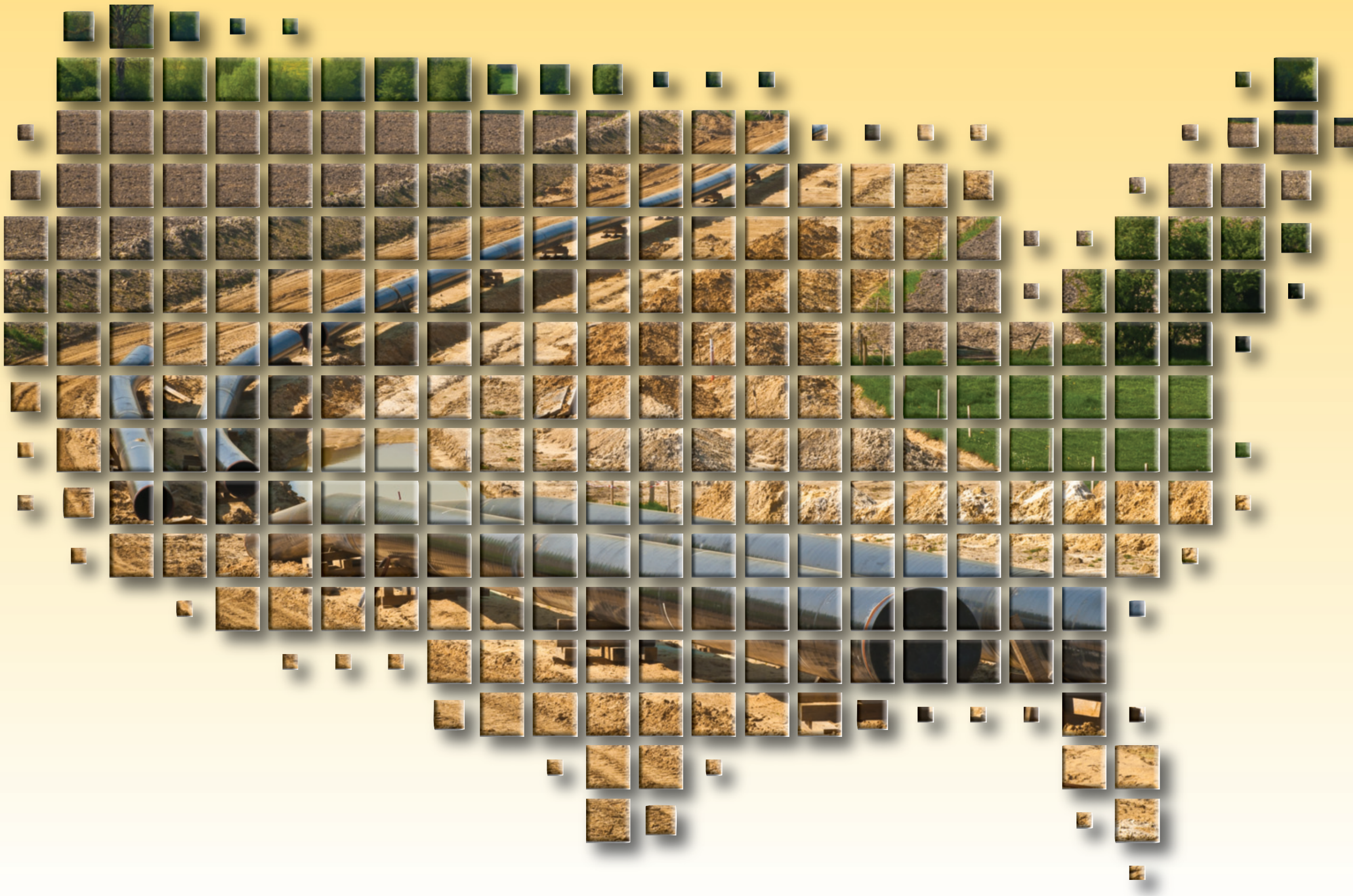


Geography And Risk

The federal government's model for setting natural gas pipeline tariffs may not work anymore, thanks to the shale revolution.

By **John Harpole,** Senior Midstream Advisor

It could be one of the largest issues facing the midstream sector of the U.S. natural gas industry. Some say it's the proverbial elephant in the room, the issue that people are generally aware of but most don't know how to address.

How will gas pipelines continue to earn an acceptable return on their investments during these early years of the shale gas revolution? What is the risk of transportation contracts rendered unprofitable, either seasonally or regionally, to pipeline investors, shareholders, shippers and consumers of natural gas?

There is no doubt that the shale boom is a positive development, however it has and will continue to have a ripple effect throughout the nation with its dark side affecting a host of industry participants.

Pipeline 101

Today's market reality has its roots in the U.S. pipeline policy and regulatory revolution of the mid-1980s and early 1990s. That period was marked by a Federal Energy Regulatory Commission (FERC) effort to encourage market solutions for resource-allocation problems. The FERC issued three precedent-setting orders—436, 500 and 636—that would change the landscape for interstate pipeline economics.

FERC wanted to create a vibrant market for interstate pipeline transportation capacity between producing regions and consuming regions of the country. One policy "backbone" of that effort rested on the requirement that pipeline shippers commit to long-term, 10-year firm transportation contracts. The FERC reasoned that long-term commitments, which incorporated mandatory shipper demand charges (use it or pay for it) would incentivize pipelines to build and expand their asset base for a FERC-guaranteed rate of return.

Those market solutions required pipelines to operate under a cost-of-service financial model. That is, interstate pipelines could earn a FERC agreed-upon rate of return on their investment, but it all had to relate to and be founded upon what the true cost of providing that service would be for potential shippers.

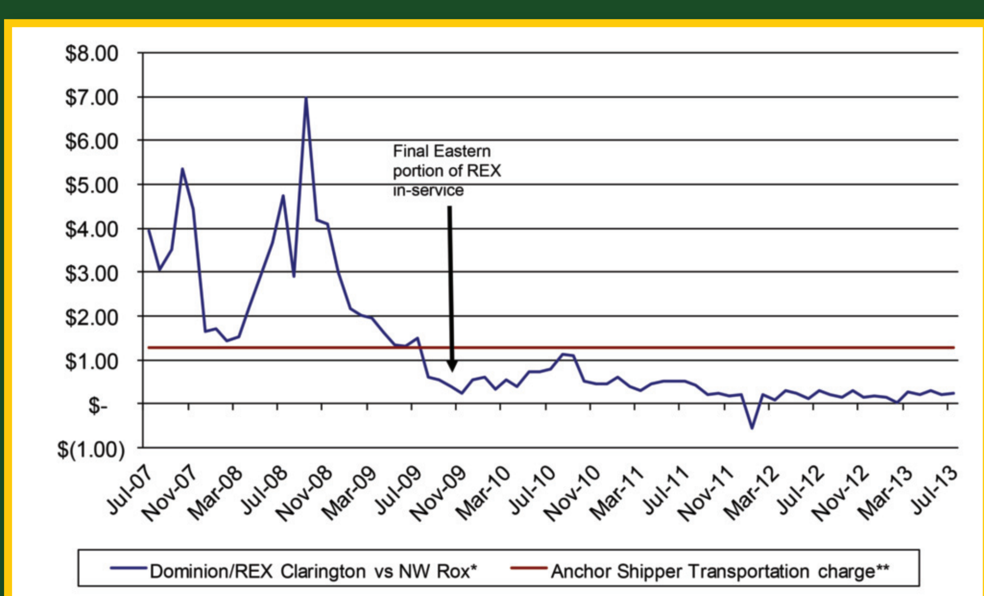
That model and system worked well when pipelines were in a monopoly position and potential shippers had few options. But what would happen down the road when shippers were asked to renew their original 10-year firm transportation commitments in a world with more pipeline and production options?

The cost-of-service model is a "broken pricing model for pipelines facing decontracting in the shale era" Tom Price, former vice president of Colorado Interstate Gas (CIG) and now principal at Global Infrastructure Partners, tells *Midstream Business*. Price began to make that case to the FERC as far back as 2003.

In hindsight, his prediction was prophetic. It's an understatement to say that a lot has changed in the gas market these past 10 years. It obviously hasn't taken 10 years to see pricing relationships between production areas and market areas change dramatically.

"Imagine a business model that promotes the construction of pipelines in an effort to take advantage of regional-pricing differentials," Rick Smead, director of energy at Navigant Consulting, a global expert services firm, tells *Midstream Business*. "Once the pipeline is in service the price differentials either narrow or disappear altogether … That's a tough business model to sustain, and it's been exacerbated by new shale gas."

VALUE OF REX TRANSPORT BEFORE AND AFTER IN-SERVICE DATE



Source: John Harpole

Root of the problem

Becca Followill, senior managing director with U.S. Capital Advisors, updated a study last year on firm transportation-contract capacity on long-haul interstate and regional pipelines.

"Our reviews were driven by investor concern and questions around gas pipeline risk given changing gas flows and a much more proactive FERC," Followill said in the study.

She and her staff identified the expiration date on each and every pipeline's firm transportation contract. She reported, "of the pipelines we analyzed, 64% have more than 50% of their firm transportation contracts up for renewal by 2015."

That unilateral right to renew would be the pipeline shipper's sole decision—a decision obviously influenced by market forces. The key question for each shipper is whether or not, over the long term, would a higher price be received by committing to 10 years of firm transportation? That answer, in many cases, has been negatively affected by new market-area shale gas production.

Ten years ago, few people could have imagined the birth of new gas-production areas near some of the largest market areas in the U.S.—all thanks to the shale gas revolution.

How does a long-haul pipeline respond when production is suddenly discovered in its market area, rendering firm transportation spreads uneconomical? Are the historical cost-of-service calculations and profit margins suddenly irrelevant and discarded?

Perhaps no group of shippers on one pipeline appreciates that financial exposure more than the legacy, firm-transportation shippers on Rockies Express (REX) Pipeline.

REX could be the poster child for the midstream industry's need for a new regulatory pricing model. REX's future may be more in question than other pipelines, but nearly every pipeline in the country will face some degree or variation of the decontracting problems facing REX.

REX and the legacy

REX, a 1,679-mile pipeline connecting the Rockies to eastern Ohio, first came fully into service in 2009. REX Pipeline is a joint venture of Tallgrass Development LP (a private limited partnership), Sempra Energy Corp. and Phillips 66 Co. The original legacy, firm-transportation shippers were committed to moving Rockies production to eastern markets.

Their commitment was supported by a historic high price, or basis differential, between Rocky Mountain production and eastern markets that was $3 to $4 per million Btu (MMBtu) in 2007 and 2008. That price differential has since vanished with the discovery of natural gas in the Marcellus shale play.

The elephant-sized financial strain on REX shippers is more than obvious. They are paying $1.10 per MMBtu, excluding fuel cost, to transport gas to a market that's only a few cents higher in value than the Rockies index price. One shipper, Encana Marketing (USA) Inc., has a demand charge in excess of $500,000 per day. Those shippers are clearly forced to treat the "use it or pay for it demand charges" as sunk costs. During the first two years of REX pipeline operations, some anchor shippers were experiencing $1.50-plus profit margins on their transport and marketing. Back then, one Encana trader bragged, "We're printing money." Those days are long gone.

In a marketer's world, it doesn't make any sense to transport natural gas unless you can at least cover the variable cost of firm transportation. A pipeline shipper only incurs a variable cost if the shipper actually chooses to transport the gas. A producer might choose to transport the gas irrespective of the variable cost just to move the gas out of a production area.

What it costs

In a very simple analysis, there are two types of costs embedded in all pipeline firm transportation contracts: demand (fixed) charges and variable charges.

A pipeline shipper pays demand charges whether utilizing firm transportation capacity or not. Variable charges are only incurred if gas is actually transported. These are fuel-related charges for compressors needed to move the gas. On REX, the current long-haul fuel charge is 4.86%. At a gas commodity price of $3.50 per MMBtu, in order to cover the variable cost of transportation a shipper should at least have a trading spread between the production area and the market area of ($3.50 x 4.86%) of $0.1701 per MMBtu.

The forward-price strip for the Marcellus production area (Dominion Transmission Inc., Appalachia Index) for 2015 is only $0.05 per MMBtu higher than the forecasted Northwest Rockies index price for the same time period.

As a result of new Marcellus production, the variable cost of REX transport is more than three times the forecasted price spread between Rockies production areas and East Coast markets. When pipeline shippers are unable to cover even their variable cost of transport, the premise that they might renew their firm transportation contracts upon expiration becomes preposterous.

New Marcellus shale production is the spoiler in this equation, and it appears that Marcellus shale reserves and production will only spiral upward. According to a Barclay's report released earlier this year, Marcellus production could grow to 10.6 billion cubic feet (Bcf) per day by the end of 2013. That production growth is expected even with a 15% decrease in the Marcellus rig count—2012 vs. 2011.

Five years ago, REX pipeline was built through shipper commitments to capture the anticipated market growth in the eastern U.S. No REX anchor shipper, in their worst nightmare, thought that they would be building into a market area that would experience local production growth that was five-to-six times the 1.8 Bcf per-day capacity of REX.

Fair play

In May, Bill Moler, chairman of REX Pipeline, stated, "Marcellus and Utica are so voluminous that the original transport pattern is not necessary anymore." In a word of advice to Marcellus and Utica shale producers who are reviewing their drilling plans he said, "keep them up, we can take your gas and move it to Chicago, we can take your gas and move it to Indianapolis, we can take your gas and move it to St. Louis."

Now, nearly half of the Rockies produced REX gas exits in the Midcontinent region thanks to gas-on-gas competition from Marcellus producers. Analysts expect that trend to continue as Marcellus gas captures the Northeast markets—the very same markets targeted by Rockies producers five years ago.

In June, Tallgrass Partners announced a deal with a "large producer" in the Utica shale to backhaul natural gas on REX to Midcontinent markets. Per the terms of a binding precedent agreement, an unnamed producer will transport up to 200,000 MMBtu per day from MarkWest Energy Partners' Seneca Processing Complex in southeast Ohio toward the Chicago market.

Clearly, Tallgrass considers a future business model that recognizes a bidirectional pipeline moving eastern shale play natural gas production to Midwest markets and Rockies gas to those same markets.

LEGACY ROCKIES EXPRESS SHIPPERS

- Arrowhead Resources (USA) Ltd.
- Berry Petroleum Co.
- Bill Barrett Corp.
- BP Energy Co.
- ConocoPhillips Co.
- Encana Marketing (USA) Inc.
- EOG Resources Inc.
- Marathon Oil Co.
- Occidental Energy Marketing Inc.
- Sempra Rockies Marketing LLC
- Shell Energy North America (US) LP
- Ultra Resources Inc.
- Wyoming Interstate Co. LLC
- Yates Petroleum Corp.

Evolution or revolution?

A bidirectional strategy clearly supports REX pipeline's current economics; but what happens when the majority of the original eastbound capacity expires in 2019? Those demand charges are worth more than $1.8 million per day to Tallgrass, its partners and shareholders. It's difficult to imagine that discounted backhaul rates could ever replace that revenue to REX.

"Once that demand charge revenue is gone, is there enough revenue for the pipeline to support ongoing operations?" says Bill Demarest, Jr., partner at the law firm of Husch Blackwell LLP. Demarest has represented REX shippers in FERC matters for several years.

He tells *Midstream Business*, "the major pipelines will go through the same transitions that we saw years ago (for different reasons) with United Pipeline and Kansas Pipeline Co. Quite simply, revenues could not provide a reasonable return, which forced a sale—in essence a write-down of valuation—so that the new owner had a different operating cost structure that might be met by revenues.

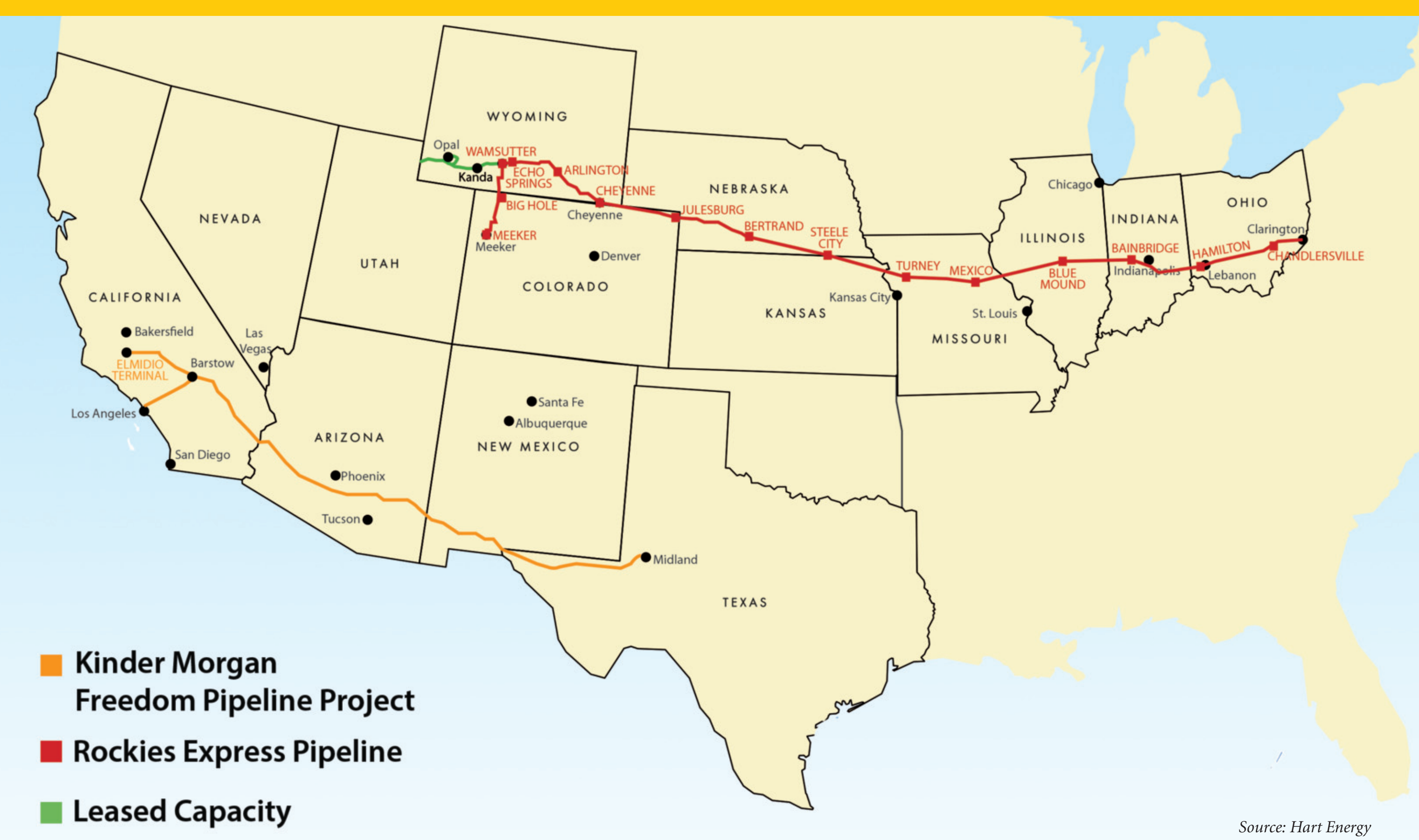
"One would hope that Tallgrass paid virtually nothing for REX. If debt financing was tied to the original contracts and the debt is paid off once those original contracts expire, what value would the pipeline have when transportation capacity is totally decontracted?" he says.

Porter Bennett, founder of Bentek Energy and now with newly formed Ponderosa Energy Advisors, is perhaps the most matter-of-fact about the future of pipelines: "You will have to see wholesale changes in how the pipeline system is regulated, operated and financed," he tells *Midstream Business*.

Adds U.S. Capital Advisors' Followill, "I think it will be more of an evolution than a revolution. There is a lot going on to address the changing flows across the country. Pipelines are being repurposed to convert segments from moving gas from south to north, to moving natural gas liquids and crude oil from north to south. Texas Gas and Trunkline are two great examples. Consider the possibility that Columbia Gulf has three legs that have historically moved gas from the south to north. Two of those legs will likely reverse flow to facilitate providing Gulf Coast LNG [liquefied natural gas] exports with gas supply. You must also consider the possibility that rate structures will change, from traditional zonal rates, where the further you move gas, the more you pay, to postage-stamp rates designed to better accommodate short-haul flows of gas."

It may not be necessary to wait five years to see the impact of the capacity decontracting revolution and whether FERC plans to deal with it through a new regulatory pricing model.

ROCKIES EXPRESS AND FREEDOM PIPELINES



Source: Hart Energy

Freedom Pipeline

El Paso Natural Gas Pipeline (EPNG) and its shippers are currently embroiled in a rate case at FERC that could reveal FERC's long-term plans.

This is the same EPNG, owned by Kinder Morgan, that conducted an open season in March to gauge potential shipper interest in converting 740 miles of its dry gas pipeline to transport crude oil from Texas to West Coast refineries. The project, perhaps the largest pipeline repurposing effort in the industry to date, was known as Freedom Pipeline and shelved by Kinder Morgan at the end of May due to lack of shipper interest.

Some saw this as a desperate attempt at solving larger problems for EPNG. That is supported by EPNG's need to accelerate the timing of its FERC rate case.

EPNG, in its FERC filing, stated, "the primary driver for EPNG filing earlier in its filing window is the significant demand destruction it has experienced since the last case. This destruction is manifested in four ways: loss of throughput, degradation of prices received for short-term services, degradation in price associated with certain long-term contract renewals and decline in billing determinants. These factors have prompted the timing of this case … EPNG has continued to experience contract expirations without renewals and contract renewals, reformations, or other changes since the 2008 rate case. The changes have resulted in a significant net reduction to the levels in EPNG's 2008 rate case, which, in turn, results in a reduction to billing determinants in this case."

There is ample FERC precedent, as stated by FERC staff in the El Paso Rate case: "The commission has long held that pipelines are not necessarily entitled to recover all prudently incurred costs. For example, costs of facilities that are not used and useful to ratepayers should be borne by the pipeline's shareholders, even if such costs are prudently incurred."

The problem, FERC staff argues, is not one of fault. "The commission has explicitly recognized that pipelines should share the risk of unsubscribed capacity with their customers."

It's not one of prudence either. No one is arguing that the initial investments in these pipeline facilities were not prudent at the time they were made. But the inquiry doesn't end with prudence. It is not yet clear if FERC will follow this precedent as it grapples with capacity decontracting and changing flow pattern issues.

Dena Wiggins, partner at Ballard Spahr, agrees that the problem the industry is facing is being caused by a fundamental change in market conditions. She has been involved in nearly every significant FERC rulemaking effort in the past 20 years.

"When REX was built it made sense, but the world has changed," she tells *Midstream Business*. "It's no one's fault, it's not the pipelines' fault, and it's not the shippers' fault, either. In recent rate cases, pipelines have tried to argue that even in the face of declining throughput, the appropriate regulatory solution is to spread the costs over the much lower throughput volumes, even if the result is a huge rate increase for the remaining shippers. This strikes me as wrong and fundamentally unfair because, it's not the shippers' fault, either."

What's the precedent?

Can the FERC take into consideration how market conditions have changed? Is there a historical precedent?

"Going back to the days of the take-or-pay solutions, when the FERC found that market conditions had rendered those contracts uneconomical, the FERC required that the costs be shared between the pipeline shareholders and the shippers," adds Wiggins.

One could argue that there is a similar situation here: The market has changed and pipelines that were designed and built to move gas, from a production area to a traditional market area, now face production in what used to be the market area. Thus, some portions of the pipeline are underutilized.

"The pipeline and its shareholders need to share in the pain and not, as the pipelines apparently prefer, just spread the costs over the remaining shippers and thereby impose all of the pain on the shippers," Wiggins reasons.

In many recent pipeline rate cases, "the shippers have settled on terms that provide what I call a Band-Aid solution, not really addressing the fundamental problem of changing flow patterns but arriving at a negotiated solution to resolve the case," she adds. The pending El Paso case might shed some light on how FERC will address these issues.

"At some point, the FERC will have to call balls and strikes. The problem is too pervasive and the stakes are too high," Wiggins concludes.

Whether its write-downs, billion-dollar pipeline bankruptcies or a series of rate cases that can't truly be fixed by a FERC-prescribed Band-Aid, it's quite clear that the ripple effect of new shale gas and its impact on interstate pipelines will be felt for years to come.

In the realm of potential outcomes, is it possible that pipeline capacity decontracting could impact the netback price to an entire producing region like the Rockies? Is it also possible that master limited partnership unit shareholders might soon be expected to step up to the table and share the shippers' burden of pipeline transportation costs?

The range of questions and issues related to decontracting will continue to present itself to the marketplace. There is no agreement on whether or not FERC will address these issues in a piecemeal, rate case-by-rate case approach or in a larger industry-wide rulemaking. ■

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