

Natural Gas Transportation Price Regulation and the Dash for Gas

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The large reduction in natural gas prices due to horizontal fracturing has led to an unprecedented expansion in natural gas use for electricity generation. Another innovation that helped facilitate the expansion of natural gas electricity generation is the deregulation of natural gas pipeline transportation. Previous to June 2008, the price for transacting space in natural gas pipelines was set by the Federal Energy Regulatory Commission (FERC). FERC Order 712 allowed transactions under one year in duration, generally known as the secondary market, to transact at market prices. This regulatory innovation should facilitate natural gas power plants in procuring natural gas and lead to expanded generation. This analysis finds an average 2 percentage point increase in natural gas capacity factors that is attributable to FERC Order 712, and that the impact is larger in places with relatively little pipeline capacity.

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I. Introduction

The US electricity industry has undergone massive changes over the last decade. The share of electricity generation from natural gas has doubled along with large increases in renewable electricity generation. The main reason for the increase in natural gas use is the large reduction in natural gas prices from record high prices in 2008. However, another change that occurred in 2008 that is less well known is the deregulation of the natural gas transportation market. With Order 712, the Federal Energy Regulatory Commission (FERC) allowed owners of natural gas pipeline capacity to sell pipeline space at unregulated prices. As natural gas prices have fallen due to the technological innovation of horizontal fracturing, the ability to move natural gas throughout the pipeline network should become increasingly important as firms attempt to procure more natural gas.

This paper aims to quantify the impact of FERC Order 712 on natural gas electricity generation. As the market price for natural gas transportation is allowed to be set by supply and demand we expect to see expansion of power plants' ability to purchase and receive delivery of natural gas. The conceptual framework laid out would suggest that previous to Order 712 there would be natural gas electricity generators interested in but unable to procure natural gas, given the cap on the price of its transportation, and thus not able to generate electricity. After Order 712, it is expected that electricity generators are able to procure natural gas as they can offer a higher price for transportation services, enabling them to generate electricity. The framework provides a testable hypothesis of increased generation of electricity from gas due to the deregulation of the natural gas transportation market.

One difficulty in testing this hypothesis is that the price of natural gas began falling considerably due to horizontal fracturing around the same time as Order 712 was introduced. To overcome this confounder, we estimate a plant's capacity factor (actual generation divided by maximum achievable generation) based on nearby coal to natural gas price ratios (and other controls) for a short time period around the implementation of Order 712. Additionally, our analysis utilizes the distribution in pipeline space near the power plant to reveal whether plants that have more limited pipeline space nearby—where we would expect the price cap to be more binding—increased their capacity factor by a greater amount than those with ample pipeline space who therefore would have been less affected by Order 712.

Results indicate that, on average, natural gas power plants increased their capacity factor relative to before the removal of the price cap by 2 percentage points, representing a 9% increase from a baseline

capacity factor of 22%. Plants with little nearby pipeline space showed a larger increase in capacity factors after Order 712 relative to those with ample pipeline space, consistent with our framework. The analysis uses multiple measures of pipeline space including those that take into account pipeline usage by other sectors. Finally, a number of alternative functional forms for the estimating equation reveal the same pattern of results as in the baseline case.

This work contributes to several strands of the literature. Many recent papers have examined how the decrease in natural gas prices have impacted the electricity sector. Fell and Kaffine (2018), Linn and Muehlenbachs (2018), and Holladay and LaRiviere (2017), among others, showed the impact of low natural gas prices on emissions from the electricity sector and the consumption of coal. This analysis differs in that it is not necessarily concerned with how low natural gas prices have increased natural gas generation but whether the ability to transport natural gas at market prices has allowed natural gas plants to operate when they otherwise would not have been able to. Our results imply that natural gas plants would have been restricted in their use had Order 712 not been implemented.

As this analysis attempts to understand the impact of a price restriction, it fits into the long line of literature on the costs of price controls. Davis and Killian (2011) analyze how the price caps for residential natural gas pre-1990 in the US hurt consumer welfare. Another paper along the lines of how lifting market controls can improve market outcomes is Cicala (2017), who shows that the movement to deregulate the electricity sector in the late 1990s led to an increase in allocative efficiency as cost effective plants generated more often in deregulated areas.

II. Background

Makhholm (2012) provides a thorough history of natural gas pipeline regulation in the U.S. Until the early 1990s, natural gas transportation was highly controlled by pipeline builders who used their market power to restrict entry of natural gas producers. Price regulations at the wellhead led to large inefficiencies in consumption of natural gas (Davis and Killian, 2011).

Unlike oil, natural gas has proven prohibitively costly to transport by any method other than pipelines.¹ In 1992, FERC issued Order 636, which required the unbundling of transportation services from

¹ The last 10 years has seen liquefied natural gas introduced for long range transport on ships but this is exclusively for international trade and has not been used for intra-national trade of natural gas. Current innovations are exploring means by which natural gas may be transported by road, but these have yet to meaningfully penetrate the gas transportation market.

natural gas production. Pipeline companies could only build and operate pipelines and could not restrict a producer's ability to place their gas in the pipeline network.

Natural gas is used in multiple sectors of the US economy. The three largest consumers of natural gas are commercial and residential space heating, electricity generation, and industrial consumption. While these three are by far the largest users of natural gas, it should be noted that commercial and residential space heating demand for natural gas is driven by temperature. As such, prices for natural gas are largely driven by temperature as higher temperatures mean that commercial and residential space heating demand is essentially zero.

Customers of natural gas transportation services generally fall into two categories. The first are those who purchase transportation services in the primary market, which comprise contracts longer than one year, at FERC-regulated rates. The primary market is how pipeline companies earn their revenue and is used as evidence in FERC permit applications that the pipeline is economically needed. FERC sets the rate that can be charged for the sale of transportation services in the primary market largely as a means to limit pipeline companies' ability to use their market power to overcharge. Customers in the primary market are generally natural gas utilities or local distribution companies (LDCs), who sell gas for residential and commercial space heating under state-level economic regulation, and gas marketers, who purchase transportation services for resale to other customers (FERC, 2015).

A secondary market for transportation services exists where those who bought pipeline space in the primary market may resell that space to customers as long as the contracts are less than one year, a result of mismatched supply and demand in the price-regulated primary market. FERC Order 712 has allowed these secondary market transactions to be sold at market rates since June 2008, and at the same FERC-regulated rate as in the primary market previous to June 2008. Natural gas power plants are one of the main customers on the secondary market.

Another aspect of natural gas transportation is the type of transportation services purchased, i.e., firm or interruptible. A firm contract, either in the primary or secondary market, implies that space in the pipeline has been reserved and the transportation occurs regardless of demand from other customers. Interruptible contracts do not reserve pipeline space and thus can be stopped from transporting natural gas if the pipeline is "full", i.e., customers with firm transportation have occupied all of the space in the pipeline.

The issuance of *Order 712: Promotion of a More Efficient Capacity Release Market* allowed the owners of natural gas transportation rights to (re-)sell their rights at market rates as long as the contract was less than one year. This order is particularly relevant for natural gas plants as they are unlikely to sign long-term contracts for gas transportation given the demand for these longer contracts from LDCs in this market. The ability to transport natural gas in pipelines in a quick and efficient manner is crucial given the lack of alternative transportation methods and the relatively high cost of natural gas to stockpile (compared to coal or oil).

III. Conceptual Framework

Consider the market for gas transportation services in three regions of the US as depicted in Figure 1. The horizontal axis represents the quantity of pipeline space transacted, and the vertical axis represents the price per unit of pipeline space. The thick dashed line represents the maximum price for transportation space that FERC allows in the pre-FERC Order 712 period. At this point we abstract from the difference between firm and interruptible transportation due the finding in Doyle and Lange (2016) that fixed plant characteristics drive the choice of contract type and thus plants rarely change the type of contract they sign for transportation. Each region has either a relatively high amount, an average amount, or a relatively low amount of spare pipeline capacity. As pipelines are long-lived assets and the demand for gas from sectors other than power plants (namely space heating and industrial) can change due to demographic or other macroeconomic trends, we assume that the contemporary distribution of the amount of spare pipeline capacity is unrelated to any individual power plant.

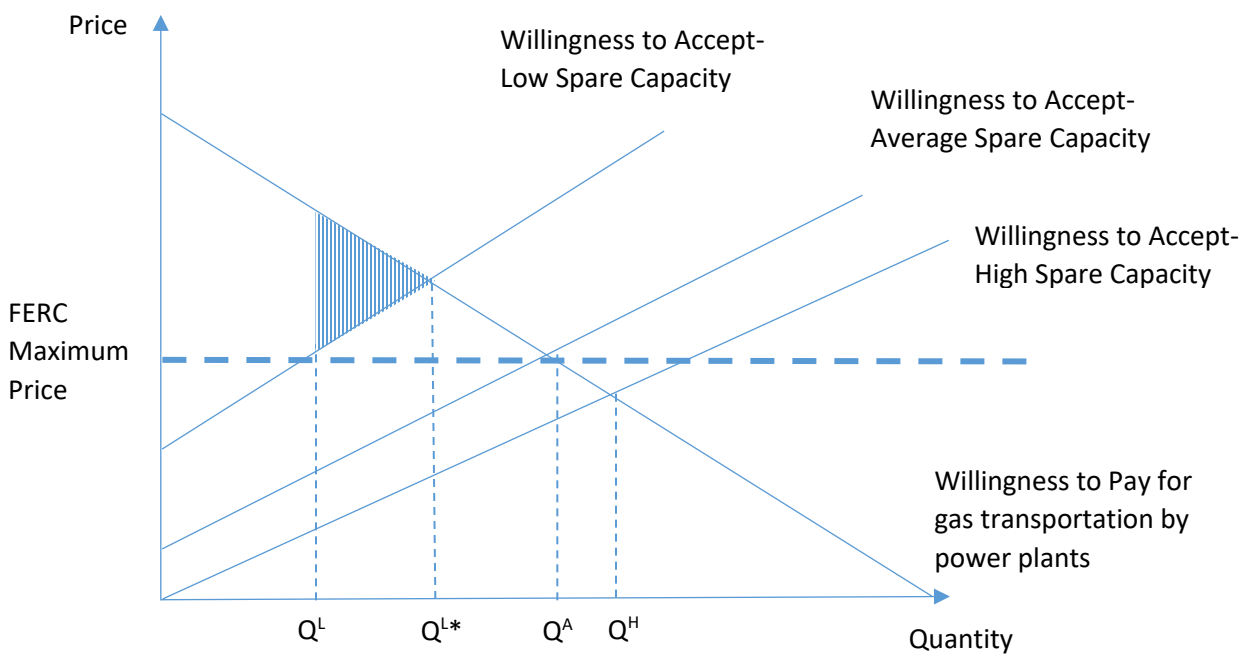
Current holders of natural gas transportation rights have an upward sloping willingness to relinquish their rights over pipeline transportation as more space is offered for sale. Recall that the holders of the transportation rights have paid the FERC regulated rate to acquire those rights.² A given owner of natural gas transportation space is willing to offer the space for sale if its use of the space is of lower value than what other potential users are willing to pay.

In areas of high spare pipeline capacity in Figure 1, market clearing prices for pipeline transportation services are lower than the FERC maximum rate and thus transactions are not restricted. The quantity transacted in this case would be Q^H . On the other extreme, noted as low spare capacity, is a situation

² Normally this would be a sunk cost, however if we believe there are any heuristics or loss aversion at play, as suggested in Borenstien et al (2012) and Doyle and Lange (2016), this issue could be relevant.

where power plants are willing to pay more than the regulated rate and there are owners of transportation rights that would be willing to sell their rights, however the regulated price leads to only Q^L pipeline capacity being transacted whereas Q^{L*} represents the efficient quantity of transportation, since power plants are still willing to pay a value greater than the current holder is willing to accept. Pre-FERC Order 712, the market for transportation of natural gas was not allowed to reflect relative value of transporting natural gas if that price was above the maximum rate set by FERC, leading to deadweight loss represented by the shaded triangle. In Figure 1, we have assumed that the average spare pipeline capacity corresponds to a willingness to pay for transportation services that is in line with the regulated price and we see Q^A pipeline capacity being transacted.

Figure 1: Market for Secondary Transportation Services



After the price regulation is removed, we would expect to see the amount of pipeline space being transacted increase to Q^{L*} in the low spare capacity region. Now the market price is able to adjust to

supply and demand conditions and thus more transactions occur which allow natural gas power plants to generate more often. We take this hypothesis to the data in this analysis.

IV. Methods and Data

We estimate a plant's capacity factor using the coal-to-gas price ratio and temperature. The estimating equation is:

$$CF_{i,t} = \alpha_i + \beta_1 f \left(\frac{C_{i,t}}{G_{i,t}} \right) + \beta_2 h(HDD \text{ and/or } CDD_{i,t}) + B_3 Treat_t + \varepsilon_{i,t} \quad (1)$$

Where $CF_{i,t}$ is the capacity factor (actual generation divided by total generation capacity) for plant i in month t , f and h are polynomial orders, $\frac{C_{j,t}}{G_{j,t}}$ is the coal-to-gas prices ratio in state j , HDD is heating degree days and CDD is cooling degree days for state j in month t , $Treat$ is a variable equal to 1 after June 2008 and 0 otherwise, and $\varepsilon_{i,t}$ is an error term. The estimation model follows Cullen and Mansur (2017) and Maniloff and Fell (2018) in that the coal-to-gas price ratio enters the model with higher order polynomials due to the “kink point” that is commonly found in the relationship between fuel price ratios and capacity factors.

Data for this analysis come primarily from the Energy Information Administration (EIA) Form 923. The EIA 923 data contain actual generation, and physical capacity is derived from the EIA 860. Data on the HDD and CDD come from NOAA.³

To investigate the impact of the deregulation of transportation, we interact the $Treat$ variable with information on either the length of pipeline within 40 square miles of the power plant i , state j 's pipeline capacity, or the ratio of state j 's pipeline capacity to the consumption of gas by the residential, commercial, and industrial sector in state j (a measure of pipeline congestion). Data on residential, industrial, and commercial natural gas consumption come from the EIA's Natural Gas Monthly.⁴ Information on pipeline capacity is available from the EIA.⁵ This specification brings cross sectional variation to the analysis, thus allowing us to rule out that these results are driven by other temporal issues not related to the treatment.

³ Data are available at: <http://www7.ncdc.noaa.gov/CDO/CDODivisionalSelect.jsp#> (Last visited on 6/25/18)

⁴ Data are available at: https://www.eia.gov/dnav/ng/ng_cons_sum_a_epg0_vcs_mmcf_m.htm (Last visited 6/25/18)

⁵ Data are available at: <https://www.eia.gov/naturalgas/data.php#pipelines> (Last visited 6/25/18)

V. Results

Table 1 provides some preliminary results of estimating the capacity factor. In order to limit confounding from other market changes, the analysis presented here focuses on the time period of May through September 2008. The months of August and September are the treated months while May, June, and July are the control months. A second-order polynomial is used for the price ratio and the temperature variables (f and h in Equation 1) in Table 1, with other polynomial orders shown in Appendix Tables A1 and A2 for robustness.

Table 1: Regression Results

Dependent Variable: Plant Capacity Factor				
Variable	1	2	3	4
Treat	2.03*** (0.68)	3.17*** (0.91)	3.84*** (1.17)	2.48*** (0.83)
Treat*Capacity of Nearby Pipelines		-0.002** (8.3e-4)		
Treat*State Pipeline Capacity			-1.6 e-4** (7.7 e-5)	
Treat*Pipeline Congestion				-1.028 (0.83)

Notes: Standard Errors are clustered at the plant level. A squared functional form is used for price ratio, HDD, and CDD.

* p<0.10, ** p<0.05, *** p<0.01

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The treatment effect is an absolute 2 percentage point increase in capacity factors as given in Column 1. The average capacity factor for this sample is 22%, implying a treatment effect corresponding to a 9% increase in capacity factor resulting from the policy change. Columns 2-4 interact different measures of pipeline capacity with the treatment to measure how pipeline availability impacts the treatment effect. From the conceptual framework in Figure 1, we would expect that plants located in areas with spare pipeline capacity would be less likely to be impacted by the removal of the FERC maximum rate. Columns 2-4 use three different measures of spare pipeline capacity to test whether natural gas plants in areas with less spare pipeline capacity expanded production more than those in areas with more spare pipeline capacity after FERC Order 712. The three measures of pipeline capacity

are the length (km) of pipelines within 40 miles of the plant, the total pipeline capacity in the state in which the plant is located, and the ratio of the state's pipeline capacity to the amount of gas used in the residential, commercial, and industrial sectors in the state. All three coefficients for the interaction of the treatment with the spare pipeline capacity variables are negative and two of them are statistically significant. The coefficients from Column 2 put the turning point from an increase to a decrease in capacity factors for the treatment at plants in states with about 1600 km of pipeline, the 92 percentile for the sample of plants. This finding implies that when a power plant was near spare pipeline capacity, it was not impacted by the price regulation on secondary market transactions.

VI. Conclusion

This analysis tests whether lifting the maximum price in the natural gas transportation market, through FERC Order 712, facilitated the movement of natural gas into the electricity sector. This regulatory innovation should allow natural gas power plants to procure natural gas and expand generation. Results of the analysis find that natural gas power plant capacity factors, the ratio of actual production of electricity to maximum possible production, increased by about 2 percentage points on average after FERC Order 712 went into effect. This average effect was not uniform throughout the U.S. For plants with relatively large amounts of pipeline capacity nearby or in the state, there was no increase in capacity factors. This finding is consistent with a simple supply and demand model of the market for natural gas transportation where higher levels of supply are less likely to lead to a market price that is above the maximum price set by FERC.

The large reduction in natural gas prices due to horizontal fracturing has led to an unprecedented expansion in natural gas use for electricity generation. Another innovation that helped facilitate the expansion of natural gas electricity generation was the deregulation of natural gas pipeline transportation. Previous to June 2008, the price for transacting space in natural gas pipeline was set by FERC. FERC Order 712 allowed transactions under one year in duration, generally known as the secondary market, to transact at market prices. This little-known FERC Order appears to have contributed significantly to the large expansion in natural gas use in the electricity sector.

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Appendix

In Table A1, results are shown for a number of alternative functional forms of the model. The table reflects a number of alternative specifications in conjunction with the three different measures of pipeline capacity. The same general pattern emerges of the impact of FERC Order 712 as is seen in Table 1. Column 1 of table A1 uses the log of the capacity factor in the estimation.⁶ In Column 2, the standard errors are clustered at the state level instead of at the plant level. There are 43 states in the sample, meaning there are 43 clusters in the analysis. While there is no firm number of acceptable clusters, more is better to ensure that the law of large numbers in statistical theory applies for inference (Cameron and Miller, 2015). Clustering will adjust standard errors to account for state-level unobservable attributes that may lead to correlation between plants in the same state.

Column 3 of Table A1 removes the HDD and CDD variables and replaces them with the total state electricity generation for the month. While HDD and CDD variables are often used as predictors of electricity demand, state electricity generation has also been used in the literature so we include it in this specification. In Column 4, we use a cubic polynomial for the fuel price ratio, CDD, and HDD variables in addition to state-level clustered standard errors to reveal how altering those variables' functional forms impacts the treatment coefficients.

Finally, Table A2 shows that the interaction of treatment with the measures of spare pipeline capacity results holds when monthly dummies are included in the analyses. Since the treatment has only temporal variation, the models previously estimated do not contain any time controls. Adding in the month dummies will control for general time trends but does not allow for estimation of a treatment effect. The interaction of the treatment with measure of pipeline capacity can be estimated given the spatial variation in spare pipeline capacity. Thus, the results in Table A2 confirm that the spatially varying treatment effects that were found in Table 1 are not due to other time trends.

⁶ Since capacity factors are between 0 and 1, the actual log transformation is $\log(CF/1-CF)$.

Table A1: Robustness Results around Functional Forms

Dependent Variable: Plant Capacity Factor				
Variable	1	2	3	4
Treat	0.076** (0.04)	3.34* (1.97)	3.71*** (1.06)	4.16* (2.32)
Treat*Capacity of Close Pipelines	-5.6e-5 (4.9 e-5)	-0.002 (1.4e-3)		
Treat*Pipeline Capacity				-1.7e-4 (1.2e-4)
Treat*Pipeline Congestion			-3.30*** (0.901)	
Model	Log of CF	State Clustered S.E.	State Electricity Load instead of HDD/CDD	Cubed Polynomial Order & State Clustered S.E.

* p<0.10, ** p<0.05, *** p<0.01

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Table A2: Robustness Results with Month Fixed Effects

Dependent Variable: Plant Capacity Factor			
Variable	1	2	3
Treat*Capacity of Close Pipelines	-1.4 e-3* (8.2 e-4)		
Treat*Pipeline Capacity		-1.3 e-4* (7.5 e-5)	
Treat*Pipeline Congestion			-1.18 (0.80)
Model	Month Dummies	Month Dummies	Month Dummies

Notes: Standard Errors are clustered at the plant level.

* p<0.10, ** p<0.05, *** p<0.01

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