# Pipeline Pricing to Encourage Efficient Capacity Resource Decisions

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## I. Executive Summary

As the Federal Energy Regulatory Commission (Commission) re-examines the structure of gas industry regulation and evaluates whether its existing framework remains appropriate,[1] some industry participants argue that certain Commission policies will have unintended side effects that require correction. For example, it has been suggested that the "let the market decide" policy on pipeline capacity additions via both new and expansion projects could lead to overbuilding.[2] Also, straight fixed-variable (SFV) pricing coupled with state-level retail unbundling initiatives could result in excessive, inefficient capacity turnbacks by local distribution companies (LDCs).[3] Similarly, some argue that attempts to introduce innovation in pipeline ratemaking methods, e.g., market-based rates or even negotiated rates, might result in abuse of pipeline market power.[4] Overbuilding, turnbacks and abuse of market power will, it is alleged, lead to attempts by the pipelines to shift costs to those customers lacking good competitive alternatives.

As a result, these commenters have called on the Commission to first shield customers' exposure to such unpleasant outcomes by: putting pipelines at risk for unsubscribed capacity, more carefully scrutinizing attempts at roll-in of incremental facilities under the Commission's Pricing Policy, and preventing new pipeline project proponents and participants from evading the costs associated with the devaluation or premature turnback of existing capacity resulting from their new project. A second, related set of recommendations by these parties emphasizes improving the efficiency of the market and providing pipelines with marketing flexibility. These suggestions include: removing

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[1] See, for example, PL98-2-000, Conference on the Financial Outlook of the Natural Gas Pipeline Industry, Notice of Public Conference, December 17, 1997.

[2] See, e.g., *If You Build It, Will They Come? (and who'll pay for it?)*, American Gas Association, January 1998.

[3] See, e.g., *The Changing Nature of Pipeline Capacity Contracts and the Potential For Future Capacity Turnback by Local Distribution Companies*, American Gas Association, January 1998.

[4] See, e.g., Motion to Accept Reply Comments and Reply Comments of Amoco Energy Trading Corporation and Amoco Production Company, Docket No. PL97-1-000, Issues and Priorities for the Natural Gas Industry, October 15, 1997.

the price cap on secondary market transactions, allowing non-SFV pricing, and eliminating unreasonable conditions on reverse open seasons.

While some of the above recommendations may be justified, the fundamental shortcoming of the majority of the policy solutions being offered to the Commission today is that they address individual symptoms rather than remedy the underlying disease. Many of the concerns raised, including the overbuilding of capacity and turnback risk, stem from the same two root causes: (1) inefficient primary market capacity pricing[5] and (2) the lack of well-developed option and forward markets in the contracting for capacity. The disconnect that currently exists between regulated rates in the primary market and prices in the secondary and tertiary[6] capacity markets can result in inefficient capacity decision-making. This situation is only going to get worse as current long-term contracts reach expiration over the next several years and LDCs reduce their capacity commitments in line with their diminished merchant function. Relatedly, the inability of a shipper to control when, where, and at what price capacity gets added makes it more difficult to coordinate the development of new gas reserves or electric generation facilities and ultimately leads to lumpy capacity additions. Potential shippers jump on board an announced expansion project because it may be the last such expansion project for several years. This could result in oversized projects that can cause dislocative effects in the markets they enter.

Accordingly, the main theme of this paper is that the Commission, in its deliberations about the structure of natural gas industry regulation, should carefully consider reforms to primary market pricing and examine policies that would ultimately foster the development of forward markets in

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[5] As explained herein, the term "primary" refers to long-term firm capacity contracts between shippers and the pipeline itself.

[6] For the purposes of the discussion in this paper, the secondary market refers to capacity release transactions. The tertiary capacity market refers to capacity values established by the basis differentials that arise between two locations. These values are currently reflected in gray market sales.

capacity. Specifically, with regard to primary market pricing, the Commission should encourage primary pipeline rates that better reflect peak/off-peak patterns found in market values. The current practice of flat, equal monthly demand charges throughout the year is a vestige of a prior era of bundled service. We suggest three alternative methods for achieving this peak/off-peak differentiation rather than advocate one specific solution: seasonalized embedded costs (that are not predicated solely on traditionally-defined operating cost differences between the peak and off-peak periods), long-run marginal cost pricing (LRMC) that reflects capacity congestion, or even regulated rates that vary throughout the year in ways that reflect variations in basis differentials. Further, with respect to the secondary market i.e., for released capacity, the Commission should allow the price caps on such transactions to mirror variations in the underlying regulated primary market prices, whether seasonal, LRMC, or basis-indexed.

These reforms to primary and secondary market pricing policies will allow for more rational capacity decisions by all market participants. In particular, a more efficient capacity market will be attained if there is greater consistency between the price signals sent by regulated rates in the primary market and the competitive pricing signals of the secondary and tertiary markets. Indeed, regulated pricing of primary market capacity in a manner that better reflects opportunity costs should enable the secondary and tertiary markets for capacity to converge. This convergence will enhance the efficient use of current capacity and the efficient development of future capacity.

Recognize that this vision does *not* involve the price deregulation of primary market capacity. All of the primary market pricing approaches mentioned above would continue to be subject to cost of service ratemaking. That is, all suggestions herein involve retaining the requirement that rates for primary market pipeline capacity be based upon a regulated cost of service, thereby avoiding divisive and difficult debates concerning whether given pipelines face sufficient competition to allow market-based rates for pipeline capacity. This vision also does not require that price caps be lifted on secondary market capacity release, though that would be consistent with it. Instead, it requires that price caps be consistent with the reformed primary rates. Finally, this vision is consistent with policies that permit negotiated prices with recourse to regulated rates; the recourse rates under the framework proposed herein would have a richer structure, while still being based on an annual cost of service framework.[7]

We believe that these reforms will cause the secondary and tertiary markets for capacity to become more congruent, resulting into two salutary effects. First, the liquidity and transparency of short-term natural gas markets will increase as there will be greater incentives to release capacity into the secondary market during peak periods. Market participants will have an observable means by which to gauge downstream market conditions.

Second, it is our expectation that these pricing policy changes will foster the development of efficient forward markets in capacity which will, in turn, help rationalize future pipeline expansion and capacity recontracting decisions. To further such advances, the Commission should actively encourage firms to offer new products such as forward and option contracts on capacity subscription. These products will permit market participants to both manage capacity contracting risk and efficiently signal their capacity requirements.

The above reforms are not radical or difficult to implement. We believe that if they are pursued broadly, firms will create and offer a new wave of innovative products for the trading of existing and future pipeline capacity rights, just as they have created a myriad of new products for the trading of the gas commodity.

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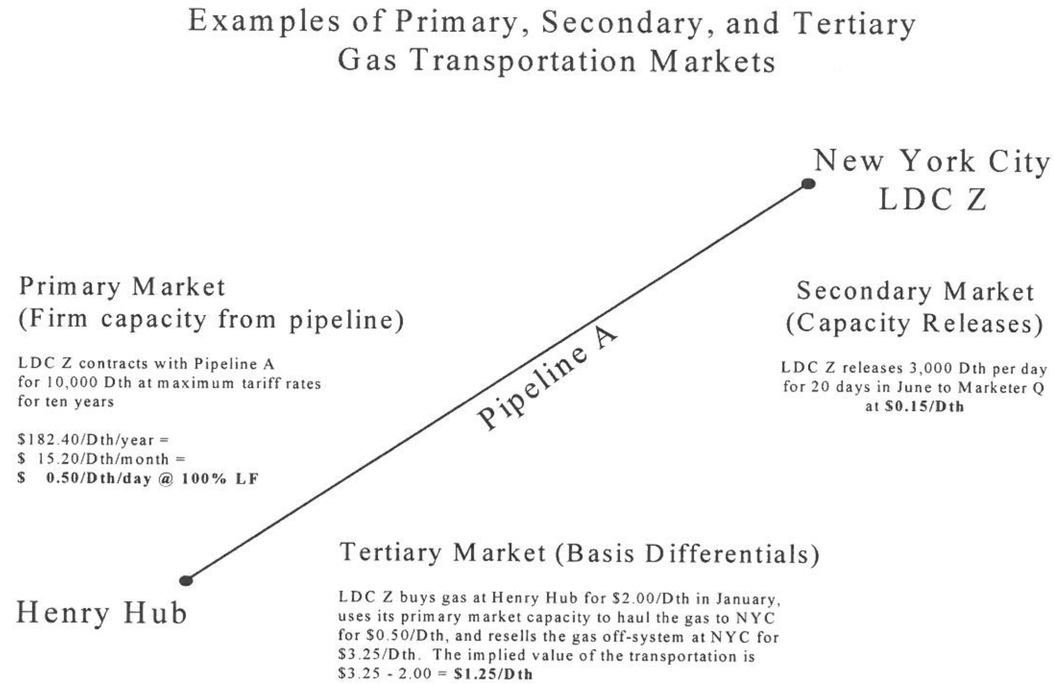
[7] In other words, the recommendations herein are consistent with the "standard/customized" service structure put forward by Columbia and Brattle. See Comments of Columbia Gas Transmission corporation and Columbia Gulf Transmission Company, Docket No. RM96-7-000, Regulation of Negotiated Transportation Services of Natural Gas Pipelines and the attached paper by The Brattle Group, *Basic and Enhanced Services for Recourse and Negotiated Rates in the Natural Gas Pipeline Industry*, May 29, 1996.

## II. INEFFICIENCIES WITHIN EXISTING CAPACITY MARKETS

### A. Introduction to Primary/Secondary/Tertiary Distinction

In the market for natural gas pipeline capacity, there are at least three distinct price patterns associated with what are referred to as the primary, secondary, and tertiary markets, respectively. The **primary** market represents the market for firm pipeline capacity contracted directly from the pipeline. Traditionally, i.e., prior to restructuring under Order No. 636, primary market contracts were long-term contracts in duration (ten to twenty years) with an LDC that had an exclusive merchant function and were priced at maximum tariff rates. The LDC that typically contracted for long-term firm pipeline capacity saw an extremely stable month-to-month capacity price — i.e., one that did not differentiate peak and off-peak periods — that only changed infrequently, e.g., as a result of a pipeline rate case. Figure 1 displays simple examples of primary, secondary and tertiary transactions in order to illustrate what we mean by the three terms. In Figure 1, an example of a primary market transaction is where LDC Z contracts for 10,000 Dth/day of firm pipeline capacity between Henry Hub and New York City on Pipeline A at $182.40/Dth/yr of capacity or $15.20/Dth/month which translates to $0.50/Dth/day on a 100% load factor basis.

**Figure 1**




There now also exists an active **secondary** market in interstate pipeline capacity transportation rights. Through capacity release transactions, holders of primary market capacity (and holders of released capacity) are able to re-sell unneeded capacity or capacity that is valued more highly by another shipper, subject to certain pricing and posting restrictions. In part because of these restrictions, these releases tend to be relatively short-term in nature; many are for thirty days or less. A marketer or direct access industrial customer acquiring firm capacity from a releasing shipper may see significant day-to-day or month-to-month variability in the price of that capacity due to more immediate changes in supply/demand conditions. Release prices are based on then-current market conditions, with the provision that releases can only be done at or below the 100% load factor maximum firm transportation tariff rate. An example of a secondary market transaction, as shown in Figure 1, is where LDC Z releases 3,000 Dth per day in the secondary market at $0.15/Dth--30% of the maximum tariff rate--for twenty days in June.

We refer to the basis differential in gas prices between two locations as the **tertiary** market. The basis differentials from the tertiary market reveal the spot value of gas transmission rights. Indeed, the value of a new pipeline expansion can, in principle, be represented as the present value over the life of the contract of the expected basis differential across locations the expansion would serve. This is because buying at a low-cost location and simultaneously selling the same quantity at a high price location is financially equivalent to buying the gas commodity at the low end and flowing it to the high end for a shipping fee equal to the basis differential. As long as the spot prices at either end are unregulated and the local markets trading at each end are active enough to be competitive, then the basis differential reflects the marginal cost of incremental service, including the implied value of transportation capacity. The basis differential is then the full spot value of "capacity" between the two locations, even if they are not directly interconnected.

The most visible example of a tertiary market transaction is a gray market sale, which involves the sale of both the gas and transportation on a bundled basis at a downstream location. Much of the time, these sales set the observed basis differentials, because the price of these bundled sales is not regulated. This allows the market to establish (with varying degrees of success) the value for capacity without reference to the maximum tariff cap on secondary market transactions during those times of the year when the basis differential between two locations exceeds the maximum tariff rate on the underlying regulated transportation. In Figure 1 the value of transportation implied by the tertiary market in a cold January is the difference in price between $3.25/Dth and $2.00/Dth or $1.25/Dth[8].

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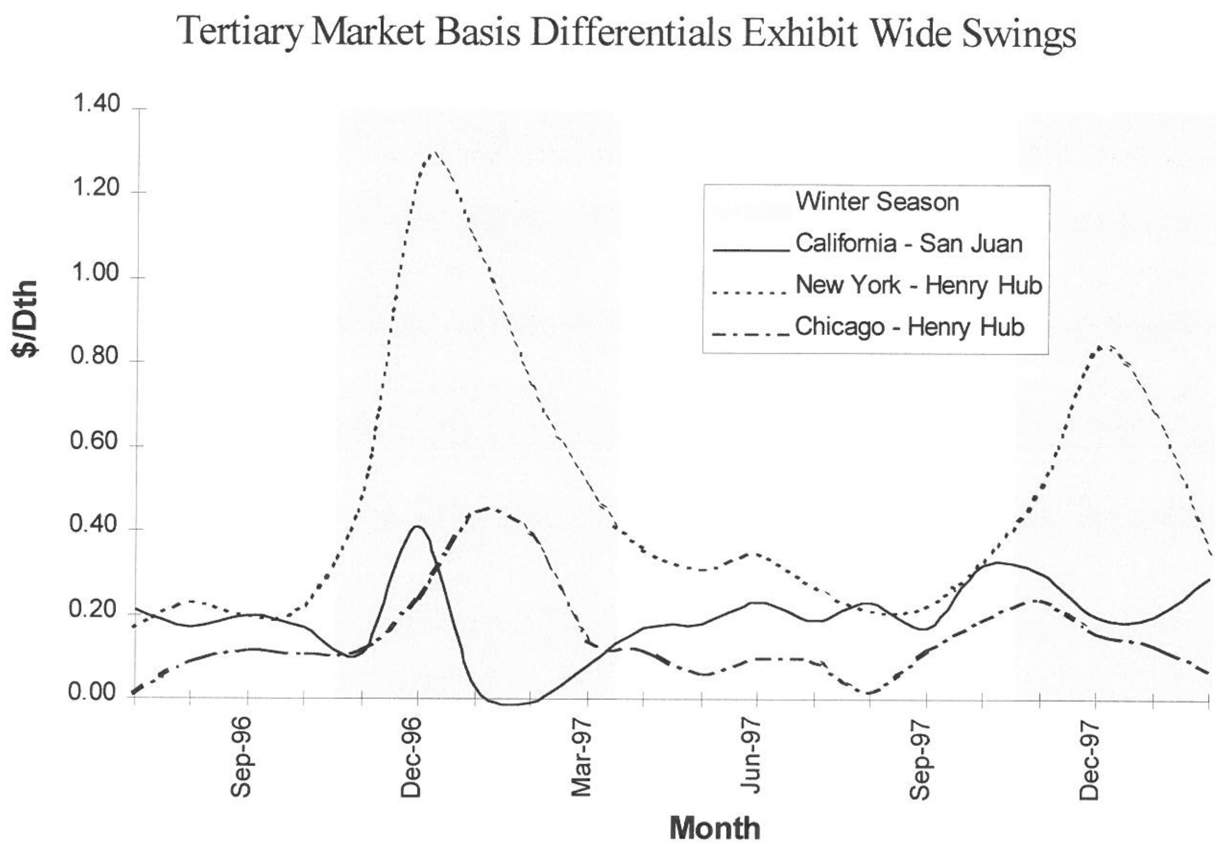
[8] The example in Figure 2 has been simplified for purposes of depiction. In reality, fuel and variable transportation costs would have to be netted out from the basis differential to determine the reservation charge equivalent implied by the basis differential.

**Figure 2**




Source: Bid Week Prices, Natural Gas Week

Tertiary markets permit observation of the differential value of capacity in peak and off-peak markets. The differences can be dramatic. Peak period capacity often commands five times the value of off-peak capacity. Figure 2 presents the basis differentials between delivery and receipt points for New York - Henry Hub, Chicago - Henry Hub, and the California Border - San Juan Basin. The New York - Henry Hub differential reached approximately $1.25 in the winter of

1996/97 and fell to approximately $0.25 during the summer of 1997. The fluctuations are also significant for the Chicago - Henry Hub differential. The high differentials during the winter months (on-peak periods) reflect the true value of being able to buy gas at the basin and sell it at the citygate, or in other words, transport the gas from the basin to the citygate.

### B. The Interrelationship Between the Primary, Secondary, and Tertiary Markets

There are several ways in which these three capacity markets are disconnecting from one another — which is why our fundamental recommendation is that the Commission pursue policies designed to bring the three capacity markets into closer alignment. While it may not have mattered in the past whether the primary market was in consonance with the secondary or tertiary spot market value (indeed these market distinctions are a relatively recent phenomena), it will definitely matter in the future. A persistent disconnect or even a disconnect with a recurring pattern will distort usage of pipeline systems and lead to poor decisions regarding recontracting and expansions. The significant amount of capacity expected to be turned back to pipelines by LDCs in the context of retail unbundling[9] and the seemingly contradictory wave of new pipeline capacity proposals[10] dramatically increase the likelihood that large differences between primary, secondary, and tertiary prices will distort the market.

To facilitate a discussion of these disconnects, Figure 3 provides a simple depiction of the interrelationships between the three markets as well as their influence on capacity expansion and recontracting decisions.

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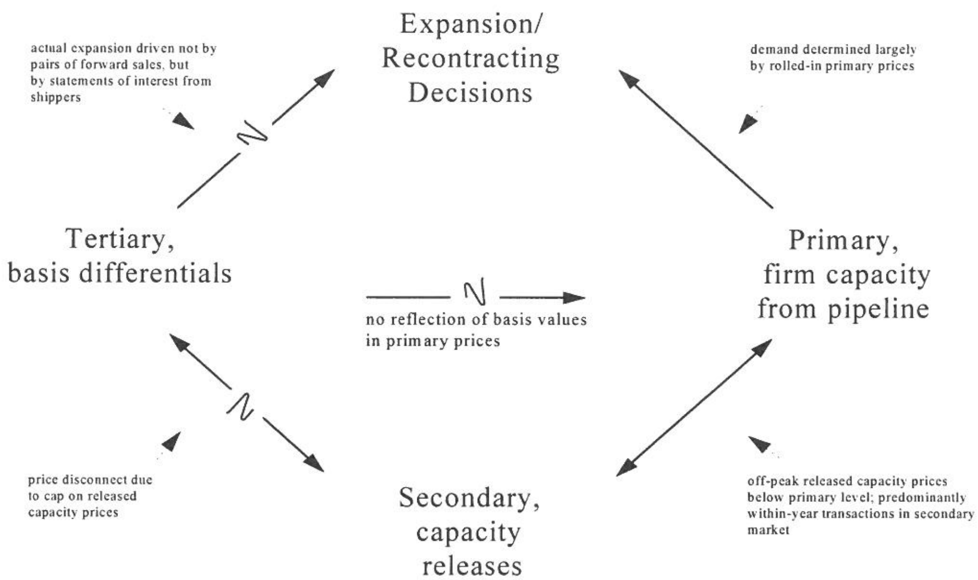
9 See *The Changing Nature of Pipeline Capacity Contracts and the Potential For Future Capacity Turnback by Local Distribution Companies*, American Gas Association, January 1998.

10 See *If You Build It, Will They Come? (and who'll pay for it?)*, American Gas Association, January 1998.

**Figure 3**

Interrelationship of the Three Gas Transportation Markets
and Capacity Expansion/Recontracting Decisions




In principle, the secondary market was designed to reflect the day-to-day variance in the value of capacity and to allow primary market holders to participate in that market when appropriate. While the true underlying value of primary firm capacity held by the LDC under an embedded cost tariff is also dictated by spot market differentials, those variations in value are not being felt fully by the LDC. The opportunity to release (primary) capacity over short periods corrects part of the disconnect, but price caps tied to primary tariffs which, in turn, are based on an average monthly pricing regime, cancels out the potential efficiency gains precisely at those times (specifically, on peak) when the capacity would be most useful. In other words, the flaw of the current secondary market pricing mechanism is that the primary and secondary markets only "connect" at the least desirable time, when the true short-run economic value of the capacity exceeds both the primary and the secondary market price, the latter two of which are capped at the maximum tariff rate[11]. This has tended to inhibit the liquidity and competitiveness of short-term markets.

There is a second noteworthy disconnect between primary and secondary markets. In the future, pipelines re-marketing turned-back primary capacity will be competing with secondary market (released) capacity. Participants in the secondary market have already established that they will neither contract nor pay for capacity in time periods when they do not need the upstream access. To compete in these submarkets, suppliers of capacity--including pipelines marketing primary capacity--must be willing to offer capacity on a monthly and seasonal basis.[12]

This concern is reinforced by AGA in its recent study:

> Unbundled LDCs will continue to hold some capacity, however it is likely to be substantially reduced amounts and only enough to meet obligation to serve requirements. (p. 17)
>
> As the survey results expressed above clearly demonstrate, LDCs overwhelmingly desire short-term capacity contracts in the future. (p. 18)[13]

To foster a liquid, competitive capacity market in which providers offer new services covering shorter or more novel time periods, the Commission must reform the current primary capacity pricing regime in a fashion that allows primary capacity prices to reflect the shorter term economic

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[11] To the extent the pipeline discounts or sells short-term firm when the economic value is below the maximum tariff rate, it is true that the primary and secondary markets connect, but only partly so. This is because it is unlikely that the pipeline can engage in such activity in large quantities for extended periods of time without experiencing financial repercussions.

[12] This is even true in the market for new pipeline capacity. Both Maritimes & Northeast and Portland signed winter season firm service contracts with LDCs that leave their systems significantly undersubscribed during the summer months.

[13] *The Changing Nature of Pipeline Capacity Contracts and the Potential For Future Capacity Turnback by Local Distribution Companies*, American Gas Association, January 1998.

pressures that will drive recontracting decisions, and permit the secondary market price caps to mirror changes in primary capacity pricing—otherwise inefficient pricing will almost undoubtedly lead to poor capacity resource decisions. As a result, pipelines and existing holders of capacity will compete with one another to offer services that meet the needs of buyers at prices that reflect the appropriate value of the capacity. Otherwise, buyers may be restricted in their choice of alternatives during peak periods.

On many pipeline transportation paths, basis differentials are only weakly correlated with primary or even secondary market prices. That is, tertiary markets are disconnected from both primary and secondary markets. For example, basis differentials in peak winter months on some systems vastly exceed both primary and secondary market prices. Even more intriguing, large summer basis differential premiums are starting to emerge on systems with substantial electric generation loads, again departing from secondary and primary prices. Conversely, during off-peak months the basis differentials are often well below primary capacity prices. Ironically, some industry observers speak of this latter circumstance as pipeline capacity being "devalued" in off-peak months relative to maximum tariff rates, but in part this perception is due to the use of a flat, monthly reservation rates and the failure to recognize peak period and off-peak period pricing differentials in the traditional pricing of primary capacity. In fact, in these off-peak months the capacity most likely is valued appropriately[14]. It is during the peak months, precisely when market participants could most benefit from clear price signals, that the basis differential value often exceeds the average annual rate cap, thereby largely causing the primary and secondary markets to inappropriately value capacity.

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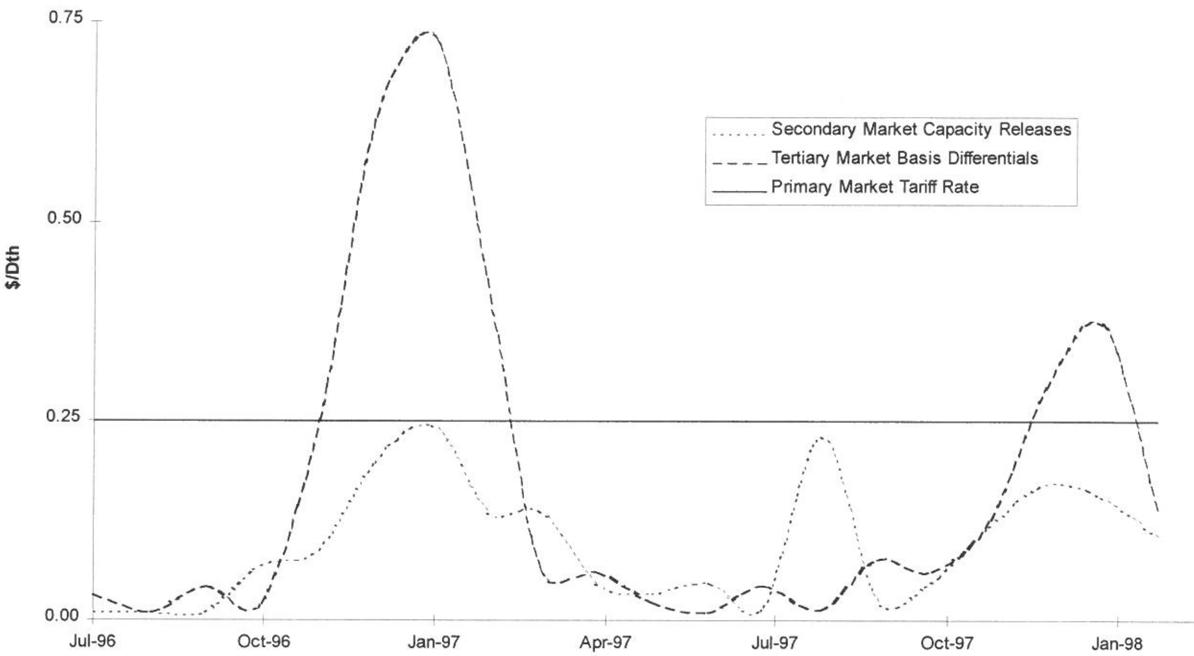
14 Note that in slack months, when the value of capacity is below the maximum tariff rate, the secondary and tertiary markets should (and does) yield roughly similar prices. That is, the strategy of buying at the basin and acquiring capacity in the secondary market to haul gas from the basin to the citygate should be comparable to buying gas directly at the citygate and thereby "paying" the tertiary transportation market price implied by the basis differentials.

Evidence on the Columbia system supports the notion that tertiary market prices often bear little relation to primary and secondary market prices. Figure 4 displays a comparison of tertiary market prices (as represented by the difference in bidweek prices between the entry point into the Columbia Transmission system and a benchmark MidAtlantic citygate price), secondary market prices reported for release transactions into Columbia Transmission's Operating Zone 4 (eastern Pennsylvania, New Jersey, and Delaware), and Columbia Transmission's primary market maximum tariff rate (on a 100% load factor basis)[15]. During the peak winter 1996-97 and 1997-98 months, basis differentials vastly exceeded both the maximum tariff rate and secondary market prices. In off-peak months, the tertiary and secondary market values are well below the maximum tariff rate with slight deviations between tertiary and secondary market prices due to minor measurement and timing differences.

[15] Due to differences in timing, location, contract provisions (e.g., regarding recallability) and market liquidity, it is difficult to structure a pure "apples-to-apples" comparison of the three markets. Thus, the data presented here are primarily for illustrative purposes.

**Figure 4**

Comparison of Primary, Secondary, and Tertiary Market Capacity Prices on Columbia Transmission's System *




* Information presented for Columbia Transmission's Operating Area 4
Source: Columbia Gas Transmission

## C. The Relationship Between Efficient Recontracting and Expansion Decisions and the Primary, Secondary, and Tertiary Markets

Industry participants face an unusually large number of capacity-related decisions over the next several years. The American Gas Association (AGA) reports that contracts for 40 percent of total firm interstate pipeline capacity are due to expire between April 1, 1997 and December 31, 2001. An additional 27 percent will expire between January 1, 2002 and December 31, 2005.[16] A large

[16] See *The Changing Nature of Pipeline Capacity Contracts and the Potential For Future Capacity Turnback by Local Distribution Companies*, American Gas Association, January 1998.

proportion of these contracts are with LDCs facing a diminishing merchant role who will have to make difficult decisions regarding how much capacity to turnback, how much to retain, and the characteristics of the retained capacity.

At the same time, interstate pipelines have announced an enormous number of new projects in the past two years. It is estimated that these projects represent 28 Bcf per day of capacity.[17] Many of these projects are mutually exclusive, in that they seek to serve the same markets. Others are in locations where significant existing contract volumes will be reaching expiration.

In the nomenclature of this paper, these recontracting and expansions decisions all involve **primary** capacity. In the first instance mentioned above, shippers are deciding how much of their existing contracts with the pipelines they should retain. In the second, shippers are contracting directly with pipelines for expansions to existing lines and new facilities or new facilities to accommodate shippers needs.

Nonetheless, while these contracts involve primary capacity, the turnback and recontracting decisions that are made will be largely influenced by current and expected prices in tertiary markets. This is because a holder of existing rights to use transmission at embedded cost rates (i.e., a primary market holder) has the equivalent of a forward contract on the expected future tertiary market basis differentials. Holding pipeline capacity grants the right but not necessarily the obligation to transact at a value equal to the difference between the sell and buy price (i.e., the location differential) less the variable cost of transmission. In other words, the market value of pipeline capacity is derived from the ability it gives a capacity holder to transact in commodity gas between the locations. This

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[17] See *If You Build It, Will They Come? (and who'll pay for it?)*, American Gas Association, January 1998.

means that when the basis differentials change, so does the value of the forward contract. The value clearly increases when the basis differential widens or when the variable cost of transmission falls.[18]

One implication of this characterization is that there is risk that a transmission contract, once procured, will subsequently become unattractive to the shipper. Recognize that this characterization represents a sea change in the transmission capacity market. Traditionally, the decision to procure additional pipeline capacity by an LDC was largely driven by demand growth in the service territory subject to the condition that the delivered gas be competitive with local fuel alternatives. As the industry unbundles further, the LDCs are seeing a diminishing of their merchant function and new capacity-holders are increasingly becoming non-regulated suppliers of gas services. Thus, the potential for out-of-market pipeline capacity contracts is becoming more apparent and worrisome to shippers, leading them to a desire for less exposure (shorter and fewer long-term contracts) and more liquidity (shorter and more tradeable contracts).

In the recontracting area, the negotiating balance between existing, mostly LDC shippers and the pipelines is such that shippers are demanding and getting shorter terms of service. If the primary market is to evolve so that it offers these new products and services such as peak season service,[19] its pricing will have to be reformed to conform to secondary and tertiary market behavior. Otherwise, LDCs and marketers will have a strong incentive to demand contracts solely for peak season capacity at the annual average embedded cost rate, thereby leading to cross-subsidies from other shippers or stranded costs for the pipeline.

In the new capacity market, the dynamic is different but the importance of tertiary market prices is still significant. First of all, pipelines are generally obtaining long-term commitments on the

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18 The value also increases to the extent that the volatility underlying the buy and sell price of gas increases since, according to the correlation between the prices, more volatile prices have a greater likelihood of realizing a positive basis differential.

19 Or off-peak season service, for that matter.

grounds that the project will otherwise not go forward absent signed contracts for durations covering repayment of the project-financed debt. Second, the prospective shippers on many of these new projects are not the "downstream" LDCs but are "upstream" producers and marketers looking to gain access to new markets. These latter shippers are keenly aware of the importance of securing transportation rights along paths where the expected basis differentials equal or exceed the primary market cost of the transportation.

This emphasis on basis differentials, when coupled with a "let the market decide" policy, leads to prospective shippers often making contracting decisions on the basis of incomplete information. One risk is that such information gaps may lead to the best or most desirable expansion project not necessarily getting built. Here, option and forward markets in capacity would help alleviate some of these undesirable biases and we discuss those alternatives in more detail later in the paper. Our expectation is that reforms to primary market pricing would facilitate the development of trading in such instruments.

## III. Efficiency in Capacity Pricing and Expansion

### A. Recognizing the Problem: The Traditional Collection of Pipeline Capacity Costs on an Equal Monthly Basis Has Inadvertently Evolved into a Pricing Paradigm

If the key to improving the efficiency of capacity pricing is to align the primary market regulated price signals with those in the secondary and tertiary markets, then the first step is to recognize that there is nothing sacred about the current scheme of equal monthly reservation rates on primary capacity. Traditionally, pipeline firm transmission reservation rates in the primary market have been derived by dividing the allocated portion of revenue requirements by peak contract demand and then recovering those amounts in equal monthly installments via uniform rates. The problem here is not allocating revenue requirements to peak demands, as incremental peak demands do generally determine the size and cost of a new facility. Nor is the problem the use of straight fixed variable cost allocation/rate design. The problem instead arises from the convention of recovering those allocations of annual revenue requirements on a uniform, flat, unseasonalized, non-market responsive basis. While this may not have mattered in a pre-Order No. 636 era, these flat prices in the primary market now typically bear little or no resemblance to secondary market prices or the basis differentials that reflect prevailing utilizations and scarcity patterns. What were essentially accounting and payment conveniences are now leading to distortions in the market.

Flat primary capacity pricing is nothing more than a financing or risk-management arrangement between the pipeline and its customers that allows customers to spread payments in even, fixed monthly installments, despite uneven value of service (as reflected in the volatile and shifting nature of basis differentials) over the course of the year. This scheme worked, at least with regard to cost recovery and long term capacity management, when most consumption decisions were also long term, *i.e.*, when the bulk of gas was flowing under multi-year, firm service contracts where the customers (largely LDCs with exclusive merchant functions) held the capacity year-round. Even then, the LDCs primarily needed and contracted for the capacity for the peak winter months, but the contracting arrangements led to the LDCs holding the capacity on a year-round basis. Given the inability to avoid holding the capacity off-peak, the LDCs pursued a number of avenues to improve the load factor of their interstate pipeline commitments and make use of the excess off-peak capacity. These efforts included the contracting for market-area storage with off-season injection obligations as well as seasonal sales to large industrial facilities that would otherwise burn alternate fuels.

The changes to capacity markets discussed above in Section II make it obvious that such a pricing scheme will not work well in the future. In principle, there appears to be nothing in Commission policy which necessitates this uniformity. For example, the Commission's 1989 Rate Design Policy Statement encourages consideration of seasonal pricing. But in practice, the Commission seems to have clung to the need for embedded cost-based justifications of differences in seasonal prices.

The most notable example of which we are aware is Opinion No. 369,[20] issued in one of the Commission's first rate proceedings litigated under the 1989 Rate Design Policy Statement. In that Opinion, the Commission rejected the time pattern implicit in Panhandle's filed rates on the grounds that

> "costs do not vary materially by season in the manner claimed by Panhandle. . . As a result, its seasonal rates do not properly reflect whatever seasonal variation [in costs] might exist on its system. Panhandle's proposed seasonal firm rates are thus unjust and unreasonable and must be rejected."

The necessity that variations in peak and off-peak rates somehow be linked to variations in underlying embedded cost severely undermines the usefulness of such a pricing mechanism. As discussed below, the changing nature of natural gas markets suggests that non-uniform pricing would

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20 57 FERC ¶ 61,264, Panhandle Eastern Pipe Line Company (November 26, 1991)

be more valuable if it were related to usage or market demand characteristics rather than to embedded cost differences.[21]

### B. Possible Solutions

The tertiary market data presented earlier demonstrates that capacity is not equally valuable throughout the year. On many (albeit not all) pipelines, the times and locations where it is most valuable tend to be predictable, e.g. mid-winter (and, increasingly, July or August in systems with substantial gas-fired electric generation). For these pipelines, flat primary prices strongly misrepresent economic value (or opportunity costs). The inefficiency is reflected in on-peak release prices, interruptible rates, and elsewhere.

There are several levels of economic sophistication and administrative complexity possible in reforming primary capacity prices. We are not advocating any specific solution here, but instead present three possible frameworks below. All involve the introduction of peak/off-peak distinctions. All also retain the regulated revenue requirement framework; the discussion here does not contemplate market-based rates for primary capacity. In addition, it is not necessary to remove the price cap on secondary market capacity releases under these proposals. It is, however, anticipated

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[21] Similarly, when three pipeline companies--Trunkline Gas Company, Texas Eastern Transmission, and Panhandle Eastern Pipe Line Company--recently requested mechanisms that resembled seasonal pricing, the Commission approved these three pipelines' mechanisms for primary pipeline customers (i.e., those holding long-term contracts directly with the pipeline), but denied extension of the altered reservation charges to the secondary (i.e., capacity release) market. These mechanisms, known as "customized reservation patterns" ("CRPs"), allow firm shippers to shift the timing of their reservation payments to pipelines, thus abandoning the standard equal month-to-month payment schedules. For example, Trunkline's proposal allows a firm shipper to shift up to 80% of its total reservation charges for the April-October period to the preceding November-March period. Under the Commission's decisions, capacity release transactions are still subject to the equal month-to-month maximum tariff rates that previously existed, thereby severely limiting the value of these changes. The Commission's rationale for denying extension of the CRPs to the secondary market was the lack of a recourse rate in the three pipelines' secondary markets due to the lack of available firm capacity from the pipelines. The Commission believed a recourse was necessary since the pipelines did not provide evidence that they lacked market power.

that the capacity release price caps would vary from period to period in line with changes in primary market prices.

### *1. Seasonalize Embedded Cost*

One solution to flat primary capacity prices is to seasonalize the allocated portion of the annual revenue requirement. This seasonalization could be done by a variety of means. For example, the peak month price could be set to reflect the typical seasonality of load roughly equal as follows:

$$Peak\ Month\ Price = \frac{\left[\dfrac{Annual\ Revenue\ Requirement/Dth}{12}\right]}{System\ Load\ Factor}$$

While in off-peak months, the capacity price would resemble:[22]

$$Off\text{-}Peak\ Price = \left[\frac{Annual\ Revenue\ Requirement/Dth}{12}\right] \times System\ Load\ Factor$$

[22] Adjustments would have to be made in the shoulder and trough months to ensure the prices summed to 100% of the annual revenue requirement. On a system with market area storage, adjustments to reflect different load factors on assets up vs. downstream of storage might be appropriate as well.

In its 1989 Rate Design Policy statement, the Commission suggested an alternative seasonal price formulation with the same general effect:

| | |
|---|---|
| *Peak Period Costs=* | *Peak Premium/Dth*<br>*+ System Load Factor x*<br>*[Annual Revenue Requirement/Dth - Peak Premium/Dth]* |

where,

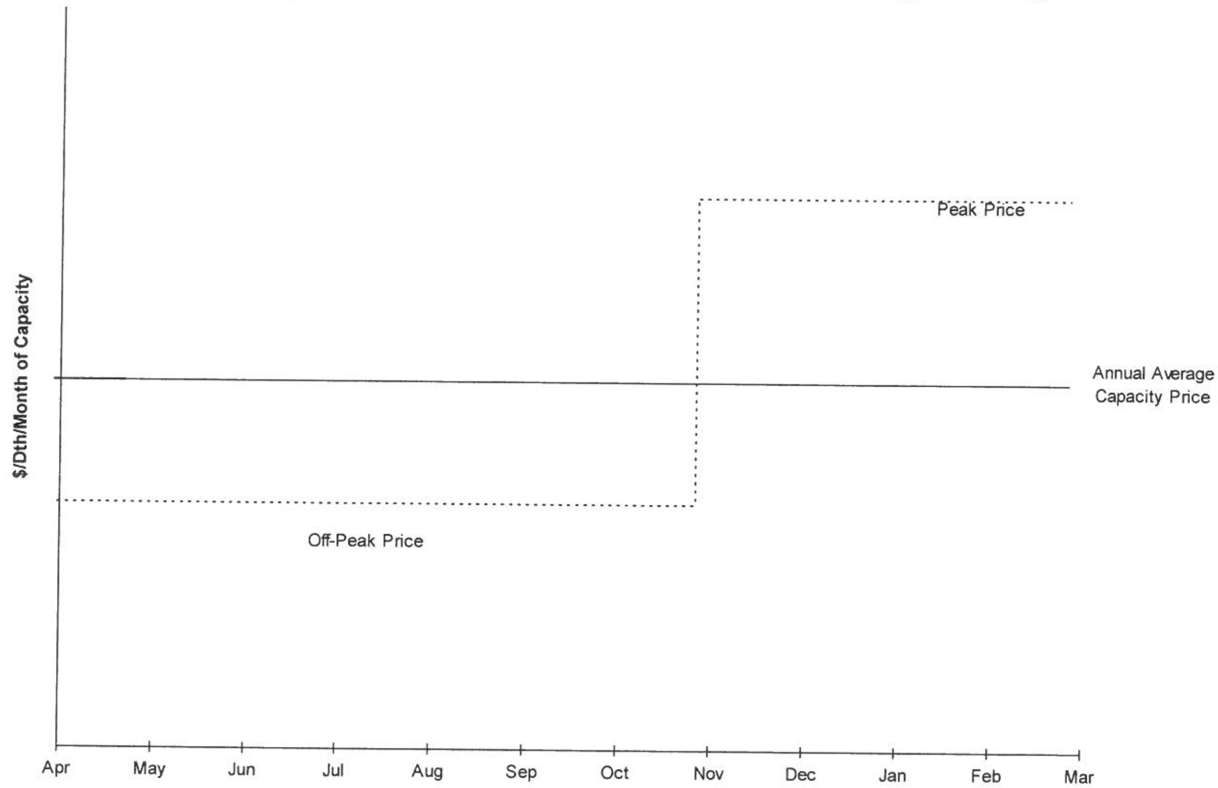
| | |
|---|---|
| *Peak Premium/Dth =* | *[Peak Period Load Factor - System Load Factor] x*<br>*Annual Revenue Requirement/Dth* |
| *Off-Peak Period Cost =* | *System Load Factor x*<br>*[Annual Revenue Requirement/Dth - Peak Premium/Dth]* |

Figure 5 displays an illustrative comparison of seasonal pricing to flat capacity payments using hypothetical data. Even more sharply seasonalized schedules could easily be justified on some systems, especially where assets are very old and depreciated relative to replacement cost. These systems should be able to explore rates sharply concentrated on a few peak periods, subject to, e.g., monthly caps at replacement cost x (1/system average load factor) and an annual embedded cost recovery expectation. (Replacement cost caps provide an efficient ceiling price in that they reflect approximate long-run marginal cost, i.e., the avoidable expansion plan in addition to the marginal value of avoided usage.) Such pricing would also serve to fulfill the allocative efficiency goal of the Commission's regulations, namely that "rates for service during peak periods should ration capacity."[23]

[23] 18 CFR 284.7(c)

**Figure 5**

Hypothetical Comparison of Peak/Off-Peak Pricing (Using Seasonalization) vs. Traditional, Annual Average Pricing




Another complementary approach to seasonalization is to create short period firm rates that are greater per unit than longer period rates. For example, daily rates would be capped at 1/21st of (annual replacement cost/12)x(1/system load factor) where 21 is the average number of business days per month. Weekly rates would be capped at 1/4 of (annual replacement cost/12) x (1/system load factor) and so on.[24] While rates would be higher for shorter term transactions, the pipeline would continue to be subject to an annual revenue requirement. There is already precedent for such variation of this kind in the electric market, where the Commission authorizes electric transmission rates that increase per unit over short duration wheels. [25]

It is important to note that the above seasonal and short period "tilts" should not have to be justified as "cost-based" in the conventional sense of demonstrating extra O&M costs borne in precisely those high-use, high-value times. Rather, the objective is that they remain cost-based on an annual basis with subperiod allocations that are contoured to reflect time-of-use market values.

### 2. *Generic Long Run-Marginal Cost*

The notion of long-run marginal cost pricing allows more rigorous recognition of the fact that not only does demand, hence capacity scarcity, vary seasonally, it also varies by location. Some regions on a pipeline are relatively deeper in alternative supplies and/or slack incumbent capacity, while other regions are tight. Long-run marginal cost pricing would allow location premiums for the latter and discounts elsewhere--this is in addition to recognizing the seasonal differential discussed above.

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24 For longer periods, such as a year, the capacity price would equal the annual revenue requirement per Dth.

25 ANR Pipeline recently proposed a short-term firm service at unit rates that were significantly higher than the unit rates implicit in its proposed longer-term firm transportation service. The Commission rejected ANR's proposal stating that:

> acceptance or modification of ANR's proposal at this time would be premature. . . The Commission has issued a notice of proposed rulemaking proposing certain changes in its capacity release regulations.[14] In addition, the Commission has held a conference and received comments on issues facing the natural gas industry today, including the pricing of short-term services.[15] Until the Commission completes its review of current policy and the comments on all the issues in those proceedings, the Commission prefers not to consider pipeline-specific proposals, such as that at issue here.
>
> ---
>
> 14 Secondary Market Transactions on Interstate Natural Gas Pipelines, 61 FR 41046 (August 7, 1996), IV FERC Stats. & Regs. ¶ 32,520 (proposed July 31, 1996).
>
> 15 Issues and Priorities for the Natural Gas Industry, Notice of Public Conference and Opportunity to Comment, 78 FERC ¶ 61,209 (1997).

This of course, would discourage some expansions while encouraging rights holders in the bottlenecked regions to release capacity. It also reduces the distinction between rolled-in and incremental pricing, thereby reducing the incentive for any differential between the two to be gamed.

The implementation of LRMC requires a method by which likely capacity constraints can be identified and priced. Most alternatives require the simulation modeling of the flows on the pipeline system at issue, in order to identify as realistically as possible the likelihood that capacity constraints will be encountered under reasonable future demand conditions. The cost of alleviating such constraints (or bypass) would constitute the LRMC for that segment or zone of the system. The relationship, location and timing of constraints, and thus LRMC, can then be used to "scale" the annual revenue requirement over time and locations on the system.

### *3. Basis Indexation*

To achieve complete linkage and consistency among the four types of prices (primary/pipeline firm, secondary/capacity release, tertiary/gray market spot, and forwards or options), primary prices would need to precisely track gray market spot basis differentials. This requires making a distinction between prices for transmission system <u>usage</u> and transmission system <u>reservations</u>. The idea would be to let firm capacity holders procure access, or capacity rights, on the basis of reservation contracts. These would be long-term agreements much like current firm transmission tariffs and contracts, priced at embedded cost. All users, whether firm capacity rights holders or not, would pay usage fees determined by the actual realized basis differential between receipt and delivery points, during the hours of their transaction(s). This gives all users a spot signal of the value of their transaction. (The electric industry is already implementing a scheme similar to this, e.g., on the PJM power pool.)

The efficiency advantages of this approach are numerous. Among the benefits is that every transaction faces an opportunity cost signal. These spot signals are avoidable in so far as the shipper can enter a hedge against them by contracting over a medium term horizon in financial markets. Those prices would no longer be capped, in order to float with the expected basis differential patterns. After some experience with these basis differentials and spot transmission usage charges, embedded cost primary prices should be seasonalized to match typical basis differentials. This would assure that short-term firm contracts (e.g., seasonal or monthly) pay a share of system costs that reflects underlying economic value. Again, the point is not to collect more than the revenue requirement but to collect it in an economically rational way.

One of the advantages of this approach over the LRMC method is that it relies on true market signals as opposed to modeling exercises to determine whether or not capacity constraints are likely to exist. As such, it may be a less contentious method for the determination of pipeline rates. A potential drawback could be the need for a fully liquid, competitive spot market for the points used to determine the basis difference.

Note that all of these mechanisms for redistributing embedded costs over time more efficiently help dispel a common misperception that prices above uniform cost-of-service levels are anticompetitive (and the converse myth that prices below uniform cost-of-service are per se reasonable). Prices are anticompetitive when and where they can be sustained above prevailing competitive levels at will. The relevant level to measure this against is not embedded cost but the gray market cost (in the absence of that anticompetitive influence), which reflects an essentially unregulated, competitive market for bundled gas. In the off-peak months, a market participant with market power could exercise it by raising prices well above competitive levels, in some instances while still being below the uniform monthly capacity prices. Conversely, raising primary prices on peak above uniform, average annual levels, if in phase with the gray market, could actually <u>increase</u> competition in the short term by encouraging more released capacity and discouraging some usage that would otherwise be cross-seasonally subsidized. As stated previously, while we suggest refocusing the time profile of primary prices we are not advocating the elimination of price regulations without some appropriate showing regarding the absence of market power.

## C. Options and Forwards on Pipeline Capacity

### *1. Concept*

Figure 3 above identified three markets that ideally would be in equilibrium with each other. There is a fourth market, in option and forward contracts on capacity, that needs to be considered in policy deliberations. Two of these markets are regulated (primary pipeline tariffs and secondary released capacity) while the other two are not. Regulators should aspire to make primary and secondary pricing policies more consistent with the economic values revealed in tertiary, gray market spot prices and in forward, derivative markets. In order to do this, it is necessary to consider how derivative markets behave in relation to spot prices.

As explained earlier, a capacity holder paying a primary, embedded cost rate has a forward contract on the expected future basis differentials across the receipt and delivery points. As expected basis differentials change, so does the value of the forward contract. That is, the economic value of pipeline capacity is purely a function of the expected future value of potential spot gas swaps between pairs of locations that the capacity connects.[26] Gas futures contracts exhibit this behavior quite clearly. At the time they are entered, they lock in a future trading price. In that sense, they are riskless instruments. However, the locked in value does not generally remain the appropriate value for trade commitments made on subsequent days, even as little as the day after a given futures contract is struck. Accordingly, futures contracts change in price every day. Since the price difference between futures contracts for delivery at different points is equivalent to a futures contract

[26] This assumes that there are no special rights that attend to firm pipeline capacity contracts, such as extra scheduling flexibility (such as greater imbalance tolerances or secondary receipt point priority) not available to spot/interruptible users of the system. In fact, there may be such differences, but they only complicate the analysis, not changing the general point.

on the transportation rights between the two points, implicitly transportation market values also change value frequently.

This relation between capacity value and expected forward basis differentials reveals that the value of capacity is much more dynamic than is typically acknowledged in cost of service ratemaking. Cost of service pricing formulae traditionally look at cost and usage data but not market price data to assign and allocate shares of revenue requirements. But in an increasingly unbundled market, any persistent gaps between the economic value of an asset and the ratemaking allocations of its value across time and locations can become a source of inefficiency and financial risk. Market values can change for reasons independent of cost and usage on a single pipeline. In particular, changes in the utilization rates of co-terminating pipelines will alter all of their market values, even if their points of origination are distinct. Such changes could be recognized as useful regulated pricing information without abandoning embedded cost recovery practices.

### *2. Benefits re: Efficient Expansion Decisions*

There are multiple ways in which options and forwards can assist in the expansion planning process. For example, a party seeking to expand the pipeline system could in principle write very long forward contracts against future basis differentials (since those basis differentials reflect the spot value of capacity) to lock in a margin that justifies expanding. For instance, a developer might buy ten years of forward purchases at the low cost end of the future pipe and sell ten years of future deliveries at the projected high cost end. This locks in the value of capacity to the system today, when it is constrained, eliminating the problem of trying to collect a premium for service across that path later, after the expansion eliminates the bottleneck.

This kind of planning and financing of capacity additions expansion is very clean; it involves no ambiguities over "need" for the expansion or willingness of future shippers to pay for the pipes. But a prerequisite for this mechanism to be efficient is that the underlying price signals must be efficient and unconstrained, which in turn requires active trading in spot and forward gas contracts at each end of the pipes by as many participants as possible. The current practice of capping primary pipeline prices at annual averages and secondary prices at the primary price discourages some potential sellers from participating in the market. They cannot release their capacity for a premium when the market is "hot", so they retain it, perhaps hoping for a few gray market sales as the next best alternative. If the bulk of their end-use customers are seeing delivered gas prices that are further averaged in a weighted average cost of gas, then the demand for peak pipeline capacity may be artificially high. The traditional pricing simultaneously reduces the supply of available transportation capacity and elevates peak demand, encouraging entry.

A related approach to contracting for expansions would be for pipelines to write call options on capacity. Consider, for example, a shipper that expects to need capacity of 50,000 Dth/day sometime between 2000 and 2004. The shipper could buy *today* one 50,000 Dth/day option on capacity commencing operation between 11/01/1999 and 11/01/2003. This gives the shipper the right, but not the obligation, to have the pipeline add capacity. The maximum rate for the capacity referred to in the option is the strike price. The shipper pays the pipeline a nominal amount today for the option. This payment is referred to as the option price. On or before 11/01/2002[27], referred to as the strike date, the shipper decides whether it wants the pipeline to provide additional capacity 24 months later, the delivery date. If the decision is yes, the shipper exercises or strikes the option. For example, if the shipper strikes on 11/01/2000, then the pipeline constructs or procures additional capacity, the capacity is delivered on 11/01/2002, and service runs for an agreed-upon delivery period at rates not to exceed the previously agreed upon strike price. If the decision is no, the option is allowed to expire or sold to another shipper. Parties have no remaining obligation regarding the option following 11/01/2002.

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[27] The pipeline will have to determine the appropriate strike date, i.e., the one that allows enough time to obtain regulatory approval and construct before the commencement date. The pipeline will also have to determine the appropriate conditions regarding the minimum volume that must be struck in order to pursue new construction and so forth.

Such options would provide buyers with insurance against the likelihood of being unable to obtain capacity when they most need it and, thus, permit shippers to better manage firm transportation contracting uncertainties. For example, if future market demand is highly uncertain, the shipper can wait to commit to firm capacity until the demand growth is more assured. The shipper also does not have to sign up for a new project today on the grounds that it does not know when the next project is coming along. For both gas producers and electric power generation companies, such options would provide assurance that if their development efforts pay off, transportation capacity will be available when they need it, but not before.

The lesson here is not that these transmission "derivatives" provide the single right value for primary market capacity pricing that the Commission should imitate. To the contrary, there is no necessary relationship between these derivatives and the embedded costs, because there are so many ways that the derivatives could be written. For the same reason, there is no single best representation of capacity valves in these financial transactions. The lesson is that the Commission should do whatever it can to make the spot/gray, tertiary market more efficient so that capacity decisions can be derived from an efficient commodity price. Such a policy will be conducive to the development of forward markets in capacity. The most important first step that the Commission could take, in our opinion, would be to encourage the rationalization of primary market capacity pricing so that primary prices behave qualitatively like financial contracts do, i.e. with seasonal, time-of-use, and location variation.

### *3. Benefits re: Recontracting Decisions*

Just as the value of new capacity is determined by the basis differentials it could alleviate, the true economic value of existing capacity depends on the prevailing basis between supply and demand locations. It would be economically inefficient to plan expansions against spot basis values, while not evaluating contract renewal and cancellation rights against the same standards. A complication here is that firm pipeline customers traditionally have rights of first refusal (ROFRs) for contract extension at tariffed rates, which effectively grants a call option for them whereby these customers can choose "the lower of cost or market" alternative at the time of recontracting. Unfortunately, these uncompensated options create expansion planning ambiguities and distortions for the pipelines. If their capacity is likely to be "in the money," i.e., have tariffed rates below average basis differentials, then a need for expansion is signaled, but existing customers have no incentive to ration their future consumption to reflect the high cost of continued use of this line. They also remain free to change their minds at the last minute, if an expansion is pursued that happens to make the embedded capacity prices "out of the money." In that case, they will decline their ROFR and simply switch to the interruptible or released capacity markets for a lower average price of transmission.

This is a source of risk imbalance among market participants and inefficiency for the industry. It almost preordains that we will have future turnback problems and the associated stranded costs. It is therefore useful if not essential to bring the same economic discipline to contract renewal decisions as we seek in expansion planning. Again, innovations in primary and secondary market pricing could help achieve more consonance between these regulated markets (where expansion and recontracting decisions take place) and unregulated spot markets (where consumption takes place).

## IV. THE COMMISSION'S ROLE

The Commission has recently expressed its desire to review the state of the natural gas industry. Toward that end, the Commission has indicated that it intends to hold additional proceedings beyond the one held at the end of January.[28] As part of its deliberations, we strongly recommend that the Commission include a careful examination of primary market capacity pricing. The evolving nature of capacity markets to shorter-term, within-year activity necessitates that the Commission encourage primary market reform toward rates that better reflect the peak / off-peak signals found in market

[28] In its Notice of Public Conference, PL 98-2-000 (December 17, 1997) the Commission stated "[The Conference is] the first of several proceedings on the future of gas industry regulation that are likely to be initiated as part of [the Commission's] ongoing gas industry review."

prices. In pursuing this objective, the Commission should look at a variety of methods, rather than a single ratemaking approach. In conjunction with reforms to the primary market, the Commission, at a minimum, should allow the price caps on secondary market transactions to mirror the within year variations in primary market capacity prices (if it does not choose to eliminate secondary price caps entirely).

Finally, we recommend that the Commission actively support the development of option and forward markets in capacity as a means of managing risk exposure to capacity contracting decisions. To the extent there is any activity is these areas today, it is limited in nature. In contrast, option and forward contracts on gas itself have assisted in the commoditization of gas supply in recent years. Development of these products in capacity markets could help promote the commoditization of gas transmission. Toward that end, the Commission should evaluate whether regulated participants in the market (i.e., pipelines and LDCs) can fully avail themselves of these instruments.

It is our belief that these changes will serve to improve the liquidity and competitiveness of short term markets and to stimulate better capacity contracting decisions on the part of all market participants.