FTI CONSULTING™

U.S. OBSERVATIONS AND EXPERIENCES IN NATURAL GAS INFRASTRUCTURE INVESTMENT

AN FTI CONSULTING REPORT

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FTI Consulting Report / Published November, 2019

November 2019

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I. Background and Summary

In this high-level briefing paper, FTI Consulting seeks to provide an overview of the United States experience in the development of natural gas infrastructure and the regulatory structure that regulates such infrastructure, in an effort to help key stakeholders, investors, natural gas market participants and the Government of India to identify policies and regulations that may serve to foster meaningful natural gas infrastructure investment and development in India. This research is being conducted by a tailored team comprised of FTI Consulting's Power and Utilities and Strategic Communications practices, with experts located in both the United States (U.S.) and India. This briefing paper is being published/circulated through the US-India Strategic Partnership Forum ("USISPF").

This briefing paper provides a high-level understanding of the evolution of natural gas infrastructure and infrastructure-enabling policies and regulations in the U.S., and experiences and observations related to U.S. policies and regulations that may be ripe for consideration to foster meaningful natural gas infrastructure development in India. FTI Consulting's understanding of India's natural gas pipeline industry, which was used to inform the observations shared in this document, is provided in Appendix A. This paper also makes recommendations regarding additional research and analyses that are most likely to enable the most meaningful, sustainable, and economic platforms to support India's natural gas infrastructure and energy needs now and into the future. We emphasize, however, that this paper is a primer, focusing only on policy and regulatory levers for natural gas infrastructure development and that the recommendations may or may not ultimately result in overall optimal solutions for India. Accordingly, we recommend that a holistic analysis of market fundamentals (e.g., supply and demand, resource availability, macro-economic energy portfolio optimization, etc.) be undertaken, particularly in the context of shaping policies with long-term investment and social welfare implications. Regulatory and policy stability are key components to encouraging infrastructure investments and enabling market confidence. Therefore, establishing strong and durable policies that do not require significant changes will be critical to sustained natural gas infrastructure build-out in India.

Reliable, affordable access to sustainable energy is intended to support India's "Power for All" program and enable Indian citizens who are bereft of 24/7 electricity to gain access to reliable electricity. We also recognize that meeting industrial, household, power generation and transportation needs against a backdrop of evolving economic dynamics and environmental goals will require the use of innovative technologies *and* low emitting resources such as natural gas. Energy demand in India is projected to go up by 2.7-3.2 times between 2012 and 2040, and the electricity component is projected to increase 4.5 times over the same period.[1] Against this backdrop, the current Indian administration has articulated its goal "to increase the use of natural gas by 2.5 times by the end of the next decade," and to "increase the use of natural gas in India's total energy mix from 6.5 percent to 15 percent between 2028 and 2030."[2] India's climate change pledge at the United Nations Conference of Parties 21 ("COP21") is also helping

[1] *Draft National Energy Policy*, NITI Aayog, Government of India, version as on 27.06.2017.
[2] https://af.reuters.com/article/commoditiesNews/idAFL4N1XX43U

to drive Indian policies to promote the use of natural gas in industry, transportation and power generation.

A brief summary of our key observations based on the U.S. experience are provided below. Additional detail and discussion are provided in subsequent sections of this document.

Key Observations Based on the U.S Experience

- **Clear energy legislation and mandates:** Legislation should enable, but not unduly constrain, the regulatory body.
- **Independent and empowered regulators:** An independent, empowered regulator that provides regulatory certainty and makes decisions based on sound frameworks and the evidence before it is a precondition for attracting capital, liquidity and participation in competitive markets.
- **Implement competition where appropriate:** Some segments of the natural gas value chain, such as wholesale gas marketing and retail supply, may lend themselves well to competition and deregulation.
- **Tariff structures should be designed based on the merits of the case before the regulator:** Enhanced tariff structures that enable efficient allocation of resources, as well as sufficient recovery of and on capital investments, may help to improve natural gas pipeline utilization and incentivize pipeline investment where it is needed.
- **Natural gas market centers, within competition enabling frameworks, may be considered:** Natural gas market centers may improve the transparency of natural gas commodity prices, help shippers manage their portfolios and develop market signals to help incent infrastructure development and services where needed.
- **Consideration of gas-electric interdependencies:** As India's demand for both electricity and natural gas grows, an assessment of electric and natural market rules and fundamentals may enable proactive policies that minimize potential gas-electric interdependency concerns.
- **Incentives:** Incentives may be a tool considered to help effectuate policy, but they must be appropriately tailored to the outcome desired, not the action to achieve it.
- **Returns to investors must be consistent with risk and opportunities:** Investors will be –and should be –exposed to risk when they invest in pipelines. Returns must be sufficient for them to deploy capital in Indian infrastructure over other, similarly risky alternatives.

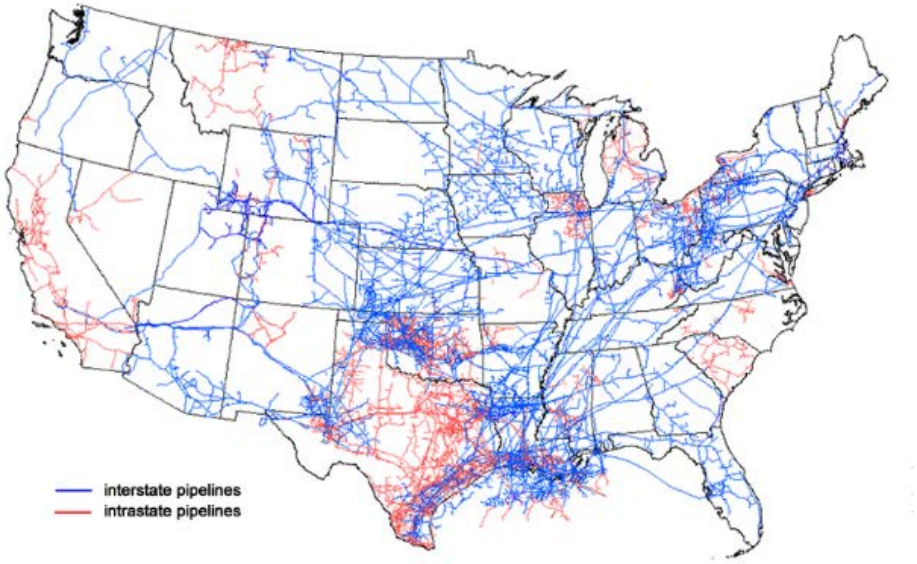
II. Overview of Key U.S. Regulatory Philosophies and Natural Gas Value Chain

This section provides a high-level overview of U.S. natural gas infrastructure and a cursory primer on key regulatory and policy constructs that have shaped it. This introduction is not intended to be an intensive report on U.S. policies and regulation, but rather, to provide foundational understanding of the U.S. system to help the reader understand our recommendations for additional areas of study.

A. Overview of U.S. Natural Gas Value Chain

In the U.S., nearly 3 million miles of mainline and other pipelines link together to create a highly integrated natural gas transportation network between production areas, storage facilities and approximately 75 million customers.[3] The natural gas value chain consists of elements including natural gas gathering lines, processing facilities, transmission pipelines, natural gas storage facilities, liquefied natural gas ("LNG") production/storage facilities and distribution pipelines and systems. As of 2015, there were over 400 storage facilities in the U.S.[4]

Figure 1: Map of U.S. interstate and intrastate natural gas pipelines



Source: U.S. Energy Information Administration, About U.S. Natural Gas Pipelines

The U.S. natural gas industry is interlinked in many ways, but regulatory responsibility is generally separated by function. Natural gas production is not economically regulated. Generally speaking, efforts to facilitate the development of the upstream value chain, including domestic natural gas fields, have been addressed via legislation and regulation promogulated by the U.S. Congress. Both federal and state agencies regulate pipelines across the United States. Interstate pipelines are overseen by the Federal Energy Regulatory Commission ("FERC" or "Commission"), the economic regulator and the U.S. Department of Transportation ("DOT"), the safety and inspection regulator. FERC primarily regulates the midstream gas segment, ensuring just and reasonable rates as well as fair access and provisions for all interstate pipeline and storage customers. Individual states, through their utility commissions, regulate the downstream value chain, primarily the distribution system, by ensuring just and reasonable rates for end-use customers. The distribution facilities under state and/or local jurisdiction are privately

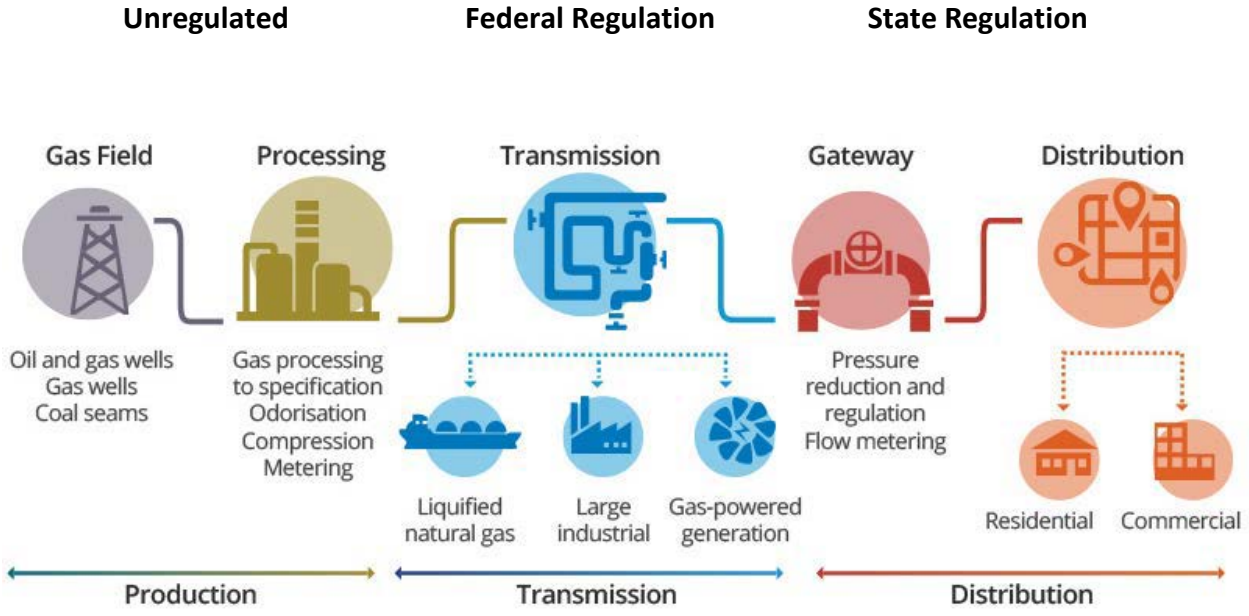
[3] https://www.eia.gov/energyexplained/index.php?page=natural_gas_pipelines
[4] https://www.eia.gov/naturalgas/storage/basics/

owned and unregulated. At both the federal and state levels, various regulators are responsible for ratemaking, safety standards and ensuring open access.

In the U.S., the Dormant Commerce Clause[5] helps to provide a boundary between state and federal jurisdiction, restricting state powers from passing legislation regulating activities that are subject to federal laws. Additionally, the Supremacy clause of the U.S. Constitution establishes that states are bound by federal law.

With respect to upstream natural gas production and midstream services, including transportation and storage, the U.S. federal government does not own or operate the assets, nor does it provide services. In these sectors, the federal government has assumed only policy and regulatory roles.

Figure 2: Regulation of the Natural Gas Value Chain



Source: Australian Energy Market Operator[6]

With respect to natural gas distribution utilities, or local distribution companies ("LDCs"), there are three kinds of business structures in the U.S. They are investor-owned distribution companies, publicly-owned distribution companies (municipals) and natural gas distribution cooperatives. An investor-owned distribution company is a for-profit enterprise, owned by stockholders. A public gas distribution system is owned by a city, state or federal government. A cooperative is owned by its members who are also the customers. Therefore, all of the owners live in the cooperative's service area. A cooperative operates on a non-profit, cost-of-service basis.

[5] The Commerce Clause refers to Article 1, Section 8, Clause 3 of the U.S. Constitution.

[6] http://australianenergymarketoperator.blogspot.com/2014/12/this-is-also-test-sed-ut-perspiciatis.html

B. Safety Regulation

Economic and safety regulation are linked in that pipelines must be able to recover the costs associated with maintaining or enhancing system reliability and safety. However, regulatory compliance and economic and safety regulations are carried out in a separate and distinct manner by different entities. Pipeline safety in the U.S. is regulated by both federal and state agencies through a large network of regulators. To illustrate, pipeline safety regulations regarding construction, inspections, operations and violations are under the purview of the Pipeline and Hazardous Materials Safety Administration ("PHMSA") of the DOT. Some safety responsibilities are shared or assigned to state agencies, while intrastate pipelines may be subject to state safety regulations; such state regulations must be consistent with, and at least as stringent as, federal regulations. The National Transportation Safety Board ("NTSB") investigates pipeline accidents and issues reports and recommendations to regulators, companies and industry groups.

C. Overview of U.S. Regulatory Philosophy

The U.S. experience suggests that appropriate incentives for infrastructure investment are rooted in sound policy and regulatory certainty. In our view, policy and regulation are not one in the same, but rather two distinct levers by which decision makers can influence natural gas infrastructure investment.

Policy, promulgated by the legislative branch, outlines what a government intends to achieve, as well as the principles by which those goals will be achieved. These policies are developed into law by establishing legal standards, procedures and principles. The law is also what grants powers to the regulatory entity. For example, FERC and State Commissions are creatures of clearly-defined statutes and laws and have no authority beyond the powers articulated in those laws. Within this framework, the regulatory entity is tasked with implementing, not creating, policy.

For purposes of this paper, we will be primarily focused on economic regulation. Ultimately, economic regulation at both the federal and state levels must balance the interests of customers and shareholders. Economic regulation is intended to replicate competitive outcomes when market failures occur, such as when natural monopolies emerge. Such regulation is necessary to protect customers from natural rent-seeking behaviors of the natural monopoly. Natural monopolies in and of themselves are not "bad" things, rather, they develop due to the characteristics of barriers to entry, economies of scale and scope, capital intensity and lumpiness of investment. Regulation outside of economic regulation is largely outside of the focus of this particular exercise.

The U.S. experience suggests that good regulation can encourage private natural gas infrastructure investment by:

- Providing regulatory certainty in the course of implementing policy;
- Providing investors an opportunity to earn competitive returns to compensate them for risks inherent in investment;
- Ensuring that customers receive gas transmission and distribution services at reasonable rates;

- Promoting transparency;
- Implementing a framework in which competition, or something that closely resembles competition, can exist;
- Recognizing the need and benefits of regulatory pricing, such as cost-of-service, where natural monopolies occur; and
- Promoting efficient utilization of resources through price signals.

Moreover, the U.S. experience suggests that meaningful and effective regulation does not seek to create policy outside of the regulator's own regulatory purview.

In the U.S., regulation does not guarantee returns on investments, allow for preferential treatment or access to public utility assets, grant subsidies, treat "similarly situated" customers differently or pick technological winners and losers. To help facilitate efficient use of finite resources, effective natural gas pipeline regulation does not shield customers from commodity price fluctuations and allows pipelines to offer a variety of services to meet customer needs and risk profiles. Effective regulation does not allow for information prohibitive of meaningful competition and allows for competitive markets where appropriate.

Key Observation 1: Clear Energy Legislation and Mandates

Legislation should enable, but not unduly constrain, the regulatory body. Principles should be annunciated, but specific outcomes should be determined by regulatory authorities. Legislative initiatives should be designed to create frameworks and standards and to remove structural obstacles to development. Details like rate design, specific levels of authorized returns, etc., should largely be the purview of regulators, whose mandate will be to implement the specified policy goals.

- Establish Regulatory Principles
  - Create standards to which regulators will adhere
  - Clearly define and establish the commercial and allocation role of the government
- Continue to Empower Regulators
  - Expand and/or strengthen agencies charged with regulatory oversight through legislation; this includes but is not limited to: appropriate funding, staffing, training, deference to the regulators on certain issues, and enforcement authority.
- Legislation Can Help to Address Structural Obstacles
  - Promote and/or ease the path for infrastructure additions
  - Modification of tax treatments and structures for infrastructure assets

D. The Just and Reasonable Standard

To more fully appreciate U.S. natural gas pipeline regulation, it is helpful to understand the context in which appropriate economic regulation is measured. U.S. regulated utilities, including interstate natural

gas pipelines, refer to their rates as being "just and reasonable." This is a term of legal art on which the U.S. regulatory paradigm is built. The "just and reasonable" standard is used to measure the reasonableness of utility rates across the U.S., both in federal and state jurisdictions. This standard is rooted in long-standing U.S. Supreme Court precedent established in *Hope*[7] and *Bluefield*[8]. Generally speaking, just and reasonable rates allow for the utility's recovery of costs prudently incurred in the course of providing services, and the right to earn a reasonable return on investment. In the U.S., rates, which include allowed returns, must be deemed "just and reasonable," consistent with Supreme Court Law. Generally speaking, allowed returns must balance the needs of the company's shareholders and customers; returns must be sufficient to attract sufficient capital to operate safe, efficient systems and to maintain the firm's financial integrity; and should be similar to returns available to other firms of similar risk profiles. Investors in natural gas infrastructure face numerous risks such as, but not limited to, lengthy project lead times, opposition from stakeholder groups, permitting and siting processes, pipeline on pipeline competition and volumetric risk.

Key Observation 2: Independent and Empowered Regulators

While the U.S. regulatory model bifurcates responsibilities for the midstream and downstream functions, each regulator has a conceptually similar mandate:

- Ensure rates are just and reasonable
- Ensure safety
- Promote competition in a fair and transparent manner, when appropriate

Regulators are (mostly) insulated from political interference and implement policy:

- Regulatory authority is derived from legislation and statute. Regulation itself is a mix of statute and precedent.
- Regulators seek to provide regulatory certainty through a generally neutral framework in which policy measures can be implemented without being overly prescriptive.

Why it matters to India: An independent, empowered regulator that provides regulatory certainty and makes decisions based on sound frameworks and the evidence before it is a precondition for attracting capital, liquidity and participation in competitive markets.

E. Evolution of U.S. Regulation Over Time

In the early days of the U.S. natural gas industry, local governments regulated natural gas distribution networks. Eventually, pipelines connected municipalities and thus, regulatory needs expanded beyond municipalities. These intrastate[9] pipelines began to be regulated by the states. As technology improved, so too did the long distance of natural gas pipelines, eventually crossing state boundaries.

[7] *FPC v. Hope*, 320 U.S. 591, 603 (1944) ("Hope").
[8] *Bluefield Water Works & Improvement Co. v. Pub. Serv. Comm'n*, 262 U.S. 679, 693 (1923) ("Bluefield").
[9] In the U.S., infrastructure or services within the boundaries of a state are intrastate; those that cross state boundaries are considered interstate.

While regulation of intrastate commerce remained with state and local authorities, the U.S. federal government became involved in the regulation of interstate natural gas in 1938 with the passage of the Natural Gas Act ("NGA"), requiring the Federal Power Commission ("FPC") to oversee the rates, terms and conditions for "transportation of natural gas in interstate commerce." At this time, natural gas was sold by the producer directly to the pipeline that then sold the natural gas to a LDC. The LDC ultimately sold it to the end-use customer.

From the 1940s through the 1970s, the FPC (succeeded by FERC in 1978) also regulated natural gas wellhead prices to varying degrees. Prices were ultimately set below the market rate, causing market distortions, contributing to natural gas shortages in the 1970's. In response, the U.S. Congress enacted the Natural Gas Policy Act in 1978, decontrolling gas prices at the point of production. That same year Congress also passed the Powerplant and Industrial Fuel Use Act ("Act"), prohibiting the use of natural gas for electricity generation. Later repealed in 1987, the Act shaped, and potentially distorted, the electric power generation portfolio with respect to fuel choices (including use of natural gas).

In 1985, the Commission issued Order No. 436[10] (sometimes referred to as the Open Access Order) changing the way interstate pipelines were regulated in response to changed economic conditions. Markets for the purchase and sale of natural gas had become relatively competitive, while the pipeline network for natural gas transportation remained monopolistic. Order No. 436 initiated a voluntary program in which pipelines were allowed to transport natural gas without prior Commission approval as long as the services were provided on a non-discriminatory basis. Under this open access regime, interstate pipelines could act purely as transporters, offer transportation service to customers on a first come, first serve basis and were not allowed to discriminate against transportation requests to protect their own merchant services. The intent was to enable pipeline customers, including LDCs, to access competitively priced sources of natural gas. Eventually, all of the major pipeline systems took part.

In 1992, FERC issued Order No. 636[11] (clarifying companion orders were issued through 1997) with the intention of continuing the evolution toward a more competitive natural gas pipeline transportation system for both producers and customers. Order No. 636, often referred to as "The Restructuring Rule," completed the final steps of unbundling, mandating that interstate pipeline companies must offer transportation, storage and other services separately from being the producer/supplier of natural gas. This Order requires pipelines to transport natural gas regardless of who owns the gas, essentially ensuring that "open access" would mean "equal access" in moving natural gas from the wellhead to other users.[12]

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[10] FERC Order 436, Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol, 50 Fed. Reg. 42,408 (1995)

[11] Pipeline Service Obligations and Revisions to Regulations Governing Self Implementing Transportation Under Part 284 of the Commission's Regulations, Order No. 636, 57 FR 13267 (Apr. 16, 1992), FERC Stats. & Regs. Regulations Preambles [Jan. 1991-June 1996], 30,939 (Apr. 8, 1992).

[12] Pipelines were allowed to recover costs of implementing the new order from customers, including termination and modification of existing contracts, as long as FERC determined they were prudently incurred.

Under Order No. 636, pipelines could now offer firm and interruptible sales services and are required to offer a variety of transportation services, such as no-notice, firm, interruptible transportation services. Storage services can now be provided on an open access basis. Order No. 636 also established a capacity release program that allowed customers to sell their excess firm capacity rights to other customers in a secondary market.

However, because pipeline transportation was still considered a monopoly service, the Commission continued to regulate the transportation rates pipelines can charge, and still does today. Customers with "firm" or uninterruptable service pay more of the pipeline's fixed costs, while those with "interruptible" services pay a lower percentage of the pipeline's fixed costs.

In the wake of Order No. 636, as markets became more competitive, more market centers emerged organically. Market centers enable gas trading and transportation, help provide liquidity to the natural gas trading market and provide a central forum for buyers and sellers to conduct business. Market centers may facilitate either physical or purely financial transactions.

In 1999-2000, FERC issued Order Nos. 637, 637-A, and 637-B[13], furthering the removal of "bundling" between natural gas sales and pipeline transport. This Order did a number of things including 1) waiving the price ceiling for short-term release capacity for a limited time[14] 2) allowed pipelines to propose peak and off-peak rates and term-differentiated rates, 3) made changes to regulations regarding scheduling procedures, capacity segmentation and pipeline penalties and 4) improved reporting requirements to increase transparency.

Over the years, FERC has issued various orders and policy statements to strengthen non-discriminatory pipeline access, adjust rate-making methodologies, encourage pipeline modernization and ensure timely certification of infrastructure investments.

State regulation of LDCs has also changed over time. Since the mid-1990s some states have allowed for "deregulation" or "retail choice," in which LDC customers, including residential customers, may choose to purchase natural gas from an entity other than the LDC. Under the retail choice paradigm, LDC services for distribution are separate from the sale and marketing of the commodity. Large commercial and industrial customers have enjoyed this option for many years, and the option has become more available to residential customers over time. Approximately one-third of states in the U.S. now allow for some type of natural gas retail choice.

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[13] *Regulation of Short-Term Natural Gas Transportation Services and Regulation of Interstate Natural Gas Transportation Services*, Order No. 637, FERC Stats. & Regs. 31,091 at 31,300, clarified, Order No. 637-A, FERC Stats. & Regs. 31,099, reh'g denied, Order No. 637-B, 92 FERC 61,062 (2000), aff'd in part and remanded in part sub nom. *Interstate Natural Gas Ass'n of America v. FERC*, 285 F.3d 18 (D.C. Cir. 2002), order on remand, 101 FERC 61,127 (2002), order on reh'g, 106 FERC 61,088 (2004), aff'd sub nom. *American Gas Ass'n v. FERC*, 428 F.3d 255 (D.C. Cir. 2005).

[14] Several years later, FERC permanently lifted the price ceilings on short-term capacity releases but maintained them for sales by pipelines.

Key Observation 3: **Implement Competition Where Appropriate**

Some segments of the natural gas value chain, such as wholesale gas marketing and retail supply, may lend themselves well to competition and deregulation.

- Many U.S. states have introduced natural gas customer choice programs, giving consumers the option to purchase natural gas from a supplier (marketer) that is a different company than the local natural gas utility.
- Sales of natural gas by marketers are unregulated, and marketers can earn profits on natural gas sales. Natural gas distribution companies are regulated by state commissions and are not permitted to earn profits on the delivered natural gas.

Other segments, like pipelines and LDCs, tend to be natural monopolies for which cost of service regulation is appropriate.

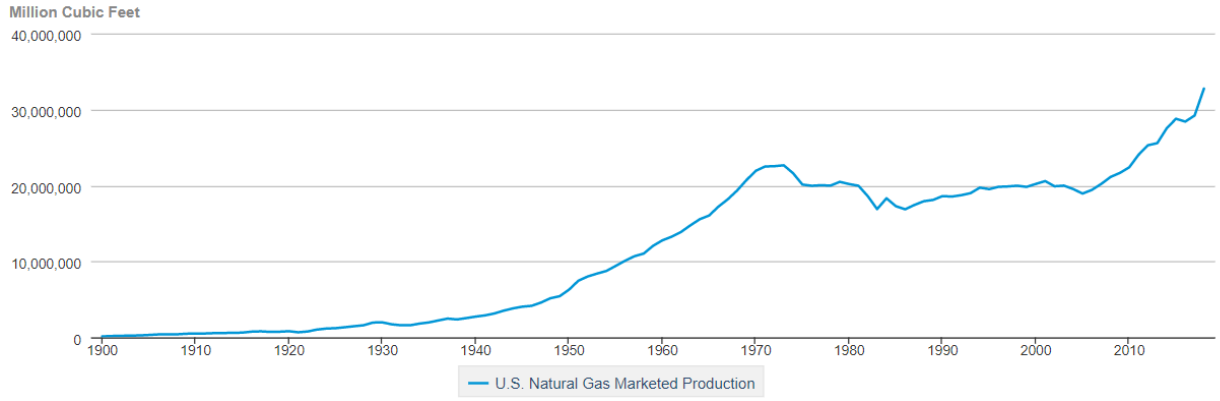
Competition should be introduced incrementally and with a full assessment of potential market failures.

Why it matters to India: In the U.S., results from deregulating have been mixed. Risks and benefits are both significant. Positive outcomes require open access, solid regulation and a positive business environment.

F. Drivers of U.S. Infrastructure Growth: Supply and Demand Over Time

Demand for natural gas in the U.S. more than doubled by the 1950s and 1960s, following World War II. A significant amount of infrastructure was developed to meet growing demand, including neighborhoods, and new industrial customers emerged. More recently, the U.S. natural gas industry has changed significantly in a short period of time thanks to the "shale revolution." Between 2003 and 2008 natural gas prices increased, providing an incentive for producers to expand development of existing and undeveloped natural gas fields. At the same time advances in drilling, including hydraulic fracturing and horizontal drilling, paved the way for the "shale revolution" in the U.S. Starting around 2005, natural gas production in the U.S. significantly increased, leading to a decline in prices that has been observed since around 2009. U.S. natural gas production has increased approximately 55 percent since 2009 as well, resulting in lower prices and increased demand from the electric power generation, industrial sectors and exports of natural gas. Accordingly, new transmission pipelines have been constructed to meet increased demand, while natural gas exploration and production continues to increase.

Figure 3: U.S. Natural Gas Marketed Production



Source: U.S. Energy Information Administration

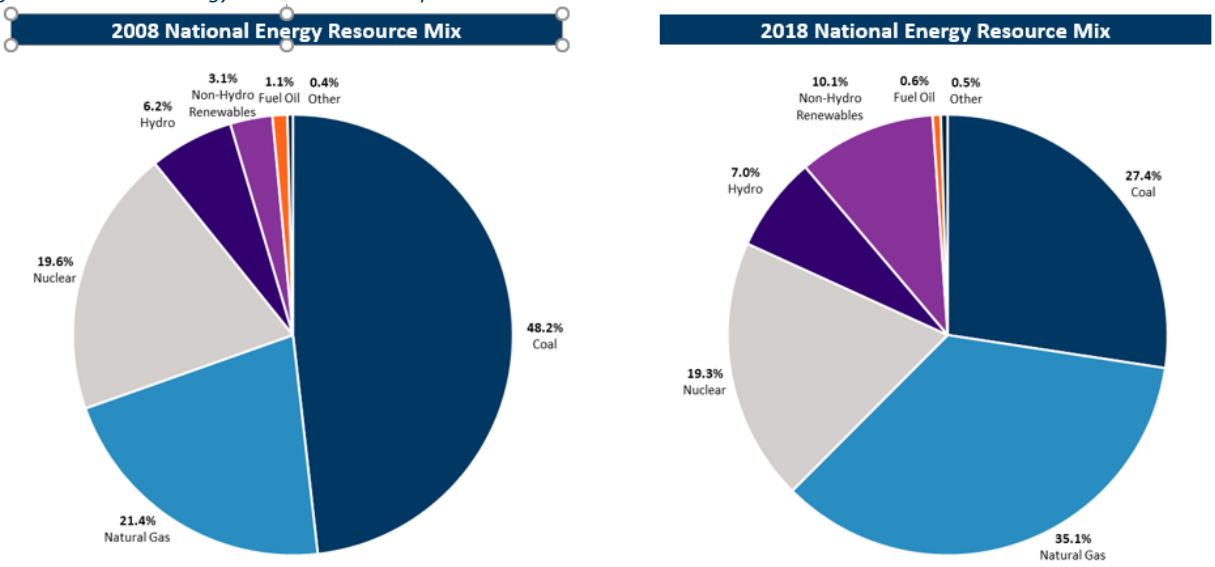
Impacts of the U.S. shale revolution have been dramatic. Market dynamics have caused a shift from traditional regions, such as the Gulf of Mexico, toward onshore regions with shale rock formations, such as the Marcellus shale formation. Natural gas from hydraulically fractured wells accounted for 67 percent of total U.S. natural gas production in 2015, up from just 7 percent in 2000.[15] Moreover, the rate of U.S. shale gas production is not expected to slow anytime soon, as U.S. natural gas production reached a new high in 2018 for the second year in a row.[16]

Domestic production of dry natural gas is projected to grow from 26.5 trillion cubic feet in 2016 to 39 trillion cubic feet by 2040, with shale gas responsible for nearly all of the increase.[17] The U.S. Energy Information Agency ("EIA") estimates by 2040 natural gas prices of below $4.00 to nearly $10 per million Btu, depending on extraction costs and resource availability.[18]

Increased abundance of natural gas, combined with low commodity prices, has significantly changed the economics, and therefore, the demand for the fuel. Plentiful domestic shale gas has fundamentally changed the fuel mix in the U.S. electricity sector. For example, natural gas constituted approximately 21 percent of the U.S. electric generation mix in 2008; it constitutes 35 percent in 2018.

[15] https://www.businessroundtable.org/natural-gas-infrastructure
[16] https://www.eia.gov/todayinenergy/detail.php?id=40973
[17] https://www.businessroundtable.org/natural-gas-infrastructure
[18] https://www.eia.gov/todayinenergy/detail.php?id=34852

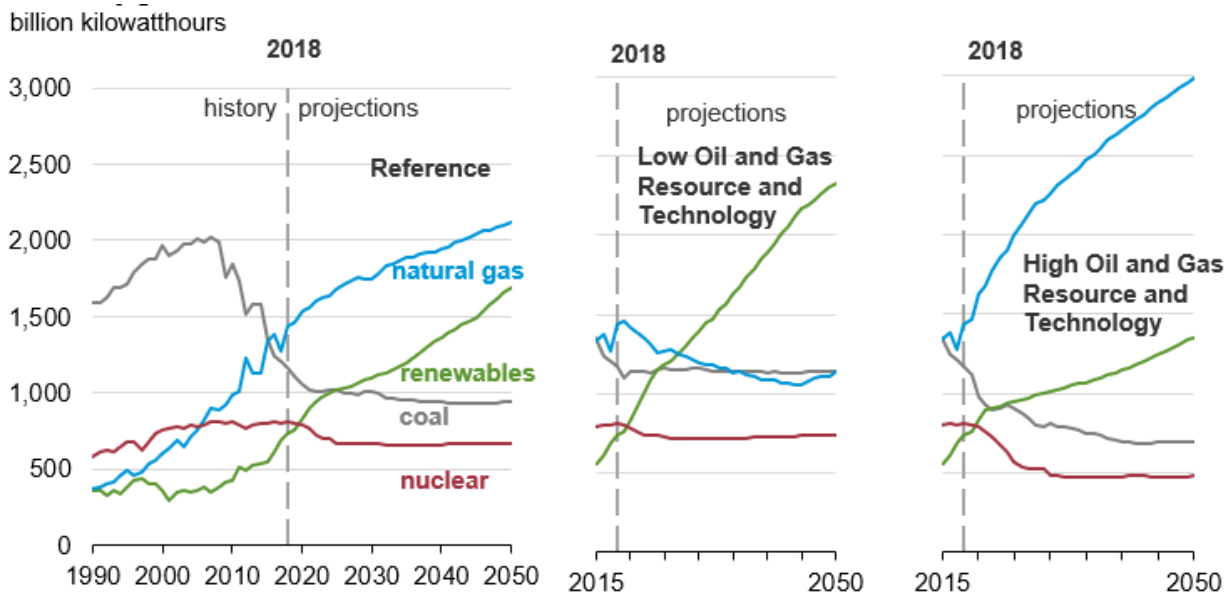
Figure 4: National Energy Resource Mix Comparison



Source: Department of Energy, Energy Information Administration

Natural gas is becoming the predominant fuel for electric power. While use of natural gas as a fuel for electric generation is largely dependent on fuel prices, U.S. reliance on the fuel is expected to continue into the future. See Figure 5 below, for example.

Figure 5: Electricity Generation From Selected Fuels



Source: U.S. Department of Energy, Energy Information Administration

III. State/Federal Regulation Overview

A. FERC

The Commission is an independent agency by statute and is designed to be independent from undue political party influence as no more than three of its five commissioners, appointed by the U.S. President, may come from an individual political party. FERC employs a number of additional commission staff, such as utility analysts, engineers, attorneys, economists, accountants and compliance specialists, among others. Broadly, FERC aims to ensure that interstate natural gas services are reliable, affordable and efficient service for shippers, while also ensuring that investors can reasonably recover the costs incurred for providing the service, including a fair return on the investment.

Though FERC is an independent agency, it is still subject to legal review; its decisions must be based on the merits of the record and survive legal review by the courts should challenges arise. This is true for all Commission actions, including but not limited to final adoption of new regulatory rules and rate decisions.

Under authority of Section 7 of NGA, FERC (which was preceded by the FPC), has jurisdiction only over the facilities used in interstate commerce. FERC regulates rates, terms and conditions of service for "transportation of natural gas in interstate commerce" to ensure that they are just and reasonable and not unduly discriminatory. This includes interstate natural gas pipelines, storage facilities and LNG facilities. FERC also certificates construction and operation of interstate facilities, upon a finding of public convenience and necessity, and approves the abandonment of certification of new facilities. FERC has also codified a system of accounts and records that pipelines must maintain and has also established a code of conduct for affiliates.

Pursuant to the NGA, FERC's primary approach to establish just and reasonable rates for interstate natural gas pipelines is cost-of-service ratemaking. Under this paradigm, rates are based on a pipeline's cost of providing service including an *opportunity* for the pipeline to earn a reasonable return on its investment. Cost-of-service ratemaking will be discussed in more detail in later sections.

B. State Regulation

Regulatory Bodies and Jurisdictions

While FERC has jurisdiction over the regulation of interstate pipelines, state regulatory authorities, such as Public Utility Commissions ("PUCs") or Public Service Commissions ("PSCs"), regulate intrastate pipeline capacity and LDCs. State PUCs have jurisdiction over the operation of a local distribution network by an LDC if the facilities of the LDC are located within the state. PUCs regulate investor-owned utilities ("IOUs") but not cooperatives, utility districts or municipally-owned utilities, except in matters relating to safety or other public issues.

Broadly, state utility regulators aim to ensure that LDCs provide reliable, affordable and efficient service to their customers, while also ensuring that LDCs can reasonably recover the costs incurred for providing service and provide a fair return to investors. PUCs have oversight over cost allocation and cost

recovery, retail rates charged to customers, utility resource planning, siting, construction, and expansion of local distribution systems, environmental issues and pipeline safety issues not covered by PHMSA. PUCs also aim to integrate policy, market and technology changes as the utility sector evolves, such as utility incentives related to energy efficiency.

State PUC Structure

State PUCs are typically led by three to five state commissioners, each serving terms of four to six years. While the majority of state commissioners are appointed to their positions by the state's governor or legislature, commissioners in fourteen states are elected.[19] Like FERC, PUCs employ a number of additional commission staff, such as utility analysts, engineers, attorneys, safety inspectors and compliance specialists, among others.[20]

Similar to how the NGA granted FERC the jurisdiction over natural gas facilities used in interstate commerce, various state laws and statutes outline the powers and responsibilities of PUCs.[21] Under state legislature, PUCs can exercise traditional rulemaking authority as well as preside over various quasi-judicial regulatory proceedings. Key among these proceedings are rate proceedings, in which utilities or LDCs seek permission from PUCs to raise rates charged to customers.

In states with "deregulation" or "customer choice," PUCs retain responsibility for regulating the rates charged for distribution services provided by the LDCs.

C. Rate Review Pathways

Natural gas utilities typically initiate a rate proceeding by filing a rate case with the appropriate commission in order to recover the costs associated with new infrastructure projects or increases in operating and maintenance expenditures. A natural gas utility, whether it is an interstate pipeline or an LDC, may initiate a rate case by filing an application or petition to increase rates with the applicable federal or state commission. This initial filing typically contains several different components,[22] which will usually include the requested rate increase, and financial data and testimony supporting the establishment of a revenue requirement and any existing revenue deficiency, the cost of serving customers in different rate classes, the proposed rate design and a requested return on equity. The company may also request temporary rates in order to reduce the impact of the regulatory lag between the rate case filing date and the date the new and permanent rates would go into effect.

There are several procedural pathways for FERC jurisdictional rates to be examined. In the first pathway, under Section 4 of the NGA, the pipeline may propose to increase its rates at any time, unless that pipeline has agreed to a settlement establishing limitations to this option and will have the burden of proving that its proposed rates are just and reasonable. These types of filings are typically set for

[19] National Association of Regulatory Utility Commissioners, "About NARUC," at https://www.naruc.org/about-naruc/about-naruc/.

[20] See, e.g., Pennsylvania Public Utility Commission, "PUC Organizational Charts," July 22, 2019, at http://www.puc.pa.gov/general/pdf/PUC_Org_Chart.pdf.

[21] See, e.g., Indiana Code at §§ 8-1-1 and §§ 8-1-2; Illinois Compiled Statutes at 220 ILCS 05.

[22] Minimum filing requirements are typically codified in each jurisdiction.

hearing and settlement procedures, with an Administrative Law Judge ("ALJ") presiding over them. These may also take the form of a "limited" proceeding when pipelines propose to add a new service with corresponding new rates. Regardless of whether participants choose to settle or litigate the case, the Commission must make a final determination based on the record that was developed during the proceeding. In the second pathway, the Commission can open a proceeding on its own motion or pursuant to a complaint or grant a complaint filed by a customer of the pipeline or a state commission that believes their citizens are being charged unjust and unreasonable costs. The complaint process is carried out under Section 5 of the NGA. In this instance, the Commission can require prospective changes if it carries its burden of proving that the pipeline's rates are no longer just and reasonable. This pathway is not used as frequently as the former, although the Commission has exercised its discretion more frequently since 2009. Under both of these pathways, parties and participants to the proceeding have the opportunity to review and analyze data from the pipeline and present their own case for "just and reasonable" rates.

At the state level, rate proceedings operate in much the same way, though variances may be observed across state jurisdictions. For example, rate proceedings before the PUC will often be heard by the commission members, not an ALJ. Generally speaking, commissions tend to be receptive to rate settlements, as they can help to reduce administrative burdens for all parties. Settlements must be approved by the commission, however.

For newly constructed interstate pipelines, FERC also sets "initial rates" under Section 7 of the NGA. These initial rates remain in place until the pipeline files a rate case under the first procedural pathway described above. Intrastate pipelines that transport natural gas for interstate pipelines and LDCs in interstate commerce under certain circumstances are also regulated by FERC. These rates must meet a "fair and equitable" standard and are based on the cost-of service ratemaking approach. These types of pipelines also have the option to use the cost-based rate approved by its state regulator.

D. Rate/Tariff Review Process

Regardless of the path taken, commissions make their final decision based on the merits of the record developed over the course of the proceeding. Generally speaking, if a sufficient record has been established in an initial filing, the commission will render a decision based on that record. If, however, the record is insufficient, commissions have discretion to exercise a number of options, such as a paper hearing, a trial-type evidentiary hearing or a technical conference. At the federal level, the FERC may also refer the case to its dispute resolution service or provide other forms of alternative dispute resolution.

As an example of the process that is generally practiced by FERC and across state jurisdictions, the frequently exercised adjudicatory process begins 1) with a hearing order, usually establishing settlement and hearing proceedings; moves on to 2) the hearing and settlement process; and 3) ends with a final decision made by the commission.

At a high level, the hearing process begins with the initial filing and hearing order as part of the record and allows for discovery in which parties can seek information from one another to develop evidence. As utility regulatory proceedings are generally open to the public, parties to the proceeding participate in the proceedings themselves.[23] Such participation can occur a number of ways, including procedural motions, public comments and submission of expert analyses and testimony.

During the discovery process, parties to the proceeding are allowed to ask for information and evidence pertaining to the case at hand. Generally speaking, they are seeking cost, revenue, cost of capital and operational and other useful information to develop their position. Parties to the proceeding prepare and file written testimony based on evidence gathered and may also offer oral testimony and cross-examination before the commission or presiding ALJ. Throughout this process, parties may choose to settle the case. This is the record upon which the commission will render a decision. Again, the commission's decision must be sound so as to withstand judicial scrutiny should challenges arise.

E. COS Regulation Mechanics

In cost of service regulation, the regulation determines the total cost of service, also referred to as the "revenue requirement," which indicates the total amount of revenues that must be collected in rates for the utility to recover both its prudently incurred costs for providing service, as well as a reasonable return on its investment.

The revenue requirement formula is provided below:

Rate base x **Overall Rate of Return**	=	Return
	+	Operation and Maintenance Expense
	+	Administrative and General Expense
	+	Depreciation Expense
	+	Taxes
	-	Revenue Credits
		Total Cost of Service

Generally speaking, the regulator reviews all of the pipeline's cost components to determine if the costs are reasonable and to determine whether the overall rate of return results in just and reasonable rates.

Generally speaking, rates for customers are developed in the following manner: costs associated with the provision of service are determined; they are then allocated to customer classes based on usage patterns; costs are then designed to recover these costs from customers though rates and charges.

[23] Legal requirements for being considered a "party" to a proceeding may vary across jurisdictions. Interested parties often include the large industrial and commercial customers, consumer advocates, and environmental organizations, among others.

F. Other Rate Options

Cost of service ratemaking is the cornerstone approach most typically used by the FERC. However, it is worth noting that FERC has allowed other ratemaking approaches in certain situations. Importantly, the approval of such alternative methods must still meet the just and reasonable standard. Alternative ratemaking methods that have been allowed in specific situations include:

- Selective discounting
- Market-based rates
- Negotiated rates

Key Observation 4: Rate Structures Should be Designed Based on the Merits of the Case Before the Regulator

- Rate design is more a term of art rather than science.
- There is no "one-size fits all" rate structure methodology; there are tradeoffs among the various options.

Why it matters to India: Enhanced rate structures that enable efficient allocation of resources, as well as sufficient recovery of and on capital investments, may help to improve natural gas pipeline utilization and incentivize pipeline investment where it is needed.

IV. Permitting and Siting Overview

FERC issues certificates of "public convenience and necessity" for "the construction or extension of any facilities for the transportation in interstate commerce of natural gas" pursuant to NGA.[24] It essentially has backstop citing authority. However, several federal agencies have various responsibilities to review interstate natural gas projects under the National Environmental Policy Act ("NEPA"), and various other entities (including state entities) have requirements that must also be met.[25] Example agencies include but are not limited to: the U.S. Army Corps of Engineers, U.S. Forest Service, Tribal Councils and State Public Utility Commissions.[26] Requirements must be met or obtained to protect waterways, wetlands, agriculture, threatened and endangered resources and cultural resources. In an attempt to expedite the permitting process, the U.S. Congress passed Energy Policy Act of 2005 ("EPACT 2005"),[27] designating

[24] Section 7(c) of the Natural Gas Act of 1938 (NGA) (15 U.S.C. §717f(c))

[25] Of note, the Applicant must obtain its own right-of-way. Pipeline routes, as well as storage field locations, can be impacted by geology, landowner interests, and more.

[26] FERC has experienced increased challenges to how it undertakes environmental reviews, particularly with respect to greenhouse gas emissions. Opponents to infrastructure development assert that FERC is applying its own policies related to eminent domain incorrectly; they argue eminent domain should be used for the public good, not private profits.

[27] Energy Policy Act of 2005, Pub. L. No. 109-58, 119 Stat. 594 (Aug. 8, 2005).

FERC as the lead federal agency for the review of interstate natural gas projects under NEPA.[28] Similar permitting and siting authorities, as well as complexities, can be observed at the state level; details will vary across each jurisdiction.

More recently, the Trump Administration issued an Executive Order ("EO") requiring federal agencies to evaluate and process environmental reviews and authorization decisions for "major infrastructure projects" as *One Federal Decision*.[29] At a high level, the EO established a federal government-wide goal of reducing the completion time for environmental reviews and authorization decisions for major infrastructure projects to no more than two years. This EO only applies to infrastructure within federal jurisdiction.

With respect to interstate infrastructure, generally speaking, a pipeline seeking construction or expansion will file an application requesting the Commission to issue a certificate authorizing the construction of a pipeline project. There are a myriad of federal and state environmental requirements and permits that must be met or obtained to protect waterways, wetlands, agriculture, threatened and endangered resources and cultural resources. While FERC has the lead role in developing either an environmental impact statement or an environmental assessment for a project, other entities have requirements that must also be met.[30] Examples include but are not limited to: the U.S. Army Corps of Engineers, U.S. Forest Service, Tribal Councils and State Public Utility Commissions.[31] While FERC itself has no jurisdiction over pipeline safety or security, FERC also ensures that applicants certify that they will comply with other agencies, such as DOT and Department of Homeland Security ("DHS"), on these issues. FERC may approve the project, with or without modifications, or reject it. Similar authorities, as well as complexities, can be observed at the state level; details will vary across each jurisdiction.

V. Natural Gas Trading Hubs

Market centers, located at strategic points along the pipeline network, are important to natural gas markets for several reasons. They allow for the interchange of natural gas across pipeline systems and provide a platform for natural gas trading, as well as access to storage and pipeline capacity, which can in turn can help promote improved natural gas market transparency, competition and liquidity. Market centers facilitate transfers across pipeline interconnection, can enable efficient trading platforms and provide enhanced shipper services. Such market center services may include, but are not limited to: wheeling, parking, loaning, storage, access to capacity release programs, title transfer, etc. These

[28] EPACT 2005 also granted FERC citing authority over LNG facilities.

[29] EO 13807: Establishing Discipline and Accountability in the Environmental Review and Permitting Process for Infrastructure Projects, issued on August 15, 2017.

[30] Of note, the Applicant must obtain its own right-of-way. Pipeline routes, as well as storage field locations, can be impacted by geology, landowner interests and more.

[31] FERC has experienced increased challenges to how it undertakes environmental reviews, particularly with respect to greenhouse gas emissions. Opponents to infrastructure development assert that FERC is applying its own policies related to eminent domain incorrectly; they argue eminent domain should be used for the public good, not private profits.

services, which are priced separately, help customers to manage their supply, transportation and storage needs.

Market center operations rely on management from both the center's administrator, as well as the interconnecting pipeline operator. Market centers may also provide customers access to internet-based trading and nominations platforms, making such transactions relatively easy.

Though some market centers already existed, many industry participants attribute the increased number of market centers in the U.S. to the implementation of FERC Order No. 636. Market centers have developed organically in the sense that they are largely dependent on factors such as location of natural geographic formations and productions fields, demand centers and pipeline interconnections. In turn, market centers can also encourage additional pipeline interconnections.

Key Observation 5: Natural Gas Market Centers, Within Competition Enabling Frameworks, May be Considered

Such efforts may:

- Help shippers manage their portfolios
- Improve market liquidity
- Encourage pipeline interconnections

Additionally, capacity release options and secondary markets can also add to market liquidity.

Why it matters to India: Natural gas market centers may improve the transparency of natural gas commodity prices, help shippers manage their portfolios and develop market signals to help incent infrastructure development and services where needed.

VI. Gas-Electric Interdependencies

In the U.S., as use of natural gas fired generation has increased, so too has the interdependency between the electric power and natural gas sectors. Accordingly, increased attention has recently been paid to potential reliability challenges to the electric grid as it depends on the natural gas grid, physical and cybersecurity issues for pipelines and alignment of gas and electricity bidding and scheduling. In some regions of the country, there are currently challenges related to the interdependency of wholesale electric market pricing rules and incentivizing appropriate gas infrastructure investment. Additionally, current debates about fuel security for electric generation, including "just in time gas deliveries" continue to evolve. These interdependencies are expected to increase over time in light of abundant

U.S. natural gas supplies, increased reliance on natural gas fired generation and the need to back up increased renewable generation with natural gas fired generation to maintain electric reliability.

Key Observation 6: Consider Gas-Electric Interdependencies

Why it matters to India: As India's demand for both electricity and natural gas grows, an assessment of electric and natural market rules and fundamentals may enable proactive policies that minimize potential gas-electric interdependency concerns.

VII. Incenting Infrastructure Investment

In the U.S., pipeline investors bear the risk of investment, and they are compensated for that risk. However, new pipelines require shippers to sign contracts to finance expansion. Accordingly, long-term gas supply and demand affect the pace of midstream infrastructure investment. Transmission, storage and distribution infrastructure is generally considered to be a relatively low-risk investment. Because of this sector's consistent cash flow generation, capital is available for projects that have a predictable revenue stream, have stable cash flows and are based on proven technologies. This environment is in large part created by regulatory certainty and constructs. Private financing is often available for distribution infrastructure investments where the rate base and the allowed return on equity is established through the public service commission through in a rate case proceeding, or for midstream investments such as intrastate pipelines that have signed long-term contracts with suppliers or shippers. These stable, predictable returns are attractive to capital markets, including institutional investors.

Adverse market fundamentals or regulatory challenges and uncertainties can, in contrast, create impediments to investment. Such dynamics can increase the cost of capital, thus raising barriers to additional investment and increasing overall costs of consumers. In special circumstances, regulatory or policy interventions such as de-risking projects to encourage new technologies, providing return on equity incentives for investments that help achieve policy goals or providing for financing or ratemaking treatment to avoid rate shock issues may be implemented. However, interventions such as these can also distort market signals.

Key Observation 7: Incentives

Incentives may be a tool considered to help effectuate policy, but they must be appropriately tailored to the outcome desired, not the action to achieve it.

Examples of incentives could be developed to reward early or timely commissioning of projects, taking on a particularly risky project, incorporation of new or innovative technologies, etc.

Why it matters to India: Incentives specifically tailored to outcomes could be considered to help India meet its policy goals.

A. Compensating Investors for Risk

Providing stable, predictable and adequate returns for infrastructure investment has been a primary key to the U.S. infrastructure story, in large part due to the long asset life and multiyear development cycles associated with natural gas infrastructure. Regulators can wield significant influence over gas infrastructure investment by allowing investors the *opportunity* to earn a return on their investment, consistent with the level of risk taken by the investor. We note, however, that the investor has the *opportunity*, but is not g*uaranteed*, a return on the investment. Allowed and earned ROEs send meaningful signals to investors and market participants regarding an asset's regulatory support and riskiness through various credit metrics, such as cash flows. Stable, predictable and adequate returns can help encourage investment by signaling regulatory support and the asset's ability to attract capital over its lifespan.

U.S. regulators, as well as the courts, have recognized the importance of durable structures to ensure reasonable returns to investors. Accordingly, no single methodology for estimating ROE has been adopted, as there are several widely accepted ROE estimation models and market indicators used to assess risk by the financial community. Establishing both rates and their underlying ROE requires careful judgment that is employed by the regulator to evaluate the applicability of any financial model or indicator used, particularly in the context of the applicant pipeline's risk and current capital market conditions.

FERC's cost of service ratemaking approach for natural gas pipelines is holistic. Accordingly, the ROE component of a pipeline's cost of service is evaluated in the context of the overall cost of service and is not carved out or evaluated separately on a single-issue basis. The Commission has traditionally relied on discounted cash flow ("DCF") analyses, applied to a specially tailored proxy group made of companies of comparable risk to the applicant pipeline, to estimate the appropriate cost of capital or ROE for the applicant pipeline. Because the cost of acquiring equity is a market-based concept that is not explicit in regulated industries, the development of the proxy group is useful and necessary for this exercise. A similar process is used in state regulation; PUCs often employ several financial models and market indicators, in addition to those used by FERC, to estimate and establish a firm's allowed ROE.

Key Observation 8: Returns to Investors Consistent with Risk and Opportunities

The regulator reviews each of the expense and revenue line items and establishes the authorized rate of return that investors are allowed to earn on the capital they deploy.

- Returns must be high enough to attract sufficient capital to operate safe, efficient systems.
- Authorized returns are designed to provide returns competitive with other investments.
- Because returns are authorized rather than guaranteed, pipelines bear most execution, regulatory and sales (throughput) risk.

Why it matters to India: Investors will be –and should be –exposed to risk when they invest in pipelines. Returns must be sufficient for them to deploy capital in Indian infrastructure over other, similarly risky alternatives.

VIII. Summary

We reiterate that this briefing paper is a primer, focusing only on policy and regulatory levers for natural gas infrastructure development in India. The recommendations herein may or may not ultimately result in overall optimal solutions for India. Accordingly, we suggest that additional comprehensive economic analyses of market fundamentals (e.g., supply and demand, resource availability, macro-economic energy portfolio optimization, etc.) be pursued, particularly in the context of shaping policies with long-term investment and social welfare implications. We offer that a comprehensive approach is most likely to enable the meaningful, sustainable and economic platforms to support India's natural gas infrastructure and energy needs now and into the future.

Three key differences observed between the U.S. and Indian natural gas markets are 1) the relative age and maturity of the natural gas markets in each respective country, 2) the relative difference in the availability of domestic natural gas resources, and 3) market-driven versus command and control methods of shaping energy policy, markets and infrastructure. Finally, regulatory stability is a key tenet in the U.S., and we believe such stability has contributed to the robust infrastructure network. Overarchingly, we encourage similar regulatory stability and compensation for investment risk to meet India's long-term infrastructure goals.

Appendix A: Our Understanding of the Indian Context

In order to provide meaningful and potentially actionable perspectives based on the U.S. natural gas infrastructure experience, FTI Consulting sought to understand the current state of India's natural gas markets, infrastructure and regulation at a very high level. Our in-depth research is summarized in this Appendix.

A. An Overview of India's Natural Gas Market and Infrastructure

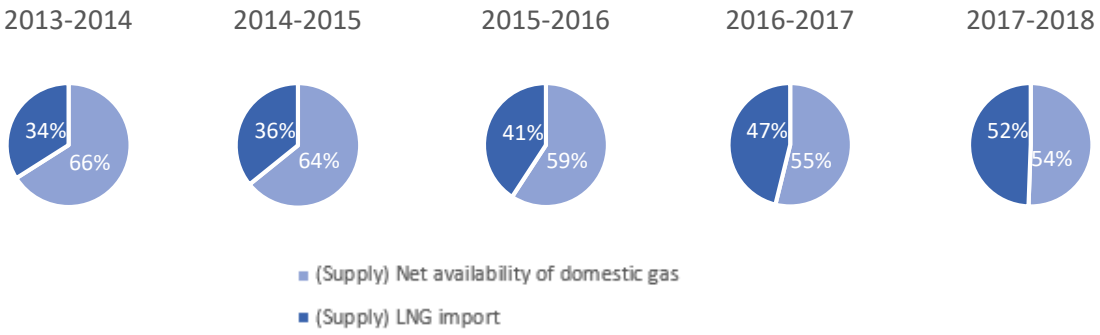
Natural gas supplies in India are generally categorized as 1) domestic natural gas and 2) imported re-gasified liquefied natural gas ("LNG"). The Indian government directs, or allocates, domestic natural gas supplies to Tier-1 and Tier-2 priority sectors and establishes prices based on government policies. LNG supplies, however, are not restricted in the same way, falling under the list of Open General License Item. Accordingly, marketers are free to import LNG and sell the RLNG to customers based on market outcomes.

Domestic gas production has not been able to supply total consumption in the country. In fact, domestic gas production declined from approximately 34,574 MMSCM in 2013/2014 to approximately 31,731 MMMSCM in 2017/2018, or approximately 8 percent. At the same time consumption increased from 52,375 MMSCM to 59,170 MMCM, or 13 percent. To meet the gap between domestic supply and consumption, LNG imports increased over time, from 17,801 MMCM in 2013/2014 to 27,439 MMCM from to 2017/2018, or approximately 54 percent. In FY 2017-18, imported LNG accounted for approximately 50 percent of total gas consumption in the country.

Figure 6: Natural Gas Demand and Supply

Year	2013-14	2014-15	2015-16	2016-17	2017-18
(Supply) Net availability of domestic gas[32]	34,574	32,693	31,129	30,848	31,731
(Supply) LNG import	17,801	18,607	21,388	24,849	27,439
(Demand) Total consumption	52,375	51,300	52,517	55,697	59,170

Figures in million metric standard cubic meters (MMSCM).

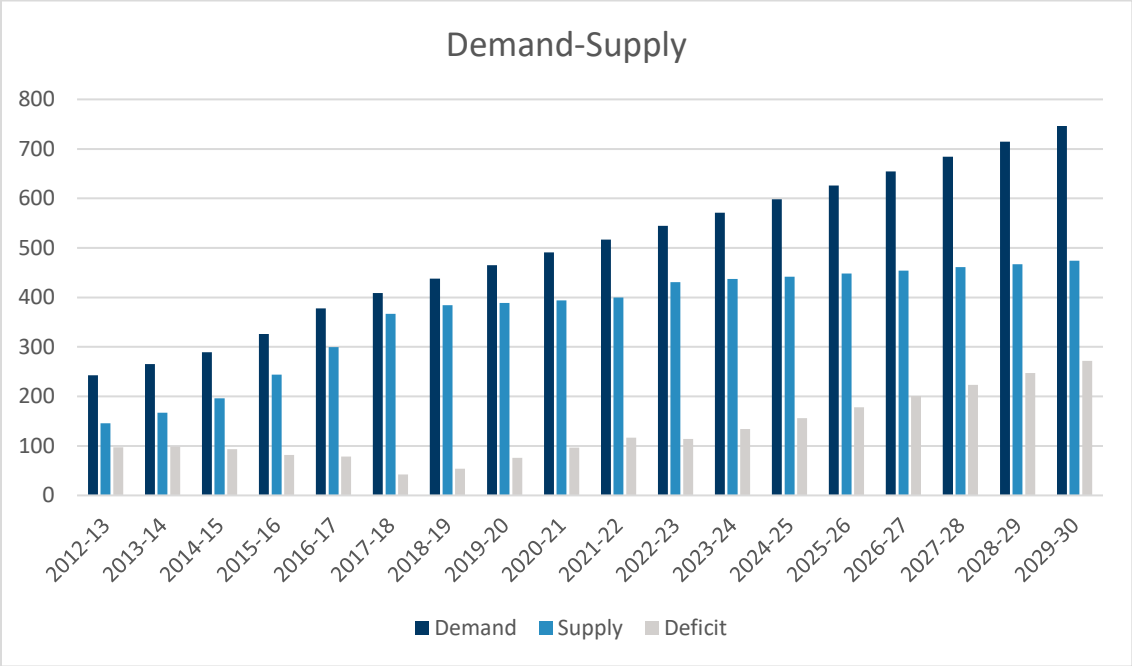


Source: PPAC, June 2019

While we have observed variances in estimates on current and projected supply and demand conditions for natural gas in India, the overall trend is clear. India's domestic natural gas production has not increased to meet demand, nor is it expected to do so in the future. See Figure 7 below. LNG imports are filling the supply gap and are expected to do so in the future. Accordingly, additional terminals are being currently either proposed or under construction with a regasification capacity of about 26 MMTPA. The combined regasification capacity of existing and planned terminals is expected to be 52.5 MMTPA.[33]

[32] Net production is derived by deducting gas flared and loss from gross production by producing companies.
[33] *Id.*

Figure 7: Natural Gas Demand and Supply Projections



Figures in million metric standard cubic meter per day (MMSCMD). Source: Petroleum and Natural Gas Regulatory Board[34]

Primary consumers of natural gas in India are in the fertilizer and power sectors (about 57 percent), which are critical to the economic development of the country. City Gas Distribution ("CGD") is a growing sector and recently overtook the fertilizer sector as the primary allocation priority for domestic gas. At present, domestic gas is being supplied to meet the entire requirement of the Compressed Natural Gas ("CNG") (transport) and domestic Piped Natural Gas ("PNG") segments.

[34] https://gailvoice.com/natural-gas-demand-supply-dynamics-india/

Figure 8. June 2019 Gas Consumption, by Sector

Sector	Domestic Gas (mmscm)	LNG (mmscm)
Power	641	687
Fertilizer	499	769
CGD	463	328
Refinery	92	564
Petrochemical	53	223
Others	303	243
Total Consumption	2051	2814

Total gas consumption during the month of June 2019 was 4865 MMSCM.

Source: PPAC, June 2019 (P)

The Indian government has indicated that it plans to increase the use of natural gas and move toward a gas-based economy. Demand for natural gas in India is projected to increase significantly by 2040, driven by industry, transport and households. Demand is also affected by government allocation, pricing and other policies. There are varying projections for Indian natural gas demand growth. One estimate suggests that natural gas demand in India could increase from 242.6 MMSCMD in 2012-13 to 746 MMSCMD in 2029-30, a compounded annual growth rate of 6.8 percent.[35]

With respect to the energy mix, the Indian government has a goal of increasing natural gas's share from the current 6.7 percent to 15 percent by 2030, or from approximately 137 MMSCMD currently to over 548 MMSCMD by 2030.[36] The Indian government also has a goal to achieve universal electrification with 24/7 electricity by 2022.[37] BP projects that power generation will increase by 207 percent by 2040, accounting for 61 percent of demand growth, followed by industry, transport and non-combusted. [38] The Indian government[39] has also been actively encouraging the coverage of the CGD network,

[35] "Vision 2030" Natural Gas Infrastructure in India, retrieved at: https://www.pngrb.gov.in/Hindi-Website/pdf/vision-NGPV-2030-06092013.pdf

[36] "*The Challenges Facing India on its Road to a Gas-Based Economy*," Anne-Sophie Corbeau, Shahid Hasan and Swati Dsouza, King Abdullah Petroleum Studies and Research Center, October 2018.

[37] *Draft National Energy Policy*, NITI Aayog, Government of India, version as on 27.06.2017.

[38] BP Outlook Through 2040 https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019-country-insight-india.pdf

[39] In 2007, the Government of India established Petroleum and Natural Gas Regulatory Board ("PNGRB") under the PNGRB Act 2006. Under the Act, PNGRB grants the authorization to the entities for developing a CGD network (including PNG network) in a specified Geographical Area ("GA") of the country. CGD sector has four distinct segments –CNG is predominantly used as auto-fuel and PNG is used in in domestic, commercial and Industrial

facilitating bidding rounds for entities to build out CGD to increase coverage to 74 percent of the country's population in just a few short years.[40]

Tier-1 priority sectors (CGD[41], fertilizer plants, grid-connected power plants, and transport) receive allocations of lower-priced domestic natural gas; tier-2 sectors (steel, refineries and petrochemical plants, industrial and commercial customers, captive and merchant power plants, other customers, feedstock and fuel) primarily rely on LNG. The allocation mechanism effectively results in price discrimination, as domestic gas has a lower price than LNG. Pooling of domestic gas and LNG prices is currently only allowed for fertilizer plants. This puts sectors that must use LNG at a pricing disadvantage. The government's priorities for allocating domestic natural gas has evolved over time. Despite fertilizer plants and gas fired generation being high priority in the allocation scheme, the current Indian administration has made allocating to CGD the top priority.

In India, the domestic gas price is revised every six months and is linked to prices on four international hubs – Henry Hub in the US[42], Alberta in Canada, National Balancing Point in Europe and Russian gas prices (with a lag of a quarter). The current pricing is $ 3.69/MMBtu for the April-September period. A 30-35 percent decline in the prices of LNG since January this year has helped gas prices become competitive to other alternative fuels (e.g., industrial PNG has become cost-competitive with fuel oil). From the perspective of CNG and household PNG, strong demand is expected to continue because of the clear cost advantage of these fuels over alternates such as petrol and liquified petroleum gas ("LPG"). At current estimates, CNG is approximately 33 percent cheaper than petrol.

segments. Source: Petroleum and Natural Gas Regulatory Board, http://petroleum.nic.in/natural-gas/about-natural-gas

[40] 2018-2019 Annual Report of the Ministry of Petroleum and Natural Gas, Government of India. http://petroleum.nic.in/sites/default/files/AR_2018-19.pdf

[41] CGD includes CNG and PNG.

[42] A hub is where two or more pipelines connect with each other. The Henry Hub, located along the U.S. Gulf Coast, interconnects 13 different pipelines and is arguably the most important hub in North America. This hub is the pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX) and is used a benchmark for the North American market. Importantly, these prices are based on actual supply and demand conditions of natural gas as a stand-alone commodity; prices are not linked to other commodities, such as oil, and are correlated with wellhead prices (which are not regulated).

B. Our Understanding of Current Natural Gas Challenges In India

Pricing

Government intervention in pricing and allocation impacts supply and demand, weakens market signals and affects all components of infrastructure growth. Such intervention is not necessarily without merit, as energy affordability is a key challenge in Indian energy policy and transitioning the price-sensitive gas customers (e.g., fertilizer and generation) from administratively determined prices and allocations from a market-based paradigm has remained a significant issue for the Indian gas market. However, the combination of lower-than-expected domestic gas production, higher international LNG prices, transportation costs and gas taxes have rendered the use of gas for power generation uneconomical.

Infrastructure

Despite best efforts to improve the situation, government interventions distort the market. Changes to the pricing policy several years ago linking domestic natural gas prices to four natural gas trading hubs outside of India, discussed above, do not adequately reflect Indian gas market fundamentals. While current prices for domestic natural gas is $3.69/MMBtu and $9.32 for Deepwater, Ultradeep water, and HPHT fields,[43] domestic gas producers have indicated they require prices in excess of $6-$8/MMBtu.[44] The result is a negative effect on domestic supply production due to a lack of price incentives, increased prices for those forced to rely on LNG, weakened demand and uncertainty in market fundamentals that underpin infrastructure development.

Natural gas pipeline infrastructure development has been challenged on several fronts, including jurisdictional conflicts between multiple regulators, as well as permitting and right of way ("RoW") issues, particularly when community/landowner opposition occurs. Infrastructure development is also challenged by the lack of integrated infrastructure planning between LNG, pipelines and growing demand centers. As an illustrative example, portions of the pipeline and LNG infrastructure are underutilized, and a key sector, grid connected natural gas fired electric generation that is financially constrained, sends weak market signals for additional build.

Incentives for private infrastructure investment, or a lack thereof, are challenged in several ways. For example, existing pipelines companies are both transporters and marketers of gas, dominating the market with significant access to customers. This limits the market for competition, and therefore investment. While the Indian government has expressed interest in unbundling pipeline services, efforts have been unsuccessful to date. Another challenge is the allocation of investment risk, as pipeline

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[43] Prices are set by the Ministry of Petroleum &Natural Gas, Government of India. Figures reported are based on the April-September time period on a GCV basis; prices are revised every six months. Retrieved from: https://www.ppac.gov.in/WriteReadData/CMS/201904040841507374511DomesticNaturalGasPrice.pdf and https://www.ppac.gov.in/WriteReadData/CMS/201904040840322929673GasPriceCeiling.pdf

[44] The Oxford Institute for Energy Studies, *Gas Pricing Reform in India*, April 2015, retrieved from: https://www.oxfordenergy.org/wpcms/wp-content/uploads/2015/04/NG-96.pdf

investors bear volumetric risk. If volumes are lower than expected, the pipeline under-recovers its costs, thus discouraging additional pipeline development.

India's natural gas pipeline tariffs (excluding statutory taxes and levies) are reviewed every five years by the PNGRB at the end of the initial tariff period for each pipeline.[45] The rate of return on capital is twelve percent, post tax, for the entire economic life of the project.[46] India utilizes a zonal pricing mechanism in which the further the gas travels, the higher the total transportation cost. The length of each tariff zone is 300 kilometers. This pricing structure can negatively impact natural gas demand in locations distant to injection centers, potentially exacerbating infrastructure investment challenges.

Taxes

In addition to recovering the gas commodity price and pipeline tariff rate from customers, taxes must also be recovered. Natural gas is not currently included under the Goods and Services Tax ("GST") regime. This structure has led to different tax rates, ranging from 5 percent to 26 percent, across different states.[47] All else being equal, this taxation puts natural gas at a disadvantage compared to other fuels such as coal, fuel oil and LPG, which are included in the GST and incur a uniform tax rate of 5 percent. As international development is of interest to India, we note that non-resident companies face a higher corporate income tax rate than resident companies.

[45] *Notification, G.S.R. 807(E), NGPL Tariff, Petroleum* and Natural Gas Regulatory Board, November 20, 2008.
[46] *Id.*
[47] We are also aware that the current tax structure also creates a "double taxation" of gas swaps.