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An Introductory Guide with Research Questions for the Energy Transition

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The U.S. Gas Pipeline Transportation Market:

An Introductory Guide with Research Questions for the Energy Transition

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Abstract

Natural gas currently represents close to a third of U.S. primary energy consumption and has often been described as a bridge fuel in the context of the ongoing energy transition. As coal plants are retired and the share of variable renewable resources in the U.S. power markets grows, power sector CO_2 emissions are declining and gas-fired power plants increasingly relied upon to provide peak and balancing services to complement the variable electricity supply from wind and solar plants. Growth in gas-fired electricity generation in the past decade has made the power sector the largest user of the U.S. interstate gas pipeline network, just ahead of the industrial and building sectors. Nevertheless, future gas demand from these latter two sectors, and from the power sector, is expected to be reduced by policy and regulatory initiatives aimed at electrification of heating loads and economy-wide decarbonization. These developments open up important questions around the role of the U.S. interstate pipeline network in the ongoing energy transition. Such questions include what changes may be needed in the gas transportation markets to provide more flexible gas delivery services to gas-fired generators that provide valuable balancing in the power markets, and how long-term stranded asset risk for gas transportation infrastructure should be managed in the face of electrification and decarbonization. The objective of this paper is to facilitate further research to address these types of questions by outlining the main market features and regulations important for understanding the U.S. gas transportation market.

Keywords

Gas transportation markets, natural gas, pipelines, market design, economics of regulation, electrification, decarbonization

JEL classification numbers

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Contents

1. Introduction

Natural gas has often been described as a bridge fuel in the context of decarbonizing the energy system, even though achieving greenhouse gas (GHG) benefits from replacing coal or petroleum with natural gas relies on limiting the methane emissions along the gas supply chain.[1] The U.S. power system is already going through a major transition in which variable renewable energy sources (VREs) and gas-fired power plants are providing an increasing share of electricity supply and coal plants are being retired. This energy transition will be driven further by continued cost reductions for utility-scale wind and solar power, which in many places are already cost competitive compared to fossil fuel-fired generation,[2] and by policy goals for economy-wide decarbonization. These drivers imply pressure to further reduce fossil fuel resources in the power markets and to electrify at least parts of the building, transportation and industrial sectors, resulting in energy demand moving away from natural gas and petroleum and toward the power markets.

While gas-fired power plants currently produce close to 40% of U.S. electricity, continued penetration of wind and solar power into the market due to their advantagous economics and policy targets for 100% clean electricity implies decreasing future demand for electricity generated with natural gas. To reach policy goals for economy-wide net zero GHG emissions by 2050, capacity factors for gas-fired genetors will need to fall as we get closer to that date. Any gas-fired power plants remaining in three decades' time would need to have their carbon emissions compensated by negative emissions elsewhere and/or be outfitted with carbon capture and storage (CCS) technology. As their capacity factors fall during this transition, gas-fired generators will instead play a key role as peak capacity at times when VRE electricity production from wind and solar plants is low and/or electricity demand is high. They can also provide valuable ramping services for grid balancing in power markets with high shares of VREs in response to deviations from the predicted electricity supply from VREs. By implication, the U.S. interstate pipelines have an important role to play in the energy transition by providing the

[1] See Alvarez et al. (2012) on methane leakage as a determinant of the climate impacts of switching to natural gas, and Alvarez et al. (2018) for an assessment of the methane emissions from the U.S. oil and gas supply chain.
[2] See Lazard (2020) for a comparative analysis of various power-generation technologies on a levelized cost of energy ($/MWh) basis.

flexible gas delivery services that the gas-fired generators will need to deliver these peak and ramping services in the power markets.[3]

Lower future demand for gas-generated electricity would, in combination with electrification of heating loads in the residential and commercial sectors, also imply a reduction in the total volumes of gas transported through the interstate pipelines (as well as the gas distribution system, where space and water heating are large fractions of end-use demand for gas in some regions). These trends thereby open up important questions around how the interstate pipelines will manage this reduction in their revenue base, and who is, or should be, shouldering the costs of the gas transportation infrastructure and the risk of some of these assets becoming stranded in a low-carbon-energy future.

As further described in this report, the interstate pipeline market and its operational practices were primarily designed to deliver gas to more predictable sources of gas demand. These include heating loads in residential and commercial buildings, as a fuel source and feedstock for industry, and for 'baseload' gas-fired power generation, but not for gas-fired generators with highly variable gas demand. More analysis is therefore needed of how the gas transportation market design can be improved to better accommodate this shift in customer composition, gas demand profiles and pipeline service needs throughout the energy transition.

This paper is intended as a guide for anyone interested in the U.S. gas transportation markets. It outlines the main market features and regulations important for understanding the basic features of this market. The objective of the paper is to stimulate further research and analysis on how to improve the design, regulation and operation of this market to facilitate an efficient use of the U.S. gas transportation system throughout the ongoing energy transition, and to manage stranded asset risk and associated distributional impacts.

Section 2 describes the primary market for gas transportation, which is defined by the long-term contracts between the interstate pipeline companies and their customers, and how the rates charged to primary customers are regulated by the Federal Energy Regulatory Commission (FERC). Section 3 describes the secondary market and the main features of the gas spot market. Section 4 describes pipeline operations and practices. To facilitate new research and analysis, Section 5 provides guidance on where to find data on the U.S. gas transportation markets.

[3] As the energy system gets closer to net zero CO_2 emissions, gas-fired peak and ramping capacity will likely need to be complemented with energy storage.

Section 6 discusses potential market design updates that could potentially improve market efficiency in the U.S. gas transportation markets. Section 7 describes models that can be used for simulation analyses of the U.S. gas–electric intersection. Finally, Section 8 outlines a few of the many possible avenues of research on the role of natural gas and the gas pipeline network in the U.S. energy transition.

2. The primary market for gas transportation

The current market design for U.S. natural gas transportation was established through a series of reforms implemented by FERC in the 1980s and 1990s. These reforms separated the gas transportation service market from the gas commodity market and required interstate pipeline companies to sell their transportation services through long-term contracts for pipeline capacity (Marks et al. 2017). Previously, interstate pipeline companies would buy gas from producers at the wellhead, transport it to retail distributors, and sell it for a single bundled price that encompassed the costs of both the transportation service and the gas commodity itself (for more background, see Oliver and Mason [2018]).

Since the reforms of the 1980s and 1990s, the interstate pipeline companies no longer take ownership of the gas at any point and sell only gas transportation and storage services. The majority of their revenue comes from the long-term gas transportation contracts under which they charge their customers, such as local gas distribution utilities, rates that are regulated by FERC (as described in Section 2.1).[4] The long-term contracts between the pipeline companies and their customers define the main features of the primary market for interstate gas transportation.

2.1 Cost-of-service regulation of interstate gas pipelines

As an industry with natural monopoly features under federal jurisdiction, interstate pipeline companies have their revenues regulated by FERC.[5] Under the Natural Gas Act of 1938, the rates

[4] The degree to which FERC regulation is binding depends on whether there are several competitive alternatives for gas pipeline transportation between the point of gas injection and the point of gas delivery (P. L. Joskow, pers. comm., November 2020).

[5] Intrastate transportation of natural gas is typically regulated by state agencies, such as a state public utilities commission, rather than FERC.

charged to the pipeline users are required to be "just and reasonable." The default methodology used by FERC is cost-of-service ratemaking, in which it sets rates at the level required to recover a pipeline's cost of providing service, including a rate of return on its investments (FERC 2019a). However, compared to more traditional cost-of-service regulation of gas and electric utilities, FERC's regulation of the gas pipelines is more "lighthanded," since some gas transportation routes are served by several different pipelines that compete for customers. Instead, FERC practice relies on competitive bidding and negotiation between the pipelines and their customers under the shadow of cost-of-service regulation, which functions more as a backstop (P. L. Joskow, pers. comm., November 2020).

2.1.1 Costs of service and ratemaking

An interstate pipeline's rates are typically established using one of the three methods below. See, e.g., AGA (2011) and FERC's (1999a) *Cost-of-service rates manual* for further details beyond the overview provided in this section.

- The cost-of-service method (further described below) is based on the pipeline providing FERC with documentation of capital investments and operational costs in a cost-of-service study, which in turn is used to set the pipeline's so-called "recourse rate."
- The negotiated rate method allows the pipeline to charge a rate that is negotiated and agreed upon between it and the pipeline customer. To safeguard against unequal bargaining power, the customer has the option to select service under the pipeline's recourse rate, which is based on the pipeline's cost of service as above. The recourse rate effectively serves as a price cap.[6]
- The market-based rate method may be employed when a pipeline can demonstrate that it does not have market power on the relevant gas transportation route. In this case, the pipeline is allowed to charge rates based on market conditions (AGA 2011).

The primary contracts established with either of these methods may have different durations and different terms of service. The cost-of-service study is an analysis that is used to determine the costs of serving the pipeline's customers. The three main cost categories are rate base, return and operational expenses. Since the gas transportation market is, as noted above, separated

[6] For more details on FERC's approach to market-based and negotiated rates, see Federal Register (1996).

from the physical gas commodity market, the costs discussed here therefore relate only to the costs of transporting gas and do not include the cost of the gas commodity.[7]

The rate base is the amount of capital investment the pipeline company has made in facilities and equipment, such as pipes, land, buildings and compressors (AGA 2011). Return is the amount the operator earns as a return on those investments and is generally determined by multiplying the rate base with the allowed rate of return (further discussed in Section 2.1.2). The rate base at FERC (and most state public utility commissions) is based on the "depreciated original cost" of these facilities. Because accumulated depreciation is subtracted, other things being equal, the rate base declines over time if there is no additional investment (see, e.g., Davis [2009] and FERC [1999a] for more details).[8]

Operational expenditures include items such as operating, labor and maintenance costs, taxes, and administrative costs (AGA 2011). Operational costs are passed through to customers without the pipeline companies charging a markup, and — in contrast to the rate base — are therefore not a source of net revenue and potential profits to the companies. Operational expenditures also include an annual depreciation item, even though this is a non-cash expense and is usually based on straight-line depreciation (Davis 2009).

Once these cost categories have been identified, they are used to determine the recourse rate and assigned to be recovered through either of the two elements of a pipeline's demand rate: the usage fee and the reservation fee (GAO 1993).[9] Recourse rates typically decline over time, as the pipeline's rate base depreciates. Under the negotiated rate method, these two elements are both negotiable (Jost and Benson 2016).

- The usage fee is set to recover the variable costs — i.e., costs that vary with the amount of gas transported (GAO 1993) — and is applied per unit of gas transported under the billing period.

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[7] The cost of the gas commodity does, however, feature as part of the operational cost, e.g., the cost of the gas used to fuel compressor stations.

[8] See Schmalensee (1989) for a discussion on the relationship between depreciation schedules and profitability under rate of return regulation. Companies keep two measures of "book value" (the depreciated value of their assets), one for rate of return regulations and related reporting, and another for tax purposes, since the allowed depreciation rate for taxes can differ from the one allowed under rate of return regulation.

[9] Other common rate designs, more typically used by electric and gas distribution utilities, are flat volumetric rates and/or fixed monthly fees.

- The reservation fee is typically significantly higher and set to recover the pipeline's fixed costs — i.e., costs that do not vary with the amount of gas transported (GAO 1993). The reservation fee is applied to each unit of capacity the customer is allowed to reserve during periods of peak demand under the contract.

Customers with so-called firm service primarily pay for their pipeline capacity through this reservation fee, which is constant regardless of how much gas they end up transporting on the pipeline (GAO 1993). Essentially, the firm customers pay for the right to use the pipeline when they need to, rather than for their actual usage of it.

In contrast, customers with so-called interruptible (non-firm) service primarily pay for their pipeline services through a usage fee that is applied to each unit of gas they transport (GAO 1993). The interruptible service usage fee typically differs from the usage fee under the firm service rate and may be set to additionally recover some of the pipeline's fixed costs.

These regulated rates are designed to give pipeline companies the opportunity to recover their costs and make a return on investment, but they are not a revenue guarantee. If a pipeline does not achieve its authorized level of revenue (as determined by the cost of service and associated rates), there is usually no compensation. In such cases, the company can request a new rate going forward, but it may not recover revenue lost in the past. Customers can also file a complaint with FERC challenging a pipeline's rates (AGA 2011).

That the majority of the interstate pipelines' primary customers, the firm service customers, face a reservation fee that is a fixed cost to them regardless of how much gas they end up using is an important consideration in the context of decarbonization and the ramping services needed from the gas-fired generators to balance VRE generation. In regions with restructured electricity markets and centrally organized wholesale electricity markets, such as ISO New England (ISO-NE) and PJM, merchant gas-fired electric generators have tended not to sign up for firm long-term contracts with associated fixed reservation fees because doing so is considered too financially risky.[10]

Alternative pipeline service options need to be considered in pipeline tariffs, with rate designs that are more suitable for gas-fired generators and their highly variable gas demand (see, e.g., INGAA [2019] for the natural gas pipeline industry's own recognition of this need). Primary

[10] The firm service customers can, however, choose to sell their capacity in the secondary market somewhat mitigating this risk.

contracts with more sophisticated rate designs that are reflective of both location- and time-varying gas delivery constraints and the costs of providing flexible gas delivery services could improve utilization of the interstate pipeline capacity. At the same time, they could also facilitate reliable provision of ramping services in power markets with high shares of VREs.

2.1.2 Regulated rates of return

The allowed rate of return under FERC regulation reflects the estimated weighted average cost of capital for the pipeline, and is the weighted average of the return on equity (ROE) and the embedded cost of debt, adjusted for income taxes net of the tax shield from debt (see FERC [1999a] for details).[11] However, unlike many of the cost items in a cost-of-service study — including the cost of debt — a pipeline's ROE is not directly observable and is therefore estimated by FERC according to the methods described in this section.

Interstate pipelines currently receive regulated ROEs of approximately 10% as established by FERC practice (see, e.g., FERC [2018]), but in practice ROEs may also be higher than that (see, e.g., Troutman Pepper [2019]). According to rulings by the Supreme Court, "the return to the equity owner should be commensurate with the return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital" (U.S. Supreme Court 1944). In May 2020, FERC updated its methodology for establishing a reasonable ROE for natural gas and oil pipelines (see FERC 2020). The main features of this policy statement are summarized here; readers are referred to the document for more detail.

The main policy change adopted by FERC in May 2020 was a move away from its reliance since the 1980s on the so-called discounted cash flow (DCF) model. Instead, FERC decided to use an average of the results from both DCF and capital asset pricing model (CAPM) analyses, with equal weight given to both (the two models are briefly described below). The motivation given for this policy change was that including "the CAPM in addition to the DCF model will better reflect how investors in those industries measure cost of equity while tending to reduce the model risk associated with relying on the DCF model alone. This should result in our ROE

[11] Income taxes are accounted for differently from other taxes in cost-of-service assessments since they are tied to a firm's taxable income, which is determined by the ROE. Since interest on debt is tax deductible, interest payments on debt "shield" some of the gross return on equity. Pipelines may also earn more or less than the allowed rate of return in negotiated contracts (P. L. Joskow, pers. comm., November 2020).

analyses producing cost-of-equity estimates for natural gas and oil pipelines that more accurately reflect what ROE a pipeline must offer in order to attract capital" (FERC 2020).

Since most natural gas pipelines are wholly owned subsidiaries and their stock is not publicly traded, FERC develops an estimate based on a range of ROEs in a proxy group of publicly traded entities with similar risk profiles. These entities must be comparable to the pipeline whose ROE is being determined with respect to their risk exposure, and unless the specific pipeline faces unusually high or low risks, FERC sets the pipeline's cost-of-service nominal ROE at the median of the range of returns estimated for the proxy group (FERC 2020).

Proxy group of similar firms

FERC has historically required the proxy group to consist of at least four, and preferably at least five, members. Each firm in the proxy group should also satisfy three standards: (1) the company's stock must be publicly traded; (2) the company must be recognized as a natural gas company and its stock must be recognized and tracked by an investment information service; and (3) pipeline operations must constitute a high proportion of the company's business (at least 50% of the company's assets or operating income on average over the most recent three-year period). However, this approach has been complicated by a reduction in the number of publicly traded corporations with significant shares of natural gas pipeline operations due to mergers and acquisitions, and a trend toward master limited partnerships (MLPs) owning natural gas pipelines (FERC 2011). In its May 2020 policy statement, FERC said it would maintain a flexible approach to forming proxy groups and would also continue to relax the 50% standard in (3) when necessary to obtain a proxy group of five members.

Discounted cash flow (DCF) model

The DCF model is based on the theory that "a stock's price is equal to the present value of the infinite stream of expected dividends discounted at a market rate commensurate with the stock's risk" (FERC 2019b, footnote 7). This can be represented by the following formula for the stock price:

$$P = \frac{D}{R-g} \tag{1}$$

where P represents the price of the stock, D the dividend, R the discount rate (or investors' required return) and g the expected growth rate in dividends (FERC 2019b).

To come up with a formula for the required return for each proxy firm, FERC rearranges equation (1) to solve for the discount rate R:

$$R = \frac{D}{P} + g \tag{2}$$

This formula gives the investor's required return as equal to the dividends divided by share price plus the projected future growth rate of dividends. R can then be said to represent the investor's required return for investing in the proxy firm (FERC 2019b).

In practice, FERC uses the following adjusted DSF formula, which places greater weight on short-term growth projections (FERC refers to this as the two-step DSF model):

$$R = \frac{D}{P}\left[1 + \frac{1}{2}g_{short-term}\right] + \left[\frac{2}{3}g_{short-term} + \frac{1}{3}g_{long-term}\right]$$

where $g_{short-term}$ is a short-term growth projection and $g_{long-term}$ a long-term growth projection. FERC's motivation for (rather confusingly) multiplying the dividend yield (D/P) by the expression $\left[1 + \frac{1}{2}g_{short-term}\right]$ is that this adjustment accounts for dividends being paid on a quarterly basis. For the short-term growth rate estimate, FERC uses investment analysts' five-year forecasts for each company in the proxy group as published by the Institutional Brokers Estimate System (FERC 2020).

For the long-term growth rate, FERC uses the expected long-term GDP growth rate in the U.S., based on the assumption that it is "reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy, because regulation will generally prevent the firm from being extremely profitable during good periods, but also protects it somewhat during bad periods" (FERC 2019b). For MLPs, the long-term growth projection is adjusted to 50% of the projected long-term GDP growth rate (FERC 2020).

Capital asset pricing model (CAPM)

The CAPM is based on the theory that the rate of return for a security is equal to a risk-free rate of return (typically represented by the return on treasury bonds), plus a risk premium proportional to the security's level of risk. Cost of equity is therefore estimated by the sum of the risk-free rate and the "market-risk premium," multiplied by a measure of the volatility ("risk level") of the security's price (FERC 2020).

The CAPM formula is:

$$R = r_f + \beta[r_m - r_f]$$

where r_f is the risk-free rate, r_m is the expected market return and β is a measure of the volatility of the security compared to the rest of the market. The risk-free rate is typically represented by the yield on 30-year U.S. Treasury bonds. The expected market return is, in a forward-looking CAPM analysis, based on a DCF analysis — as previously described — but for a large segment of the market, such as the dividend-paying companies in the S&P 500. Measures of the volatility, β, of a particular stock are published by several commercial sources (FERC 2020).

In its May 2020 policy statement, FERC determined that for the CAPM it would: "(1) use as the risk-free rate, the 30-year U.S. Treasury average historical bond yield over a six-month period corresponding as closely as possible to the six-month financial study period used to produce the DCF study in the applicable proceeding; (2) estimate the expected market return using a forward-looking approach based on a one-step DCF analysis of all dividend paying companies in the S&P 500; and (3) exclude S&P 500 companies with growth rates that are negative or in excess of 20%" (FERC 2020). For the value of the parameter β in the CAPM formula, FERC stated that it would use "Value Line" adjusted betas (see, e.g., Value Line [2020] for more details).

It is not yet clear what FERC's May 2020 policy statement and its decision to include the CAPM in its methodology will mean for pipeline-regulated ROEs going forward compared to previous practice. Nevertheless, FERC will also continue to rely on the two-step DSF model (albeit with the same weight now given to both the DSF and the CAPM model), in which the GDP growth rate is a weighted average across all U.S. productive sectors that individually have different growth rate projections. While electric utilities are likely to see long-term growth in their industry in light of new policy drivers pushing for electrification and decarbonization (perhaps even at a rate higher than average GDP growth), it is not clear that the same long-term growth rate is relevant for regulated gas assets.

Given projections for the future electrification of the heating sector and increasing shares of renewables in the power sector, FERC and state public utility commissions may want to pass the future demand risk from electrification and decarbonization trends to the pipeline companies. One way to do this would be to make it clear that cost recovery for new capacity is not guaranteed if future demand for their gas services falls short of projections.[12] This would give firms an incentive to actively manage the risks around future demand. There have also been proposals to FERC to use its 1996 incentive ratemaking policy statement (FERC 1996) to provide increased returns to pipelines that provide more flexible gas transportation services. Jointly, such policy signals would incentivize the pipeline companies to improve their service offerings through their existing assets rather than building new pipeline capacity.

2.2 Long-term gas transportation contracts

Buyers of firm pipeline capacity enter into multi-year contracts with a pipeline at the type of FERC-regulated rates described in Section 2.1.2. Pipelines primarily offer firm and interruptible service contracts. Firm service is offered on a guaranteed basis, with the pipeline warranting service on every day of the contract unless prevented by an act of *force majeure*. The firm capacity contract gives the holders (also known as "shippers") the right to transport an agreed daily quantity of gas. Shippers exercise their capacity rights by electronically submitting "nominations" to the pipeline company on a daily basis (see Section 4.1). Additionally, pipelines own or contract with storage facilities, and there are also independent storage facilities.[13]

In contrast, interruptible service contracts give the pipeline the option to cease the service with short or no notice — e.g., if the capacity is required to serve a firm service customer. The regulated charges for the lower-priority interruptible service contracts are lower than those for the firm service (as described in Section 2.1.1).

Local gas distribution companies (LDCs or gas utilities) are typically the largest subscribers of interstate pipeline capacity. In turn, LDCs provide gas to their retail residential, commercial and industrial customers, and procure enough firm contract capacity from the interstate pipelines to meet their peak retail customer demand. LDCs assume little financial risk by entering into these long-term contracts, because as revenue-regulated utilities they are able to pass procurement costs through to their ratepayers (as long as the state public utility commission has implemented

12 Interestingly, some pipelines are flagging this stranded asset risk in their rate case applications to FERC to motivate higher depreciation rates and thereby seek to increase their approved revenue requirement (see, e.g., WBI Energy Transmission, Inc. [2013, October 31]. Section 4 Rate case, Docket no. RP14-118, Exhibit no. WBI-110, page 35, lines 4–7; and Dominion Cove Point LNG. [2016, November 23]. Section 4 Rate case, Docket no. RP17-197, Exhibit no. DCP-0088, page 19, lines 17–22).

13 In general, gas storage plays an important role on the U.S. interstate pipeline system, but further discussion of storage is beyond the scope of this paper.

decoupling of utility revenues and sales volumes; otherwise, there is some risk for the utilities if there is an unexpected reduction in customer gas demand). Other buyers of long-term interstate pipeline capacity contracts include industrial facilities and gas marketers (Marks et al. 2017).

The process by which pipelines offer up gas transportation capacity on new or existing pipelines is called open season. The pipeline typically notifies shippers of the availability of capacity by posting an open season notice on its electronic bulletin board or website and allows shippers to bid for the capacity. FERC requires the pipelines to award the capacity to the shippers that value it the most, up to the maximum recourse rate (as determined by the cost-of-service method described in Section 2.1.1). The value of the shippers' bids is typically evaluated using the net present value (NPV) method and is determined by the offered price, the volume of gas and the duration of the contract. The shipper submitting the bid with the highest NPV receives the capacity, and this principle applies until all the available capacity has been allocated (see, e.g., Federal Register [2011] and Jost and Benson [2016]).

A shipper that successfully bids for pipeline capacity in an open season will next negotiate a precedent agreement (PA) with the pipeline. The PA includes specifics on the financial terms under which the shipper is to purchase the capacity, the transportation path, volumes and terms of service. When negotiating a PA, the pipeline will typically offer the shipper to take service at a negotiated rate (which can take many forms). The shipper, however, always has the option to elect service at the pipeline's recourse rate (Jost and Benson 2016).

One of the requirements a company must meet to get approval from FERC to build a new pipeline or expand a pipeline's capacity is demonstration of what FERC calls "market need" for the capacity expansion. Up until now, FERC has let market need be demonstrated by documenting a sufficient number of firm contract signatories and quantities committing to subscribe to the new pipeline capacity.[14] This practice has been heavily criticized where both pipeline developer and shipper are affiliated entities. The reason is the inherent risk-shifting in such transactions, whereby pipeline developers stand to earn a return in excess of risk and captive utility customers are levied with significant reservation costs regardless of whether their gas utility actually uses the pipeline capacity.

[14] See FERC (1999b) for the policy statement that guides its review of applications to build natural gas pipelines and associated infrastructure, and Tierney (2019) for a summary of the comments submitted in response to a notice of inquiry FERC has opened to consider changes to this policy.

3. The secondary market for gas transportation

Holders of long-term gas transportation contracts are allowed to sell temporary use of their pipeline capacity on a secondary "capacity release market." Secondary capacity release sales can last anywhere from several hours to the total duration of the initial contract.[15] Thus, firm pipeline capacity purchased directly from a pipeline in the primary market can be sold by the shipper in the secondary market for gas transportation, either in the long- to medium-term capacity release market (with prices capped by FERC if the duration is longer than a year) or the short-term gas spot market (without a price cap). Furthermore, pipeline operators are allowed to sell or allocate unreserved capacity on an interruptible basis (and charge an associated volumetric rate that is regulated by FERC). These policies are designed to promote a more liquid market for gas transport and to allow pipeline operators to allocate scarce capacity efficiently. (Section 3 is an amended version of market descriptions found in Marks et al. [2017]).

3.1 The gas spot market

There are many gas trading hubs on the interstate pipeline system, with secondary market prices for different gas injection and gas delivery locations reflected in gas price indices for the different trading hubs (see Section 5.2.). When FERC first decoupled gas transportation from the gas commodity market in the 1990s and created a capacity release program, it was concerned about insufficient competition in the secondary market and therefore instituted a rate ceiling. FERC removed this ceiling for short-term capacity release transactions of one year or less in 2008 with FERC Order 712 (FERC 2008). The motivation for this was that the rate ceiling worked against the interests of short-term shippers, because a shipper who needed gas deliveries on a peak day and was willing to offer a price above the rate ceiling was not legally allowed to do so. Because the prices of primary contracts for capacity are regulated but short-term capacity release and spot market prices are not (as a consequence of Order 712), the holders of firm capacity contracts can extract congestion rents when capacity is scarce by selling their gas transportation rights in the secondary market at prices above their own cost of using them (Oliver et al. 2014).

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[15] See, e.g., Oliver and Mason (2018) and David and Percebois (2004) for further discussion of the U.S. capacity release market, but note that the David and Percebois discussion precedes the FERC ruling in 2008 that lifted the price cap on short-term capacity release sales.

In the spot market, gas transportation contracts are typically traded without the benefit of a central exchange where bids and asks can be matched and settled for market-wide price determination. Instead, it is a bilateral contract market, with private brokers and exchanges that help buyers and sellers find willing and able counterparties and negotiate prices. Sales on the gas spot market involve delivery to a specific pipeline node and typically rebundle the physical commodity with the transportation service. Spot market prices therefore incorporate the wellhead price of the gas, the cost of the pipeline capacity needed to transport it and the shadow price of the pipeline capacity constraint. This shadow price captures the difference in gas prices between the receipt and delivery points due to differences in available gas transportation capacity when the pipeline is congested. In other words, it reflects the scarcity of available pipeline capacity along the gas transportation route (Cremer et al. 2003) and is the source of the congestion rents earned by primary firm contract holders when selling scarce transportation capacity in the spot market.

3.2 Gas spot market participants

Most LDCs are both buyers and sellers of gas transportation capacity. Because they must hold sufficient long-term primary contracts to provide reliable gas supply for their rate-paying end-use customers, LDCs usually have excess pipeline capacity rights on most days of the year — aside from the coldest winter days, with their peak gas-heating loads. LDCs can use that excess capacity either to ship gas to the region and sell it on the spot market, or sell it directly on the capacity release market. Furthermore, FERC regulations intended to ensure pipelines are fully utilized require that pipeline operators sell any excess capacity (that is not scheduled by firm contract holders) to interruptible contract holders who request access to that capacity (by means of nominations to use it, as described in Section 4.1).

Merchant gas-fired generators purchase the vast majority of their gas on the spot market, on a “delivered to their location” basis, because their gas delivery needs are typically much more variable and less predictable than those of LDCs and therefore not well served by long-term contracts. A mechant generator that has forward contracts to sell electricity may nevertheless hedge the gas price risk by entering into gas supply contracts or futures that match the duration and volume of its forward commitments to sell electricity.

Additionally, there are independent marketers who do not themselves use gas, but instead hold long-term contracts in anticipation of profiting from short-run sales to pipeline users (primarily gas-fired generators). These independent marketers hold long-term contracts either as a principal directly with the pipeline, or as a replacement shipper under a long-term capacity release transaction. Another set of spot market participants are asset managers, who act as third-party agents and/or principals for firm contract holders such as LDCs.

3.3 Local distribution companies and the gas spot market

The LDCs forecast their customers' aggregate daily gas demand[16] and, based on those forecasts, schedule their total daily gas deliveries on the interstate pipelines a day in advance according to the terms in their long-term gas transportation contracts and the practices described in Section 4. An LDC can sell on the spot market any excess pipeline capacity in their long-term contracts that they do not need for servicing their customers. Investor-owned LDCs are regulated by their respective state public utility commission. Like the interstate pipelines, they are allowed to make a rate of return under cost-of-service regulation. The LDCs pass through to their ratepayers the cost of their firm pipeline capacity contracts. When selling excess contracts on the spot market, LDCs are subject to rules that limit their ability to profit from excess contracts. These revenue-sharing rules are set by the respective public utility commission and vary across states.[17] In general, they require LDCs to return a certain percentage of revenues from capacity release and spot market sales (sometimes referred to as non-firm margin sales) to their ratepayers.

4. Pipeline operations and practices

This section, which is based on excerpts from Marks et al. (2017), describes the main operational features of the pipeline capacity markets in terms of gas flow nominations and scheduling. In addition, it details the imbalance penalties used to enforce contract stipulations and ensure operational integrity and system safety.

[16] For example, according to gas demand aggregation methods, as described in Vitullo et al. (2009).
[17] Revenue-sharing rules sometimes also vary across firms within states.

4.1 Nominations and scheduling

Each contract for capacity gives the shipper holding it the right to use, on a daily basis, a certain amount of space along the pipeline between one or more specifically listed receipt (intake) points and one or more specifically listed delivery (outflow) points.[18] To exercise this right, the shipper must electronically submit a nomination to the pipeline company, stating the quantity of gas they intend to move, where it will enter the pipeline and where it will exit. This capacity scheduling process is carried out on a daily basis for each gas day, which runs from 9 a.m. until 9 a.m. the following day.[19] Importantly, capacity is nominated not as a rate of flow, but rather as a total quantity to be transported at a roughly constant rate over the course of the 24-hour gas day. The precise rule for most contracts is that the total daily nominated gas volume must be transported ("flowed") over a period lasting from 16 to 24 hours.[20]

Nominations consist of an intake "receipt" point, an outflow "delivery" point, and a scheduled daily quantity of gas to flow.[21] To induce shippers to manage nominations and flows judiciously, and not create significant system pressure imbalances, they are subject to imbalance penalties if there are differences between their scheduled nominations and actual flows. These penalties are more or less severe depending on the size and nature of the infraction, and are generally more severe when there is less slack available in the system to compensate, as in winter. Imbalance penalties are described further in Section 4.2.

Shippers must submit their initial nominations by the close of the timely cycle, which occurs at 1 p.m. the day before the gas day (i.e., 20 hours before the start of the gas delivery day), in order to be given priority and guaranteed the capacity provided by their contracts.[22]

[18] At least in theory, a contract for firm capacity should guarantee access such that the total quantity of firm capacity contracts across all firm customers on a given route should not exceed maximum transmission capacity.
[19] The gas day and all associated scheduling times are in Central Time for all interstate pipelines to facilitate harmonization of the gas transportation industry across the U.S.
[20] For example, a capacity owner holding 24,000 MMBtu would generally be entitled to flow 1,000–1,500 MMBtu per hour, as specifically set out in their service agreement.
[21] Net a small percentage that is skimmed by the pipeline operator to power compression stations.

[22] If shippers neglect to nominate by the timely cycle, the pipeline may use their contracted capacity to allow other shippers to move gas to other points on the pipeline that are not specifically allocated to them. These nominations — which are called secondary in-path, secondary out-of-path and interruptible nominations — are used by LDCs and independent marketers to sell gas on the wholesale market to generators located at other parts of the pipeline. On a day when the pipeline is fully scheduled, the shipper that did not nominate on time will be able to utilize pipeline capacity only if another shipper will adjust their nomination downward later in the scheduling period to free up some capacity.

Shippers can make adjustments to their nominations during the gas day. FERC requires pipelines to offer a minimum of three intraday scheduling cycles, although some pipelines offer more frequent scheduling opportunities. On some pipelines, the last intraday cycle generally occurs a few hours before the end of the gas day and is commonly know as the cleanup cycle. During this cycle, shippers match their scheduled nominations to their actual flows.

Most interstate pipelines allow schedule adjustments at just five specific times following the initial timely cycle nomination: a late cycle in the evening the day before the gas day, three intraday cycles during the gas day and a final cleanup cycle near the end of the gas day. However, some interstate pipelines allow shippers to adjust their nominations on an hourly basis over the 44-hour scheduling period, which begins with the timely cycle at 1 p.m. the day before and concludes at 9 a.m. at the end of the gas day.

In addition to firm and interruptible service contracts, some pipelines offer no-notice contracts, which are a form of legacy contract generally available only to LDCs.[23] When combined with a gas storage service contract, a no-notice contract can allow an LDC to adjust its scheduled flows without prior notice, and to flow their total scheduled quantity of gas on an uneven hourly basis and over a period of less than a full 24 hours.

If at any point during the gas day there is unused space on the pipeline after all holders of primary and secondary capacity have made their nominations, the pipeline company can sell the extra capacity as “interruptible” service, meaning the pipeline will stop the flow of gas if a primary or secondary capacity holder increases their nomination. The schedule adjustments made in the window between 6 a.m. and 8 a.m. at the end of the gas day represent shippers matching the node’s final scheduled daily nomination to the quantity of gas that was actually delivered to it, in what the industry refers to as the cleanup or true-up cycle. Beyond accurate bookkeeping, this adjustment is necessary for shippers to avoid the accounting imbalance penalties assessed for monthly deviations between scheduled and actual flows in excess of 5% (see Section 4.2 for further details on imbalance penalties).

No-notice contracts are exempt from this requirement. For the most part, provided a non-zero nomination is submitted in the timely cycle, these contracts enable scheduled quantities to be adjusted at any time during the scheduling period with guaranteed approval.

[23] At the request of LDCs, a requirement that interstate pipeline companies offer no-notice contracts was included in FERC Order 636, the policy that mandated the unbundling of gas transportation service from the physical commodity. The LDCs argued that no-notice contracts would be needed in the new market structure to ensure they could reliably serve unexpected fluctuations in demand.

Capacity cannot be double-booked, and the pipeline company manages nominations such that the scheduled flows through any point on the pipeline do not exceed safe operating limits. Thus, a negative adjustment in the cleanup cycle indicates capacity that was scheduled but not used to ship gas to that node. When aggregate nominations reach the pipeline's capacity constraint and the negative schedule adjustment is not accompanied by a positive adjustment at another node, the negative adjustment in the cleanup cycle corresponds to capacity that went unused across the entire system for that gas day.

4.2 Pipeline imbalance penalties

To enforce contract stipulations, interstate pipeline companies charge two types of imbalance penalties. These are important to ensure reliable pipeline operations, because if some shippers draw gas from the pipeline in excess of their nomination, the pressure balance is affected and other customers will not be able to draw the gas they had scheduled. Conversely, if shippers inject more gas into the pipeline than they had scheduled (or inject the scheduled amount but withdraw less), pipeline pressure may build to unsafe levels. Information on the penalty levels for a pipeline can be found in the pipeline's gas tariff, typically available on the pipeline company's website.

The severest type of imbalance penalty is called an operational flow order (OFO) imbalance penalty, which is assessed when shippers cause a physical imbalance on the system on a day when pipeline operations are at risk of running into critical constraints. The pipeline company issues an OFO warning by electronically notifying all of its customers that the pipeline has reached, or is about to reach, its capacity constraint on at least one bottleneck on the system (usually a compressor station). On a congested day, this warning is usually sent out well before the gas day starts, but it may be issued or updated during the gas day. For example, once an OFO has been issued on the Algonquin pipeline (which serves New England), any shipper that causes a physical imbalance in the system by withdrawing in excess of 2% more or less gas at their delivery node than they had injected at their receipt node is served a penalty equal to three times the Algonquin Citygate price multiplied by the quantity of the infraction (see Spectra Energy 2020). This penalty is severe because causing a physical imbalance on the system can lead to serious operational challenges on days when the pipeline is near its capacity constraint.

The second type of penalty is an accounting imbalance penalty, which is assessed symmetrically for deviations in either direction between the quantity of gas the shipper had scheduled to flow through the pipeline and the amount they actually flowed on an aggregate monthly basis. For example, shippers on Algonquin are served a penalty that ranges from 1.1 to 1.5 times the Algonquin Citygate price multiplied by the quantity of the infraction, with the scaling factor increasing with the size of the infraction.[24] This penalty is much less severe because infractions do not affect the safety and reliability of the system. Nevertheless, it is still substantial — especially for LDCs, which cannot pass any imbalance penalties they incur onto their ratepayers.

5. Where to find gas transportation market data

To facilitate new research and analysis, this section provides brief guidance on where to find data on the U.S. natural gas transportation markets.

5.1 Pipeline tariffs and rates

The FERC-approved regulated pipeline rates relevant to the primary market are available on the respective pipelines' websites and described in detail in their gas tariffs, which also include information on imbalance penalties. Some examples are given below:

- Algonquin Gas Transmission Tariff
- El Paso Natural Gas Tariff
- Florida Gas Transmission Tariff

FERC also provides a database of different tariffs on its website (https://etariff.ferc.gov).

5.2 Spot market prices

The natural gas price at Henry Hub, in Erath, Louisiana, is the benchmark price for natural gas traded in the U.S., including natural gas futures traded on the New York Mercantile Exchange,

[24] To be specific, the penalty is $1.1 \times P_{ACG} \times Q$ for deviations between 5% and 10%, $1.2 \times P_{ACG} \times Q$ for 10–15%, $1.3 \times P_{ACG} \times Q$ for 15–20%, $1.4 \times P_{ACG} \times Q$ for 20–25%, and $1.5 \times P_{ACG} \times Q$ for deviations in excess of 25% (see Spectra Energy [2020, section 25]).

and is considered reflective of the commodity value without gas pipeline transportation costs. Shale gas development in Texas, Pennsyvania, Ohio, and other parts of the country have also increased the importance of other gas trading hubs.

The unregulated secondary market prices for different delivery locations on the interstate pipeline system are reflected in gas price indices (bundled for both gas commodity and transportation) for the different trading hubs. These are provided for day-ahead as well as forward markets by data providers such as Intercontinental Exchange (ICE), Natural Gas Intelligence and S&P Platts.

These indices are based on confidential survey data from market participants on their recent transactions, and are aggregates for deliveries to or from certain segments of the pipeline as detailed in the respective data provider's methodology section. Prices from Friday trades represent gas deliveries for Saturday, Sunday and Monday (as there is no trading on the weekends). Posted Friday price indices are therefore an aggregate across all three days.

The day-ahead gas price indices therefore do not provide information for deliveries during certain hours of the day or for a particular delivery point on the pipeline, and represent only the aggregated prices for trades made the day before for delivery points along the relevant pipeline segment. Thus, in the U.S. gas wholesale gas markets, there is no available price information equivalent to the locational marginal prices (LMPs) in organized U.S. wholesale electricity markets such as ISO-NE and PJM, which reflect sub-day demand, supply and transmission constraints. Gas transportation markets therefore do not provide granular price information that can indicate time- and location-specific capacity constraints and serve as a basis for robust objective assessments of the need for new infrastructure investment, such as for new compressor station capacity or local gas storage.

5.3 Gas quantities delivered (scheduled)

FERC mandates that the interstate pipelines provide data on daily scheduled quantities during the previous three years on their electronic bulletin boards. Those data contain information on the daily total quantities scheduled from each receipt point to each delivery point for each of the FERC mandated scheduling cycles, and they specify the type of delivery point (i.e., LDC, power plant, end user or storage) as well as the identity of the point operator (who manages actual gas flows to the delivery point).

The pipeline companies themselves have access to more granular gas delivery data than these daily quantities through their supervisory control and data acquisition (SCADA) systems, but these data are proprietary and the pipelines are not required to make them public.[25]

5.4 Firm contract ownership

Data on firm contract ownership are available through index of customers reports, which interstate pipelines are also required to make publicly accessible on their reporting websites for the previous three years. These data can be also found on Form 549B — Index of Customers on FERC's website (https://www.ferc.gov).

5.5 Gas infrastructure data

Gas distribution systems have been designated as critical energy infrastructure information (CEII), which makes it a challenge for the general public to retrieve information due to national security restrictions. Nonetheless, some information on main interstate pipelines reported capacity can be found in the following sources:

- The Energy Information Adminstration provides monthly pipelines inflows, outflows and capacity, by state and region (EIA 2020). EIA also provides maps of the interstate pipeline network, with an associated online geographic information system database.
- Some other data providers, such ICE and S&P Global Platts, have details of pipeline point maximum capacity, scheduled volume, available capacity, utilization rate and maps. The Pipeline and Hazardous Materials Safety Administration provides pipeline mileage and facilities data, as well as a general public map that is available only by county and at a large scale. However, detailed and granular information on node and pipeline real capacity, which is derived from parameters such as compressors and diameter, is not available.

FERC Form 567 contains specific information on the pipeline system, including pipeline diameter, pressure and volume data, but access is restricted because natural gas pipeline flow diagrams are protected under the security level of CEII. This form is a report containing pipeline

[25] For an example of an analysis using hourly historical SCADA data from an actual — but small — part of the interstate pipeline system that an undisclosed pipeline company agreed to share, see Rudkevich et al. (2019).

cross-section diagrams by more than 100 interstate natural gas pipelines with system delivery capacity in excess of 100 million cubic feet per day. These diagrams reflect operating conditions of a company's main transmission system during the previous 12 months. Companies are required to submit five copies of this diagram, and can do it either on paper or by e-filing. This implies that not all of the data are digital. Specific engineering and detailed design information about pipeline facilities, components and equipment is limited. The requirements for the report are very general (e.g., units, which dimensions should be reported, which labels should be included, etc.). This lack of a standardardized reporting format hinders data analysis, as well as consistent review and comparisons across pipeline companies.

6. Potential updates to the market design for gas transportation

This section provides a brief discussion of potential updates to the market design for U.S. gas transportation from an economics standpoint and suggestions for further readings.[26] It focuses on market updates that could improve economic efficiency both in the short term (by enabling additional trades such that limited pipeline capacity is more likely to be allocated to the uses of highest value) and in the long term (by providing more granular price signals to facilitiate improved assessment of the net social benefit of new gas infrastructure investments).

As described in Sections 3 and 4 (and further discussed in Carter et al. [2016] and MIT [2013]), the pipeline market and operations are currently set up such that spot market clearing, flow scheduling and planning of physical operations are conducted consecutively and separately rather than being jointly coordinated. This arrangement makes optimization of the system and its associated market challenging. Instead of being coordinated by the pipeline operator, day-ahead trades of gas transmission capacity are conducted through bilateral agreements between market participants who do not have the overview and information to account for relevant operational constraints (Carter et al. 2016).[27]

This arrangement can be contrasted with the way in which nonprofit independent system operators (ISOs) in restructured electricity markets, such as ISO-NE and PJM, clear the day-

[26] For more of a regulatory and gas and electricity industry perspective on these issues, see, e.g., FERC Order 809 and related docket (FERC 2015).

[27] Under current operational practices on interstate pipelines, pipeline operators may already have access to predicted hourly gas takes for their interconnected gas-fired power plants, but that information may nevertheless remain unused.

ahead market and solve a series of optimization problems to miminize the cost of serving electricity load given bids from generator and load-serving entities, transmission capacity and other operational constraints. The system operator thereby generates a jointly consistent dispatch schedule and associated set of day-ahead LMPs. The associated real-time spot market and prices (and ancillary service markets) then serve to adjust for deviations from day-ahead forecasted conditions.[28]

To optimize the use of the pipeline system along similar lines to the arrangement in restructured electricity markets, market and physical operations would need to be jointly coordinated and pipeline operators (or another entity) tasked with solving optimization problems that would generate day-ahead prices that account for forecasted next-day conditions. Real-time (hourly) spot markets could then deal with readjustments of prices and flow schedules according to deviations from forecasted conditions. Such a market design would determine hourly prices for each given location on a pipeline network based on demand and the physical ability to deliver gas there (Carter et al. 2016).

The Australian state of Victoria has such a gas market design, managed by the Australian Energy Market Operator (AEMO), which also manages the Australian wholesale market for electricity. In this market, AEMO simultaneously determines optimal gas dispatch and corresponding LMPs based on a linear programming (LP) formulation (Read et al. 2012).[29] According to Read et al., however, this market has not fully exploited the potential of its market-clearing approach due to its small size, degree of vertical integration and relative lack of congestion, and therefore provides only limited evidence of its value.

To optimize the system (as also noted by Read et al. [2012] as a limitation of the LP formulation), this type of day-ahead market-clearing mechanism would ideally take transient gas flows into account due to the slow speed of gas relative to electricity flow. The high nonlinearity and complexity of the associated optimization problem requires the use of so-called transient optimization methods (Carter et al. 2016). A tool that implements such methods to provide consistent gas market clearing, flow schedules and prices is the gas system optimizer (GSO), which was deveveloped as part of the Gas-Electric Co-Optimization (GECO) project

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[28] For a rigorous discussion of market design in electricity markets, see, e.g., Wilson (2002).
[29] Linear programming is a mathematical optimization method based on a linear objective function and linear constraints — i.e., based on making the (then often simplifying) assumption that the relevant mathematical relationships are linear.

funded by the U.S. Department of Energy's Advanced Research Projects Agency — Energy (ARPA-E) program. ARPA-E funded this project to "improve coordination of wholesale natural gas and power operators both at the physical and market levels" and address current inefficiencies by developing methods and a market mechanism that enable access to pipeline capacity "on the basis of its economic value as determined by gas buyers and sellers" (ARPA-E [2015]).[30]

The nature of the existing pipeline capacity property rights and the operational practices given by the current market design likely create practical and political challenges to market reforms. For example, one such challenge is confidentiality concerns with respect to the exchange of proprietary data such as network data and customer information across different pipelines and electric system operators (see Zhao et al. [2018]).

In effect, the U.S. pipeline capacity market is currently based on *physical* transmission rights, which entitle the holder to *use* the pipeline capacity as stipulated by the contract. This can be contrasted with the *financial* electricity transmission rights in the markets operated by nonprofit electricity system ISOs, which instead entitle the holder to a share of the congestion rents as given by the differences in LMPs between transmission nodes (for more details, see Joskow and Tirole [2000]).

Implementing a day-ahead and real-time gas spot market similar to the restructured electricity markets would likely require the type of capacity release program and redefinition of property rights as described by Joskow and Tirole (2000, pp. 466–468) for electric power networks. Applying this design to the gas transmission context, the existing bilateral market for gas transportation would remain for all trades negotiated at any point in time (a year ahead, a week ahead, etc.) before the day ahead of delivery and the associated physical rights and flow schedules registered with the pipeline operator. The day before delivery, however, any unscheduled remaining capacity would turn into financial rights, which the pipeline operator (or another entity) would auction to the highest bidder in day-ahead and real-time spot markets, as in the restructured electricity markets. The owner of the pipeline capacity could still be awarded the value of the congestion rents in the real-time market under what Joskow and Tirole (2000) refer to as the "use-it-or-get-paid-for-it" rule.

[30] The GECO project ran between 2016 and 2019. For further details, see ARPA-E (2015).

However, there is a challenging institutional mismatch between the gas transportation industry (with long private pipelines crossing many states) and its by now largest customer, the electric power industry (with multiple ISOs that organize wholesale electricity markets for more compact geographies, but also large areas of the country — e.g. the Southeast — that have no electric market ISOs). In this context, it is not clear what a gas ISO would look like in the U.S. and whether such an entity could coordinate day-ahead and real-time markets on pipelines belonging to several different pipeline companies (P. L. Joskow, pers. comm., November 2020).

Given the challenge of redefining markets and existing property rights,[31] researchers have proposed alternative market designs that can work within the constraints given by current market and contract structures (but that would nevertheless require substantial changes to the responsibilities of the U.S. interstate pipeline operators). Specifically focusing on improving the efficiency of the gas–electric market intersection, Zhao et al. (2018) proposed a market-based mechanism designed to efficiently coordinate the gas and electric systems day ahead and maximize the economic value of the gas delivered to gas-fired generators, while also serving other sources of gas demand. Importantly, their proposal does not require the exchange of proprietary information between natural gas and electricity system operators, which would otherwise be a key constraint for actual implementation, since electric system operators do not transact directly with the interstate pipelines and would therefore not be at liberty to share such information.

Another mechanism that aims to maximize the value of existing pipeline capacity and enable gas-fired generators to schedule gas deliveries according to their time-varying demand for gas is outlined in Rudkevich et al. (2018). Based on the GSO, this intraday market mechanism for coordinated gas scheduling (developed as part of the GECO project) would enable beneficial real-time trades in the secondary gas market while being compatible with current contract and capacity ownership structures.

Although they do not provide the equivalent of electricity market LMPs in the way more comprehensive market reforms would, these latter two market mechanisms would still generate more granular gas price signals that could provide more detailed information. In turn, this more

[31] As another illustration of these challenges and potential opposition from current property rights holders, a proposal to the North American Energy Standards Board to introduce a standard for how a primary customer under existing contract structures could submit nominations to the pipeline for each hour of the day (rather than the current arrangement based on nominations of daily total gas volume) was rejected due to opposition from one of the voting industry segments.

detailed information would allow better assessment of the value of proposed investment in new gas transmission assets (e.g., in compressor stations or liquefied natural gas [LNG] storage that can increase the pipeline's ability to deal with gas-fired generator ramping requirements and associated pressure deviations).

7. Integrated gas–electric energy system models

Considering the importance of the intersection between the gas transportation and electricity markets for the U.S. energy transition, there is a relative paucity of energy modeling frameworks formulated in a way that makes it possible to analyze the relevant interactions and interdependencies between the sectors. This section briefly describes some of the few existing modeling frameworks that include a detailed representation of both the gas and electric markets and that could be used for future integrated analysis of the intersection between the two.[32]

A more granular representation of the power system and associated gas system as offered by some — but not all — of these models is needed for many investment planning decisions related to integrating large shares of variable renewable resources. Essentially, such integration planning requires models able to take into account when and where wind and solar electricity can be expected to be available (given associated probability distributions), and what flexible resources such as gas-fired generation capacity (potentially with CCS), transmission and storage will be required to address the variability and associated uncertainty and ensure a reliable electricity supply.

EIA's economy-wide National Energy Modeling System (NEMS) framework includes the Natural Gas Market Module (NGMM), which represents the North American natural gas transmission and distribution system and was first incorporated into the NEMS framework for the Annual Energy Outlook 2018. The NGMM optimizes welfare subject to a number of gas system constraints, and thus solves for production, flows and prices of natural gas at the state level for the U.S. pipeline network and at the regional level for the Canadian and Mexican pipeline networks for all months in the model year. The NGMM also solves for gas used for liquefaction, LNG export capacity new builds and pipeline capacity expansions. The NGMM currently does not include gas demand curves and instead holds gas consumption from each

[32] For details on dedicated gas market models, see the EIA (2014) review of natural gas models.

sector (residential, commercial and industrial, and the power sector) constant in each iteration. Gas consumption from the power sector derives from the NEMS Electricity Market Module, which solves for consumption by North American Electric Reliability Corporation regions and three seasons in each year, and is then disaggregated to the state and monthly representation required by NGMM (EIA 2018).

An open-source model framework specifically focused on optimizing flows and capacity expansions between the gas and electricity sectors is the simultaneous steady-state natural gas and electric power network optimization framework developed at Los Alamos National Laboratory and available on Github for use by other researchers (Bent and Sundar 2020). An example of this framework, applied and calibrated to the U.S. Northeast, can be found in Bent et al. (2018).

A gas market module is also being developed for pairing with the open-source power system modeling framework Switch 2.0, which has been specifically developed for planning transitions to low-emission electric power systems and provides granular representation of variable renewable technologies (see Johnston et al. 2019). A U.S.-wide version of Switch 2.0 is being developed at the University of Hawai'i, and will be calibrated to correspond to the Environmental Protection Agency's Integrated Planning Model of the U.S. power system.

The Joint Institute for Strategic Energy Analysis has developed a modeling platform that is not an optimization model but instead is more focused on representing the potential for improved coordination between gas and electricity systems . This "cooperation" platform pairs the PLEXOS unit commitment and economic electricity dispatch model with the SAInt simulation model of gas network flows. The platform and findings from three studies based on this model on coordination of gas and electric system operations are presented in Guerra et al. (2020).

Planning models such as NGMM and Switch 2.0 focus on predicting optimal capacity expansion for long-term energy infrastructure planning. For mathematical tractability, such models often have coarser time resolution and abstract away from some of the physical constraints relevant to the short-term operation of the pipeline systems and associated gas flows. A model that provides a more granular and sophisticated representation of those constraints, and that is more focused on optimizing short-term operations of existing gas pipeline capacity, is the GSO developed as part of the GECO project. An application of the (transient optimization) GSO model and the intraday gas balancing market mechanism (described in Section 6) it is designed to represent can be found in Rudkevich et al. (2019).

For long-term energy infrastructure planning, energy system model resolution such as sub-day and daily resolution are important so that the uncertainty and variability associated with variable renewable resources is taken into account. Modeling needs to include appropriate sampling approaches to represent the probability distributions for resource availability across hours, seasons and years, and associated flexibility and storage needs. These models should also be able to represent a responsive and flexible demand side — especially as more of the heating sector is electrified and offers opportunities for demand-side management.

Another priority for strengthening modeling of decarbonization pathways in U.S. power system models is creating mutually consistent scenarios for future electricity load and gas supply capacity. This is important because electrification will lead to both higher levels of aggregate electricity demand and potential changes in its load shape, as well as decreases in gas-heating demand (from the residential, commercial and industrial sectors), with associated increases in the availability of gas transportation capacity for the power sector. Thus, creating consistent electrification scenarios for future electricity demand and gas supply availability for gas-fired generators is important for robust analyses of decarbonization pathways for the U.S. power sector. One potential framework for creating such scenarios is Tools for Energy Model Optimization and Analysis (Temoa) and the Open Energy Outlook (OEO) project. The OEO is intended to complement NEMS and the EIA's Annual Energy Outlook, and is focused on examining technology and policy pathways to achieve deep decarbonization in the U.S. using open-source tools and data.

8. Areas for future research and analysis

The objective of this paper has been to facilitate and stimulate new research and analysis into how to improve the design, regulation and operation of the U.S. gas transportation market in the context of the ongoing energy transition and decarbonization of the U.S. energy system. Such studies would be valuable for providing new insights and decision support to policy makers and energy market regulators, as well as electric and gas industry players and other stakeholders. The intersection between the gas and electricity markets is ripe with interesting research questions; this section outlines just a few of these, categorized by topic.

More flexible and granular gas transportation markets and their value

Exploring alternatives to the current market design for gas transportation that will be better able to deal with the current and future needs of gas-fired generators is an important avenue for research. Analysis of whether more granular scheduling (e.g., based on hourly rather than daily total quantities) and primary contracts with more sophisticated rate designs could significantly improve efficiency in the primary market would be valuable. For the secondary market, it would be useful to have larger-scale evaluation of the potential welfare gains from a centrally cleared intraday market mechanism (e.g., the mechanism outlined by Rudkevich et al. [2018]) that enables additional trades in the secondary market and can improve capacity utilization on pipelines with delivery constraints. Another question of interest is how different ownership structures for gas-fired generators (e.g., merchant versus cost-of-service regulated entities) affect their willingness to enter into long-term firm gas transportation contracts under both existing and potential new primary contract designs.

Importantly, what are the distributional implications of these potential reforms? How would they impact costs to gas-fired generators and to consumers, as well as the ability of pipeline companies to recover costs and earn a return despite trends toward declining gas demand? A related outstanding question is how to design revenue incentive mechanisms to reward the pipeline companies for providing flexible delivery services in both primary and secondary markets and/or change their operations to manage a centrally cleared intraday market.[33]

Financial returns from gas pipelines

Relevant research questions in financial economics include how the regulated returns for the natural gas pipeline industry compare to returns from other industries; what rate of return is implied by competitively bid projects that fall below the allowed regulated rate of return backstop; how FERC's new ROE policy, which now includes the CAPM in addition to its previous reliance on the DCF model, will affect the pipeline ROEs; how pipeline rates of return relate to regulatory risk given trends toward future electrification of the heating sector; and if (or to what extent) the regulated rates of return of the pipeline companies hinder efficient use (and retirement) of gas transmission assets.

[33] See also the related discussion on incentive-based regulation in Oliver and Mason (2018).

Stranded gas assets

Electrification also opens up questions about how the pipeline companies will deal with any unrecovered costs of existing pipeline capacity. Widespread switching from gas heating in the residential and commercial sectors would, for the interstate pipelines, result in significant reductions in long-term firm contracts with local gas utilities. Could such costs be partially recovered through introducing new primary contracts for pipeline capacity that are more attractive to gas-fired generators (e.g., contracts with more sophisticated rate designs)? Could they be at least partially shouldered by the pipeline companies themselves? And/or could they be recovered with increased rates for industry and other remaining users of the interstate pipelines? What are the potential distributional and welfare impacts of these alternatives?

And what incentives should be provided to ensure pipelines companies still invest in monitoring, upgrades and necessary replacements throughout the energy transition to maintain system reliability and safety, as well as addressing methane emissions from leaky and malfunctioning equipment?

LNG demand

How will the expansion of the international LNG market continue to impact the economics of U.S. gas pipelines and their regional markets? How could LNG export demand be impacted by new climate and energy policy initiatives in key export markets and how are such developments incorporated into the financial assessments of existing and proposed U.S. LNG export capacity?

Potential for hydrogen gas transportation

What is the potential to upgrade the U.S. interstate pipeline system to be compatible for hydrogen transportation? What role can hydrogen play in U.S. decarbonization efforts? How could a hydrogen market be created and which parts of the pipeline network would it be beneficial to transform given potential centers of hydrogen supply and demand? How could such a transition be financed and incentivized? How should a potential hydrogen transportation market be designed to best benefit public welfare? Are there fundamental differences compared to how one would ideally design a natural gas transportation market?

Answers to these questions would be valuable for informing policy and regulatory discussions on the future role of the gas pipeline industry, how to regulate it for cost-effective decarbonization of the U.S. energy system and how to deal with related distributional impacts.

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Appendix. An illustration of pipeline capacity utilization patterns

As described in Section 5, gas delivery quantities and spot prices are currently availabe only at a daily resolution, which makes assessments of actual pipeline utilization patterns and the specific timing of potential capacity constraints challenging. Anectodal evidence from gas market experts indicates that in some places pipeline delivery constraints may be binding for only a few hours during the peak day of the year. However, the lack of transparency and granular data in the pipeline capacity markets makes it difficult to evaluate such claims, much less provide proposals for how to best manage perceived pipeline capacity constraints — be it through the fairly new concept of gas demand response programs (see, e.g., Weiss et al. [2018]), or more traditional investment in strategically placed LNG storage facilities or new compressor capacity.

For an illustration of current pipeline capacity utilization and why there may be potential for improvement (e.g., through implementing one of the market reforms discussed in Section 6), Figure 1 provides a stylized picture of aggregate LDC gas loads during a winter day. Figure 2 similarly shows an aggregate gas load pattern from the power sector derived from the electricity generation patterns of gas-fired generators.

Figure 3 combines Figures 1 and 2 to illustrate a hypothetical total aggregate gas load pattern for an interstate pipeline by combining the hourly LDC and power sector gas loads (in this example, potential gas loads from large industry with their own primary gas contracts are disregarded).

Assuming a pipeline with a capacity constraint of 70,000 MMBtu per hour, Figure 3 indicates that pipeline capacity utilization is very close to maximum capacity at 8 a.m. and 7 p.m. In other words, these are the hours of the day when gas delivery capacity is the most valuable. Had there been a transparent market for pipeline capacity in which firm contract holders such as LDCs could sell any excess capacity to gas-fired generators, these are the hours during which the gas spot price would be highest.

However, since the gas transportation markets are so opaque and do not provide data on hourly usage patterns and prices, there is no way of knowing the extent to which such trades actually take place. Because secondary gas market trades take place bilaterally without the benefit of a central exchange where bids and asks can be matched and the scheduling of pipeline capacity coordinated centrally according to how the market clears, it is fairly likely that quite a few mutually beneficial trades do not happen under the current market design. A market mechanism like the one outlined by Rudkevich et al. (2018) would likely lower transaction costs and coordinate the market such that more mutually beneficial intraday trades of pipeline capacity could take place. LDCs could also feasibly release and sell even more excess capacity in such a market if they rolled out comprehensive gas demand response programs as described in Weiss et al. (2018). Gas demand response programs are not yet a common occurrence but have been piloted by National Grid and Consolidated Edison in New York.

Figure 1. Illustrative local distribution company aggregate gas flow curve for a winter day.

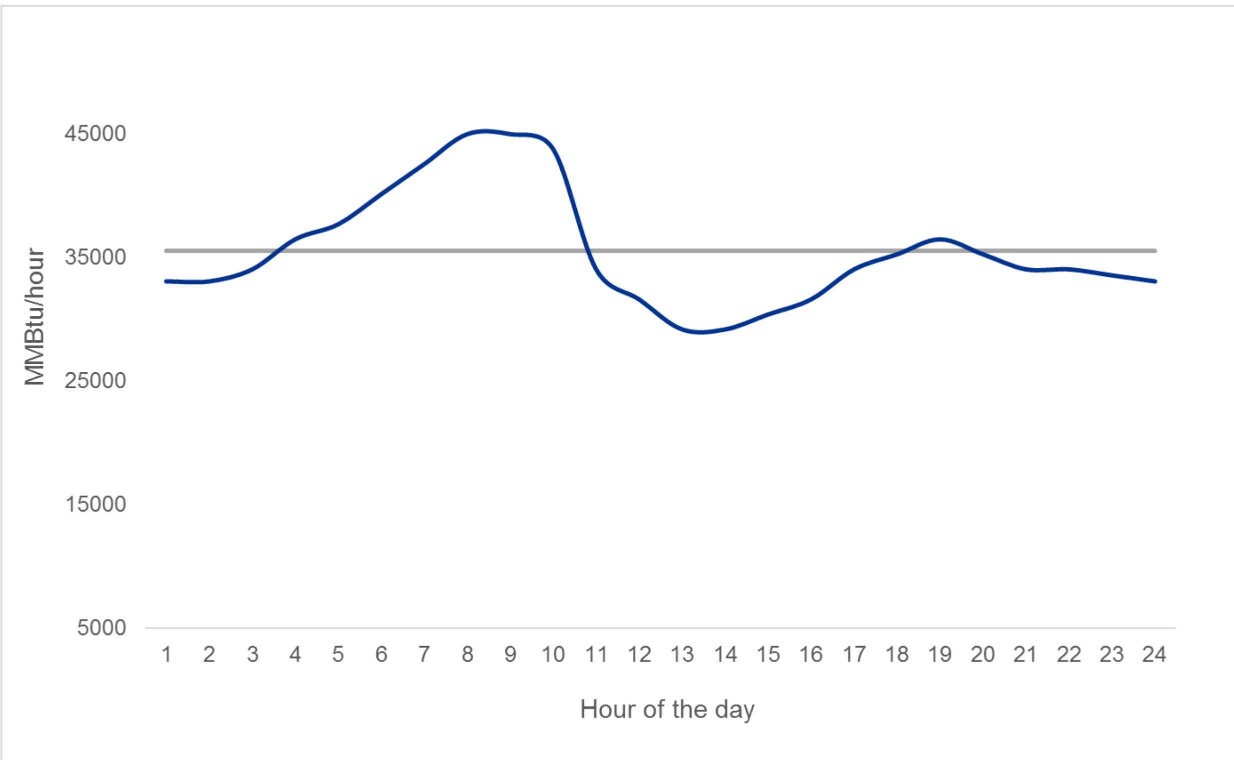

Figure 2. Illustrative power sector aggregate gas flow curve for a winter day.

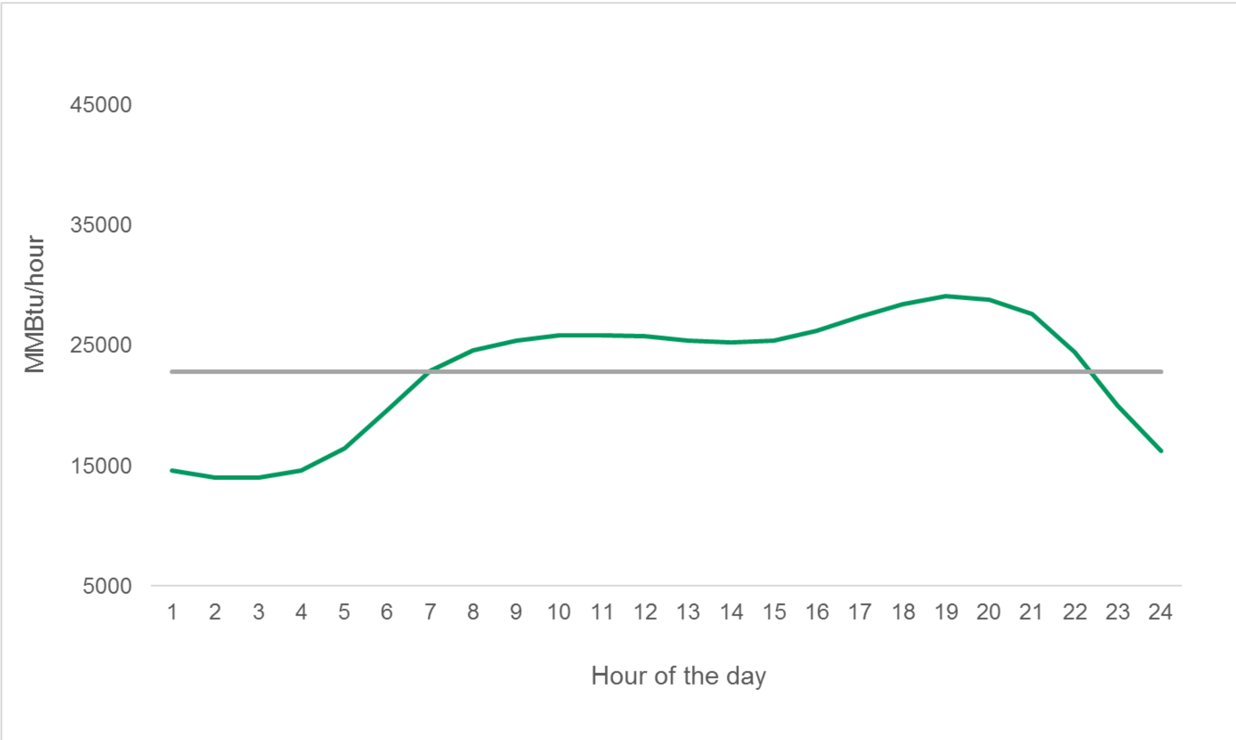

Figure 3. Illustrative combined aggregate gas flow on interstate pipeline from local distribution company and power sector gas demand.