Long-Term Contracts and Secondary Markets: Theory and 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 of price setting from both buyers and sellers based on their market share, which could reduce the secondary market's efficiency gains.

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 a period of 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 by regulations to sign long-term contracts (typically 10 years or more) with customers prior to the pipeline construction which entitles the customer to reserved capacity. The presence of long-term contracts in the primary market can create situations of artificial constraint in which physical capacity is available but contracting frictions impedes the flow of natural gas. For these reasons, there is a secondary market unique to the US 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 US 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 and other regions. We study shocks to large weather fluctuations which affect the supply and demand for energy, increasingly common with the advent of anthropogenic 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 the entire US natural gas pipeline network between 2005 and 2023, our pilot study finds that the secondary market responds to large regional fluctuations in demand for natural gas. We narrow down our study on the extreme cold wave of February 2021. This cold wave is likely to have significantly increased demand, particularly residential demand for natural gas heating. Notably, natural gas prices at hubs in Texas and southeastern California rose substantially during this period whereas prices at hubs outside of 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 pipelines. We choose Gas Transmission Northwest (GTN) as a control, which caries natural gas from Western Canada to Northwestern California. We choose the El Paso pipeline as a treatment, which caries natural gas to important hubs in Texas and Southeastern California. 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 cost between replacers and releasers, but fosters an anti-competitive environment with price setting behavior from both sides of the market.

The secondary market of capacity release for natural gas pipeline is one of the only real examples of a Coasian market. 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 US.

To understand the aforementioned trade-offs better, we show that the vast majority of shippers that release capacity are end-consumers (power plants, local distribution companies that serve specific urban areas, and industrial plants) who have long-term contracts with pipelines and must pay the large reservation fees even if they do not utilize their capacity. The vast majority of replacers are marketeers. Marketeers are intermediaries that engage in arbitrage opportunities, buying gas in cheap hubs and selling gas in expensive hubs to consumers.

In this context, we provide empirical evidence for long-term relationships between market participants in the capacity release market and propose potential hypothesis for why such relationships exist. we show that over 95% of contracts signed are private arrangements made between shippers. Many of these arrangements are made between shippers that meet multiple times over the sample period, which we call long-term relationships. This is similar to the U.S. trucking industry, where 80% of the shipping contracts are signed through existing relationships between shippers (analogous to capacity holder) and carriers (analogous to capacity releaser), and only 20% of the contracts are signed through a spot market (Harris and Nguyen, 2023).

Considering the unique aspects of this market, we believe that search costs are the key factor influencing the formation of long-term relationships. This is attributed to the frequent requirement to secure capacity at various delivery and receipt locations, along with other common contractual obligations such as the option for a releaser to be able to recall its capacity at any time, making each contract a highly differentiated product. Thus, when releasers don't need their capacity, they search for replacers to avoid paying those reservation fees, whereas replacers search for releasers when facing an arbitrage opportunity. Using event studies, we find that contracts are much more likely to be signed between long-term partners during the cold wave, suggesting that the opportunity cost of searching is higher in periods of high demand, and that long-term relationships reduce search costs.

Moreover, the secondary market facilitates the formation of long-term relationships. While contracts are mostly private arrangements, the Federal Energy Regulatory Commission (FERC) mandates that pipelines publicly posts details of each transaction from the secondary market on data sharing platforms. We argue that this regulatory constraint is what facilitates the formation of long-term relationships.

However, the quasi-lack of regulation on the price charged for pipeline capacity in the secondary market fosters an anti-competitive environment.[1] To show this, we leverage variation in market concentration across different pipelines and regions, where some pipelines have zones with dominant releasers, some with dominant replacers, and some with both. We find that a 1% increase in releaser market share is associated with a 0.1% increase in prices for capacity, whereas a 1% increase in replacer market share is associated with a 0.04% decrease in capacity prices. The welfare implications of these price-setting behaviors are uncertain, and we plan to study them using a search model with two-sided market power in future research.

Related Literature

This paper contributes to three broad strands of literature that relate to: (i) supply-chain and energy market resilience; (i) effectiveness secondary markets; and (iii) the pipeline industry

Chen (2023) shows that mergers among those networks result in significant cost reductions and also a notable rise in markup. Nonetheless, there is still 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 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, in this project, 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 US 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, 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

[1] 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.

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 interact with these physical constraints in preventing spatial price integration. By contrast, we study the role of artificial capacity constraints created 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 (which we call 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 terms of comparison to other modes of domestic freight pipelines transport the most in terms of tonnes-kilometers. Natural gas transportation in anything other than pipelines is extremely difficult and uneconomic. Within the US there are more than 120 major natural gas transmission pipelines whose tolls/rates are directly regulated by the Federal Energy Regulatory Commission (FERC). A majority of these pipelines facilitate the transmission of natural gas from production areas, which are concentrated in regions such as Texas, Pennsylvania, and Canada, to demand areas such as major metropolitan areas, major export interconnections, and natural gas storage facilities. The major interstate transmission pipelines are shown in the map below in Figure 1.

Transmission pipelines are extremely costly to build, averaging \$5 million/km with a period of 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 by regulations to sign long-term contracts (typically 10 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

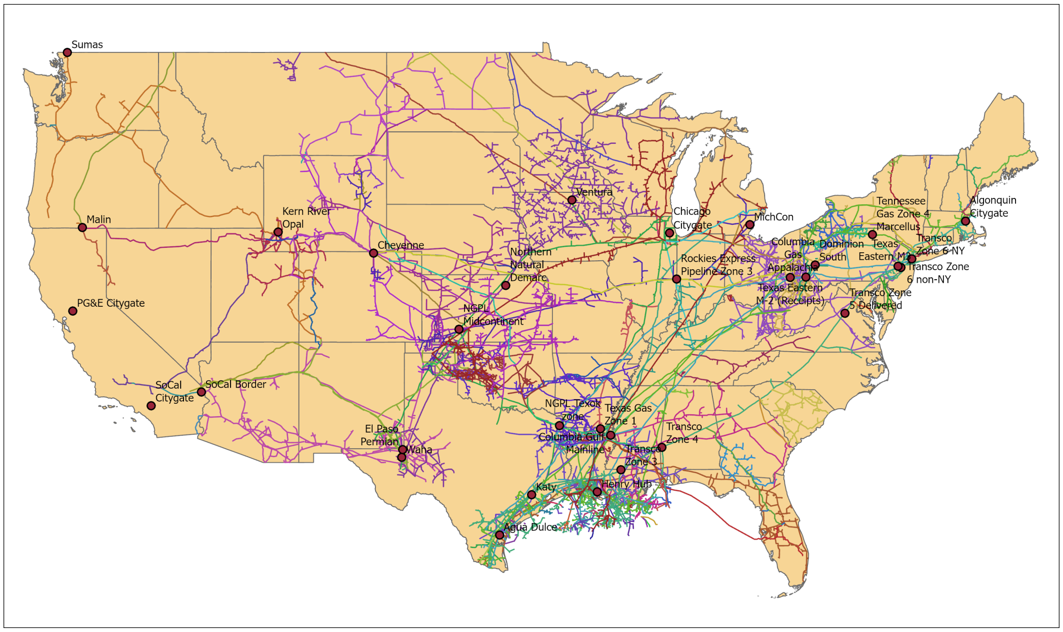


Figure 1: Natural Gas Pipelines in the US

shipment capacity,[2] as shipment pricing is often heavily regulated. Pipeline rates are often 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.[3] In Appendix A we provide further details on rate regulation within the pipeline industry.

While long-term contracts in the primary market help to reduce investment risks, they can introduce substantial frictions in capacity allocation amidst fluctuations in the natural gas supply and demand, thereby obstructing the delivery of gas to customers in need. To address these frictions, a secondary market has emerged. In this market, service requesters

[2]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 point over a specific time period.

[3]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 cost of service regulation is typically determined through something known as a rate base. A rate base is defined as a pipelines gross plant in service less its accumulated depreciation. You then earn a return based on an assumed capital structure set by the regulator. 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. Cost of debt is typically based on a pipelines outstanding debt, while 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 risk assets (mainly other pipeline systems).

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 full length of the contract.

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*.

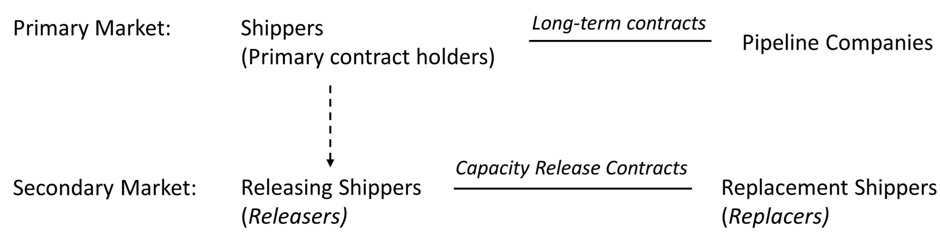


Figure 2: Relationships of the primary and the secondary market

For primary contract holders, the value of transportation tends to rise when there are substantial price differentials between natural gas trading hubs. Consequently, we should expect to observe an increase in capacity releases from these customers when such differentials widen. Additionally, it is important to note that a substantial number of natural gas end users either do not possess transportation capacity on interstate pipeline systems or 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 main reasons these end users lack transportation capacity on pipelines are due to concerns about 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. 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.

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.

3 Data

We utilize four 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, and 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 an index of customers, from which we obtain our data. Second, the capacity release data from each pipeline system, which includes 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).[4] Third, the daily spot prices of natural gas at all US-based hubs which is compiled by Capital IQ Pro. We obtained the first three datasets from 2004 to 2023.[5] Last, we use geographic data from the US Energy Information Administration (EIA) to gather information about the entire US interstate natural gas pipeline system and the locations of key natural gas gateways and hubs.

[4]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.).

[5]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. To access historical data, we purchase the entire history of the capacity release market and spot prices at hubs between 2004 and 2023 from the Capital IQ Pro database.

3.1 Descriptives for the primary market

We first provide summary statistics for the long-term contracts in the primary market for selected pipelines. Across our sample, the average duration of a contract is approximately 9 years.

Table 1: Contract Duration (in Months)

Pipeline	p5	p25	p50	p75	Mean	Max
El Paso Natural	9	57	115	180	122	475
Natural Gas Pipe	12	36	60	120	84	432
Texas Eastern	13	48	105	184	118	612
Transwestern	4	12	36	101	65	361
All Sample	12	36	72	154	100	612

Next, we provide insight into the competitive landscape of the industry. Table 2 shows the overview of market concentration in U.S. Interstate Pipelines.

Table 2: U.S. Market Share: Top 5 Interstate Pipelines by Capacity (2022)

Pipeline	**Market Share**
Transcontinental Gas P L Co	.1
Texas Eastern Trans Corp	.08
Tennessee Gas Pipeline Co	.08
ANR Pipeline Co	.05
Rockies Express Pipeline	.04
Mean	.006
N	170

Table 3 shows the major contract holders in the primary market. The data indicate that the top 5 companies own 75% of interstate pipeline capacity. The market power observed in the primary market will significantly impact who can participate in the capacity release market (the secondary market) and will affect firms' capacity releasing decisions during demand or supply shocks.

3.2 Descriptives for the secondary market

Regarding the capacity release market, we first demonstrate its importance. Table 4 shows the amount released in the secondary market in comparison to the primary market. The percentage of the amount released is calculated at the Pipeline-Shipper-Quarterly level,

Table 3: Top 10 Contract Holders by Capacity in the Primary Market (2022)

Primary Owner	**Market Share**
Kinder Morgan	.195
TC Energy	.192
Enbridge	.151
The Williams Companies	.12
Energy Transfer	.1
Tallgrass Energy	.05
Boardwalk Pipeline	.035
Berkshire Hathaway	.032
Boardwalk Pipelines	.024
Dominion Energy	.024
Mean	.013
N	76

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

	p25	p50	p75	Mean	Max
Proportion of quantity released	2.3%	6.8%	25.0%	32.4%	4212.7%

using the Max Daily Transport quantity as a basis. The result shows that in any quarter, on average 30% of capacity is being treaded on the secondary market.

Next, we examine the percentage of shippers who participate in the capacity release market at any point during the contract period. Table 5 reveals that 40% of shippers holding long-term contracts participate in the capacity release market. This underscores the significant importance and active usage of the secondary market in this industry. 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 on a quarterly basis.

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

Not in the Capacity Release Market	555	60%
In the market	373	40%
Total	928	100%

Table 6 shows the average duration of a contract in the capacity release market. Most of the contracts have a duration of a month, with some contracts 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

3 illustrates the distribution of contract durations.

Table 6: Contract Durations in the Capacity Release Market (Days)

	Mean	p5	p50	p95	Min	Max
Contract Duration	85.17	27	30	364	1	1000

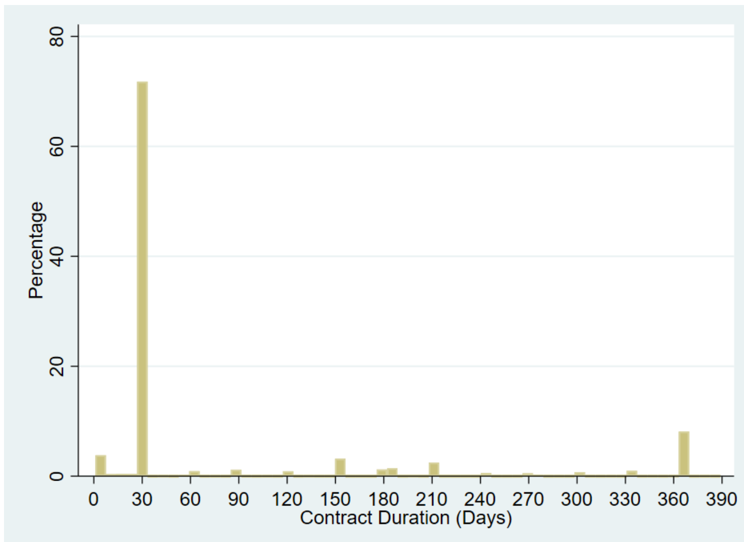


Figure 3: Distribution of Contract Durations

In the capacity release market, there are several options that a contract might include: recallable, reputable, capacity resale allowed, affiliation of the counterparty with the contracting party, and inclusion of previously released capacity. Table 7 shows the percentage of contracts that feature these options.

Table 7: Percentage of Contracts with Different Options

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%

We then present data descriptives to illustrate the interactions between releasers and replacers in the secondary market. The selected pipelines are “El Paso Texas Pipeline”, “Texas Eastern Transmission”, “Natural Gas Pipeline Company of America” (*NGPL*), and the Transwestern Pipeline. We observe data between 2006 and 2023. Using the points identifiers for the contracts, we were able to separate capacity release between different categories:

Table 8: Distribution of sub-contracts by category—Selected pipelines

	Number of sub-contracts	Percentage
Compressor	984	0.7
Delivery to End User	3,057	2.1
Delivery to an LDC	**58,877**	**40.3**
Exchange	59	0.0
Gas Processing Plant	458	0.3
Gathering	278	0.2
Interconnect	**53,146**	**36.4**
LNG	36	0.0
Park and Loan	1	0.0
Pool	3,662	2.5
Power Plant	93	0.1
Receipt by LDC	79	0.1
Segment	313	0.2
Stand Alone Meter	3,033	2.1
Storage Injection	264	0.2
Storage Quantity	**19,093**	**13.1**
Storage Withdrawal	352	0.2
Unknown	973	0.7
Wellhead	1,265	0.9
Total	146,023	100.0

Notes: A sub-contract is defined as an agreement on capacity release at a specific point, as part of larger capacity release contracts.

We aggregate these categories into local distribution companies (LDC), storage and other (where other is mostly comprised of transmission between pipelines). Additionally, we separated contracts into two types based on the frequency of contracts between the same shippers on a pipeline:

1. Met < 5 times

2. Met ≥ 5 times

We refer to shippers that met more than 5 times as engaged in long-term relationships. These categories will prove useful to understand results from the event studies.

4 Emprical Model and Results

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 event, swept across Canada, the United States, and northern Mexico. This rare meteorological event led to severe winter storms, unprecedented snow and cold temperature in states forming the deep south such as Texas, Oklahoma and Arkansas.

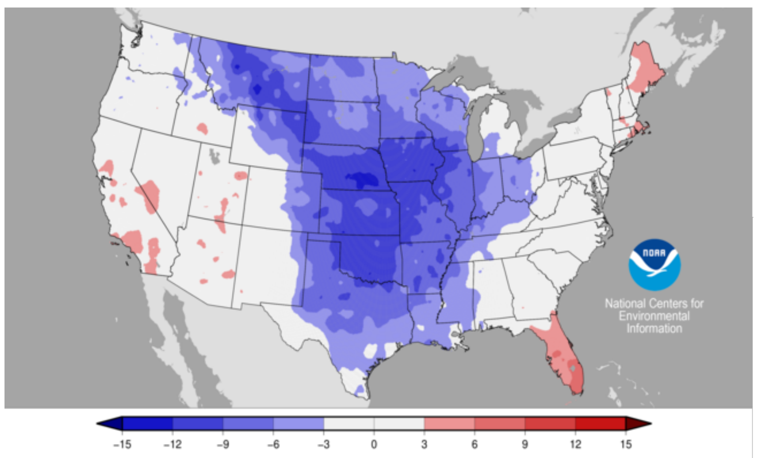


Figure 4: Temperature Deviation from Historical Average – February 2021

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

This cold wave led to unexpected demand increase for home heating, affecting demand for natural gas as a direct heat source for homes but also 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.[6] 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.[7]

In this section, we investigate the role of the secondary market to allocate natural gas capacity during the cold wave, as well as some of the mechanisms underlying this effect

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

and potential trade-offs associated with the secondary market. We first investigate a simple Difference-in-Difference event-study allowing us to compare outcomes between treated and 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 similar ratio of activity in the secondary market relative to the pipeline's total capacity and of course, the pipeline's location. We choose El Paso Natural Gas Company as a treated pipeline, which transport gas from 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 5 shows the treated pipelines map with selected hubs.

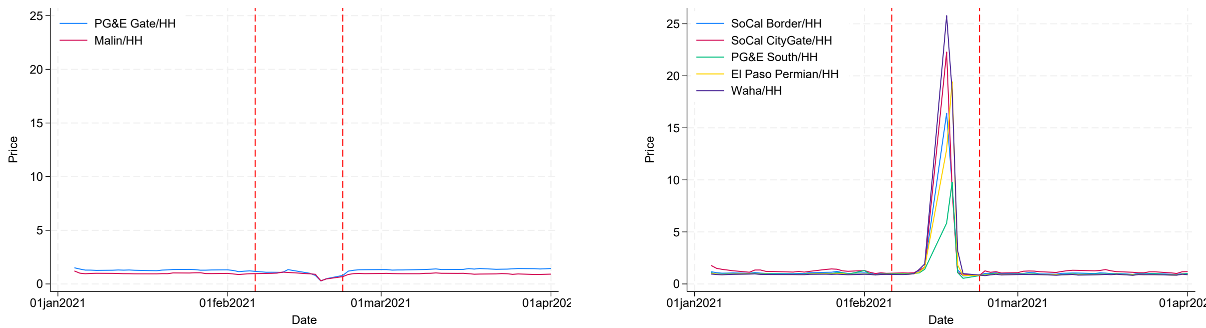
(a) Control Pipeline

(b) Treated Pipeline

Figure 5: Treated and Control Pipeline Maps with Selected Hubs

As control, we choose the Gas Transmission Northwest pipeline (GTN) which takes gas from Western Canada and takes it to Northern California. By contrast to prices at hubs serviced by the El Paso pipelines, prices at hubs in Northern California remained relatively stable, between 0.5 and 1.5 time the national Henry Hub benchmark. This suggests that the the West Coast of the U.S. did not get affected by the cold wave and that intermediaries were not able to arbitrage natural gas between. Panel (a) of Figure 5 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 6 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.



(a) Relative Price at Control Hubs

(b) Relative Price at Treated Hubs

Figure 6: 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)

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 regions (here the West Coast) and sell it in affected regions (the Deep South). However, such arbitrage would increase demand at unaffected hubs, rising gas prices. We do not see large rise in prices 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 bottleneck 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 in a parsimonious two-way fixed-effects specification. We cannot rule out anticipation as shippers may be predicting adverse weather events, and extreme events may be correlated with temperature patterns over a longer period of time, 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.

We allow for anticipation and persistence by investigating the effect in a larger window around the cold wave. As Figure 7 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) and 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.

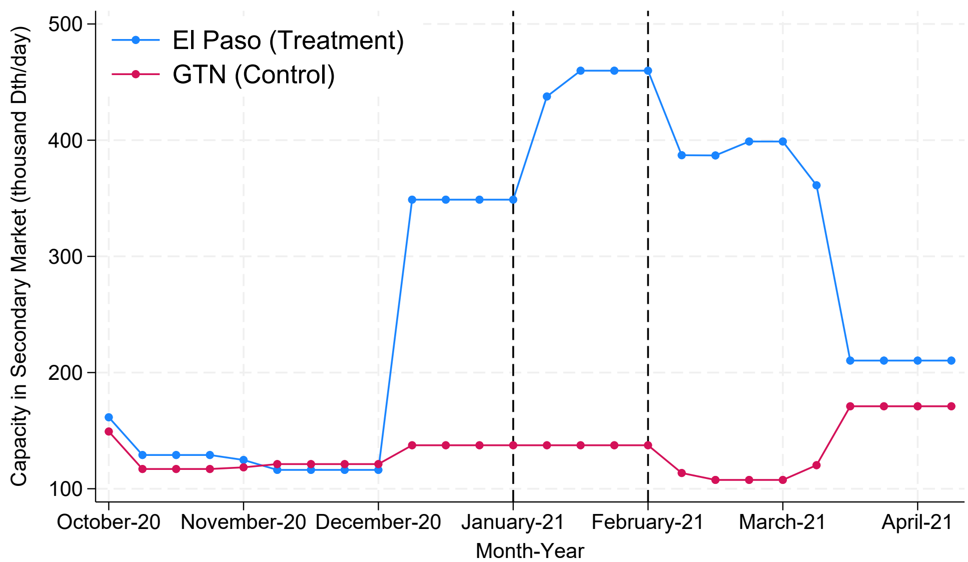


Figure 7: Total Capacity in Secondary Market by Pipeline

Notes: the outcome variation displayed in this figure is the total capacity available in the secondary market in each week. It is constructed by aggregating all contracts signed at previous dates that have contrated capacity to be 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 begining and the end pf the cold wave.

We also need to account for important seasonal variation 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 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 between each others. For example, utilities may be leasing some of their capacity to power plants every summer.

To account for this rich heterogeneity, we allow for heterogeneous seasonal variation across pipelines in the main specification below. 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 the majority of contracts are signed for a duration of one month, there is mechanically a lot of auto-correlation in y_{it}. We cluster standard errors at the monthly level to conduct inference that is robust to auto-correlation in the errors within 30 days periods.

To visualize the results, we follow the approach of Freyaldenhoven, Hansen and Shapiro (2019) by normalizing the treatment effect one week prior to 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 it is possible that shippers anticipate a cold winter as they make predictions for natural gas requirements before the winter starts. As discussed previously, there is likely a lot of persistence in these treatment effects since contracts are signed without knowing when the cold wave will end. For this reasons, we plot an estimate of the cumulative effect up to 5 weeks before and 10 weeks after the beginning of the cold wave, along with 95% confidence intervals. Normalizing the effect one week prior to the beginning of the cold wave, estimates of the cumulative event path are defined as follow:

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

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 2 months after the cold wave using the following specification:

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

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

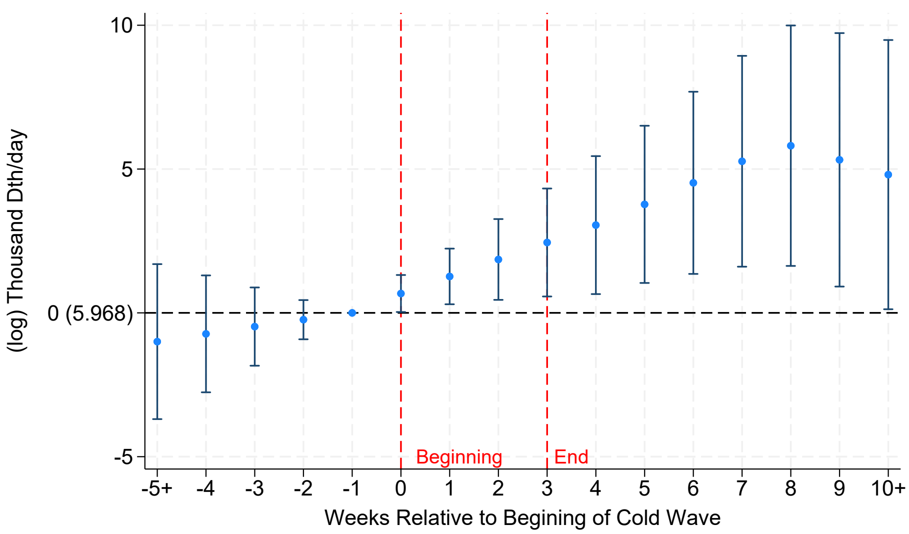
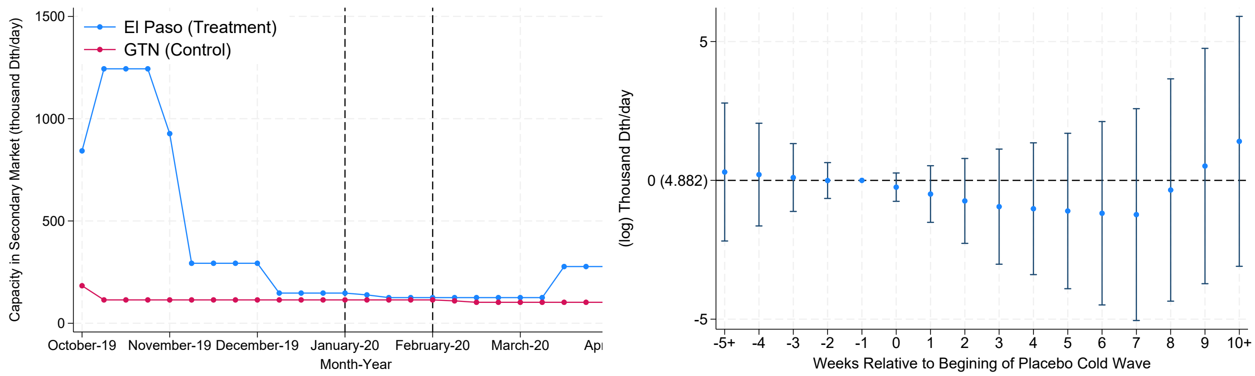


Figure 8: Baseline Cumulative Event Path

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 across all contracts that were signed prior and up to this 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 8 shows the estimated cumulative event path from the main specification in Equation 1. While there are no statistically significant anticipation effects or violation of the pre-trend assumption, these results do not literally suggest a lack of anticipation. Rather it should be interpreted as a lack of anticipation that a cold wave would start earlier than planned. Anticipation is directed embedded in the outcome variables, which aggregates previously signed contracts. However, we do find large and significant persistence 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 9.

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



(a) Total Capacity In Secondary Market by Pipeline

(b) Cumulative Event Path

Figure 9: Placebo Cold Wave (One Year Before)

Table 9: Main Results — Average Effect of Cold Wave on Capacity Release

	Real cold wave (log) Capacity	Placebo cold wave (log) Capacity
𝕀(Two Months Before x Treated)	0.251	0.349
	(0.376)	(0.405)
𝕀(One Month Before x Treated)	0.215	-0.112
	(0.336)	(0.331)
𝕀(During x Treated)	0.579*	-0.203
	(0.237)	(0.242)
𝕀(One Month After x Treated)	0.674*	-0.130
	(0.280)	(0.278)
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 rather 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.

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 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 play a crucial role when shippers face large unexpected demand shock such as the cold wave of 2021.

To be consistent with our classification in Section 3, we group all contracts from the secondary market in 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 10: Distribution of Relationship Frequency by Pipeline

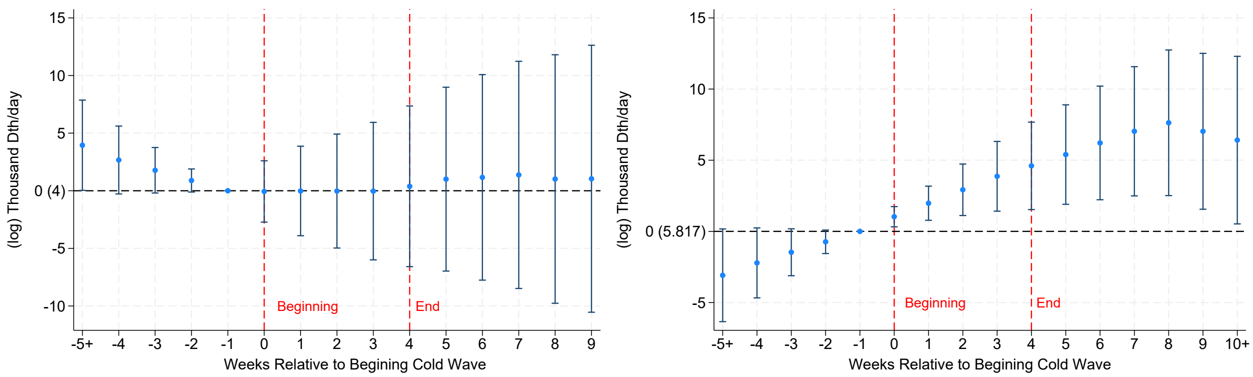
Frequency of Identical Shippers Signing Contracts	El Paso (Treatment) *Percentage (%) of Contracts*	GTN (Control) *Percentage (%) of Contracts*
Never met	1	2
Met > 0 but ≤ 5 times	22	9
Met > 5 but ≤ 10 times	18	16
Met > 10 but ≤ 15 times	15	10
Met > 15 but ≤ 20 times	8	5
Met > 20 but ≤ 25 times	9	25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

Notes: the distribution correspond 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 10, 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%.

There is a high search cost associated with finding new partners, 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 regula-

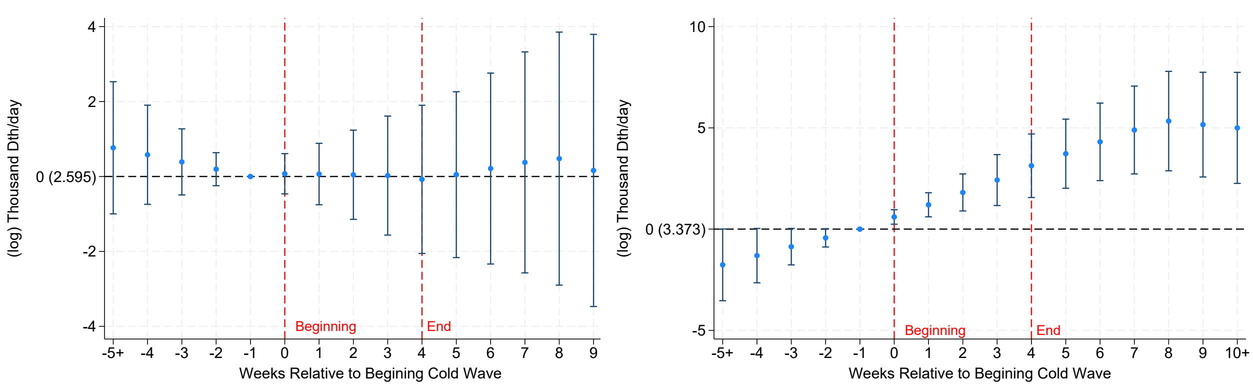


(a) Shippers met < 5 times **(b)** Shippers met ≥ 5 times

Figure 10: Cumulative Event Path by Relationship Length

tion which mandates that all contracts are posted on public platforms, the secondary market fosters the formation of long-term relationships by providing shippers with daily information on who are the key players in each market.

We further substantiate this narrative that the cold wave is associated with higher opportunity cost of searching by looking at the structure of contracts that are effective during the cold wave. Indeed, we find that 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 11: 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 the formation of relationships between an intermediary (the releaser) and a releaser.

Table 11: 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. $^{+}$ $p < 0.10$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

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 when they don't need their capacity because they want to avoid paying reservation fees for unused capacity.

Market Power

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.[8] Deregulation can incentivize market participants to engage in the secondary market, but can also introduce market power which causes frictions. We now investigate market concentration across different pipelines and zones. We find evidence that some markets have more concentrated releasers, while some have more concentrated replacers, some have both. We relate this variation in market concentration to price-setting behaviors, and find that releasers (replacers) with a higher market share tend to charge higher (lower) price.

[8]There are some exceptions, as certain contracts cannot have a rate above some maximum threshold set by the FERC. This constraint is based on the contract duration. Tarrifs on capacity released for a duration of 31 days or less or for a duration of one year or more can freely vary. Tarrifs on capacity released for a duration between 31 days and one year cannot exceed maximum tarrifs. As Figure 3 suggests, the vast majority of contracts fall within the fully deregulated time constraints.

Table 12 provides a summary statistics of market concentration across selected pipelines that have 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 tarrifs relative to the tarrifs. Since these maximum tarrifs set by the FERC and are specific to delivery and receipt points, they vary a lot across contracts and provide a benchmark to compare tarrifs. However, Table 12 does not suggest a monotonicity between releaser/replacer market power and prices. For example, both El Paso and GTN have a high concentration of releasers relative to replacers, tarrifs are significantly more likely to be below the maximum in El Paso.

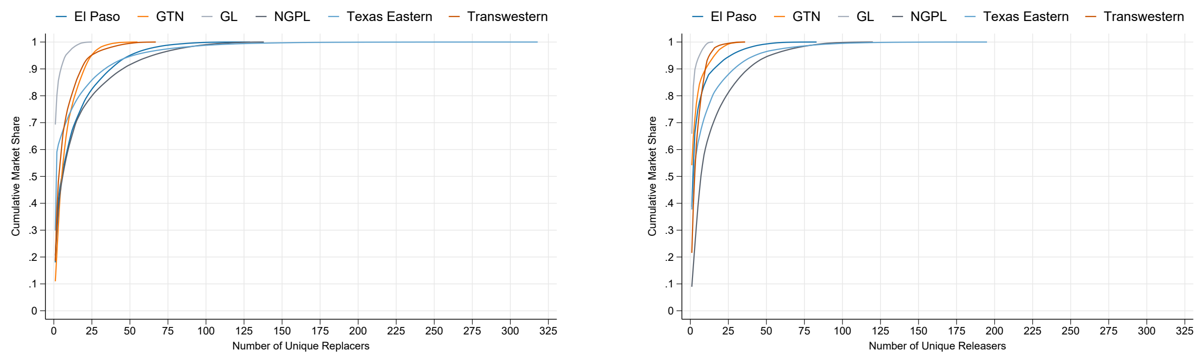
Table 12: Summary Statistics – Market Power and Prices (Secondary Market)

	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 4 price. Max correspond maximum tariff set by the FERC for those 4 prices. HHI refers to the Herfindahl–Hirschman index.

To understand this point better, we also show in Figure 12 that the cumulative distribution of market power in releasing shippers tend to be highly correlated with the cumulative distribution of market power for replacement shippers, which is likely be correlated with market thickness. Great Lakes is the most concentrated in both releasers and replacers, whereas NGPL is the least concentrated. GTN and Transwestern are more concentrated in releasers and replacers than El Paso and Texas Eastern. For this reason, only looking at variation in market concentration may not provide enough variation to investigate its effect on tariffs.

Next, we investigate the role of releaser and replacer market power on tarrifs in more details. Specifically, we investigate variation in market power at the individual releaser/replacer level. We specified the following regression model, where we consider both the log of tarrifs and the log of tarrifs relative to maximum tarrifs as outcome variables:



(a) Replacers (b) Releasers

Figure 12: Market Concentration Across Pipelines

$$\ln Y_{pcit} = \alpha_t + \alpha_p + X_{it}^T\beta + z_{cpit}^T\gamma + \beta^{rep}\ln S_{rep,it} + \beta^{rel}\ln S_{rel,it} + \epsilon_{cpit}$$

Where p indexes a delivery and receipt point pair, c indexes a contract, i indexes a pipeline and t indexes days. The main independent variables of interests are the market share of releasing and replacement shippers signing the contract, $\ln S_{rep,it}$ and $\ln S_{rel,it}$ respectively. For robustness, I consider various specifications for this market share: (1) total pipeline market share (constant across all years); (2) annual pipeline market share; (3) total market share in pipeline-specific zones (constant across all years); and (4) annual market share in pipeline-specific zones.

X_{it} are seasonal adjustments that vary by pipelines, and Z_{it} are control variables, and include relationship length between shipper and other contract characteristics such as contract duration. α_p are pipeline-specific delivery-receipt point fixed effects, so they absorbs pipeline fixed effects, and α_t are week fixed-effects. Here, β^{rep} and β^{rel} capture variation in market share across shippers and within shippers over time because we do not include shipper fixed effects.[9] All the results are robust to inclusion/exclusion of all control variables, fixed effects and seasonality.

The results in Table 13 suggest a strong relationship between market share and tariffs charged, both for replacers and releasers suggestive of price-setting behavior. Moreover, this relationship is twice as large for releasers. Remembering that releasers benefit from higher tarrifs (supply) and replacers benefit from lower tarrifs (demand), a 1% increase in releaser market share is associated with a 0.09% increase in tarrifs, whereas a 1% increase in replacer

[9] We also tried including shipper fixed effects, but there isn't enough remaining variation (e.g. only over time within shippers) because market shares tend to be fairly consistent over time.

market share is associated with a 0.04% decrease in tarrifs.

These results suggests there are two-sided market power. In such a context, it is unclear what are the welfare implications of partially deregulating the natural gas transportation industry through its secondary market. One the one hand, the secondary market allows tariffs to vary over time and respond to fluctuation 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 13, which may restrict the allocation of capacity. Thus, not only are the aggregate implications unclear, but there may be significant variation across pipelines and regions. We plan to investigate these welfare implications in future research.

Table 13: Estimation Results – log Tarrifs

	(1)	(2)	(3)	(4)
Releaser share	0.088***			
	(0.003)			
Replacer share	-0.040***			
	(0.001)			
Annual releaser share		0.063***		
		(0.003)		
Annual replacer share		-0.042***		
		(0.001)		
Zone releaser share			0.113***	
			(0.003)	
Zone replacer share			-0.037***	
			(0.001)	
Annual zone releaser share				0.103***
				(0.003)
Annual zone releaser share				-0.040***
				(0.001)
Time FE	Yes	Yes	Yes	Yes
Pipeline FE	Yes	Yes	Yes	Yes
Delivery and Receipt point FE	Yes	Yes	Yes	Yes
N	86,112	86,082	78,778	78,657
adj. R^2	0.777	0.773	0.726	0.721

Standard errors in parentheses

$^{+}$ $p < 0.10$, * $p < 0.05$, ** $p < 0.01$, *** $p < 0.001$

5 Conclusion

In this paper, we investigate a major deregulation effort in a highly deregulated industry characterized by natural monopolies: the secondary market for natural gas capacity release. This is one of the first empirical investigation of a real Coasian market in which market participants can trade contracts, allowing us to shed light on the resilience of supply chains, particularly on the supply of natural gas during period 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 by 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 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 Capacity Release Market

B.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.

B.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.