Long-Term Contracts and Secondary Markets: Evidence from Natural Gas Pipelines*

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Abstract

We examine the role of long-term contracts and secondary markets in influencing the resilience of supply chains. Specifically, we assess the efficiency of the US natural gas pipeline network in allocating capacity in response to unexpected demand and supply shocks, which are increasingly common with the advent of climate change. Long-term contracts can create an imbalance between supply and demand because they reserve capacity for contract holders prior to shocks. Utilizing daily transaction data from 2005 to 2023, we find that a secondary market, where contract holders can lease capacity to other shippers, reacts to significant regional demand fluctuations and alleviates the imbalance between supply and demand. We also find evidence that the formation of long-term relationships between buyers and sellers reduces search costs in the secondary market. However, the presence of a largely unregulated secondary market within a heavily regulated primary market raises concerns about market dominance. We find evidence that both buyers and sellers can influence prices based on their market shares, which vary across location. Market concentration reduces the market's efficiency during extreme weather events, as captured by large and persistent price differences across natural gas hubs. We rationalize market concentration as coming from upstream "peak-demand day" regulation imposed on large utilities that must hold excess capacity through long-term contracts with pipelines. We then build and estimate a structural model of the entire pipeline network to study alternative regulatory designs.

Keywords: Capacity Release, Secondary Market, Pipeline, Supply-Chain, Transportation

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1 Introduction

In North America, pipelines are the dominant method for transporting natural gas. They are extremely costly to build, averaging $5 million/km with 10 to 20 years for the pipeline to break even on its investment. To share the risk associated with large sunk investment costs, pipelines must sign long-term contracts (typically ten years or more) with customers prior to the pipeline's construction, which entitles the customer to reserved capacity. Long-term contracts in the primary market can create situations of artificial constraint in which physical capacity is available, but contracting frictions impede the flow of natural gas. For these reasons, there is a secondary market unique to the U.S. where shippers can lease capacity to other shippers for any length of time. The secondary market is much less regulated than the primary market, with the aim of fostering a competitive environment between shippers.

In this project, we evaluate the efficiency of the U.S. natural gas pipeline network at intertemporally allocating pipeline capacity in response to demand and supply shocks through its secondary market. We study trade-offs associated with the secondary market and provide guidance for deregulation efforts in similar industries. We study shocks to large weather fluctuations that affect the supply and demand for energy, increasingly common with the advent of climate change (Wang, Biasutti, Byrne, Castro, Chang, Cook, Fu, MGrimm, Jaha, Hendon et al., 2021; Bathiany et al., 2018). Through the lense of the secondary market for capacity release, we contribute to a growing literature studying the resilience of energy systems and markets in response to such atmospheric conditions (Gonçalves, Costoya, Nieto and Liberato, 2024; Jasiūnas, Lund and Mikkola, 2021; Waseem and Manshadi, 2020).

Using novel daily transaction data for selected U.S. natural gas pipelines between 2005 and 2023, we find that the secondary market responds to large regional fluctuations in demand for natural gas. Using the extreme cold wave of February 2021 as a motivating example, we find an increase in natural gas demand, particularly demand for residential heating and electricity generation in the Deep South. Natural gas prices at hubs in Texas and southeastern California rose substantially during this period. In contrast, prices at hubs outside the cold wave's radius, such as in Northwestern California, did not rise.

We leverage this spatial variation in natural gas prices to identify control and treated regions. In a difference-in-difference event study framework similar to Miller (2023) and Freyaldenhoven, Hansen, Pérez and Shapiro (2024), we find that the cold wave caused a 50% increase in capacity released from buyers (replacers) to sellers (releasers) in the secondary market. We also find that the secondary market facilitates a reduction in search costs between replacers and releasers but fosters an anti-competitive environment where both sides of the market influence prices.

To understand the aforementioned trade-offs better, we investigate how the motivation of various market participants interact. The vast majority of shippers that release capacity are large end-consumers (power plants, local distribution companies and industrial plants) who have long-term contracts with pipelines and must pay large reservation fees even if they do not utilize their capacity. Many of these consumers have regulatory requirements to maintain enough capacity to absorb extreme shocks, and thus have an incentive to lease their excess capacity when they do not need it. The vast majority of replacers are marketers: intermediaries that engage in arbitrage opportunities, buying gas at cheap hubs and selling it at expensive hubs to smaller consumers who do not have the financial capacity to directly engage with pipelines[1]. Marketers are thus critical in ensuring that gas reaches a wide variety of consumers.

We observe a prevalence of long-term relationships between releasers and replacers (marketers) and propose hypotheses rationalizing these relationships. Rather than being the outcome of formal auctions, over 95% of contracts signed are private arrangements made between shippers, similarly to the U.S. trucking industry (Harris and Nguyen, 2023). Many of these arrangements recur between shippers at specific intervals and include the possibility that capacity be recalled by the releaser and further reput to the replacer. This allows releasers to maintain their regulatory requirements of excess capacity without having to constantly pay reservation fees to hold excess capacity. These features make contracts highly differentiated products and underlie potentially large search costs that long term relationships help dissipate

Using event studies, we find that contracts are much more likely to be signed between long-term partners during cold waves, suggesting that the opportunity cost of searching is higher in periods of high demand, and that long-term relationships reduce search costs. However, a market with high search costs for a highly differentiated product along with a quasi-lack of regulation can foster anti-competitive practices.[2] To show this, we leverage spatial variation in market concentration across different origin-destination pairs on both sides of the market (releasers and replacers).

We find significant effects of market shares on the secondary market's transportation tarrifs. A 1% increase in releaser market share increases tarrifs by 0.3%, whereas a 1% increase in replacer market share decreases tarrifs by 0.06%. Moreover, these price-setting effects increase by 50% on both sides of the market during periods of extreme weather.

[1] Often these consumers do not even meet the pipelines' credit requirements to directly engage in the secondary market. Moreover, they do not have the liquidity to commit ex-ante to expensive long-term contracts

[2] There are some constraints on capacity prices in the secondary markets based on how long capacity is expected to be released. See Section 2 for details.

We also revisit the role of market concentration on price arbitrage across natural gas hubs during periods of extreme weather, motivated by the price at various hubs rising between 10 to 25 times the price Henry Hub during extreme cold waves. The ability of regional markets to integrate through relative price harmonization is considered a key measure of market efficiency Avalos et al. (2016); Oliver et al. (2014). We find that origin-destination hub pairs with more concentrated replacers (marketers) faced much larger relative price increases during cold waves, which has important dynamic implications. A 1% increase in replacer Herfindahl–Hirschman index (HHI) is associated with a 1.25% increase in price disparity across hubs. This is suggestive of market power on the downstream market, where concentrated marketers can maintain arbitrage opportunities and remain "in the money". Moreover, we show that the persistence of shocks on relative hub prices is increasing with concentration on both sides of the market during cold waves.

The welfare implications of these price-setting behaviors is uncertain as we expect some of these forces to cancel each others. We develop a parsimonious network model to study the implication of two-sided market power on capacity release transportation tariffs and natural gas prices at hubs. The market is segmented by two types of consumers: one that has access to long-term contract and one that doesn't. A secondary market with marketers (intermediaries) facilitating exchanges are necessary to get gas from one type of consumers to the other. In a perfectly competitive market without physical capacity constraints, we find that regional demand shocks induce perfect price arbitrage despite the asymmetry of the demand shock.

This secondary market is one of the only real examples of a Coasian market in which participants trade legal entitlement to natural gas pipeline capacity. Our paper is the first to empirically study such a secondary market. We aim to provide some evidence that generalize to other similar heavily regulated markets with large sunk investment costs, and to provide guidance for the organization of pipeline networks outside of the U.S.

Related Literature

This paper contributes to three broad strands of literature on (i) supply-chain and energy market resilience, (i) the effectiveness of secondary markets, and (iii) the pipeline industry.

Chen (2023) shows that mergers among those networks result in significant cost reductions and a notable rise in markups. Nonetheless, there is still a cost pass-through to customers, leading to a reduction in shipment prices. Based on the findings of Chen (2023), we investigate the effects of decreased shipping costs resulting from the consolidation of transport networks on downstream firms. However, transport companies and their downstream customers typically establish long-term relationships, and our knowledge of these long-term relationships is limited. To shed light on these issues, we examine how these relationships are formed and how demand and supply shocks affect the formation of such relationships. One challenge in examining these relationships is that typically, the specifics of such contracts are not observed. However, the U.S. natural gas pipeline industry is an exception, as all contract details are observable. This includes information on the ownership of transmission capacity in the primary market and details of transactions related to capacity release in the secondary market. By examining the formation of long-term relationships in the natural gas pipeline industry, we offer insights that could be applied to other similar transport markets with substantial sunk investment costs.

Our study of the secondary market in the natural gas pipeline industry also contributes to a literature investigating the effect of capacity constraints, bottleneck, and congestion on market efficiency measures such as price integration across hubs (Avalos, Fitzgerald and Rucker, 2016; Oliver, Mason and Finnoff, 2014; Brown and Yücel, 2008; Marmer, Shapiro and MacAvoy, 2007). This literature studies physical constraints and how regulation interacts with these physical constraints in preventing spatial price integration. By contrast, we study the role of artificial capacity constraints created by long-term contractual agreements that reserve capacity, which has not been studied before. Our findings on the effectiveness of the secondary market suggests that these constraints are important and should be considered along with physical constraints when studying market efficiency.

Lastly, our findings on the exercise of market power in the secondary markets relate to the literature on intermediation in search markets and monopsony power (Berger, Herkenhoff, Kostøl and Mongey, 2023; Salz, 2022; Spulber, 1996; Gehrig, 1993). Our results are consistent with some of these results in contexts where intermediaries (marketers) have market power.

2 Industry Background

Natural gas transmission pipelines provide for the bulk of natural gas transportation within North America, often transporting commodities hundreds or thousands of kilometers from production locations to three main demand markets: electricity generation, local distribution companies (LDCs) primarily used for space heating, and industrial consumption. In comparison to other modes of domestic freight, pipelines transport the most tonnes-kilometers. Natural gas transportation in anything other than pipelines is complicated and often unprofitable.

In our analysis, we focus on interstate transmission pipelines. During the period we studied, from 2014 to 2023, the competitive landscape for pipeline systems remained quite stable, with very few entries and exits of operating pipelines. There were 69 interstate transmission pipelines in 2014 and 70 in 2023. During this period, there were three new entries and two exits (one exit due to abandonment and one through a merger and acquisition), but all involved relatively small regional pipelines. In Appendix A, we illustrate and elaborate on the cases of entry and exit. We plot the existing pipeline networks in Figure 1.[3]

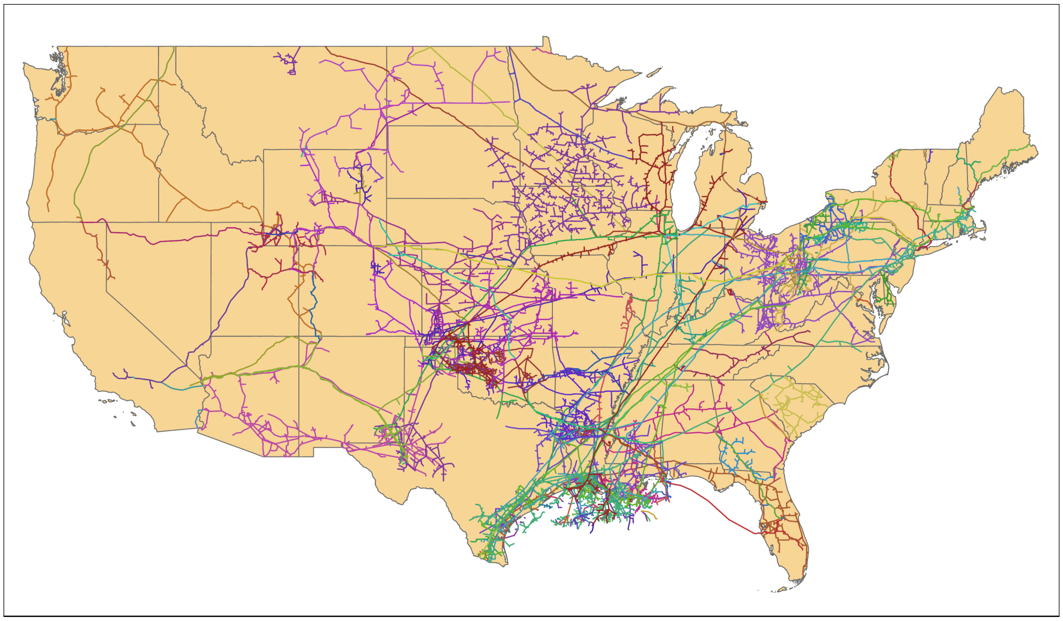


Figure 1: Natural Gas Pipelines in the U.S.

Source: The U.S. Energy Information Administration

Transmission pipelines are extremely costly to build, averaging $5 million/km with 10 to 20 years for the pipeline to break even on its investment. To share the risk associated with large sunk investment costs, the pipelines are required to sign long-term contracts (typically ten years or more) with customers prior to the pipeline construction, which entitles the customer to reserved capacity.

Long-term contracts in the natural gas transmission pipeline industry primarily focus on shipment capacity,[4] as shipment pricing is often heavily regulated. Within the U.S., the tolls/rates of natural gas transmission pipelines are directly regulated by the Federal Energy

[3]The geographic information for the natural gas pipeline system is obtained from the U.S. Energy Information Administration. Pipelines regulated by the Federal Energy Regulatory Commission are required to publish a quarterly index of customers. From the index of customers data, we infer the entry and exits of the pipeline companies. Further details about our data are provided in Section 3.

[4]A firm transportation contract grants capacity to a service requester at one or more points along a pipeline. Capacity is either specific as to both location (point) and quantity or is general as to location and specific as to quantity. A firm transportation contract gives a service requester the right to cause a TSP to receive a specific quantity of gas from that service requester at a point and/or deliver a specific quantity of gas to that service requester at a point over a specific time period.

Regulatory Commission (FERC). Pipeline rates are set to enable pipelines to recover all prudently incurred expenses associated with service delivery while also earning a reasonable profit. Regulators usually establish this by determining the revenue requirement for pipelines — the yearly revenue needed to maintain service and secure a fair return.[5] In Appendix B, we provide further details on rate regulation within the pipeline industry.

While long-term contracts in the primary market help reduce investment risks, they can introduce substantial frictions in capacity allocation amidst fluctuations in the natural gas supply and demand, thereby obstructing gas delivery to customers in need. The secondary market has emerged to address these frictions. In this market, service requesters who hold long-term contracts in the primary market can trade their contractual rights. This process, known as "Capacity Release," allows for the sale of all or part of a contract holder's rights for varying durations, ranging from less than a month up to the entire contract length.

Figure 2 illustrates the interactions between the primary and secondary markets. Within the capacity release market, those holding primary contracts are known as *releasers*, and their counterparts are referred to as *replacers*.

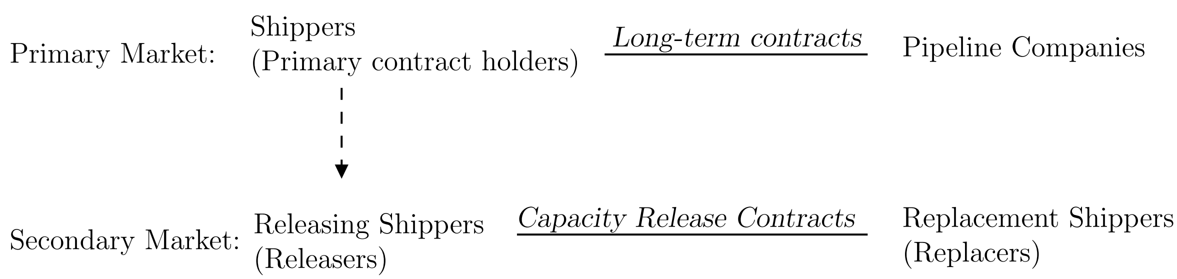


Figure 2: Relationships of the primary and the secondary market

For primary contract holders, the value of transportation tends to rise when there are substantial price differentials between natural gas trading hubs. Consequently, we expect to observe increased capacity releases from these customers when such differentials widen. Additionally, it is important to note that many natural gas end-users either do not possess transportation capacity on interstate pipeline systems or are not connected to natural gas

[5] A typical revenue requirement will be comprised of the following:

$$Operations\&Maintenance\ Costs + Taxes + Depreciation + Return = Revenue\ Requirement$$

Looking more specifically at the "fair" return for a pipeline in the cost of service regulation terminology, the return is typically determined through a rate base. A rate base is defined as a pipeline's gross plant in service less its accumulated depreciation. You then earn a return based on an assumed capital structure the regulator sets. Those portions of debt and equity then earn a return based on your cost of debt and cost of equity, both of which are determined by the regulator. The cost of debt is typically based on a pipeline's outstanding debt. In contrast, the cost of capital is determined through regulatory proceedings utilizing various financial models to determine an appropriate cost of equity for the pipeline based on similarly risky assets (mainly other pipeline systems).

distribution utilities. These customers are often industrial facilities, agricultural operations, smaller power generation facilities, and natural gas retailers. Thus, many of these natural gas end users rely on natural gas marketers to meet their gas needs, both in terms of supply and transportation.

These end users lack transportation capacity on pipelines mainly due to concerns about creditworthiness and balance sheet obligations. The credit obligations necessary for a company to hold pipeline transportation services are often steep, and most companies cannot meet them. For example, a typical credit evaluation criterion for firm service on a natural gas pipeline is to provide security guarantees for three months of firm service at the maximum tariff rate for the entire volume of your contract. This requires companies to have large amounts of cash on hand (in the form of an advance deposit), a strong standing letter of credit from a financial institution, an acceptable security interest in collateral, or a guarantee from a more credit-worthy parent company. As for the balance sheet obligations, given the take-or-pay nature of natural gas transportation firm service contracts, financial institutions view these transportation contracts as debt obligations. If a company were to take out large amounts of transportation capacity, this would result in a large liability on their balance sheet, which may impact their credit metrics, impacting their ability to secure their own financing and financial obligations.

Given these restrictive requirements, many of these end users rely on marketers to arrange for the supply and transportation of their gas needs. This comes at an increased cost to the end user, as marketers often require a service fee or markup for arranging the supply and transportation of natural gas.

Since these end users rely on marketers to provide them service when unexpected shocks in demand happen, either to end-use residential, commercial, and industrial demand (increased demand for natural gas retailers) or unexpected shocks in their various industries that do not impact demand for gas utilities/retailers (for example an increase in demand for steel production) they often turn to marketers to supply them with additional natural gas. While the primary market for natural gas transportation is mainly held by utilities to meet their regulatory obligations, they do not require the full use of their transportation capacity for most periods of the year. They would prefer to release that capacity to a marketer who will ultimately provide the transportation services to another end user.

3 Data

We utilize five datasets in our analysis—first, the index of customers data. An index of customers provides each specific contract on a pipeline system, including which shipper holds that contract, the start and end dates of the contract, the type and path of the service, the amount of pipeline capacity the shipper can utilize, and the contract rate. In the United States, pipelines regulated by the Federal Energy Regulatory Commission (FERC) are required to publish a quarterly index of customers from which we obtain our data. Second, we obtain the capacity release data from each pipeline system, which includes daily details such as the transaction date, type of contract, duration of the contract, rate, and options associated with the contract (such as recall or reput information).[6] Third, we observe the daily spot prices of natural gas at all US-based hubs, which Capital IQ Pro compiles. Fourth, we get the entire history of daily throughput between each origin and destination point on each interstate pipeline from Capital IQ Pro. This dataset provides the daily utilization rate of physical capacity within each pipeline system.[7] We obtained the first four datasets from 2014 to 2023. Last, we use geographic data from the U.S. Energy Information Administration (EIA) to gather information about the entire U.S. interstate natural gas pipeline system and the locations of major natural gas gateways and hubs, as well as daily average temperature across U.S. counties.

For the capacity release, index of customers and throughput datasets, we identify precise origin and destination points which we aggregate to U.S. counties. We further aggregate origin-destination points at the economic area level and we identify the closest natural gas hub from each origin and destination point.

This spatial mapping allows us to merge these datasets with natural gas prices at the nearest hubs for all origin and destination points on the pipeline system. It also allows us to match each origin and destination point with daily temperature data at the county level, which we use to construct exogenous extreme weather events.

3.1 Descriptives for the Primary Market

We first provide summary statistics for contracts in the primary market. Across our sample, the average duration of a long term contract is approximately eleven years, and pipelines tend to have a large number of shippers.

Next, we provide insight into the competitive landscape of the industry. The takeaway is that this is a fairly concentrated industry, with 50% of pipelines above standard thresholds of high concentration. Moreover, concentration has been increasing at the top (within already

[6] With the advent of the capacity release market, the FERC required pipelines to openly post the deals that their service requesters were seeking to transact (FERC Order No. 636, et al.).

[7] While all of this data is technically public information, most pipelines periodically delete information from past transactions, such as contracts signed in the capacity release market. We purchase the entire history of the capacity release market, throughput and spot prices at hubs from the Capital IQ Pro database to access historical data.

Table 1: Summary Statistics — Primary Market

	Shippers per pipeline	Contract Duration (Months)	Shippers per O-D Hub
Mean	97	140	30
5^{th}	2	10	1
25^{th}	12	41	3
Median	64	120	10
75^{th}	110	220	32
Observations	72 pipelines 3,739 shippers	382,983 contracts 9,762 active (2023q3)	38 Hubs 547 O-D hub pairs

Notes: All data is reported starting from 2014. Each contract specifies multiple origin and destination points, and there are 1,892,187 observations. Origin-destination (O-D) hub pairs are constructed by taking the nearest natural gas hub from each origin and destination point. Among all observations, 74% of the contracts are spatially identified. The remainder consist either of pooled contracts without specific origin/destination locations or contracts that we are unable to spatially identify.

concentrated pipelines). However, this hides substantial heterogeneity. We show how this heterogeneity is reflected across U.S. regions. We construct measures of concentration by the economic area of destination of contracted capacity. We find substantial heterogeneity within and across regions. The Midwest and Prairie region is extremely concentrated, and much less so for the East Coast and Rockies. Nonetheless, the majority of economic areas are well above thresholds for high concentration.

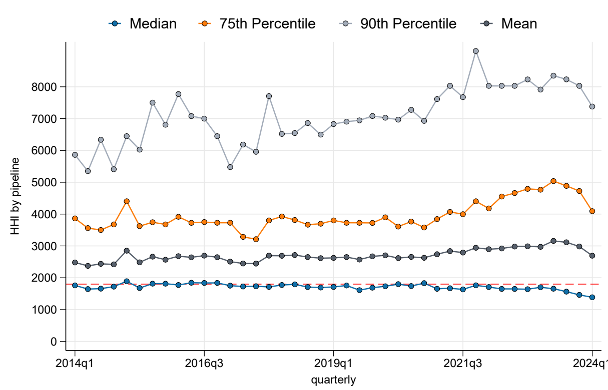


Figure 3: Primary Market: Quarterly HHI by Pipeline

Notes: Quarterly HHI are calculated by taking each shipper's quantity contracted on the pipeline relative total contracted pipeline capacity. We use quarterly measures because the index of customers is updated every quarter. The red dash line correspond to a standard high concentration threshold of 1,800.

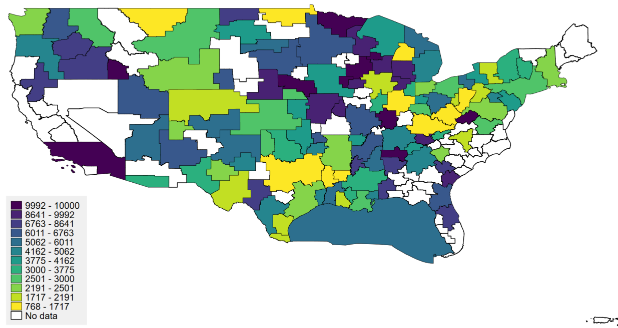


Figure 4: Primary Market: Average HHI by Economic Area of Destination

Notes: HHI for economic area of destination are constructed by taking each shipper's contracted capacity that is received in each economic area relative total contracted capacity received in that economic area (both within and across pipelines). We construct these HHIs at the quarterly level and average across quarters to create the map.

3.2 Descriptives for the secondary market

Next, we show similar summary statistics for the secondary market since 2024 in Table 2. Most contracts last a month, with some lasting half a year or a whole year. It is rare for a contract in the secondary market to last for more than a year. Figure 5 illustrates the distribution of contract durations.

Table 2: Summary Statistics — Secondary Market

	Releasing Shippers per pipeline	Replacement Shippers per pipeline	Contract Duration (Days)
Mean	87	113	125
5^{th}	6	8	2
25^{th}	29	35	29
Median	61	56	30
75^{th}	129	163	30
Observations	35 pipelines		491,797 contracts
	1,710 releasing shippers	1,297 replacement shippers	

Notes: Each contract specifies multiple origin and destination points, and there are 1.7 million observations. Sixty-seven percent of the contracts are spatially identified. The remainder are either pooled contracts without specific origin/destination locations or contracts that we cannot spatially identify. The summary statistics here include all contracts, whether spatially identified or not.

In the capacity release market, there are several options that a contract might include. Table 3 shows the percentage of contracts that feature these options. Most interesting is the fact that many contracts allow capacity to be recallable, meaning that the releasing shipper can recall its capacity at any point. Similarly for reputable contracts, capacity that was previously recalled can be "reput" to the replacement shipper. These options are necessary for many releasers who have regularity requirement to hold excess capacity to weather extreme

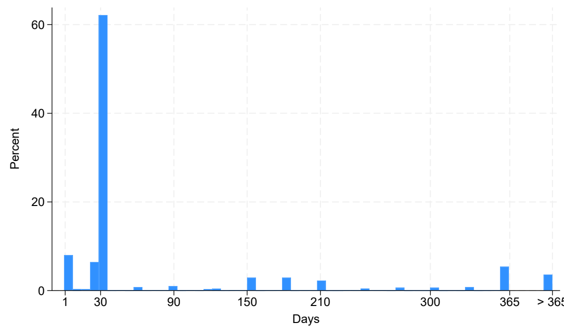


Figure 5: Distribution of Contract Duration (Days) — Secondary Market

demand shocks (e.g. utilities). This implies a high level of trust between parties, which naturally increases search costs, and favors the formation of long term relationships. To strenghten this argument, we find that almost every contract is signed as a private arrangement rather than through open auctions and the vast majority of releasing and replacement shippers meet multiple times.

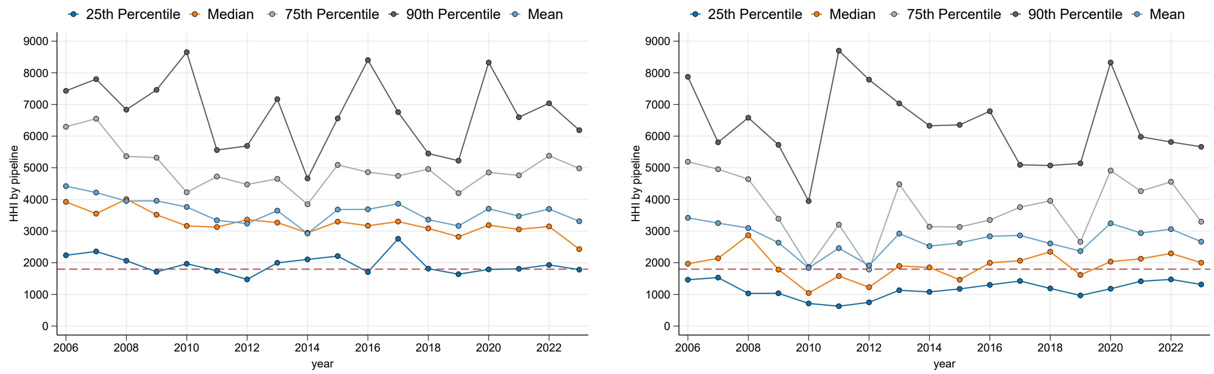
Year	Recallable	Reputable	Resale Allowed	Affiliate	Previously Released
2006	72%	58%	72%	0%	13%
2011	93%	65%	92%	1%	12%
2016	97%	78%	97%	0%	6%
2021	98%	78%	96%	0%	18%

Table 3: Percentage of Contracts with Different Options

Turning to the competitive landscape of the secondary market, we find even more concentration in the hand of releasers than in the index of customers. 75% of pipelines feature concentration of releasers above standard high concentration thresholds, compared to 50% in the primary market. This is partly explained by the fact that many releasers in the index of customers never release capacity. However, we find less concentration in the hand of replacement shippers.

Again, this hides substantial heterogeneity across U.S. regions. Similarly to the primary market, we construct measures of market concentration by economic area of destination. We find that many economic areas in the East Coast and the Deep South have concentration of replacement shippers (marketers) below standard high concentration thresholds, whereas the concentration of releasers is above is above the threshold.

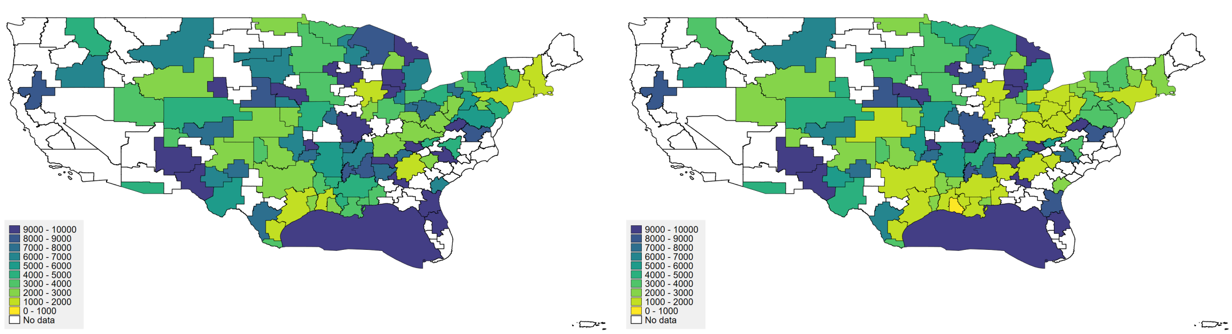
This variation in market concentration in both the primary and secondary market is economically important. As we show below, it helps explaining why some natural gas hubs face substantially different price increases during periods of extreme weather events, and why some shocks to natural gas prices are much more persistent in some hubs than others



Releasing Shippers | Replacement Shippers

Figure 6: Annual HHI by Pipeline in the Secondary Market

Notes: Annual HHIs are constructed by taking the total capacity that was released in a given pipeline and year, then breaking it down by releasing shippers (left) and replacement shippers (right). The dashed red line corresponds to a high concentration threshold of 1,800.



Releasing Shippers | Replacement Shippers

Figure 7: Average HHI by Economic Area of Destination in the Secondary Market

Notes: Average HHIs are constructed by taking the total capacity that was released from any point of origin to a given economic area of destination, then breaking it down by releasing shippers (left) and replacement shippers (right). We do this exercice by year, and then aveage annual HHIs to construct the maps.

3.3 Interactions between the primary and secondary markets

Regarding the capacity release market, we first demonstrate its economic importance. Table 4 shows the amount released in the secondary market compared to the primary market. The percentage of the amount released is calculated at the Pipeline-Shipper-Quarterly level, using the Max Daily Transport quantity as a basis. The result shows that in any quarter, on average 30% of capacity is being traded on the secondary market.

Table 4: Amount Released in Comparison to IOC Data (Quarterly)

	p25	p50	p75	Mean
Proportion of quantity released	2.3%	6.8%	25.0%	32.4%

Next, we examine the percentage of shippers participating in the capacity release market at any point during the contract period. Table 5 reveals that 46% of shippers holding long-term contracts participate in the capacity release market at least once. This underscores the significant importance and active usage of the secondary market in this industry. However, it also explains why the secondary market is more concentrated than the primary market. The data therein highlights substantial variations in both the number of capacity releases and the number of participants in the secondary market across different pipeline systems every quarter.

Table 5: Number of Shippers that are Within the Secondary Market

Not in the Capacity Release Market	2,009	54%
In the market	1,710	46%
Total	3,719	100%

4 Emprical Model and Results

Our analysis then proceeds as follows: We first establish that the secondary market is an important market constituent in periods of extreme shock. We then investigate how the presence of high search costs affect the behavior of market participants during these extreme events. Second, we show how variation in market concentration on both sides of the market affect transportation tariffs from the secondary market. We then show how this can cause a lack of regional integration between hubs during extreme events, both contemporaneously with high price differential across hubs and inter-temporally with highly persistent price differentials.

4.1 Event Study – Investigation of a Cold Wave

February 2021 Cold Wave

In February 2021, an extraordinary cold wave, driven by a polar vortex's southward shift following a sudden stratospheric warming, swept across Canada, the United States, and northern Mexico. This rare meteorological event led to severe winter storms, unprecedented snow, and cold temperatures in states forming the deep south, such as Texas, Oklahoma, and Arkansas.

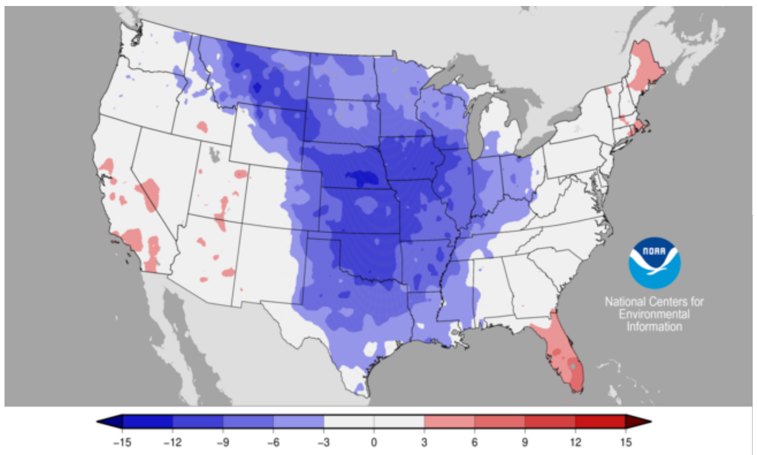


Figure 8: Temperature Deviation from Historical Average – February 2021

Notes: Temperatures are expressed as deviation (in Fahrenheit) from average temperatures during the 20^{th} century across 5km grid points. Source: National Center for Environmental Information (NCEI).

This cold wave led to an unexpected demand increase for home heating, affecting demand for natural gas as a direct heat source for homes and indirectly through electricity generation. In states such as Texas, natural gas directly heats 35% of homes, and electricity heats the remaining 65%. Meanwhile, natural gas is responsible for over 50% of electricity generation.[8] We expect this cold wave to have led to unprecedented pressure on natural gas pipelines, not only due to the unexpected rise in demand but also as some pipeline segments froze and burst, disrupting some of the supply.[9]

In this section, we investigate the secondary market's role in allocating natural gas capacity during the cold wave, as well as some of the mechanisms underlying this effect and potential trade-offs associated with the secondary market. We first investigate a simple difference-in-difference event study that allows us to compare outcomes between treated and

[8] Texas uses natural gas for electricity generation and home heating.
[9] February 2021 North American cold wave.

control pipelines throughout the cold wave. Outcomes such as contracted quantity may have persisted in the weeks following the shock because the end date was not known ex-ante.

Defining Control and Treatment Pipelines

To define control and treatment pipelines, we looked at interstate pipelines with a similar activity ratio in the secondary market relative to the pipeline's total capacity and location. We chose El Paso Natural Gas Company as a treated pipeline, which transports gas from the San Juan, Permian, and Anadarko basins to selected states, including Texas and Oklahoma. The El Paso pipeline is a good candidate because it covers most hubs that saw massive hikes in natural gas prices relative to prices at Henry Hub during the cold wave. Prices in southwestern Texas and southeastern California rose between 10 and 25 times the national benchmark due to the unprecedented uptake in demand. Panel (b) of Figure 9 shows the map of the treated pipeline with selected hubs.

(a) Control Pipeline

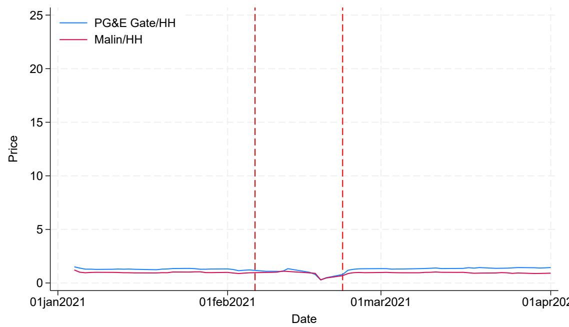
(b) Treated Pipeline

Figure 9: Treated and Control Pipeline Maps with Selected Hubs

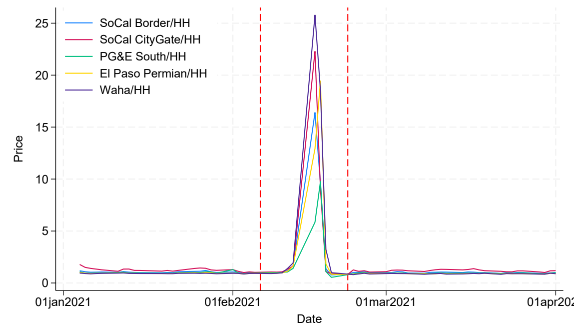
As a control, we chose the Gas Transmission Northwest pipeline (GTN), which takes gas from Western Canada and takes it to Northern California—in contrast to abnormal weather variation in Texas, Figure 8 indicates that Northern California was not affected by the cold wave because temperature did not deviate from historical averages. Panel (a) of Figure 9 shows the control pipeline map.

To further validate the categorization of treated and control groups, we calculate the price of natural gas at selected hubs served by treated and control pipelines relative to the Henry Hub benchmark. Figure 10 shows the prices. We can see that during and after the cold wave, the relative prices at control hubs are quite stable. However, for treated hubs, there is a spike in gas prices during the cold wave.

As discussed by Marmer, Shapiro and MacAvoy (2007), the possibility for arbitrage could imply that the entire pipeline network is treated as intermediaries buy gas from unaffected



(a) Relative Price at Control Hubs



(b) Relative Price at Treated Hubs

Figure 10: Prices relative to Henry Hub

Notes: This figure plots the price of natural gas at selected hubs served by treated pipelines relative to the Henry Hub benchmark. The dotted red lines correspond to the official beginning of the cold wave (February 6^{th}, 2021) and the end of the cold wave (February 22^{nd}, 2021)

regions (here, the West Coast) and sell it in affected regions (the Deep South). However, such arbitrage would increase demand at unaffected hubs and raise gas prices. We do not see a large price rise at unaffected hubs such as Malin and PG & E City gate (which serves San Francisco). Just as Marmer et al. (2007) found, there are likely important bottlenecks in the system preventing arbitrage between regions far away from each other. While the El Paso pipeline is a larger pipeline system than the GTN pipeline, the average percentage of capacity from the capacity release market is similar across both pipelines.

4.2 Difference-in-Difference Analysis

We perform a difference-in-difference event study with a single treated pipeline and a single control pipeline, allowing us to investigate the effect using a parsimonious two-way fixed-effects specification. We cannot rule out anticipation as shippers try to predict adverse weather events. Such extreme events may be correlated with temperature patterns over an extended period, such as an abnormally cold winter. We also cannot rule out persistent effects because shippers make decisions on capacity release without knowing the end date of the demand shock and may want to air on the side of caution in the aftermath of the cold wave. Polar vortices can last from a few days to multiple months.

We allow for anticipation and persistence by investigating the effect in a larger window around the cold wave. As Figure 11 suggests, capacity released in the secondary market during the cold wave significantly increased in the El Paso pipeline (by 30% immediately following the beginning of the cold wave). It did not increase in the GTN pipeline. However, there was also a significant increase in capacity release for El Paso relative to GTN one month prior to the cold wave, which persisted up to one month after the cold wave.

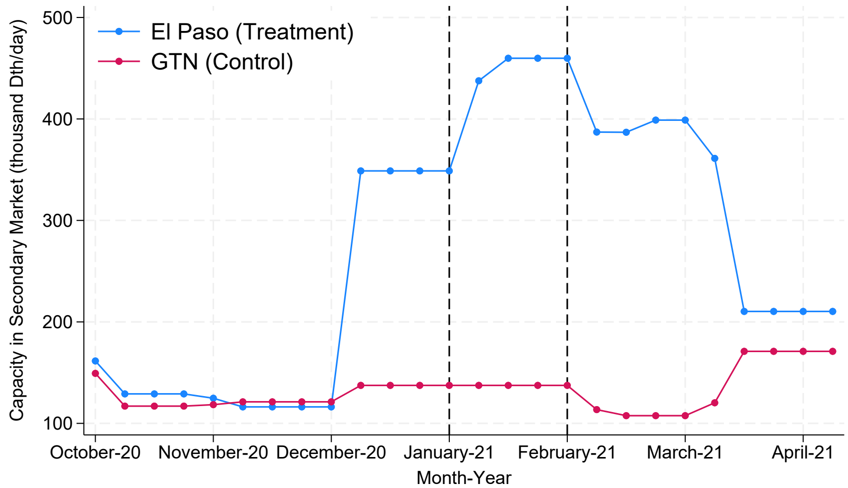


Figure 11: Total Capacity in Secondary Market by Pipeline

Notes: The outcome variation displayed in this figure is the total capacity available in the secondary market each week. It is constructed by aggregating all contracts signed on previous dates with contracted capacity released during the current week. In the time axis, each month's tick corresponds to the end of the month. The dashed black lines correspond to the cold wave's beginning and end.

We also need to account for important seasonal variations across both pipelines. A careful look at the time series of capacity released in the secondary market outside of the window around the cold wave suggests a very distinct time series across pipelines. Much of the variation around the cold wave may obfuscate important seasonal patterns. Much of this variation can be attributed to pipeline-specific seasonal variation, in which different shippers make recurring contracts with each other. For example, utilities may lease some of their capacity to power plants every summer.

As shown in the main specification below, we allow for heterogeneous seasonal variation across pipelines to account for this rich heterogeneity. To study the causal effect of the 2021 cold wave on capacity released, we then propose the following two-way fixed effects specification:

$$y_{it} = \alpha_i + \alpha_t + q_{it}^T \delta + \sum_{m=-5}^{10} \beta_m D_{i,t-m} + \epsilon_{it} \tag{1}$$

Where i indexes pipeline, t indexes weeks. y_{it} is the log of capacity available in week t from the secondary market. q_{it} are pipeline-specific seasonality controls. These include week of the year (1-52) and year of observation. $D_{i,t-m}$ is a treatment indicator defined as follows:

$$D_{i,t-m} = \begin{cases} 1 & \text{if } i \text{ is treated and we are } t-m \text{ weeks relative to start of cold wave} \\ 0 & \text{otherwise} \end{cases}$$

The outcome variable y_{it} aggregates all contracts signed at previous dates $t-k$ that have contracted capacity to be released at t. Since most contracts are signed for one month, there is mechanically a lot of auto-correlation in y_{it}. We cluster standard errors at the monthly level to conduct autocorrelation-robust inference within 30-day periods.

To visualize the results, we follow the approach of Freyaldenhoven, Hansen and Shapiro (2019) by normalizing the treatment effect one week before the shock, plotting the cumulative treatment effect in a window around treatment. Under a null hypothesis that the cold wave was not anticipated, lasted throughout February (4 weeks), and did not have persistent effects, the cumulative treatment effect would be defined as:

$$\gamma_k = \begin{cases} 0 & \text{for } k < 0 \\ \sum_{m=0}^{k} \beta_m & \text{for } 1 \leq k \leq 4 \\ 0 & \text{for } k > 4 \end{cases}$$

However, as discussed earlier, shippers may anticipate an abnormally cold winter as they predict natural gas requirements before the winter starts. As discussed previously, there is likely much persistence in these treatment effects since contracts are signed without knowing when the cold wave will end. For these reasons, we plot an estimate of the cumulative effect up to five weeks before and ten weeks after the beginning of the cold wave, along with 95% confidence intervals. We then define estimates of the cumulative event path as follows:

$$\hat{\gamma}_k = \begin{cases} \sum_{m=-k}^{-1} \hat{\beta}_m & \text{for } -5 \leq k < 0 \\ \sum_{m=0}^{k} \hat{\beta}_m & \text{for } 0 \leq k \leq 10 \end{cases} \tag{2}$$

To investigate anticipation and persistence more formally, we also present the results from a specification that aggregates the effect up to 2 months prior to the cold wave and two months after the cold wave using the following specification:

$$\begin{aligned} y_{it} = \alpha_i + \alpha_t + q_{it}^T \delta + \underbrace{\beta_d D_{i,t \in dec20} + \beta_j D_{i,t \in jan21}}_{\text{Treated pipeline two months before}} + \beta_f D_{i,t \in feb21} \\ + \underbrace{\beta_m D_{i,t \in mar21} + \beta_a D_{i,t \in apr21}}_{\text{Treated pipeline two months after}} + \epsilon_{it} \end{aligned} \tag{3}$$

4.3 Results — El Paso (treatment) and GTN (control)

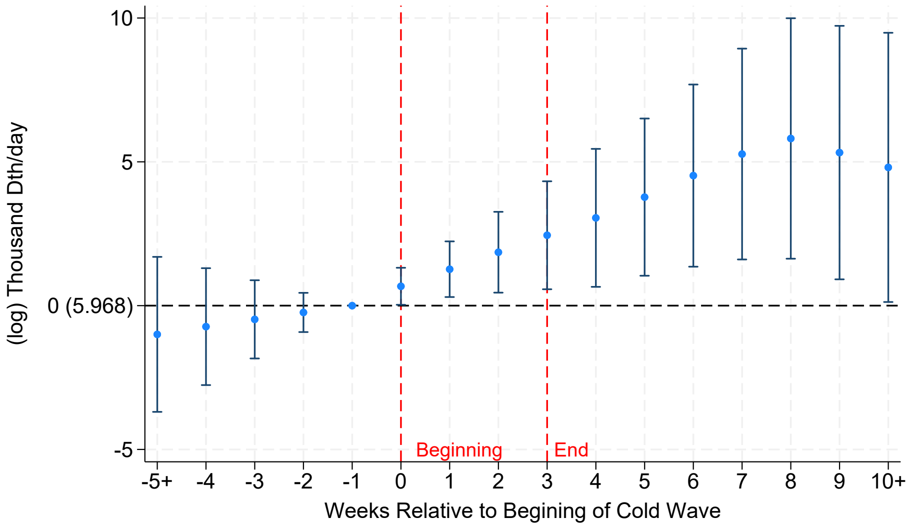


Figure 12: Baseline Cumulative Event Path

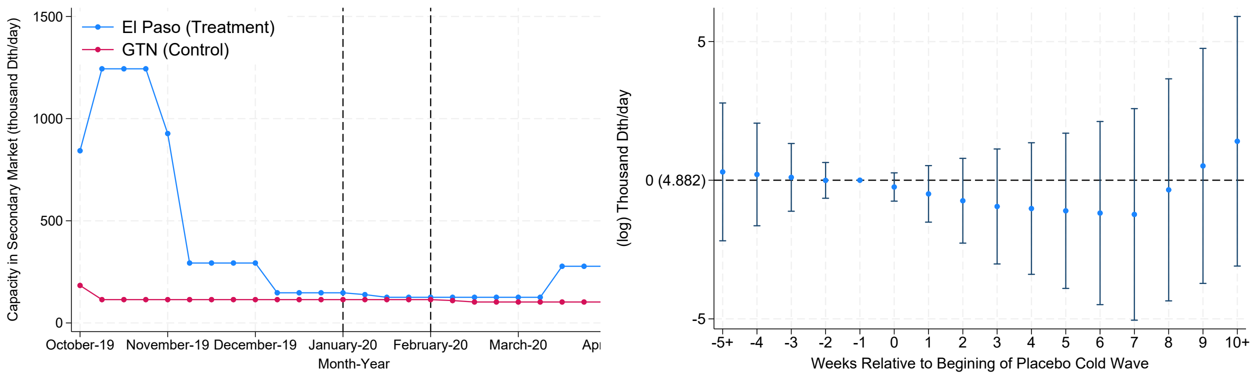
Notes: This figure plots the event path specified in equation 2 along with 95% confidence intervals. Specifically, we plot the cumulative effect of the February 2021 cold wave on the quantity of pipeline capacity contracted in the secondary market. Specifically, this quantity is defined as the total quantity released in the current week, aggregating all contracts signed prior to and up to the current week. We do so because many contracts are often signed weeks before the capacity is released. We exclude contracts that are signed for periods of one year or more.

Figure 12 shows the estimated cumulative event path from the main specification in Equation 1. While we do not find statistically significant violations of the pre-trend assumption, these results do not suggest a lack of anticipation. Rather, it should be interpreted as a lack of anticipation that the cold wave would start earlier than planned. Anticipation is directly embedded in the outcome variables, aggregating previously signed contracts. On the other hand, we find large and significant persistent effects many weeks after the cold wave, suggesting that shippers did not know when the demand shock would end. Overall, the cold wave caused an increase in capacity release by an average of 50% across the duration of the cold wave. See Table 6.

To further validate these findings, we performed a robustness check by imposing a placebo cold wave one year before, in 2020, and found no evidence of a placebo treatment effect.

Secondary Market and Search Costs

To investigate trade-offs associated with a deregulated secondary market, we first provide evidence that the cold wave, interpreted as a demand shock, increased the search cost between a releasing and a replacement shipper. As argued previously, the secondary market



(a) Total Capacity In Secondary Market by Pipeline

(b) Cumulative Event Path

Figure 13: Placebo Cold Wave (One Year Before)

Table 6: Main Results — Average Effect of Cold Wave on Capacity Release

	Real cold wave (log) Capacity	Placebo cold wave (log) Capacity
$\mathbb{I}$(Two Months Before x Treated)	0.251	0.349
	(0.376)	(0.405)
$\mathbb{I}$(One Month Before x Treated)	0.215	-0.112
	(0.336)	(0.331)
$\mathbb{I}$(During x Treated)	0.579*	-0.203
	(0.237)	(0.242)
$\mathbb{I}$(One Month After x Treated)	0.674*	-0.130
	(0.280)	(0.278)
$\mathbb{I}$(Two Months After x Treated)	-0.266	0.624*
	(0.338)	(0.294)
N	1,278	1,278
adj. R^2	0.784	0.782

Notes: Standard errors in parentheses. $^{+}$ $p < 0.10$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Notes: these results are exactly as specified in Equation 3. As such, they are not the cumulative treatment effects but the average treatment effect across the specified period. The first column presents results with the real cold wave whereas the second column presents results for the placebo cold wave (one year earlier), including two months before and after this placebo cold wave.

provides a mechanism to reduce these search costs by fostering the formation of long-term relationships. Indeed, more than 95% of contracts in the secondary market are private arrangements between shippers, and shippers often use these private arrangements to form long-term relationships. We now argue that these long-term relationships are crucial when shippers face large unexpected demand shocks such as the cold wave of 2021.

To be consistent with our classification in Section 3, we group all contracts from the secondary market into two categories: contracts between shippers that met less than five times in the past (which we call new relationships) and contracts between shippers that met more than five times in the past (which we call long-term relationships). Below is the distribution of relationship frequency between shippers:

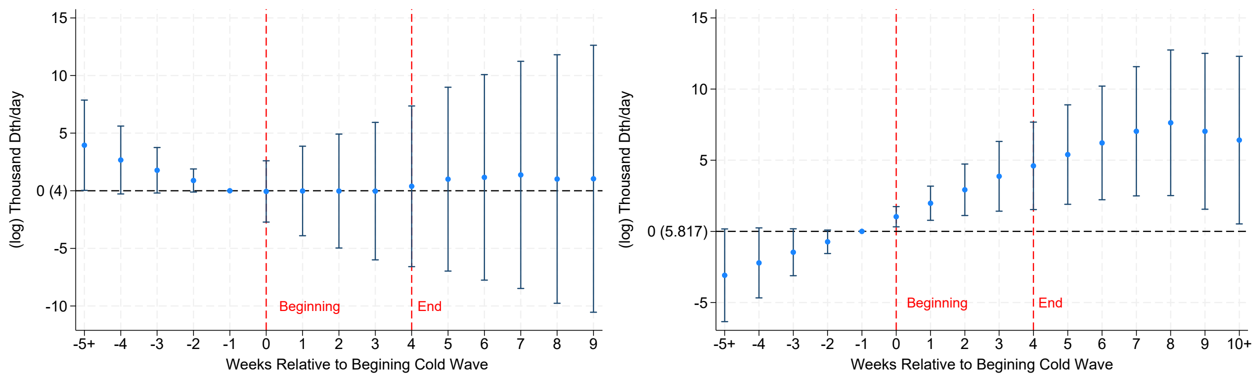
Table 7: Distribution of Relationship Frequency by Pipeline

Frequency of Identical Shippers Signing Contracts	El Paso (Treatment) *Percentage (%) of Contracts*	GTN (Control) *Percentage (%) of Contracts*
Never met	1	2
Met >0 but ≤ 5 times	22	9
Met >5 but ≤ 10 times	18	16
Met >10 but ≤ 15 times	15	10
Met >15 but ≤ 20 times	8	5
Met >20 but ≤ 25 times	9	25
Met >25 but ≤ 30 times	7	5
Met >30 times	20	28
Total	100	100

Notes: The distribution corresponds to the percentage of unique contracts signed between shippers.

We then re-estimate the two-way fixed effects regression of equation 1 separately by groups. When grouping the contracts by relationship frequency in Figure 14, we find that the effect of the cold wave on capacity released is overwhelmingly driven by long-term partners. Moreover, the effect nearly doubles when narrowing down on long-term partners. On average, we find that the cold wave caused an increase in capacity between long-term partners by approximately 90%.

Finding new partners has a high search cost, and in times of unexpected shock, the opportunity cost of searching is high. For this reason, shippers reduce the search cost by leveraging their existing relationships. Moreover, the secondary market provides a platform for shippers to form new relationships during normal times, which can be leveraged during shocks. In this context, the secondary market provides a mechanism to reduce the search cost. Due to the FERC regulation, which mandates that all contracts be posted on public platforms, the secondary market fosters the formation of long-term relationships by providing

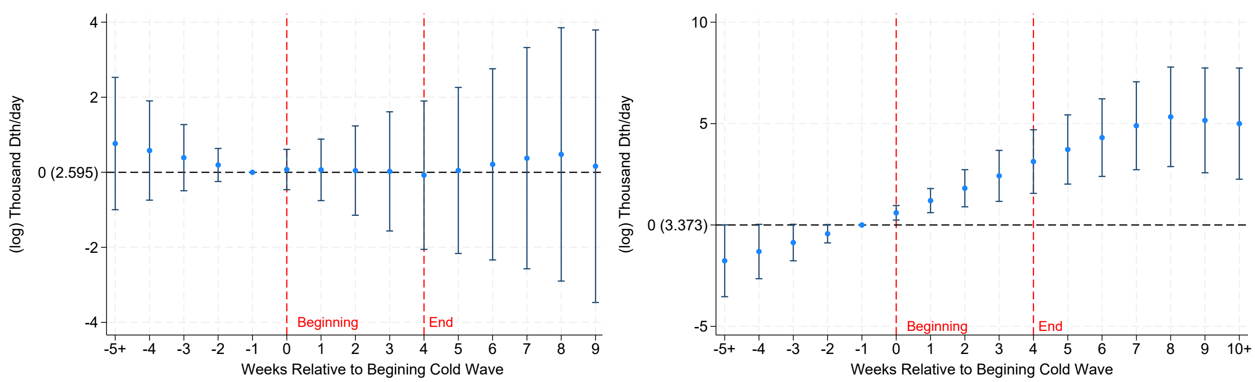


(a) Shippers met < 5 times **(b)** Shippers met ≥ 5 times

Figure 14: Cumulative Event Path by Relationship Length

shippers with daily information on the key players in each market.

We further substantiate this narrative that the cold wave is associated with a higher opportunity cost of searching by looking at the characteristics of contracts during the cold wave. Indeed, what drives the main result is not an increase in the number of contracts, which would be costly, but rather an increase in the average quantity released by contract.



(a) Number of Contracts **(b)** Quantity per Contract

Figure 15: Event Path – Number of Contracts and Quantity per Contract

While this narrative on search costs is broadly consistent with the literature, there is one key difference. In the literature on intermediation with search costs (Spulber, 1996; Gehrig, 1993), it is often assumed that parties on two sides of a market can either engage in search or go through an intermediary to avoid search costs. In our case, the margin to reduce search cost is forming relationships between an intermediary (the replacer) and a releaser. This means that the presence of an intermediary does not eliminate search costs. We also argue that both releasers and replacers engage in search. The replacers search for available capacity when they face arbitrage opportunities between hubs. Releasers search for buyers

Table 8: Average Effect of Cold Wave — Extensive and Intensive Marigns

	(log) Number of Contracts	(log) Average Quantity per Contract
$\mathbb{I}$(Two Months Before x Treated)	1.146***	-0.895**
	(0.141)	(0.290)
$\mathbb{I}$(One Month Before x Treated)	-0.194	0.409^{+}
	(0.125)	(0.229)
$\mathbb{I}$(During x Treated)	0.003	0.577***
	(0.126)	(0.166)
$\mathbb{I}$(One Month After x Treated)	0.084	0.589**
	(0.152)	(0.174)
$\mathbb{I}$(Two Months After x Treated)	-0.229	-0.037
	(0.160)	(0.210)
N	1,278	1,278
adj. R^2	0.726	0.860

Notes: Standard errors in parentheses. $^{+}$ $p < 0.10$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

when they do not need capacity to avoid paying reservation fees for unused capacity.

Market Shares

While the secondary market provides a platform for shippers to reduce search costs of releasing capacity, it is also largely unregulated. For the majority of contracts signed, releasing and replacement shippers can freely negotiate a contract rate, which can be below, equal, or above what the releaser pays to the pipeline.[10] Deregulation can incentivize market participants to engage in the secondary market but can also introduce market power, causing friction. In the data section, We investigated market concentration across different pipelines and economic areas. We found evidence of highly heterogeneous market concentration across regions.

Table 9 summarizes market concentration across selected pipelines with considerable activity on the secondary market. We find substantial variation in market power across pipelines. For example, the Great Lakes (GL) pipeline has a high concentration of replacers and releasers, whereas El Paso has a low concentration of replacers but a high concentration of releasers. We also find lots of variation in average tariffs relative to the tariffs. Since the FERC sets these maximum tariffs specific to delivery and receipt points, they vary widely across contracts and provide a benchmark for comparing tariffs. However, Table 9 does not suggest a monotonicity between releaser/replacer market power and prices. For example,

[10]There are some exceptions. Certain contracts cannot have a rate above some maximum threshold the FERC sets. This constraint is based on the contract duration. Tariffs on capacity released for 31 days or less or one year or more can vary freely. Tariffs on capacity released between 31 days and one year cannot exceed the maximum tariffs. As Figure 5 suggests, the vast majority of contracts fall within the fully deregulated time constraints.

Table 9: Market Concentration and Tariffs (Secondary Market) — Selected Pipelines

	Replacer HHI	Releaser HHI	$P < Max$	$Price = Max$	$P > Max$	$P = 0$
El Paso	1,660	4,821	0.81	0.15	0.04	0.21
GTN	1,723	4,746	0.21	0.75	0.04	0.03
GL	5,366	5,491	0.48	0.51	0.01	0.33
NGPL	1,529	1,769	0.68	0.24	0.08	0.09
Texas Eastern	2,708	1,586	0.50	0.42	0.08	0.32
Transwestern	1,889	2,685	0.95	0.03	0.02	0.15

Notes: In this Table, P refers to the tariff charged for a specific section of a contract in the secondary market, and always has two parts: a reservation fee and a volumetric charge based on gas flown. For example, a shipper can release capacity between delivery point A and receipt point B and between delivery point B and receipt point C. In this case, there would be four prices. Max corresponds to the maximum tariff set by the FERC for those four prices. HHI refers to the Herfindahl–Hirschman index.

both El Paso and GTN have a high concentration of releasers relative to replacers, and tariffs are significantly more likely to be below the maximum in El Paso.

We now relate this variation in market concentration to capacity release tariffs and find that releasers (replacers) with a higher market share tend to charge higher (lower) prices, and that this effects increases by 50% during cold waves. Specifically, we investigate variation in market shares at the individual releaser/replacer level with the following regression model:

$$\ln \tau_{ict}^{od} = \alpha_t + \alpha_{od} + \alpha_c + \beta_1 \ln s_i^{od} + \beta_2 Dtreat_t^{od} + \beta_3(\ln s_i^{od} \times Dtreat_t^{od}) + \gamma' z_{ict}^{od} + \epsilon_{ict}^{od}$$

Where α_t denotes time (daily) fixed effect. α_{od} denotes origin-destination pair fixed effect. α_c denotes pipeline fixed effect. $\ln s_i^{od}$ denotes participants' log of historical (annual) market share in origin-destination pair. These market shares are constructed at the nearest hub of origin and nearest hub of destination level. We include two separate variables for these market shares, one for releasers and one for replacers. $D_{treat_t^{od}}$ denotes extreme weather indicator. Extreme weather indicators are equal to one only when the destination faces a weather shock while the origin doesn't. We define extreme cold (hot) weather when the counties nearest to each destination hub have a number of cooling (heating) degree days relative to historical average above the 95^{th} percentile. Control variables z_{ict}^{od} include the maximum rate allowed (even if it is not binding) and monthly throughput.

The results in Table 10 suggest a strong relationship between market share and tariffs charged, both for replacers and releasers, suggestive of price-setting behavior. Moreover, this relationship is significantly larger for releasers. Remembering that releasers benefit from higher tariffs (supply) and replacers benefit from lower tariffs (demand), a 1% increase

Table 10: Effect of Releaser and Replacer Market Share on Transportation Tariffs — Secondary Market

	(1)	(2)
	$\ln \tau_{ict}^{od}$	$\ln \tau_{ict}^{od}$
ln(Releaser Share)	0.304***	0.303***
	(0.001)	(0.001)
ln(Replacer Share)	-0.061***	-0.061***
	(0.001)	(0.001)
Cold Wave		-0.034
		(0.025)
Cold Wave × ln(Releaser Share)		0.137***
		(0.008)
Cold Wave × ln(Replacer Share)		-0.036***
		(0.006)
N	1,381,934	1,381,934

Standard errors in parentheses
* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Notes: In this Table, we only included the interaction with cold waves because extreme heat waves do not have a statistically significant impact on transportation tariffs. This is not just true for tariffs, but also for quantity released in the secondary market and other regressions specified in this paper. We also investigated different thresholds for cold waves and found similar results.

in releaser market share is associated with a 0.3% increase in tariffs, whereas a 1% increase in replacer market share is associated with a 0.06% decrease in tariffs. Both these effects increase by 50% during cold waves, where a 1% increase in releaser market share is associated with a 0.44% increase in tariffs, whereas a 1% increase in replacer market share is associated with a 0.1% decrease in tariffs.

These results are suggestive of two-sided market power. In such a context, it is unclear what the welfare implications of partially deregulating the natural gas transportation industry through its secondary market are. On the one hand, the secondary market allows tariffs to vary over time and respond to fluctuations in supply and demand. These tariffs are otherwise constant and set by long-term contracts in the primary market, which may prevent the efficient allocation of capacity, particularly during shocks. On the other hand, Deregulation of pipeline capacity implies that market participants influence tariffs based on their market share, as seen in Table 10, which may restrict the allocation of capacity. With that in mind, we build a simple theoretical model in the next section to understand the implications of two-sided market power.

Market Concentration

Now that we established that market shares impact transportation tariffs, we now show how spatial variation in market concentration on both sides of the market affects natural gas prices at different hubs during periods of extreme weather. We first do so by looking at contemporaneous variation in relative hub prices:

$$\ln|p_{dt} - p_{ot}| = \alpha_t + \alpha_{od} + \beta_1 HHI_t^{od} + \beta_2 Dtreat_t^{od} + \beta_3 \left(\ln HHI_t^{od} \times Dtreat_t^{od}\right) + \gamma' z_t^{od} + \epsilon_t^{od}$$

Where t indexes days, o indexes origin, d indexes destination. The main dependent variable of interest is the log of absolute difference in daily gas price at destination vs. origin $\ln|p_{dt} - p_{ot}|$. We take absolute value because we want to capture dispersion in prices. The main independent variables of interest are the annual origin-destination HHI_t^{od}, which are constructed separately from releasers and replacers market shares in the secondary market. The extreme weather indicator $Dtreat_t^{od}$ include cold waves, heat waves and 2021 February cold wave (all separately).

The main takeaway is that concentration in replacement shipper (marketers) significantly increases price differentials between hubs during cold waves. The effect is especially pronounced during the 2021 cold wave, but less so during other cold waves, and insignificant during heat waves. This is good for marketers, as it allows them to stay "in the money" when arbitraging between hubs. One way to interpret this finding is that replacement shippers

Table 11: Impact of Market Concentration on Relative Hub Prices — Contemporaneous

	Cold Waves	Heat Wave	Feb 21 Cold Wave
ln(Throughput)	0.200***	0.201***	0.201***
	(0.019)	(0.019)	(0.019)
ln(Capacity) *(thickness)*	-0.032***	-0.032***	-0.032***
	(0.005)	(0.005)	(0.005)
Extreme Weather x ln(HHIrep)	0.233*		
	(0.093)		
Extreme Weather x ln(HHIrel)	-0.026		
	(0.119)		
Extreme Weather x ln(HHIrep)		-0.069	
		(0.081)	
Extreme Weather x ln(HHIrel)		0.022	
		(0.110)	
Extreme Weather x ln(HHIrep)			1.225***
			(0.258)
Extreme Weather x ln(HHIrel)			-1.029*
			(0.439)
Observations	53,238	53,238	53,238

Standard errors in parentheses

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Notes: Control variables include monthly throughput and quarterly capacity from IOC (to capture market thickness).

have market power in the downstream gas market, allowing them to market prices in hubs where demand is high.

Lastly, we look at a similar impact of market concentration on the persistence of price differential across hubs during extreme weather events. We specify the following AR(1) regression:

$$\ln|p_{dt} - p_{ot}| = \alpha_t + \alpha_{od} + \rho_1 \ln|p_{dt-1} - p_{ot-1}| + \rho_2 \left(D_{treat_t^{od}} \times \ln|p_{dt-1} - p_{ot-1}|\right) + \gamma' z_t^{od} + \epsilon_t^{od}$$

We study the persistence of relative price shocks in three specifications: one including all observations, one only including origin-destination pairs where the replacer HHI is above the median HHI, and one only including origin-destination pairs where the releaser HHI is above the median HHI.

Table 12: Impact of Market Concentration on Relative Hub Prices — Persistence

	Baseline	High Releaser HHI	High Replacer HHI
ρ_1 (no cold wave)	0.599***	0.577***	0.603***
	(0.005)	(0.008)	(0.008)
$\rho_1 + \rho_2$ (during cold wave)	0.748***	0.778***	0.827***
	(0.079)	(0.103)	(0.153)
Observations	25,926	12,231	10,749

Standard errors in parentheses

* $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

Notes: Control variables include monthly throughput and quarterly capacity from IOC (to capture market thickness).

The takeaway is that cold waves increase the persistence of relative price shocks between origin and destination hubs by a significant margin. The persistence of shocks increases with concentration on both sides of the market, suggesting that market concentration create frictions preventing prices from returning to normal.

5 Market Concentration as Unintened Consequences of Regulation (in Progress)

Many pipeline users (large utilities) are regulated entities who need to plan for "peak demand days".

- Causes these users to sign overly conservative long-term contracts with pipelines to reserve enough capacity to withstand extreme demand.
- These overly conservative long-term contracts contribute to market concentration in the secondary market for capacity release. The secondary market is an important market segment allowing small firms (smaller gas users) to have access to natural gas.

Thus, we hypothesize that peak-day regulation creates a negative network externality which is imposed on small users of natural gas (represented by marketers) who do not have long-term contracts with pipelines. We this this is particularly relevant in contexts of large aggregate demand shocks.

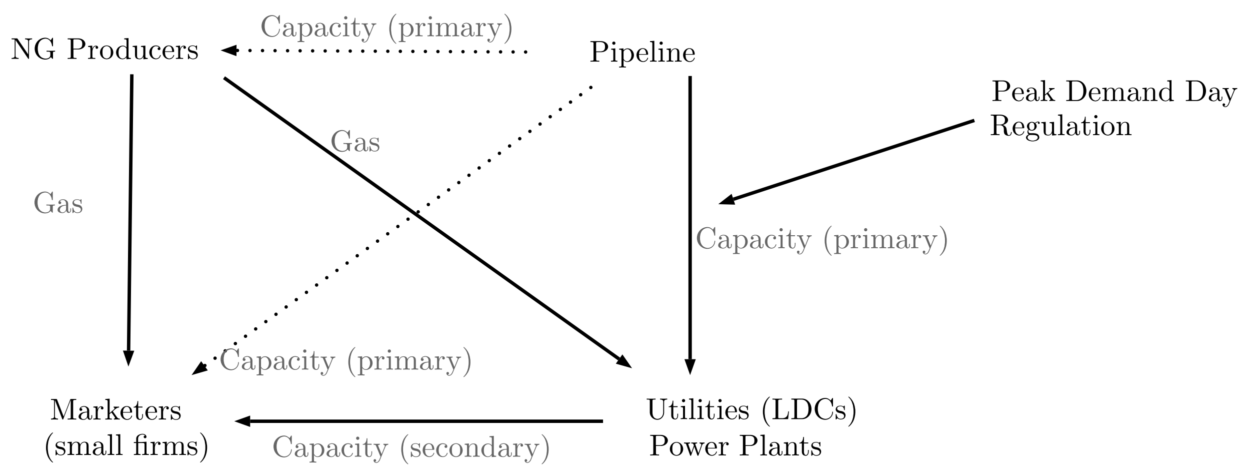


Figure 16: Overview of Market

Notes: Dash lines represent relations that exist, but are less common. We abstract from these relationships. We also abstract from power plant regulations, which are more consolidated but also very different. They affect the entire grid network, not just individual power plants. For example, an individual natural gas-powered power plants may only be turned on during peak demand periods. These plants are known as "peaking power plants".

5.1 Overview of what we do in this section

- We leverage variation in state-level regulation, particularly the stringency of peak-day regulation, to study how market concentration affects gas prices and quantity supplied during peak demand periods.
- To do so, we build a structural model of the natural gas pipeline network, taking as given the distribution of long-term contracts between pipelines and large gas users.

- The structural model allows us to study the following **counterfactual**: what would happen if regulators we concerned about the entire network of gas users in their state rather than large individual utilities? Taking into account that pipeline capacity is a tradable asset which can be traded in an unregulated secondary market.
  - In practice, we study various reshuffling mechanisms of primary market contracts. Importantly, we do not wish to tell policymakers what to do, but to raise awareness about the unintended consequences of peak demand day regulations.

5.2 Regulation Stringency Index

We want to create a regulation stringency index which varies by state. While utilities are very familiar with the concept of peak-demand day (or "design day") regulation, creating the index is non-trivial. The structure of regulation is not consolidated across states. Public Utility Commissions (PUCs) and Public Service Commissions (PSCs) generally oversee the regulation of utilities.

However, most regulation seems to be in the form of legal recourse against utilities that do not meet their targets, such as fines and compensation to consumers for disruption of services. The kind of legal recourse that state commissions can use varies based on how much authority they have (precedents in courts, etc.). In many states, commissions lack the authority to mandate utilities to compensate customers, but in some states such as NY, there are well-established compensation mechanisms. Depending on the type and stringency of regulation, utilities can use different tools to plan for peak demand day and will be more/less conservative.

Once we have the regulation stringency index, we want to investigate how much of the variation in regulation is correlated with variation in primary market concentration.

5.2.1 Alternative ways to think about regulation

If we cannot get a good measure of variation in regulation stringency for utilities across US states, we can study the predicted level of concentration in a market based on the composition of shippers. The following should hold:

- For peak demand day regulation to matter for concentration (HHI), we need that some shippers are not utilities. Otherwise, they will all increase/decrease contracted capacity and concentration doesn't change.

- If there are other, less regulated shippers that hold long term contracts, then a higher share of shippers that are utilities increases concentration (keeping the number of shippers constant)

- Keeping everything else constant, a higher number of utilities decreases concentration. Same is true for the number of shippers that are not utilities.

Is there a way to use this information such that we can map observed HHI to number of shippers/share of shippers that are utilities?

Counterfactual is still reshuffling the contracts by changing regulation stringency, but impact of changing stringency will be different in different states

5.3 Structural Model

Overview — Baseline

We separate the model in two sub-parts to think realistically about uncertainty. In any period, shippers who hold long-term contracts with pipelines first decide what capacity to release to the secondary market (Cournot Oligopoly) given some information about their future demand, trading off revenues from secondary market with the ability to meet their own demand. Then, shippers observe the realization of their demand shock and decide how much natural gas they want to purchase (competitive market).

Marketers buy capacity from the secondary market on behalf of small firms/consumers. Like releasers, they make decisions in two parts. They first decide how much capacity they want to purchase from the secondary market, taking into account their expectation about future demand. Then, they observe their demand shock and purchase gas to be consumed by small firms.

Objective Function — Releaser

We now show the problem of a releaser who has capacity from one origin (o) to one destination (d), but we later relax the model to allow capacity to come from multiple origins so that it can be taken to the data. A releaser can decide to release capacity or not:

$$\pi_d^r = \max_{d_r \in \{0,1\}} \{d_r(\pi_{1r} + \epsilon_{1r}) + (1 - d_r)(\pi_{0r} + \epsilon_{0r})\}$$

where,

- π_{0r} is the profit of the releaser from not entering in the capacity release market ($q_{od}^r = 0$). π_{1r} is the profit for releasing some positive quantity.

- ϵ_{0r} and ϵ_{1r} are standard type 1 extreme value shocks.
- d_r is an indicator for positive entry into the capacity release market.

A releaser that doesn't release any capacity gets:

$$\pi_{0r} = -\tau_p^r \overline{q}_{od}^r + \mathbb{E}_A \Big(U_r(A_r, p_o, \overline{q}_{od}^r) \mid \mathcal{I} \Big) \Big)$$

A releaser that releases some positive capacity gets:

$$\pi_{1r} = \max_{0 < q_{od}^r \leq \overline{q}_{od}^r} \left\{ \tau\Big(Q_{od}\Big) q_{od}^r - (\overline{q}_{od}^r - q_{od}^r)\tau_p^r + \mathbb{E}_A \Big(U_r(A_r, p_o, \overline{q}_{od}^r - q_{od}) \mid \mathcal{I} \Big) \right\}$$

Where,

- $\overline{q}_{od}^r$ is the releaser's capacity available from the primary market
- q_{od}^r is the quantity released
- $Q_{od} \equiv \sum_r q_{od}^r$ is the total quantity released by all releasers to destination d.
- τ_p^r is what the tariff that releaser must pay the pipeline for all unreleased capacity.
- $\mathbb{E}_A \Big(U_r(.) \mid \mathcal{I} \Big)$ is the expected utility of the releaser from own consumption, given information set $\mathcal{I}$. The information set captures, for instance, expectations over a cold wave.

A releaser will enter if expected profits net of cost shock are greater under positive than no release. Taking expectation over the distribution of cost shocks:

$$Pr(d_r = 1) = \frac{\exp(\pi_{1r})}{\exp(\pi_{1r}) + \exp(\pi_{0r})}$$

Profit under positive releases ($d_r = 1$)

The expected utility of the releaser's own consumption can then be written as

$$\mathbb{E}_A \Big(U_r(A_r, p_o, \overline{q}_{od}^r - q_{od}^r) \mid \mathcal{I} \Big) = \int_0^\infty \max_{\tilde{q}_{od}^r \leq (\overline{q}_{od}^r - q_{od}^r)} \Big\{ A_r u_r(\tilde{q}_{od}^r) - p_o \tilde{q}_{od}^r \Big\} dF(A_r \mid \mathcal{I}) \tag{4}$$

Where $u_r(.)$ is the utility function of the releaser's own consumption. We assume that the demand shock A_r log separable with the utility function, $u_r(0) = -\infty$ (e.g. CRRA, which will help with corner solutions), $u_r'(.) > 0$ and $u''(.) < 0$. Given some capacity released and some demand shock, the solution to the utility maximization problem is either binding or not binding depending on the realization of the demand shock:

$$U_r(A_r, p_o, \overline{q}^r_{od} - q^r_{od}) = \begin{cases} A_r u_r(u_r'^{-1}(p_o/A_r)) - p_o u_r'^{-1}(p_o/A_r), & \text{if} \quad A_r < p_o/u_r'(\overline{q}^r_{od} - q^r_{od}) \\ A_r u_r(\overline{q}^r_{od} - q^r_{od}) - p_r(\overline{q}^r_{od} - q^r_{od}), & \text{if} \quad A_r \geq p_o/u_r'(\overline{q}^r_{od} - q^r_{od}) \end{cases}$$

Let $\tilde{A}_r = p_o/u_r'(\overline{q}^r_{od} - q^r_{od})$ be the productivity threshold. Then, we can write the ex-ante expected utility as:

$$\mathbb{E}_A\Big(U_r(A_r, p_o, \overline{q}^r_{od} - q^r_{od}) \mid \mathcal{I}\Big) = \int_0^{\tilde{A}_r} \big[A_r u_r(u_r'^{-1}(p_o/A_r)) - p_o u_r'^{-1}(p_o/A_r)\big] f(A_r \mid \mathcal{I}) dA_r$$
$$+ \int_{\tilde{A}_r}^{\infty} \big[A_r u_r(\overline{q}^r_{od} - q^r_{od}) - p_o(\overline{q}^r_{od} - q^r_{od})\big] f(A_r \mid \mathcal{I}) dA_r$$

The basic intuition is straightforward. Releasers trade-off increased net revenue from releasing capacity from the ability to weather demand shocks in the future. Noting that $u_r(0) = -\infty$, we can slightly simplify the overall problem because the releaser will never release all of its capacity and $q^r_{od} < \overline{q}^r_{od}$ (this will be less straightforward when we introduce multiple points of origin). Then, it can be shown that the releaser will equalize net marginal revenue to marginal cost, given the action of all other releasers:

$$MR_r\big(q^r_{od}, Q_{od}\big) = MC_r(q^r_{od})$$

Where, net marginal revenues are defined as the additional revenues releaser r gets from the marketer net of its payment to the pipeline:

$$MR_r = \tau'(q^r_{od}, Q_{od}) q^r_{od} + \tau(q^r_{od}, Q_{od}) - \tau^r_p$$

And marginal costs are defined as the marginal loss in utility that a releaser would get if they are constrained in the consumption period due to having less remaining quantity available. Under Leibniz rule, we get:

$$
\begin{aligned}
MC_r &= -\frac{\partial\, \mathbb{E}_A \Big(U_r(A_r, p_o, \overline{q}^r_{od} - q^r_{od}) \mid \mathcal{I} \Big)}{\partial q^r_{pd}} \\
&= \int_{p_o/u'_r(\overline{q}^r_{od} - q^r_{od})}^{\infty} \big[A_r u'_r(\overline{q}^r_{od} - q^r_{od}) - p_o \big] dF(A_r \mid \mathcal{I})
\end{aligned}
$$

Profit under no releases ($d_r = 0$)

While we've established that the releaser will never release all of its capacity, the releaser may choose not to release capacity, and get:

$$
\pi_{or} = -\tau^r_p \overline{q}^r_{od} + \int_0^{\infty} \big[A_r u_r(u'^{-1}_r(p_o/A_r)) - p_o u'^{-1}_r(p_o/A_r) \big] dF(A_r \mid \mathcal{I})
$$

Objective Function — Marketer (small firms)

The objectve function of the marketer is quite similar. The marketer takes capacity released from all releasers to maximize expected utility on behalf of its consumers:

$$
\pi_m = \max_{Q_d \geq 0} \Big\{ -\tau_d Q_d + \underbrace{\int_0^{\infty} \max_{Q^c_d \leq Q_d} \Big\{ A_c u_c(Q^c_d) - p_o Q^c_d \Big\} dF(A_d \mid \mathcal{I})}_{\mathbb{E}_A \big(U_c(A_c) \mid \mathcal{I} \big)} \Big\}
$$

To find the solution to this problem, we can get an expression for the expected utility component similar to the one of the releaser:

$$
\begin{aligned}
\mathbb{E}_A\big(U_c(A_c) \mid \mathcal{I}\big) = \int_0^{p_o/u'_c(Q_d)} & \big[A_c u_c\big(u'^{-1}_c(p_o/A_c)\big) - p_o u'^{-1}(p_o/A_c) \big] dF(A_c \mid \mathcal{I}) \\
& + \int_{p_o/u'_c(Q_d)}^{\infty} \big[A_c u_c(Q_d) - p_o Q_d \big] dF(A_c \mid \mathcal{I})
\end{aligned}
$$

To find the solution to this maximization problem of the marketer, we can use Leibniz rule and get:

$$
\begin{aligned}
\tau_d(Q_d) &= \frac{\partial \mathbb{E}_A\big(U_c(A_c) \mid \mathcal{I}\big)}{\partial Q_d} \\
&= \int_{p_o/u_c'(Q_d)}^{\infty} \big[A_c u_c'(Q_d) - p_o\big] dF(A_c \mid \mathcal{I})
\end{aligned}
$$

Essentially, the marketer demands a quantity of capacity to destination d, Q_d, such that the per-unit price paid is equal to the marginal gain in expected utility from an additional unit of quantity. That marginal gain in quantity allows the marketer to be marginally better off when constrained.

A very modest beginning to equilibrium characterization

Absent of the extensive margin choice (whether releasers enter capacity release market or not) and the payment to the pipeline originating from the primary market τ_p^r, this is a standard Cournot oligopoly model in which firms produce a perfectly substitutable good with firm-specific marginal cost MC_r. The goal here is to investigate whether standard results of existence and uniqueness can be applied to our setting (Long and Soubeyran, 2000; Szidarovszky and Okuguchi, 2010). (...)

An equilibrium, if it exists, must satisfy the following pricing equation with variable markups:

$$
\tau\Big(\sum_r q_{od}^r\Big) = \frac{\epsilon_d}{\epsilon_d + s_r} MC_r(q_{od}^r)
$$

Where $MC_r(q_{od}^r) = \frac{\partial \mathbb{E}_A U_r}{\partial q_{od}^r} - \tau_p^r$ is the releaser's net marginal cost from releasing capacity, $\epsilon_d = \frac{\partial \sum_r q_{od}^r}{\partial \tau} \frac{\tau}{\sum_r q_{od}^e}$ is the elasticity of demand for aggregate quantity released, and $s_r = \frac{q_{od}^r}{\sum_r q_{od}^r}$ is releaser r's market share in the secondary market in equilibrium.

Key question: do shippers having more quantity in the primary market (higher concentration) necessarily imply higher tariffs? Answer is ambiguous:

- On the one hand, no because having more capacity reduces the marginal cost of releasing capacity.
  - Non-distortionary as it doesn't go through markups?
  - However, different shippers may have different "permanent" demand (consumer base). How can we capture that?

- On the other hand, yes because equilibrium market shares (s_r) for those shippers are likely to go up, raising markups (distortionary?).

Market Clearing — Gas Market

We assume that the gas market is competitive such that all agents take prices as given. In equilibrium, gas prices are such that the supply of gas to any location l must be equal to the demand of gas to that location (which includes demand for consumption in every location that originates in l). While we have good data on the flow of natural gas across all origins and destinations, we do not have great data on the supply of natural gas to the pipeline system. To get around this problem, here are some ideas to simplify the supply of gas:

- Natural gas originates from one or more exogenously defined supply hubs (e.g. Henry-hub).
  - The supply of natural gas from that hub to any other hub could be perfectly elastic at some exogenous price p, and functionally infinite.[11]
  - Alternatively, supply could be perfectly inelastic at some exogenous quantity which we can pin down by the data.[12]

Extensions

- Allowing for multiple origin per destination. Have to think about multidimensional entry decisions by origins, but should be more straightforward than it appears.
  - I could see some kind of simplification for this due to natural gas being a homogeneous good. For instance, the entry decision could be binary (across all markets). If it enters, a releaser that has access to multiple points of origin releases **all** capacity from the point of origin that yields highest profits (e.g. lowest gas price), then goes to the second, and so on.
- Semi-dynamic to fully dynamic. In principle, not that difficult but going from period utility functions to value function can make this harder to characterize.
  - e.g. every period, releaser releases capacity for one period ahead and can consume gas using existing capacity (long term contract - previously released capacity)

[11] As it stands, I am not sure this works because supplying from a supply hub to any hub at constant price would imply that the price of gas is p everywhere.

[12] This could work because we observed quantity of gas traded in every region.

  - every period, marketer (small firms) can consume gas from existing capacity that was released and sign contract for one-period ahead capacity.

- Allowing the releaser to get natural gas from other sources than primary market (buy from marketers?)

- Allowing for contracts with recall (think of another separate secondary market)

- Bilateral bargaining instead of oligopoly? not sure.

- Intermediate points (e.g. if considering releasing from B to C, also think about releasing from A to B).

  - Would be very hard to model but can be very useful for identification.

Ideas to get Model to Data

- Find distribution of productivity that can be characterized analytically

- Shocks to information set: introduction of cold wave in neighboring regions?

- Identification of releaser's utility separately from marketer/consumer's utility:

  - leverage variation spatial variation in cold wave. I have some notes on this, but need to go over it.

6 Conclusion

This paper investigates a major deregulation effort in a highly regulated industry characterized by natural monopolies: the secondary market for natural gas capacity release. It is one of the first empirical investigations of a real Coasian market in which market participants can trae legal entitlements, allowing us to shed light on the resilience of supply chains, particularly on the supply of natural gas during periods of high demand. Our results highlight that the secondary market is an important market constituent during shocks, as evidenced by the large and persistent increase in capacity released in that market during the February 2021 cold wave in Texas. We argue that the secondary market improves the efficiency of capacity allocation by deregulating transportation tariffs and providing information to market participants, which fosters the formation of long-term relationships between releasers and replacers. However, deregulation comes at a cost, and we find evidence of market power that reflects price-setting behavior from both releasers and replacers.

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Online Appendices: Not For Publication

A Entry and Exit in the US Pipeline Industry

We first provide a general description of the competitive landscape of interstate transmission pipelines in the US. During the period we studied, from 2014 to 2023, the competitive landscape for pipeline systems remained quite stable, with very few entries and exits of operating pipelines. There were 69 interstate transmission pipelines in both 2014 and 2023.

The number of operating pipelines varies significantly across different geographic areas. Following the definition of the U.S. Energy Information Administration (EIA), we categorize U.S. markets into six main regions, as shown in Figure A.1.[13]

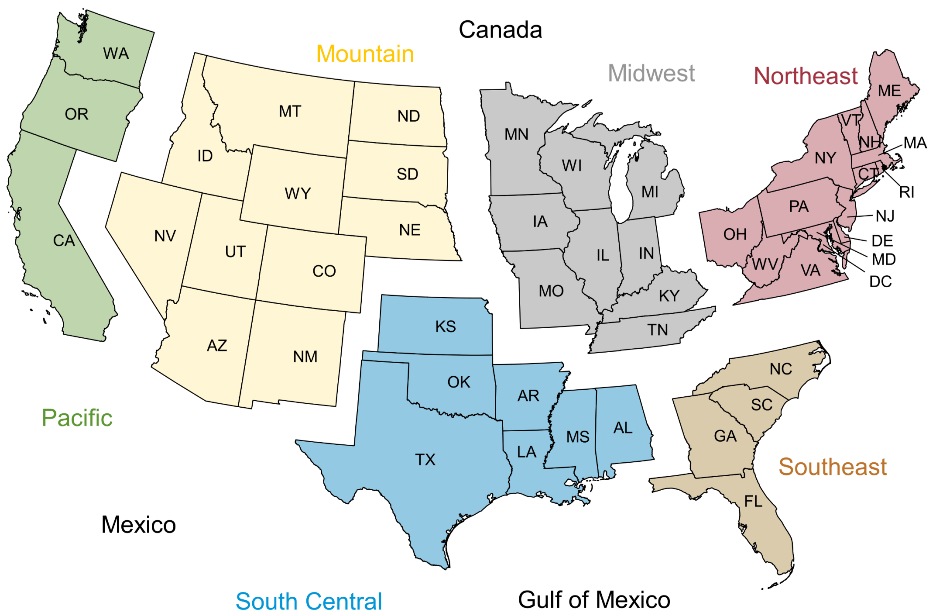

Figure A.1: Regions of the Natural Gas Pipeline Systems

Source: The U.S. Energy Information Administration

We calculate the number of pipeline systems operating in each of these six regions to demonstrate the competitive landscape of interstate pipeline systems. Table A.1 summarizes the results.

During the period from 2014 to 2023, there were three new entries and three exits, all of which involved relatively small regional pipelines. Regarding the exits, one was due to

[13]The definition of regions and historical information regarding pipeline systems is obtained from EIA website here.

Table A.1: Number of Operating Pipelines in Each Region

Region Name	Number of Pipelines Operating in this Region
Midwest	27
Mountain	29
Northeast	19
Pacific	5
South Central	32
Southeast	8

Notes: The number of pipelines operating in each region, as labeled in Figure A.1, is calculated by counting pipelines in each region separately. If a pipeline operates in multiple regions, it is counted once per region.

abandonment, one occurred through a merger and acquisition, and one was a temporary shutdown due to regulatory concerns over leakage. Below, we provide a detailed explanation of these entry and exit cases.

Entry

Three entries occurred during the study period: the Rover Pipeline, which runs through the Northeast and Midwest regions; the Sabal Trail Transmission in the South Central and Southeast regions; and the Sierrita Gas Pipeline, a small 61-mile pipeline that runs from Tucson, Arizona, to the Mexican border near Sásabe. Figure A.2 illustrates the three newly built pipelines.

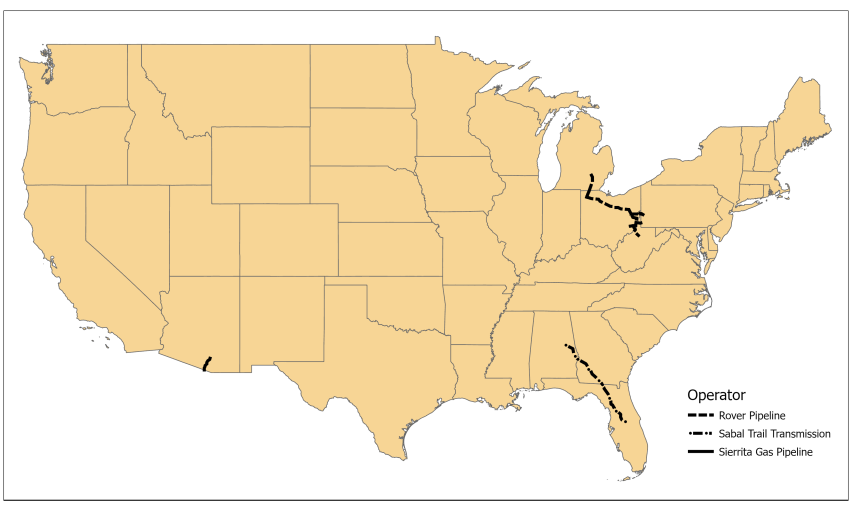

Figure A.2: Newly Constructed Pipelines

Source: The U.S. Energy Information Administration

The Rover Pipeline project (FERC Docket No. CP15-93) began service in 2017. The pipeline system spans over 711 miles, with a construction cost of $4,220 million and a transmission capacity of 3,250 MMcf/d. It runs through states including Pennsylvania (PA), West Virginia (WV), Ohio (OH), and Michigan (MI).

The Sabal Trail Project (FERC Docket No. CP15-17) also began service in 2017. The pipeline system spans over 516 miles, with a construction cost of $3,200 million and a transmission capacity of 1,000 MMcf/d. It runs through states including Alabama (AL), Georgia (GA), and Florida (FL).

The Sierrita Pipeline Project (FERC Docket No. CP13-73/74) began service in 2014. The pipeline system spans 60.9 miles, with a construction cost of $200 million and a transmission capacity of 201 MMcf/d. It runs through Arizona (AZ) and into Mexico.

Generally speaking, the newly built pipelines are minimal in terms of length and transmission capacity compared to existing pipeline systems. As for the most important of the three newly constructed pipelines, the Rover Pipeline, we analyze its effect on trade in the capacity release market in section 4.

Exit

Two exits occurred during the study period from 2014 to 2023. Strictly speaking, there was only one exit within the study period: the Questar Southern Trails Pipeline, which was abandoned in 2022 (FERC Docket No. CP18-39). Another pipeline, the Gulf Crossing Pipeline, which runs from Texas to Louisiana, was merged into Gulf South Pipeline Company in December 2019.

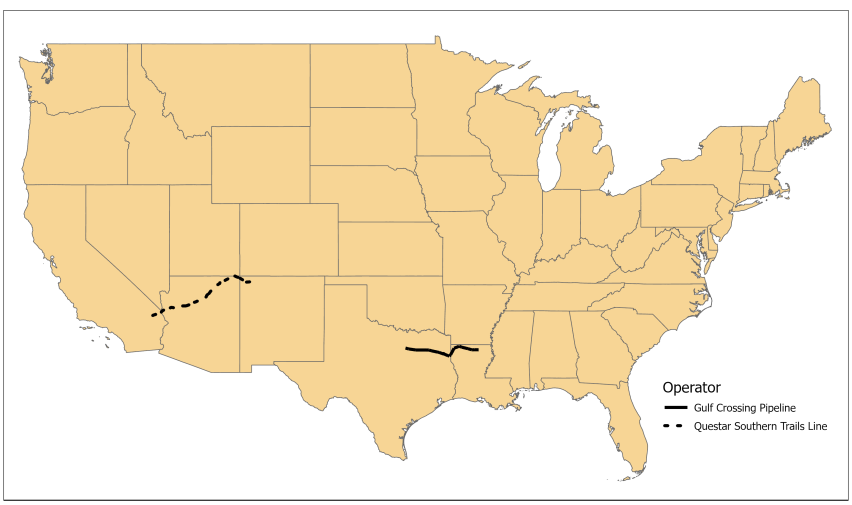

Figure A.3: Exiting Pipelines

Source: The U.S. Energy Information Administration

Figure A.3 illustrates these two pipelines.[14] Similar to the case of entries, exits were very rare during the study period. The pipelines that did exit were regional and minimal compared to the remainder of the pipeline systems. Overall, the interstate pipeline systems remained very stable during the period we studied.

[14] The plot for the Gulf Crossing Pipeline is approximate, as we could not find the exact shapefile for this particular exited pipeline. The actual map of the Gulf Crossing Pipeline can be found here.

B Rate Regulation in the US Pipeline Industry

The United States pipeline regulatory authority, the Federal Energy Regulatory Commission (FERC), has both an established framework and legislation allowing it to approve pipelines of charging market-based rates. Much of this framework and legislation was developed in the late 80s and early 90s and today a handful of pipelines charge market-based rates, mostly oil pipelines. While the FERC grants oil and natural gas pipelines market-based rate authority under two separate pieces of legislation generally the following must be included by a pipeline as evidence to move towards market-based rates:

- Describe proposed service.
- Define relevant product and geographic markets.
- Provide applicant's ownership and then list affiliated energy companies, services provided, and their location. If an affiliate operates in the same geographic market, the market shares of the applicant and the affiliate should be combined.
- Identify good alternatives to the proposed service - which parties provide similar service within the same geographic market. List the applicant's competitors and location.
- Include market share and Herfindahl-Hirschman Index (HHI) calculations to measure market concentration. The Commission's traditional HHI threshold is 1,800.
- Discuss other relevant competitive factors such as ease of entry and excess capacity held by competitors.
- Describe how the applicant's rates compare to the competitors.

In addition to the evidence above some pipelines have also provided econometric analysis to show that its shippers have a relatively high elasticity of demand, as a means to quantify the competitive position these pipelines face. It has also been required that pipelines provide cross-price elasticities for different products transported in their pipeline or by competitors. For example, a liquids pipeline may be constructed to ship various types of petroleum products (heavy crude, light crude, condensate, refined products, etc.) vs. another pipeline within the same area only capable of transporting a single type of petroleum product. In that case the regulator does not seem the product transported through the pipeline as homogenous and may review cross-price elasticities.

The FERC also has authority to determine if only a certain portion of a system may be granted market-based rate authority. For example, the origin market for pipelines is often considered as the production areas, which often could be considered not sufficiently concentrated and may result in the pipeline having market power in the origin market. However, many pipelines, before reaching their ultimate destination, pass through storage hubs. These storage hubs often have many pipelines entering them and are seen as a more competitive market. Therefore, a pipeline may not be granted market-based rates for its entire system but only a portion of its system, say from these storage hubs to its destination market.

As is evident the United States has a much more established framework for determining market-base rate authority. This is largely due to the more competitive nature of the pipeline industry in the United States in comparison to Canada. While this framework is established it is also important to note that this represents a relatively steep bar to cross and there are very few pipelines that are granted this authority.

B.1 Throughput (Utilization Rate)

Most pipelines split pipeline flow into 4 nomination windows/cycles that create 3 periods of potentially unique flow conditions.

1. 7am – 12pm
2. 12pm – 4pm
3. 4pm – 7am (next day)

The scheduled capacity is what they are actually nominating to flow in any of these particular periods and the maximum capacity is essentially the size of their contract and available capacity is what they do not utilize. Note if these are firm contracts they still pay the full demand rate on the maximum capacity and pay variable charges (extremely small compared to the demand rate, essentially only fuel) on the scheduled capacity for that nomination window. However, lots of times the less sophisticated shippers will just set their scheduled capacity and leave it the same for all 4 windows, even set that for a full week or month and generally if there is no nomination the pipeline assumes it to be the previously nominated amount.

So taking the average of 4 nomination cycle scheduled capacity is a good proxy for daily flow of the contracts, with a few caveats:

1. The period of 12am – 6:59am of any given days capacity will be dependent on the intraday 2 nomination from the previous day, we could get around this by defining a day as 7am-7am (the next day).

2. When defining this utilization we want to be very specific of what we are saying here. Particularly this is utilization of an existing contract within a day/week. I think it would be too definitive of a statement to say this is the utilization of the entire pipeline because we do not have information on things like interruptible/ancillary service being sold by the pipeline after firm nominations are tallied.

The ability for pipelines to vary their capacity on a day to day basis is very limited and could be influenced by the following factors however they would likely not result in large volumes of sustained capacity:

1. Operating Pressure: Pipeline sections have licensed maximum and minimum operating pressures. You could potentially increase flow through a section of pipeline by either increasing the pressure in that section or decreasing the pressure in a downstream section. However this would still result in limited available capacity.

2. Heat Value/Ambident Temperature Assumptions: Two assumptions necessary for determining pipeline capacity is heating value (which is the assumption of the composition of the molecules that make up the natural gas and at what energy they burn at) and ambident temperature (the assumption of the temperature around the pipeline underground). Switching these assumptions could result in further capacity however they typically like to keep these assumptions very true to actual composition and heat of the pipeline to avoid any potential pipeline integrity issues. Further, pipelines have specifications for the composition of gas within a pipeline and have maximum hydrocarbon dewpoints (the measure of heat value).

3. Contracting Practices: Finally the commercial construct available for contracts may limit the ability of a pipeline to provide excess capacity on a day to day basis. Firm contracts have a minimum period and while some pipelines have short-term firm service most of the changes of the above assumptions would not likely guarantee a sustained period of stable service and so the pipelines are not likely to offer firm service by tweaking the above mentioned assumptions or pressure. They could likely create small amounts of capacity for a limited time which they would just sell as interruptible service.

C Capacity Release Market

C.1 How does Capacity Release Market Work?

We first explain in more detail the capacity release programs:

1. Capacity releases can be put forward by the pipeline or requested from shippers. Both get posted on the pipeline's website.

2. There are generally two types of capacity releases biddable and non-biddable. Biddable capacity releases are subject to an open season (bidding process) where the individual who bids the highest gets the capacity. Non-biddable capacity releases are generally agreements that are entered into before posting on the regulatory website and are only eligible for releases with contract lengths of 31 days or less, or more than 1 year. This is why we see most of the releases at 31 days in length or 1 year. Furthermore, capacity releases less than one year can be above the Tariff specified firm toll while those above a year cannot exceed the firm Tariff rate.

3. We discussed another very interesting feature the recall and reput options. Essentially if recall and reput conditions are included in a capacity release transaction then the original entitlement holder can at any time (within nomination window deadlines) "recall" that capacity and utilize it if they need it, this waives any tolls for the shipper that purchased the capacity release when it was recalled. Once the capacity is recalled the original entitlement holder can decide to "reput" that capacity if it no longer needs it and give it back to the shipper that originally purchased the capacity release. A recall/reput have to happen on separate days. From what Alan said this is a very common provision and we can see on the capacity release data from the pipeline whether these conditions are included in the contract.

4. Capacity release above the maximum tariff rate (releases less than or equal to 31 days, greater than or equal to 1 year, or bidded on).

5. The pipeline receives the same reservation charge whether it be from the releaser or the replacement shipper where they could potentially benefit is from the volumetric charge.

Below, we outilne the timelines detailing the processes for conducting open season auctions for short-term and long-term releases, respectively.

Short Term Release (Less than 1 year)

1. The capacity release request is posted by 9:00am on a business day (the specific timing of which will vary depending on the pipeline to meet their nomination windows, I found 9am to be the most common).
2. The open season/auction period is held between 9:00-10:00am. This is a silent auction, no parties can see what others bid, and during this period bids can be withdrawn.
3. The pipeline company begins evaluation of the bids at 10:00am, contingencies are cleared, and a determination of the best bid is made based on the process specified by the releaser/requester.
4. Both parties are notified by 11:00am and confirmed by 12:00pm. The capacity release contract is awarded within an hour.

Long Term Release (More than 1 year)

1. The capacity release request is posted by 9:00am on a business day.
2. The open season/auction period is then held for three consecutive business days, such that the open season process ends at 10:00am three business days after the capacity release posting.
3. The pipeline company begins evaluation of the bids at 10:00am three days later, contingencies are cleared, and a determination of the best bid is made based on the process specified by the releaser/requester.
4. Both parties are notified by 11:00am and confirmed by 12:00pm. The capacity release contract is awarded within an hour.

C.2 Interviews with Practitioners

Below we document our interviews with practitioners that participate in the capacity release market:

- Q: Why someone would not have an incentive to just nominate 100% of their firm contract?

  A: This is due to there also being a certain amount of variable costs associated with transportation. We discussed these briefly before Yanyou. but I was not aware it could be such a factor, for example, pipeline abandonment surcharges or fuel costs for shipping on the pipeline. If you nominate a particular level of gas for that nomination window it is assumed you use up to 100% of the gas you nominated, therefore you incur variable costs on a volumetric basis equal to your nomination. While these are small in comparison to the overall demand charges (fixed costs) there is little to no incentive for certain types of customers (industrial user or a local distribution company) to incur those costs if they do not require the gas. Whereas marketers/natural gas traders will only choose to nominate their full amount of their contract if the contract path is "in the money": price of natural gas at destination plus variable cost of transportation is greater than the price of natural gas at origin.

- Q: How often do people choose biddable agreement?

  A: In terms of biddable or non-biddable he would be surprised if more than 1% of the capacity releases were the result of a biddable process. Most are prearranged deals where you have negotiated before posting it on the pipeline's website. In particular, even in the US many relationships are established, and many players are aware of who to call if they need a capacity release.

- Q: What is the difference between a natural gas utility, marketer, and retailer?

  A: A natural gas utility is a regulated entity that distributes natural gas, sometimes known as a local distribution company (LDC), to end use customers such as residential, commercial, and industrial customers. LDCs will often have an exclusive franchise area of a city or region and in turn their rates charged for their services are regulated by state regulatory authorities. Utilities source the transportation of their gas from interstate and intrastate pipelines which are in turn regulated by federal or state regulatory authorities, respectively. These utilities are required by their regulators to hold a certain percentage of their peak day demand requirements in long-term contracts on these pipeline systems. Utilities average day demand requirements are often much lower than their peak day requirements and therefore utilities hold excess transportation capacity on interstate and intrastate pipeline systems.

  Natural gas marketers are unregulated companies that arrange for the purchase and sale of natural gas. Most typically marketers arrange for gas supply agreements with natural gas producers or purchase gas at trading hubs. They then sell this gas to end users or at other market hubs to earn profit based on the spreads between different prices of natural gas hubs. To transport natural gas marketers must also hold capacity on natural gas pipelines but are not required to hold any typical amount of capacity and often choose to be nimble in the amount of capacity they hold on pipeline systems. When arranging the supply of gas for an end user marketers will typically charge for the cost of gas, cost of transportation, and then a service fee for arranging the transactions.

Natural gas retailers are also unregulated companies that arrange for the purchase and sale of natural gas. However, the main distinction between them and marketers is that retailers typically hold capacity on natural gas distribution systems and sell to end users such as residential, commercial, and industrial customers. The distinction between retailers and LDCs is that the provision of natural gas distribution (responsibility of LDCs) is regulated but the retail sales of natural gas is often competitive. End use consumers can choose to purchase gas directly from the LDC, which offers a regulated rate, or from natural gas retailers which have competitive rates. Natural gas retailers typically source their natural gas from natural gas marketers or in certain circumstances are vertically integrated with a marketing company. Since both marketers and retailers are unregulated entities they do not require supply obligations and typically hold transportation or distribution capacity that is more in line with average day demand for natural gas, in contrast to peak day demand like utilities.

- Q: Why do we see a large portion of end users of natural gas utilize marketer's services instead of contracting for their own service on interstate natural gas pipelines?

  A: A significant portion of end users of natural gas do not actually hold transportation capacity on interstate pipeline systems, or they are not connected to natural gas distribution utilities. These customers are often industrial facilities, agricultural operations, smaller power generation facilities, and natural gas retailers. Thus, a large amount of these end users of natural gas rely on natural gas marketers to meet their gas needs, both in terms of supply and transportation. The reason these end users do not hold transportation capacity on pipelines is for two primary reasons: creditworthiness and balance sheet obligations.

  The credit obligations that are necessary for a company to hold pipeline transportation service are often quite steep and that most companies could not meet. For example, a typical credit evaluation criteria for firm service on a natural gas pipeline is to provide security guarantees for three months of firm service at the maximum tariff rate for the entire volume of your contract. This requires companies to have large amounts of cash on hand (in the form of an advance deposit), a strong standing letter of credit from a financial institution, an acceptable security interest in collateral, or a guarantee from a more credit worthy parent company.

  As for the balance sheet obligations, given the take or pay nature of natural gas transportation firm service contracts financial institutions view these transportation contracts as debt obligations. If a company were to take out large amounts of transportation capacity this would result in a large liability to appear on their balance sheet which may impact their own credit metrics, impacting their ability to secure their own financing and financial obligations.

Given these restrictive requirements many of these end users rely on the services of marketers to arrange for supply and transportation of their gas needs, since marketers require lower levels of credit requirements and the less restrictive outcomes on their balance sheet obligations. This comes at an increased cost to the end user as marketers often require a service fee or mark up for arranging supply and transportation of natural gas.

- Q: Why do we see natural gas marketers as replacers in the capacity release market?

  A: Since these end users rely on marketers to provide them service when unexpected shocks in demand happen either to end use residential, commercial, and industrial demand (increased demand for natural gas retailers) or unexpected shocks in their various industries that do not impact demand for gas utilities/retailers (for example an increase in demand for steel production) they often turn to marketers to supply them with additional natural gas. While the primary market for natural gas transportation is held largely by utilities, to meet their regulatory obligations, most periods of the year they do not require the full use of their transportation contracts and would prefer releasing that capacity to a marketer that will ultimately provide the transportation services to an end user.

D Identification of Cold Waves[15]

We collected daily geospatial temperature data from the National Oceanic and Atmospheric Administration (NOAA).[16] We integrated temperature data across Bureau of Economic Analysis (BEA) regions to determine the average daily temperature for each BEA region. Figure D.1 shows the maps of the BEA regions. The contiguous United States is comprised of a total of 170 BEA regions.

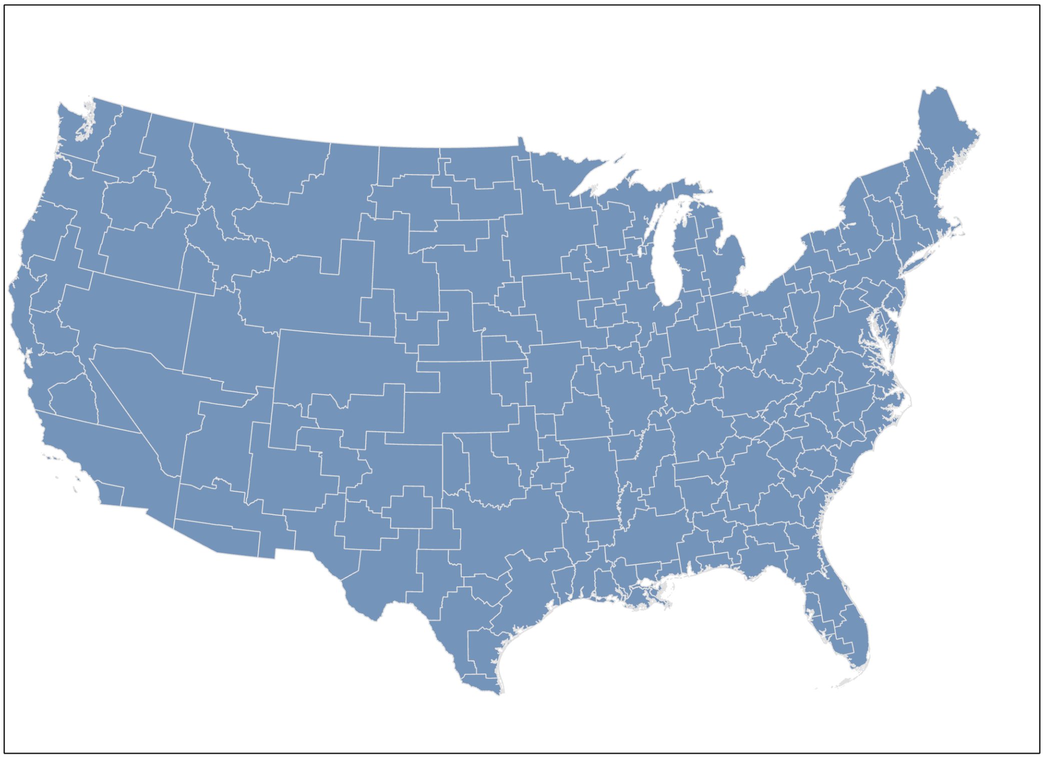

Figure D.1: Illustration of the BEA Regions

To identify days of extreme cold, we filtered the dataset by BEA region and date, and we marked the BEA–date pairs with temperatures in the lowest 10th percentile. These dates were then combined into a new dataset, *Extreme Cold*, which contains the days when BEA regions recorded 10th percentile temperatures.

A *Cold Wave* is then defined as a sequence of consecutive dates in which adjacent BEAs experienced 10th percentile coldest temperatures, as recorded in *Extreme Cold*. We define a *line* as a sequence of date–BEA pairs found in *Extreme Cold*.[17] We refer to each BEA region as a node and the node containing the latest date in a line as a termination node.

[15]We thank our research assistant William Qi for preparing Python code to identify the cold waves and for drafting the explanations of our method in this appendix.

[16]https://psl.noaa.gov/cgi-bin/data/narr/plotday.pl/.

[17]A line is stored as a simple Python list of tuples, the tuples containing the date–BEA combination.

In Figure D.2, we illustrate an example of *nodes* and *lines*. Dates are shown in rows, and the number inside each node represents a BEA region. The sequences $1 \rightarrow 1 \rightarrow 2$ and $1 \rightarrow 3$ constitute two distinct lines. Since nodes 2 and 3 do not have any continuations, we call 2 and 3 termination nodes for line 1 and 2 respectively.

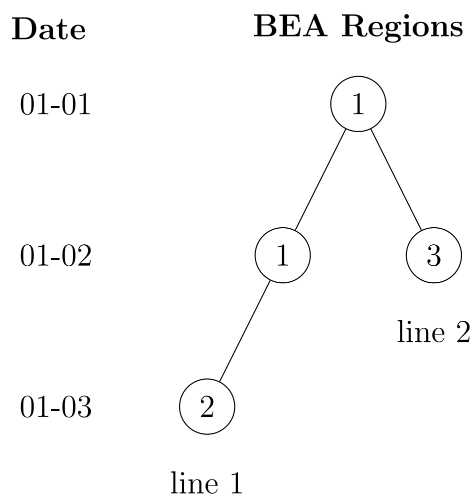

Figure D.2: Visual Representation of a Line's Definition

Notes: We define a *line* as a sequence of date–BEA pairs contained in *Extreme Cold*. We refer to each BEA region as a node and the node containing the latest date in a line as a termination node. In our example here, node 'BEA region 2 on 01-03' is the termination node for line 1, and node 'BEA region 3 on 01-02' is the termination node for line 2.

We identified the adjacent regions for each BEA region based on their geographic location. For ease of use, every BEA was included in its own neighbor list to account for consecutive *Extreme Cold* dates within the same BEA region. The process of identifying cold waves was divided into two parts: line-making and line-combination. We explain each part in detail below.

Line Making

For each node in *Extreme Cold*, the list of BEA neighbors was cross-referenced on the following date to determine whether they were also experiencing extreme cold temperatures. For example, at node 'BEA region 1' on 01-01, we looked to see if any BEAs adjacent to BEA region 1 were in *Extreme Cold* on 01-02. If there were, we appended node 'BEA region 1' on 01-01 to the neighbor's node on 01-02. We call any lines that have continuations into future dates *partial lines*. In this case, node 'BEA region 1 on 01-01' is a partial line.

We define the longest duration of each cold wave as its *length*. For example, a cold wave with a length of 30 means the cold wave lasted for 30 days.

In the coding process, we identified the longest line for each cold wave as follows: Before appending a pair to ensure the longest possible line, we compared the earliest date in the current pair's partial line with that of its neighbor. If the earliest date in the current pair was earlier than the neighbor's, any elements with duplicate dates were removed, and the current pair was then appended.

For example, in Figure D.3, the partial line $1 \rightarrow 2$ will be appended to node 4 to make complete line $1 \rightarrow 2 \rightarrow 4$. Since partial line $1 \rightarrow 2$ exceeds the length of partial line 3, partial line 3 will not append itself to 4. However, we will keep track that partial line 3 attempted to append itself to 4.

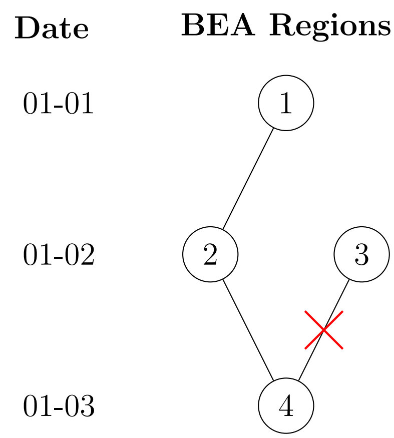

Figure D.3: Illustration of Line Making

Notes: This figures illustrates the procedure of line making. We append a date–BEA pair to ensure the longest possible line. In the case of a tie in lengths, the existing line is kept. This decision is arbitrary, but ultimately irrelevant as discussed in 'Line Combination.'

Line Combination

The information lost from the removal of lines can be recovered by moving backwards through existent lines and aggregating related lines to form cold waves. In Figure D.4, consider line $1 \rightarrow 2 \rightarrow 4 \rightarrow 6$. Starting at node 6, we observe that node 5 had previously attempted to append itself, so we add node 5 to the cold wave. Since node 5 is not a termination node, we add all termination nodes associated with node 5 (termination node 7) and each of their associated lines ($3 \rightarrow 5 \rightarrow 7$) to the acknowledged cold wave.

After identifying the cold wave dates from 01-01 to 01-04, we search for BEA regions experiencing Extreme Cold throughout this period and include those date–BEA pairs in our identification of the cold wave. For example, in Figure D.4, BEA region 9 on 01-02 was identified and included in the cold wave definition.

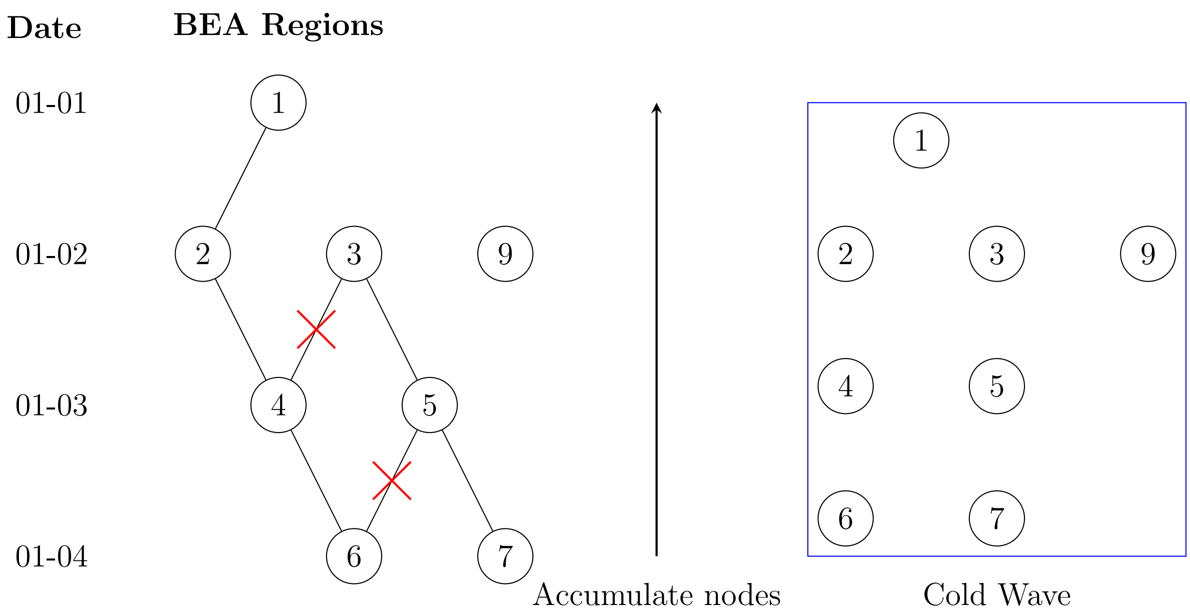

Figure D.4: Identification of a Cold Wave

Notes: This figure illustrates the procedure for identifying a cold wave. We define the longest duration of each cold wave as its length. In this case, we identify a cold wave with a length of four, meaning the cold wave lasted four days. We identified the line $1 \rightarrow 2 \rightarrow 4 \rightarrow 6$ as the longest line for this cold wave. After identifying the cold wave dates from 01-01 to 01-04, we search for BEA regions experiencing *Extreme Cold* during this period and include those date–BEA pairs in our identification. In this case, the right panel shows the date–BEA pairs included in this cold wave.

In our main analysis, we use cold waves that last more than thirty days. We identified two such events: one in 2015 and one in 2019. We have verified both identified cold waves by referencing news articles.[18]

For example, we identified the 2015 cold wave as occurring from February 6, 2015, to March 10, 2015. Figure D.5 illustrates this cold wave, with the darkness of the color indicating the order of dates when local temperatures fell below the 10th percentile, with the darkest shades representing the earliest dates.

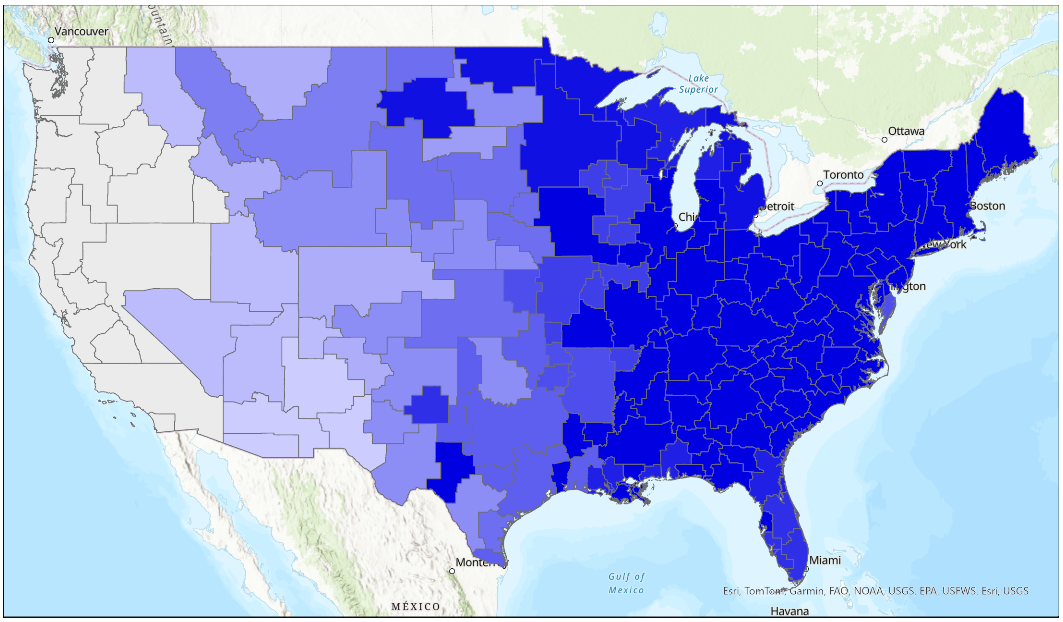

Figure D.5: Illustration of the Identified Cold Wave in 2015

Notes: This figure illustrate the cold wave that we identified in 2015. The darkness of the color indicates the order of dates when local temperatures fell below the 10th percentile, with the darkest shades representing the earliest dates.

[18] For 2015, we referenced the Washington Post article on the Arctic outbreak shattering records in Eastern U.S. and Weather.com's report on the Arctic coldest this winter season in the Northeast; for 2019, we referred to Weather.gov's report on the Arctic cold outbreak of January 30-31, 2019 and NBC News' live blog tracking the 2019 winter weather storm.