Principles of Rate Making and Rate Design for Oil Pipelines

Emma J. Broming
Research Analyst
Premier Quantitative Consulting, Inc.

Introduction

Shippers and pipeline owners frequently disagree over what a just and reasonable rate should be for petroleum pipeline shipments. These rates affect the bottom-line of both the pipeline and the shipper and as a result, both parties litigate frequently. Oil pipelines are critical to the transportation of petroleum products, which are consumed by virtually all Americans. According to the Association of Oil Pipelines, 71 percent of petroleum products on a ton mile basis were transported by pipeline in the United States in 2008.[1] To ensure that shippers are charged just and reasonable rates and that the pipelines providing the services earn adequate returns, rates are regulated by both state (e.g., California Public Utilities Commission, CPUC) and federal (Federal Energy Regulatory Commission, FERC) agencies. Regulation is intended to prohibit shippers from being overcharged for service as well as to prevent pipelines from grossly over recovering their cost of providing service.[2]

Section 1(5) of the Interstate Commerce Act (ICA) requires oil pipeline rates to be just and reasonable.[3] Establishing just and reasonable rates for oil pipelines requires two major steps: (1) rate making, which determines the cost of service or revenue requirement of the pipeline for cost-based rates or the use of an alternative rate making method such as market-based rates, and (2) rate design, which determines the actual rates to be charged through various methodologies, which depend on the rate making methodology employed. Although rates may be designed using a variety of methodologies including cost-based rates, market-based rates, and settlement-based rates, it is important to note that mixing rate making and rate design methodologies is not permitted by the FERC.

A fundamental principle of rate design is that one set of ratepayers should not subsidize other ratepayers, and they should only be responsible for paying for the

[1] *Why Pipelines?* Association of Oil Pipelines. http://www.aopl.org/aboutPipelines/
[2] *Five Year Review of Oil Pipeline Pricing Index.* 133 FERC ¶ 61, 228. December 16, 2010.
[3] *Order 561.* FERC. 2002, p. 4

services (costs) that they consume. Because of the complexity of markets and oil pipeline operations, there is no single "one-size-fits-all" rate making and rate design methodology, and the appropriate methodology may change depending on market conditions. This paper will discuss the principles underlying petroleum pipeline regulation, the various applicable rate making methodologies, and the rate design mechanisms used to determine just and reasonable petroleum shipment rates.

Petroleum Pipeline Rate Regulation

Regulation of oil pipelines is justified as a means to ensure efficient pricing and resource allocation. In the absence of regulation, pipelines that possess market power are likely to charge monopoly or near monopoly prices for transportation because ratepayers have few economically feasible alternatives (i.e., the shippers are captive). Because pipelines experience long run declining costs, there is often only one efficient provider in a given market. For this reason, absent a showing of a lack of market power, pipelines are regulated to ensure that pipeline operators do not abuse their market power. As a practice, regulation also attempts to prevent discriminatory or preferential (unfair) service.

Oil pipeline rates may be established in regulatory proceedings following public applications for rate changes or new rates, and their determination has become increasingly complex over the past three decades due to the advent of grandfathered rates under the 1992 Energy Policy Act and the shift to trended original cost from depreciated original cost rate making as a result of FERC Opinion 154-B. Both changes are discussed below in subsequent sections. Shippers can challenge a new rate arguing that the rate is unjust and unreasonable.[4] In proceedings initiated by a protest, the pipeline carries the burden of proof. Shippers can file a complaint at any time to challenge an existing rate. In a complaint, however, the shipper carries the burden of proof.

Rate Making Methodologies

FERC Order 561 explicitly outlines five different rate making methodologies that are acceptable for use by oil pipelines: cost-based rate making, market-based rate making, settlement-based rate making, negotiated rate making, and indexing. Issues related to rate making arise in three different situations: (1) when a pipeline is establishing an initial rate for new service; (2) when a pipeline is changing an existing rate; (3) when a shipper challenges an existing rate. Rate making methodologies are designed to function individually and cannot be hybridized or combined to invent a new

[4] *Order 561.* FERC. October 22, 1993. http://www.ferc.gov/docs-filing/forms/form-6/overview/order-561.pdf

rate making methodology. Further, certain rate making methodologies are only compatible from an economic standpoint with select rate design methodologies, which will be discussed in subsequent sections.

Cost-Based Rates

The fundamental goal of cost of service (COS) rate making is to match costs with cost causation and to determine an overall cost of service that can be used to design just and reasonable rates. COS ratemaking can be used to establish new rates and to modify existing rates. The cost of service determined through the rate making process must then be translated into individual rates for various origin-destination pairs through rate design, again matching costs with cost causation to ensure that no subsidization results. FERC Opinion 154-B outlines FERC's accepted approach to cost-of-service rate making. Opinion 154-B rate making is based on the concept of trended original cost in which the equity portion of the rate base adjusts for inflation and the inflation adjustment to the rate base is recovered as a deferred return over the life of the investment. In addition, a real return on equity is applied to the equity portion of the rate base and the method provides for an adjustment to the starting rate base relative to the depreciated original cost rate base.[5]

A fundamental goal of pipelines charging cost-based rates is to set rates that allow for cost recovery plus a reasonable profit (return on rate base). Rates based on an appropriate and accurate cost of service analysis ensure that revenues from the provision of services (i.e., petroleum transportation) equal the sum of expenses incurred in providing those services, including a reasonable return on the pipeline's investment. Determination of a reasonable rate of return is often disputed, as is the question of the reasonableness of certain costs.

Throughput levels and cost levels used in COS calculations are based on anticipated test period volumes and expenses. The FERC requires that pipelines use representative throughput and costs in calculating a cost of service and revenue requirement based on a base year and a test period. The base year is the most recent year for which cost and volume data are available. It may be necessary to make objective adjustments to the base year to account for changes in revenues and costs that are non-recurring or extraordinary. A test period is the nine month period after the base year used to calculate the pipeline's revenue requirements reflecting known and measureable cost and volume changes[6] over the base year. A test period should

[5] Depreciated original cost rate making is used by other regulatory authorities and has no inflation adjustment to the rate base or return on equity.
[6] 18 C.F.R. § 346.2(a)(1) (2011)

reflect as closely as possible the conditions the pipeline will face when the proposed rates go into effect and for the foreseeable future.

The cost of service includes operating expenses (e.g., salaries and wages, materials and supplies, fuel and power costs, oil losses and shortages, insurance), a reasonable return on the rate base, depreciation expenses, the amortization of deferred earnings (in FERC cases), amortization of deferred income tax (ADIT), an income tax allowance (where the pipeline pays an income tax), and the amortization of an allowance for funds used during construction (AFUDC). Rates should be determined in an objective manner and should only take into account costs that are prudently incurred, jurisdictional, and functionally related to the services provided. Justice Brandeis originated the prudent investment standard for utilities requesting full cost recovery in *Southwestern Bell Telephone Co.* v. *Public Service Commission of Missouri*. [7] Generally, prudently incurred costs and decisions are those that were "reasonable at the time and under the circumstances the decisions were made." [8] Although determining the cost of service is a component of rate making, the cost of service, inclusive of a reasonable return on the pipeline's investment, serves as the starting point for various rate design methodologies.

Market-Based Rates

Market-based rate making authority permits a pipeline to engage in competitive pricing in an effort to react to changes in market conditions, including changes in supply and demand.[9] The concept of accepting rates "regulated" by the market relies on the belief that the "invisible hand of competition" can most effectively regulate rates. [10] Further, it relies on the principle that "placing competitive risks on pipelines and their shareholders would produce more efficient investment decisions than a cost-plus regulatory regimen."[11] Market power is defined as "a firm's ability to sustain a price increase over a significant period of time or to exclude competition," [12] which has subsequently been defined by FERC to mean a 15 percent price threshold for pipelines.[13]

---

[7] *The Theory of Prudent Investment.* CQ Researcher. http://library.cqpress.com/cqresearcher/document.php?id=cqresrre1937122200

[8] *Who Pays for Sunk Costs?* J.W. Wilson & Associates, Inc. The National Regulatory Research Institute. September 1988. http://www.ipu.msu.edu/library/pdfs/nrri/JW-Associates-Sunk-Cost-88-10-Sept-88.pdf

[9] FERC Order 592

[10] *Cost-of-service rates to market-based rates to price caps to ?!#?#!?* The Electricity Journal. May 2001, p. 62-63

[11] *Cost-of-service rates to market-based rates to price caps to ?!#?#!?* The Electricity Journal. May 2001, p. 62

[12] FERC Order 391-A

[13] 133 FERC ¶ 61,192 Docket No. OR07-21-000, December 1, 2010

The FERC does not allow the application of market-based rates until it finds that the pipeline does not exercise significant market power in the relevant market, which is documented with a complete market analysis. However, the FERC recognizes that there may be circumstances that necessitate the flexibility afforded by market-based rates to compete. According to 18 CFR §348, applications for market-based rate making authority require the following:

- Definition of the relevant geographic markets
- Definition of the relevant product markets, including capacity and throughput by commodity
- Descriptions of facilities and services rendered
- Analysis of competitive alternatives
- Identification of potential competition
- Calculation of market power measures

The Herfindahl-Hirschman Index (HHI) is a measure of market concentration,[14] and is used to proxy market power. The HHI is used to assess market concentration in each market in which market-based ratemaking authority is sought.[15] The HHI is calculated by summing the squares of the market shares for each competitive pipeline and theoretically ranges from 0 to 10,000 with 0 being the most competitive market possible and 10,000 being an absolute monopoly.[16] Other factors considered include potential market entrants and trends in supply and demand. Further, applications for market-based rate making authority must demonstrate that shippers are not captive to the pipeline.[17] Captive shippers are those with no other transportation alternatives. Until the FERC makes the finding that the pipeline lacks significant market power, a pipeline's rates cannot exceed the index ceiling level or the level justified by the cost of service analysis for the pipeline.[18]

Market-based rates are determined by competition. Under market-based rates, the pipeline benefits when the market supports rates in excess of its cost of service and it bears the risk that it may not be able to recover its costs if the market no longer supports rates that do so. Since pipelines file for market-based rate making authority, they voluntarily and explicitly assume this risk, and if successful, face a far lessened regulatory burden. Pipelines can file for market-based rates at any time, but they carry the burden of proof in establishing the relevant geographic markets and identifying the

[14] FERC Order 592
[15] FERC Order 391
[16] For example, in a market where there are four competing pipelines with market shares 10%, 30%, 35%, and 25%, the $HHI = 10^2 + 30^2 + 35^2 + 25^2 = 2850$
[17] FERC Order 391
[18] FERC Order 561, 2002 [30,941]

product markets in which they lack significant market power.[19] One advantage to the pipeline of market-based rates is that they do not require shipper agreement for changes above the applicable index ceiling levels. However, pipelines are not guaranteed a reasonable return on their rate base under the market-based approach and voluntarily assume this risk. Thus one must view market-based rates and cost-based rates as entirely separate rate making methodologies, relying on different economic principles and providing different risk profiles to the pipeline and its shippers.

Settlement Rates

Settlement rates can be established by two mechanisms. Settlement rates are established when all shippers agree to a proposed rate under 18 CFR § 342.4. Within the confines of settlement based rate making, pipelines are not required to make a cost of service filing, market power study, or justify application of indexing in the event that the shippers unanimously consent to a given rate. Although the agreed-upon rate may be in excess of the ceiling level established by the indexing methodology, if the shippers and the pipeline come to a mutual agreement on a rate or set of rates, it may be deemed acceptable. The FERC's policy of favoring and accepting settlements as a means to establish new rates attempts to avoid costly litigation and thus, reduces the regulatory burdens on all involved. In the event that all shippers settle on a rate, protests are prohibited.

If at least one existing non-affiliated shipper agrees on a rate change, the pipeline can file a rate application based on that agreement[20] or negotiation under 18 CFR § 342.4. For new service governed by negotiated rates, the pipeline must submit a sworn affidavit to its regulatory body certifying that at least one shipper has agreed to the proposed rate. However, other shippers can protest tariffs based on agreements with one shipper, which then necessitates a cost of service filing.

Indexation

Once cost-based rates have been established and accepted by the FERC, the most common method for changing rates is through indexation. As such, indexation cannot be used to establish new rates. In 1992 the FERC designated indexing as the primary method by which rates should be changed as a result of the Energy Policy Act of 1992,[21] in which Congress mandated that the FERC develop a "simplified and

[19] FERC Order 592
[20] FERC Order 561, 2002 [30,947]
[21] Under the 1992 Energy Policy Act, existing rates were grandfathered in as just and reasonable if they met the following conditions: (1) the rate was in effect for a full year before October 24, 1992, and (2) there was no protest, complaint, or investigation of the rate. Rates that were considered just and reasonable as a result of the 1992 grandfathering process could only be challenged if there was a

generally applicable" oil pipeline ratemaking methodology.[22] Indexing allows pipelines to increase their rates by a single factor tied to inflation. The index establishes the annual ceiling levels for oil pipeline rates and is not a stand-alone rate design mechanism; in other words it typically works in conjunction with cost of service-based rates or settlement-based rates. Annual ceiling levels are the maximum rates which pipelines are permitted to charge. The theory behind indexing is to allow pipelines to recoup cost increases roughly commensurate with inflationary increases without requiring a full blown cost of service proceeding. The appropriate maximum rate of increase is reevaluated every five years and is determined by the FERC, which is the only regulatory body that applies the indexing rate change methodology. The current index is the Producer Price Index for Finished Goods (PPI-FG) plus a 2.65 percent "productivity" adjustment.

Indexed rate increases are not automatic. In practical application of the index, the rate of increase or decrease is applied to the individual rates and not to the pipeline's cost of service.[23] Changing rates via the indexing methodology is a "light-handed" approach to regulation. One possible advantage of the indexing approach is that rates are permitted to increase or decrease within the ceiling limit without the pipeline being required to make a new cost of service filing or provide additional supporting information,[24] conserving both time and resources for the pipeline as well as the FERC. In order to apply the index to existing just and reasonable rates, the FERC applies a "Percentage Comparison Test." This test compares the cost data as recorded on page 700 of the pipeline's Form 6 for a given year with analogous data for the prior year. If the difference between the pipeline's change in costs and the proposed index-based rate increase exceeds 10 percent[25], a shipper can protest the index increase and the Commission must determine whether or not the proposed rate increases are substantially in excess of the change in actual costs such that the proposed rates are unjust and unreasonable.[26]

---

substantial change in: (1) the economic conditions of the pipeline that were the basis for the rates, or (2) the nature of the services on which the rate was based.

[22] FERC Order 561

[23] FERC Order 561, 2002 [30,950]

[24] FERC Order 561, 2002 [30,9461]

[25] To illustrate, assume the index-based increase is 7 percent and the year to year change in the pipeline's cost of service from the Form 6 was negative 4 percent; this would exceed 10 percent, and thus if a shipper protested, FERC would likely hold a hearing to determine whether the pipeline should be permitted to apply the full index increase to its rates.

[26] 140 FERC ¶ 61,016. Docket No. IS11-444-001. July 11, 2012 and 143 FERC ¶ 61,213. Docket No. IS11-444-001. June 6, 2013.

Through the use of the Producer Price Index, the indexing system is based on economy-wide average costs as opposed to pipeline-specific costs,[27] although the productivity factor attempts to tie the index to changes in the pipeline-specific environment. The productivity factor is reviewed and determined every five years following commentary from the industry and has been determined by using a methodology[28] which takes into account changes in industry averages of operating expenses and capital costs.[29] Changing rates via indexing may not always be appropriate and other methods (e.g., cost-based rate applications) may be used to change existing rates and to set and justify new rates.[30]

Although the indexation approach streamlines the process of changing rates and was designed to decrease the regulatory burdens on all parties involved, there are shortcomings to the approach which have not been addressed by the FERC. The indexation approach focuses solely on changes in costs reported on page 700 of the annual FERC Form 6. However, there are factors besides costs that influence design of cost-based rates. For example, the indexing approach, by focusing entirely on costs, fails to consider the effects of volume increases and decreases, which directly affect the pipeline's revenues. All else equal, an increase in throughput will increase revenues relative to costs and will decrease the pipeline's per barrel costs.[31] Therefore, the pipeline will be able to increase its per barrel rates under the indexing approach despite actually experiencing a decrease in per barrel costs due to an increase in throughput volume. This will lead some pipelines that have experienced significant throughput increases to over recover their cost of service by a significant amount.

Table 1 illustrates this issue for a hypothetical pipeline. In year 1, the pipeline has a cost of service of $5, throughput of 10 barrels and a single rate of $0.50 per barrel. It generates $5 in revenue and its cost of service and revenue are identical and thus, its rate may be considered just and reasonable. In year two however, the pipeline's cost of service increases to $5.50, a 10 percent increase. Throughput however increases by 50 percent to 15 barrels. The index permits an increase of up to 8 percent so the pipeline increases its rate by 8 percent to $0.54 per barrel. Therefore, its revenue increases to $8.10 [15 x .54] and the pipeline is now over recovering its cost

[27] FERC Order 561. 2002 [30,946]
[28] This methodology measures the change in operating expenses and capital costs on a per barrel mile basis using FERC Form 6 filing data from the previous five years. For more information, see http://www.ferc.gov/industries/oil/gen-info/pipeline-index/RM10-25-000.pdf
[29] 133 FERC ¶ 61,228 Five-Year Review of Oil Pipeline Pricing Index.
[30] This is true if the pipeline can show a substantial divergence between its actual costs and the rate resulting from the application of the index such that the rate at the ceiling level would preclude the pipeline from being able to charge a just and reasonable rate.
[31] Volume increases may causes certain operating expenses such as fuel and power to increase, but they are unlikely to have a major cost impact.

of service by $2.60 or 47 percent, a clear sign that its rates are unjust and unreasonable! This issue requires the attention of the FERC and is an important issue to consider in practical application of the indexing methodology.[32]

Table 1
Illustration of the Failure of the FERC Indexation Rules to Account for Changes in Throughput

	Year 1	Year 2	Change
Cost of Service	$5.00	$5.50	10%
Throughput	10	15	50%
Index	NA	8%	
Rate	$0.50	$0.54	8%
Revenue	$5.00	$8.10	62%
Overrecovery	$0.00	$2.60	
Overrecovery %	0%	47%	

Rate Design

A fundamental precept of oil pipeline rate design is that shippers should only be responsible for paying for services they consume and should not be required to cross-subsidize other ratepayers. Further, it is important to note that mixing rate design methodologies to create new hybrid methodologies is not permitted by the FERC.[33] As such, pipelines with two different rate making methodologies should have two different rate design methodologies. For example, a pipeline with both market-based rate making authority and cost-based rates should design the market-based rates according to the principles discussed below, separately from the design of its cost-based rates to avoid cross-subsidization between services based on different ratemaking principles.

Fully Allocated Cost Rate Design

For a pipeline with a single origin and destination pair, the rate is simply the cost of service divided by the number of barrels being shipped or projected to be shipped. However, many petroleum pipelines operate as a system of multiple origin-destination points with varying costs of services to each location, which necessitates a rate design mechanism. The fully allocated cost (FAC) rate design methodology is the most efficient methodology for designing rates on pipelines with multiple origin-destination

[32] When volume declines result in a pipeline being unable to recover its cost of service, the pipeline will file for a rate increase under the substantial divergence rule noted above. Under current rules, shippers do not have the ability to challenge an index increase when a pipeline's volumes increase. This is unfair to shippers.
[33] FERC Order 561

pairs as it allocates the specific costs incurred at each location and for each shipment, thereby eliminating the potential for cross subsidization and properly aligns costs with cost causation. For instance, it may be more expensive to ship from point A to B on a per barrel mile basis[34] than it is to ship from point A to C. As such, it is necessary to determine the throughput volumes and costs associated with providing service at each location to calculate the appropriate rates for that location using a fully allocated cost rate design.

The FAC rate design methodology separates a pipeline's cost of service into distance and non-distance costs and serves to allocate costs over individual product movements. As such, FAC rates are comprised of both a distance and a non-distance component. The non-distance component is calculated by dividing the total costs that do not vary by distance (the non-distance costs) by the total test year throughput, and is identical for all origin-destination pairs. The distance component of the total rate for a specific location is calculated by multiplying the fraction of specific location barrel miles to total system barrel miles by the fraction of the costs within the COS that vary by distance (such as fuel and power) to the test year volumes for a specific location.[35] The total shipment rate for a given location is the sum of the non-distance and distance rate components.

Separating costs into their distance and non-distance components requires analysis of the functionality of each cost category. Operating expenses for oil pipelines are categorized according to their functionality by the FERC Uniform System of Accounts (USofA) and are separated into two service categories: (1) operations and maintenance [direct costs] and (2) general and administrative [indirect costs]. Operations and maintenance expenses include every cost associated with the operation, transportation, repairs, and maintenance of the pipeline. General and administrative expenses are by definition, expenses not directly allocable to operations and maintenance expenses.[36] In principle, distance costs are those that vary with the distance the petroleum is transported. Non-distance costs are costs that do not change based on the distance the petroleum is transported.

Depending on the nature of the costs included by a pipeline in each account, the classification of distance and non-distance costs may vary. Costs such as operating fuel and power (account 330) are classified as distance costs since the amount of fuel

---

[34] A barrel mile is defined as one barrel of shipped product moving one mile.

[35] $\text{Distance Component } = \frac{\text{location barrel miles}}{\text{total system barrel miles}} \times \frac{\text{distance costs}}{\text{location test year volumes}}$

[36] FERC Uniform System of Accounts, Title 18, Part 352. http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.15.72&idno=18

and power expended in transporting petroleum products depends on the distance over which the product travels. It is important to note the distinction between similarly labeled categories, such as rentals (accounts 350 and 530). Account 350 includes the cost of renting property used as a part of carrier transportation service, such as equipment and facilities. As these costs increase with distance, they are classified as distance costs. In contrast, account 530 includes the cost of renting property for general and administrative purposes that may not vary by distance, depending on the pipeline. The classification of costs as distance and non-distance can be a point of controversy in rate-case proceedings. As such, it is important for practitioners to carefully examine the functions of each cost category when separating and categorizing distance and non-distance costs.

To illustrate fully allocated cost rate design, we discuss a hypothetical pipeline system, USA Pipelines. USA Pipelines operates in the Midwestern United States with 427 miles of petroleum pipelines and 7 locations. The locations and pipeline lengths as well as the associated test year volumes are shown in Table 2. USA Pipelines has a test year cost of service of $14 million.

Table 2
Test Year Volumes for USA Pipelines

Location	Test Year Volumes	Miles
Alpha	6,479,410	105.9
Beta	230,670	15.3
Gamma	4,760,000	87.2
Delta	1,076,580	35.7
Epsilon	282,750	22.0
Zeta	7,084,000	136.9
Omicron	40,500	24.0
Total	19,953,910	427

The separation of distance and non-distance operating expenses for USA Pipelines is shown below in Table 3. The only non-distance costs incurred by USA Pipelines are for outside services (account 520) and other general and administrative expenses (account 590). Account 520 includes the cost of management and general and administrative services performed by outside entities, such as those under a service contract. Account 590 includes all general and administrative costs incurred for general purposes, such as travel, meals, and lodging. As these costs do not vary by how much oil is shipped on the pipeline for the USA Pipelines system, we classify them as non-distance costs in Table 3.

Table 3
Cost of Service Elements for USA Pipelines

Account	Operating Expenses	Test Year Amount	Distance	Non-Distance
	Operations and Maintenance			
300	Salaries and Wages	$ 1,620,000	$ 1,620,000	$ -
310	Materials and Supplies	$ 324,000	$ 324,000	$ -
320	Outside Services	$ 900,050	$ 900,050	$ -
330	Operating Fuel and Power	$ 2,025,000	$ 2,025,000	$ -
340	Oil Losses and Shortages	$ (324,000)	$ (324,000)	$ -
350	Rentals	$ 738,000	$ 738,000	$ -
390	Other Expenses	$ 78,600	$ 78,600	$ -
	Subtotal	$ 5,361,650	$ 5,361,650	$ -
	General and Administrative			
500	Salaries and Wages	$ -	$ -	$ -
510	Materials and Supplies	$ 16,450	$ 16,450	
520	Outside Services	$ 1,550,000	$ -	$ 1,550,000
530	Rentals	$ 54,900	$ 54,900	
550	Employee Benefits	$ 777,600	$ 777,600	
560	Insurance	$ -	$ -	$ -
580	Pipeline Taxes	$ 761,400	$ 761,400	
590	Other Expenses	$ 150,000	$ -	$ 150,000
	Subtotal	$ 3,310,350	$ 1,610,350	$ 1,700,000
	Other COS Elements	**Test Year Amount**	**Distance**	**Non-Distance**
	Return on Rate Base	$ 2,250,000	$ 2,250,000	$ -
	Depreciation Expense	$ 1,944,000	$ 1,944,000	$ -
	AFUDC Amortization	$ 1,134,000	$ 1,134,000	$ -
	Subtotal	$ 5,328,000	$ 5,328,000	$ -
	Total Cost of Service	**$ 14,000,000**	**$ 12,300,000**	**$ 1,700,000**

The non-distance component of the rate is uniform across all locations and is calculated by dividing the total non-distance costs by the total test year throughput because it is assumed that all origin-destination pairs benefit equally from the provision of certain services, such as outside services in the case of USA Pipelines. For USA Pipelines, the per barrel non-distance cost is $0.085 per barrel.[37] The distance component of the total rate will vary according to the distance and volume between the origin and destination for that route. For instance, to calculate the distance related costs for the Alpha location on USA Pipelines, we divide the Alpha barrel miles by the total system barrel miles to obtain a ratio of 0.3236.[38] We then divide the total system

[37] $1,700,000 / 19,953,910 = $0.085/bbl.
[38] 686,169,519 / 2,120,196,776 = 0.3236

distance cost of service by the test year volumes for Alpha to obtain a ratio of 1.898.[39] The product of the two ratios is the distance component of the Alpha shipment rate of \$0.614.[40] The total cost per barrel to ship on the Alpha line is the non-distance cost plus the distance cost: \$0.700 per barrel.[41] For the remaining six locations, the rates are calculated in an identical manner and are shown in Table 4.

Table 4
Fully Allocated Cost Rates for USA Pipelines

Location	Test Year Volumes	Miles	BBL Miles	Non-Distance Related	Distance Related	Total Rate
Alpha	6,479,410	105.9	686,169,519	\$ 0.085	\$ 0.614	\$0.700
Beta	230,670	15.3	3,529,251	\$ 0.085	\$ 0.089	\$0.174
Gamma	4,760,000	87.2	415,072,000	\$ 0.085	\$ 0.506	\$0.591
Delta	1,076,580	35.7	38,433,906	\$ 0.085	\$ 0.207	\$0.292
Epsilon	282,750	22.0	6,220,500	\$ 0.085	\$ 0.128	\$0.213
Zeta	7,084,000	136.9	969,799,600	\$ 0.085	\$ 0.794	\$0.879
Omicron	40,500	24.0	972,000	\$ 0.085	\$ 0.139	\$0.224

Uniform Percentage Change Rates

For previously established cost-based rates, a pipeline may elect to design rates based on a uniform percentage change in the cost of service or revenue requirement. Where the rates were initially based on a fully allocated cost rate design, this may not be an unreasonable approach and essentially mirrors the indexation approach. Nevertheless, any rate increase or decrease via a uniform percentage change requires an application for rate change authority by the pipeline's regulator. For example, if a pipeline's COS was \$100 million but has increased to \$105 million, they could apply for a uniform 5 percent increase in their rates. An important distinction between indexing, which is a uniform percentage change, and cost-based uniform percentage change rates is that cost-based rates take into account volume changes whereas indexing does not.

Market-Based Rates

Market-based rates are in effect another form of rate design that is unrelated to the costs of providing service. Market-based rates are directly related to competitive conditions and what the market will allow in terms of a price for transportation service. As a result, a pipeline may elect to set its market-based rates based on its estimate of

[39] \$12.3 million / 6,479,410 = 1.898
[40] 0.3236 x 1.898 = \$0.614
[41] \$0.085 + \$0.614 = \$0.700/bbl. (rounded)

the price elasticity of demand for service for different locations. In this sense the pipeline is using the elasticity of demand as a measure of the degree of competition for each route. For example, assume a pipeline has two routes, one from origin A to destination B and a second from origin A to destination C. Further assume that the costs to serve each destination are approximately the same. While the origin and both destinations face competition and the FERC has ruled that the pipeline may charge market-based rates for both destinations, the degree of competition varies at each destination. Destination B is served by a competing pipeline as well as by truck and barge competition and the pipeline faces a highly elastic demand curve, meaning that small increases in its rate will lead to a large loss of volume. Destination C, however, is served by only one competitor and the elasticity of demand is closer to unitary. The pipeline is likely to design its rates such that the rate to destination C is higher than the rate to destination B even though its costs of serving each are about the same. The reason for doing this is that the degree of competition differs by destination which affords the pipeline flexibility in the rates it can charge in hopes of maximizing the volume traffic it obtains for each destination.

Discounted and Negotiated Rates

Where a pipeline may face competition at certain locations, fully allocated cost rates may not be competitive and the pipeline may lose volume to competitive alternatives. As such, pipelines may be required to discount their rates as a result of competition in order to attract increased shipments. Only existing rates can be discounted and the FERC only permits pipelines to discount rates when required by competitive forces. Lower rates attract new customers, retain existing shipments, and benefit shippers. As such, discounted rates can lead to increased revenue, which is beneficial for the pipeline. Discounted rates are similar to negotiated rates and may apply to only one or a select few customers due to exclusionary terms. Further, discounted rates can take the form of a product-specific discount, such as one for specific refined products only. As a general matter, the FERC prohibits pipelines to discount negotiated rates unless it can be shown that the discount was in response to competition. Principally, negotiated rates are not necessarily available to all shippers as part of a pipeline’s tariff. A pipeline may make an agreement with a particular shipper that may not be applicable to other shippers as a result of exclusionary terms.

Iteratively Discounted Rates

Within cost-based rate making, iterative discounting is permitted as a mechanism to retain or capture new volumes in markets where the pipeline still possesses market power (i.e., is not eligible for market-based rate making authority) but where it may be in danger of losing volume to another carrier or mode of transportation. In the event that a fully allocated cost rate is unable to attract sufficient volume to the pipeline, iterative discounting may be used to determine a rate that will maximize throughput. The FERC permits application of the iterative discounting methodology only when cost-based rates meet two criteria:[42] First, the rates are below the Commission-approved fully-allocated cost maximum rates and are discounted according to Commission policy. Second, iterative discounting is to be applied only when required by competitive forces within the context of cost of service rate design, and cannot be applied as a rate design methodology when market-based rates are being charged.[43]

Iterative discounting is traditionally applied in natural gas pipeline rate design and has only been recently considered for oil pipelines. Although iterative discounting is appropriate in a natural gas setting, a variety of differentiating factors between natural gas and oil pipelines exist that complicate the application of iterative discounting for oil pipelines. For example, natural gas pipelines generally face greater competition than oil pipelines. Additionally, transportation is a small component of the natural gas market when compared to the purchase and sale of gas. Thus far there has been little success in applying iterative discounting to oil pipelines, because most proposals erroneously apply iterative discounting to a mix of market-based and cost-based rates, which we have already noted is not permitted. As such, iterative discounting is applicable as a rate design methodology only when a single rate making methodology is used for a given system and only if no discrimination or cross-subsidization occurs with the iteratively discounted rates.[44]

A basic tenet of regulatory economics is that rate design methodologies cannot be mixed. Iterative discounting leads to cross subsidization in an oil pipeline system employing multiple rate making methodologies, such as one in which both market-based rates and cost-based rates are in effect. As discussed above, under market-based rate making authority, the pipeline bears the risk that it may fail to recover its costs when its rates do not cover its costs, but experiences gains when it is able to charge rates that produce excess revenues. As such, cost-based and market-based rates are based on two entirely different and incompatible economic concepts. Iterative discounting, when used in a mixed methodology context, embeds market-based rates within a cost of service rate design. The principle economic effect is a shift of costs from market-based ratepayers to cost-based ratepayers.

[42] "Cost-of-service rates manual," FERC, June 1999
[43] A pipeline that only has market-based rates cannot use iterative discounting to rate design since the rate it charges is determined by the market not cost of service principles.
[44] Williams Pipe Line Co., Opinion 391-B, 84 FERC ¶61,021 (1999)

Cross-subsidization between ratepayers is an unacceptable outcome, as a fundamental precept of economics is that costs from an unregulated market should not be shifted to a regulated market. From an economic standpoint, iterative discounting is applicable only within the context of cost-based rate design and only when it is required by competitive forces. The application of the iterative discounting methodology to pipeline rates in which both cost-based and market-based rates are in effect is inappropriate, results in cross-subsidization, and is not accepted by the FERC. This follows the principle that customers in non-competitive markets should not have to pay excessive rates to recoup losses on the pipeline's part in competitive markets, where voluntary market-based rate making authority exposes the pipeline to the risk that it may not fully recoup its COS.[45]

The iterative discounting process involves adjusting and comparing the maximum rate (defined as the fully allocated cost rate) to the discounted rates multiple times. Additionally, the iteratively discounted rate must be above a minimum threshold rate, which is defined as the rate at which the pipeline can recover its marginal costs. What constitutes a marginal cost is dependent on the functionality of a specific pipeline system and is not necessarily related to the separation of distance and non-distance costs discussed above. The discounting iteration is continued until the final two iterations produce identical rates[46] and the cost of service is fully recovered.

Incentive Rates

Incentive rates can be used to charge rates below established ceiling levels and are required to be posted on the pipeline's tariff and to be available to all shippers (i.e., they are non-discriminatory). Further, a pipeline posting a tariff with incentive rates is required to show that the incentive rates were required to meet competition. Different from negotiated rates, incentive rates are available to all shippers as part of an "open season" or as part of a filed tariff. Open seasons typically occur when a pipeline is beginning service, expanding its operations, or when it is considering a major change in its rates. During an open season, pipelines may offer any shipper who ships a minimum volume a decreased rate. For example, a pipeline may offer a 10 percent discount off the tariff rate for a guaranteed shipment of 5 million barrels.

Separate from discounted rates, which may be available only to a select few customers, incentive rates require a commitment from the shipper in exchange for a decreased rate, for example, a multi-year exclusive commitment. For instance, if a shipper guarantees that it will ship exclusively on a given pipeline, the pipeline may offer

[45] *Williams Pipeline Co.*, 84 FERC ¶ 61,022 at 61,107 (1998)
[46] "Cost-of-service rates manual," FERC, June 1999, p. 46

the shipper a long-term locked and/or reduced rate as an incentive for its continued business. Volume incentive rates may be coupled with a minimum shipper volume commitment in a take or pay contract, where the shipper pays for volume shortfall below the incentive threshold. Take or pay contracts may be included in the tariff. For example, a pipeline offers a shipper a rate of $2 per barrel if it ships 100 barrels. The shipper only ships 98 barrels during the incentive period, but it is still required to pay for the 2 barrels it failed to ship in return for the incentivized rate it received. Incentives for excess shipments are another mechanism that pipelines may use. In this case, the incentive rate applies to a volume above a given threshold amount and increases loads by offering customers an attractive rate.

Surcharges

Temporary surcharges may be used to recover costs due to specific incidents, activities, or changes in the industry. A surcharge is typically billed to shippers based on their shipping activity level commensurate with the tenet that shippers should only be responsible for paying for costs they cause to be incurred, and may be amortized over a given time period. An example of a temporary surcharge is that for costs related to processing ultra-low sulfur diesel (ULSD) fuel in the mid-2000s. ULSD requires increased processing to remove sulfur from the oil. In order to comply with new regulations, pipelines were required to alter their equipment and make modifications to increase product sampling and testing. Surcharges are allowed only in the context of cost-based rate making. In order for a pipeline to recover these increased and non-recurring costs as a surcharge, the FERC required that the pipeline account for ULSD surcharge costs separately and footnote their expenses in their annual Form 6 filings. This ensured that the shippers only incurred costs directly related to their services in line with the principle of aligning costs with cost causation.

Conclusion

The goal of rate making and rate design, to establish just and reasonable rates for all parties involved, is a cornerstone of regulatory economics. Rate making and rate design are critical issues in rate case litigation proceedings for petroleum pipelines. Cost-based oil pipeline rates should be designed to both attract customers (in competitive markets) and generate adequate revenues for the pipeline to earn a reasonable return on its investment. The FERC has a statutory obligation to ensure that pipelines charge just and reasonable rates. Rate design is intended to balance the interest of both shippers and the pipeline and may take a variety of forms depending on market conditions. With cost of service based rates, a pipeline will employ a proper rate design method in an attempt to recover its costs. On the other hand, shippers (ratepayers) should only pay for services that they directly receive and thus, an important goal of rate design is to prevent cross-subsidization among ratepayers as well as between different entities within a pipeline’s organization. Identifying and correctly categorizing costs associated with providing pipeline services is a complicated and contested matter in rate making, as it directly affects the rates which shippers pay.

Premier Quantitative Consulting, Inc. is an economic consulting firm focused on matters relating to energy, utility, and regulatory economics. Several of our professionals are noted experts in oil pipeline rate making and rate design with substantial experience preparing and scrutinizing regulatory filings and related documents to determine just and reasonable shipping rates. We possess extensive knowledge of the industry and market conditions and assist our clients in challenging rate increases by analyzing complex rate making and rate design issues on behalf of shippers in both state and federal (FERC) regulatory proceedings. We have testified on numerous occasions before the FERC and other regulatory commissions. We provide our clients with clear, concise, defensible, and accurate analyses and counsel on matters relating to cost of service rates, indexation, access terms, rate design and market-based rate making.