pipeline company has "normal" risk relative to the oil pipeline companies in the proxy group, then the oil pipeline company is assigned the expected cost of common equity capital for an average or typical oil pipeline company. If the oil pipeline company has "above normal" risk, then it would be assigned an expected cost of common equity capital between that of the average or typical oil pipeline company value and the upper end of the zone of reasonableness. A parallel approach is used if the FERC believes the oil pipeline company has "below normal" risk. In my direct testimony, I argue that Olympic has above normal risk, and therefore should be assigned a cost of common equity capital within the zone of reasonableness that is 75 basis points above the cost of common equity capital for an average or typical oil pipeline company.

b. The WUTC Methodology

Q. Has the Commission determined what it considers to be an appropriate approach for calculating the cost of common equity capital for a regulated utility?

A. Yes, but the Commission's approach is broader and more generic than the FERC's approach for oil pipeline companies. The Commission's approach has been applied to different types of regulated utilities and is made up of general principles and not specific calculation instructions. In reaching this opinion, I reviewed several Commission rate cases where the Commission's decisions addressed, in some detail, the approach it relied on to determine the cost of common equity capital for a regulated company.

Q. Based on this review, how do you characterize the WUTC's approach to determining a regulated company's cost of common equity capital?

A. The Commission appears to rely on a forward-looking DCF analysis. In its most recent decision providing specific details on its preferred approach to defining the cost of common equity capital for a regulated utility, the Commission stated:

> The Commission will continue to rely on the discounted cash flow analysis as the most satisfactory method of measuring investor expectation. The various other methods employed by the parties, including CAPM, Risk Premium, Earning/Price Ratio, and Market to Book Ratio, are useful as a check. The results of all the other methods are interesting for the Commission to see as points of comparison. However, those methods are not relied upon in this order to reach a decision on a rate of return. The Commission thus continues to discourage the approach of averaging DCF with other methods.

In the Matter of GTE Northwest Inc., 1994 Wash. UTC LEXIS 92, at *14-15 (Dec. 21, 1994) ("GTE Northwest"). In a matter considered a year earlier, the Commission stated:

> The Commission continues to believe, based on experience and consideration of alternate approaches, that the discounted cash flow analysis represents the most satisfactory method of measuring investor expectation. We also remain convinced that the CAPM methodology is flawed and of extremely limited usefulness in this analysis. As such, the Commission finds little to recommend the approach of averaging the results of the two methods.

WUTC v. Wash. Natural Gas Co., 1993 Wash. UTC LEXIS 87, at *51 (Sept. 27, 1993) ("Washington Natural Gas").

The Commission's reliance on the DCF method is longstanding, as evidenced by its decisions regarding the cost of common equity capital in three earlier cases as follows:

> Cost of equity is a true cost of capital for a regulated utility, because in order to attract and keep investment it must make sufficient earnings to cause the investor to make or to retain his or her investment. We have long accepted the discounted cash flow (DCF) method of recognizing investor earnings requirements, and will not depart from that method in this proceeding.

WUTC v. Gen. Tel. Co. of the Northwest, Inc., 1982 Wash. UTC LEXIS 35, at *39-41 (Apr. 8, 1982) ("General Telephone").

> The reliance on the DCF theory and the market data of comparable companies has been approved by the Commission on numerous occasions in the past, particularly in connection with examinations of the required rate of equity return for Cascade. It is the Commission's conclusion that the discounted cash flow method

> continues to represent the most satisfactory and exact method of determining a fair rate of return on common equity.

WUTC v. Cascade Natural Gas Corp., 1979 Wash. UTC LEXIS 3, at *14 (June 20, 1979) ("Cascade Natural Gas").

> We have previously rejected the comparable earnings analysis as a sole basis for determining a utility's cost of equity. We believe that there is insufficient evidence to show that the risk is similar between Mr. Mount's selected groups and the Respondent [Washington Water Power Co.]. Mr. Mount's utilization of the DCF method utilized past growth, rather than anticipated growth, in dividends per share; we believe that the growth rates utilized were greater than could be assumed for the future. Finally, our analysis of figures used by Mr. Mount in determining an appropriate spread between the rate earned on book equity and the cost of debt indicate that during the most recent five-year period, spreads were far less than a sum which a long-term analysis produces. We conclude that this method is not sound in determining a utility's future equity costs.

WUTC v. Wash. Water Power Co., 1978 Wash. UTC LEXIS 3, at *47-48 (Mar. 24, 1978) ("Washington Water Power").

Finally, in the Commission's most recent rate case decision, the Commission reaffirmed its reliance on the DCF method as follows:

> Avista, Commission Staff, and Public Counsel agree on certain fundamental issues:…; and applying a discounted cash flow (DCF) model to estimate the cost of equity for comparable groups of utilities, based on the fundamental premise that this will serve to "replicate investor's expectations" when they pay the current market price for utility common stocks. *Ex. T-135, p. 1, ll. 14-21."*

and

> The cost of common equity capital, stated as a rate of return on common equity, is a function of several variables, and is primarily an attempt to quantify a rate of return required by investors for that particular investment. All three of the experts provide Discounted Cash Flow (DCF) studies. The DCF model relies on the equivalence of the market price of stock with the present value of the cash-flows investors expect from the stock. The total return to the investor, which equals the required return according to this theory, is the sum of the dividend yield and the expected growth rate in the dividend. DCF studies compare the utility whose cost of equity is the focus of the study (Avista) to the return found appropriate for a group of companies.

WUTC v. Avista Corp., 2000 Wash. UTC LEXIS 558, at *154-55 (Sept. 29, 2000) ("Avista").

Q. What is the Commission's apparent opinion of methods--other than DCF-based--for calculating a regulated company's cost of common equity capital based on your review of the above-cited cases?

A. The Commission appears to prefer an analysis based solely on the DCF method, and, if an analyst wishes to consider other methods, the results produced by these other methods should be presented separately. Regarding these other methods, the Commission has stated that, at most, it will consider them as checks on the DCF method. See GTE Northwest citation above.

In the above cited decisions, the Commission has expressed particular concerns with the CAPM approach which it describes as "flawed and of extremely limited usefulness." See Washington Natural Gas citation above. The Commission also has singled out the CEM and RPM method for criticism stating that the RPM method "is not sound in determining a utility's true equity cost." See Washington Water Power citation above.

Q. Has the Commission provided any guidance regarding how it believes the DCF analysis should be performed?

A. Yes. The Commission has indicated that it prefers the long-run expected dividend growth rate component of DCF to be estimated based on expectations regarding future growth and not on measures of historical growth. See Washington Water Power citation above.

Q. Have you reviewed the most recent Commission rate case decisions?

A. Yes. To my knowledge, there have been three tariff rate cases decided by the Commission since 1995.[9] The most recent case is Avista. In that case, three parties (Dr. Avera for Avista, Dr. Lurito for Staff, and Mr. Hill for Public Counsel) submitted testimony regarding the cost of common equity capital. All three parties sponsored DCF studies. Dr. Lurito and Mr. Hill sponsored what the Commission referred to as "standard DCF studies," while Dr. Avera sponsored a "multi-stage DCF study." The Commission did not accept the assumptions underlying Dr. Avera's study and based its determination of Avista's cost of common equity capital on the "standard DCF studies" submitted by Dr. Lurito and Mr. Hill.

Q. Have you reviewed the "standard DCF studies" submitted by Dr. Lurito and Mr. Hill in Avista?

A. Yes. The so-called "standard DCF studies" utilize a DCF model that is virtually

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[9] WUTC v. Avista Corp., 2000 Wash. UTC LEXIS 558 (Sept. 29, 2000); WUTC v. Am. Water Res., Inc., 1999 Wash. UTC LEXIS 63 (Jan. 21, 1999); and WUTC v. U.S. West Communications, Inc., 1996 Wash. UTC LEXIS 7 (Apr. 11, 1996).

identical to the FERC version of the DCF model as presented in Equations 1 and 2 above. The DCF study performed by Dr. Lurito in the Avista matter used an identical structure, while the study performed by Mr. Hill considered an alternative approach to defining expected dividends to be paid during the immediate upcoming twelve-month period (i.e., D_1 was defined using Equation 2 and an alternative method). The expected growth component (g) was estimated using analyst forecasts of earnings per share (such as the IBES forecasts employed under the FERC method) although other methods of projecting g also were considered.

Q. How would you expect the Commission to respond to the FERC DCF methodology?

A. The FERC DCF methodology, including the use of the five-company oil pipeline proxy groups, should qualify as a "standard DCF study." The only question is whether the Commission would approve defining expected long-term dividend growth per share (g) as a weighted average of the IBES earnings forecast (a 2/3 weight) and the expected long-run growth of nominal GDP (a 1/3 weight).

The FERC's rationale for combining the analysts forecast of earning per share growth with a forecast of long-run nominal GDP growth stems from the FERC's conclusion that the five-year horizon employed by analysts is too short to be considered a true long-run estimate of dividend growth (g). The FERC's rationale for using the long-run expected growth in nominal GDP as a proxy for the long-run expected growth in dividends is based on two assumptions: (1) in the long-run, the expected earnings and dividend growth of all companies converge to a common rate and (2) this common long-run growth rate is reasonably approximated by the long-run nominal growth in GDP. Neither of these assumptions was tested by the FERC, but the former assumption does have some support in the financial literature.[10] The Commission, in its prior decisions, has determined that the five-year analyst's forecasts are sufficiently long-run in nature to qualify them as appropriate estimates of g. I concur with the Commission's determination on this issue, but the FERC has considered this issue in numerous proceedings and has determined otherwise.

I investigate below the implications of defining g based solely on the IBES earnings per share forecast. I also have done a historical evaluation of the relationship between dividend per share growth and earnings per share growth for the oil pipeline proxy group companies. In addition, I have investigated the historical relationship between the weighted average historical growth of earnings per share (a 2/3 weight) and nominal GDP (a 1/3 weight) and the historical dividend growth rate for the oil pipeline proxy group companies.

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[10] See, e.g., Marshall E. Blume, "Betas and Their Regression Tendencies," *The Journal of Finance,* Vol. XXX, No. 3, June 1975, pages 785-795; and Marshall E. Blume, "On the Assessment of Risk," *The Journal of Finance,* Vol. XXVI, No. 1, March 1971. In the first article cited, Professor Blume formed several portfolios of stocks alternatively consisting of stocks with high (above one) and low (below one) individual betas. He compared the estimated betas for each portfolio across periods and noted that the betas had a tendency, over time, to regress towards one, which corresponds to the overall market beta value. He found that this tendency was only partly due to measurement error. After adjusting for possible measurement error, Professor Blume found that the tendency to regress toward one was statistically significant

3. Update of the Cost of Common Equity Estimate

a. Definition of Update Periods

Q. Have you updated your cost of common equity calculations to reflect the most current data?

A. Yes. When my direct testimony was filed in December 2001, data were only available to support calculation of the cost of common equity capital as of the end of the third quarter of 2001. Currently, it is possible to calculate the cost of common equity capital for the end-of-year 2001 and also through the end of the first quarter of 2002. The cost of common equity calculations done by Mr. Hanley on behalf of Tesoro considered data through January 2002 and selected data for February 2002. Dr. Wilson on behalf of Staff utilizes end-of-year 2001 data. I have redone my cost of common equity capital calculations using the FERC methodology based on end-of-year 2001 data and also based on data through the first quarter of 2002. The FERC based methodology used is identical to those employed in my direct testimony.

b. Updates of the Unmodified FERC Method Results

Q. Please explain the updates under the unmodified FERC approach.

A. I have updated the cost of common equity capital for the proxy group companies under the unmodified FERC approach for end-of-year 2001 (see Exhibit No. GRS-11 and through the first quarter of 2002 (see Exhibit No. GRS-12. These updated results are summarized in Exhibit No. GRS-13.

The zone of reasonableness for the real cost of common equity capital ranges from 10.72% to 17.34% based on the results through the first quarter of 2002 and is somewhat narrower based on the end-of-year 2001 results. The median real cost of common equity capital for the oil pipeline proxy group is 13.20% under the end-of-year 2001 results and 12.89% under the through the first quarter of 2002 results. There is greater stability in the mean real cost of common equity capital for the oil pipeline proxy company between the two sets of results. Under the end-of-year 2001 results, the mean value is 13.12% and, for the through the first quarter 2002 results, the mean value is 13.17%.

Based on these results, my recommended estimate for the real cost of common equity capital for a typical or average oil pipeline company is 13.10% which is the overall average of the four mean and median estimates. Under the strict FERC methodology, the real cost of common equity capital for a typical or average pipeline would be set equal to the median value for the oil pipeline proxy group companies. In this instance, there are two median estimates: (1) 13.20% for the end-of-year 2001 analysis; and (2) 12.89% for the through the second quarter of 2002 analysis. The average of these two results is 13.05%.

The zone of reasonableness for the nominal cost of common equity capital ranges from 12.20% to 18.12% under the results through the first quarter of 2002 which is a somewhat wider range than pertains under the end-of-year 2001 results. The median nominal cost of common equity capital for the proxy group companies is 14.75% under the end-of-year 2001 results, and, under the results through the first quarter of 2002, the median value is 14.37%. Under the end-of-year 2001 results, the mean value is 14.67%, while, under the results through the first quarter of 2002, the mean value is 14.65%. The mean nominal cost of common equity capital values are more stable between the end-of-year 2001 results and the through first quarter of 2002 results than are the median values.

Based on these results, my recommended estimate for the nominal cost of common equity capital for typical or average oil pipeline company is 14.60% which is the average of the four median and mean estimates.

c. Updates of the Modified FERC Method Results

Q. Please explain the updates under the modified FERC approach.

A. I have updated the cost of common equity capital for the proxy group companies using a modification of the FERC method. This modification pertains to how dividend payments for the immediately upcoming 12-month period are calculated. This modification is discussed in my direct testimony at page 32, line 624 to page 33, line 649 and in Appendix C to my direct testimony at pages 8 to 10. The immediately upcoming 12 month dividend payments (D_1) are calculated based on dividend payments for the most recent historical 6 month period (D_0) and the long-run expected growth rate in dividend payments (g) using the following equation:

$$D_1 = D_0 \ast (1 + 0.745\ g) \qquad \text{Equation (3)}$$

The modified FERC approach results for the oil pipeline proxy group companies for end-of-year 2001 are presented in Exhibit No. GRS-14 and for through the first quarter of 2002 are shown in Exhibit No. GRS-15. These updated results are summarized in Exhibit No. GRS-16. The net effect of my proposed modification to the FERC method is to increase the average (median or mean) real cost of common equity capital for an average or typical oil pipeline by between 11 and 13 basis points as can be seen by comparing Exhibit No. GRS-16 to Exhibit No. GRS-13.

If this modification were accepted by the Commission, it would increase my recommended estimate (based on the modified results) of the real cost of common equity capital for a typical or average oil pipeline company to 13.20%.

Regarding the effect of my proposed modification to the FERC method on the average (median or mean) nominal cost of common equity capital, the modification would result in an increase of 11 to 13 basis points as can be verified by comparing Exhibit No. GRS-16 to Exhibit No. GRS-13.

If this modification were accepted by the Commission, it would increase my recommended estimate (based on the modified results) of the nominal cost of common equity capital for a typical or average oil pipeline company to 14.70%.

Q. Have you compared the FERC's DCF method to the DCF methods that the WUTC has relied on in its past determinations of the cost of common equity capital?

A. Yes. Based on the WUTC rate cases that I reviewed,[11] I have concluded that the FERC DCF methodology should qualify as a "standard DCF study" of the sort that the WUTC has relied on in earlier rate cases to determine the cost of common equity capital. The only area where the FERC DCF methodology

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[11] All these cases are cited above.

differs substantively from that of the WUTC is in terms of how the expected long-term growth of dividend payments per share (g) is estimated. The FERC method defines g as a combination of the 5-year IBES forecast of earning per share for the oil pipeline proxy group companies (a 2/3 weight) and the long-run expected future growth of nominal GDP (a 1/3 weight). The “standard DCF studies” relied on by the WUTC defined g based just on 5-year analyst’s forecasts of earnings per share such as the IBES forecasts used under the FERC DCF method. In the context of earlier rate cases, the WUTC evaluated the reasonableness of the analysts’ forecasts of earnings per share by comparing the historical growth rates in earnings and dividends per share for the proxy group companies and by examining the relationship between the forecasted 5-year growth rate in earnings per share and the historical growth in dividends per share for the proxy group companies.

I have performed such an analysis on the companies in the oil pipeline proxy group as shown in Exhibit No. GRS-17. The historical data on dividends per share (DPS) and earnings per share (EPS) are available on a consistent basis only back to 1992. I have compared the average annual historical compound growth rates in DPS and EPS over two periods: (1) 1992 to 2001; and (2) 1996 to 2001. Some of the companies in the oil pipeline proxy group were in their relative infancy in the early 1990s so the latter comparison may be more relevant. As shown in the upper panel is Exhibit No. GRS-17, the EPS for some of these companies has been quite volatile historically. This reflects the relatively highly competitive nature of the market for oil pipeline transportation services as compared to the markets for most other regulated utilities. Historically, DPS growth has been much less volatile than EPS growth. However, the oil pipeline compares with higher historical EPS growth also tended to have higher historical DPS growth. I find the comparison of the IBES' 5-year forecasts of EPS growth with the historical DPS growth the most helpful in assessing the reasonableness of the former as a predictor of long-term future DPS growth. The 5-year IBES' forecasts of EPS are very similar to or lower than the observed historical DPS growth for all of the oil pipeline proxy group companies.

The historical negative EPS growth for Enbridge Energy Partners, L.P. or Enbridge (formerly Lakehead PipeLine Partners, L.P. or Lakehead) followed by forecasted positive EPS growth deserves further examination. On the second page of Exhibit No. GRS-17, the EPS levels in dollars per share for Enbridge peaked in 1998 at $3.07 per share. Between 1992 and 1998, the average annual compound growth rate in Enbridge's EPS was 6.3%. As explained in Lakehead and Enbridge Form 10-Ks for 1999, 2000 and 2001, the drop in earnings after 1998 is due to a drop in throughput. Enbridge (the U.S. limited partnership pipeline and the Canadian pipeline) are in the midst of an expansion project that is expected to generate a substantial increase in throughput. This increase in throughput had begun by late 2001. See Enbridge Energy Partners, L.P., Form 10-K, for the fiscal year ended December 31, 2001 at pages 27-28. The forecasted 8% growth in Enbridge's EPS over the next 5 years would increase its EPS to $1.69 per share in the fifth year which is below its EPS value for the year 2000. Given that Enbridge maintained DPS levels despite a drop in its EPS, a resumption of DPS growth with a recovery in EPS would seem likely.

The bottom panel of Exhibit No. GRS-17 compares historical DPS growth with the combination of historical EPS growth and nominal GDP growth with weights of 2/3 and 1/3, respectfully. This comparison is intended to test the FERC DCF method of defining g against historical DPS growth. This lower panel also presents the combination of IBES' 5-year EPS forecast and the long-run nominal GDP forecast with weights of 2/3 and 1/3, respectively. The forecasted long-run growth in dividend payments (g) under the FERC method, on average, is slightly lower than the value of g produced based just on IBES' 5-year forecasts of EPS. The historical comparisons and the comparison of the forecasted long-run dividend growth rate (g) with the historical DPS growth rate indicates that the FERC method's definition of g should satisfy the WUTC's reasonableness criteria.

Q. Have you redone your DCF calculations to incorporate the WUTC's use of analysts forecasts to define the expected dividend growth component of DCF?

A. Yes. I have redone the FERC method DCF calculations using IBES' 5-year forecast of EPS to define g, which I will refer to as the WUTC DCF method. Under this method, the dividend yield for the last six months as increased by ½ the expected dividend growth rate (g) to produce the expected dividend yield for the immediately upcoming 12-month period.

The WUTC DCF method results for the oil pipeline proxy group companies for end-of-year 2001 are shown in Exhibit No. GRS-18 and for through the first quarter of 2002 are presented in Exhibit No. GRS-19. These results are summarized in Exhibit No. GRS-20.

For the nominal cost of common equity capital, the range of estimates obtained for the individual companies (i.e. the FERC's zone of reasonableness) is from 11.99% to 22.05%. The median cost of common equity capital for the oil pipeline proxy group companies is 15.56% for the end-of-year 2001 period and is 14.49% for the through the first quarter of 2002 period. The mean cost of common equity capital for the pipeline proxy group companies is 15.47% for the end-of-year 2001 period and is 15.39% for the through first quarter 2002 period. The mean is less volatile than the median between the two periods. The range of average results (median and mean) for these two recent periods is from 14.49% to 15.56%.

Based on the results produced by the WUTC DCF method, my recommended estimate for the nominal cost of common equity capital for a typical or average oil pipeline company is 15.20%. This equals the overall average of the four median and mean estimates of the nominal cost of common equity capital

d. Summary of Updated Cost of Common Equity Results for A Typical or Average Oil Pipeline Company

Q. Please summarize your updated cost of common equity results for a typical or average oil pipeline company.

A. The unmodified FERC method produces estimates for the average (median or mean) real cost of common equity capital ranging from 12.89% to 13.20% with the overall average of the four estimates being 13.10% which is my recommended estimate.[12] The zone of reasonableness for the real cost of common equity capital is from 10.72% to 17.34%.

Under the strict FERC methodology, the real cost of common equity capital for a typical or average pipeline would be set equal to the median value for the oil pipeline proxy group companies. In this instance, there are two median estimates: (1) 13.20% for the end-of-year 2001 analysis; and (2) 12.89% for the through the first quarter of 2002 analysis. The average of these two results is 13.05%.

The proposed modification to the FERC's calculation method of the dividend yield for the immediately upcoming 12 month period would increase the above real cost of common equity capital estimates by 0.10% making the overall average of the four estimates 13.20% which is my recommended estimate. The modification increases the other measures of the real cost of equity capital by similar amounts.

These results are consistent with those obtained in previous analyses of the cost of common equity capital for a typical oil pipeline company. See Exhibit No. GRS-21. My DCF estimate is included as the value for 2001. The DCF estimates in prior years were developed by a number of witnesses in SFPP and other cases. The nominal rates of return have been fairly stable over time. The

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[12] In my direct testimony I recommended the mean as the best estimate of the cost of common equity capital. The FERC uses the median as the best estimate of cost of common equity capital. In this testimony, I have combined these two measures and use averages of the means and medians as my preferred estimate. The cost of common equity capital in this testimony is a compromise between the FERC's opinion and my opinion. However, I continue to believe that a mean is a better measure of the average or actual tendency than is the median.

real rates of return have risen recently due to the decrease in inflation, not because of an increase in nominal rates.

The unmodified FERC method based estimates for the average (median or mean) nominal cost of common equity capital ranges from 14.37% to 14.75% with the overall average of the four estimates being 14.60%. The FERC's zone of reasonableness for the nominal cost of common equity capital is from 12.20% to 18.82%. The proposed modification to the FERC method would increase all the estimates of the nominal cost of common equity capital by about 0.10%.

The WUTC DCF method based estimates for the average (median and mean) nominal cost of common equity capital range from 14.49% to 15.56% with the overall average of the four estimates being 15.20% which, based on the WUTC method, is my recommended estimate for a typical or average oil pipeline company.

e. The Equity Risk Premium Adder for Olympic

Q. Do you believe that Olympic's cost of common equity capital is higher than that for a typical or average oil pipeline?

A. Yes.

Q. Please explain.

A. Olympic, as discussed above, has higher than average business risk due to the extensive waterborne competition it faces. Further, as was also discussed above, Olympic is a highly financially distressed company. This risk is referred to as asymmetric risk. In order for Olympic to regain full capacity operation and to ensure its long-run reliability, Olympic must make very substantial investments over the next several years. Given all these circumstances, Olympic clearly is an above average risk oil pipeline which puts its cost of common equity capital somewhere between that for the typical or average pipeline and the upper end of the reasonable range.

In my direct testimony, I recommended a 75 basis point risk-adder for Olympic relative to the cost of common equity capital for a typical or average oil pipeline company. See pages 46-49 of my direct testimony. In my direct testimony; the range for the risk-adder for Olympic was estimated to be between 50 and 100 basis points. I adopted the mid-point of this range (75 basis points) as my recommended estimate for Olympic's risk adder.

I have updated the analysis presented in my direct testimony at page 48 line 911-913. The risk-adder range implied by the four calculations shown in Exhibits Nos. GRS-11, GRS-12, GRS-14, and GRS-15 is 0.56% to 1.35%. I have rounded this to 0.55% to 1.35%. The mid-point of this range is 0.95% or 95 basis points, which is the updated value for my recommended risk-adder for Olympic.

Q. Have you calculated a risk-adder based on the WUTC method DCF calculations?

A. Yes. The parallel calculation based on Exhibit Nos. GRS-18 and GRS-19 produces a risk-adder range of 0.82% to 1.99% which I have rounded to 0.80% to 2.00%. The mid-point of this range is 1.40% or 140 basis points. However, given that the analysis of the cost of common equity capital done using the FERC methodology produced a lower 90 basis point estimate of Olympic's risk-adder, I will use the 95 basis point estimate for Olympic's risk-adder here also.

f. Olympic's Updated Cost of Common Equity

Q. What is Olympic's updated real cost of common equity capital?

A. Starting with the strict FERC methodology, where the real cost of common equity capital for a typical or average oil pipeline company is set to the median value for the proxy group, the range of estimates is 12.89% to 13.20% with a mid-point of 13.05% which, given its 95 basis point risk-adder, implies real cost of common equity capital for Olympic of 13.84% to 14.15% with a mid-point of 14.00%

Based on my recommended estimate for the real cost of common equity capital for a typical or average oil pipeline company based on the unmodified FERC approach of 13.10%, Olympic's real cost of common equity capital would be 14.05% including the 95 basis point risk-adder.

Using the modified FERC approach, my recommended cost of common equity capital for a typical or average oil pipeline company is 13.20%. Given its 95 basis point risk-adder, my recommended value for Olympic's real cost of common equity capital is 14.15%.

In summary, my recommendations for Olympic's real cost of common equity capital, under alternative methodology use are as follows:

Methodology	Real Cost of Common Equity for a Typical Oil Pipeline Company	Olympic's Real Cost of Common Equity Capital	Average Real Cost of Common Equity Capital for the Proxy Group Excluding the Two Lowest Results
Strict FERC Methodology			
End-of-Year 2001	13.20%	14.15%	14.42%
Through 1st Quarter 2002	12.89%	13.84%	14.50%
Midpoint	13.05%	14.00%	14.46%
Unmodified FERC Methodology	13.10%	14.05%	14.46%
Modified FERC Methodology	13.20%	14.15%	14.61%

The upper end of the FERC's zone of reasonableness for the real cost of common equity capital is 16.15% for the end-of the year 2001 results and 17.34% for the through the first quarter of 2002 results. All of Olympic's real cost of common equity capital estimates that include the 95 basis point risk-adder, as shown in the above table, are well below the upper end of the zone of reasonableness. Further, all are less than the average real cost of common equity capital for the proxy group companies when the two lowest results are excluded (i.e. Olympic's real cost of common equity capital including its risk-adder is below the average real cost of common equity for the three oil pipeline proxy group companies in the proxy group whose cost of common equity is equal to or above the median cost of common equity for the proxy group.)

My recommendation, based on the above analysis, is that Olympic's real cost of common equity be set to 14.15% which is the result produced by the modified FERC method plus the 95 basis point risk-adder for Olympic. This modified FERC method result is based on averaging the median and mean cost of common equity capital produced by the two DCF analyses and includes my modification to the FERC's DCF method regarding how the dividend payments for the immediately upcoming 12 month period are determined. If the latter modification were not accepted by the Commission, my recommendation would be reduced to 14.05%. If the Commission decided to only consider the median values and not the mean values, my recommendation would be reduced to 14.00%.

Q. If the Commission were to not accept a risk-adder for Olympic, what would be your resulting real cost of common equity capital recommendation for Olympic?

A. It would be 13.20%. If the Commission also did not accept my modification to the DCF methodology, my recommendation would be reduced to 13.10%. Finally, if the Commission decided to consider only the median values and not the mean values, my recommendation would be reduced to 13.05%.

Q. What rate of inflation is consistent with your estimates of the real cost of common equity capital for Olympic?

A. The average of the CPI inflation rates for the 12 month periods ending December 2001 and March 2002 which is 1.515% (i.e. the average of 1.55% and 1.48% is 1.515%).

Q. What is Olympic's updated nominal cost of common equity capital?

A. Based on alternative assumptions regarding methodology, three different recommended values were developed for the nominal cost of common equity capital for a typical or average oil pipeline company. These estimates, and the corresponding estimates for Olympic including the 95 basis point risk-adder, are as follows:

Methodology	**Nominal Cost of Common Equity Capital for a Typical Oil Pipeline Company**	**Olympic's Nominal Cost of Common Equity Capital**	**Nominal Cost of Common Capital for the Proxy Group Excluding the Two Lowest Results**
Unmodified FERC Method	14.60%	15.55%	15.98%
Modified FERC Method	14.70%	15.65%	16.12%
WUTC DCF Method	15.20%	16.15%	17.42%

Olympic's recommended nominal cost of common equity capital including the 95 basis point risk-adder under each of the alternative methodologies is less than the average nominal cost of equity capital for the proxy group companies when the two lowest results are excluded (i.e. Olympic's nominal cost of common equity capital including its risk-adder is below the average nominal cost of equity for the three oil pipeline companies in the proxy group whose cost of common equity is equal to or above the median cost of common equity for the proxy group).

My recommendation, based on the analyses immediately above and the earlier analyses of the real cost of common equity capital for Olympic, is that Olympic's nominal cost of common equity should be set to 15.65%.

Q. If the Commission were to not accept a risk-adder for Olympic, what would be your resulting nominal cost of common equity capital recommendation for Olympic?

A. It would be 14.70%.

Q. Why didn't you recommend the higher nominal cost of common equity capital estimate produced by the WUTC DCF method?

A. The recommendation that I made for the nominal cost of common equity capital is consistent with the real cost of common equity capital recommendation made to the FERC.

4. Critique of the Methods Used By Other Witnesses to Calculate Olympic's Cost of Common Equity Capital

a. Frank Hanley on Behalf of Tesoro

(1) Methodology Issues

Q. What methods does Mr. Hanley employ in estimating Olympic's cost of common equity capital?

A. Mr. Hanley employs the DCF method, the risk premium model (RPM), the capital asset pricing model (CAPM), and the comparable earnings model (CEM). Mr. Hanley averages the results produced by these four methods to produce his recommended cost of common equity capital. Regarding the DCF method used by Mr. Hanley, it does not conform to the method adopted by the FERC. Mr. Hanley performs several DCF calculations and one is somewhat similar to the

FERC's DCF methodology.

Mr. Hanley does perform a DCF calculation that conforms to the WUTC DCF methodology, but he averages the result of this DCF calculation with the results produced by two other DCF calculations that do not conform with the WUTC's DCF methodology. Mr. Hanley then averages the results produced by the combination of DCF methods with the results produced by three other methods (RPM, CAPM, and CEM) giving each equal weight (i.e. the overall DCF result is given a ¼ weight). The DCF method that conforms to the WUTC DCF methodology has a 1/3 weight in the overall DCF result so the DCF method that conforms to the WUTC DCF methodology has a 1/12 or 8.3% weight in Mr. Hanley's final cost of common equity capital recommendation. In its prior decisions regarding the cost of common equity capital, the WUTC has instructed the expert witnesses submitting testimony to present separately the results of the DCF calculations that are consistent with the WUTC's DCF methodology.

Mr. Hanley has not done this despite the fact that the WUTC admonished him for not doing so regarding testimony he submitted in the Matter of GTE Northwest Inc., 1994, Wash. UTC LEXIS 92, at *14-15, (Dec. 21, 1994). See the above citation from the GTE matter where the WUTC stated that "[t]he Commission thus continues to discourage the approach of averaging DCF with other methods." This WUTC statement was made in response to a claim by Mr. Hanley on behalf of GTE arguing in favor of such averaging which is described in the GTE matter decision by the WUTC as follows:

> "The company [Mr. Hanley] argues that DCF should not be used as the primary method to measure common equity rate of return, and

> that averaging the results helps offset the defects contained in the DCF model. Both Public Counsel and Staff criticize the use of other models, except as a check. In addition, Public Counsel criticizes the company's application of the other methods." See GTE matter.

Nonetheless, Mr. Hanley has submitted testimony in this matter that has ignored the WUTC's admonition in the GTE matter.

(2) Evaluation of Mr. Hanley's DCF Results

Q. Are you only going to evaluate just Mr. Hanley's DCF results?

A. Yes. Given that, in oil pipeline rate matters, the FERC relies on the DCF methodology applied to the oil pipeline proxy group, I have focused my critique of Mr. Hanley's estimate of Olympic's real cost of common equity on his DCF analysis of the oil pipeline proxy group companies and on his estimate of the inflation rate.

The WUTC also relies on the DCF method. While the WUTC DCF methodology is less rigidly defined than is the FERC's DCF methodology, the DCF analysis performed by Mr. Hanley that most closely conforms to the FERC's DCF methodology is also the DCF method that appears to be consistent with the WUTC criteria.

In his DCF analysis, Mr. Hanley calculated the base period dividend yield using a different methodology than is employed under the FERC methodology. See page 31, line 7-14 of his WUTC testimony and Exhibit No. ___ (FJH-9) of his WUTC testimony.

The DCF model version used by Mr. Hanley that is most similar to the FERC's approved DCF approach and appears to conform to the WUTC's criteria is his "single-stage growth version." To develop his estimate of the long-run expected dividend growth rate (g), Mr. Hanley relies exclusively on the analysts' 5-year forecasts of earnings per share (EPS) and does not combine it with a long-run forecast of nominal GDP in the manner prescribed under the FERC methodology. Mr. Hanley's "single-stage growth version" DCF calculations and results are presented in his Exhibit No. ___ (FJH-10) of his WUTC testimony.

Mr. Hanley calculates an estimate of g based on what he identifies as two separate sets of analysts' forecasts: (1) the IBES consensus forecast; and (2) a combination of the Value Line forecast and a consensus forecast published by Thomson FN First Call. The second set differs from the first only in terms of including Value Line forecast, because Thomson runs IBES and publishes the IBES results.[13]

Regarding Value Line, Mr. Hanley only used forecasts for two of the five companies in the oil pipeline proxy group (Buckeye and Kinder Morgan). Value Line also publishes a forecast for TEPPCO which Mr. Hanley did not use for unexplained reasons. Value Line does not cover Enbridge or Kaneb. The Value Line forecasts differs from the Thomson and IBES consensus forecasts because the Value Line forecasts are produced by a single Value Line analyst while the

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[13] At any given time, the results reported by IBES and Thomason may differ slightly.

consensus forecasts are averages or medians of the forecasts produced by a substantial number of analysts.[14] Mr. Hanley's approach of simply averaging the Value Line and Thomson/IBES consensus forecasts is not appropriate. He should weight the Thomson/IBES consensus forecast by the number of analysts included and the Value Line forecast should be given a weight of one.

Finally, Mr. Hanley appears to have made a mistake in compiling the Thomson data; namely, he appears to have used the Thomson consensus forecast for Kaneb's EPS for both Kaneb and Enbridge. Given the numerous problems with the data underlying the DCF results produced by Mr. Hanley using the Thomson/Value Line forecasts, I have considered only his "single-stage growth version" results generated using the IBES consensus forecast.

Q. Have you compared Mr. Hanley's DCF results to the one you produced?

A. Yes. The nominal cost of common equity capital estimates produced using the IBES 5-year consensus forecasts of EPS growth by Mr. Hanley by applying his "single-stage growth version" of the DCF model to the oil pipeline proxy group companies are shown in the lower panel of his Exhibit No.__ (FJH-10), page 1 of 2 of his WUTC testimony. The mean nominal cost of common equity capital results for the five companies is 15.8% and the median is 15.5%.

These results produced by Mr. Hanley are most closely comparable to my estimates of the nominal cost of common equity capital for a typical or average

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14 Currently, the number of analysts included in the IBES consensus forecast for the five proxy group companies are 4 for Buckeye, 8 for Enbridge, 5 for Kaneb, 12 for Kinder Morgan, and 10 for TEPPCO.

oil pipeline company produced using the unmodified FERC method. See Exhibit No. GRS-13. These results, and the comparable results produced by Mr. Hanley, are as follows:

Nominal Cost of Common Equity Capital For A Typical Oil Pipeline Company Calculated Using Mr. Hanley's DCF Method and the Unmodified FERC DCF Method (%)

Measure	Mr. Hanley's Estimate	Average of My Two Estimates	My End-of-Year 2001 Estimate	My Through the First Quarter 2002 Estimate
Mean	15.8%	14.66%	14.67%	14.65%
Median	15.5%	14.56%	14.75%	14.37%
Average	15.65%	14.61%	----	----

Mr. Hanley's "single-stage growth version" of the DCF model produces a higher nominal cost of common equity capital than do my calculations using the unmodified FERC DCF method. However, recall that Mr. Hanley's "single-stage growth version" of the DCF model defines the long-run expected growth in dividends (g) based just on the 5-year analysts forecasts by EPS and does not combine this forecast with long-run expected nominal GDP growth as is done under the unmodified FERC DCF method. Nonetheless, the DCF results produced by Mr. Hanley's "single-stage growth version" of DCF, which is the closest to the FERC DCF methodology that Mr. Hanley ventures, produces a nominal cost of common equity capital estimate for a typical or average oil pipeline that is about 100 basis points above those produced using the unmodified FERC DCF methodology.

I also have produced estimates of the cost of common equity capital for a typical or average oil pipeline using the WUTC DCF method which, like Mr. Hanley's "single-stage growth version" of DCF, defines g based solely on the analysts 5-year forecasts of EPS. The results that I produced using the WUTC DCF method and those produced by Mr. Hanley are contrasted below:

Nominal Cost of Common Equity Capital for A Typical Oil Pipeline Company Calculated Using Mr. Hanley's DCF Method and the WUTC DCF Methodology (%)

Measure	Mr. Hanley's Estimate	Average of My Two Estimates	My End-of-Year 2001 Estimate	My Through the 1st Quarter of 2002 Estimate
Mean	15.8%	15.43%	15.47%	15.39%
Median	15.5%	16.03%	15.56%	14.49%
Average	15.65%	15.23%	---	---

Mr. Hanley's estimate of the cost of common equity capital for a typical oil pipeline company based on his "single-stage growth version" of the DCF model is higher than the result I obtained using the WUTC's DCF method by about 40 basis points.

Q. Are Mr. Hanley's DCF results consistent with those you produced?

A. Mr. Hanley's DCF analysis that is most closely comparable to the FERC's unmodified DCF method and to the WUTC's DCF method produces estimates of the cost of common equity capital for a typical oil pipeline company that are higher than these produced by the FERC's approved approach or by the WUTC's approach. Therefore, if one focuses on the only relevant part of Mr. Hanley's cost of common equity capital analysis, Mr. Hanley's results support the nominal cost of common equity capital estimates that I have developed for a typical oil pipeline company.

(3) The Expected Inflation Rate

Q. Please describe the inflation rate used by Mr. Hanley to define the real cost of common equity capital.

A. Under the FERC methodology, the expected inflation rate is calculated as the percentage change over the most recent 12-month period in the CPI. In the context of my DCF analysis through the end-of-year 2001, the expected inflation rate equals the percentage charge in the CPI between December 2000 and December 2001. In my DCF analysis through the first quarter of 2002, the expected inflation rate equals the percentage change in the CPI between March 2001 and March 2002.

Like almost all aspects of the FERC DCF methodology, the appropriate method of calculating expected inflation has been subject to extensive regulatory review. In the context of the SFPP litigation, the issue of how to define expected inflation was investigated at length. The Commission, in Opinion No. 435, endorsed the Administrative Law Judge's (ALJ's) selection of the inflation factor as defined under the FERC methodology described above stating that "[t]he ALJ's adoption of the inflation factor is clearly correct under the Commission's test period methodology and is affirmed." See 86FERC ¶61, 022 at 61, 099. In the initial decision in this matter, the ALJ was confronted with a recommendation by shippers to use a ten-year forecast of CPI growth instead of the measure chosen. The ALJ rejected this option. However, the ALJ also noted that if one were to select such a long-term expected growth definition of CPI as the inflation factor in defining the real cost of common equity capital, one would have to use the same inflation factor concept in defining the trended rate base instead of the annual changes in CPI that are conventionally used. See pages 66 and 67 of the online version of the Initial Decision (80 FERC ¶ 63, 014 (1997)).

Mr. Hanley, despite the clear adoption by the FERC of the annual change in the CPI as the appropriate measure of inflation to use in defining the real cost of common equity capital, has chosen to use the 30-year intermediate cost assumption forecast rate of CPI inflation produced by the Social Security Administration for the purposes of evaluating the long-run financial condition of the Social Security trust funds. See Mr. Hanley's FERC testimony, Exhibit No. TES-8, at pages 55 and 56 (this analysis is not presented in Mr. Hanley's WUTC testimony). Mr. Hanley does not address why the FERC should reconsider its decision regarding the inflation factor as set out in Opinion No. 435. Instead he asserts that this is the appropriate horizon to use because this is the horizon over which the long-term nominal GDP growth is calculated. I fail to see the connection.

Q. Is Mr. Hanley's use of the long-run expected growth of the CPI inconsistent with inflation assumptions made elsewhere in Tesoro's testimony?

A. Yes. The Tesoro testimony is inconsistent in terms of how it defines the inflation factor that is used in calculating the trended rate base and how the inflation factor is defined for calculating the real cost of common equity capital. Mr. Grasso uses the actual annual percentage change in the CPI to define the trended rate base. See Exhibit No. GG-2C, Schedule 20 of Mr. Grasso's WUTC testimony. To be consistent with Mr. Hanley, Mr. Grasso would have to use the long-run expected value for the CPI growth that prevailed each year from 1983 through 2002 as the inflation factor in calculating the trended rate basis. This follows from the ALJ's determination in the SFPP matter as affirmed by the Commission, that if one were to use a long-run measure of expected CPI inflation rate to define the real cost of common equity as Mr. Hanley has done, then the trended rate base defined by Mr. Grasso also should be based on the same measure of the long-run expected CPI inflation. Instead Mr. Grasso, following Mr. Collins for Olympic, uses the annual rate of change in the CPI to define the trended rate base.

Q. Given these inconsistencies and the FERC's view on how the inflation factor should be defined, how should the real cost of common equity capital estimates be calculated based on Mr. Hanley's nominal cost of common equity capital?

A. The appropriate and consistent measure of the CPI inflation factor that should be used to translate Mr. Hanley's estimated nominal cost of common equity capital into an estimate of the real cost of common equity capital is the annual percentage change in the CPI measure that I employed. This CPI inflation measure, based on the average of the two annual estimates of percentage change in CPI that I employed in my analysis, is 1.515%. Therefore, the nominal cost of common equity capital estimates produced by Mr. Hanley's "single-stage growth version" of the DCF model of 15.8% for the mean and 15.5% for the median translate into 14.3% and 14.0% real costs of common equity capital. This is much higher than Mr. Hanley's recommended 9.74% cost of common equity capital that is produced by Mr. Hanley for a typical oil pipeline company based on his much higher inflation factor.

(4) Olympic's Cost of Common Equity Capital

Q. How does Mr. Hanley define Olympic's cost of common equity capital?

A. Without any supporting analysis or data, Mr. Hanley claims that Olympic faces no greater operational risk than does a typical oil pipeline company. In addition, again with no supporting analysis or data, Mr. Hanley states that he does not believe that waterborne transportation provides any competitive discipline for Olympic. Given these two assumptions, Mr. Hanley concludes that Olympic is no more risky than a typical oil pipeline company.

Based on his assumption that Olympic's risk is the same as that of a typical oil pipeline company, he assumes that Olympic's cost of common equity capital is the same as that of a typical pipeline.

I strongly disagree, as was discussed at length above.

b. Dr. Means on Behalf of Tosco

(1) The Nominal Cost of Common Equity Capital

Q. How does Dr. Means determine the cost of common equity capital for a typical oil pipeline company?

A. Dr. Means, in making his recommendations regarding Olympic's cost of common equity capital, adopts what I have referred to above as the modified FERC DCF methodology for calculating the cost of common equity capital for the oil pipeline proxy group companies. The modification is a change in how the dividend yield for the immediately upcoming 12-month period is calculated from that used under the unmodified FERC method.

Dr. Means, however, argues that the median cost of common equity capital result for the oil pipeline proxy group companies should be used to define the cost of common equity capital for a typical oil pipeline company as opposed to the use of the mean result that I advocated in my direct testimony. In this testimony, as a compromise position, I have used the average of the mean and the median as my preferred estimate. This compromise was offered as an alternative in my direct testimony. I assume that Dr. Means continues to advocate the use of the median value.

Q. Have you updated Dr. Means' calculations to reflect current data?

A. Yes. Dr. Means accepted and used my calculation of the cost of common equity capital for the oil pipeline proxy group companies using the modified FERC DCF methodology in his testimony. The updated median nominal cost of common equity capital values under this methodology are 14.88% under the end-of-year 2001 analysis and 14.48% under the through the first quarter of 2002 analysis, which correspond to the results that Dr. Means adopted from my direct testimony. Therefore, based on Dr. Means' approach in his testimony, the current range for the nominal cost of common equity capital for a typical oil company is 14.88% to 14.48% with a midpoint value of 14.68%. These results are consistent with my recommended nominal cost of common equity capital for a typical oil pipeline company of 14.70%

(2) The Inflation Factor

Q. What inflation factor does Dr. Means use?

A. Dr. Means uses the same inflation factor definition that I used which is the definition specified under the FERC DCF methodology. The current inflation factors corresponding to the above two nominal cost of common equity capital estimates of 14.88% and 14.48% are 1.55% and 1.48%, respectively, with midpoint inflation factor of 1.515%. The corresponding updated real cost of common equity capital estimates for a typical oil pipeline company are 13.33% and 13.00% with a mid-point value of 13.17%. Therefore, Dr. Means' cost of common equity capital approach, applied to current data, produces real common cost of equity estimates for a typical oil pipeline company that are consistent with my recommended real cost of common equity capital of 13.20%

(3) Olympic's Cost of Common Equity Capital

Q. How does Dr. Means calculate Olympic's cost of common equity capital?

A. Dr. Means claims that the market risk faced by Olympic is quite low and that Olympic's risk is not higher than that of typical oil pipeline company. As a consequence, Dr. Means states that Olympic does not require a risk-adder to its cost of common equity capital, and Olympic's cost of common equity capital is the same as that for the typical oil pipeline company.

Dr. Means' arguments in support of this claim essentially are that I offered no proof that waterborne transportation was an effective competitor to Olympic and that Olympic's ability to operate at a full capacity utilization rate almost steadily from 1982 to 1998 demonstrated that waterborne transportation is not a cost effective competitive alternative to Olympic.

I disagree with Dr. Means' claim that I did not demonstrate the competitiveness of waterborne transportation in my direct testimony. The fact that waterborne transportation was able to replace Olympic within months of the 80% throughput restriction with no increase in wholesale refined product prices, in fact, does offer strong evidence of the competitiveness of waterborne transportation. Dr.

Means' claim at page 13 of his testimony that the lack of any permanent effect on wholesale refined product prices from the Olympic accident and the subsequent sustained drop in Olympic throughput might be explained by the largess of refiners who were willing to accept less than market prices is speculative and unrealistic.

Regarding the fact that Olympic operated at, or very near full, capacity from 1982 to 1998, this fact says nothing regarding whether waterborne transportation does or does not offer effective competition to Olympic. Dr. Means recognizes this in his own testimony at page 15, lines 8 to 13, where he correctly states that the fact that a firm has a very large market share (and may be operating consistently at or near a full capacity utilization rate) is not, by itself, "inconsistent with the existence of significant market risk." But Dr. Means then goes on to argue the opposite when he claims that the effectiveness of waterborne competition is documented by Olympic's being able to consistently operate at or near full capacity prior to 1999.

c. Dr. Wilson on Behalf of WUTC Staff

(a) Methodology Issues

Q. Please discuss the methodology used by Dr. Wilson.

A. Dr. Wilson employs the two versions of the DCF method, and a CAPM and CEM method or four distinct methods. He applies these four methods to three different proxy groups: (1) the FERC's five-company oil pipeline proxy groups; (2) a group of seven natural gas pipeline companies selected by Dr. Wilson and

(3) a group of 15 integrated oil companies selected by Dr. Wilson. As a result of using 4 distinct methods applied to 3 proxy groups, Dr. Wilson produces 12 estimates of the cost of common equity capital. Dr. Wilson assigns equal weight to the 12 results, and his recommended cost of common equity capital for a typical oil pipeline company is set equal to the simple average of the 12 results. As discussed above in relation to Mr. Hanley's testimony, the WUTC, in prior decisions, has stated that it wants the DCF results presented separately and not as part of an average of results produced by an array of methods.

Regarding Dr. Wilson's use of proxy groups other than the five-company oil pipeline proxy group, there is no reason for looking beyond the oil pipeline proxy group because it consists of five almost "pure-play" oil pipeline companies. Further, the reliability of the cost of common equity capital estimates produced by this method has been validated in the context of litigated regulatory proceedings. See Opinion No. 435. Dr. Wilson gives no substantive justification for his definition of the two other proxy groups and offers no meaningful evidence supporting their relevance to the determination of the cost of common equity capital for a typical oil pipeline company. See Dr. Wilson's testimony at page 30, line 2-13.

Therefore, I will only evaluate the results that Dr. Wilson generated using the five-company oil pipeline proxy group.

Further, given the WUTC's reliance on the DCF model, I will focus just on the cost of common equity capital estimates that Dr. Wilson generated using his two versions of the DCF model. As Dr. Wilson notes, he and I have no disagreements regarding DCF theory, but we do disagree as to how the dividend yield and growth component of the DCF model should be defined. See Dr. Wilson's testimony at page 15, line 5-7. Dr. Wilson is also correct in his subsequent claim that the most important disagreement between he and I regards how the long-run expected growth in dividends (g) should be estimated. See Dr. Wilson's testimony at page 16, line 6-21.

Dr. Wilson claims that the analysts' 5-year forecasts of earnings per share growth, such as those published by IBES, do not provide reliable estimates of the expected long-run growth of dividends (g). Dr. Wilson claims that the analysts' forecasts, to be valuable, must not just reflect market expectations regarding earning per share growth but must contain new information that causes a change in market expectations. This may be true in terms of the relative value of these analysts' forecasts to a highly informed investor, but it has nothing to do with whether the analysts' 5-year forecast of earnings per share (EPS) is also a good forecast of the expected growth in dividends per share (DPS) over the same period. If Dr. Wilson, on the other hand, is claiming that these analysts in fact know something that the market doesn't know and somehow won't know over the upcoming 5-year period, then Dr. Wilson does not believe in the efficient market hypothesis that underlies DCF theory.

In an alternative attempt to discredit the value of the analysts' 5-year forecasts of EPS growth as a predictor of the 5-year expectation for DPS growth, he asserts that these analysts in fact are touts who publish false or misleading information on the companies they follow in order to inflate the prices of these companies' stocks.

I disagree strongly with both of Mr. Wilson's arguments against using the analysts' 5-year forecasts of EPS to estimate g (the expected long-term growth in DPS). If either of his arguments were correct, we would have no reasonable method of estimating g. In the first case, Dr. Wilson claims that the market isn't efficient which, if true, would imply that none of the models (e.g. DCF or CAPM) could be expected to produce reasonable estimates of the cost of common equity capital. Dr. Wilson's second argument is speculative and unfounded. If the market is efficient, Dr. Wilson's bad analysts would be revealed and discredited. There is no merit in either of Dr Wilson's arguments against using analysts' 5-year forecasts of EPS as an estimate for g.

Q. Have studies been done that evaluate the relative reliability of alternative approaches to estimating the long-term expected growth in dividends (g) within the context of the DCF model?

A. Yes. In the context of a generic proceeding before the New York Public Service Commission to evaluate, among other things, alternative approaches of estimating the cost of common equity capital, research papers prepared by Professors Richard Bower[15] (hereinafter the Bower Paper) and Stuart Myers[16]

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[15] Richard Bower, "Why Worry About Using DCF to Estimate Cost of Equity," Paper prepared for the New York Generic Proceeding on the Motion of the Commission to Consider Financial Regulatory Policies for New York State Utilities, Case 91-M-0509, Presented as Appendix to Attachment 1, Document, Return on Equity Consensus Document, Prepared by the Signatory Members of the Electric and Gas Industry Group, June 2, 1993 (hereinafter referred to as the Bower Paper).

[16] Stuart Myers, "Discounted Cash Flow Estimates of the Cost of Equity Capital," Paper prepared for the New York Generic Proceeding on Motion of Commission to Consider Financial Regulatory Policies for the New York State Utilities, Case 91-M-0509 presented at Attachment 2, Return on Equity Consensus Document, Prepared by the Signatory Members of the Electric and Gas Industry Group, June 2, 1993 (hereinafter referred to as the Myers Paper).

(hereinafter the Myers Paper) evaluated alternative approaches to estimating the expected growth term (g) for the DCF model. These two researchers concluded that:

1) There is no one "best" method for estimating g;

and

2) The retention growth (or sustainable growth) methods of estimating g do not provide accurate estimates of future earnings or dividend growth and other methods perform consistently better.

Professor Myers, in his conclusions where he is reviewing the accuracy of alternative methods of estimating the growth component of the DCF model as depicted in a series of figures, concludes:

> "DCF is not one method but many; it is difficult (probably impossible) to say which growth rate measure or variable growth method is correct."
>
> (Myers Paper, p. 22)

Regarding the relative merits of alternative approaches to estimating the growth component of DCF, with specific reference to the retention growth form (or the sustainable growth form) of the DCF, Professor Bower concludes:

> "Our empirical work provides evidence. Growth rates in dividends, earnings and book value differ historically and prospectively. Cost of equity calculations are neither consistent between types of

> growth estimates nor from year to year for a single type of growth estimate. Among growth estimates, earnings retention estimates provide neither the best explanation of differences in yield and price among utilities nor the most accurate forecast of earnings, dividend or book value growth." (Bower Paper, p. 24)

Professor Bower also concludes that:

> "Regulators who use the constant growth DCF model as the primary tool for estimating cost of equity, should reconsider their approach. If earnings retention is their chosen from of the model, they should change the approach." (Bower Paper, p. 25)

Q. Are there other studies that provide guidance on a preferred approach to estimating the growth component (g) of the DCF model?

A. Yes. Professor Myron Gordon and others have advocated the use of analysts forecasts such as those published by IBES instead of retention growth methods and historical trend methods to estimate the growth component of the DCF model. Professor Robert Harris[17] (hereinafter the Harris Article) evaluated the composite of analysts forecasts as measures of investor expectations regarding the growth component of DCF and concluded that the IBES data "offers a

[17] Robert S. Harris, "Using Analysts' Growth Forecasts to Evaluate Shareholder Required Rates of Return," *Financial Management*, Spring 1986, pp. 50-67; (hereinafter, the Harris Article).

straightforward and powerful aid in establishing required rates of return either for corporate investment decisions or in the regulatory arena." (Harris Article, page 67). In a study prepared by Professor Gordon with David Gruber and Lawrence Gould[18] (hereinafter the Gordon et al. Article), the most accurate estimates of share yield were shown to be produced using the IBES forecasts of earnings growth (as opposed to using the "b x r" method, historical earnings' trend growth, or historical dividends' trend growth). The Gordon et al. Article concludes that the "superior performance of KFRG [forecasts of earnings per share growth prepared by security analysts as reported by IBES] should come as no surprise. All four estimates of growth evaluated, (which, in addition to analysts' forecasts, included historical trend growth in dividends, historical trend growth in earnings, and retention growth), rely upon past data, but, in the case of KFRG (the analysts' forecasts), a larger body of past data is used, filtered through a group of security analysts who adjust for abnormalities that are not considered relevant for future growth." (p. 54) In a subsequent paper, [19] (hereinafter the Gordon Paper) Professor Gordon concludes that one cannot rely on "b x r" as a reliable guide to expected growth and that analysts' forecasts can be expected to produce accurate estimates of expected future growth.

Q. **What are the implications of these study results for the appropriate choice of the growth rate component (g) of DCF in this proceeding**?

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[18] David A. Gruber, Myron S. Gordon, and Lawrence I. Gould, "Choice Among Methods of Estimating Share Yield", *The Journal of Portfolio Management*, Spring 1989, pp. 50-55 (hereinafter the Gordon et al. Article).

[19] Myron J. Gordon, "The Prices of Common Stocks," paper presented to the Spring 1990 Seminar of the Institute for Qualitative Research in Finance, March 27, 1990 (hereinafter the Gordon Paper).

A. First, these study results indicate that the preferred method for estimating the expected growth rate component (g) in the DCF model are analysts forecasts of earnings per share, such as those published by IBES, Zacks, S&P and Value Line. These forecasts provide a good estimate of investor expectations regarding g. To the extent that a large number of investors rely on (or consult) these analysts' forecasts in making their investment decisions, then one can expect these forecasts to be an important determinant of investor expectations regarding growth. The issue is not just the absolute accuracy of these forecasts of future earnings growth. Accurate or not, these forecasts are important if investors give these forecasts credibility when making their investment decisions. Since these services (e.g., IBES, Zacks, S&P and Value Line) have a large number of subscribers who pay for these services, one can presume that these subscribers utilize the information provided by these services in making their investment decisions.

Second, these studies indicate that the retention growth form of the DCF model cannot be relied upon to provide an accurate estimate of the expected growth component of the DCF model.

Third, these studies question the value and reliability of the historical EPS and DPS growth experience of a company as a predictor for its future EPS and DPS growth. The historical growth experience is contingent on the overall economic circumstances prevailing during the historical period and on the specific historical circumstances of the company relative to what will pertain in the future.

Q. Is Dr. Wilson also critical of the use of the long-term growth forecast for

nominal GDP as a proxy for the long-term growth in g beyond the 5-year period covered by the analyst's forecasts of EPS?

A. Yes. As I noted above I do not believe that it is necessary to use anything other than the 5-year analysts' forecasts of EPS. However, the FERC does have a plausible rationale, which Dr. Wilson does not address. Dr. Wilson's recommendation that the nominal GDP growth rate be reduced by ½ is not appropriate.

Q. How does Dr. Wilson estimate the growth component (g) of the DCF model?

A. Dr. Wilson uses a computation of the historical growth rate of DPS and the 5-year ahead forecast of dividend yield produced by a single analyst: Value Line.

For the oil pipeline proxy group companies, the historical growth experience is of particularly questionable value given that these companies were formed in the early 1990s. Second, the historical growth experience shows substantial fluctuations as documented in my Exhibit No. GRS-17. The historical growth method of defining g should not be used for the oil pipeline proxy group companies.

Dr. Wilson's use of the DPS 5-year forecasts produced by the analyst at Value Line is bizarre. It appears that he believes that all analysts other than those at Value Line cannot be relied on. Further, Value Line only covers 3 of the 5 companies in the oil pipeline proxy group so Dr. Wilson is relying on a single analyst's forecast of DPS and only 3 of the 5 companies in the proxy group to develop his cost of common equity capital estimate for the oil pipeline proxy group.

Given all of the above problems, the Commission should give no weight to the DCF results for the oil pipeline proxy group companies that Dr. Wilson generates using a combination of historical experience and forecast growth of DPS.

Q. Does Dr. Wilson employ a second variant of the DCF model?

A. Yes. He uses a variant, which he calls the "fundamental" DCF model, which is in fact the retention growth variant. In addition to the concerns expressed above regarding the retention growth variant of the DCF model, Dr. Wilson only can perform this analysis for 2 of the 5 companies in the oil pipeline proxy group. As a result of these problems, the Commission should give no weight to Dr. Wilson's fundamental DCF model results for the oil pipeline proxy group companies.

Further, Dr. Wilson's "fundamental" DCF model is flawed and incomplete relative to other more carefully implemented retention growth models. Dr. Wilson's "fundamental" DCF calculations use retained earnings as its growth factor. See Exhibit No. __ (JWW-1T), page 32, line 1 – page 33, line 12 and Exhibit No. __(JWW-5). There are several problems with Dr. Wilson's fundamental DCF calculations. First, he considers only revenue raised by a company internally through the retained earnings and does not include revenue a company can raise externally by issuing new stock. This is in contrast to other analyses presented to the WUTC where external growth is correctly included in the estimate of a company's future growth. See, for example, Stephen G. Hill, Exhibit __(STGH-T) in Avista Corporation WUTC Case Nos. UE-991606 and UG-991607.

(2) Dr. Wilson's DCF Results for the Oil Pipeline Proxy Group Company

Q. What is your recommendation regarding Dr. Wilson's DCF based calculation of the cost of common equity capital for the oil pipeline proxy group companies?

A. For the reasons discussed above, I recommend that the Commission give no weight to his results.

(3) Olympic's Risk Relative to that of Other Oil Pipelines

Q. What is Dr. Wilson's opinion of Olympic's risk relative to that of other oil pipeline companies?

A. Dr. Wilson does not address this issue directly. He asserts that there is no need for a positive risk-adder for Olympic so, implicitly, he is arguing that Olympic's risk is the same as that for a typical oil pipeline company. See Dr. Wilson's testimony at page 51. Dr. Wilson also claims that waterborne transportation is not a cost-effective competitive alternative to Olympic. Dr. Wilson incorrectly infers, as did Dr. Means, that Olympic's full capacity operation prior to June 1999 supports the view that waterborne transportation is not competitive. In fact, the fact that Olympic operated at full capacity prior to June 1999 sheds no light whatsoever on the competitiveness of waterborne transportation.

C. Cost of Debt

Q. How did you define Olympic's cost of debt in your direct testimony?

A. I calculated the cost of debt for Olympic based on its parents' embedded cost of debt. This is the approach that the FERC advocates when a regulated entity does not issue its own debt or when the regulated entity's debt is guaranteed by its parents. Part of Olympic's debt is guaranteed by throughput and deficiency agreements between Olympic and its shippers which includes Olympic's parents. Olympic's remaining debt is either guaranteed by Olympic's parents or is in the form of direct loans to Olympic by its parents. Olympic's circumstances are such that the FERC would expect to use Olympic's parents' embedded cost of long term debt as Olympic's cost of debt. See 31FERC ¶61, 377 at 61, 833 (Opinion No. 154B).

Q. Have you updated your calculation of Olympic's cost of debt since you filed your direct testimony?

A. Yes. At the time my direct testimony was filed, the most recent data available for Olympic's parents' embedded cost of debt was for 2000. The implied cost of debt for Olympic was 6.74%. Currently, data are available for 2001 for Olympic's parents' embedded cost of debt. Weighting Olympic's parents' embedded cost of debt for 2001 by their ownership share in Olympic yields a cost of debt for Olympic of 5.26%. See Exhibit No. GRS-22.

Q. What are the recommendations of the other witnesses who have addressed Olympic's cost of debt in this matter?

A. Mr. Hanley, on behalf of Tesoro, recommends that Olympic's cost of debt be set to 7.54% which is the average debt cost rate for the five companies in the oil pipeline proxy group. See Exhibit No. ___(FJH-7) of his WUTC testimony. Mr. Hanley "justifies" using this debt cost estimate for Olympic by simply asserting that "[t]here is no logical reason to use the weighted debt cost of OPL's parent companies." I disagree for the reasons given above. Mr. Hanley goes on to recommend that Olympic be "punished" if its parents don't make equity capital infusions by reducing Olympic's debt cost rate to 6.74% which is its parents' weighted average embedded cost of debt. I fail to see the logic of this supposed "punishment."

Dr. Means, on behalf of Tosco, concurs with my recommendation that Olympic's cost of debt be set to the weighted average of its parents' embedded cost of debt.

Dr. Wilson, on behalf of the Staff, recommends that Olympic's cost of debt be set to 7.0% because 7.0% is "the approximate current cost of high quality long term corporate bonds." See Dr. Wilson's testimony at page 50, lines 16-21. I have been unable to locate the WUTC decision involving a regulated entity that did not issue and guarantee its own debt, so I cannot determine the WUTC precedent. However, the logic of using the actual cost of debt of the parties issuing or guaranteeing debt seems to me to be compelling. However, since Dr Wilson is recommending a higher debt cost for Olympic than it is requesting, I suspect that Olympic would not object to the WUTC adopting Dr. Wilson's recommended debt cost.

D. Capital Structure

Q. How did you define Olympic's capital structure for ratemaking purposes in your direct testimony?

A. I recommended that Olympic's capital structure be defined based on the capital structure of its parents. The specific calculation weighs each parent's equity share of capital by that parent's ownership share in Olympic. In a situation like Olympic's where the regulated entity issues no stock and is dependent entirely on its parents for financing, the FERC's preference is to define the regulated entity's capital structure as I did in my direct testimony. See 52FERC ¶61, 055 at 61, 234 and 31FERC ¶61, 377 at 61, 836 (Opinion No. 154B).

Q. Have you updated your calculation of Olympic's capital structure since you filed your direct testimony?

A. Yes. At the time my direct testimony was filed, the most recent data available for Olympic's parents' capital structure was for 2000. The implied equity share of capital was 82.92%. Currently, data are available for 2001. The implied equity share of capital for Olympic is 86.85%. See Exhibit No. GRS-22.

Q. What are the recommendations of the other witnesses who have analyzed Olympic's capital structure in this matter?

A. Mr. Hanley, on behalf of Tesoro, recommends a capital structure for Olympic with a 46.40% equity share. This value is the average equity share of the five companies in the oil pipeline proxy group. See Exhibit No. __(FJH-4) in his WUTC testimony. There is a problem with Mr. Hanley's calculations of the capital structure for the pipeline proxy group companies. He uses total debt instead of long-term debt to define the debt/equity capital structure. This is inconsistent with FERC practice which includes only long-term debt in the calculation. See 52FERC ¶ 61, 055 at 61, 223 and 43 FERC ¶ 63, 033 at * 61 of 1988 FERC LEXIS 1491.

Dr. Means also argues that Olympic's equity share should be set to the average (median) equity share for the five companies in the oil pipeline proxy group. Dr. Means appropriately calculates the equity share using only the long-term debt of the companies. Dr. Means' recommended equity share for Olympic is 47.4%.

Dr. Wilson, on behalf of Staff, recommends two alternative polar capital structures for Olympic. He recommends setting Olympic's equity share between these polar assumptions. In the circumstance that Olympic's own capital structure continues to consist almost entirely of debt, Dr. Wilson recommends a 20% equity share. If Olympic's parents make a "major infusion of equity capital" into Olympic, then Dr. Wilson recommends a higher equity share for Olympic ranging to as high as 50% depending, presumably, on the extent of the equity infusion.

Q. Is there any reason why the fact that Olympic's capital structure is made up of entirely of debt should be a concern to Olympic's creditors?

A. No. The fact that Olympic's own capital structure contains largely or even exclusively debt is irrelevant because Olympic does not issue stock and Olympic's actual and potential creditors look to Olympic's parents for loan guarantees. As was discussed above, the "creditors" concern is not with Olympic's capital structure but with Olympic's cash flow. The only capital structures of concern to Olympic's creditors are those of Olympic's parents.

The WUTC cases cited by Dr. Wilson where the WUTC strongly requests that the regulated entity increase the equity share in its capital structure involved stand-alone regulated entities that issued stock and issued and guaranteed their own debt. See Dr. Wilson's testimony at 49-50. For such stand-alone companies, capital structure does matter to creditors and a thicker equity share should improve the access of stand-alone regulated entities to capital markets. Olympic not is a stand-alone regulated entity.

Q. What reasons do the other witnesses give for not using Olympic's parents' capital structure for Olympic?

A. Mr. Hanley claims that Olympic's parents' capital structure is not appropriate for Olympic, because this structure is not representative of the capital structures used by the companies in the oil pipeline proxy group. Mr. Hanley then notes that Olympic's parents are not primarily pipeline companies. However, all the companies in the oil pipeline proxy group issue stock, and they also issue and guarantee their own debt.

In rejecting the use of Olympic's parents' capital structure for Olympic, Dr. Means claims that Olympic's business risk is lower than that of its parents and consequently, Dr. Means argues, Olympic's capital structure should have a lower equity share than that of its parents. Instead, Dr. Means argues that the average (median) capital structure for the companies in the oil pipeline proxy group should be used for Olympic.

Dr. Wilson states that the equity share in Olympic's parents' capital structure is too high for Olympic and would result in too high costs for Olympic's shippers.

Dr. Wilson appears to believe that there is a cost minimizing capital structure for Olympic although he does not explicitly claim this. Dr. Wilson's ultimate choice of capital structure for Olympic appears not to be related to his criticism of using Olympic's parents' capital structure or to minimizing shippers' cost.

Q. If the Commission were to determine for ratemaking purposes that Olympic's parents' capital structure was not appropriate for Olympic, do you have an alternative recommendation for the Commission to consider?

A. Yes. As I have argued above, I believe that Olympic's business risk is substantially higher than that of a typical oil pipeline company. As a consequence, for ratemaking purposes, I believe it should have an equity share in its capital structure that is substantially higher than that of a typical or average oil pipeline company.

In Exhibit No. GRS-23, I have analyzed the equity shares of the capital structures for the five companies in the oil pipeline proxy group during the 1996 through 2001 period. The mean equity share for 2001 is 49.43% equity share and the mean equity share over all years and all companies is 49.28%. The median equity share in 2001 is 47.38%.

If the Commission agrees that Olympic has an above average risk for an oil pipeline company, then it would be appropriate for ratemaking purposes to consider an equity share for Olympic that was near the upper end of the range of equity shares for the companies in the oil pipeline proxy group. As can be seen in Exhibit No. GRS-23, an equity share of 60% for Olympic would put it just under the average of the annual high equity shares which equals 61.35%

However, I believe that for ratemaking purposes even a 60% equity share for Olympic is too low because I believe that Olympic is a higher risk company than any of the companies in the oil pipeline proxy group. For ratemaking purposes, a possible compromise value for Olympic's equity share would be one that was halfway between the upper end of the range for the companies in the oil pipeline proxy group and the equity share in Olympic's parents' capital structure. This exact compromise was used in a FERC approved settlement for the Hoover Offshore Oil Pipeline (HOOPS). See 91FERC ¶ 61, 182 and 98FERC ¶ 63, 016. For Olympic, the equity share halfway between 60% and 86.85% is rounds down to 73%. The compromise capital structure for HOOPS had a 74% equity share. If the Commission were to determine for ratemaking purposes that a 73% equity structure were appropriate for Olympic, this would be consistent with the view that Olympic was riskier than the companies in the oil pipeline proxy group but not as risky as its parents.

E. Olympic's Overall Cost of Capital

Q. What is the implied overall before-tax cost of capital for Olympic based on your recommendations for Olympic's cost of equity, cost of debt, and capital structure?

A. The calculation is as follows:

		Nominal Capital Cost Rates (%)		
Capital Types	**Percentage Share In Capital Structure**	**After Tax**	**Before Tax**	**Weighted Before Tax**

Common Equity	86.85%	15.65%	24.08%	20.91%
Long-Term Debt	13.15%	5.26%	5.26%	0.69%
Total	100.00%	---	---	21.60%

The effective overall income tax rate underlying the above calculations are 35%. The overall before-tax cost of capital for Olympic is 21.60%.

VIII. Unconventional and Inappropriate Approaches to Ratemaking

A. The Tesoro Witnesses' Blame and Punish Approach to Ratemaking

Q. Please explain what you mean by the Tesoro witnesses' blame and punish approach to ratemaking.

A. All three Tesoro witnesses (Mr. Brown, Mr. Grasso, and Mr. Hanley) engage in the practice of assuming effectively that Olympic is "guilty" of willfully causing the June 1999 accident, of intentionally delaying restoring Olympic to service and to 100% operating pressure, and of engaging in willfully inappropriate management and financial practices that had the effect of causing Olympic's current operational and financial problems.

These unfounded and unsupported allegations are then used to justify punishing Olympic by reducing its allowed cost of common equity capital, its cost of debt, disallowing operating expenses, removing investment from the rate base, and using an unrealistically high throughput for Olympic. If Tesoro believes it was somehow damaged by Olympic's actions, the courts are the venue where they can have the opportunity to try to prove liability on Olympic's part, and, if Tesoro were to succeed, to be compensated for any resulting damages. Tariff rates should be set in this proceeding based on the facts regarding Olympic's costs and throughput and not based on arbitrary adjustments to these items which are designed to lower Olympic's tariff rates and revenue as a punishment for alleged transgressions. Olympic has responded to the issues related to the facts regarding Olympic's costs and throughput and has not attempted to argue the "merits" of the numerous blame and punish based recommendations of Tesoro's witnesses.

To his credit, Dr. Means, on behalf of Tosco, does not use the blame and punish approach. In his initial testimony, Dr. Means appropriately raises issues of fact regarding Olympic's costs and throughout. However, in his cross-answering testimony, Dr. Means unfortunately suggests that it might be appropriate for the Commission to take up the blame and punish allegations of Tesoro's witnesses. I disagree.

Dr. Wilson, on behalf of Staff, does engage in the blame and punish approach in his recommendations regarding Olympic's capital structure. However, the other Staff witnesses do not.

B. The WUTC Staff Witnesses' Practice of Arbitrarily Replacing Actual Data with Hypothetical Data

Q. Please explain what you mean by the Staff witnesses' practice of arbitrarily replacing actual data with hypothetical data.

A. The Staff witnesses have used the fact that Olympic does not have audited financials to arbitrarily discard or modify Olympic data. While it is true that there were errors in the cost data submitted in Olympic's initial testimony, it is not correct that it is appropriate to assume that Olympic's data are so unreliable that it is appropriate to replace the Olympic data with adjusted or estimated values whenever there is any question regarding a data item. The Staff witnesses have aggressively altered and replaced Olympic's data based on their view that Olympic has not adequately justified individual data items or that, because Olympic's financials are not fully audited, all Olympic's financial data are highly suspect. Other Olympic witnesses are addressing the specific data issues and the issue of the reliability of Olympic's unaudited financials.

Olympic has not attempted to critique all the data adjustments and replacements that were done by the Staff witnesses. Instead, Olympic has put its efforts into correcting Olympics' data where appropriate and justifying other data items that have been questioned.

IX. Retroactive Ratemaking Issues

A. Olympic is Not Attempting to Engage in Retroactive Ratemaking

Q. Does Mr. Elgin, on behalf of Staff, accuse Olympic of attempting to engage in retroactive ratemaking?

A. Yes. However, Mr. Elgin's assertion is incorrect.

Q. Please explain.

A. Mr. Elgin states that the short term loans that Olympic's parents made to Olympic to cover operating expenses should not be considered as debt but instead should be considered equity. He implies that recording these cash infusions as debt effectively moves historical losses into current expenses. This is incorrect. Olympic's own capital structure and the nature of the instruments comprising the structure have absolutely no effect on Olympic's cost of service. No parties to this matter have recommended that Olympic's own capital structure should be used for regulatory purposes. Instead, all parties have proposed hypothetical capital structures and have estimated Olympic's debt cost based on either Olympic's parents' embedded debt cost or on the debt cost of the oil pipeline proxy group companies.

B. Tesoro's Witnesses Urge the Commission to Engage in Retroactive Ratemaking

Q. Please discuss the cases where Tesoro's witnesses are recommending that the Commission engage in retroactive ratemaking.

A. Mr. Brown, at pages 2 and 22 of Exhibit No. TES-1 of his FERC testimony (but not in his WUTC testimony), discusses his historical analysis of Olympic's revenues and costs. Based on his analysis, he concludes that Olympic overearned substantially during the 1983 through 1995 period and, as a consequence, should have lower tariff rates today.[20] I have not checked Mr. Brown's historical calculations because, even if he is correct, which I do not concede, Olympic's earnings during the 1983 to 1995 period are not relevant to this proceeding. Complaints about past overearnings are properly addressed in a complaint

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[20] Mr. Brown also offers the specious argument that Olympic did not utilize the 154B ratemaking methods prior to 1996 because it did not do a 154B filing prior to 1996.

proceeding, but such proceedings only look back two years (i.e. to 2000). Therefore, Mr. Brown's calculations also would be moot in a complaint proceeding.

Mr. Grasso makes an adjustment to Olympic's cost of service to reflect Mr. Brown's allegations of Olympic's overearnings during the 1983 through 1995 period. See Exhibit No. TES-3, at Schedule 6 of Mr. Grasso's FERC testimony (this is not contained in his WUTC testimony). This Tesoro recommended adjustment, if accepted by the Commission, would be retroactive ratemaking. This adjustment should be rejected by the Commission.

Mr. Brown makes a similar argument in his WUTC testimony at pages 2 and 28-29. Mr. Brown recognizes that a switch from a trended original cost (TOC) ratemaking methodology to a depreciated original cost (DOC) ratemaking methodology will strand the accumulated deferred earnings under TOC thereby denying Olympic the opportunity to earn a fair return on its existing investments. Mr. Brown attempts to justify ignoring this stranded investment problem on the grounds that Olympic overearned during the 1983 through 1999 period. This is nothing more than trying to reduce Olympic's current tariff rates based on prior earnings performance (i.e. it is retroactive ratemaking). As was the case for Mr. Brown's FERC testimony, we have not checked Mr. Brown's historical calculations because they are not relevant to this proceeding. Complaints about past overearning are properly addressed in a complaint proceeding, but such proceedings can only look back two years (i.e. 2000). Therefore, Mr. Brown's calculations also would be moot even in a complaint proceeding.

Mr. Grasso, based on the calculations by Mr. Brown that are discussed above, claims there is no need to compensate Olympic for the stranded deferred earnings that inevitably occur as a result of a switch from a TOC to a DOC methodology. See Mr. Grasso's WUTC testimony at page 31. Failure to take the stranded deferred earnings into account amounts to retroactive ratemaking in the sense that alleged past overearnings are the basis for not compensating Olympic for these stranded costs.

X. Operating Cost and Throughput Issues

A. Olympic's Power Costs

Q. Have you reviewed the cost estimates for electricity and drag reducing agent ("DRA") in this proceeding?

A. Yes. Olympic recently compiled the most complete analysis. It relies on 10 months of actual cost data, with an extrapolation for May and June 2002, and is based on the same throughput volumes that are appropriate to use for setting rates, (103 million barrels a year), eliminating the need for complicated scaling adjustments.

Q. How do these costs compare with those put forth by Dr. Means and Mr. Grasso?

A. The actual cost data are approximately 8 percent higher on a dollar per barrel basis than the estimates provided by Dr. Means and Mr. Grasso. This difference appears to arise from three factors.

First, the latest Olympic cost figures are based on actual data that includes four months from 2002, while Dr. Means and Mr. Grasso used only the last six months of 2001, and costs in the later period were moderately higher. Obviously, since all parties based their analysis on actual data, it makes sense to rely on the most complete data available and eliminate errors that are introduced through unnecessary forecasting.

Second, in the original testimonies of Dr. Means and Mr. Grasso, neither adjusted the cost of the DRA to reflect the higher throughput volumes they were assuming. This resulted in an underestimate of the DRA cost per barrel of oil. This problem remains in Mr. Grasso's figures, but the revised analysis provided by Dr. Means claims to correct for this error. Dr. Means' cost per barrel estimate did increase in his revision, but detailed work papers were not provided. Therefore, I can not determine the extent to which there may still be a problem in Dr. Means' analysis.

Third, there appear to be problems associated with the approach used by Dr. Means for scaling the electricity cost to adjust for different throughput volumes. He adjusts electricity costs for each pumping station individually to reflect the higher flows associated with his forecast throughput volume. When I take the resulting cost, and scale it back to actual levels in the last half of 2001 using a simple volume adjustment, the cost estimate is less than actual costs. Part of this is likely attributed to the errors that Dr. Means acknowledged in his revision. Again, I cannot check the revised figures from Dr. Means, because detailed worksheets are not available. In any case, the scaling issue should not be a concern if the Commission bases the rates on actual cost data and a throughput volume of around 103 million barrels a year.

Q. How should electricity costs be adjusted if the Commission decides to base

its conclusion on a different throughput volume?

A. The most recent analysis provided by the company should be used as the starting point for any calculation because it relies on the most complete data. For minor differences in volume, a simple linear extrapolation, assuming $0.08780 per barrel of oil shipped, can be used. However, as throughput increases, the incremental power and DRA costs per barrel will increase in a non-linear fashion due to increased friction. This non-linear cost increase was not discussed in the testimony of either Dr. Means or Mr. Grasso, and I consider this to be a significant error in their analyses. The linear cost-per-barrel adjustment would significantly underestimate costs if substantially higher throughput volumes were used, such as the extremely high hypothetical throughput values advocated by Dr. Means and Mr. Grasso.

Q. To what extent is Olympic pipeline subject to risk associated with changing electricity prices?

A. Electricity purchases are a substantial part of Olympic's operating costs and price increases could adversely affect Olympic. There have been major changes in wholesale electricity markets in the past two years, with substantial price spikes occurring and a great deal of price volatility. While wholesale spot prices have moderated in recent months, there is a great deal of uncertainty regarding how the markets will operate in the future. The relationship between wholesale and retail prices is often not direct, and this introduces a further uncertainty regarding the retail prices that Olympic will have to pay.

Q. Can you provide a brief overview of changes in the wholesale market for

electricity during the past few years?

A. Yes. The recently instituted competitive wholesale market for electricity in California has had profound implications for the state and the entire region. Electricity prices rose dramatically during the summer of 2000 for a number of reasons, including capacity shortages, low hydroelectric energy availability, and alleged market manipulation by some participants. Over the following year into June 2001, high prices drove utilities to the brink of, or into bankruptcy, the California Power Exchange was abandoned, and the state of California entered into a massive electricity purchasing program.

On June 19, 2001, the FERC issued an order requiring all generators across a broad region of the western United States to make all of their generation available to electricity markets at its marginal cost ("mitigation order"). This order, which is still in effect, was issued in response to concerns regarding the exercise of market power, and followed a similar order issued on April 26, 2001 that focused only on the behavior of certain electric generators in California.

The requirements under the mitigation order are temporary, and are currently set to expire on September 30, 2001. There is a great deal of debate currently under way as to what will occur after that time. Some are calling for the FERC to extend the requirements of the mitigation order. Meanwhile, the California ISO has proposed a revised market design which will have implications far beyond California's border. The FERC has also instituted a process for standardizing the electricity market design across the country, and this will surely play a role in future Western electricity markets.

The current mitigation order has reduced electricity prices in the short term, but has also caused power project developers to cancel the development and construction of substantial quantities of new generation resources. If prices are not high enough to attract the needed investment, the region could face substantial energy shortages. Finding a way to balance the need for proper price signals for new construction while ensuring prices are not unjust and unreasonable is just one of the many issues that must be addressed in the further evolution of western electricity markets. It is very difficult to forecast future prices in this climate, because so much depends on regulatory and political processes. It is sufficient to conclude that future prices are uncertain, and further dramatic changes are possible.

While substantially higher wholesale electrical prices are possible, the extent to which they translate into higher retail prices for Olympic and others depends on the electricity suppliers' resource balances, their rate structures, and another layer of regulatory involvement. Each electricity supplier will face different circumstances, and Olympic purchases its power from several electricity suppliers. I have not attempted to conduct a thorough analysis of these factors but Olympic, like all other similarly situated retail electricity customers, faces a great deal more uncertainty today regarding electricity costs than has been the case historically.

B. Issues with Olympic's Throughput

Q. Please discuss the positions of the various parties to this matter regarding the Olympic throughput level to use in determining Olympic's tariff rates.

A. In Olympic's testimony submitted earlier in this matter, Olympic estimated that its test year throughput volume would be 105,987,000 barrels. Currently, Olympic has 10 months of actual throughput data for the test year. Based on this additional actual data, Olympic now estimates that test year throughput will be 103,136,081 barrels which is the volume Olympic now requests be used to calculate its tariff rates.

Mr. Grasso, on behalf of Tesoro, recommended that an Olympic throughput level of 121,349,000 be used to calculate Olympic's tariff rates. See pages 32-34 of Exhibit No. ___ (GG-1T) in his WUTC testimony. Mr. Grasso's recommended Olympic throughput is his estimate of what Olympic's throughput would be when Olympic is allowed by the Federal Office of Pipeline Safety (OPS) to resume 100% operating pressure. The date when such permission will be granted by the OPS, if it is granted, is highly uncertain. Olympic believes that it could occur no earlier than second quarter 2004.

Further, even if the OPS grants Olympic permission to resume 100% operating pressure, further delay could ensue if suits were filed to block the pressure increase and seek and obtain a court injunction pending resolution of the suit. Therefore, even if Olympic makes all its planned investments to restore 100% operating pressure and to ensure long-run system integrity in a timely fashion, regulatory and litigation processes could delay restoring 100% operating pressure indefinitely. Further, if shippers have entered into longer-term firm agreements for waterborne transportation services, these shippers would not return to Olympic until these agreements expired.

Therefore, it is not appropriate to set Olympic's tariff rates in this matter based on estimated 100% operating pressure throughput for Olympic. The timing of the restoration of Olympic to 100% operating pressure is not known, and it is not under Olympic's control. While Olympic must make substantial investments before the OPS will consider a request from Olympic to allow it to resume 100% operating pressure, there is no guarantee that OPS will not require further investments by Olympic. Even if no further investment is required by OPS, OPS is likely to conduct a thorough and time consuming investigation before it renders a decision. Finally, as discussed above, even a favorable decision by OPS does not ensure that Olympic will then be able to immediately resume 100% operating pressure.

Olympic's position is that it would be appropriate for the Commission to revisit the issue of Olympic's tariff rates when and if Olympic is allowed to resume 100% operating pressure. All that is known and measurable with reasonable certainty today is Olympic's throughput capability at 80% operating pressure. Further, this throughput capacity is best measured by the actual Olympic throughput at 80% operating measure.

Q. What is the Staff's conceptual position on the level of Olympic's throughput to use in setting rates in this matter?

A. The Staff's position on the appropriate conceptual throughput to use in determining Olympic's tariff rates in this proceeding coincides with Olympic's position; namely, throughput at 80% operating pressure would be used to set Olympic's tariff rates in this proceeding. Staff adds the proviso, however, that these tariff rates should expire at the end of 2003 when the issue of Olympic's throughput would be revisited. See testimony of Robert Colbo, Exhibit No.

__(ROC-4T), Pages 28-32.

Q. Does Staff accept Olympic's estimate of test year throughput provided in earlier testimony?

A. No. Mr. Colbo estimated what I would describe as maximum potential throughput at 80% operating pressure, with no provision for down time (i.e. no maintenance of the sort that requires taking the pipeline out of service). Olympic conducted a test in July 2001 to determine to maximum possible monthly throughput at 80% operating pressure with no down time for maintenance. Mr. Colbo in developing his Olympic throughput estimate, effectively assumed that Olympic could be run on this basis all the time which is not correct. Mr. Colbo's resulting recommended test year throughput for Olympic is 108,323,721 barrels which, as Mr. Colbo calculates, is 93.7% of Olympic's 1998 throughput of 116,260,991 barrels. In 1998, Olympic ran at 100% operating pressure and was fully utilized allowing for necessary maintenance downtime and for unavoidable scheduling and timing problems which keep actual operating throughput below Mr. Colbo's concept of maximum potential throughput.

Olympic's current estimate of actual test year throughput based on 10 months actual data is 103,136,081 barrels. This equals 88.7% of the 1998 throughput volume.

I am aware of no evidence that suggests that Olympic's actual test year experience is not representative of what can be expected on an ongoing basis with Olympic operating at 80% pressure. Therefore, the current Olympic estimate of test year throughput should be used to set Olympic's tariff rates.

Q. What Olympic throughput does Dr. Means recommend be used to determine Olympic's tariff rates?

A. Dr. Means recommends that Olympic's tariff rates be set based on his estimate of Olympic's annual throughput at 100% operating pressure, but he also recommends a surcharge that would increase the effective current rates to essentially what they would be if the tariff rates were set based on actual test year throughput. Dr. Means further recommends that the surcharge be reduced on a fixed schedule to provide Olympic with a strong incentive to restore operating pressure to 100% as quickly as possible.

Q. Do you believe that Dr. Means' recommendation is conceptually appropriate?

A. No. First, Dr. Means' approach implicitly assumes that restoring Olympic to 100% operating pressure is fully under Olympic's control. For the reasons discussed above, this is not a correct assumption. Second, Mr. Means implicitly assumes that Olympic may not be highly motivated to restore 100% operating pressure. This is not correct. It is in both Olympic's and Olympic's owners interest to restore 100% operating pressure as soon as possible as was discussed earlier. As a consequence, I believe that the Commission should use the best available estimate of actual test year throughput to set Olympic's tariff rates and revisit the issue of Olympic's tariff rates when Olympic resumes operating at 100% pressure

Q. Do you have any concerns with Dr. Means' estimate of Olympic's likely throughput at 100% operating pressure?

A. Yes. Dr. Means' estimate of Olympic's annual throughput at 100% operating pressure is 129,953,000 barrels. This is much higher than Mr. Grasso's estimate of 121,349,000 barrels for Olympic's annual throughput at 100% operating pressure. Finally, when Olympic last operated at 100% pressure (1998), Olympic's annual throughput was 116,263,991 barrels. Mr. Grasso's estimate is based on Olympic's estimate in 1998 that constructing the Bay View facility would allow Olympic to transport 121,349,000 barrels per year. Dr. Means does his own calculation in reaching his higher throughput estimate for 100% operating pressure.

The actual versus planned throughput benefits of the Bay View facility is an engineering issue outside the scope of Dr. Means' and Mr. Grasso's expertise. However, if the Commission sets Olympic's tariff rates based on the best available estimates of actual test year throughput, then the issue of what Olympic's throughput will be at 100% operating pressure is moot within the context of this proceeding.

Q. Does end your testimony at this time?

A. Yes.