Natural Gas Expansion and the Cost Of Congestion

By Matthew E. Oliver, Charles F. Mason and David Finnoff*

With the emergence of new technologies such as hydraulic fracturing and horizontal drilling, large new deposits of oil and gas are poised to become economically viable. As this happens, substantially increased deliveries will make their way into the market, benefiting both producers and consumers. However, these potential benefits cannot be fully realized with the existing transmission capacity. Limited transmission capacity on key delivery routes creates bottlenecks that drive a wedge between the prices consumers pay and the prices sellers receive, lowering consumer surplus and reducing the incentive to develop the new deposits. A question of some policy relevance is therefore: How large is this wedge?

In general, answering this question is quite difficult. Consider the market for natural gas in the United States, illustrated in Figure 1. There are scores of supply sources, and many trading hubs. Hundreds of pipelines connect the various supply sources and trading hubs; the interactions amongst the various supply sources trading hubs and pipelines is, therefore, very complicated.

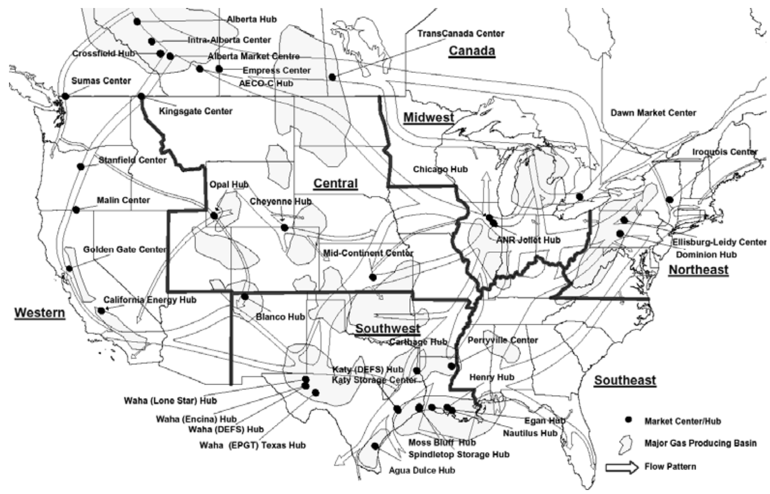

Figure 1: Natural Gas Centers, Hubs, and Major Pipelines.
Source: EIA.

An alternative to evaluating the effect of delivery constraints at the national level is to study a smaller version of the problem—that is, one with fewer sources of supply, fewer trading hubs, and fewer pipelines. In this article, we summarize evidence from such a stripped-down problem involving two trading hubs in the state of Wyoming connected by three pipelines. Gas generally flows from west to east between these two hubs, so that one may interpret the source of supply as represented by the trading hub in the western part of the state (the Opal trading hub) and the source of demand as represented by the trading hub in the eastern part of the state (the Cheyenne trading hub). Our results indicate a persistent difference in prices at the trading hubs, reflecting the cost of transmitting gas between the hubs, in the range of \$0.15 per MCF. When scheduled deliveries utilize more than 95% of the available capacity, however, the wedge between the prices at the two trading hubs rises sharply; the tighter are the capacity constraints, the more pronounced is the wedge between the two prices.

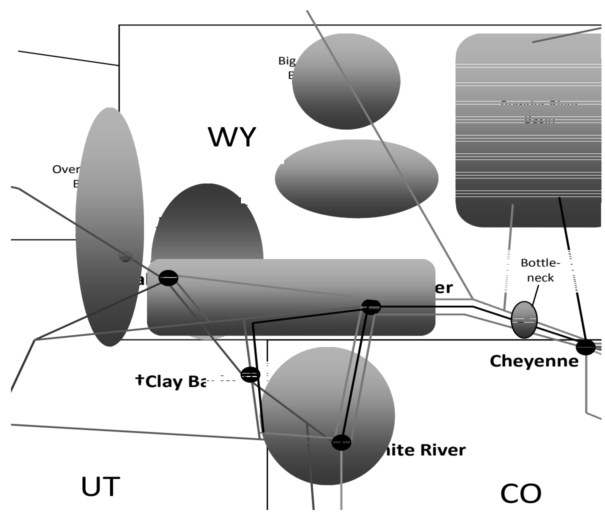

Figure 2: The Rocky Mountain Regional Pipeline Network.

The conceptual underpinning for this story is straightforward. The spot price at the upstream hub, which in this case is the trading hub, depends upon the supply curve for upstream sellers and the demand curve for downstream buyers. In turn, the price downstream buyers are willing to pay depends upon the price they believe they can obtain for the gas when they sell it, less the cost of transportation between the two trading hubs. This transportation cost reflects the opportunity costs associated with the use of the pipeline, and can be thought of as a form of tax on the transaction. The "incidence" of this tax upon sellers depends upon the elasticities of supply and demand. The magnitude of this "tax", in turn, is likely to depend positively on the degree to which transmission capacity is constrained; alternatively, it will depend negatively on the amount of unused capacity at a point in time.

The key logistical features of our example are illustrated in Figure 2.

Most of the natural gas that passes through the Opal trading hub originates in the upper Green River Basin. There, the distribution of the gas is split: some

* Matthew Oliver is with the School of Economics, Georgia Institute of Technology; Charles Mason is the H.A. "Dave" True Professor of Oil and Natural Gas Economics, Department of Economics and Finance, University of Wyoming; and David Finnoff is with the Department of Economics and Finance, University of Wyoming. Charles Mason may be reached at bambuzlr@uwyo.edu

is sent westward, either to Southern California or to the Pacific Northwest; most is sent eastward, ultimately passing through the Cheyenne trading hub. After passing the Cheyenne hub, this gas is sent south towards the Denver metropolitan area, or east towards metropolitan areas in the Midwest. Additional gas enters the pipeline between Opal and Cheyenne; some of this gas is delivered from the Piceance Basin, while some is delivered from the Powder River Basin. Between these three sources of supply, the scheduled deliveries in the pipeline occasionally approaches the three pipelines' combined physical capacity. This situation leads to a "bottleneck" in the pipeline, impeding transmissions.

To evaluate the impact of pipeline capacity constraints upon spot price differentials, we collected data on spot prices at the two trading hubs, scheduled deliveries over the pipeline route that connects the two hubs, and the physical capacities of the pipelines. We have daily observations on these variables for the period between May, 2007 and October, 2010. Using this data, we calculate the difference between the two spot prices (which we call the "basis differential") and the ratio of scheduled deliveries to available capacity in percentage terms (which we call the "utilization rate"). We then sort the data by utilization rate, placing observations into eight cohorts (< 75%, 75%-80%, 80%-85%, 85%-90%, 90%-95%, 95%-97%, 97%-99%, > 99%). For each of these eight cohorts we calculated the mean and median values of the basis differential. Figure 3 illustrates the statistics.

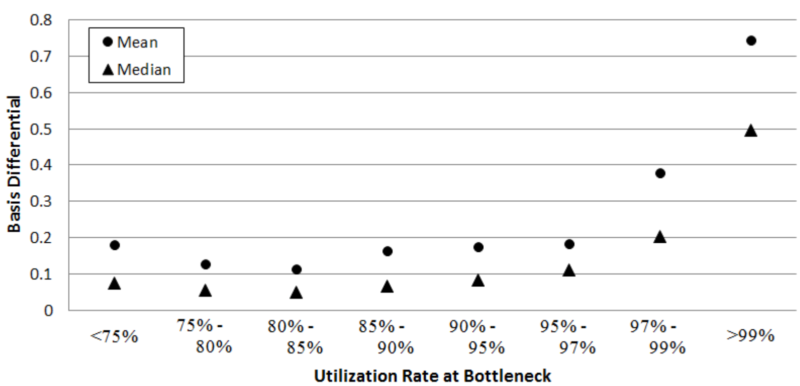

Figure 3: Basis Differential vs. Utlitzaton Rate

When the utilization rate does not exceed 97% we see that the mean basis differential is between $0.10 and $0.20, with the median basis differential roughly half the mean value. Once the utilization rate exceeds 97%, however, the basis differential starts to rise rapidly. For observations where the utilization rate falls between 97% and 99%, the mean basis differential is roughly $0.40 (with a median value of about $0.20). When the capacity constraint is very nearly binding, i.e., when the utilization rate exceeds 99%, the basis differential increases to nearly $0.80 on average (with a median value of $0.50). As a utilization rate in excess of 97% seems likely to signal the imminent potential for capacity constraints to bind, the data suggest binding capacity constraints can exert a powerful effect on spot prices.

The implication is that capacity constraints (and the associated congestion) can be excessively costly to natural gas market participants. Figure 3 demonstrates the potential for a five-fold increase in the median basis differential if the utilization rate increases from 95% to 99%! As the capacity of the bottleneck we consider is roughly 3.2 million MCF/day, with an estimated 22% of the gas flowing transacted at spot prices (FERC, 2010) the magnitude of the 99% utilization rate median differential implies $352,000 per day in transport costs. Because the Federal Energy Regulatory Commission (FERC) regulates transmission tariffs the pipelines are unable to capture the scarcity rents. Instead, non-pipeline owners of firm capacity capture the rents in the unregulated secondary market for transportation services. This diversion of scarcity rents away from the pipeline owner ultimately weakens the incentive for capacity expansion, compounding the congestion problem and resulting in an increased likelihood of binding capacity constraints. Thus, if pipelines are unable or unwilling to keep pace with the almost certain growth in demand for natural gas transmission over the coming decades, significant cost increases may well undermine the ability of the national market to fully integrate spot prices across geographic locations.

References

Federal Energy Regulatory Commission (FERC). (2010). 2009 Analysis of Physical Gas Market Transactions Using FERC Form 552 Submissions. Item No. A-3, December 16, 2010.