Methane and Markets: Firm Incentives to Emit *

Coly Elhai and Toren Fronsdal
Harvard University

September 22, 2023

Abstract

As the primary component of natural gas, methane is both a powerful greenhouse gas and a valuable commodity. We explore the economic factors that influence firms' decisions to emit rather than to sell the gas that they produce. Using novel data on methane emissions from the Permian Basin, we provide empirical evidence that emissions respond to high-frequency price variation. In particular, emissions are positively correlated with capacity constraints in natural gas processing and pipelines, as captured by the Henry-Waha Hub price spread. To rationalize these dynamics, we present a model of the natural gas industry in which firms make production and emissions decisions in response to oil and gas prices, as well as the cost of capturing and transporting gas. The model implies a substantial social cost to insufficient processing and transmission capacity. With the model, we estimate the impact of taxing methane emissions assuming different levels of capacity constraints.

*Many thanks to Daniel Varon and Lucas Estrada for providing data and scientific expertise to guide this project. We also thank Jim Stock, Rob Stavins, Nathan Hendren, and Jesse Shapiro for feedback on this idea. Mark Agerton, Michael Plante, Garrett Golding, and Kunal Patel provided us with valuable industry insights. We are grateful to participants of the Harvard/MIT Environmental Workshop for their suggestions. Elhai gratefully acknowledges support from the Chae Family Economics Research Fund and the National Science Foundation Graduate Research Fellowship Program.

1 Introduction

Methane is a powerful greenhouse gas, 80 times more potent than CO_2 in its first 20 years. However, as the primary component of natural gas, it is also a valuable commodity. About a quarter of U.S. methane emissions are from the oil and natural gas sector. If a greater share of this methane were captured and sold rather than emitted, the U.S. would be well on its way toward achieving its commitments under the Global Methane Pledge.

Because of methane's dual nature, it would be natural to think that emissions should decrease when the price of natural gas increases. Indeed, firms have more incentive to abate emissions when the reward for doing so increases. However, gas supply decisions are not only a function of price. For one, gas is a byproduct of oil production. As a result, gas production is determined in conjunction with oil production. For another, transporting gas is difficult. Pipelines are the only cost-effective way to move natural gas long distances, without first liquefying the gas (an expensive, energy-intensive process). When pipelines are full, producers are unable to bring their gas to market even if they would very much like to.

In this project, we explore the relationship between methane emissions, natural gas prices, and pipeline capacity constraints. We focus on the Permian Basin, an area of rich natural resource deposits located in West Texas and the southeastern corner of New Mexico. The Permian is a natural setting for our investigation because it is an area of intense oil and natural gas production. The area accounts for 17% of U.S. natural gas extraction, and over 40% of its oil (Federal Reserve Bank of Dallas, n.d.). It is also a region where pipelines have frequently hit capacity limits. We make use of recent advances in methane monitoring technology to analyze how emissions respond to these capacity constraints and other economic factors. Until recently, it has been impossible to accurately track methane emissions at any time scale, let alone at high frequency. New methods (Varon et al., 2022) use satellite measurements and atmospheric inversion techniques to produce weekly measurements of methane emissions over the Permian Basin.

Using the differential between the local (Waha) hub price and the benchmark (Henry) hub price as a proxy for pipeline capacity constraints, we find that Permian methane emissions and flaring are both significantly and positively correlated with capacity constraints. Together, our estimates suggest that during periods of constrained capacity, producers flare gas that cannot be sold rather than reducing production. Because flaring is imperfect, increased flaring releases additional methane directly into the atmosphere. These correlations are strongest in areas of the Permian where production is tilted more towards oil, a pattern implying that producers whose profits are less dependent on gas sales are also less likely to restrict gas production in the face of capacity constraints.

To rationalize our reduced-form estimates, we build a static model of firm emission decisions. In this model, firms decide on a level of oil and gas production to maximize profits at prevailing prices. Concurrently, they decide what share of the gas they produce to emit rather than capture and sell, given that both capture and transmission to customers are costly. We estimate this model using data on emissions, gas and oil prices, and gas flows through the Permian Basin. Key to our estimation strategy is a dataset on pipeline outages due to unplanned maintenance events, which provides us with exogenous shocks to pipeline capacity.

Our estimates allow us to calculate the marginal social benefit of additional pipeline capacity. We also model the emissions impact of a tax on methane (as has been proposed in the U.S.), assuming different baseline levels of capacity. We find that when capacity constraints bind, methane taxes have little to no impact on emissions. Conversely, when capacity constraints are slack, methane taxes effectively reduce producers' methane emissions while increasing the amount of natural gas brought to market.

With this research, we bring new perspectives to the policy conversation around methane emissions, which until now has focused exclusively on increasing the price of emitting. Our conclusions highlight the importance of non-price market mechanisms in determining emissions, and the possibility for alternate policies (changes in pipeline permitting, new regulations around well drilling, etc.) in addressing this important issue. In future work, we plan to build a dynamic model of pipeline investment decisions to better understand how market structure and regulation contribute to pipeline capacity frequently undershooting natural gas production.

2 Background

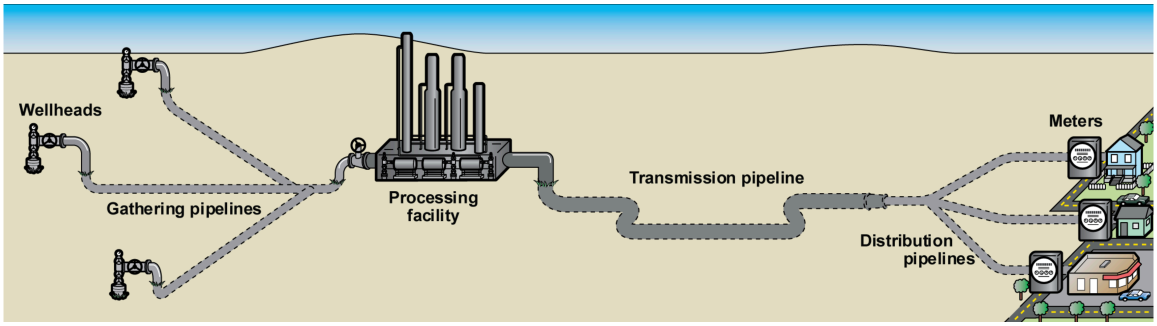
2.1 Gas Extraction and the Permian Basin

The Permian Basin's geological formations contain a substantial amount of both oil and natural gas. Drilling for oil produces gas as a byproduct, even at wells that are intended primarily for oil production, because oil can contain a significant quantity of dissolved natural gas. Oil is the more lucrative business in the Permian, which means that producers are willing to sustain very low profits (or even losses) from the gas side of their operation if it allows them to continue producing oil. McKinsey estimates that just one quarter of gas production is not associated with oil, and is thus responsive to natural gas prices (Brick, 2018).

Because of the vast amounts of methane released and transported by the oil and gas sector, methane emissions in the Permian Basin are substantial. Permian Basin methane emissions were estimated to be 2.5 Tg in 2019, about 15% of the U.S.' total methane emissions, or equivalent to the emissions from the electricity used to power 12 million U.S. homes over the course of one year (Lu et al., 2023). Recent estimates by Cusworth et al. (2021) indicate that about half of Permian methane emissions are from production, which is the segment of the industry that we focus on in this paper.

The fracking revolution led to a tripling of natural gas production in the Permian since 2011, but pipeline infrastructure has not always kept pace with this rapid expansion in supply. Industry news sources describe frequent shortfalls in pipeline capacity as the primary reason why natural gas spot prices at Waha Hub (the main hub serving the Permian Basin) often enter negative territory.

Figure 1: The Natural Gas Supply Chain



Notes: This figure was produced by the GAO.

This points towards an important feature of natural gas: it is difficult to transport, far more so than oil. Whereas oil can be stored in tanks and carried on trains, natural gas cannot be cost-effectively moved long distances in its gaseous state except via pipeline. Aboveground storage of natural gas is also cost prohibitive. Despite recurring capacity issues in the Permian, producers have been unable to find a scalable alternative to long-distance transmission pipelines for bringing their gas to market. Capacity is a challenge further upstream as well: producers need to use gathering pipelines and processing plants to bring their gas to transmission pipelines in the first place (Figure 1). Construction of this upstream infrastructure has also failed to keep pace with gas production.

The main legal alternative producers have to selling their natural gas is to flare it, i.e. burn it in a controlled way so that the methane is transformed into less environmentally harmful gasses (mainly carbon dioxide) before entering the atmosphere. Flaring is regulated in both Texas and New Mexico. In Texas, flaring is permitted in the first 10 days after a well is completed. Outside of this window, producers must file a flaring permit request with the Texas Railroad Commission (RRC) and pay a $375 fee. However, according to a Wall Street Journal investigation, the RRC approves all flaring requests (Elliott, 2018). Importantly, flaring does not entirely prevent methane emissions: Lyon et al. (2021) find combustion efficiency in the Permian to be around 93% due to unlit and malfunctioning flares.

The other alternative to selling or flaring gas is to vent the gas directly into the atmosphere, which is far more environmentally damaging. In Texas, venting is permitted for up to 24 hours at a time, or up to 72 hours in a month. Venting is otherwise prohibited in the state. In this paper, we consider venting to be outside the option set of producers because of these legal restrictions.

Qualitative work suggests a link between frequent capacity issues and flaring activity. A 2019 Dallas Federal Reserve survey asked 146 oil and gas executives why flaring increased in the Permian Basin that year. Nearly three-quarters of respondents attributed flaring increases to insufficient pipeline takeaway capacity, while nearly half cited a lack of gathering and processing capacity (Figure A.1). In this project, we seek to quantify the significance of the capacity channel for methane emissions.

2.2 Satellite Measurement of Methane Emissions

Previous research on the climate costs of oil and gas production has been hampered by the quality of data available on methane emissions. Until recently, large-scale methane measurement has only been possible using firm surveys, bottom-up inventories, and aircraft campaigns. The EPA's Greenhouse Gas Reporting Program is an example of the first: this annual survey is mandatory for large emitters, but relies on firms being honest and accurate regarding their own emissions. The second method, bottom-up inventories, involves measuring the carbon intensity of different activities (e.g. drilling for oil) and multiplying by how many units of activity (e.g. wells) there are. This method is not suited to tracking how carbon intensity varies across units or over time. The final method, flying aircraft armed with methane sensors over areas of interest, is accurate but resource intensive. It has not been feasible to use this technique to create panel datasets on an entire region's emissions.

Recent advances in satellite instruments and atmospheric modeling have revolutionized methane measurement. Varon et al. (2022) is an example of this progress. The authors' work is based on satellite observations from the TROPOspheric Monitoring Instrument (TROPOMI). The TROPOMI instrument can sense methane concentrations at a high spatial resolution, but is unable to determine where the methane originated from. To that end, the authors apply a cutting-edge model of atmospheric transport (GEOS-Chem) combined with prior estimates of emissions from the EDF's 2018 bottom-up inventory. The result is a set of weekly emissions estimates at a 25×25 km^2 resolution, covering the entire Permian Basin over the period from May 2018 to October 2020.

2.3 Prior Economic Literature

We contribute to an emerging literature on the marginal abatement costs of methane, much of which is summarized in Agerton, Gilbert and Upton (2023). Lade and Rudik (2020) calculates firm-specific abatement cost curves for oil and gas producers in North Dakota using observed distances between wells and pipeline infrastructure, and then linking estimated costs with actual flaring behavior. We expand on this work by linking flaring behavior with methane emissions, which they are unable to measure directly. We also provide a framework to explain how firm incentives to abate could vary not just with the presence of infrastructure but also with the costs associated with its use. In complementary work, Hausman and Muehlenbachs (2019) estimate abatement costs using data on spending to prevent natural gas pipeline leaks. They find that firms spend less on leak prevention than they should, based on the value of the leaked gas. The authors posit that distribution firms underspend on leak prevention because they can exercise their monopoly power to pass on the cost of leaked gas to consumers. This research highlights the importance of market incentives in firm emission decisions, a theme that our project explores on the production side of the industry.

Closest to our work is Marks (2022), which estimates a marginal abatement cost curve for methane among oil and gas producers using annual, firm-reported statistics on emissions. There are known issues with these self-reported statistics, since firms may not be forthcoming about (or even aware of) their true emissions. The annual nature of the firm-reported data also makes it impossible for this work to follow high-frequency variation in both emissions and prices. We build on this work by applying estimates from Varon et al. (2022) to the problem. The availability of more accurate, higher frequency data gives us a better vantage point from which to examine the decisions that operators make. Furthermore, while Marks uses only the spot price of natural gas to infer abatement costs, our model allows for producer decisions to vary with oil prices and congestion as well. We believe that this is a better fit for an industry characterized by joint production and binding capacity constraints.

There is a substantial literature on optimal emissions regulation. Fowlie, Reguant and Ryan (2016) examines greenhouse gas regulation in the cement industry, and how regulations can increase welfare gains by accounting for market power and emissions leakage. Werner and Qiu (2020) simulates audit-based methane regulation policies, proposing an audit strategy that targets wells based on remotely sensed data on leaks. Cicala, Hémous and Olsen (2022) propose a policy in which firms can voluntarily disclose emissions and pay a tax based on those emissions to avoid paying a tax based on average emissions among non-disclosers. Given this setup, adverse selection leads the market to unravel in favor of disclosure. Our work contributes to this literature by studying the way in which firms' emissions decisions vary with market forces. Rather than taking as given the cost of abatement, we work to better understand the factors entering into firm decisions and how regulation could interact with these factors.

Finally, our work relates to the literature on pipelines, transport costs, and investment decisions. Covert and Kellogg (2017) models crude oil pipeline investment in the presence of an alternate transport technology (railroads), examining optimal regulation given the environmental externalities of each technology. Oliver, Mason and Finnoff (2014) builds a network model to evaluate the connection between natural gas pipeline congestion and spot prices. Brito and Rosellón (2011) examine the trade-off between the costs of excess pipeline capacity and the risk of congestion, finding that for reasonable parameter values consumers prefer to pay the former to avoid the latter. Ponder (2022) estimates the impact of price regulation on pipeline investment during the fracking revolution of the 2010s, using a dynamic structural model to show that price caps imposed by the government more effectively incentivized market entry and efficient operations than alternate regulation would have. We bridge the gap between the pipeline and emissions literatures, showing how pipeline capacity can influence emissions and what this implies for optimal pipeline regulation.

3 Data

We use the aforementioned weekly estimates of methane emissions over the Permian Basin from Varon et al. (2022), which cover the period May 2018 to October 2020. These estimates are generated at the level of 25×25 km^2 cells. We primarily use basin-level and sub-basin level aggregates of these estimates, though we are also able to aggregate to the county level.

We use daily natural gas spot price data for Henry Hub and Waha Hub from S&P Global Platts, along with Cushing WTI spot prices from EIA. In most of our analysis, we use weekly averages of daily prices.

Oil and gas production data are from Enverus DrillingInfo at the well-month level. This dataset includes information on first production date, as well as features such as well operator and well type that we have not yet integrated into our analysis.

Data on flaring is from Lyon et al. (2021), which uses observations from the Visible Infrared Imaging Radiometer Suite (VIIRS) satellite instrument to calculate the number of flares and volume of gas flared each month. Not that because this methodology is based on VIIRS-derived radiant heat, it may not capture malfunctioning or unlit flares.

To examine gas flows through pipelines, we use S&P Capital IQ Pro's data on gas receipt and delivery points. This resource provides measurements of maximum capacity, utilized capacity, and contracted capacity for over 2,000 receipt and delivery points in the Permian Basin. These points represent places where gas enters the pipeline system, is transferred to end-use customers, moves between pipelines, or is processed at a processing plant. Importantly, all of the points on this dataset are on interstate pipelines, which are much more highly regulated than intrastate pipelines. Unfortunately, many of the pipelines connection the Permian Basin to the Gulf Coast are intrastate, and thus unobservable to us. Another limitation of this dataset is that pipeline operators do not always update reported maximum capacity numbers when equipment failures occur. As a result, we are unable to confidently distinguish between points that are operating with low utilization because of low demand as opposed to low available capacity.

References

Agerton, Mark, Ben Gilbert, and Gregory B. Upton. 2023. "The Economics of Natural Gas Flaring and Methane Emissions in US Shale: An Agenda for Research and Policy." *Review of Environmental Economics and Policy*, 17(2): 251–273. Publisher: The University of Chicago Press.

Anderson, Soren T., Ryan Kellogg, and Stephen W. Salant. 2018. "Hotelling under Pressure." *Journal of Political Economy*, 126(3): 984–1026. Publisher: The University of Chicago Press.

Besanko, David, and Ulrich Doraszelski. 2004. "Capacity Dynamics and Endogenous Asymmetries in Firm Size." *The RAND Journal of Economics*, 35(1): 23–49. Publisher: [RAND Corporation, Wiley].

Brick, Jamie. 2018. "Permian, we have a gas problem(s)." McKinsey & Company.

Brito, Dagobert L., and Juan Rosellón. 2011. "Lumpy Investment in Regulated Natural Gas Pipelines: An Application of the Theory of the Second Best." *Networks and Spatial Economics*, 11(3): 533–553.

Cicala, Steve, David Hémous, and Morten G Olsen. 2022. "Adverse Selection as a Policy Instrument: Unraveling Climate Change." National Bureau of Economic Research w30283, Cambridge, MA.

Covert, Thomas, and Ryan Kellogg. 2017. "Crude by Rail, Option Value, and Pipeline Investment." National Bureau of Economic Research w23855, Cambridge, MA.

Cusworth, Daniel H., Riley M. Duren, Andrew K. Thorpe, Winston Olson-Duvall, Joseph Heckler, John W. Chapman, Michael L. Eastwood, Mark C. Helmlinger, Robert O. Green, Gregory P. Asner, Philip E. Dennison, and Charles E. Miller. 2021. "Intermittency of Large Methane Emitters in the Permian Basin." *Environmental Science & Technology Letters*, 8(7): 567–573.

Elliott, Rebecca. 2018. "In America's Hottest Drilling Spot, Gas Is Going Up in Smoke." *Wall Street Journal*.

Federal Reserve Bank of Dallas. n.d.. "Energy in the Eleventh District: Permian Basin."

Fowlie, Meredith, Mar Reguant, and Stephen P. Ryan. 2016. "Market-Based Emissions Regulation and Industry Dynamics." *Journal of Political Economy*, 124(1): 249–302. Publisher: The University of Chicago Press.

Hausman, Catherine, and Lucija Muehlenbachs. 2019. "Price Regulation and Environmental Externalities: Evidence from Methane Leaks." *Journal of the Association of Environmental and Resource Economists*, 6(1): 73–109.

Kreps, David M., and Jose A. Scheinkman. 1983. "Quantity Precommitment and Bertrand Competition Yield Cournot Outcomes." *The Bell Journal of Economics*, 14(2): 326–337. Publisher: [RAND Corporation, Wiley].

Lade, Gabriel E., and Ivan Rudik. 2020. "Costs of inefficient regulation: Evidence from the Bakken." *Journal of Environmental Economics and Management*, 102: 102336.

Lu, Xiao, Daniel J. Jacob, Yuzhong Zhang, Lu Shen, Melissa P. Sulprizio, Joannes D. Maasakkers, Daniel J. Varon, Zhen Qu, Zichong Chen, Benjamin Hmiel, Robert J. Parker, Hartmut Boesch, Haolin Wang, Cheng He, and Shaojia Fan. 2023. "Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics." *Proceedings of the National Academy of Sciences*, 120(17): e2217900120.

Lyon, David R., Benjamin Hmiel, Ritesh Gautam, Mark Omara, Katherine A. Roberts, Zachary R. Barkley, Kenneth J. Davis, Natasha L. Miles, Vanessa C. Monteiro, Scott J. Richardson, Stephen Conley, Mackenzie L. Smith, Daniel J. Jacob, Lu Shen, Daniel J. Varon, Aijun Deng, Xander Rudelis, Nikhil Sharma, Kyle T. Story, Adam R. Brandt, Mary Kang, Eric A. Kort, Anthony J. Marchese, and Steven P. Hamburg. 2021. "Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic." *Atmospheric Chemistry and Physics*, 21(9): 6605–6626. Publisher: Copernicus GmbH.

Marks, Levi. 2022. "The Abatement Cost of Methane Emissions from Natural Gas Production." *Journal of the Association of Environmental and Resource Economists*, 9(2): 165–198.

Oliver, Matthew E., Charles F. Mason, and David Finnoff. 2014. "Pipeline congestion and basis differentials." *Journal of Regulatory Economics*, 46(3): 261–291.

Ponder, Mark. 2022. "The Impact of Price Regulation on U.S. Pipeline Investment During the Shale Revolution."

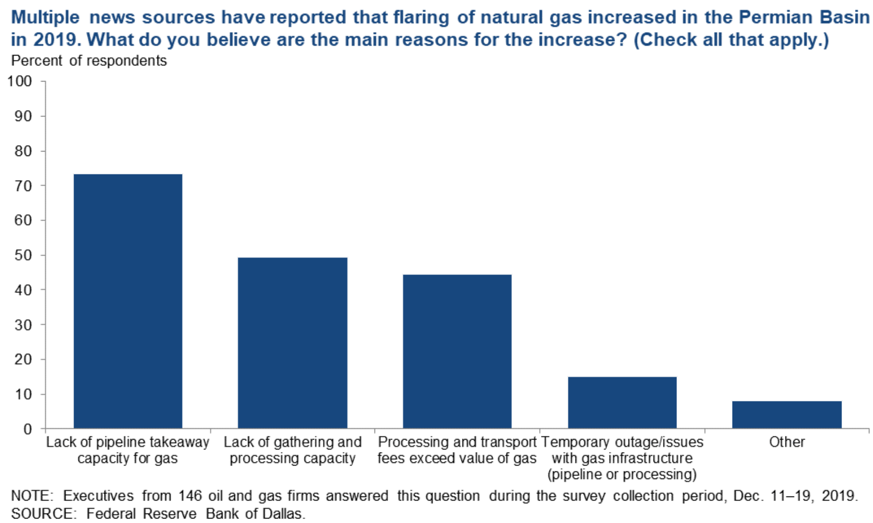
Varon, Daniel J., Daniel J. Jacob, Benjamin Hmiel, Ritesh Gautam, David R. Lyon, Mark Omara, Melissa Sulprizio, Lu Shen, Drew Pendergrass, Hannah Nesser, Zhen Qu, Zachary R. Barkley, Natasha L. Miles, Scott J. Richardson, Kenneth J. Davis, Sudhanshu Pandey, Xiao Lu, Alba Lorente, Tobias Borsdorff, Joannes D. Maasakkers, and Ilse Aben. 2022. "Continuous weekly monitoring of methane emissions from the Permian Basin by inversion of TROPOMI satellite observations." Atmospheric Chemistry and Physics preprint, European Geosciences Union.

Werner, Karl Dunkle, and Wenfeng Qiu. 2020. "Hard to Measure Well: Can Feasible Policies Reduce Methane Emissions?" Energy Institute at Haas WP 310.

7 Appendix

A Figures

Figure A.1: Self-reported reasons to flare



Notes: This chart was produced by the Dallas Federal Reserve as part of their report on their 2019 survey.

Figure A.2: Mitigation decisions and firm size

Response	Percent of respondents (among each group)		
	Small firms	Large firms	All firms
Plan to reduce CO_2 emissions	22	65	34
Plan to reduce methane emissions	38	65	46
Plan to reduce flaring	43	61	48
Plan to recycle/reuse water	25	48	31
Plan to invest in renewables	2	17	6
None of the above	35	17	30

NOTES: Executives from 83 exploration and production firms answered this question during the survey collection period, Dec. 7–15, 2022. Small firms produced less than 10,000 barrels per day (b/d) in fourth quarter 2022, while large firms produced 10,000 b/d or more. Responses came from 60 small firms and 23 large firms.
SOURCE: Federal Reserve Bank of Dallas.

Notes: This chart was produced by the Dallas Federal Reserve as part of their report on their 2022 survey.

Production problem

- Firms co-produce oil and gas, then decide what share of gas to capture vs. emit
- Gas production q^g is a linear function of oil production q^o. For firm-specific α,

$$q^g(q^o) = \alpha q^o$$

- Firm decision:
  - **State variables**: p^o (price of oil), p^g (price of gas), u (pipeline utilization rate)
  - **Control variables**: q^o (oil production), e (emissions rate)
- Firms profit maximize according to:

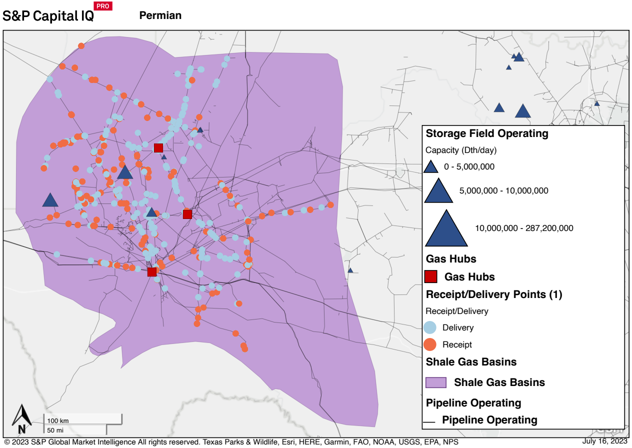
$$\max_{q^o, e \in [0,1]} \underbrace{p^o q^o - c^o(q^o)}_{\text{oil profit}} + \underbrace{p^g[(1-e)q^g(q^o)]}_{\text{gas revenue}} - \underbrace{c_a(1-e)q^g(q^o)}_{\text{capture cost}} - \underbrace{c_t(u)(1-e)q^g(q^o)}_{\text{transmission cost}}$$

- When pipelines are near capacity constraints (u is large), $c_t(u)$ is high
- But, given p^o sufficiently high, firms optimally choose large e and continue to produce

Challenge: How to measure capacity utilization?

So far, we have relied on the Henry-Waha gap to proxy for congestion. Can we measure this more directly?

1. Use receipt/delivery point data
   - For points on interstate pipelines, observe daily flows and max capacity
   - Estimate $p_H - p_W \approx c_t^{HW} = \hat{g}(u_t^{HW})$. Then, obtain $\hat{c}_t^P = \hat{g}(u_t^P)$
   - However: figures are reported by pipelines, max capacity not always up-to-date
   - Missing data on intrastate pipelines



Challenge: How to measure capacity utilization?

2. Instrument using maintenance
   - Purchase dataset of pipeline-reported maintenance and outages
   - Use known capacity reductions to determine effect of capacity constraints on price gap: $c_{t+1}^{HW} - c_t^{HW} = \hat{g}(u_{t+1} - u_t)$
3. Instrument using shocks to oil prices
   - Wells are most productive when first drilled
   - Drilling responds strongly to oil prices
   - Hypothesis: $\uparrow$ oil prices $\rightarrow \uparrow$ new wells $\rightarrow \uparrow$ gas supply $\rightarrow \uparrow$ pipeline congestion
   - Link exogenous increases in gas volumes to observed changes in price gap

Prices and production: intensive margin

Figure: Gas from existing gas wells

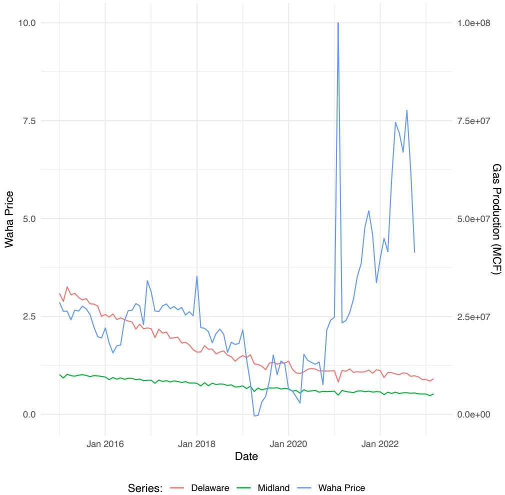
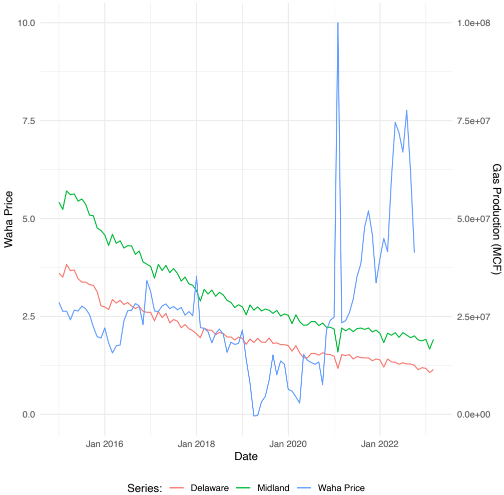


Figure: Gas from existing oil wells



Prices and production: extensive margin

Figure: Drilling + gas prices

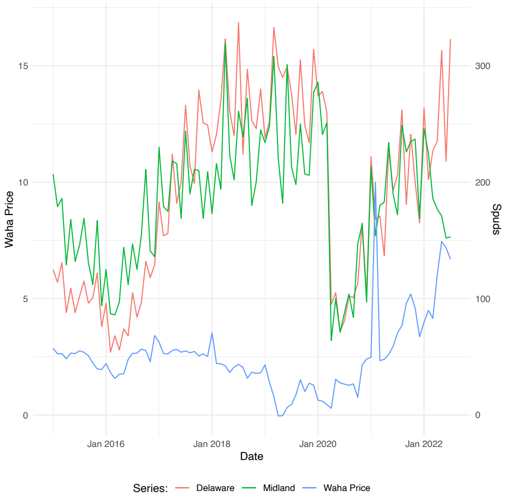


Figure: Drilling + oil prices