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The economic impact of price controls on China's natural gas supply chain☆

Bertrand Rioux [a,*], Philipp Galkin [a], Frederic Murphy [a,b], Felipe Feijoo [c], Axel Pierru [a], Artem Malov [a], Yan Li [d], Kang Wu [a]

[a] King Abdullah Petroleum Studies and Research Center, P.O. Box 88550, Riyadh 11672, Saudi Arabia
[b] Fox School of Business, Temple University, Philadelphia, PA 19103, USA
[c] School of Industrial Engineering, Pontificia Universidad Católica de Valparaíso, Valparaíso, Chile
[d] Academy of Chinese Energy Strategy, China University of Petroleum-Beijing, 18 Fuxue Road, Changping, Beijing 102249, China

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ABSTRACT

Despite significant progress made by China in liberalizing its natural gas market, certain key areas such as market access and pricing mechanisms remain controlled by the government. To assess how such distortions impact the market, we have developed a Mixed Complementarity Problem model of China's natural gas industry, with a novel representation of price caps associated with supply obligations. The model is used to assess how government pricing policies and restricted third party access to midstream infrastructure impacted the supply logistics of China's profit maximizing natural gas firms in the year 2015. We find that lifting the price caps for regulated natural gas demand sectors could yield a 4.7% (1.4 billion USD) reduction in total system cost and reduce the national average of marginal supply costs by 14%. Improving third party access to the pipeline and regasification infrastructure would result in an additive total cost saving of 7.6% (2.2 billion USD) and a 16% reduction in average prices, due to replacing domestic and imported LNG with pipeline imports. The LNG industry would be negatively affected by the reforms investigated in this study, as market players would gain more flexibility in their logistics and would utilize lower cost supply pathways.

1. Introduction

Natural gas production in China has grown rapidly in the 21st century increasing over 500% from 27.2 billion cubic meters (bcm) in 2000 to 136.9 bcm in 2016. Yet, the growth in demand has outpaced supply, increasing about 850% over the same period. The gap between supply and demand has been filled by imports which totaled 74.6 bcm in 2016 or 36% of total consumption (CEIC, 2017). This gap has been projected to increase further, reaching 210 bcm by 2020 (Wang et al., 2013). The share of gas imports in total consumption has expanded to over 40% in 2017 with a surge of China's LNG imports and, to a lesser extent, pipeline gas imports.

Despite the rapid development of the sector and a significant domestic resource base, 50,000 bcm of conventional recoverable resources according to the Ministry of Natural Resources (MNR, 2015), natural gas accounts for a modest share in China's energy mix. In 2016 it accounted for 6.4% of total energy consumption, with coal representing the majority at 62%. Analysts cite low efficiency, opaque and complex pricing mechanisms, problematic transportation infrastructure and organizational inflexibility (Shell and DRC, 2017; Li, 2015; Wang and Li, 2014) as major problems that have led to a slowdown in production growth and impede development of the gas sector.

These issues must be addressed in order to achieve the ambitious targets set by Chinese policy makers for the natural gas industry; 10% of total energy consumption by 2020 and 15% by 2030, and increasing annual demand to 360 bcm by 2020 (NDRC, 2016, 2017). However, due to economic infrastructure and energy security considerations, such ambitious demand targets cannot be met by increased imports alone. The 13th Five-Year Plan for Natural Gas Development outlines a substantial build up in capacity, particularly in the natural gas power generation and pipeline transportation segments (NDRC, 2016). A significant development potential also lies in optimizing the utilization of existing capacities in the domestic natural gas upstream and midstream sectors.

Reform of pricing mechanisms and ensuring efficient third party access to infrastructure have been the top priorities of China's policy agenda for the natural gas industry. While unconventional gas and

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* Corresponding author.
E-mail address: bertrand.rioux@kapsarc.org (B. Rioux).

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LNG imports have been largely liberalized, certain consumer groups (commercial and residential demand, small industrial users) are favored by fixed prices or price caps for pipeline deliveries. These price distortions incentivize profit-maximizing firms to avoid supplying gas at capped prices by altering their operational, logistic and investment strategies. They can also result in cross-subsidization of lower-priced regulated demand sectors with higher tariffs charged in deregulated markets. Limited access to midstream infrastructure further distorts logistics patterns and leads to a suboptimal market structure and less efficient national resource allocation (Xu et al., 2017 and Song et al., 2015).

In order to estimate the magnitude of such distortions and potential gains from liberalization reforms, we developed a single-period equilibrium model that provides a short-term perspective of China's gas market. Key model output elements include total production, domestic liquefaction, pipeline and LNG imports, average short-run cost (weighted by provincial demand), and total system cost. The model is formulated as a Mixed Complementarity Problem (MCP) and represents the profit-maximizing behavior of price-taking suppliers – three large National Oil Companies (NOCs) and smaller fringe suppliers – with some market segments subject to price caps. The model is calibrated to simulate the structure of China's natural gas supply market in 2015 at the provincial level. Several scenarios study the impact of lifting the price caps and providing all market players with equal access to pipelines and regasification infrastructure.

Modeling regulations in MCPs is a new research area. Böhringer and Rutherford (2008) discuss modeling the rationing problem in an MCP but do not provide a mathematical formulation. Recent work by Murphy et al. (2016, 2018) explores how to measure the effects of price controls using MCPs. Gouel (2013) presents an MCP for stabilizing commodity prices by a country using inventories, based on the work of Miranda and Helmberger (1988). The complementarity constraints include releasing inventory and violating a lower bound on prices because the inventory becomes too large and exceeding a price cap at zero inventory. Abrell and Rausch (2017) evaluate improvements in the efficiency of carbon policies with different political entities regulating different industries through relaxations of carbon prices and carbon constraints. They minimize the costs of distortions by using a mathematical program subject to equilibrium constraints (MPEC) to set bounds on policy parameters.

There has been a significant body of literature discussing natural gas price reforms and its evolution in China (e.g., Paltsev and Zhang, 2015, and Aolin and Qing, 2015). However, the energy and economic implications of market liberalization, specifically the combined impact of the price regulations and the access to midstream infrastructure, the focus of the analysis presented in this paper, have not been studied in detail. Among the existing research, Tian et al. (2017) studied the promotion of natural-gas-fired electricity with energy market reforms in China via a dynamic game-theoretic model. They concluded that deregulating the natural gas price, imposing a carbon tax and adopting environment subsidies would promote the market penetration of natural gas-fired electricity. Although this study is limited to the power sector, it indicates that a liberalized market could increase the use of gas in China.

With regard to natural gas transportation in China, Zhang et al. (2016) present one of the few studies assessing the impacts of natural gas supply cost on gas flow and infrastructure deployment. They conclude that import prices are important to determine the infrastructure development and interregional flows within China. They did not assess the role of price caps nor who has access to infrastructure. However, high import costs compared to the low, capped prices set by the government are likely to exert great pressure on China's price reforms (Lin and Want, 2012). A third-party access (TPA) model for the Chinese gas network was investigated by Xu et al. (2017). The study includes scenarios without third party access and an alternative case where an independent pipeline operator optimizes flows (maximizes social benefit). The study indicates that pipeline capacity scarcity must be properly managed by the Chinese government. Although some research has been done in this area, the evaluation of the Chinese energy infrastructure would be better assessed using more detailed infrastructure models. For instance, those done in the context of North America (Feijoo et al., 2016; Egging et al., 2010; U.S. Department of Energy, 2015 and Sankaranarayanan et al., 2018) and Europe (Dieckhöner et al., 2013, Egging and Holz, 2016, Holz and Von Hirschhausen, 2013).

The rest of the paper is organized as follows. In Section 2 we discuss the past, current, and planned developments of the market reform. We then present the details of the model and its construction as an MCP. In Section 4 we introduce the model calibration and scenarios, and discuss the impact of lifting price caps and improving third party access. Finally, in Section 5 we summarize the main conclusions drawn from this study.

2. Regulatory environment and reform initiatives

2.1. Background

China has made significant progress on the path towards transforming its natural gas sector from being highly centralized and centrally planned to market-driven. Originally the government combined the functions of the owner, investor, operator and regulator under the centrally planned economic system. Various ministries were responsible for exploration, development and transportation of natural gas, and the government set the prices. The government changed the structure of the industry to be more market oriented. Since then China created three large NOCs that dominate natural gas production and transportation infrastructure, publicly listed them on foreign markets, introduced a licensing system, and allowed private capital to explore for conventional gas. The government also liberalized the unconventional gas segment and gradually relaxed its price controls. These measures have contributed greatly to the development of the sector (Hu and Xu, 2013; Paltsev and Zhang, 2015).

The NOC's include China National Petroleum Corporation (CNPC), China Petroleum & Chemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC). Smaller private firms, often in partnership with the NOCs, engage in production – primarily, in the unconventional segment – as well as LNG liquefaction, transportation, and regasification.

As a result of the administrative reforms, The National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) emerged as major industrial regulators across the national natural gas supply chain. The NDRC is responsible for the overall strategy and planning, macro-policy, pricing and fiscal policy, overall reform direction and approval of major projects (Shell and DRC, 2017). The NEA is primarily focused on industrial policy and supervision. In the upstream sector, the Ministry of Natural Resources (MNR) defines the policies for mineral rights allocation, exploration of resources and foreign cooperation and drafts relevant legislation and development plans. Provincial governments are more involved in the midstream and downstream sectors where they can adjust regulated prices within established boundaries and are responsible for monitoring, inspection and supervision.

The problem the Chinese government faces is that parts of the natural gas market can be made workably competitive while other parts are natural monopolies. This is best understood through the structure of gas markets in other countries.

Exploration and production is competitive in countries with multiple sources of supply and a resource base that is not dominated by a few players. Gas supply is a competitive market in the United States with a large number of producers and multiple supply regions. With its large and diverse resource base China has the potential to be more like the United States than Europe, which has the problem that Russia provides one third of the supply with an even more dominant share in

Central Europe. Like Europe, China's contracts with Russia can lead to regions with a dominant supplier. Furthermore, the practice of favoring the dominant firms means that not enough producers focus on supply competition. LNG imports, on the other hand, can be workably competitive, as the LNG market has evolved to include a large number of players with a growing spot market.

The failure of the early cost-based regulations in China parallels the unsuccessful attempts by the Federal Power Commission (now the Federal Energy Regulatory Commission, FERC) in the United States to use cost as the basis of regulating prices at the wellhead (MacAvoy, 1970). The reason that using cost to regulate prices does not work is that finding gas is a chancy business. Including the costs of unsuccessful exploration attempts in the cost of gas produced means subsidizing unskilled exploration companies, while not including these costs excludes a legitimate cost of doing business.

Fixing a price ceiling for gas has its own problems. The ceiling works as long as demand is below production from associated gas that would have been flared. Here any price is better than the cost of flaring. However, once non-associated gas production is at capacity, regulatory inertia can keep prices too low. That happened in the United States in the 1970s when massive shortages led to the temporary shutdown of major industries and led to the abandonment of price controls in the form of ceilings. In China's case, a sufficiently low price can lead to supply shortage and an increase in government subsidized imports as the development of domestic resources falls short.

The approach to blending markets with regulated monopolies that has been taken in the United States is to require the pipelines to maintain open access and treat all customers equally. Since pipeline companies can restrict the flow of gas and achieve monopoly rents by buying a large share of the capacity and not using it, FERC monitors the pipeline contracts to make sure companies do not buy too much capacity, and exercise market power. In the EU the economic rationale behind unbundling (vertical disintegration) and ensuring open access to infrastructure was supplemented by the intention to create an integrated European market and establish a supranational mechanism to guarantee security of supply (Lowe et al., 2007). Hence, pipeline infrastructure expansion is driven by the authorities, who allocate construction and maintenance contracts on a cost-plus basis. Investment in LNG and storage terminals is driven by the market. Regulators ensure third party access to capacities but do not interfere with pricing mechanisms.

The US and EU experiences highlight that there is no single approach to regulating gas markets. China has to strike its own balance of regulation with using markets to achieve economic efficiencies.

The recent transition of China's economy from explosive growth in industrialization to a ‘new normal’ phase that focuses on consumption has relieved some pressures on energy supplies and created an opportunity for accelerating reforms in the natural gas sector. Substantial progress still can be made in moving towards more market-oriented pricing mechanisms and stimulating competition and efficiency through reducing barriers to market access. Here we examine the economic consequences of the current market rules and regulations.

2.2. Price reform

Tight control of natural gas prices in China has been a major hindrance to the development of available resources, competitiveness with other fuels and overall market efficiency (Fang and Ma, 2017). In recent years, the Chinese government has attempted to remedy the situation by introducing a number of natural-gas pricing reform initiatives.

Before 2013 ex-plant prices had been set by the NDRC to cover wellhead costs, processing fees and a regulated margin. Prices were set for each basin based on the type of consumer: fertilizer, power, industry and residential. Producers and consumers could negotiate within a $\pm$ 10% range of the set prices. However, the cost-plus approach was insufficient to compensate suppliers for purchasing imported pipeline gas and LNG and did not provide sufficient incentives for infrastructure investment.

The government introduced major sectoral reforms in 2013 in order to address fundamental issues in pricing. The price controls for all types of gas supplied by pipeline switched from the wellhead to the City Gate. The City Gate pricing mechanism consisted of a 2-tiered price ceiling for a base level of demand (fixed at the 2012 demands) and incremental demand, which varied significantly by province (Aolin and Qing, 2015). Prices for LNG deliveries sourced from domestic offshore and unconventional resources, and imports, became exempt from price controls unless delivered via regional pipeline networks (Paltsev and Zhang, 2015). CNOOC received exclusive rights to buy offshore gas from independent producers at annually-reviewed prices set for each project.

Recent measures aimed at rationalizing non-residential natural gas prices (NDRC, 2015) represent the seventh adjustment to prices and formalize the current pricing mechanism. In 2015 price controls were removed for the Direct Consumer category, including government approved large industrial users, except for the chemical industry. This has motivated China's NOCs to lobby to have their large consumers categorized as Direct Supply, particularly in the strategic industrial provinces. Reforms have also been put into effect to lift the preferential gas prices paid by chemical fertilizer producers (He and Jianrong, 2017).

However, it is also recognized that as the market matures the City Gate and distribution gas prices need to be reformed. In 2015 the 2-tiered price ceiling was modified, resulting in a single price cap for City Gate consumers in each province. In 2017 China kick started a pilot program to rationalize City Gate prices in Fujian province following the corresponding notice released by NDRC in late 2016 (Daiwa Capital Markets, 2016). At the same time the government announced that it would improve pricing mechanisms for urban gas networks in an effort to increase competitiveness of gas and reduce the inflated prices and profits received by distributors (China Daily, 2017a).

The current pricing structure also leaves a number of unresolved market distortions. Capped prices for residential gas consumption (as a part of the City Gate price controls) are substantially lower than deregulated prices for large industrial consumers. This is generally opposite to the pricing structure compared to OECD countries, where distribution charges to large customers are much lower than for small customers. Such price differentials occur when the regional caps are lower than the marginal cost of supplies. They can be exacerbated if suppliers attempt to compensate for such losses by charging – where possible – higher prices to industrial consumers in deregulated markets. This leads to cross-subsidization between various demand sectors. Price caps imposed on particular demand sectors and supply sources can also affect suppliers' operational (choice of the market, region, supply path) and investment decisions, potentially causing deviations from the most efficient national resource allocation.

Without further reforms across the supply chain, China is likely to miss its planned target share of natural gas in total consumption by the end of the decade (SIA, 2017). Reducing the price spread between different market segments, that occurs due to government price interventions in certain markets, can be instrumental in supporting incremental demand. This will require further liberalizing City Gate prices that will also help address cross-subsidization issues and reduce the need for government subsidies.

2.3. Third party access to midstream infrastructure

Historically, the construction and operation of natural gas pipelines had been administered by the Department of Petroleum Industry. Subsequently, these functions were transferred to the NOCs, which retain their monopolistic control over pipelines and dominate other midstream infrastructure.

Since the beginning of the 12th Five Year Planning Period in 2011 the Chinese government initiated a series of measures aimed at fair participation in pipeline construction, facilitation of third party access to pipelines and improved supervision of midstream operations. In 2014 NDRC issued The Management Measures of Natural Gas Infrastructure Construction and Operation aimed at encouraging various types of investment and increasing transparency in operation (NDRC, 2014). In the same year NEA released the Measures for Natural Gas Infrastructure Construction and Operation requiring that pipeline owners/operators provide third parties with access to their spare capacity and associated services including gasification, storage and transportation (NEA, 2014). However, this initiative has not been gaining much traction due NOC reluctance to share their infrastructure with competitors and a claimed lack of spare pipeline capacity (Chen, 2016).

In the LNG import segment only eight companies managed to take advantage of the TPA policy and receive up to only 1 million tons of imported LNG at NOC-owned terminals since the guidelines were released (Interfax Global Energy, 2017). Independent gas companies have had to resort to building their own terminals, duplicating the existing underutilized infrastructure operated by NOCs (Trusted Sources, 2016).

Limited success in the implementation of the TPA initiatives has prompted the search for structural solutions to the problem. Establishing an independent pipeline operator could facilitate more efficient utilization and pricing of gas pipelines and LNG terminals (Xu et al., 2017). Other supporting measures may include liberalization of pipeline transmission fees and independent assessment of excess infrastructure capacities (Shell and DRC, 2017). Progress continued in 2017 including the audit of pipeline costs across the three large NOCs (Reuters, 2016) and the announcement of policies to open access to third parties, including separation of the pipeline business from final sales (China Daily, 2017a, 2017b).

3. Description of the model

3.1. Modeling approach

We use an equilibrium model to represent a snapshot of China's regulated natural gas market, formulated as an MCP. This model is a component of the KAPSARC Energy Model of China (KEM-China), which also includes coal and electricity sectors that use an MCP model (Rioux et al., 2017). Both KEM-China and the related family of KAPSARC energy models (Matar et al., 2015; Matar et al., 2017), are designed to directly model price regulations that shape and impact market efficiency.

The Project Independent Evaluation System (PIES), developed by the US Department of Energy in the 1970s, was also designed to simulate the effects average cost price regulation within the natural gas industry (Murphy et al., 1981). Designed to run on solvers available at the time, the model is formulated as a standard optimization problem with a modified objective function that requires an iterative method to search for an equilibrium. A similar, or alternative approach, could be used to model the price controls in the Chinese market, however, an MCP provides a direct representation of the economic equilibrium under the price caps including shortages for regulated delivery modes in the general case (see Murphy et al., 2018). No scalability issues were encountered when solving the proposed MCP model using the PATH solver (Ferris and Munson, 2000).

The model is solved over a single-period offering a short-term perspective of China's gas market calibrated to historical demands and considering only existing capacity with no new investment. We consider gas production, transportation by pipeline, liquefaction of domestically produced gas, LNG tanker shipments, and regasification infrastructure. We represent the profit-maximizing behavior of price-taking suppliers – three large NOCs and smaller fringe suppliers – with some market segments subject to price caps. For example, pipeline deliveries to consumers in City Gate markets and the chemical industry are subject to price caps, while LNG deliveries are exempt. The equilibrium problem uses locational prices and price caps applied to pipeline deliveries for certain market segments, with supply obligations imposed by the government.

In a deregulated market with fixed demands, minimizing cost is equivalent to maximizing profits, because all supplies are priced at the marginal cost of delivering gas to each province by the most expensive supplier. In the Chinese gas market this is not true since some pipeline deliveries are made at capped prices, which can fall below the marginal supply costs creating incentives to prioritize more profitable unregulated delivery modes.

In response to the price caps suppliers can alter their logistic decisions (for example, switching to more expensive LNG in order to operate in a more lucrative unregulated market). From a cost minimization perspective this can increase the overall system costs. In practice, the government enforces contractual obligations requiring suppliers to deliver pipeline gas at capped prices. In the model we enforce contractual obligations when marginal costs exceed the price caps. In practice these responsibilities are enforced irrespective of the true marginal cost, which may not be reported or known. However, when the marginal cost falls below the caps the pipeline deliveries provide a viable outcome for the market, and the obligation is not needed.

Pipeline obligations are represented as a shared constraint in the model applied to all the NOCs. This allows firms to exchange deliveries to customers to meet their obligations while minimizing the impact of the price caps on their revenue streams. Firms must meet the government-determined obligations, however, they can do this at the lowest possible cost by swapping deliveries to regulated customers when both firms save on supply costs. To understand how this is done in the oil industry and is captured in an equilibrium model, see Mudrageda et al. (2004). Although we do not have direct evidence of exchanging deliveries between suppliers, this is the most rational strategy for firms minimizing their costs and losses. To the extent that there are profitable exchanges that are not executed we underestimate the costs of the current regulation.

The model includes the production of conventional, offshore, unconventional gas (shale and gas extracted from coal reserves), plus pipeline and LNG imports. The midstream infrastructure consists of the pipeline and LNG facilities needed to move gas from supply regions to demand locations. Because of the regulations, this infrastructure is distinguished by the various gas types and market segments. To capture the incentives of the large firms, we differentiate production by firm and pipeline ownership by NOC. We use the ownership to simulate restricted access to infrastructure by third-parties.

The detailed mathematical formulation of the model is provided in Appendix 1.

3.2. Calibrating supply and demand

The model has been designed to simulate China's natural gas supply market in 2015 at the provincial level. All production, imports, and pipeline flows are reported in billions of cubic meters (bcm) per year. Costs and prices are reported in USD per thousand cubic meters (USD/kcm).

We calibrate the model to observed domestic supplies at the firm level including liquefaction, pipeline and LNG imports, and a fixed demand delivered to three market segments subject to different price regulations: Direct large industrial consumers, Chemical industry and City Gate demand. The model is also calibrated to existing pricing policies, as well as midstream infrastructure at the firm level to address third party access constraints. Gas deliveries by pipeline to the Chemical industry are subject to a flat national price cap of 136.5 USD/kcm, and provincial price caps for pipeline deliveries to City Gate consumers are listed in Table 1. In the following section we discuss transportation pathways, imports and how we use pipeline delivery obligations to tune the model results.

Production is categorized as conventional, offshore and unconventional resources, including shale, Coal Bed Methane (CBM) and Coal

Table 1
Provincial City Gate price caps (excluding VAT).
(*Source:* NDRC (2015).)

Province	Price cap (USD/kcm)	Province	Price cap (USD/kcm)
Anhui	396	Jiangsu	406
Beijing	384	Jiangxi	378
Chongqing	332	Jilin	350
Fujian	378	Liaoning	381
Gansu	303	Ningxia	314
Guangdong	409	Qinghai	280
Guangxi	385	Shaanxi	290
Guizhou	342	Shandong	381
Hainan	332	Shanghai	409
Hebei	381	Shanxi	371
Heilongjiang	350	Sichuan	334
Henan	385	Tianjin	384
Hubei	378	Xinjiang	263
Hunan	378	Yunnan	342
Inner Mongolia	290	Zhejiang	408

Mine Methane (CMM). In our model CMM is defined as a byproduct of venting methane from active coal mines as a safety requirement, while CBM is the active drilling of methane from deep coal seams that have not been mined. Each resource is assigned to one or more of the large NOCs and smaller independent producers.

Production capacities and short-run production costs for existing gas reserves are set using upstream data from a subscription to the IHS Vantage database, covering >600 assets, and field simulations using the QUE$TOR industrial software. Production profiles and costs for CBM are constructed using data from the China Mineral Resources report and other sources (MNR, 2018; Mu et al., 2015). Government subsidies are included in the short-run production cost of each unit of CBM, resulting in an average value of 47.2 USD/kcm. The production of CMM is modeled as a fixed proportion of provincial coal production in 2015. The variable cost of associated gas and CMM are set to zero as a by-product of oil and coal extraction. A detailed description of the methodology is documented in Appendix 1.2, including a list of total domestic production and average costs by type in Table A3-1.

The total provincial demand is calibrated to the natural gas balance sheet (CEIC, 2017), using the 'Industry Use as Material' category for the Chemical industry demand. As gas supplies to Direct industrial consumers are not reported, we represent the demand in market segments by dividing provinces into two groups according to their industrial structure. The proportion of industrial demand assigned to Direct demand is set to 50% in industrialized provinces with higher gas consumption, and 20% for less industrialized provinces. We selected these numbers such that the Direct is approximately 45%, in line with the levels reported by PetroChina (China Daily, 2015). All remaining demand is assigned to the City Gate category.

The provincial imbalances in domestic production and demand used in the model are summarized in Fig. 1(a).

3.3. Transportation pathways and infrastructure

Midstream infrastructure is fixed to existing pipeline and regasification capacities needed to balance supply shortage through pipeline and LNG imports. Fig. 1(b) shows the interregional pipeline capacities by firm, including the substantial capacity connecting China to Central Asia. Regasification capacities are not shown, but are also listed by ownership in the model.

Tracking upstream and midstream infrastructure ownership by the NOCs allows us to simulate Third Party Access (TPA) scenarios. In one case firms can deliver gas to provinces utilizing their own infrastructure. In another scenario, we assume equal access to capacity for all suppliers. This could be achieved through strict enforcement with more competitive pipeline tariffs, the introduction of an independent operator, or the FERC open access rules under order 636 (FERC, 1992). Companies lacking access to pipelines due to access restrictions or capacity constraints can deliver gas by LNG tanker to consumers in neighboring provinces.

In Fig. 2 we show the possible supply pathways and market regulations for domestic production, pipeline imports and LNG supplies represented in the model. The three consumer groups are exposed to different pricing policies: unregulated consumer prices for Direct consumers, capped pipeline prices for City Gate and the Chemical industry.

In the top part of Fig. 2, natural gas produced domestically or imported is sent by pipeline to meet final demand from large industries and smaller residential and non-residential consumers under the City Gate category. LNG produced from unconventional gas supplies or imports has similar pathways. It can be sent via pipelines, or via LNG tanker, which involves liquefaction and regasification. The supply pathways for imported LNG are similar: 1) re-gasified and sent via pipelines to meet Direct, City-gate or Chemical demand; 2) sent via LNG tankers to meet demand in all markets avoiding price caps.

The NOCs are contractually obliged to meet a specified amount of demand to regulated markets by pipeline, even if they incur losses. Private companies are excluded from these obligations. Actual pipeline delivery requirements are not reported, so we use the pipeline delivery obligations as a calibration parameter to tune the equilibrium point of the model. Setting obligations to an average of 63% of demand in the provincial regulated markets produced an equilibrium close to 2015 observations.

Midstream data is calibrated using a subscription to the IHS Edin database, including available pipeline, liquefaction and regasification

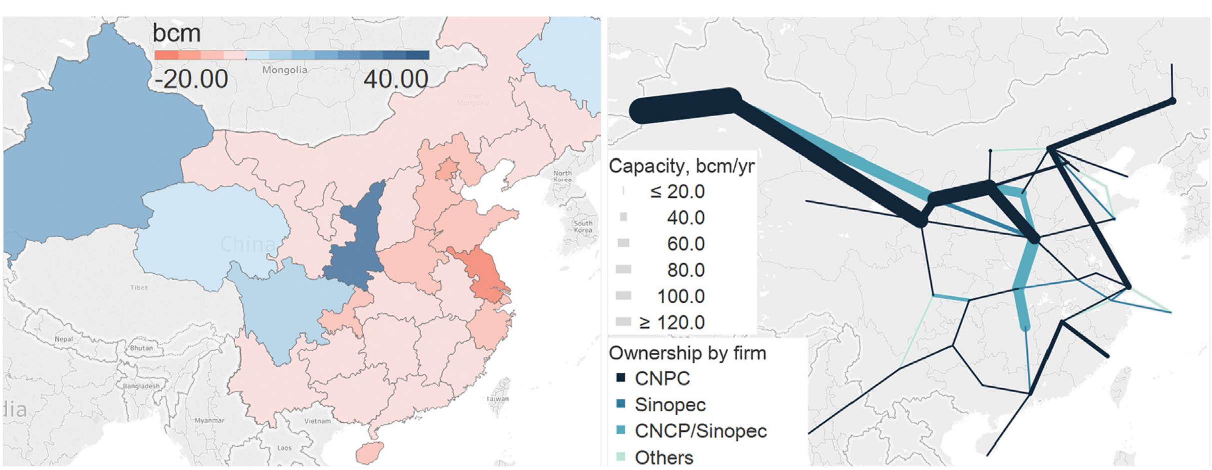

Fig. 1. Supply minus Demand (a) and Pipeline Capacity by Firm (b) in 2015.
(*Sources: IHS, Ministry of Land and Resources of China, KAPSARC research.*)

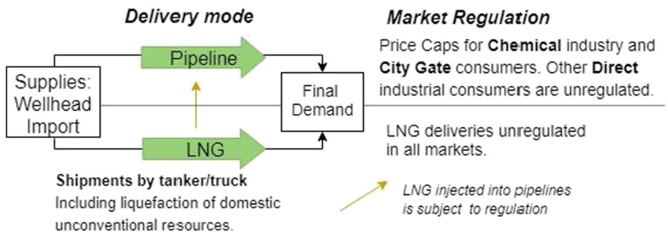

Fig. 2. Supply pathways for domestic and imported gas.
(*Source: KAPSARC research.*)

capacities. We calculate the average transportation cost for a pipeline with a diameter of 40 in. using the IHS QUE$TOR software as the standard cost for inter-provincial pipeline transportation: 0.002103 USD per thousand cubic meter per kilometer (kcm·km). The LNG ground transportation cost is estimated using data provided by ICIS (2015): 0.0118 (USD/kcm·km). The short-run costs for liquefaction and regasification activities are set to 12 and 10 USD/kcm, respectively, based on estimations for Southeast Asia (NERA Consulting, 2012).

Pipeline imports are priced at 285 USD per kcm along the western border of China with Central Asia based on average 2015 prices reported by the International Trade Centre (ITC, 2017). Pipeline imports under contract from Central Asia are set to 33.7 bcm, as a lower bound, allowing for additional imports if economic. LNG imports are priced at 397 USD/bcm in all coastal provinces.

3.4. Scenario design

We design three counterfactual scenarios to the baseline case. These scenarios are developed to analyze the impacts of price caps in the market as well as the role of limited access to midstream infrastructure by small companies. Table 2 contains short descriptions of the three scenarios, named No Price Caps, Price Caps with TPA, and No Price Caps with TP. The *No Price Caps* scenario represents a market where the price caps are lifted assuming that the demand remains unchanged, but access to pipelines is still restricted. That is, the firms coordinate to satisfy demand at the least cost, without enforcing obligations or prioritizing more expensive unregulated delivery pathways.

To measure the impact of TPA, we include two scenarios in which the TPA policy is reformed providing all market players with fair access to provincial pipelines and regasification capacity. First, we assess the impact of TPA under the price controls, *Price Caps with TPA*, then – in a market without price caps – *No Price Caps with TPA*. In this and all other scenarios available infrastructure and production capacity remain the same as the *Baseline*, and we allow the market to select import sources, beyond existing pipeline contracts.

Table 2
Description of the scenarios analyzed in this study.

Scenario name	Scenario description
Baseline	The Baseline scenario reflects the condition of the Chinese natural gas supply market in 2015, including suppliers producing, delivering and importing natural gas (both LNG and pipe gas) at observed levels.
No Price Caps	The No Price Caps scenario considers the case in which the price caps are lifted for all market segments in all provinces. Infrastructure access is still limited for smaller companies. Hence, there is not third-party access to infrastructure. Demand levels, existing infrastructure, cost estimates and all other parameters are the same as in the Baseline scenario.
Price Caps with TPA	The price Caps with TPA scenario assumes that the price caps are not lifted. However, infrastructure access is granted to third-party companies and all natural gas producers. Demand levels, existing infrastructure, cost estimates and all other parameters are the same as in the Baseline scenario.
No Price Caps with TPA	The No Price Caps with TPA scenario considers that all price caps are lifted and that third-party companies are granted access to midstream natural gas infrastructure. Demand levels, existing infrastructure, cost estimates and all other parameters are the same as in the Baseline scenario.

4. Analysis and discussion

4.1. Establishing the baseline

The *Baseline* scenario reflects the condition of the Chinese natural gas supply market in 2015, including suppliers producing, delivering and importing natural gas (both LNG and pipe gas) at observed levels. The price caps for each province (see Table 1) are imposed for pipeline gas supplied to the City Gate and Chemical markets with corresponding contractual obligations required by the large NOC's. Direct consumers are not subject to price caps and LNG supplies are unregulated. We assume a competitive market with the added feature that each firm incurs its required losses for supplying customer groups at capped prices and avoids selling additional gas to regulated markets at a loss. Firms prioritize unregulated delivery modes, in this case LNG, for demand beyond the imposed obligations. We also introduce restricted pipeline access to reflect conditions in 2015: the NOC's limit access to their interprovincial pipelines. Note that we account for volume losses in the natural gas transported by pipelines. Hence, total supply in the upstream sector may vary across scenarios depending on the natural gas transportation configuration in the midstream sector.

Table 3 compares the results of the *Baseline* scenario with the supply patterns of the Chinese gas market in 2015, as well as the other counterfactual scenarios. In this table, key model indicators include total production, domestic liquefaction, pipeline and LNG imports, average marginal cost (weighted by provincial demand) and total systems cost. The national average of the marginal supply costs is reported in USD per thousand cubic meters (kcm). The model results come close to the actual outcomes for which the indicators are available.

4.2. Scenario results and analysis

Eliminating the price caps has a significant impact on the market. Adding TPA to the elimination of price caps lowers costs further and shifts the market from LNG to greater pipeline imports. However, TPA alone does not alter the market significantly outside of shifting the source of imports.

Under the *No Price Caps* scenario, the marginal supply costs (spot prices) decrease by 14% on average across all provinces when lifting the price caps; 419 USD/kcm (10.6 USD/MMBTU) to 357 USD/kcm (9.7 USD/MMBTU). The reduction occurs because shipping LNG by tanker is no longer necessary step to deliver unregulated natural gas. Fig. 3 compares the marginal supply costs of the *Baseline* and the *No*

Table 3
Production, imports, marginal supply costs and total costs in all scenarios.
(*Sources: 2015 data from CEIC and ICIS (domestic liquefaction), KAPSARC research (scenarios).*)

Indicators	2015 data	Baseline	No Price Caps	Price Caps with TPA	No Price Caps with TPA
Domestic production (bcm)	135	136	136	136	136
Domestic liquefaction (bcm)	10	9.58	0.82	9.58	0.64
Pipeline imports (bcm)	34	35	36	43	47
LNG imports (bcm)	27	28	25	20	15
Total supply (bcm)	197	198	197	199	198
Pipeline shipment (bcm-km)	N/A	243,776	234,291	280,044	286,910
LNG shipment (bcm-km)	N/A	10,850	993	9634	844
Average of marginal supply costs (USD/kcm)	N/A	419	357	419	353
Change from *Baseline* (%)	N/A	–	−14%	0%	−16%
Total cost (million USD)	–	28,908	27,554	28,195	26,725
Saving (%)	–	–	4.7%	2.5%	7.6%
Net saving (million USD)	–	–	1354	713	2183

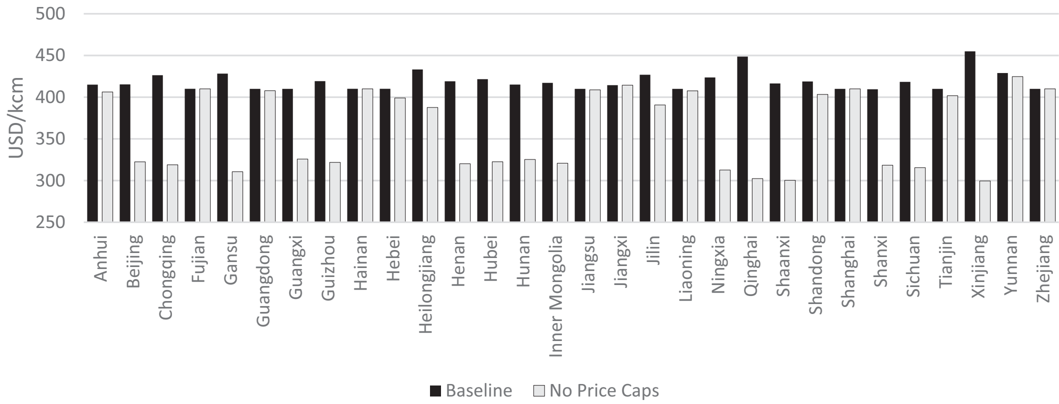

Fig. 3. Marginal supply costs (spot prices) in the Baseline and No Price Caps Scenarios, USD/kcm.
(*Source: KAPSARC research.*)

Price Caps scenarios. Total system costs are reduced in scenarios with TPA, however we found negligible changes in marginal supply costs. The marginal costs generated in all four scenarios are listed in Table A2-2 in Appendix 1.2.

The marginal costs are very high in the baseline, because companies have to incur the extra costs of liquefaction in order to receive deregulated prices. In Fig. 4 we compare the percent difference in marginal supply costs and City Gate prices for each province in the *Baseline* and *No Price Caps* scenarios. These results show that in the *Baseline* regional price caps are binding for most provinces (positive values), with the average across all provinces exceeding 17%. Certain western inland provinces, on the other hand, incur significant – >25% – price distortions. These distortions have a significant impact not only on marginal costs, but also on the choices of supply sources and transportation options, total costs and overall efficiency of the upstream gas market.

Eliminating the caps reduces total systems costs by 4.7%, or 1.4 billion USD. Domestic liquefaction and LNG tanker movements decrease by >90%. Pipeline shipments grow, with a 3.7% increase in less expensive pipeline imports. The combination of increased imports from Central Asia and injections into pipelines of what would have been shipped as LNG leads to a substantial increase in pipeline utilization, as shown in Table 3. Note that marginal costs fall below the price caps at the City Gate in several provinces under the *No Price Caps* scenario (Fig. 4), which means that enforcing the price caps can increase unregulated prices above the caps in many areas.

We find that restricted access to pipeline capacity at the provincial level plays a significant role in driving import choices. When price caps are not lifted and TPA is granted (*Price Caps with TPA* scenario) we observe a significant decline (36%) in LNG imports (see Table 3, where LNG imports are 20 bcm). However, the savings in import costs are offset by the firms prioritizing domestic liquefaction and LNG deliveries under the price caps, which reduces cost savings to 2.5%. In addition, we observe no significant impact on marginal supply costs.

Our results show that price caps have a strong impact on the marginal supply costs, by incentivizing unregulated and more expensive LNG deliveries. On the other hand reforming pipeline access constraints increases pipeline network flows and shifts the source of imported gas. Removing the price caps in 2015 in addition to TPA reform – *No Price Caps with TPA* – also drives a noticeable shift in the source of imports. Additional Coastal LNG is replaced by central Asian pipeline imports, with a large drop in domestic liquefaction and LNG shipments. Therefore, improving provincial pipeline access and removing the incentives for the domestic LNG market can lead to a much more efficient use of transnational capacity for imported pipeline gas.

4.3. Pipeline tariff and TPA

It is worth noting that when we optimize the short-run supply logistics, we consider only the operating costs. The represents a fraction of the West-East pipeline tariff by treating existing capacity as a sunk investment. Pipeline tariffs charged by CNPC along the West-East pipeline reach as high as 4 USD/MMBTU (112 USD/kcm) (OIES, 2014), designed to cover a regulated rate of return on pipeline investments, the major share of the total cost. Given a pipeline import price in Western China of 285 USD/kcm in 2015, total cost of delivering gas across 4000 km,

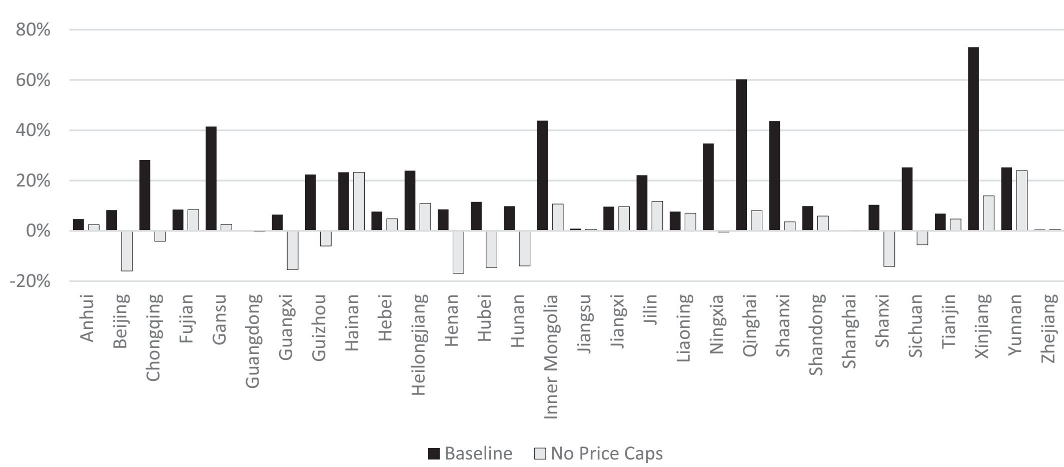

Fig. 4. Percent difference between marginal cost and City Gate price caps.
(*Source: KAPSARC research.*)

roughly the distance to Shanghai, is 397 USD/kcm, similar to the coastal LNG import price used in the model.

To determine if the marginal supply costs (prices) in the *No Price Caps* scenarios (Table A2-2) are sufficient to recover CNPC's trans-national pipeline investment, we calculate an annualized cost of moving imported gas across the West-East pipeline (about 4000 km). We derive an annualized capital cost of 46.8 USD/kcm using a total investment of 14.5 billion USD for 17 bcm of annual capacity (sourced from the IHS Edin database), and assuming a 50 year lifetime with a 5% discount rate. Taking a relatively low utilization of 50% and adding the pipeline operating cost estimate (0.0021 USD/kcm-km) we find a total cost of 102 USD/kcm. Including the pipeline import price, the total cost of delivering imported pipeline gas to Shanghai is about 387 USD/kcm, close to the 2015 LNG import prices and coastal prices in the *No Price Caps* scenario.

The annualized operating costs, and access tariff, of the West-East pipeline would be significantly lower given a higher utilization factor. In our scenarios with third-party access reform a higher utilization factor is achieved by the increase in pipeline imports and shipments (24% more gas leaving Xinjiang than in the *Baseline)*. Our finding suggests that the trans-national pipeline tariffs represent a barrier to reforming national pipeline access for third party suppliers if the infrastructure remains on the NOCs' balance sheet. Transporting their own supplies at cost, they would be able to lock out competitors under the current tariff structure.

Given the regional structure of natural gas supply and demand there is a clear potential for China to benefit from an integrated national gas market, with better access and competition between participating firms.

4.4. Implications for market participants

Our analysis carries significant insights for market players. Under the *No Price Cap* scenarios, domestic liquefaction almost disappears. The market share of smaller independent producers could shrink given that they benefit from current regulations and resort to liquefaction. Their situation would be made worse is they do not get access to pipelines due to regulatory failure and the location of their assets.

Unless there is a major shift in the price relationship between imported pipeline gas and LNG, the dominant LNG importer (CNOOC) could come under the most pressure from price cap and pipeline access reform, including more competitive tariffs. Independent importers would still have a market for their LNG spot purchases (if such purchases remain cheaper than existing long-term contracts) to supply coastal provinces.

Without price caps the incentive for domestic liquefaction and LNG deliveries are reduced as suppliers can achieve higher rents from unregulated pipeline deliveries. Overall, the growing demand for LNG in inland provinces from certain industries, such as natural gas vehicles, may be impaired due to increased share of gas supplies shipped by pipelines. Other gas consuming industries, which are not dependent on LNG, would benefit. The microeconomics of domestic LNG supplies, such as pipeline accessibility, may limit such substitution.

The TPA reform can have a significant impact on pipeline shipments and this impact can be further expanded by lifting the price caps. Under the TPA and No Price Caps scenario, pipeline gas shipments by independent producers via existing capacity increase by >80%. However, in reality the NOC with a dominant position in the upstream and midstream sectors would be capable of reducing these gains by exercising their market power even in a deregulated market.

As a pipeline import monopolist, the CNPC is well positioned to take advantage of more competitive pipeline imports following these policy reforms. It would still dominate the midstream sector given that the pipeline infrastructure is not divested into a separate entity. However, the potential increase in domestic pipeline shipments will rely heavily on establishing a pipeline tariff system based on actual costs.

In the scenarios with *No Price Caps*, the marginal supply costs fall well below (>20%) the City Gate price caps in several inland provinces (Fig. 4). Only in a few provinces where the price caps are among the lowest do the marginal costs exceed the caps by >10%. In the market with price caps we see that the spot prices for gas, dominated by LNG deliveries, exceed the price caps across the country. This creates a significant discrepancy between the prices for incremental demand and the contractual obligations for pipeline deliveries. Lifting the price caps would equalize prices without posing a significant disadvantage to consumers under the previously regulated pipeline prices and supports more competitive spot prices for existing and new consumers in serval inland provinces.

5. Conclusions

We assess the economic distortions caused by regulated prices in China's natural gas supply market and estimate the potential economic gains from improved supplier coordination in 2015. Price caps incentivize rational profit maximizing firms to deliver LNG to unregulated markets, increasing total costs of delivery and market prices. In combination with restricted TPA this results in underutilization of the existing domestic pipeline infrastructure.

Applying a detailed representation of regional supply and demand, as well as midstream infrastructure enables us to identify how regional markets may respond to strategic national policies. For instance, we address issues arising from the competitiveness of pipeline imports from Central Asia in the north-west and LNG imports landing in eastern coastal provinces. Our representation of the market as an MCP also contributes to the study of energy markets with regulated prices, building on the work of Murphy et al. (2016).

Our *No Price Caps* scenario demonstrates how existing regulation favors domestic LNG operations and higher LNG imports. CNOOC, as a dominant LNG importer, could come under pressure in case of price reform. Independent importers would still have a market for their LNG spot purchases (if such purchases remain cheaper than existing long-term contracts) to supply coastal provinces. Domestic liquefaction activities by independent producers with limited access to the inter-provincial pipeline network would be at a disadvantage.

Open access to China's midstream infrastructure is an issue at both the provincial level and for local distribution networks within each province. In response, the government continued to roll out reforms in 2016 and 2017 to improve the market. This is in line with our analysis suggesting that resolving TPA restrictions, including structural reforms, efficient enforcement and affordable tariffs, supports greater use of existing trans-national pipeline network, the integration of China's regional gas markets, and economic imports from Central Asia. However, without addressing the incentives created by the price caps, profit-maximizing firms are likely to continue prioritizing unregulated LNG supplies.

Our analysis shows how rationalizing prices for pipeline deliveries can contribute to cost savings by replacing domestic liquefaction and LNG imports with more economic supplies. Marginal supply costs averaged across the country decline by 14% and fall below the government enforced price caps in several central provinces, which would improve the cost competiveness of natural gas and support China's future growth targets.

In highly concentrated markets, such as the Chinese natural-gas upstream and midstream sectors, the dominant players can undermine the implementation of reform initiatives (such as pricing reforms) if they counter their interests. Even if price and TPA reforms eventually materialize, the NOC's can distort the efficiency gains from market liberalization through exercising their market power in a deregulated market. In this regard, representation of the supply ownership structure and capturing the market power (where applicable) in the model formulation could be a potential direction for further research.

Another potential research direction could cover the effects of distorted price signals beyond the direct economic costs. For example, the impact of unequal profit distribution in the industrial value chain (higher profits at the midstream and distribution level) on investment (or lack of thereof) in the higher-risk upstream sector. On the opposite end of the supply chain, current franchise policies in urban areas favor redundant channels of gas distribution and sales. This can drive up consumer prices and lead to excessive profits for distributers at retail levels beyond the City Gate. Eliminating artificial price differentials across consumer types and geographies would reduce the incentives to deliver expensive gas (e.g. unregulated LNG), thereby decreasing price inflation. Initiatives to rationalize wholesale prices for all gas supplies, such as the ongoing pilot program in Fujian province and recent reforms in the chemical fertilizer industry, would also help reduce the cost of supplies. The demand side impacts associated with reforming China's natural gas prices is another area for future research.

Model code

The GAMS code for the model presented in this paper has been made available at https://github.com/brioux/KEM_CHINA_EE.

Proprietary data used to calibrate the model from IHS Vantage and IHS Edin subscriptions have been removed or replaced with dummy values in the corresponding data directory. Contact the corresponding author regarding access to the complete calibration files.

Appendix 1. Model formulation

1.1. Sets

i, j	Suppliers operating in the gas market, including the 3 NOCs ($i^N \subset i$) and others
g	Production or field type (conventional, unconventional, offshore, CBM, CMM, associated)
m	Market segment (Chemical, City Gate, Direct)
m'	Market segments subject to price caps $m' \subset m$ (Chemical, City Gate)
r, r'	Model regions
s	Gas fields of the same type differentiated by marginal production costs (supply steps)
w	Gas prepared delivered for pipeline (*pipe*) or as *LNG*

1.2. Variables

d_{imrw}	Natural gas delivered in market m and region r in state w by supplier i
$\delta_{m'r}$	Enforced obligation to deliver gas to regulated market m' and region r at a capped price
$t_{ijrr'w}$	Transportation (pipeline/LNG) by firm i on infrastructure owned by firm j from r to r'
imp_{irw}	Quantity of gas imported by firm i, in region r, in state w (pipeline or LNG)
l_{ir}	Unloading of LNG by firm i for regasification, and injection into pipeline or delivery to consumer
q_{igrsw}	Natural gas production by firm i, from field type g, in r, from s, and in state w (pipeline or LNG)
$z_{m'r}$	Lost revenue in regulated market m' for pipeline deliveries at a capped price (USD/kcm)
p_r	Marginal supply cost (competitive market price) in each region (USD/kcm)
Dual Variables	
π_{mr}	Dual on the total gas supplied to each regional market, Eq. (2.3)
$\eta_{m'r}$	Dual on the distribution of contractual obligations between suppliers, Eq. (2.4)
μ_{igrs}	Dual on the production constraint for production type g, asset s, owned by firm I, Eq. (2.5)
σ_{ir}	Dual on the firm's liquefaction capacity constraint, Eq. (2.6)
λ_{irw}	Dual on the firm's supply balance constraint, Eq. (2.7)
$\gamma_{irr'w}$	Dual on the firm's transportation capacity constraint from region r to r' by type w, Eq. (2.8)
ν_{irw}	Dual on the firm's import contract constraint, Eq. (2.9)
ζ_{ir}	Dual on the firm's regasification capacity constraint, Eq. (2.10)

1.3. Cost coefficients and other parameters

CN_{irw}	Contracts for imported gas by entry region r, firm i and gas type w
CP_{igrsw}	Marginal cost of production and processing of gas by firm i for type g in region r and state w
CR	Marginal regasification cost
$CT_{rr'w}$	Variable transportation cost from r to r' for gas type w
D_{mr}	Fixed gas demand in market m and region r
$DL_{m'r}$	Supply obligations associated with the price cap $\hat{p}_{mrw}$ for gas delivered to regulated market m'
E_{igrs}	Production capacity by firm i, for gas type w, in region r, and supply step s
$F_{irr'w}$	Transportation capacity owned by firm i from region r to r' ins state w
G_{ir}	Liquefaction capacity owned by firm i in region r
H_{ir}	Regasification capacity owned by firm i in region r
I_{rw}	Import price in region r by type w
L^{liq}	Liquefaction losses
L^{reg}	Regasification losses
$L_{rr'w}^{tr}$	Transportation losses
$\hat{p}_{mr}$	Price cap in regulated market m' and region r

1.4. Regulated market condition

First we introduce a set of equations that describes the impact created by the price caps, $\hat{p}_{mr}$, for pipeline deliveries to regulated market segments (m') in each region. We introduce p_r as the market price in region r. Eq. (1.1) defines the variable $z_{m'r}$ as the potential lost revenue (USD/kcm) of gas supplied by pipeline at a capped price below the market price. It is stated as a maximum value as it should be zero when the market clears below the price cap. This expression is linearized by re-defining $z_{m'r}$ as a slack variable in Eq. (1.2). We introduce the non-negative variable $\delta_{m'r}$ orthogonal to constraint (1.2), representing government enforced pipeline delivery obligations when the price cap is binding for a given type. Constraint (1.3) sets the enforced contractual obligations to the actual levels in the market, the coefficient $DL_{m'r}$. We assume that a market for trading obligations among firms exists, ensuring an efficient distribution between firms.

$$z_{m'r} = \max(p_r - \hat{p}_{m'r}, 0) \tag{1.1}$$

$$z_{m'r} \geq p_r - \hat{p}_{m'r} \quad \perp \delta_{m'r} \geq 0 \quad \forall im'r \tag{1.2}$$

$$DL_{m'r} - \delta_{m'r} \geq 0 \quad \perp z_{m'r} \geq 0 \quad \forall im'r \tag{1.3}$$

Let's consider the two possible outcomes for the complementarity pairs in Eqs. (1.2) and (1.3). When the market price is below the price cap,

$$p_r < \hat{p}_{m'r} : z_{m'r} = 0, \delta_{m'r} = 0,$$

there is no need for the government to enforce contractual obligations, as the market clears at a price below the cap, and $\delta_{m'rw} = 0$. In the second case the price cap is binding,

$$p_r > \hat{p}_{m'r} : z_{m'r} = p_r - \hat{p}_{m'r} \geq 0,\ \delta_{m'r} > 0.$$

Now the government has to enforce the pricing policy, requiring physical delivery of gas at a capped price. Eq. (1.3) ensures that the obligations are enforced ($\delta_{m'r} = DL_{m'r}$).

1.5. The suppliers' optimization problem

Next we introduce the suppliers' optimization problem in Eq. block (2), as an adjusted total system cost minimization expressed in a complementarity format. The problem is then transformed into an MCP and solved numerically using the General Algebraic Modeling System (GAMS) and the PATH solver.

The objective function Eq. (2.1) consists of two terms; the aggregate firm costs k_i defined in Eq. (2.2), plus the total lost revenues ($z_{m'r}$) from selling at the price caps. The second term appears to result in a bilinear objective value. However, $z_{m'r}$ is not a primal variable of the suppliers, but instead a slack variable from the regulators problem (1) and, therefore, a constant in the supplier's optimization. The full MCP is derived in the following section where the bilinear objective function is transformed in the corresponding linear complementarity conditions as a convex problem.

Natural Gas Supply Problem (2)

$$\min \sum_i k_i + \sum_{im'rw} \{d_{im'rw} z_{m'r} | w = pipe\} \tag{2.1}$$

Subject to:

$$k_i = \sum_{grsw} C_{igrsw} q_{igrsw} + \sum_{jwrr'} CT_{rr'w} t_{jirr'w} + \sum_{irw} I_{rw} imp_{irw} + \sum_{ir} CR \cdot l_{ir} \quad \forall i \tag{2.2}$$

$$\sum_{iw} d_{irw} \geq D_{mr} \quad \perp \pi_{mr} \geq 0 \quad \forall r \tag{2.3}$$

$$\sum_{i^n} \sum_{w=pipe} d_{i^n m'rw} \geq \delta_{m'r} \quad \perp \eta_{m'r} \geq 0 \quad \forall m'r \tag{2.4}$$

$$\sum_w q_{igrsw} \leq E_{igrs} \quad \perp \mu_{igrs} \geq 0 \quad \forall igrs \tag{2.5}$$

$$\sum_{gsw} \left\{ q_{igrsw} | w = LNG \right\} \leq G_{ir} \quad \perp \sigma_{ir} \geq 0 \quad \forall ir \tag{2.6}$$

$$\perp \lambda_{irw} \geq 0 \quad \forall irw \tag{2.7}$$

$$\sum_{gs} q_{igrsw} \left(1 - \left\{ L^{liq} \middle| w = LNG \right\}\right) + imp_{irw} + \{l_{irw} | w = pipe\}(1 - L^{reg}) + \sum_{jr'} t_{ijr'rw}(1 - L^{tr}_{rr'w}) \geq \{l_{irw} | w = LNG\} + \sum_{jr'} t_{ijrr'w} + \sum_m d_{imrw}$$

$$\sum_j t_{jirr'w} \leq F_{irr'w} \quad \perp \gamma_{irr'w} \geq 0 \quad \forall irr'w \tag{2.8}$$

$$imp_{irw} \geq CN_{irw} \quad \perp \nu_{irw} \geq 0 \quad \forall irw \tag{2.9}$$

$$l_{ir} \leq H_{ir} \quad \perp \zeta_{ir} \geq 0 \quad \forall iw \tag{2.10}$$

$$q_{igrsw} \geq 0, t_{ijrr'w} \geq 0, imp_{irw} \geq 0, l_{ir} \geq 0, d_{imrw} \geq 0$$

Eq. (2.2) includes the total cost of production and liquefaction, transportation costs for both pipeline and LNG, natural gas import cost via pipeline and LNG, and regasification costs.

The problem is subject to the remaining logistical constraints. Next to each constraint we also introduce the corresponding orthogonal dual variables. Eq. (2.3) is the fixed demand constraint for each region and market segment. It provides the standard condition that the marginal supply cost π_{mr}, the dual variable on the constraint, is zero if the suppliers deliver an excess supply of gas. Constraint (2.4) enforces that the total government supply obligations are satisfied by the NOC's (i^N). Its dual variable $\eta_{m'r}$ represents the marginal value on the trade of government supply obligations between firms.

Eq. (2.5) is the upstream production constraints assuming a fixed capacity for each firm's regional assets E_{igrs}. Eq. (2.6) is the regional constraint on liquefaction capacity for each firm. Eq. (2.7) provides the supply balances for gas distributed by pipeline and LNG, respectively. For pipelines the sum of gas produced, imported, entering by pipeline and LNG injected (l_{ir}) into the network exceeds the gas distributed to all markets minus the gas sent out by pipeline. The same applies for LNG, except the term l_{ir} is moved to the right hand side of the inequality as an LNG sink. The dual variables on these constraints λ_{irw} represent the marginal value of supplying gas by each delivery mode.

The transportation capacity constraint for shipment by pipe and LNG is defined in Eq. (2.8), with the coefficient $F_{irr'w}$ describing existing network capacity. Existing long term import contracts are defined in Eq. (2.9), used primarily for pipeline purchases agreements. Eq. (2.10) constrains the unloading of LNG using available regasification capacity H_{ir}. Finally all the primal variables are defined as non-negative.

1.6. The KKT conditions

Now we derive the Karush-Kuhn-Tucker conditions that describe the equilibrium of the natural gas market. The resulting MCP captures the cost of the market distortion created by the capped prices. The Lagrangian of the supplier's optimization problem is shown in Eq. (3). Since the bilinear term in the objective function consists of the revenue reductions per unit as given by the regulator's problem, $z_{m'r}$, the loss per unit becomes a dual on the gas volume meeting regulated demand in the first term in the second line of Eq. (3), we do not have a bilinear term that causes a nonconvexity and the Lagrangian is a standard.

$$\forall i \tag{3}$$

$$\begin{aligned}
L = & -\sum_{grsw} C_{igrsw} q_{igrsw} - \sum_{rr'wj} t_{jirr'w} CT_{rr'w} - \sum_{irw} I_{rw} imp_{irw} - \sum_{ir} l_{ir} CR \\
& - \sum_{im'rw} \{ d_{im'rw} z_{m'r} | w = LNG \} + \sum_{igrsw} q_{igrsw} \underline{\mu}_{igrsw} + \sum_{mrv} d_{imrv} \underline{\lambda}_{imrv} + \sum_{mrv} l_{ir} \underline{\zeta}_{ir} \\
& + \sum_{mr} \left(\sum_{iw} d_{imrw} - D_{mr} \right) \pi_{mr} + \sum_{m'r} \left(\sum_{iw} \{ d_{im'rw} | w = pipe \} - \delta_{m'r} \right) \eta_{m'r} \\
& + \sum_{grs} \left(E_{igrs} - \sum_{w} q_{igrsw} \right) \mu_{igrs} + \sum_{irr'w} \left(F_{irr'w} - \sum_{j} t_{jirr'w} \right) \gamma_{irr'w} \\
& + \sum_{ir} \left(G_{ir} - \sum_{gsw} \left\{ q_{igrsw} | w = LNG \right\} \right) \sigma_{ir} + \sum_{irw} (imp_{irw} - CN_{irw}) \eta_{irw} + \sum_{ir} (H_{ir} - l_{ir}) \zeta_{ir} \\
& + \sum_{irw} \left(\begin{array}{l} \sum_{gs} q_{igrsw} \left(1 - \left\{ L^{liq} \middle| w = LNG \right\} \right) + imp_{irw} + \{ l_{irw} | w = pipe \} (1 - L^{reg}) \\ + \sum_{jr'} t_{ijr'rw} (1 - L^{tr}_{rr'w}) - \{ l_{irw} | w = LNG \} - \sum_{jr'} t_{ijrr'w} - \sum_{m} d_{imrw} \end{array} \right) \lambda_{irw}
\end{aligned}$$

Eqs. (3.1) to (3.5) come from imposing the condition that the gradient of the Lagrangian with respect to the partial derivatives of q_{igrsw}, imp_{irw}, $t_{ijrr'w}$, l_{ir} and d_{imrw}, respectively, equals to zero in the optimal solution, as it should be a stationary point.

$$0 \geq -C_{igrsw} - \mu_{igrs} + \sum_{m} \lambda_{imrv} + \{ \sigma_{ir} | w = LNG \} \quad \perp \quad q_{igrsw} \geq 0 \quad \forall irs \tag{3.1}$$

$$0 \geq -I_{rw} + \sum_{m} \lambda_{imrw} + v_{iw} \quad \perp \quad imp_{irw} \geq 0 \quad \forall irw \tag{3.2}$$

$$0 \geq -\gamma_{jrr'w} + \lambda_{ir'w} - \lambda_{irw} \quad \perp \quad t_{ijrr'w} \geq 0 \quad \forall ijrr'w \tag{3.3}$$

$$0 \geq -CR + \lambda_{irw} \left(\{ 1 - L^{reg} | w = pipe \} - \{ 1 \ | w = LNG \} \right) \quad \perp \quad l_{ir} \geq 0 \quad \forall ir \tag{3.4}$$

$$0 \geq \pi_{mr} - \lambda_{irw} + \left\{ (\eta_{mrw} - z_{mr}) | m \subseteq m' \cap w = pipe \right\} \quad \perp \quad d_{imrw} \geq 0 \quad \forall imrw \tag{3.5}$$

Next we include the original primal constraints (2.3) to (2.10). To complete the MCP describing the supply market with regulated prices we include the market conditions (1.2) and (1.3), and connect them to the supplier's problem by requiring the unregulated market price, p_r, to be greater than the regional marginal supply costs from all market segment, π_{mr}, in Eq. (4).

$$p_r \geq \pi_{mr} \quad \perp \quad \xi_{mr} \geq 0 \quad \forall mr \tag{4}$$

Appendix 2. Market Structure

Three large NOCs dominate China's natural gas production and transportation infrastructure: China National Petroleum Corporation (CNPC), China Petroleum & Chemical Corporation (Sinopec) and China National Offshore Oil Corporation (CNOOC). Smaller private firms, often in partnership with the NOCs, engage in production – primarily, in the unconventional segment – as well as in LNG liquefaction, transportation, and regasification. China's domestic supply consists primarily of onshore conventional production (80.9%) dominated by the NOC's, offshore gas (9.5%) operated by CNOOC and its joint ventures, and CBM (3.6%). In the Chinese statistics CBM typically includes vented Coal Mine Methane (CMM) extracted by domestic coal producers (about 45% of total) along with CNPC and other domestic and foreign private companies. However, in our model the drilling for CBM is represented as a separate activity with different costs to the venting of CMM from coal mines (see Appendix 1.2). Recently, power generators, coal companies and gas distributors have increased Synthetic Natural Gas (SNG) production, reaching about 1% of supplies (SIA, 2017).

CNPC, Sinopec, Shell, as well as national and provincial SOE's have developed unconventional shale gas, providing 3.3% of domestic production. Although China possesses vast unconventional resources, geological and technological challenges hinder their development, making it difficult to repeat the success of recent U.S. shale revolution. Ownership claims to the more accessible shale gas plays have been largely limited to China's NOCs, which limits future investments and innovation efforts (TLG, 2014).

China's gas pipeline imports totaled 34.2 bcm in 2015 (CEIC, 2017). They are dominated by CNPC, which controls imports from Central Asia (88.3% of the total volume). Smaller volumes are imported via the Myanmar pipeline and new contracts with Russia are expected to materialize in the foreseeable future. The NOCs also dominate LNG imports at around 27.2 bcm in 2015 (SIA, 2017), however, provincial SOE's and private companies are increasing their participation following recent market reforms (NEA, 2014; NDRC, 2014).

The NOC's own and operate the major domestic pipelines, which consist of 16 national trunk pipelines and over 80 sub-national trunk pipelines. The gas distribution market comprises large industrial and commercial consumers, provincial SOE's, private companies, joint ventures and downstream subsidiaries of NOCs.

Table A2-1
Provincial demand by market segment, bcm.
(*Source:* CEIC, 2017.)

Province	Chemical	City Gate	Direct	Total demand
Anhui		2.66	0.66	3.33
Beijing		6.79	6.79	13.58
Chongqing	3.26	2.55	5.81	11.62
Fujian		3.48	0.87	4.35
Gansu	0.43	1.90	0.58	2.91
Guangdong	0.03	5.28	5.31	10.62
Guangxi		0.62	0.15	0.78
Guizhou	0.12	0.99	0.28	1.39
Hainan	0.02	4.07	4.10	8.19
Hebei	0.16	3.29	3.45	6.90
Heilongjiang		2.79	0.70	3.49
Henan	0.36	3.43	3.79	7.58
Hubei	0.07	2.90	0.74	3.71
Hunan		1.96	0.49	2.45
Inner Mongolia	0.53	2.75	0.82	4.10
Jiangsu	0.14	7.62	7.76	15.52
Jiangxi		1.28	0.32	1.60
Jilin	0.03	1.61	0.41	2.05
Liaoning	0.44	2.32	2.76	5.52
Ningxia	0.26	1.50	0.44	2.20
Qinghai	1.04	2.74	1.00	4.78
Shaanxi	0.05	3.91	3.95	7.91
Shandong		3.85	3.85	7.70
Shanghai		3.51	3.51	7.02
Shanxi	0.02	3.09	3.12	6.23
Sichuan	3.15	5.91	9.06	18.12
Tianjin	0.14	2.92	3.07	6.13
Xinjiang		6.96	6.96	13.92
Yunnan		0.47	0.12	0.59
Zhejiang	0.02	3.73	3.75	7.50
Total	10.27	96.88	84.62	191.77

Table A2-2
Marginal supply costs under the modeling scenarios (percent difference with respect to the *baseline*).
(*Source: KAPSARC research.*)

Province	Baseline, USD/kcm	No Price Caps, USD/kcm	Price Caps with TPA, USD/kcm	No Price Caps with TPA, USD/kcm
Anhui	415	406 (−3%)	415	403 (−3%)
Beijing	415	322 (−22%)	415	322 (−22%)
Chongqing	426	319 (−25%)	426	319 (−25%)
Fujian	410	410 (0%)	410	410 (0%)
Gansu	428	311 (−27%)	428	311 (−27%)
Guangdong	410	408 (−1%)	410	327 (−20%)
Guangxi	410	326 (−21%)	410	326 (−21%)
Guizhou	419	322 (−21%)	419	322 (−21%)
Hainan	410	410 (0%)	410	410 (0%)
Hebei	410	399 (3%)	410	397 (−3%)
Heilongjiang	433	388 (−11%)	433	386 (−11%)
Henan	418	320 (−23%)	418	320 (−23%)
Hubei	422	323 (−23%)	422	322 (−23%)

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Table A2-2 (*continued*)

Province	Baseline, USD/kcm	No Price Caps, USD/kcm	Price Caps with TPA, USD/kcm	No Price Caps with TPA, USD/kcm
Hunan	415	325 (−22%)	415	325 (−22%)
Inner Mongolia	417	321 (−23%)	417	320 (−23%)
Jiangsu	410	409 (0%)	410	407 (−1%)
Jiangxi	414	414 (0%)	414	414 (0%)
Jilin	427	391 (−8%)	427	389 (−9%)
Liaoning	410	408 (−1%)	410	406 (−1%)
Ningxia	423	313 (−26%)	423	312 (−26%)
Qinghai	449	302 (−33%)	449	302 (−33%)
Shaanxi	416	300 (−28%)	416	315 (−24%)
Shandong	418	403 (−4%)	418	402 (−4%)
Shanghai	410	410 (0%)	410	410 (−24%)
Shanxi	409	318 (−22%)	409	318 (−22%)
Sichuan	418	316 (−25%)	418	316 (−25%)
Tianjin	410	402 (−2%)	410	400 (−2%)
Xinjiang	455	300 (−34%)	455	300 (−34%)
Yunnan	429	425 (−1%)	429	425 (−1%)
Zhejiang	410	410 (0%)	410	406 (−1%)

Appendix 3. Evaluation of production and costs

3.1. Methodology

Below is a description of the methodology applied to derive the costs for production of different gas types and for midstream infrastructure. For the purpose of this study, we split Chinese gas supply into 6 types:

- Natural gas onshore conventional
- Natural gas offshore
- Unconventional
  - ○ Shale gas
  - ○ Coal Bed Methane (CBM)
  - ○ Coal Mine Methane (CMM)

We define the venting of methane from active coal mines as CMM, separate from the drilling for methane in coal seams, defined as CBM below. We differentiate the two since investment and operating costs are not the same, however often when the government reports quantities both are defined as CBM.

For each type of gas, we estimated operating costs (OPEX) cost per thousand cubic meters (kcm), and identified the expected production for a given year. Where necessary, we scaled the costs to the 2015 level – the calibration year for the KEM China gas model – applying the IHS operational cost indices. The total production, average production costs of onshore, offshore and unconventional gas in each production region is shown in Table A3-1. Note that unconventional category includes shale, CMM, CBM and liquefaction costs. The variable cost of associated gas and CMM is set to zero as a by-product of the extraction of oil and coal, therefore for some regions the average costs is zero. Supply curves for conventional, offshore and unconventional (including liquefaction) production before transportation are shown in Fig. A3-1 (a), (b) and (c), respectively.

There are 270 onshore, 40 offshore gas assets, 20 shale gas assets, and 311 oil assets with associated gas production in the IHS Vantage database. We use this data to calibrate the operating cost and total production capacity from each asset in 2015.

If the reader is interested in running the model, a link to the open source code is available as additional material. The complete supply and midstream data used to calibrate the model can be requested from the authors with a valid subscription to IHS Vantage and Edin databases, respectively.

Table A3-1
Total production (bcm) and average costs (USD/kcm) by type and region.

Region	Associated	Conventional		Unconventional		Offshore	
	bcm	bcm	USD/kcm	bcm	USD/kcm	bcm	USD/kcm
Anhui				0.11	0.00		
Beijing		1.69	30.75				
Bozhong						1.05	5.98
Chongqing	0.00	3.30	23.13	0.03	15.00		
Fujian				0.01	0.00		
Gansu				0.01	0.00		
Guangdong	0.09					9.57	59.07
Guangxi	0.01			0.004	15.00		
Guizhou				0.09	155.25		
Hainan						0.19	42.15
Hebei	0.19	0.01	14.04	0.06	0.00	0.75	0.00
Heilongjiang	1.60	1.55	48.49	0.43	70.10		
Henan	0.12	0.17	29.66	0.13	15.00		
Hubei	0.01	0.12	42.89	0.01	15.00		
Hunan				0.03	0.00		
Inner Mongolia		0.08	54.84	0.84	253.93		
Jiangsu	0.00	0.01	110.60	0.02	0.00		
Jiangxi		0.01	30.75	0.03	0.00		

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Table A3-1 (*continued*)

Region	Associated	Conventional		Unconventional		Offshore	
	bcm	bcm	USD/kcm	bcm	USD/kcm	bcm	USD/kcm
Liaoning	0.07			0.59	158.92		
Ningxia				0.07	15.00		
Qinghai	0.06	6.07	38.42	0.01	15.00		
Shaanxi	1.13	38.82	62.89	1.64	281.96		
Shandong	0.05	0.004	94.29	0.12	0.00	0.02	0.00
Shanxi		2.15	30.75	2.16	113.96		
Sichuan		24.38	48.22	2.32	372.88		
Tianjin		0.94	98.74				
Xihu						1.16	97.33
Xinjiang	2.83	23.47	41.85	3.00	144.16		
Yunnan				0.04	0.00		
Total	6.50	104.68		11.80		12.74	

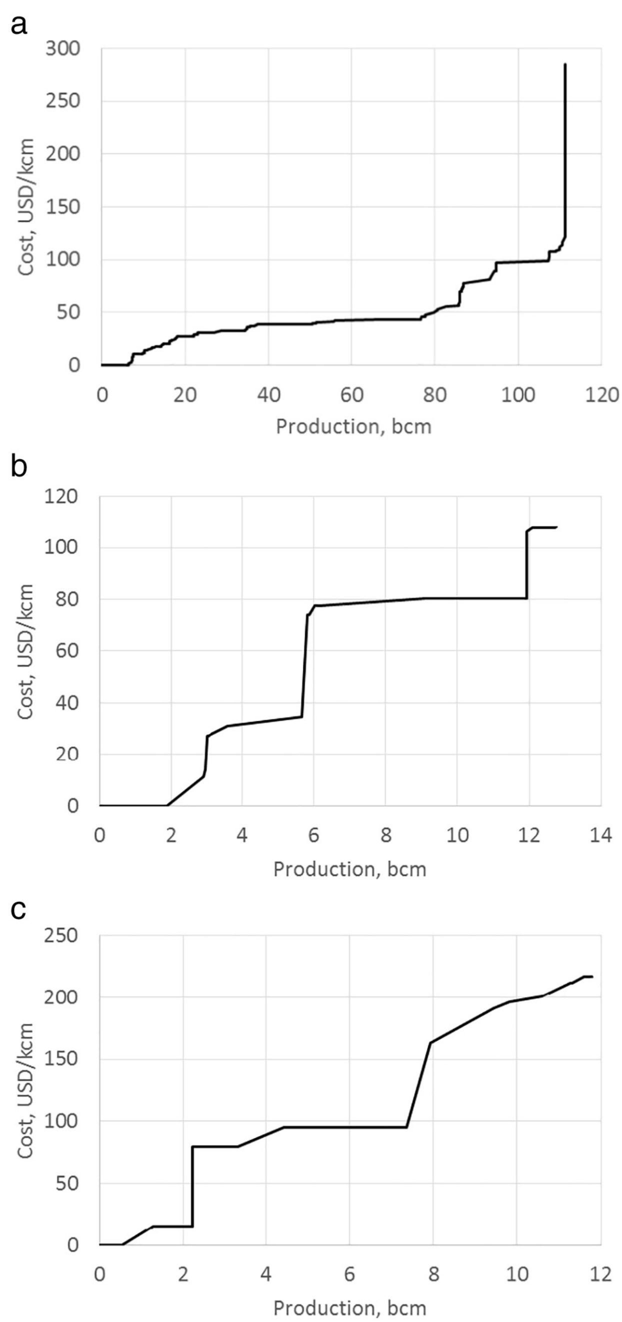

Figure A3-1. Supply curves of conventional (a), Offshore (b) and Unconventional (c) Gas.

3.2. Coal Mine Methane (CMM)

CMM is a natural gas, mostly consisting from methane, located in working coal mines associated with coal deposits. Historically, it was vented to atmosphere to reduce hazards during coal mining process. To prevent hazards or explosions methane should be removed from mine tunnels using special ventilation systems. CMM is primarily utilized near the mine – in local liquefaction plants or generation sites. Later the drilling and production techniques of the oil and gas industry were employed to extract methane from coal.

We estimate the CMM output and utilization volumes based on the levels recorded in recent years (see Table A3-2 for details). The provincial distribution is weighted by total coal production in that year. The CMM extraction costs are assumed to be a part of coal mine development expenditures.

Table A3-2
CMM output and utilization.
(*Source: China Coal Information Institute.*)

Indicators	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015
CMM Drainage, bcm	2.15	3.15	4.3	5.65	6.1	7.2	9.1	11.3	12.5	13.2	13.57
CMM Utilization, bcm	0.75	1.2	1.49	1.7	1.8	2.5	3.5	3.8	4.25	4.55	4.77
Coal production, billion tons	2.37	2.57	2.76	2.90	3.12	3.43	3.76	3.95	3.97	3.87	3.75
Utilization, %	34.9	38.1	34.7	30.1	29.5	34.7	38.5	33.6	34.0	34.5	35.2
Gas volume, m^3/t	0.91	1.23	1.56	1.95	1.96	2.10	2.42	2.86	3.15	3.41	3.62

3.3. Coal Bed Methane (CBM)

CBM is a methane gas trapped in the coal plays, an unconventional form of natural gas found in coal deposits or coal seams. Significant differences in the coalbed reservoir properties, gas storage mechanisms, the gas-transport phenomenon, resource decline rates, and water disposal have required innovations and changes to the conventional procedures. The lack of asset-specific production data for CBM required us to use the archetype project for plateau generation and cost estimation.

We used several data sources (MNR, 2018; Qin and Ye, 2015; Mu et al., 2015) to obtain the data on CBM production, reserves, and characteristics of major basins. Taking into account the data on geological resources, recoverable resources and geological reserves and applying an approximate 30% recovery rate, we obtained around 188 bcm of recoverable CBM gas for China.

We then estimated recoverable resources for specific producing regions using the following formula.

Estimated recoverable reserves, Bcm $= (Rp / Rptotal) * Rr$, where:

Rp = Predicted producing resources by basin

$Rptotal$ = Total predicted producing resources

Rr = Recoverable reserves for China (188 bcm).

Table A3-3
Distribution and characteristics of major CBM blocks.
(*Sources: Ministry of Land and Resources of the People's Republic of China, Qin and Ye, 2015, Mu et al., 2015, KAPSARC research.*)

Block play	Basin	Depth, m	CBM resources, bcm	Predicted proved resources, bcm	Predicted producing resources, bcm	Estimated recoverable resources, bcm
Class I						
Southern Qinshui Basin	Qinshui	200–1200	89.0	62.3	37.3	22.7
Eastern Ordos Basin	Ordos	300–1500	11.5	7.4	4.3	26.2
Yangquan-Heshun	Liupansui	300–1000	64.5	41.9	24.3	14.8
Gulin, Xuyong	Liupansui	300–1200	10.0	6.5	3.7	2.2
Yinggangling in Pingle	Ningwu	800–1500	2.1	1.3	0.7	0.4
Class II						
Huolinhe	Erlian	150–1500	10.3	6.6	3.6	2.2
Xixiagou in Santanghu Basin	Tuha	600–1500	21.7	13.0	6.8	4.1
Southern Tarim	Tarim	300–1500	157.0	94.2	49.9	30.3
Yili	Tianshan	500–1500	59.1	35.4	18.7	11.4
Wushenqi	Ordos	300–1500	170.0	110.5	60.7	36.9
Changji-Fukang	Junggar	800–1200	56.0	36.4	20.0	12.2
Class III						
Huangling-Binxian Changwu	Ordos	300–1500	14.4	7.8	3.7	2.2
Huhehu	Erlian	600–1500	13.3	7.2	3.4	2.1
Boli	Sanjiang Muleng	500–1500	31.0	17.0	8.5	5.2
Jixi-Hegang	Sanjiang Muleng	350–1500	15.3	8.4	4.0	2.4
Panguan	Liupansui	800–1200	19.0	10.4	4.9	3.0
Hengshanbao	Ningwu	400–1500	22.0	12.1	5.8	3.5
Shenmu	Ordos	500–1500	22.8	12.5	6.0	3.6
Southern Ningwu	Ningwu	300–1500	16.7	9.1	4.3	2.6
Total			909.0	567.0	309.4	188.0

The resulting distribution data is shown in the Table A3-3.

CBM extraction process has many similarities with development of gas from conventional reservoirs. However, significant differences between reservoirs have a great impact on profitability and operations. A coal play can be extensive by size and spread over a large territory so it requires drilling of large number of wells, water supply for further fracking and gathering system of pipelines. In China development of unconventional reservoirs is complicated because of the rough terrain, complex geology and other factors.

We studied several existing CBM project in China. Based on their parameters, we created a representative average project. The CBM project archetype was developed using IHS QUE$TOR software – a cost engineering tool for green field development concepts and cost assessment. Resulting primary project parameters are listed in Table A3-4.

Table A3-4
Parameters of an archetype CBM project.
(*Sources: IHS QUE$TOR, KAPSARC research.*)

Parameters	Characteristics	Units
Gas peak well flow	12.5	kcm/day
Plateau rate	1.6	kcm/day
Recoverable gas reserves 1P	3.5	bcm
Gas well productivity	53,200.0	kcm/well
Reservoir depth from LAT	568.0	m
Reservoir length	10	km
Terrain	Mountainous	N/A
Horizontal wells	63	#
Vertical wells	62	#

Having specified the project parameters, we created development concept (see Fig. A3-2) including:

- 63 horizontal wells
- 62 vertical wells
- Gas gathering and treatment station
- Field and transportation pipeline to the local liquefaction station

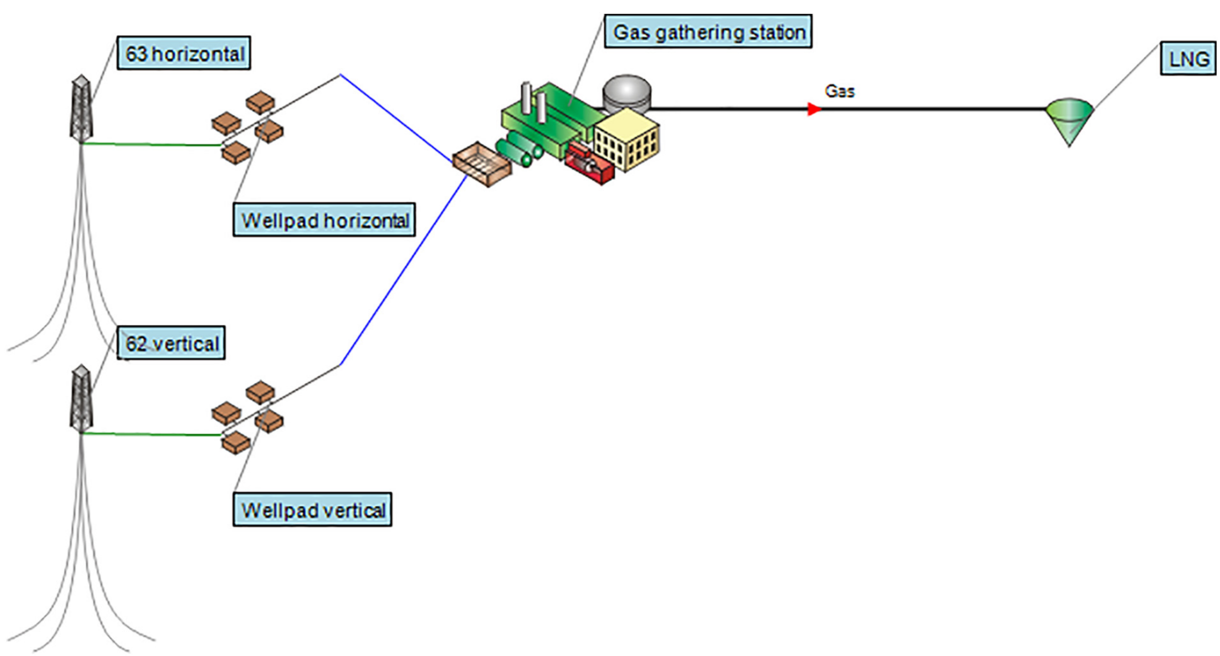

Fig. A3-2. Development concept for a CBM project.
(*Sources: IHS QUE$TOR, KAPSARC research.*)

After the project archetype was completed and adjusted, we were able to estimate a project cost in current USD and discount it to the calibration year by applying the CAPEX and OPEX indices provided by IHS. We adjusted the costs by the amount of subsidy (0.2 RMB/m^3) that CBM producers received according to the Chinese policy. Resulting cost estimations are presented in the Table A3-5.

Table A3-5
Estimated costs of an archetype CBM project.
(*Sources: IHS QUE$TOR, KAPSARC research.*)

CAPEX $/kcm	OPEX $/kcm	Decommission $/kcm	Total $/km	OPEX with subsidies $/kcm	Total with subsidies $/kcm	Number of projects
100.4	79.7	12.9	193.0	47.2	160.5	54

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