Pathways to Shale Gas Development in Asia-Pacific

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Foreword

Following the Asia-Pacific Economic Cooperation's mission of promoting economic prosperity in a sustainable way, this research document proposes a policy framework to understand the major factors involved in the commercial production of shale gas, with the aim of outlining a set of general challenges and opportunities which were applied to six member economies.

Many economies are expanding the utilization of natural gas over other fossil fuels in order to reconcile their growing energy needs with lower carbon emissions. This shift presents an opportunity for natural gas to become a bridge fuel as the share of renewable energy continues to grow in the primary energy balance. The Asia-Pacific region is at an energy crossroads, however, for this energy shift depends on overcoming the barriers ahead in trading and producing more gas.

The development of shale gas is expected to increase the domestic supplies of some Asia-Pacific economies to help them support a sustained demand for natural gas. It is also expected to enhance their energy security by allowing them to become less reliant on external sources. While the development of shale gas is largely at an early age outside the United States, the region is very fortunate to have among its members some of the economies with the most promising potential and with the most-advanced progress in developing their shale gas resources. This task however, entails higher risks and costs than the production of conventional gas, and in order to provide a net benefit to member economies and the region alike, it will need to be carried out in a cost-effective, environmentally sustainable and socially responsible way. The exploration of these issues serves as the backbone for this research document.

The contents of this document have been arranged as a series of papers which can be read in sequence to acquire a comprehensive understanding of shale gas development in the Asia-Pacific region; or separately in order to look for specific information or particular economy analyses. To accommodate users of different measurement systems, natural gas figures are displayed in metric and imperial units, and some textboxes with additional information and photographs are also included. While the research was developed from a public policy angle oriented toward leaders and decision-makers, it is expected to provide valuable insights for other disciplines and stakeholders.

I would like to thank the experts who have provided their knowledge to this document. The feedback gained in workshops, mission trips, and academic and professional events where this policy framework has been presented have greatly enriched the outcomes presented. As an independent research project however, the contents herein reflect only APERC's view and might change in the meantime depending on drastic external events or changes in the energy and policy agendas of particular economies.

Hopefully, this research document will become a cornerstone of the establishment of information exchange and international collaborative activities designed to accelerate shale gas development, leveraging APEC's economic and cooperative strengths.

Takato OJIMI
President
Asia Pacific Energy Research Centre

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EDITAGE and Juan Roberto Lozano-Maya

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As an independent effort, this research document does not necessarily reflect the views of the Asia-Pacific Economic Cooperation (APEC), its Energy Working Group, member economies, or those of the experts involved in this project. The views expressed herein are those of APERC alone as of the date of publication, and any errors and imprecision remain its responsibility.

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APEC member economies

Because APEC's mission is to support economic growth and prosperity, the term 'economies' is preferred to denote its members and avoid political connotations. This precept is extensive to other derived words: for example, the use of 'economy-wide' is preferred over 'national'.

The following are APEC's 21 member economies and their official abbreviations:

AUS	Australia
BD	Brunei Darussalam
CDA	Canada
CHL	Chile
CT	Chinese Taipei
HKC	Hong Kong, China
INA	Indonesia
JPN	Japan
MAS	Malaysia
MEX	Mexico
NZ	New Zealand
PE	Peru
PNG	Papua New Guinea
PRC	People's Republic of China
ROK	Republic of Korea
RP	The Republic of the Philippines
RUS	The Russian Federation
SIN	Singapore
THA	Thailand
USA	United States of America
VN	Viet Nam

Organizations

AER	Alberta Energy Regulator (Canada)
APEC	Asia-Pacific Economic Cooperation
APERC	Asia Pacific Energy Research Centre
CENAGAS	National Centre for Natural Gas Control (Mexico)
CFE	Federal Electricity Commission (Mexico)
CNH	National Hydrocarbons Commission (Mexico)
CNOOC	China National Oil Offshore Company (China's NOC)
CNPC	China National Petroleum Corporation (China's NOC)
EIA	Energy Information Administration (USA)
ENAP	Empresa Nacional del Petróleo (Chile's NOC)
FAO	Food and Agriculture Organization of the United Nations
IEA	International Energy Agency
MCOR	Penn State University Marcellus Center for Outreach and Research
MEMR	Indonesia's Ministry of Energy and Mineral Resources
MIGAS	Indonesia's Directorate of Oil and Gas
Pemex	Petróleos Mexicanos (Mexico's NOC)
Pertamina	Indonesia's NOC
Sener	Mexico's Ministry of Energy
Sinopec	China Petrochemical Corporation (China's NOC)
WRI	World Resources Institute

Miscellaneous

CBM	Coalbed Methane
CDN	Canadian Dollar
CSG	Coal Seam Gas
CEOPs	Special Operations Contracts (Chile)
DMO	Domestic Market Obligation
FSRU	Floating Storage Regasification Unit
IOC	International Oil and Gas Company
IRMS	Integrated Resource Management System
JSA	Joint Study Agreement
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
NOC	National Oil and Gas Company
PSC	Production Sharing Contract
R/P	Reserves to Production Ratio
RIG framework	Access to Natural **R**esources, **I**nfrastructure and Operations, and **G**overnance
RMB	Chinese Renminbi (China's currency)
USD	United States Dollar
WCSB	Western Canadian Sedimentary Basin

Energy units and conversions

Bcf	Billion cubic feet
Bcm	Billion cubic metres (10^9 cubic metres)
BTU	British Thermal Unit
Mcf	Thousand cubic feet
Tcf	Trillion cubic feet
Tcm	Trillion cubic metres (10^{12} cubic metres)

From	*To cubic metres of natural gas*	*To billion cubic feet of natural gas*	*To million tonnes of oil equivalent*
		Multiply by	
1 billion cubic metre of natural gas	**1**	**35.315**	**0.9**
1 billion cubic feet of natural gas	**0.028**	**1**	**0.025**
1 million tonnes of oil equivalent	**1.111**	**39.239**	**1**

Please note that due to the amplitude of crude oil types and the varying energy contents of the natural gas stream, these factors must be seen as approximate equivalents.

Executive summary

In order to decouple economic growth from carbon emissions, APEC economies have promoted the expansion of natural gas in their energy balances, with the aim of shifting away from the predominance of oil and coal. Given the rapid depletion and geographical concentration of proved reserves of natural gas, many economies, several of which are APEC members, have looked forward to developing their shale gas resources, due to their wider geographical distribution, their inferred magnitude (several times their own reserves), and the game-changing experience seen in the United States.

APEC Leaders have recognised this potential and aim to deepen the region's knowledge on the development and risks of shale gas. Shale gas development might provide economies enough room to support a less-carbon-intensive energy transition to more sustainable fuel options. In many cases, natural gas can co-exist with the expansion of renewable energy, which for some economies could represent an attractive opportunity to turn shale gas into a bridge fuel that contributes to the development of cleaner and more reliable energy systems.

In practice however, commercial shale gas production outside the United States and a few economies is proving very challenging, due to the convergence of numerous obstacles. This raises questions as to whether other economies will be able to support an expanded shale gas production, and if so, to what extent and requiring what amount of time and resources.

Shale gas production is a multifaceted and lengthy process

In comparison to the production of conventional gas, shale gas generally takes more time and requires more infrastructure and capital investments. Furthermore, the risk is concentrated in the commercial viability of resources rather than in the discovery and exploration.

Despite its apparent novelty, shale gas development in the United States has been a multidisciplinary process, resulting from the evolving interdependence of long-matured variables and critical strategies which were aligned by the convergence of particularly favourable circumstances over more than two decades. While there is no magic formula to shale gas, the experience in the United States shows that some key elements seem to drive its development and explain the levels of progress achieved by different economies.

Using a common policy lens for shale gas development: The RIG framework

Because of this, it is suggested that APEC economies follow certain pathways more conducive to the development of shale gas resources, with their respective paces and scales of development contingent on their own priorities and contextual characteristics. To that end, a framework was proposed which consists of several specific factors grouped in three major categories: Access to Natural Resources, Infrastructure and Operations, and Governance. The framework was termed RIG in consideration of each one of these components.

The RIG framework acknowledges that while its three components are necessary for shale gas development, it is governance which affects the economic and institutional incentives which induce the development and performance of infrastructure and technology. Better technology and infrastructure are likely to result in more efficient operations and recovery factors which will in turn, increase the size and productivity of the shale gas resources deemed to have commercial potential. The RIG framework was applied to the analysis of six APEC economies looking forward to or already engaged in some stage of shale gas production.

Australia: Current shale gas production is less competitive than other gas resources

Despite its legacy of mineral extraction and conventional oil and gas production, Australia must still exert a great deal of effort if it is to bring its shale gas to the markets cost-effectively in comparison with other types of gas resources. Significant shale resources lie across Australian basins and commercial production has been achieved, yet it remains unclear how much of this potential can be brought to markets given the exploration efforts underway, not to mention the constraints on technology and capital. Limited access to transmission infrastructure and a shortage of drilling capacity are other major challenges; in some basins, inadequate water supplies could also delay some projects.

The existence of several conventional and unconventional gas resources produced competitively in Australia might discourage the massive development of shale gas, at least in the short and medium terms, or until its cost-efficiency improves and new market demand expands. With its profile as a net gas exporter economy, much of Australia's shale gas development will depend on external market demand, just as much as its current coalbed methane output is oriented to LNG exports.

Canada: Shale gas growth depends on the search of new markets

With a strong vocation for the development of energy resources, Canada's natural gas production is progressively giving way to the extraction of shale gas. Although the access to shale gas differs across the economy's jurisdictions, in those provinces with a legacy of oil and gas development where shale gas is more abundant, there is a firm commitment to promote its massive development. In terms of infrastructure and operations, Canada's long-established oil and gas industry has disseminated practices to operate safely and in environmentally responsible ways, and its robust capabilities and oilfield services have underpinned the commercial production of shale gas.

In terms of governance, the two provinces of Western Canada provinces with ongoing shale gas production (Alberta and British Columbia) have devised dedicated fiscal regimes which provide incentives for producers in step with the market's maturity, framed by a regulatory system designed to provide certainty and minimise risks. In spite of the positive signals in Western Canada, due to the rising natural gas production in the United States, Canadian shale gas production will be increasingly driven by other export markets, most likely in Asia.

Chile: Geography and infrastructure remain the major barriers

Chile has looked forward to underpinning its natural gas demand with a more ambitious development of its domestic resources, which are scarce but might increase if unconventional gas is produced. While no shale gas exploratory or development activities have been carried out in Chile so far, the industry has taken its first steps towards understanding these resources, including their assessment and the use of technology necessary to produce them cost-effectively.

While oil and gas field services are scarce and industry practices and regulations are limited, the lack of gas-to-market infrastructure between the Magallanes region and the rest of Chile remains the largest barrier to expanding the scale of shale gas production. Increasing the output of shale gas will largely depend on the economic incentives granted to producers and on surmounting the tremendous logistic challenges presented by the Chilean territory and its natural gas infrastructure. Because of this, Chile has been exploring options to secure its gas supply more reliably and cost-effectively, including the import of LNG based on the shale gas produced in the United States.

China: Shale gas development has fallen short of ambitious official targets

As one of the major economies in the Asia Pacific region and the world, China's fast growth and the composition of its energy demand have resulted in a particularly high carbon intensity, attracting global concern. This has called for an increased use of natural gas in its primary energy mix; nonetheless, energy security has become critical as China is increasingly dependent on external sources of natural gas. To that end, in the last few years the Chinese government has attempted to increase its resource base with the aid of an ambitious strategy for shale gas.

While several infrastructure and operations challenges are present, those related to governance might be the most challenging. Several Chinese governmental agencies are in charge of issues related to shale gas, creating not only additional layers of administrative burdens and lengthier processes, but also leaving some powers undefined or subject to vague interpretations. Fundamentally, the main hurdle is a generalised lack of regulations to bring certainty to operators and address other issues of concern, including the legal regime to grant operators access to these resources. Basically, China's strategy has focused so much on the industry that it has overlooked other concerns of interest for other stakeholders which if left unaddressed, might turn into significant future barriers.

Indonesia: The current framework might be too rigid to support a faster pace of development

Indonesia looks forward to meeting its rising natural gas demand while offsetting the natural decline of its aging conventional fields and maintaining its status as an LNG exporter. Owing to this, the economy has encouraged a more active development of its vast unconventional resources including shale gas. In particular, governance might be the economy's largest deterrent to an accelerated future shale gas production.

The restrictions imposed by the fiscal regime on the financial and operational flexibility required by operators (such as production sharing contracts), the exhausting and delaying typical regulatory processes they must endure, and particularly, the uncertainty on the specific rules affecting shale gas development, provide little economic and institutional incentives to assume an optimistic scenario. Moreover, shale gas production is still in its infancy, and its development will ultimately depend on its cost-competitiveness against conventional gas and coalbed methane. Significant development might not occur within a decade.

Mexico: Will shale gas live up to the expectations of its energy overhaul?

In step with an unprecedented appetite for electricity generation purposes, Mexico's natural gas demand has grown robustly in the last few years, but the economy has increased its dependence on external sources, due to its inability to expand its domestic gas production accordingly. Since 2011 Mexico has looked to shale gas with the aim of strengthening its natural gas production, but no significant progress could be made given the structural conditions at the time. A sweeping energy reform in 2013 transformed this outlook, opening the door to private participants with the aim of reversing the industry's chronic shortfalls and underinvestment from decades of monopoly.

With the energy reform legally approved, Mexico's largest challenge now remains in making it operational. Indeed a remarkable breakthrough, Mexico's energy reform will take years to shape a more competitive industry, including the development of shale gas. While it is very likely that the domestic and international natural gas industry will develop Mexico's domestic shale gas resources at some point, this may take longer to realise than official schedules, especially as pipeline gas imports from the United States remain inexpensive. Much of Mexico's shale gas development is very uncertain until the actual tenders occur.

Is worldwide shale gas development running out of gas?

No, but economies are increasingly realizing that the scale and pace of development of their own shale gas resources will be driven by their respective contextual settings. This means that despite the lure of the remarkable outcomes seen in the United States, shale gas development outside that economy will take more time and attain more moderate output levels.

Nonetheless, a combination of effective policies, infrastructure development and good governance principles could help many economies in the Asia Pacific region to improve these issues and let shale gas become a more significant contributor to their natural gas production.

- Leveraging their large domestic natural gas markets, China, Indonesia and Mexico could extract their promising shale gas resources in step with the development of infrastructure, the provision of policy incentives and the implementation of effective regulations.

- In Australia and Canada, the acceleration of shale gas production will hinge on export markets. In the former, it will also depend on the cost-effectiveness of shale gas in comparison to abundant supplies of conventional gas and coalbed methane.

- In contrast to these economies, and in spite of the potential benefits to its energy security, Chile's major hurdle in developing its potential shale gas resources lies in its geography, which complicates the competitive access to them and the deployment of infrastructure.

On this subject, economies must assess holistically the components and factors involved in the production of shale gas. This will help them better understand the elements involved in such tasks in order to define their political position, including the decision not to pursue the development of shale gas resources. Nonetheless, in those economies opting to produce shale gas , the political motivation in place guided by the RIG framework will determine the breadth, depth, and timeframes involved in accessing those resources, along with the infrastructure required and especially, the good governance precepts to be implemented. Governance is considered critical to promote enduring win-win arrangements bound to positively affect the social response, the industry's capabilities, and the government's policies regarding shale gas development.

It is hoped that the exploration of these issues guided by the RIG policy framework will also enhance regional dialogue and cooperative mechanisms across the Asia-Pacific region on the exchange of experiences, information, insights, regulations and industry practices.

1 Introduction

In recent years the energy landscape has grown more complex, with several priorities intertwined in the global policy agenda. In addition to the quest to meet rapidly growing energy demand, the significant contribution of the current patterns of energy production and consumption to climate change have driven an energy shift towards the use of resources with lower carbon intensities.

While renewable energy has helped reduce carbon emissions, the share of fossil fuels is still dominant in the global primary energy balance. Consequently, many economies are looking forward to shifting away from the use of coal and oil to a more intensive utilization of natural gas, which produces less carbon dioxide emissions on an energy unit basis. Nonetheless, this transition hinges on a rising natural gas supply which currently faces the constraints of rapid depletion and geographical concentration.

With three economies alone accounting for a quarter of the production and half of the proved reserves of natural gas worldwide, increased demand for natural gas calls for the addition of supplies which present a larger and more extensive distribution, albeit involving greater technical complexity and higher costs than conventional mainstream resources.

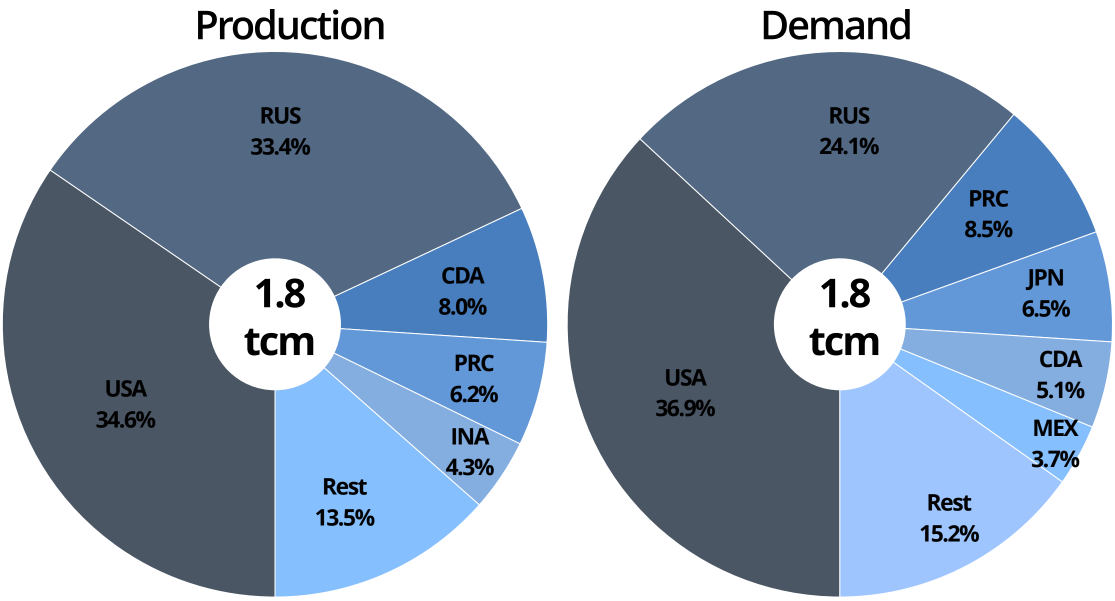
Among these unconventional gas resources, shale gas in particular has recently caught global attention due to its role as the catalyst of the energy balance in the United States. While the APEC region accounts for more than half of the global consumption and production of natural gas, it represents only a little more than one-third of proved reserves. Greater natural gas output from shale gas development could allow the APEC economies holding these resources to improve their energy balances, to become less reliant on energy imports and even export their surpluses. From a broader perspective, shale gas could reconcile the needs of energy security, accessibility and sustainability in the region as a whole.

APEC in the global natural gas landscape

Grouping together some of the largest natural gas producers and consumers, the APEC region is highly relevant to the global natural gas market. Natural gas provided roughly 21% of APEC's total primary energy needs by the end of 2012, very similar to its share in 2000.

From 2000 to 2012, primary demand for natural gas in APEC grew 37.1%, equivalent to an average rate of 2.7% per year, passing from 1.3 to 1.8 trillion cubic metres. This volume represented 53% of the worldwide natural gas demand and 74% of the total liquefied natural gas (LNG) imports in 2012 (BP, 2013). As seen in Figure 1, the United States, Russia, China and Japan are the largest consuming economies of natural gas in APEC, accounting altogether for little more than three-quarters of the region's primary demand in 2011. While the amount of natural gas demand in the region was roughly equivalent to its production in 2012; APEC as a whole was a net exporter of natural gas.

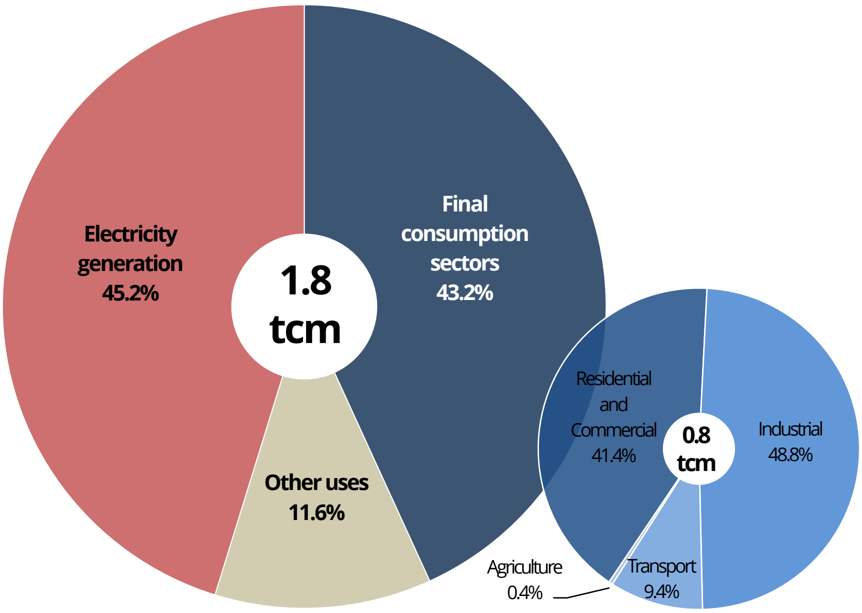
Figure 1
APEC's primary production and demand of natural gas by share of largest economies, 2012



Primary demand does not include stock changes.
Source: APEC EGEDA (2014).

As shown in Figure 2, little more than 45% of the primary natural gas demand consumed in APEC in 2012 was used for electricity generation, 43.2% was absorbed by end users in different economic sectors, and the rest was used or lost in other transformation processes. The expansion of gas demand for power-generation purposes in the APEC region from 2000 to 2012 grew at an average rate of 4.1%, much higher than in the end-use sectors, at 0.7%.

Figure 2
APEC primary and final demands of natural gas by use, 2012



The small pie is proportional to the larger pie's share of final consumption.
Source: APEC EGEDA (2014).

On an economy basis, from 2000 to 2012, the highest growth rates of natural gas for electricity generation purposes were observed in the Philippines, Peru and Singapore, with respective annual average rates of 62%, 27% and 19%. Almost three-quarters of the natural gas for electricity generation in APEC were consumed by Russia, the United States and Japan.

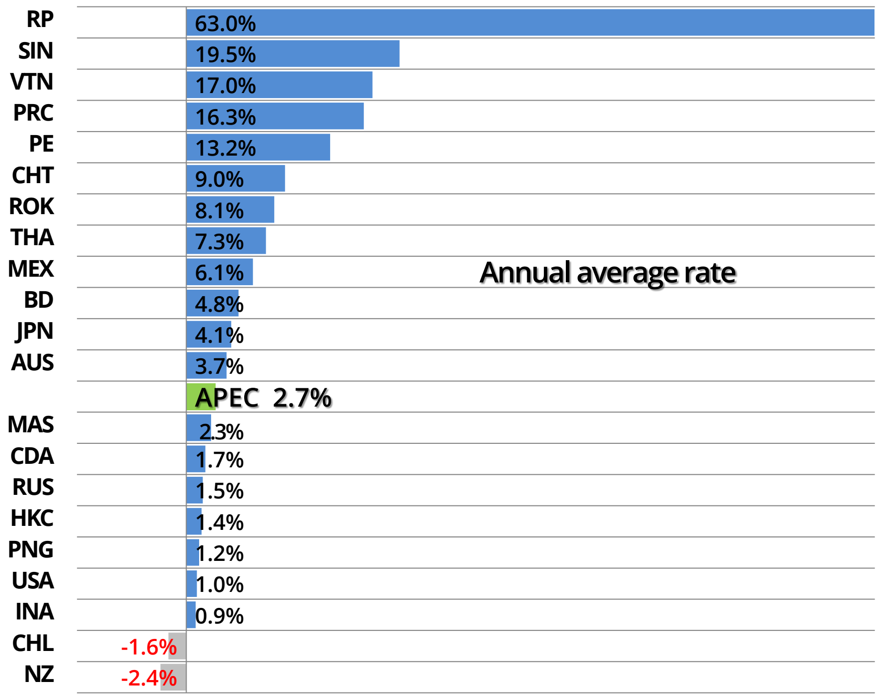
As for the sectors making up the rest of the final demand for natural gas, as shown in Figure 2, APEC's largest consumer in 2012 was the industry, accounting for almost 49%; followed by the residential and commercial sectors combined, with little more than 41%; the transport sector, with 9.4%; and marginal consumption in the agriculture sector. It is worth noting that a large amount of the natural gas consumption is not in the form of vehicle fuel, but rather as pipeline fuel at compressor stations. From 2000 to 2012, the fastest average annual growth rate was experienced in the agriculture sector, (7.4%), followed by transport (2.7%), and industrial (1.2%). In the residential and commercial sectors altogether, the demand for natural gas decreased by 0.3%.

At the end of 2012 the United States, Russia, China and Canada concentrated APEC's natural gas consumption in the final use sectors. The joint share of these four economies accounted for nearly all of the regional demand for natural gas in the transport and agriculture sectors, almost 90% of the demand in the residential and commercial sectors, and 75% of the demand in the industry sector.

Primary natural gas consumption has increased in most APEC economies in step with their economic growth and the development of different markets for this fossil fuel. As shown in Figure 3 the largest economy-wide average growth rates in the primary demand of natural gas demand were observed in the Philippines, with an average growth of nearly 63% from 2000 to 2012, followed by two-digit annual average growth rates in Singapore, Viet Nam, China and Peru.

Figure 3

APEC's growth in primary demand of natural gas by economy, 2000–2012



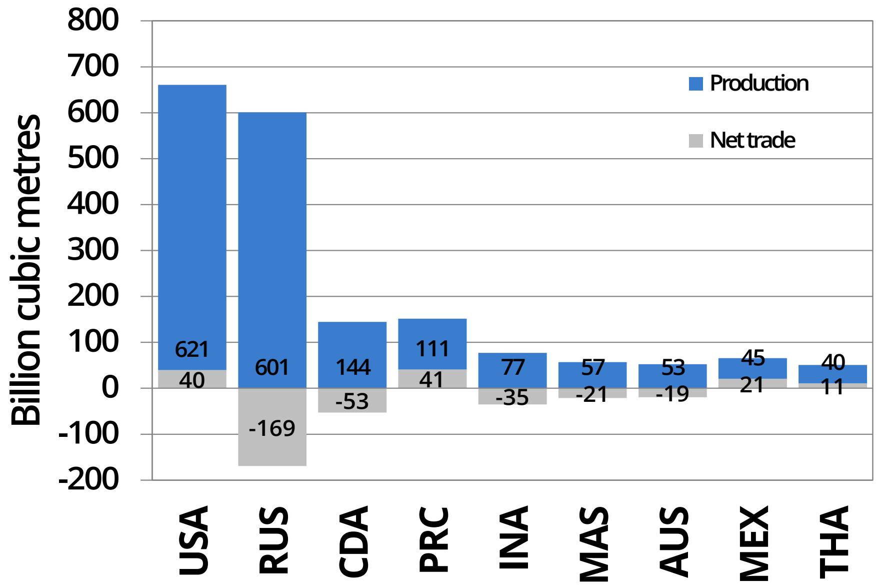
Source: APEC EGEDA (2014).

Smaller growth rates were observed in the other APEC economies, with only Chile and New Zealand having decreased their gas consumption in comparison to 2000 levels, largely as a result of the diversification in their primary energy balances. In the case of Chile, a growing reliance on coal-based generation and the introduction of LNG has decreased its high reliance on pipeline imports, while New Zealand's gas demand has followed the declining domestic production, given the economy's inaccessibility to gas imports.

In terms of production, the APEC region provided close to 54% of the world's gas output, having produced 1.8 trillion cubic metres in 2012, roughly equivalent to an average growth of 1.9% per year since 2000. By economy, the largest annual growth in the domestic production of natural gas was observed in the Philippines, with an annual average of 63%, followed by Peru (19%), Viet Nam (16%), and China (12%). Despite the rapid growth of gas production in these economies, the United States and Russia remained the largest producers, with each one accounting for about one-third of the region's total output as depicted in Figure 4.

Historically, Russia has been the leading gas producer in APEC, but by the end of 2012 the United States had surpassed it by more than 3%, chiefly as a result of its growing shale gas output. The remainder of APEC gas production was spread in much smaller proportions across Canada, China, Indonesia, Malaysia and other gas-producing economies.

Figure 4
APEC primary gas demand by origin, largest gas-producing economies, 2012

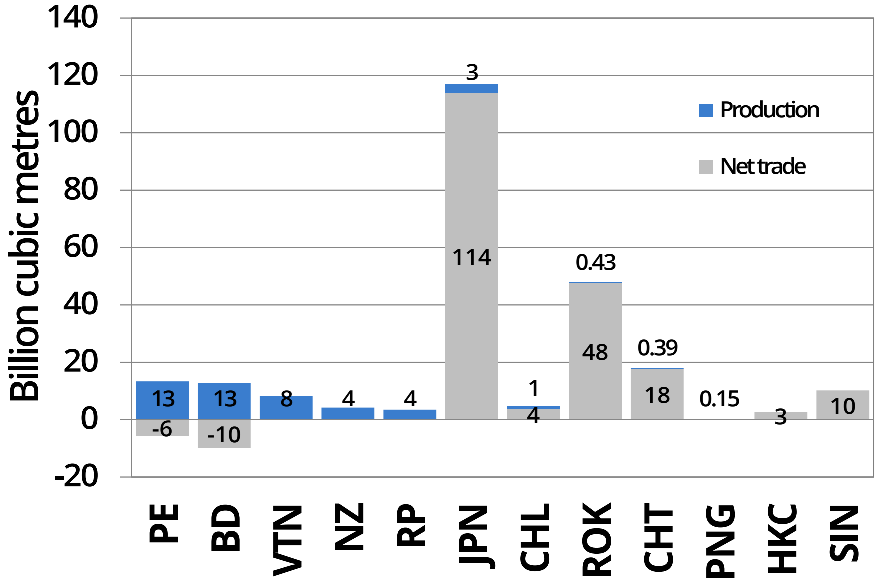


Net trade: positive values indicate net imports, negative values indicate net exports.
Imports and exports include pipeline and LNG.
Source: APEC EGEDA (2014).

With reference to this, all APEC member economies (with the exceptions of Hong Kong and Singapore) are gas producers, although in many cases at insufficient levels to meet their respective demands, calling for imported natural gas inflows coming either by pipelines from nearby economies or by LNG ships from remote locations. According to the gas balance profiles by economy, the group of net gas-importing economies is the largest in APEC, formed in decreasing order by: Japan; the United States; Korea; China; Chinese Taipei; Mexico; Thailand; Singapore; Chile; and Hong Kong.

Figure 5

APEC primary gas demand by origin, smallest gas-producing economies, 2012

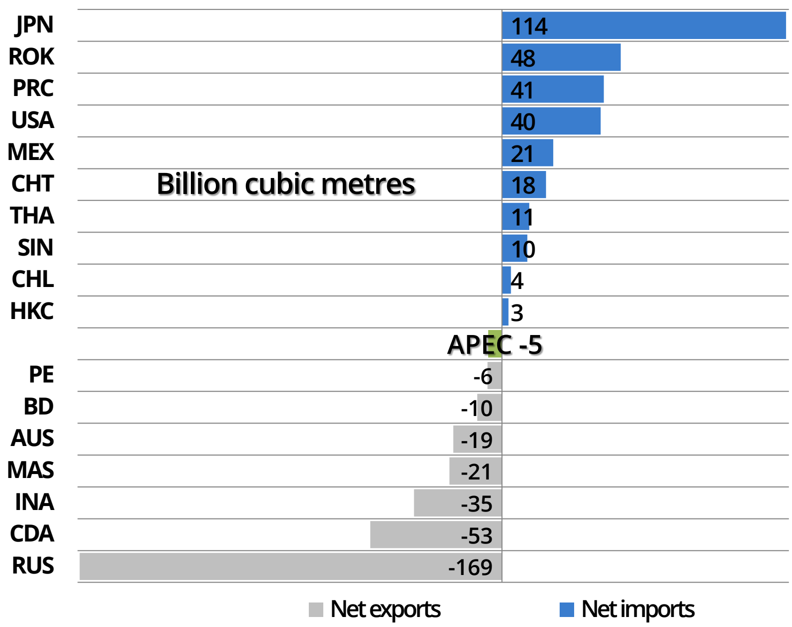


Net trade: positive values indicate net imports, negative values indicate net exports.
Imports and exports include pipeline and LNG.
Source: APEC Energy Database (2014).

Aside from the total dependence of Hong Kong and Singapore on external gas sources, the volume of net gas imports as a share of the primary demand differed across APEC economies in 2012. In Chinese Taipei, Japan and Korea it surpassed 95%; in Chile it surpassed 75%; in Mexico, Thailand and China it went above 20% and only in the United States was it 12%.

Figure 6

APEC net gas balance by member economy, 2012



Net trade: positive values indicate imports, negative values indicate exports.
Imports and exports include pipeline and LNG.
Source: APEC EGEDA (2014).

Not surprisingly, Japan and Korea stand as the two largest consumers of LNG. The volume consumed by these two economies represented almost half of the worldwide total gas inflows through this modality in 2011 (BP, 2013). On the other hand, Russia, Canada, Indonesia, Malaysia, Australia, Brunei and Peru were APEC's net gas-exporting economies. In these economies, the volume of net gas exports as a share of their production in 2011 amounted to 29% in Russia, approximately 40% in Australia, Canada and Malaysia, approximately 45% in Peru and Indonesia, and 78% in Brunei.

In addition to the group of net gas importers and exporters in APEC, the economies of New Zealand, Papua New Guinea, the Philippines and Vietnam had no gas trade flows at all by 2012. While there are many reasons for this, as a whole, the early stage of the development of their domestic gas markets reduced the need for external supplies. Another major hurdle, particularly relevant under insular conditions, was the lack of infrastructure to send or receive natural gas in the form of LNG.

In light of these considerations, the gas profiles of each APEC member economy appear in Table 1. Gas markets are increasingly open, and as a matter of reference, the liquefaction terminal of Papua New Guinea started exporting natural gas produced domestically in May 2014.

Table 1
Natural gas profile by member economy

Net trade position	Domestic gas production	
	Present	Not present
No trade	New Zealand Papua New Guinea* The Philippines Viet Nam	
Exporter	Australia Brunei Darussalam Canada Indonesia Malaysia Peru Russia	
Importer	Chile China Chinese Taipei Japan Korea Mexico Thailand United States	Hong Kong Singapore

Note: Classification based on 2012 data.
*Became a gas exporter in 2014
Source: APEC EGEDA (2014).

APEC's natural gas agenda

The importance of natural gas for APEC is supported by several projections which identify China and the Southeast Asian economies among the main growth drivers of the future global energy demand. The rapid economic development and urbanization in these economies in combination with their shortage of domestic energy resources will call for rising energy imports with a lower carbon footprint.

To illustrate the possible benefits to be derived from an expanded gas production, APERC (2013) projected that a 30% higher gas output in the region could reduce its carbon dioxide emissions by 22% in the electricity sector and by 8% overall in comparison to a business-as-usual scenario. To that end, it was assumed that constraints on the gas trade and the development of potential gas resources were suddenly removed, without price changes. Even though the economy-level assumptions underlying this scenario shown in Table 2 were very conservative, APERC's goal in assuming this 'High Gas' scenario was to assess the effect of developing additional domestic gas resources, some of them unconventional, to shore up energy systems with lower carbon emissions.

Table 2
Economy-level assumptions regarding additional gas production by 2035 in APERC's Energy Supply and Demand Outlook (5th Edition)

Economy	APERC's High Gas case assumptions	
	Type of additional gas development	Gas production increase by 2035 from BAU
Australia	Conventional and unconventional	3%
Brunei Darussalam	Conventional (marginal fields and deepwater)	315%
Canada	Conventional and unconventional	13%
China	Unconventional (shale)	28%
Indonesia	Conventional	67%
Malaysia	Conventional	36%
Mexico	Unconventional (shale)	28%
Papua New Guinea	Conventional	100%
Peru	Conventional	121%
Philippines	Conventional	1000%
Russia	Conventional	48%
United States	Conventional and unconventional	15%
Viet Nam	Conventional (deepwater)	57%
Japan, Korea, Thailand	No change from BAU	
APEC		**30%**

Source: APERC (2013).

Owing to the predominance of fossil fuels in the energy balances of its member economies and the lower carbon emissions from the use of natural gas, APEC's energy agenda has reflected the potential of unconventional gas resources to strengthen energy security and sustainability.

On June 2010, the APEC Energy Ministers gathered at Fukui, Japan, agreed to cooperate in enhancing joint energy security, promoting economic growth, and reducing carbon emissions through several mechanisms, including a more intensive utilization of natural gas. Aware of the supply expansion efforts required to raise the region's natural gas demand, the Energy Ministers strived to capture the energy security benefits underlying the development of new gas resources, particularly unconventional, for which they instructed the elaboration of an Unconventional Gas Census to

> ...evaluate the potential of unconventional resources and to recommend cooperative actions which could increase natural gas output, boost natural gas trade and use, and moderate natural gas prices to the extent appropriate both for producers and consumers in the APEC region... (APEC, 2010).

On June 2012 at their Meeting in Saint Petersburg in Russia, the APEC Energy Ministers committed to the promotion of cleaner energy options amid fossil fuels by fostering a more intensive utilization of natural gas in the energy balance of their respective economies.

Realizing the implications of such a strategy on the region's gas production, trade and infrastructure, and with the aim of identifying the opportunities and constraints for cooperation, it was decided to "review the current state and prospects of the energy markets, with emphasis on the role of natural gas in the total energy balance" (APEC, 2012a).

In September 2012 at Vladivostok, Russia, APEC Leaders ratified their commitments and agreed to carry out the following specific actions:

- Review the current state and prospects of energy markets of the APEC region, with a view to increasing the share of natural gas in the energy mix as one of the most widespread and cleanest-burning fossil fuels in the region, in order to facilitate the transition to a low-carbon economy without prejudice to other energy sources;
- Evaluate the production, trade potential, and environmental impact of shale gas and other unconventional natural gas resources;
- Promote steady investment in energy infrastructure, including natural gas liquefaction facilities, to increase energy security and economic growth in the APEC region;
- Promote activities to improve the response to oil and gas emergency situations in the APEC region (APEC, 2012b).

More recently, as of September 2014 in China, the APEC Energy Ministers supported the development of unconventional oil and gas in their economies, with an emphasis on the pursuit of scientific-based solutions to minimise the associated environmental impacts. Recognizing the novelty and complexity of unconventional oil and gas resources, a cooperative mechanism was encouraged to share best practices on the exploration and production thereof.

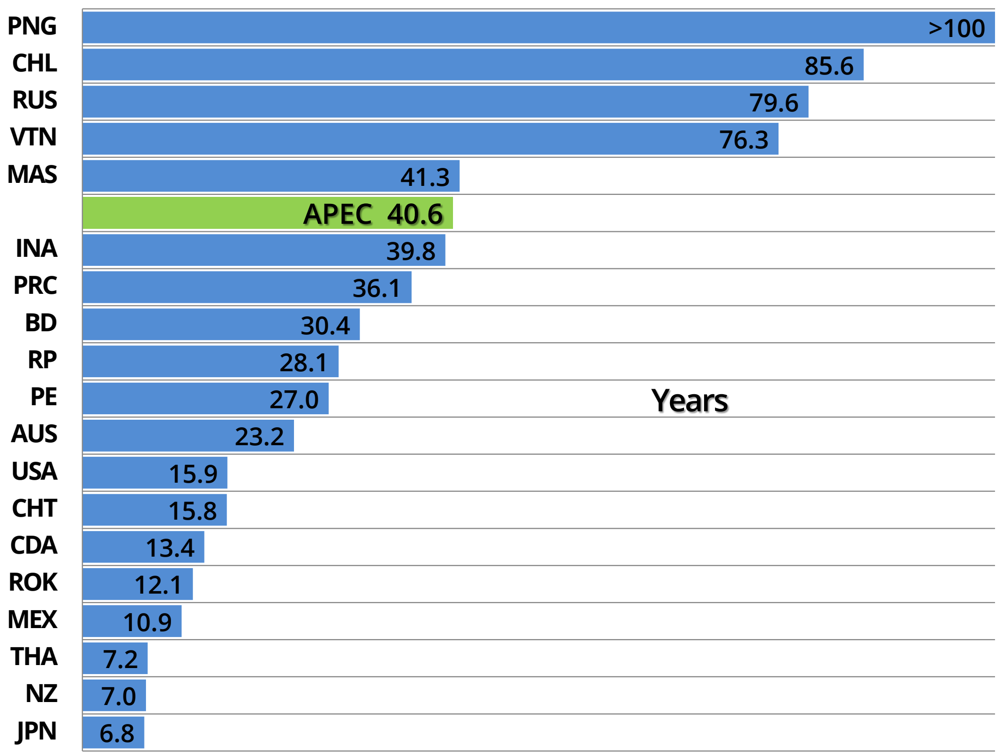
Shale gas enters the energy scene

The interest in developing unconventional gas resources, and particularly shale gas, is mainly driven by the inferred magnitude and wider distribution of these resources. According to preliminary estimates (EIA, 2013b), the size of technically recoverable shale gas resources in just one group of economies is larger than the proved global reserves of natural gas. Furthermore, shale gas resources seem to be better distributed than proved reserves of natural gas, of which more than half are currently held by Iran, Russia and Qatar alone (OGJ, 2013).

In terms of gas resources and in contrast to its high share of global gas production, APEC's conventional gas proved reserves of 73 trillion cubic meters in 2011 were equivalent to 37% of the total worldwide. From 2000 to 2012, the volume of proved gas reserves worldwide expanded 2.2%, but in APEC it only amounted to 1.1% per year. (OGJ, 2013)

Three economies possessed approximately 85% of APEC's proved gas reserves in 2012. Russia alone held 66% of APEC's proved gas reserves, followed by the United States (13.6%) and China (5.5%). In terms of the reserves-to-production ratio (R/P), as shown in Figure 7, the average in APEC was around 40 years in 2011, much lower than the average of 59 years worldwide. For most APEC economies, the relationship between gas reserves and consumption was below this average, and in some of them represented less than a decade, such as in New Zealand or Japan. It is worth mentioning that this indicator should be assessed sceptically, as domestic production represents only a fraction of demand in some economies with larger R/P ratios.

Figure 7
APEC natural gas reserves/production (R/P) ratio by member economy, 2012



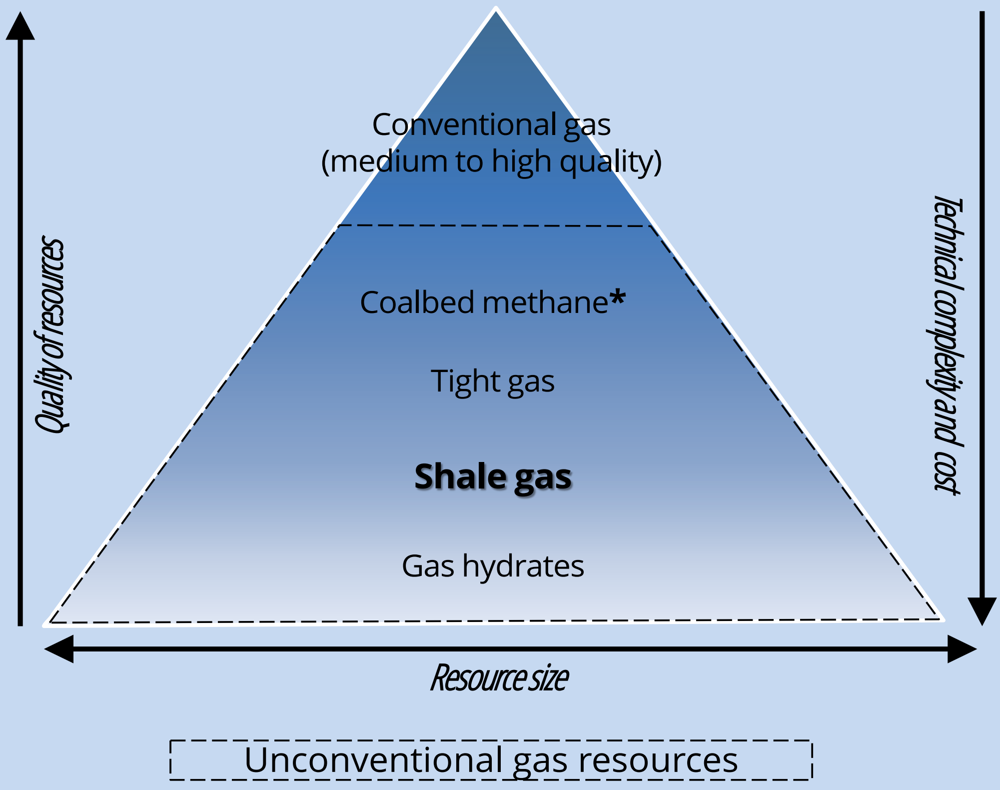
Proved reserves at January 1 2013. Hong Kong and Singapore lack of any gas reserves.
Source: APEC EGEDA (2014) and 'Worldwide look at reserves and production' (2013).

Textbox 1
Unconventional gas resources

The exact boundaries between conventional and unconventional gas resources remain somewhat blurry, although there are some geological distinctions between them. Conventional gas resources occur in discrete accumulations in structural traps, whereas unconventional gas resources lie in pervasive accumulations of low permeability, which usually lack of well-defined borders (Law and Curtis, 2002; Schmoker, 2002).

Because unconventional gas resources accumulate in large but diffuse volumes, they cannot be assessed in terms of individual countable pools, nor be produced in the same fashion as conventional gas. These characteristics make unconventional gas reservoirs a true production frontier. In the context of natural gas, the spectrum of resources spans conventional reservoirs with the highest quality and lowest costs of production. Unconventional gas resources are costlier to develop, yet far more abundant. Therefore, there is a trade-off between the quality and availability of gas resources, as graphically illustrated in the natural gas resource pyramid shown in Figure 8.

Figure 8
Natural gas resource pyramid



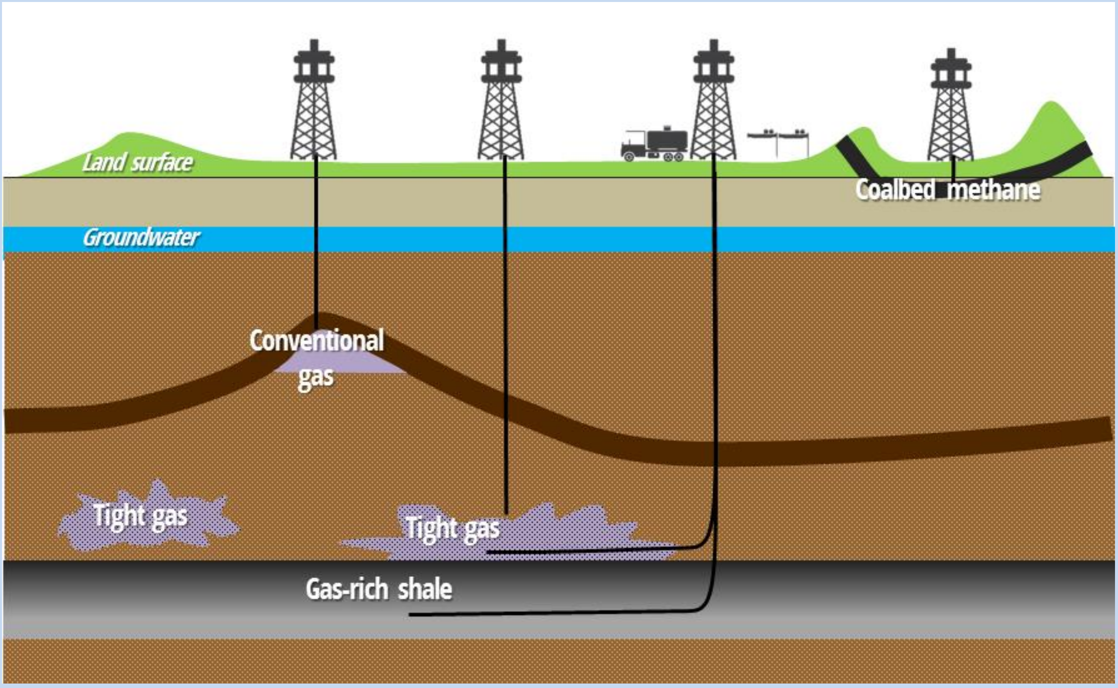
*Sometimes also referred as coal seam gas (CSG).
Source: Adapted from Holditch (2006).

Natural gas produced from shale formations is known as *shale gas.* As shales encompass a wide array of sedimentary clay-rich rocks, it is difficult to distinguish shale gas from other types of unconventional gas resources co-occurring in the geologic formations. (Speight, 2013). Nonetheless, shale gas is characterised by low to ultra-low permeability reservoirs with very little or no hydrocarbon migration, thereby acting as both source rock and reservoir (Curtis, 2002).

In contrast to the conventional gas extracted from sandstone reservoirs, the production of gas from shale formations requires more complex techniques. In this regard, the combination of horizontal drilling and hydraulic fracturing is largely credited as the major technological breakthrough underpinning the economical production of shale gas. A basic representation of these resources and the processes used to produce them are shown in Figure 9.

In comparison with vertical drilling, the use of horizontal drilling expands the contact with the shale formation to increase the volume of hydrocarbons ultimately recovered. As for hydraulic fracturing, which is commonly referred to as 'fracking', the injection of a mixture of water, sand and proppants cracks the shale formation and keeps its pores open to release the trapped gas. However, hydraulic fracturing requires larger volumes of water per well than conventional gas production.

Figure 9
Geological representation of natural gas resources



Note: Figure not to scale.
Source: Adapted from the United States Energy Information Administration (2014).

Moreover, the geology of shale gas reservoirs differs considerably and as their output declines faster, more wells are necessary to increase or maintain cumulative production levels. This in turn exceeds the regular demands for inputs, technology and skilled workforce, thus resulting in higher capital costs. In other words, unconventional gas involves more complexity and cannot be found using the same conventional methods (Zou, 2013).

Given these considerations, a larger gas resource base through shale gas development would underpin a higher gas demand across APEC. To provide a better idea of the size of these resources, the APEC Unconventional Natural Gas Census was sponsored by APEC's Energy Working Group and released in January 2013, with the aim of enhancing the information on the potential amounts of shale gas, tight gas and coalbed methane resources technically recoverable.

The Unconventional Natural Gas Census estimated APEC's technically recoverable unconventional gas resources by 2011 as 114.7 trillion cubic metres, of which 57%, equivalent to 65.8 trillion cubic metres, consisted of shale gas. This volume of shale gas resources, only available in a few APEC economies, was nearly equivalent to the region's total proved gas reserves in the same year.

By June 2013, the Energy Information Administration of the United States (2013b) released an updated assessment of technically recoverable shale gas and liquids resources in 42 economies. Unlike proved natural gas reserves, the concept of technically recoverable resources refers to the maximum amount of natural gas which could be produced with the current state of technology under appropriate policies and market conditions.

It must be mentioned that both studies were prepared by the same consulting company, and owing to the information available, the recovery factors assumed, and the number of basins included, they presented some differences in their economy estimates. However, both studies converged in their identification of some APEC economies among the largest holders of technically recoverable resources of shale gas in the world, as shown in Table 3.

As these global geological assessments are subject to a wide margin of uncertainty, their accurate qualitative and quantitative validation will depend on more specific studies; nonetheless, these findings still highlight the APEC region's potential to expand its gas supply through the development of its domestic shale gas resources.

In most economies, the volume of inferred shale gas resources is several times their current proved gas reserves. As reflected in Table 3 and Figure 10, the amount of technically recoverable shale gas resources in comparison to conventional proved reserves of gas is as high as 32-fold in Mexico, 14-fold in Chile, and 10-fold in Australia. Only in Thailand, Indonesia and Russia are their respective conventional proved reserves larger than their shale gas inferred resources.

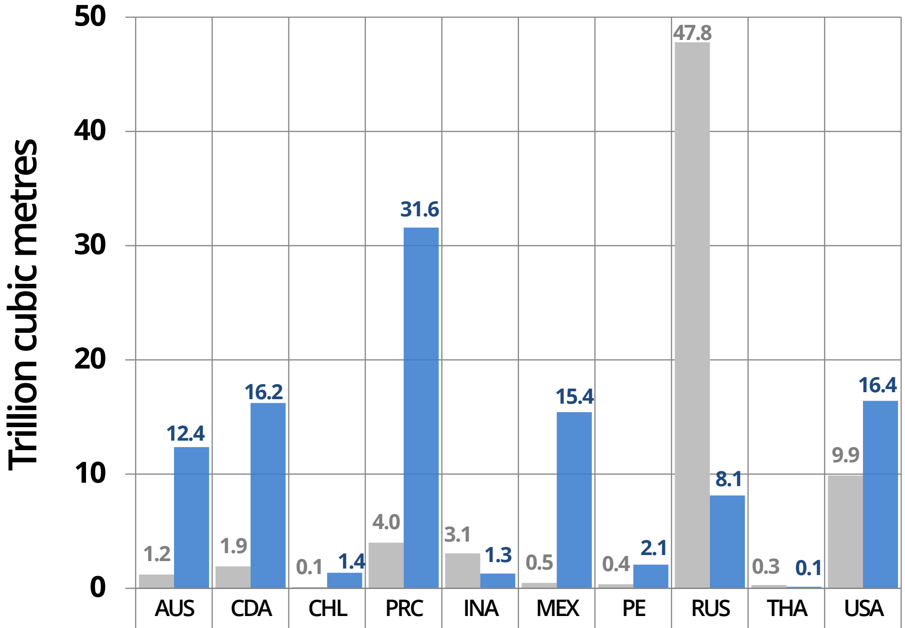
While reserves and resources are not directly comparable, as the former are a subset of the latter, the magnitude of the shale gas resources assessed has drawn significant attention. The overall amount of technically recoverable resources of shale gas in the 10 APEC economies deemed to hold these resources seems to be relatively equal if not larger, than the region's proved gas reserves. Therefore, even the development of a small share of these shale gas resources would represent many years of current gas demand in most economies, theoretically over a 100 years in many of them.

Table 3
Natural gas proved reserves and shale gas resource base in APEC economies

Economy/region	Natural gas production 2012,	Natural gas proved reserves* 2012,	Shale gas resources (technically recoverable)	
			APEC Unconventional Natural Gas Census, 2013	EIA, 2013**
Billion cubic metres (trillion cubic feet)				
Australia	52.6 *(1.9)*	1,218.7 *(43)*	11,300 *(399.1)*	12,374.5 *(437)*
Canada	144.4 *(5.1)*	1,930.2 *(68.2)*	2,550 *(90.1)*	16,225.6 *(573)*
Chile	1.1 *(0.04)*	98 *(3.5)*	-	1359.2 *(48)*
China	110.8 *(3.9)*	3,999.9 *(141.3)*	25,100 *(886.4)*	31,573.3 *(1,115)*
Indonesia	77.2 *(2.7)*	3,069.5 *(108.4)*	-	1,302.6 *(46)*
Mexico	44.8 *(1.6)*	487.7 *(17.2)*	8,410 (297)	15,432.7 *(545)*
Peru	13.3 *(0.5)*	359.6 *(12.7)*	2,070 (73.1)	-
Russia	600.9 *(21.2)*	47,805.3 *(1,688.2)*	-	8,126.9 *(287)*
Thailand	39.7 *(1.4)*	284.9 *(10.1)*	-	141.6 *(5)*
United States	621 *(21.9)*	9,877.2 *(348.8)*	16,410 (579.5)	16,055.7 *(567)*
APEC Total* **	**1,705.9** ***(60.2)***	**69,131** ***(2,441.3)***	**65,840** ***(2,325.1)***	**102,591.9** ***(3,623)***
World	**3,291.3** ***(116.2)***	**194,981.2** ***(6,885.7)***	**-**	**203,909.6** ***(7,201)***
APEC economies as share of world (in %)***	**52%**	**35%**	**-**	**50%**

*Proved reserves at January 1 2013.
**For this column, world total refers to 42 economies assessed.
***This APEC total refers to the 10 APEC economies shown in this Table.
Source: For production, APEC EGEDA (2014) individually and BP (2013) globally; for proved reserves, 'Worldwide look at reserves and production' (2013); shale gas resources from APEC Energy Working Group (2013), and EIA (2013b).

Figure 10
Proved natural gas reserves and shale gas resources in APEC economies



	AUS	CDA	CHL	PRC	INA	MEX	PE	RUS	THA	USA
A - Proved gas reserves*	1.2	1.9	0.1	4.0	3.1	0.5	0.4	47.8	0.3	9.9
B - Shale gas resources**	12.4	16.2	1.4	31.6	1.3	15.4	2.1	8.1	0.1	16.4
B times A	10.2	8.4	13.9	7.9	0.4	31.6	5.8	0.2	0.5	1.7

*Proved reserves at January 1 2012.
**Refers to the largest value of technically recoverable shale gas resources between the estimates of EIA (2013b) and where applicable, APEC Energy Working Group (2013).
Source: APEC Energy Working Group (2013), EIA (2013b) and 'Worldwide look at reserves and production' (2013).

Global development

In addition to the inferred scale and distribution of shale gas resources, the game-changing experience observed in the United States has spurred the interest of several economies in following a similar path to develop their own resources. Shale gas has rapidly become the major driver for an economy-wide energy transformation in the United States. From 2000 to 2012, shale gas production grew 25-fold, passing from 9 to 230 billion cubic metres, roughly equivalent to an average rate of 31% per year.

This expansion has resulted not only in a larger contribution of shale gas to the total gas production, from nearly 2% in 2000 to roughly 34% by 2012, but it has also allowed total gas production to maintain steady growth despite the falling output of conventional gas (EIA, 2013a). The share of gas imports in the United States has also decreased, from 15% in 2000 to 6% by 2012. This has affected market prices as well, with the Henry Hub price falling from 4.2 USD per million BTU in 2000 and 8.9 USD per million BTU at its peak in 2008 to 2.8 USD per million BTU by 2012 (BP, 2013).

The United States has capitalised on this boom. Its resulting low natural gas prices have led to the revival of certain energy-intensive industries, which have become more competitive in the global arena and in turn brought about positive economic spillover effects. In addition, the displacement of coal by electricity generation has reduced emissions of carbon dioxide and greenhouse gases, and the co-production of liquids and oil in shale formations has reversed the energy trends expected until some years ago, opening the door for the United States to become an energy exporter in the medium and long terms. Moreover, sustaining such a scenario will not only directly affect the energy security and policies of the United States, but it is very likely that it will also affect its foreign policy, entailing deeper implications for global geopolitics.

In the light of these landmark changes, which have been named the 'shale gas revolution', the United States has arisen as the major example of the benefits associated with shale gas development, with many economies following suit or considering doing so in the hope of replicating these outcomes. In the short term, a rising supply of natural gas would indeed help many economies to diversify their power generation portfolios and break away from the utilization of coal and oil, reducing carbon emissions and the economic risks associated with the latter's price volatility. In the long term, the development of domestic shale gas resources could help economies reduce their reliance on gas imports, strengthen their energy security, and mitigate climate change.

In practice, however, shale gas production outside the United States and a few other economies (including Canada and China in APEC, as well as Argentina) is proving very challenging due to the convergence of numerous barriers hindering its progress on a commercial scale. This raises questions as to whether other economies will ever be capable of expanding their shale gas production, and if so, to what extent and requiring what amount of time and resources.

In any case, the development of increased shale gas output in APEC cannot be taken for granted, as it will need to be carried out in a cost-effective, environmentally sustainable, and socially responsible way, and which ultimately allows it to contribute to the energy security of the member economies involved. The exploration of these issues is the foundation for this research report.

A great deal of uncertainty remains as to whether the United States 'shale gas revolution' will reach other economies, and if so, to what extent and requiring what amount of time and resources.

Purpose and scope of the document

The main objective of this research is to devise a policy framework for the commercial development of shale gas, including its application in a number of APEC economies believed to possess this resource. In so doing, the document underscores a number of challenges in each of these economies and outlines some recommendations to address them.

The information in this document is expected to enhance the knowledge on shale gas issues and to influence economy-level policies related to shale gas development across the Asia-Pacific region. This knowledge also paves the way for the future establishment of cooperative mechanisms to explore and promote opportunities to produce shale gas hinging on the region's economic strengths. Moreover, this exercise would be a response to the initiative put forward by the APEC Energy Ministers on September 2014 to share best practices on unconventional gas production.

The selection of the APEC member economies for analysis in this report was based firstly on geological information which supported the existence of shale gas resources in each of them. For this reason, the economies of Brunei Darussalam, Hong Kong, Japan, Korea, Malaysia, New Zealand, Papua New Guinea, the Philippines, Singapore, Chinese Taipei and Viet Nam were left out of this report, given the lack of such estimates in the APEC Unconventional Gas Census (2013) and EIA's (2013b) reports.

Some of the remaining economies with inferred shale gas resources were subsequently excluded, mainly due to the lack of promising indications for the economic development of such resources, at least in the short and medium terms, under the following assumptions:

- Russia was excluded from the report given its huge conventional gas reserves, its global position as one of the world's largest producers, and the smaller size of the available estimates of its shale gas resources in comparison to its proved conventional gas reserves. Fundamentally, these issues led to the assumption that Russia might not have an urgent need to develop its shale gas.

- Peru was not included in this report, given that its recent history as a conventional gas producer and its focus as an exporter make it unlikely to be interested in developing its shale gas resources. Peru's conventional gas production soared when the Camisea field development started in 2004, allowing the economy to become an LNG exporter in 2010. With roughly 43% of its domestic production shipped out to other markets by 2012, Peru is currently undertaking significant efforts to expand its domestic markets and consume its surpluses domestically. Owing to this abundance of conventional gas, Peru is not expected to consider the development of its unconventional gas resources in the near future.

- Thailand was also excluded from this report, given that the economy is trying to break away from its high reliance on natural gas for electricity generation purposes, and that the estimated volume of shale gas resources is smaller than its proved gas reserves.

In its role as APEC's and the world's most advanced economy in shale gas production, the United States was not targeted for any kind of economy-wide recommendations; but it was used as a case study from which to identify key insights conducive to the development of a policy framework helpful for other economies.

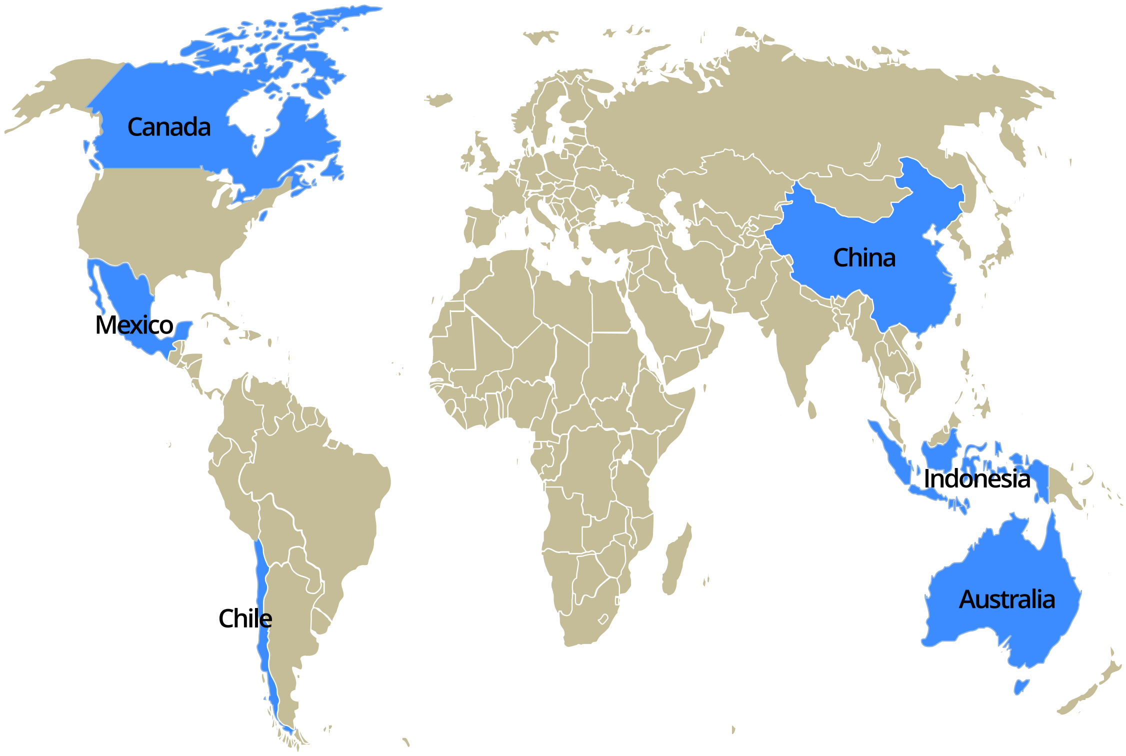
Owing to these considerations, and as depicted in Figure 11, the economies of Australia, Canada, Chile, China, Indonesia and Mexico were selected for the analysis of their challenges and opportunities in producing shale gas commercially. As these six economies are looking forward to or have already accomplished different levels of progress on the development of their respective shale gas resources, their experiences provide valuable insights for policy purposes. This also explains the inclusion of Indonesia given its estimates of shale gas resources and the efforts underway to develop them.

The nature of this report is not technical but policy-oriented, and hence it is not concerned with the assessment of technological or geological characteristics in the inferred shale gas resources of each APEC economy or the region as a whole. Neither is this report aimed at evaluating the feasibility of production technologies.

Unlike other types of unconventional gas which have already been produced on a commercial scale for quite some time, shale gas production outside the United States and to some extent Canada, is largely in its infancy. For this reason, along with constraints on resources and time, no other types of unconventional gas were directly addressed unless they overlapped with shale gas or were linked to a specific economy case. These issues however, do not preclude the validity of many of the insights and policy recommendations in this document on the development of other types of unconventional gas resources.

Finally, as much as the co-production of oil and natural gas liquids contributes to the profitability of shale gas projects, especially under settings of low natural gas prices, this report does not specifically address any hydrocarbons other than natural gas, unless associated with a particular economy case.

Figure 11
APEC economies selected for analysis



Methodology and structure

In order to gain a robust understanding of shale gas development across APEC and build a valid policy framework to fit the different contexts involved, several methods were used in this report.

In the search for relevant information, a critical review encompassed numerous peer-reviewed and professional papers, academic and industry publications and presentations, and official data from each of the economies addressed. The collection of information included attendance to government and industry events on international shale gas development in Indonesia, China and the United States. In addition, preliminary versions of the policy framework and the economy assessments in this research were presented in academic and professional forums, which provided invaluable feedback to refine the final contents.

With the aim of seeking authoritative feedback on the policy success factors for shale gas, APERC held an expert workshop in Tokyo, Japan on March 2014 with participants from most of the APEC economies examined in this report. To enrich the project with deeper insights from settings currently undergoing or expecting to undergo shale gas production, the project team undertook a two-week mission trip in June 2014 to Alberta, Canada; Pennsylvania, United States and Mexico City, Mexico. The mission trip allowed APERC to acquire first-hand information from a diversity of stakeholders involved in the development of shale gas in each economy.

This information contributed to a holistic perspective of shale gas development and helped to refine the contextual analysis of the

North American economies, which allowed the comparison of their respective stages of progress and strengthened their case studies. The details on the organizations visited and the people interviewed appear in the presentation of this report and are discussed in more detail in the next chapters.

The report is organised as follows. After this introduction, Chapter 2 examines the shale gas production in the United States to identify the major key factors underlying its progress. On the basis of this background and APERC's insights, Chapter 3 proposes a policy framework for the analysis of shale gas development, through a number of key factors grouped in three major areas.

The application of this framework is presented in Chapter 4, to outline the major challenges in each one of the economies selected for analysis in this report. Finally, Chapter 5 summarises the main findings at the general and economy levels and suggests some policy implications to improve shale gas development in other economies, within and beyond APEC.

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2

What led to the shale gas boom in the United States?

The rising interest on shale gas resources has prompted a closer observation of the United States, given its role as the pioneer and most advanced economy in terms of shale gas development. In an attempt to identify the underlying drivers in order to reproduce them in other locations, some of the success factors commonly highlighted are the unique system of mineral rights extended to private individuals (which shapes a less resistant social setting), the technological breakthroughs which allowed economic production, and the industry structure which disseminates and refines those technologies.

While the first commercial well in that economy was in fact a shale gas well drilled in Fredonia, New York in 1821 (Curtis, 2002), shale gas production remained uneconomical given the methods and techniques available at the time and the relative abundance of cheaper conventional gas resources. A few decades ago, however, specific technological breakthroughs in combination with a well-developed gas industry and a gas price environment favourable to riskier upstream projects made the large-scale production of shale gas feasible.

Nonetheless, each of these elements depended on other specific conditions, which in turn were contingent on different timeframes. Energy shortages and the decrease of domestic oil and gas production in the United States in the 1970s triggered a strategic response from the federal government oriented to expand domestic energy production. Government-funded technological research seeded the commercial development of several unconventional energy resources, including shale gas. However, governmental support alone was not enough for commercial shale gas production to flourish. In this sense, the United States experience has hinged on a generous endowment of commercially recoverable geological resources, of which detailed information has also been available; as well as the water resources necessary to perform the production methods associated.

The success in achieving technological breakthroughs has rested on the industry's long-established expertise and involvement in the government's efforts. Once the initial technological research had been assimilated and improved by the industry, governmental action focused on the provision of fiscal incentives which the profitability of unconventional gas production to support its expansion. Reliable availability of oilfield services along with a diversified and extensive infrastructure have been critical in devising cost-effective methods of production. Competitive market and pricing structures have provided producers with the necessary flexibility and opportunities to access capital markets.

The development of comprehensive federal regulations in the natural gas industry over decades have been also favourable to the methods and environmental effects associated with shale gas, contributed to a more rapid pace of production. Last but not least, the legal regime granting private ownership to subsoil resources has become the cornerstone of a social atmosphere more conducive to shale gas production, through the economic arrangements negotiated directly between landowners and producers.

In addition to these structural factors, a temporary environment of high natural gas prices from 2002 to 2009 further encouraged the growth of shale gas output. While natural gas prices have remained low in recent years, this uplift was strong enough to let shale gas technology and operations mature, with producers securing the profitability of their operations by improving their efficiency and targeting other liquids and oil.

Even though it is doubtful that other economies will be able to follow the same path as the United States in developing their own shale gas resources (Gény, 2010; Stevens, 2010), this analysis is useful as a source of adaptive learning oriented to the design of policies and strategies adapted to fit other contexts (Lozano-Maya, 2013; Rogers, 2011). These issues are examined below.

Natural resources

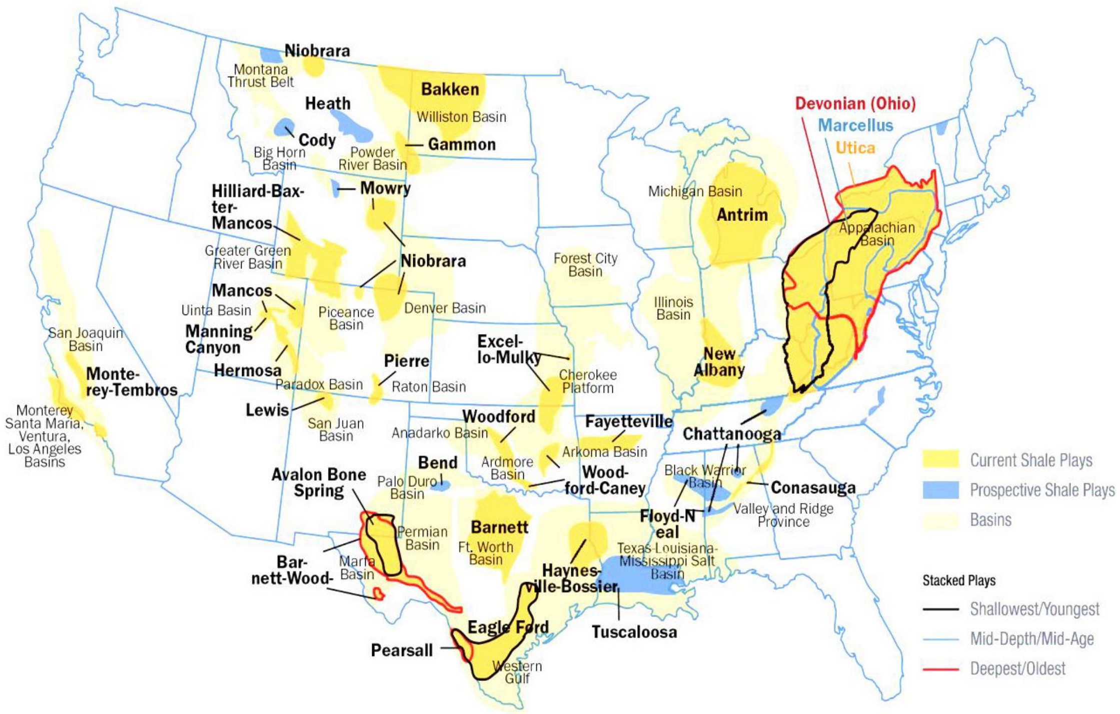
Shale formations are the most abundant rock type worldwide, and yet for them to contain any oil or gas, certain conditions must be present. In the case of the United States, its generous shale gas resource base displayed favourable properties which resulted in its intensive development, including the presence of heavier liquids and crude oil in some plays which contributed to the profitability of gas wells and to higher production levels.

Geology

The geological favourability in the United States is often claimed as one of the main pillars of the success of its shale gas production (Wang and Krupnick, 2013; Stevens, 2010) and one of the reasons why shale gas in other economies has not yet accomplished similar output levels (Tian et al., 2014; Andrews-Speed and Len, 2014).

As depicted in Figure 12, shale gas resources are dispersed across the United States; their heterogeneous geological properties are shown in Table 4.

Figure 12
Shale plays in the United States



Source: API (2015).

Table 4
Geologic properties of shale gas plays in the United States

Concept	Shale play					
	Antrim	Barnett	Eagle Ford	Fayetteville	Haynesville	Marcellus
Area (square mi)	94,893	12,000	6,458	1,090	9,000	9,000
Depth (ft)	6,750	1,400	7,500	7,000	12,000	4,000
Thickness (ft)	125	95	300	200	250	110
Porosity (%)	8	9	5	9	8.5	5
Total Organic Content (% wt)	12	11	4.5	4.3	2.3	6.9
Average Estimated Ultimate Recovery (Bcf per well)	1.18	0.28	1.42	5.00	3.57	2.07

Source: EIA (2011).

Proved reserves of shale gas have grown from around 0.1 trillion cubic metres in 2000 (Curtis, 2002) to 0.7 trillion cubic metres by 2007 and to 4.5 trillion cubic metres by 2013. This expansion, equivalent to an average rate of 37.4% per year since 2000, is remarkable when compared to the 5% growth in the total reserves of natural gas during the same period, mainly based on mature fields. Moreover, the increase of proved shale gas reserves was reflected in their share of the total natural gas proved reserves, growing from 2% in 2000, to 10% in 2007 and 47% in 2013 (EIA, 2014a; Curtis, 2002).

Intensive exploration and production activities have also produced a vast body of geological information and records, including shale resources. This information has enhanced the industry's knowledge, letting producers optimise their projects and increase profitability through a better mapping of prospective resources and an easier identification of the 'sweet spots'— those areas within the shale play wherein production is potentially higher. Furthermore, as seen in Table 5, the estimation of shale gas resources is based on current technologies and the number of producing wells (EIA, 2011), for which the resource base is likely to keep rising as more accurate and comprehensive data become available.

Table 5
United States shale gas proved reserve growth

State/Region	Proved reserves in Bcf		Proved reserves in Bcm		Annual growth rate 2007-2013 (%)
	2007	2013	2007	2013	
Louisiana	6	11,483	0.2	325.2	252
Pennsylvania	96	44,325	2.7	1,255.1	178
North Dakota	21	5,059	0.6	143.3	149
New Mexico	12	258	0.3	7.3	67
Arkansas	1,460	12,231	41.3	346.3	43
Texas	17,256	49,055	488.6	1,389.1	19
Other States	21,709	85,759	614.7	2,428.4	26
United States	**23,304**	**159,115**	**659.9**	**4,505.6**	**38**

Source: EIA (2014a).

According to a previous shale gas assessment (EIA, 2011), the United States technically recoverable resources amounted to 24.4 trillion cubic metres (862 trillion cubic feet) of gas and 24 billion barrels of oil. These resources are widely dispersed across the territory, with the Marcellus, Haynesville and Barnett shale plays accounting for 71% of the technically recoverable gas resources while the Monterey/Santos and Bakken shale plays held 79% of those for oil. More recently, these economy-wide shale resources were re-estimated at 16.1 trillion cubic metres (567 trillion cubic feet) of gas and 58.1 billion barrels of oil (EIA, 2013b).

Water availability

In addition to the abundance and growth of shale resources, water availability at the different shale plays in the United States has played a key role in sustaining the economy's booming shale gas production.

Water is essential to the production of shale gas, with demands per well ranging from 3.8 million litres to 19 million litres (U.S. Department of Energy, 2011) or even as much as 23 million litres (Speight, 2013), depending on the particular characteristics of the shale play and field. A water volume of 19 million litres is roughly equivalent to New York City's consumption in seven minutes (Chesapeake Energy, 2012).

Shale gas production in the United States has benefited from the accessibility of those water resources, both in terms of the current regulations and the logistical capabilities to bring it from locations beyond the production site when it is not present or accessible nearby.

Technology

Despite the knowledge of shale formations as a source of gas, they were neglected for decades by producers because of the lack of adequate technology to produce the gas economically.

This situation changed however, with the challenging energy landscape in the 1970s, pushing the federal government to find ways to enhance the commercial viability of unconventional energy sources, including shale gas. The efforts resulted in federal-funded research, in the hope that the technological difficulties underlying the commercial development of shale gas could eventually be taken up by private producers, increasing the domestic gas supply and strengthening the economy's energy security.

This led to the creation of several federal agencies and programs in charge of energy research and development, which eventually merged into the United States Department of Energy, also conceived at that time to enhance the economy's energy policy capabilities. In addition, the Unconventional Gas Research Program was created in 1976 with three separate subprograms: one oriented to tight sands, one to coalbed methane, and one to shale gas (National Energy Technology Laboratory, 2007).

Applied technological research

The Eastern Gas Shales Project was created in 1976 to evaluate the potential of and enhance gas production from shale formations in the Appalachian, Illinois and Michigan gas basins. This was based on a geological and geochemical study which included the development of new production techniques and brought about a number of technological innovations (Wang and Krupnick, 2013; Curtis, 2002).

Apart from the characterization of resources and the development of technologies, the Eastern Gas Shales Project sought the transfer of technological solutions to the industry. This program established demonstration partnerships with higher education institutions and gas firms in Pennsylvania and West Virginia which generated several breakthroughs, including an early directional drilling technique which developed into horizontal drilling; massive hydraulic fracturing; diamond-studded bits which were better adapted to drill shale; and three-dimensional microseismic imaging to map shale formations with more precision(Trembath et al., 2012). Other key innovations were measurement-while-drilling technologies to allow constant monitoring and accurate control of directional drilling.

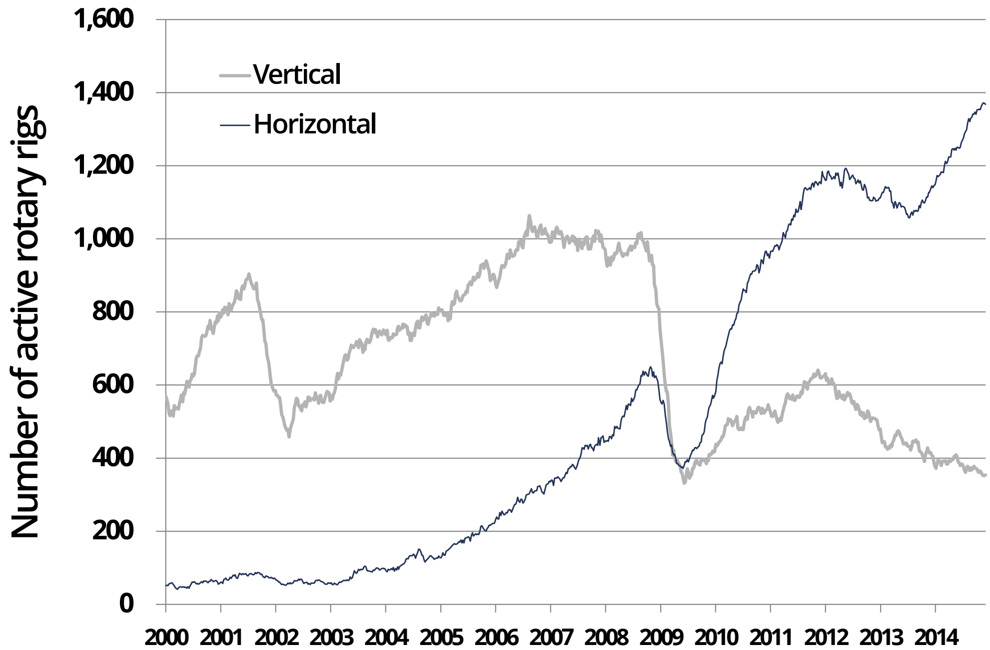
It must be noted that even at that time, hydraulic fracturing was an industry practice adopted decades before; it was however, the combination with horizontal drilling which became the key to extracting the gas trapped in the shale formations economically. Figure 13 shows that in step with the rising shale gas production, the number of horizontal rigs in operation has outpaced the number of vertical rigs, particularly since 2005. While this trend was possibly spurred by the exemption of hydraulic fracturing practices from federal water regulations (discussed in more detail below),improved equipment, better geological understanding, and the enhanced commercial viability of crossing through the natural fracture system in the shale formations have definitely contributed to the change.

Industry expertise

The success in converting the technological research seeded by the government into economic production methods was made possible by the long-established expertise of the natural gas industry in the United States. Over several decades, this industry has built solid capabilities and high quality human resources specialised across the entire natural gas value chain.

As each shale gas reservoir is bound to present heterogeneous geochemical and geological characteristics even within the same play, the gas industry's expertise and ability was central to devising 'unique methods of drilling, completion, production and reserve evaluation' (Speight, 2013, p. 9). Therefore, the industry's expertise and a continuous trial-and-error process have led to the assimilation of technology into cost-effective solutions for particular circumstances.

Figure 13
Number of drilling rotary rigs in operation by type, 2000-2014



Source: Baker Hughes (2014).

Market and economics

Besides an adequate supply of natural resources, institutional support and technological innovation, shale gas production in the United States expanded very rapidly due to the cost-effectiveness of numerous gas producers and supply chains located across the economy.

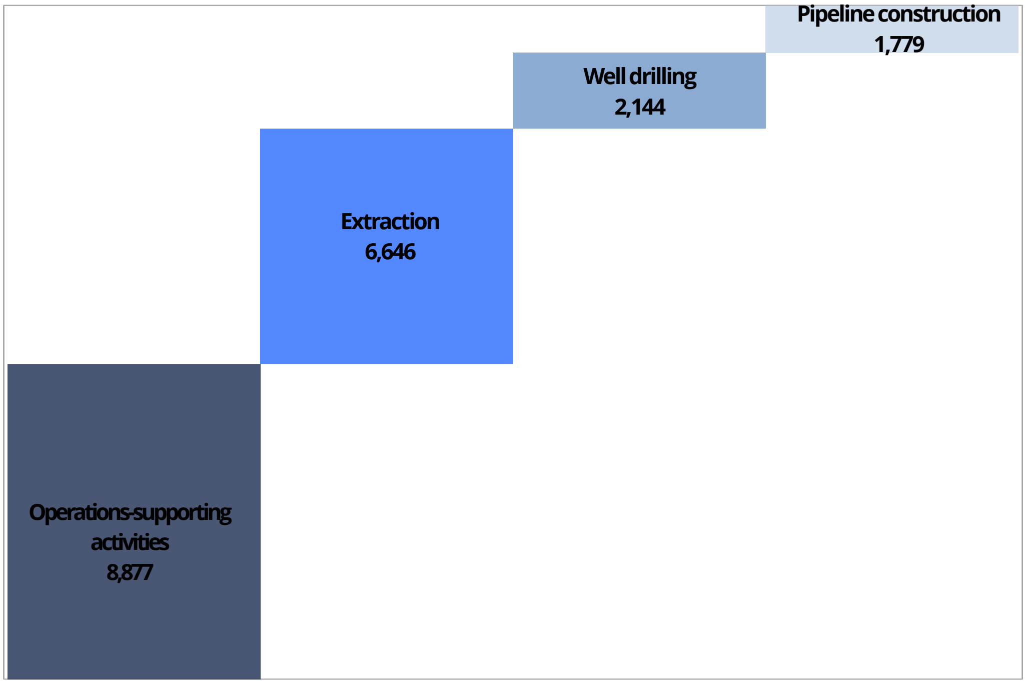
Competitive industry structure and pricing

The United States gas industry is characterised by numerous players driven by the economic opportunities underlying a market-based framework, in accordance with the deregulation of the industry decades before. The presence of these conditions was essential in providing shale gas producers a competitive platform conducive to the improvement of their operations across the value chain, as per the drivers noted above.

As shown in Figure 14, by the end of 2012 nearly 19,500 firms had carried out operations related to oil and gas production, drilling, auxiliary activities and pipeline construction across the United States, many of which targeted shale gas. These firms are predominantly small, with 82% of them employing fewer than 20 people, 16% with 20 to 500 people and only 2% with more than 500 employees (United States Census Bureau, 2014b).

This industry profile, mostly made up of small independent firms, is likely to have supported the organizational flexibility, innovation and entrepreneurship which pioneered and advanced the commercial production of shale gas (Wang et al., 2014; Rogers, 2011; Stevens, 2010). This plethora of industry operators has allowed an intensive drilling effort capable of adapting to the particular characteristics of each shale play across the economy, thereby contributing to its increasingly rapid shale gas production.

Figure 14
Oil and gas firms in the United States by type and number, 2012



Source: United States Census Bureau (2014b).

Owing to the establishment of Henry Hub as a price reference in the 1990s, and the shift towards deregulation started a few years before, the number of spot transactions in the natural gas industry increased, allowing a more accurate match between wholesale and consumer prices which made the market more liquid by serving as an interface with financial markets.

The dominance of short-term transactions promoted many changes, such as a tighter balance between demand and supply, a more competitive industry structure, the emergence of new figures such as intermediaries (marketers) who strived to optimise the transactions between producers and consumers, a more intense use of financial derivatives, and overall, a more effective form of governance than the heavy regulation of the past (Dahl and Matson, 1998). These changes also made the natural gas industry more price-responsive.

Availability of reliable oilfield services

The competitive and diversified capabilities of a vast oilfield services industry were developed in parallel with the United States oil and gas industry and have been fundamental in driving the growth of specific products and services essential to shale gas production. These firms, of which there were more than 8,000 in 2012 (as seen in Figure 14), are responsible for activities such as geophysical surveying and mapping, well cementing and casing; and well completion, including hydraulic fracturing.

The technical characteristics of shale gas production have called for adaptive and innovative practices to achieve cost-effectiveness, which altogether represent a different business model to that of conventional gas production, characterised by a manufacturing-like process in which as many shale wells as possible are drilled in different directions from a single pad, in order to minimize resources and costs. Crucial to this development has been the industry's capacity and lead times to manufacture more sophisticated equipment in step with rising demand.

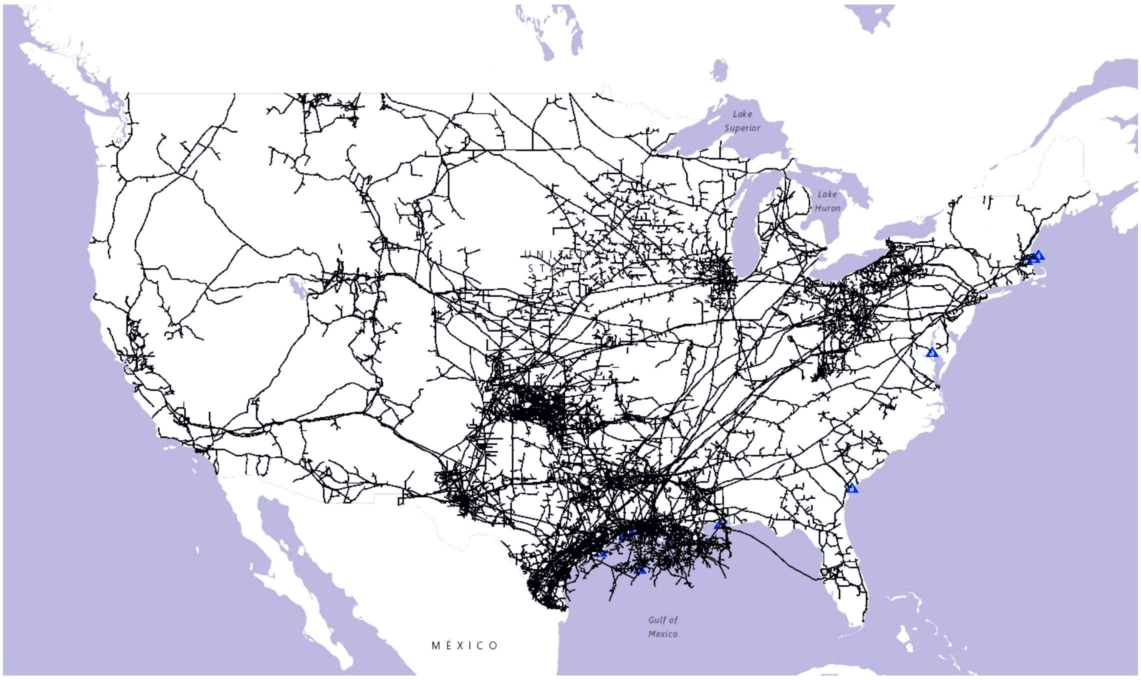
Shale gas production is bound by the market-based prices applicable to conventional gas and yet it is intrinsically more complex and costlier to produce, generally requiring higher price levels to recover the costs associated and break even. These breakeven prices vary across the United States shale plays, with estimates as low as USD 3.75 in parts of the Eagle Ford to USD 7 in New Albany (Medlock et al., 2011). In order to manage this cost complexity, shale gas development has achieved more effective management of its operations, cutting costs and lead times in synchrony with equipment and service providers in the vein of the manufacturing industry.

Extensive infrastructure

While infrastructure might be often overlooked or taken for granted, due to its scale, diversity and accessibility, shale gas production could grow and reach final markets due to the extension and capacity of the natural gas pipeline network to link the major producing States in the Southwest with the largest consuming markets in the Northeast, West and Midwest States. The density and reach of the interstate and intrastate pipelines are shown in Figure 15.

As with the development of the industry as a whole, the effective transmission of price signals, the adjustments between supply and demand, and more appropriate regulation have contributed for decades to the expansion of an impressive physical network which comprises inter and intrastate pipeline systems; railroads, tank cars and rail loading and unloading facilities; marine vessels of different sizes and LNG terminals; processing, storage, and compression facilities; and well-developed common infrastructure such as roads, ports, and mines from whence the sand and other necessary materials to perform hydraulic fracturing and other operations are sourced.

Figure 15
United States interstate and intrastate natural gas pipeline network



Note: As of the end of 2014.
Source: EIA (2014b).

The robust natural gas infrastructure in the Lower 48 states of the United States was mainly made up by (MIT, 2011):

- More than 492,000 kilometres of transmission pipelines, and nearly 2 million kilometres of distribution pipelines, with about 1,200 compression stations;

- A total storage capacity in excess of 241 billion cubic metres, as well as 418 fields for underground storage;

- Several LNG terminals, 33 market hubs; and 13,640 operators; and

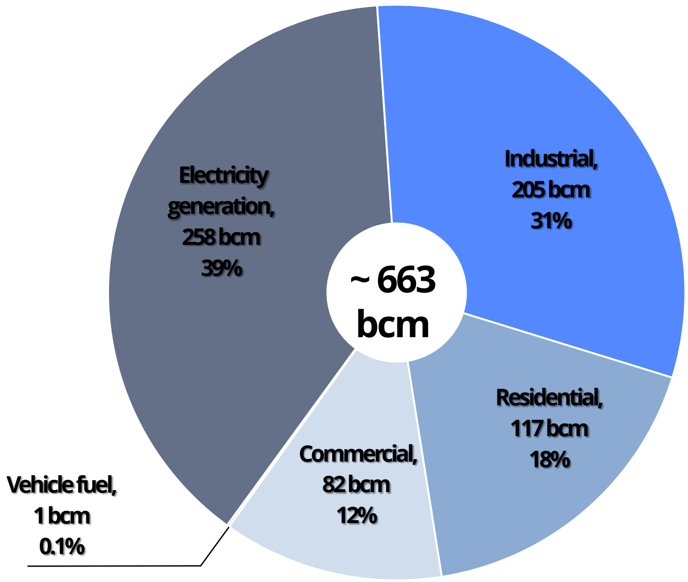
- Approximately 1,200 local distribution companies, which reached about 67 million customers across the economy.

Developed gas and financial markets

The scale and speed of shale gas production and its significant effects on the economy-wide energy balance of the United States depended on the remarkable development of its natural gas market, one of the largest and most dynamic in the world.

The natural gas market in the United States was the largest in APEC, amounting to 663 billion cubic metres in 2013 and representing an annual average growth of 0.2% since 2000. As illustrated in Figure 16, the volume of gas demanded in 2013 went mainly to electricity generation and final users in the industrial, residential, commercial, and transport sectors.

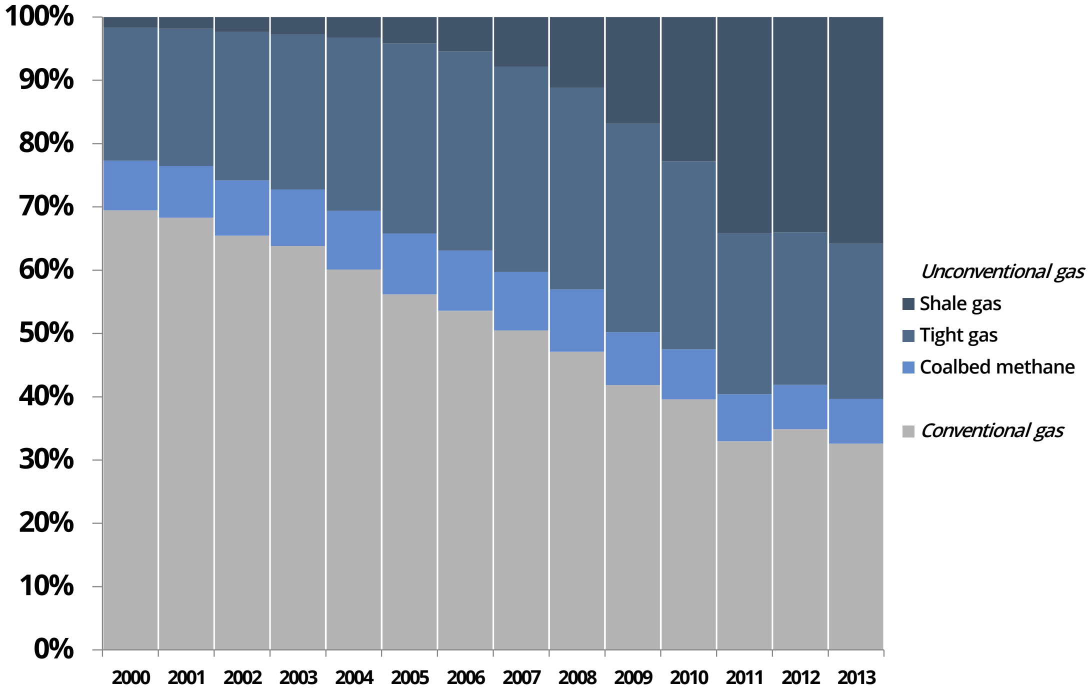
Figure 16
United States natural gas demand by sector, 2013



Source: EIA (2014a).

As seen in Figure 17, the share of shale gas in the United States' total gas production has grown very rapidly in the last few years, accounting for more than one-third of the total domestic production after 2011 and standing as its single largest source. Shale gas production not only grew faster than any other source, but especially over other unconventional sources like tight gas and coalbed methane, surpassing as well their respective shares into the economy-wide gas production.

Figure 17
United States natural gas production by type and share, 2000-2013



Note: Conventional gas refers to associated and non-associated production, onshore and offshore, including Alaska.

Source: EIA (2013a).

The numerous producers, service providers, downstream players, marketers and traders, transmission operators and local distribution companies across the value chain have extended the reach of the market and increased overall Added to these constraints, the nature of shale gas projects called for considerable amounts of capital which could be accessed through the well-developed financial infrastructure of the United States.

The intensive capital needs of the oil and gas industry in the United States have been largely met by the ample array of financing sources available, which are fuelled by risk-taking investors targeting projects with above-average returns. Private equity for example, has supported the existence of a multitude of independent firms and wildcatters spread across the economy; also, a mature futures and forwards market for gas has given producers financial liquidity and has enabled them to lock-in a price for their gas several years ahead, protecting them from intrinsic price risks.

Entrepreneurship in the oil and gas industry has been another key factor of the shale gas boom, as companies at every level have undertaken higher risks, refined technology, established new cost-effective practices, and leased large areas for intensive exploration across the heterogeneous geology of the United States. Strict intellectual property protection is crucial to this entrepreneurial wave, as players try to secure competitive advantages through technological patents.

Apart from the funding through debt and equity provided by financial markets, the private ownership of mineral rights in combination with the dynamism of the natural gas industry was also seized upon by many producers which have made a profit by becoming first-movers in many prospective areas, securing technological advantages and extensive land acreage which were later sold at higher prices(Wang and Krupnick, 2013). Furthermore, the success of these independent operators in producing shale gas caught the attention of the largest oil and gas companies, the so-called 'majors' which had previously overlooked this unconventional gas resource.

Many other firms have also been able to improve their financial capabilities and organizational flexibility through their relationships with other firms in the form of alliances, mergers and acquisitions. The acquisitions and investments of Asian companies aiming to secure shale gas supplies and learn from United States expertise has become another source of capital for shale gas producers.

Overall, these issues not only illustrate the flexibility enjoyed by shale gas producers, but explain to a great extent the growing production levels of shale gas production in spite of unfavourable prices and complex market conditions.

Institutions

The current shale gas production in the United States may have never developed at all if it were not for the legal regime in place and the federal government's vision in seizing an opportunity which paid off in the long-term. The energy turbulence in the 1970s pushed the government to support the economic development of shale gas as a means to strengthen energy security, but also called for actions to shape a regulatory framework conducive to competitiveness.

Fiscal incentives

To begin with, government actions were targeted to priorities of a technological nature which could be eventually transferred to the industry, but soon afterwards they transcended to a broader sphere which offered economic incentives to strengthen the feasibility of these resources at a time when their profitability was weak.

In consequence, and stemming from the Crude Oil Windfall Profit Act, the Alternative Fuel Production Credit, more commonly known as Section 29 (of the Internal Revenue Code) was established to promote domestic production from unconventional energy sources (including shale gas), reducing the reliance on energy imports. The credit was applicable to gas wells drilled between 1980 and 1992 and was determined by a sliding formula which initially amounted to USD 0.52 per thousand cubic feet and increased to USD 0.94 per thousand cubic feet by 1992, which was significant considering that during the same period the economy-wide average wellhead prices ranged between USD 1.5 and 2.5 per thousand cubic feet(Wang and Krupnick, 2013).

In spite of its expiration in 2002, this fiscal credit helped sustain shale gas production in subsequent years. Other fiscal policies, such as the Small Producers Tax Exemption, the Marginal Well Tax Credit and the long-established deduction of Intangible Drilling and Development Costs contributed to reducing the risks inherent in shale gas projects (Gény, 2010), attracting the interest of producers, particularly independent (non-integrated) oil and gas firms, which ended up leading the intensive drilling and perfecting the technological breakthroughs which ramped up shale gas production.

Industry reform

A comprehensive deregulation of the natural gas industry implemented at the federal and state levels was also vital to the governmental strategy towards a more efficient natural gas industry, and ultimately the success of shale gas. On the basis of its conception as a natural monopoly, the United States natural gas industry had been heavily regulated since its origins, but the serious gas shortages and price issues in the 1970s led to the introduction of complex price controls and drastic regulatory policies that included constraints on the use of natural gas in the electricity and industrial sectors.

These problems provoked calls for the regulations strangling the industry to be scaled back. Beginning in the late 1980s, controls on prices were relaxed, bans on gas utilization for specific purposes were lifted and access to pipeline transmission services was made more competitive. Altogether, these measures made the market more competitive, paving the way for dynamic shale gas output in the following years. The deregulation of wellhead prices, the unbundling of pipeline services and fees, and the rising liquidity and development of trade hubs achieved in the United States natural gas market was the platform on which shale gas production was able to thrive (Joskow, 2013).

Apart from federal lands, interstate transmission and some environmental matters, most regulations specific to shale gas are implemented by State jurisdictions. This system of regulation at the state, rather than the federal level contributed to the development of closer interaction between regulatory authorities and diverse stakeholders, allowing regulations and other concerns to be worked out more effectively.

Environmental framework

Largely due to the exemption of hydraulic fracturing—the major production technique used for shale gas—from the Safe Water Drinking Act in 2005, its production has enjoyed a relatively favourable environmental framework, in spite of recent social demands for stricter safety standards and disclosure of the chemicals injected during the hydraulic fracturing process (Rogers, 2011; Zhou, 2011). This arrangement between the federal and State powers has resulted in regulations better adapted to local characteristics which have generally allowed shale gas production continue without major disruptions from environmental opposition.

Private mineral rights

The industry adaptation to unconventional gas development was strengthened by the United States' unique legal regime, which allows the private ownership of oil and gas resources. In the majority of economies, oil and gas rights are owned by the State, and private mineral rights are only reserved for a small share of lands in Canada and some old Spanish land grants in Colombia(Johnston, 2007). The United States however, is the only economy where private mineral rights are predominant.

Private ownership of mineral rights might have also fostered more collaboration between producers with operations in a common play, regarding their individual production of oil and gas from a common pool of resources; compelling them to work jointly to preserve the productivity of the whole pool (Scott, 2008). From a broader perspective, the economic rents perceived by landowners from the lease or sale of their lands to producers has provided incentives which foster a social environment more receptive to shale gas development in spite of the associated social, land and environmental risks.

Another variable less salient but equally supportive of shale gas production is the generally low population density prevalent in the United States, especially in its shale-gas-producing states. The top shale-gas-producing States of Texas and Louisiana had respective population densities of 37 and 41 people per square kilometre in 2010, (United States Census Bureau, 2014a), was similar, and particularly much lower than most European and Asian economies.

It might be contended that population density is not an influential variable in shale gas development, as other current operations take place in densely populated areas such as the Dallas-Forth Worth urban region in Texas. Nonetheless, it could be argued as well that this is very likely an outcome of the prevalent private mineral rights system. In most other economies, especially in densely populated areas, higher social resistance has arisen because oil and gas remain the property of the State and landowners do not receive any direct economic rent. The landowners in other economies thus have no incentive to support shale gas development on their land, and may even have an incentive to oppose it if they perceive that it poses a risk of damage and disruption for which they will not be adequately compensated.

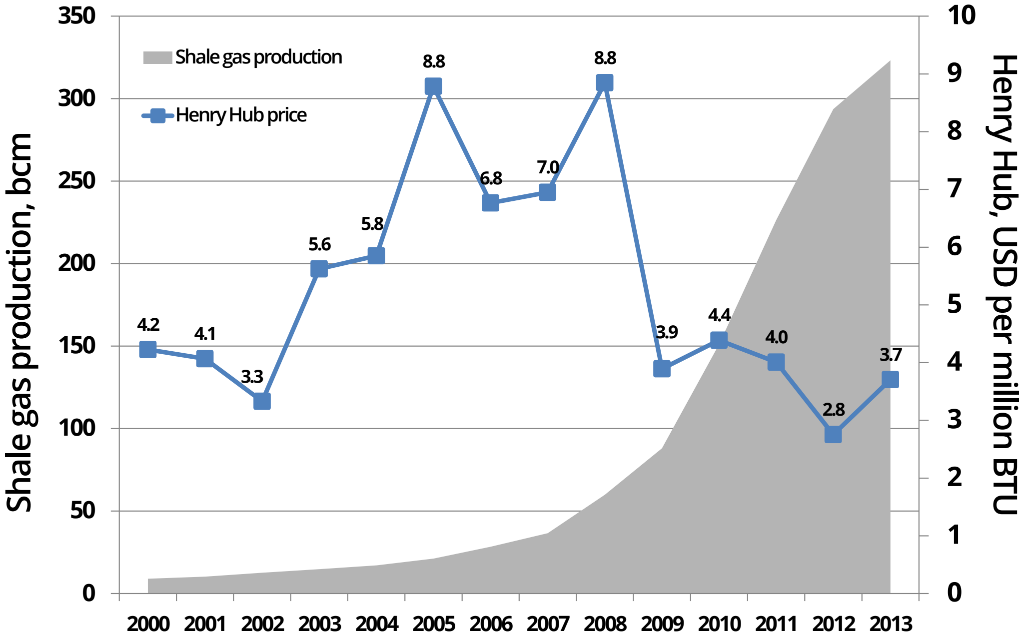
Timing

Shale gas producer capitalised on the high gas prices which lasted for several years, to make larger returns. As shown in Figure 18, spot natural gas prices in the United States rose rapidly from 2002, peaking in 2005 with USD 8.8 per million BTU and again in 2008, after a brief dip.

This upward trend helped ignite an expansion of shale gas production, which has been sustained despite the significant price drop occurred in 2009. The cost reductions which have made the continued growth of shale gas production possible hinge on a competitive industry structure with market-based pricing, availability of reliable oilfield services, extensive infrastructure, and developed markets that have allowed gas production to raise in step with the demand from end-use markets.

While high gas prices from 2002 to 2008 allowed shale gas production to grow comfortably, their reduction in the aftermath of the economic crisis entailed financial pressures for producers with breakeven prices higher than market prices. Furthermore, this downward trend and the rising trend in oil prices altered the ratio between crude oil and gas prices, which as observed in Figure 19, remained relatively stable from 2000 to 2008 at an average of 8.3, but became more erratic afterwards.

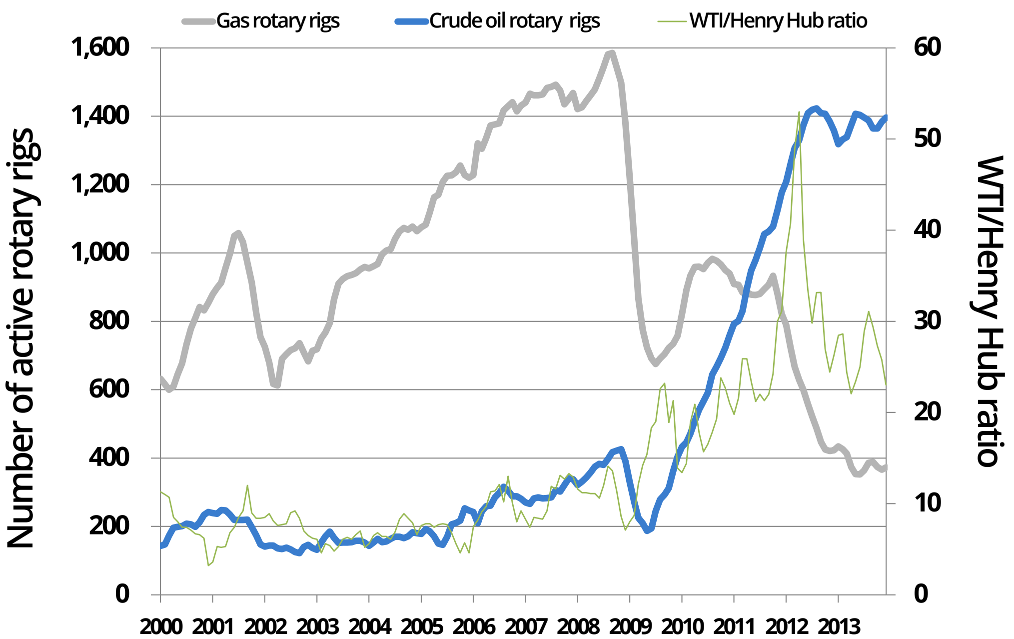
Figure 18
United States shale gas production and Henry Hub price, 2000-2013



Source: Prices from BP (2014); production from EIA (2013a) up to 2006 and afterwards from EIA (2014a).

Owing to this, many producers shifted their operations to 'wetter' shale plays where they could accomplish higher economic value through the co-production of natural gas liquids linked to oil prices. Accordingly, as shown in Figure 19, the number of rotary rigs in operation targeting oil started to grow very rapidly from the end of 2008, having outpaced those used for gas production. Yet, since gas was still being produced as a co-product with liquids, shale gas production continued to grow.

Figure 19
Number of rotary rigs in operation by type, 2000–2014



Source: BP (2014) and EIA (2014a).

Revolution or evolution?

Considering that the Eastern Gas Shale Program began in 1976 and that massive shale gas production took off in the mid-2000s, it is plausible to argue that the shale gas boom was at least 30 years old by the time it attracted international attention. Essential to this were the incentives provided in response to the diverse contextual challenges. The growing energy imports and negative economic effects produced in the United States by the international energy shocks of the 1970s drove the federal government to deploy long-term strategies to strengthen energy security through the economic production of unconventional gas resources.

Aside from the favourable quality, size and availability of shale resources, the industry's ample geological information and expertise were fundamental to leveraging the technological research seeded by the federal government and refining the combined use of horizontal drilling and hydraulic fracturing into cost-effective production methods. In this way, the federal government was able to shift towards providing fiscal incentives and liberalising and decentralising the natural gas industry, in order to promote the commercial production of unconventional gas. The industry's competitive structure and pricing, the legacies of extensive infrastructure, well-developed natural gas sectors, and financial markets, and the availability of reliable oilfield services were also key drivers to the deployment of cost-effective supply chains which refined and extended the production of shale gas.

The pace and scale of development was favoured to a great extent by the predominantly private ownership of mineral rights, which fostered a more receptive social structure through the payment of individual economic rents and easier monetization of land leases across the industry. The economy's low population density in shale plays might also have played a relevant role in this success. Lastly, once technological and economic incentives were present, a persistent upward trend in natural gas prices during the 2000s underpinned the profitability of natural gas production and attracted private firms to riskier projects such as those related to shale gas.

An appropriate example of many of the points mentioned above is Mitchell Energy, the firm credited with having 'unlocked the code' that paved the way for the commercial production of shale gas in the United States. In that sense, it has been noted (Tian et al., 2014; Zuckerman, 2013) that, aside from the company's leadership, entrepreneurship and vision in targeting the development of resources that were not attractive to the largest companies, it benefited from the initial technology and economic incentives provided by the federal government, the overlap between conventional and shale gas reservoirs in its leases, its relative financial flexibility as a publicly traded company, and the ability to monetise its leases and technology largely because of private mineral rights.

Abundant natural resources, financial and technological capabilities, governmental support, a legacy of competitive industry settings, adequate infrastructure, appropriate regulation, economic incentives, private mineral ownership, and entrepreneurial spirit were among the main variables which helped massive shale gas production in the United States to take off.

Shale gas development in the United States far from novel, as it is a long-term outcome which resulted from the evolving interdependence and alignment of structural industry features and critical strategies in response to the contextual conditions of the time.

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3

Building a policy framework for shale gas development

The role of natural gas in underpinning an energy transition with lower carbon emissions, the inferred distribution and amount of shale resources needed to support an extended gas supply, and the energy overhaul in the United States have sparked global interest in shale gas. Its development nonetheless, entails more challenges than conventional gas.

From a technical perspective, the production of shale gas faces increased geological complexity and divergences which usually result in higher costs. From a broader perspective, shale gas sparks a sharper social debate, as it poses significant challenges to society and regulators. Unlike conventional gas, shale gas production is reaching areas novel to oil and gas activities, many of them in densely populated areas often located in urban settings. Owing to the industrial methods employed and the intensive mobilization of materials to the well site, the extraction of shale gas increases noise, dust and road traffic, has a more visible land footprint, and raises environmental concerns, most notably related to the preservation of freshwater resources.

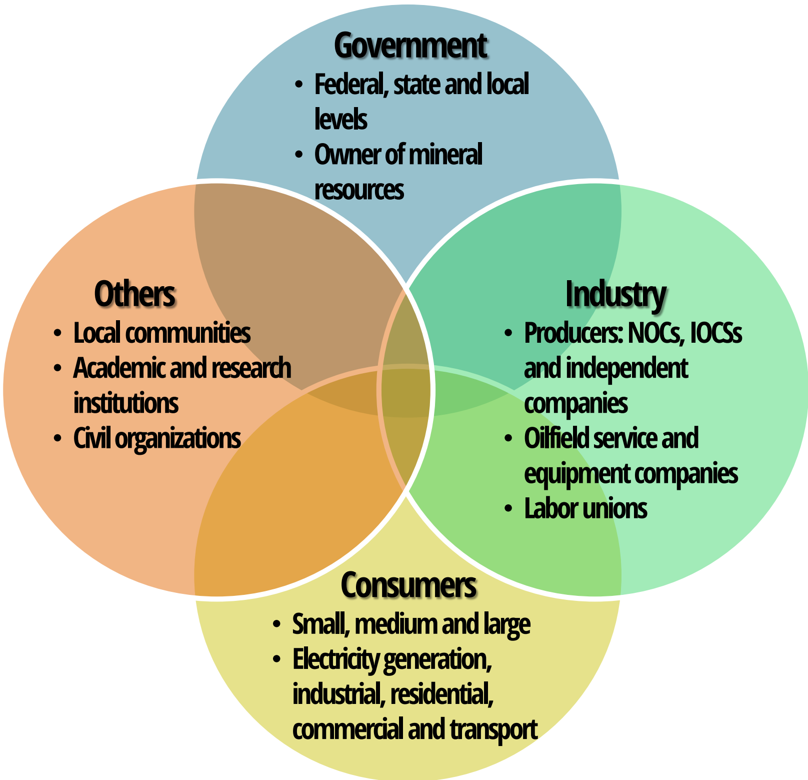
Shale gas development is also multifaceted, in that it involves several interrelated stakeholders and their interests. The multiple levels of government for instance, embrace a set of policy and regulatory priorities, including energy security, public health, environmental protection and economic spillover effects. These priorities and their derived policies frame the operations of the industry. Additionally, governments are typically the holders of mineral rights, for which they strive to maximise the fiscal revenue derived from the extraction of those fossil energy resources.

Industry players seek a return on their investments to account for the increased risks and higher upfront capital required in comparison with conventional gas projects. Displaying a variety of capabilities and profiles which span International Oil Companies (IOCs), National Oil Companies (NOCs), and non-integrated companies (Independents), gas producers pursue sustained profitability by leveraging cost-effective technologies and supply chains which to a large extent are deployed in partnership with providers of equipment and oilfield services. In some economies, NOCs' decision-making processes are also influenced by stakeholders such as labour unions.

Equally important, gas consumers of different sizes and profiles spanning several economic sectors demand reliable natural gas supplies at competitive prices. Lastly, another major group are those stakeholders affected by shale gas projects, such as local communities. Other stakeholders in this group are not directly affected by these projects, but have an interest in different aspects of shale gas, mainly related to community development, environmental impacts and effects on public health. They might include academic and research institutions, civil organizations and general citizens.

Altogether, these actors and their respective concerns exemplify the demanding implications of shale gas and the trade-offs between its benefits and negative externalities. Figure 20 simplifies these actors and their interests, although their interdependences are not as clear-cut.

Figure 20
Major stakeholders groups in shale gas development



Source: APERC

Pathways to shale gas development

Adding to the complex linkage between numerous stakeholders, the variety of contexts, jurisdictions and sectors preclude the application of a single approach which effectively addresses the issues affecting shale gas development.

In this sense, as much as the United States has illustrated the kind of benefits offered by shale gas, it is very unlikely that other economies will be able to replicate its legacy driven by the unusual private ownership of mineral rights. Moreover, even within that economy, the regulatory, social and industry divergences across States and communities prevent the recognition of a single shale gas framework which could be taken as representative of that economy and used as a role model elsewhere. Nevertheless, the analysis of this experience is still valuable for the analysis of barriers and factors of success which could be used in the policy-making process of other economies (Lozano-Maya, 2013).

The insights gained from an expert workshop organised by APERC became the starting point in the discussion of a common frame of reference for economies looking forward to or already engaged in the production of shale gas. In the first place, experts underscored that the higher geological complexity intrinsic to shale gas requires unorthodox production methods which entail greater notorious social repercussions and call for more specific regulatory approaches. Experts mentioned a number of barriers to shale gas:

- Assessment of and access to shale gas resources,
- Governmental prohibitions on shale gas development;
- Poor capital access for shale gas producers;
-
- Insufficient or inaccessible natural gas transmission infrastructure;
- Absent or limited oilfield services.
- Uncompetitive natural gas pricing and market settings;
- Lack of best practices;
- Undeveloped natural gas markets;
- Deficient regulation and lack of coordination between different levels of government; and
- Poor or absent stakeholder engagement to reduce social opposition to shale gas production.

Experts noted that several of these barriers overlap with conventional gas, and are thereby generally applicable to the natural gas industry. However, it was also stressed that for shale gas to be developed, a number of strategic conditions must be present, some of which take a long timeframe to evolve and depend on multiple actors and factors which differ in each economy. There was consensus though, that despite the multiple factors and dimensions involved, shale gas production is basically driven by economic criteria and market opportunities, and while it is carried out by oil and gas companies, governments play a key role in fostering institutional changes to improve certain structural conditions.

In this regard, the uncertainty and volatility of natural gas prices in combination with the lower production costs of conventional gas usually hamper the profitability of shale gas projects, in which case making it cost-efficient becomes crucial. While in some economies with limited or absent conventional gas resources the need for energy security will be a stronger driver in the development of their shale gas resources, bringing down the economic costs incurred will still be highly relevant.

Another highlight was the acknowledgement that the private ownership of minerals alone was not the only factor leading to shale gas development in the United States, although this factor significantly influenced the speed and scale of production in that economy. Moreover, in a field visit to the United States (see Textbox 3), APERC observed that private mineral ownership is not entirely faultless, as it entails social questions from land-owners who do not perceive direct economic benefits and yet endure the effects of shale gas development; in addition, the economic benefits accruing to owners of neighbouring properties could fluctuate considerably.

In light of these issues, it was agreed that the absence of private mineral rights beyond the United States does not preclude shale gas development elsewhere, as long as the interests of the major stakeholders involved are aligned and there are other mechanisms oriented to encourage risk-taking and entrepreneurship. Western Canada is an actual example of commercial shale gas production despite mineral rights being held predominantly by the provinces.

Overall, these issues led the workshop experts to agree that the experience seen in the United States is not replicable, and that instead of adhering to a strict one-size-fits-all approach, economies need to follow certain pathways to make the development of their shale gas resources more conducive, with their respective pace and scale conditional on their own priorities and contexts. Shale gas development generally takes more time, infrastructure and capital investment than conventional gas production, and while there seems to be no magic formula for it, there are however, some key elements to promote it and minimise its risks, which largely explain the differences in the progress achieved by several economies, particularly those examined in this report.

Policy framework pillars

Governmental, professional, and academic references, expert insights, and case studies reveal a wide array of elements underpinning shale gas development. These elements are fundamentally divided into the categories of 'underground' and 'above-ground', with the former focusing on geological and technical considerations, while the latter spans a variety of interdependent matters of economic, political, social, environmental and regulatory nature.

To simplify this multidimensionality, APERC grouped these factors following a petroleum resource management approach bound by the resource base, the market and the enterprise capacity (Al-Kasim, 2006). According to those criteria, the resource base represents the estimated endowment of hydrocarbon resources; the market refers to the economic settings which drive the production of such resource base, and the so-called enterprise capacity comprises the institutional, financial, and technological elements which frame the resource base and market altogether. This initial classification was modified however, to redefine the enterprise capacity as governance, thus reflecting the collective behaviour of the diverse participants involved in the development of natural resources (Fischer et al., 2007; Mommer, 2002).

Building on these notions, APERC developed a tripartite policy framework which distinguishes the strategic factors underlying shale gas development. First, while the natural environment predetermines the endowment of shale gas and other liquids potentially recoverable underground along with the water resources available to produce those hydrocarbons economically, political decisions ultimately determine the access to these resources. Second, the industry's tangible and intangible assets profile the natural gas industry's efficiency in commercially producing the estimated volumes of shale gas in response to market demand. Finally, governance establishes the patterns of organization that shape the economic and social interactions among shale gas stakeholders.

APERC's main message however, is that governance becomes the framework's most important element because of its pervasive role in bringing about significant changes in the other two components, especially considering that the access to natural resource bases cannot be readily changed and that it is difficult to develop infrastructure and technology, which may take much longer than expected to evolve into supply chains appropriate for the scaling-up of shale gas production. To that end, the three components in the framework form a dynamic system in which there is a co-evolution of governance with accessible natural resources, infrastructure, and technology.

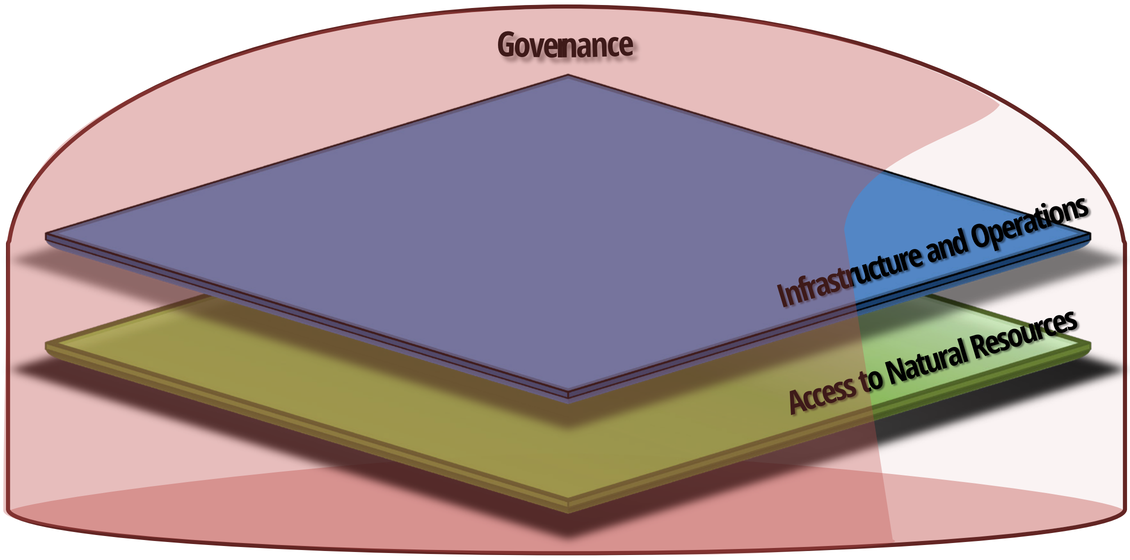
Notwithstanding the multiplicity of definitions and dimensions attributed to governance, there is consensus that the concept entails the distribution of authority and decision-making between governmental and non-governmental actors in order to increase the effectiveness of their joint outcomes in common areas of interest (Fischer et al., 2007; Krahmann, 2003). In so doing, governance affects the economic and institutional incentives which induce the development and performance of infrastructure and technology (Finger et al., 2005), including those for specific uses such as the extraction, transport and distribution of natural gas to consumers. In turn, access to better technology, infrastructure and geological data is likely to result in more efficient operations and recovery factors which increase the size and productivity of the shale gas resource base (Schmoker, 2002).

Therefore, governance is considered critical to promote enduring win-win arrangements bound to positively affect the social response, the industry's capabilities and government policies regarding shale gas development. Quoting Williamson (2005, p. 43), 'governance is the means by which to infuse order, thereby to mitigate conflict and realize mutual gain'.

On this point, the framework acknowledges that its three components are necessary for shale gas development, but discerns that certain characteristics in the governance component are desirable to support a favourable long-term environment which reconciles the interests of the different stakeholders involved.

These ideas are conveyed schematically in Figure 21, which on one hand shows two green and blue layers which symbolise the components for shale gas development respectively represented by the access to natural resources, infrastructure and operations; while on the other hand, the encircling red overlay alludes to a third condition, the governance which pervades and affects the other two. Governance is not represented by a layer as it is considered less rigid due to the diversity of stakeholders and circumstances particular to each economy.

Figure 21
Schematic representation of APERC's shale gas policy framework



Source: APERC

The design of the framework strives to be comprehensive, by condensing the type and interdependences of the major components generally involved in the development of shale gas while still accounting for contextual variations through finer factors within each component. This means that these components and their factors are systemic, insofar as they are inseparable and the qualities in any of them are expected to pervade the others to affect the entire process of shale gas development; analogous to the strength of a chain as expressed by the sum of each one of its individual links.

The components and their factors are considered endogenous insofar as they are under the control of each economy. This means that other variables such as geological settings, disruptive technologies, geopolitics, and the evolution of reference prices for oil and gas for example, simply lie beyond the framework's scope, notwithstanding their impacts on shale gas development.

In order to facilitate the understanding and memorization of the framework, it has been named *RIG*, owing to its three main components: *Access to Natural Resources (R)*; *Infrastructure and Technology (I)*; and *Governance (G)*. These RIG components divide into 9 specific factors, with three of them in the governance component alone. These factors are identified in Table 6, along with the colour and letter of their corresponding component.

Table 6
RIG framework – Key components and factors for shale gas development

Category	Label	Factor
Access to Natural Resources (R)	R1	Access to shale gas resources
	R2	Access to water
Infrastructure and Operations (I)	I1	Industry's technological and operational capabilities for shale gas
	I2	Oil and gas field services
	I3	Gas-to-market and auxiliary infrastructure systems
	I4	Recommended industry practices
Governance (G)	G1	Dedicated fiscal regime in alignment with the natural gas market structure
	G2	Regulatory effectiveness
	G3	Stakeholder engagement

Source: APERC

Access to natural resources – (R)

This component encompasses the most elementary inputs for shale gas development, in the form of the geologic resources and the water necessary for their economic extraction.

These resources are not denoted in terms of their natural supplies but rather in terms of accessibility. This distinction implies that aside from physical, technical and economic barriers, the existence of blanket and specific restrictions determine the access to develop these natural resources, with some economies blocking the exploration and production of shale gas through bans on hydraulic fracturing stemming from environmental and social concerns. In consequence, implicit in this notion of access is a political position on granting the corresponding rights to explore and develop shale gas.

To some degree, this position will be based on an early assessment of the quality and quantity of the resource base which makes some shale plays more economically viable than others. This information in combination with the associated long-term risks and benefits, the net balance of the natural gas trade, and the political and energy agendas in place will usually influence an economy's decision on the degree of control exerted and the extent of access allowed in the development of its shale gas resources.

In many economies this decision is made unilaterally at the highest administrative level; yet, within a single economy, positions may also differ, as they do in Australia, Canada and even the United States, where some states or provinces are in favour of developing their domestic shale gas resources but others are not. In any case, shale gas will not be accessed unless there is political consent to the development of these resources through the activities indicated in Figure 22.

In view of this, the first factor **(R1)** refers to the **access rights for the development of shale gas resources**. The government's action beyond this access might encompass a more active profile with goals, programs and supportive measures which are considered by other factors in the framework.

Closely related, the second factor **(R2)** relates to the **water access for drilling and hydraulically fracturing the shale gas wells**. Legal provisions aside, policies on this access must consider the endowment of nearby water resources, climatic conditions and other water needs. The water volumes accessible might diverge to a great extent between locations in their qualities, sources, costs and proximity, entailing different impacts on the commercial viability of shale gas. Water sources include surface and groundwater aquifers, municipal water supplies and recycled water flows.

Water typically represents more than 98% of the total fluid volume injected during the process of hydraulic fracturing. While water requirements vary across the geological settings in place, an assessment of actual water requirements in producing locations in some of the shale plays in the United States and the Horn River basin in Canada indicates that on average, nearly 18.8 million litres (5 million gallons) of water are consumed per well; approximately 95% of this volume is used for hydraulic fracturing, while the rest is used for drilling purposes, (King, 2012). In comparison, 20 million litres(5.2 million gallons) are approximately equivalent to the volume necessary to fill eight Olympic swimming pools.

Depending on circumstances, a relatively abundant water supply at an economy level might be insufficient in consideration of droughts or competing demands localized at the level of a region or shale play. Even though the average water intensity of shale gas is deemed low in an energy-based comparison with other fuels production processes (Mielke et al., 2010), it is still as much as 100 times larger than that of conventional gas (Korfmacher et al., 2013), and its cumulative effects on a large-scale development scenario could have a major impact on water supplies, especially of freshwater. Hence, it is vital to secure water sources and manage them effectively.

Textbox 2
The learning curve of shale gas development

In spite of the divergences across jurisdictions, shale gas development generally involves the following processes and stages.

- **Exploration**

Every shale play varies on parameters like areal extent, lithology, thickness, depth, permeability, porosity, pressure, carbon content and thermal maturity, which lead to different productivity profiles and assumptions of commercial viability. The study of these properties allows the assessment of the qualities and quantities of gas and other hydrocarbons in each shale play.

- **Pilot testing**

This stage encompasses the validation of the exploration outcomes in a shale play through actual production technologies such as hydraulic fracturing.

While pilot wells are more expensive that those in the exploratory and development stages, they help reduce the uncertainty about the shale play and contribute to optimize its technical development.

- **Demonstration**

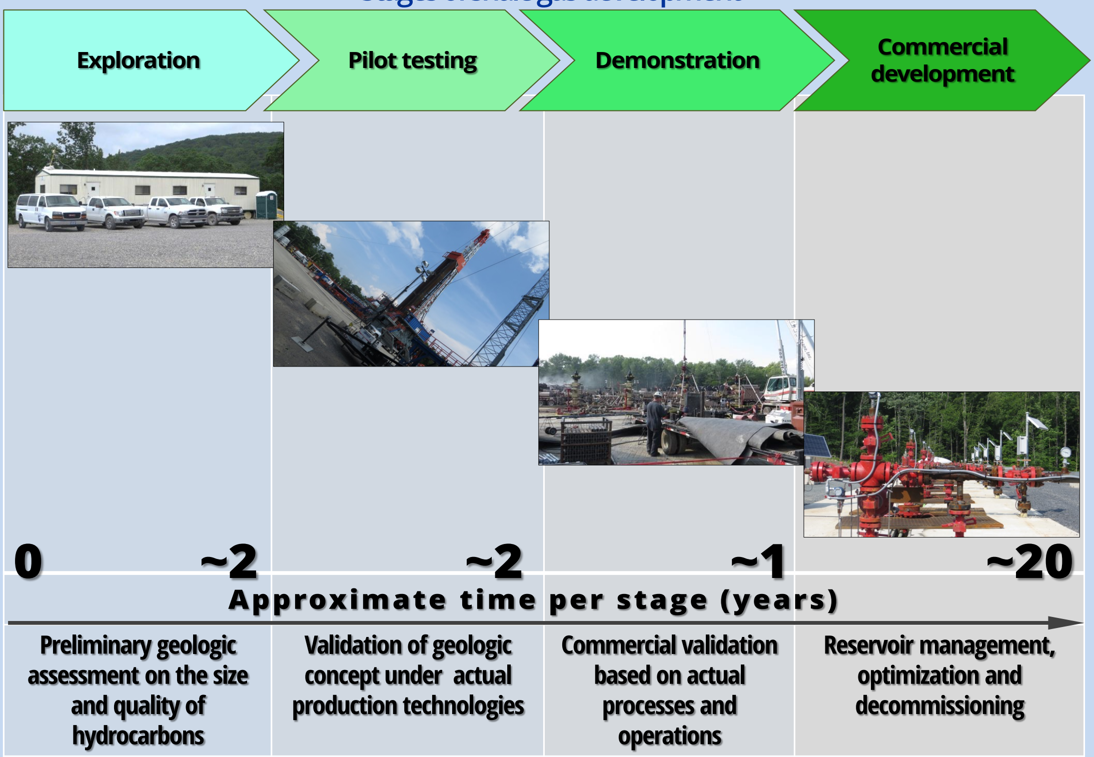
This stage aims to demonstrate the commercial viability of the resources in step with operational practices. Through pilot programs encompassing a number of appraisal wells, developers calculate the expected ultimate recovery factors (EUR) and test for the consistency of operation practices while improving productivity and efficiency.

This stage is critical to advance on the learning curve. Pad drilling operations are usually an indicator of this stage, as they are not usually feasible at an initial stage.

- **Development**

Large-scale development aims to optimize production and improve economies of scale permanently. It includes the eventual decommissioning of wells once the economic life of a reservoir has expired.

Figure 22
Stages of shale gas development



Source: APERC

In conjunction with the success of each of these stages, 'above-ground' or non-geological factors will largely drive the progress speed and timeframes in the transition between the different stages until reaching commercial development. Finally, unlike conventional gas resources, the risk involved in shale gas production is not limited to geology alone, but in combination with other factors which emphasise the commercial risk in producing these resources cost-effectively.

The information in this textbox was based on Guarnone et al. (2012), Binnion (2012), and industry insights.

Infrastructure and operations – (I)

The second component of the framework consists of the industry's infrastructure, technology and operations critical to support the economic production of shale gas. The factors in this component and their respective progress are expected to affect the resource base discussed above.

The first factor **(I1)** in this component concerns the **industry's capabilities in adapting to the complexity of shale formations through the design and execution of cost-effective gas production operations.** In comparison with conventional gas, shale gas reservoirs are more intricate to assess, their productivity is highly variable even within short spatial differences and their natural decline is more accelerated. These characteristics call for specialized technological skills to map shale gas resources, to identify the most productive areas and to improve production methods.

The combination of these geological considerations with the technological processes involved in the extraction of gas from shale formations require a larger number of producing wells to maintain stable or rising output levels. A more intensive drilling effort entails larger land acreage and more materials, equipment and personnel, which usually add up to higher capital and operating costs. In order to support a more rapid and cost-efficient pace of drilling, the industry must be able to deploy an approach reminiscent of supply chains, by employing clustered wellheads and equipment (well pads) which involve scalable, repeatable operations designed to improve performance over time.

In the few economies which have reached the commercial stage of shale gas development, including the United States, the government usually lays the foundations for the industry's technological knowledge. This includes basic research and development programs as well as resource base assessments with higher certainty. Depending on the prevalent conditions, governmental support might stretch to programs which promote a larger and more competent workforce in step with the industry's challenges and needs.

Two elements are strategic to the industry's capabilities in producing more complex resources like shale gas; the first is the interaction of multidisciplinary teams with a diversity of expertise and backgrounds to foster better problem-solving capabilities; the second is an increasingly risk-taking approach to take up more challenging projects in the face of competitive pressures.

In practice, the deployment of supply chain-like operations and the acceleration of the learning curve are accomplished in coordination with oilfield services companies and equipment suppliers. These companies provide specific inputs and carry out many of the processes involved in the development of shale gas; in so doing, they help disseminate technological innovations and improve the economic and operational efficiency across the industry. Because of their relevance, **oil and gas field services** are regarded as the second factor **(I2)** of this component.

Alongside the industry's technological and operational capabilities and the availability of oilfield services companies, a well-developed physical infrastructure is necessary to allow the extraction, processing, storage, transportation, and distribution of shale gas. Production rigs, processing units, compressor stations, gathering lines, storage facilities and transmission pipelines, are some of the main assets to consider in the development of shale gas. In cases where final markets are not accessible by land, even LNG export terminals might need to be considered within a project's lifecycle. This infrastructure must be extensive to the assets needed to access, transport, and manage the water employed in the extraction processes.

From a broad perspective, some generic or auxiliary infrastructure assets devoted to economic development underpin the planning and logistics of shale gas production. Multimodal transportation in the form of roads allow frequent movement of trucks carrying water, materials, equipment and personnel to the well site, while railroads and waterways allow the bulk transportation of materials such as like sand, cement and proppants from their original locations up to the shale plays. Catering, housing, health and other general services are equally necessary for the workforce and its operations. Where it does not already exist, this spectrum of **generic and specific infrastructure**, which may take years or decades to build up, is included in the third factor **(I3)** of this component.

Textbox 3
Natural gas development in the Marcellus Shale

With the aim of refining the understanding of shale gas development in a real-world setting, APERC's research team made a trip to Pennsylvania in June 2014 which included several technical visits in the Marcellus Shale, kindly arranged by the Penn State University Marcellus Center for Outreach and Research (MCOR). This helped APERC grasp the range and magnitude of infrastructure and technical resources necessary for the commercial production of shale gas.

APERC went to several facilities run by different companies, including a shale gas drilling rig in operations, a hydraulic fracturing site, and a compression station which allows the pipeline transportation of the gas produced to the market. Because flowback water may display qualities that prevent its conventional management and disposal, APERC also visited a water plant which specialised in the cost-effective treatment of flowback and production wastewater from the Marcellus Shale oil and gas operations, to allow their reuse and help reduce the freshwater volumes consumed.

Figure 23
Infrastructure and operations in the Marcellus Shale, Pennsylvania

Photos: APERC

During these visits, APERC observed the close proximity of many of these industrial facilities to homes, farms, and wildlife, which has greatly contributed to the adoption of practices by shale gas producers and oilfield companies alike to improve their performance and fulfil or exceed the regulations in place. These practices concern the safety of the personnel involved and the reduction of effects on the ecosystem and aspects like land clearing, roads and the transportation of personnel and materials, water management and impoundments, and well drilling and completion.

APERC also stopped by the facilities of an oilfield service company, which highlighted the role of proprietary technology and a skilled workforce in providing efficient technology solutions and operational services to shale gas producers. APERC was told by that company that due to the rising shale gas output and the personnel programs established some years ago in response to the industry's demands, the number of local staff had been rising.

Figure 24
Shale gas development in Pennsylvania

Photos: APERC

On this subject, APERC visited ShaleNET, a cross-institutional initiative between the public workforce system, the industry and consortium colleges to sustain the personnel needs of the natural gas industry in Pennsylvania. ShaleNET provides technical training on a set of transferable skills which meet the requirements of the industry's entry-level positions, and which may be expanded according to a five-tier stackable model for more specialised credentials. APERC also learned about MCOR's role in facilitating and disseminating technical research on the critical areas of shale gas development, in order to promote a science-based discussion among stakeholder groups, federal and state legislators, the natural gas industry and the public.

On APERC's arrival at Marcellus Shale through the airport in Williamsport, Pennsylvania, the aerial view showed a considerable number of wind turbines in operation. This image showed that the prolific shale gas production undergoing in the region does not obstruct the growth of renewable energy, and illustrates that the development of both energy sources is possible.

The fourth and last factor in this component **(I4)** regards the adherence to **practices to improve the safety of the industry's operations and reduce their environmental and public health risks**. As noted earlier, shale gas development is an industrial process which has stirred more debate than conventional gas production, largely because of its more noticeable effects, many of them closer to communities with no previous contact with this type of activity. Although the effects of shale gas development extend to the land, the air and the community, water is likely to be the most controversial aspect, due to the cumulative water demands (which reduce the availability of freshwater supplies) and especially, the concern that the proppants injected to the well could flow back to reach and pollute the groundwater.

The depth and breadth of these practices are contingent on contextual conditions, the industry profile, and the stage of development of shale gas resources. These industry 'best' or recommended practices usually cover the entire lifecycle of shale gas development, spanning the well's site preparation, drilling, casing and completion; processing, transportation and operation; the storage and management of flowback and other hazardous materials; the site remediation and abandonment; and the greenhouse gas emissions associated. In turn, the major risks involved with each of these activities can be assessed in terms of a specific element such as water, land, air, or community.

These practices could be developed domestically or adapted from more experienced jurisdictions, being independent from, but aligned with the regulation in place. Additionally, their design could include baseline indicators and the public disclosure of information in an attempt to help the industry exceed the regulations in place, identify areas for improvement and innovation, and foster better social monitoring and more informed discussion.

In connection with the factors in the infrastructure and operations component, three essential elements are worth mentioning:

- First, growing natural gas demand (domestic or external) is necessary to underpin any domestic development of shale gas resources. In addition to a robust natural gas demand, in some economies the need to diversify their gas supplies or reduce their dependence on gas imports might strengthen or entirely drive the efforts and capital expenditures associated with the development of shale gas, as manifested in mandatory or aspirational production targets.

- Second, the technology, workforce, and infrastructure underlying the development of shale gas entail considerable investments which highlight the importance of raising capital irrespective of the industry profile in place.

- Lastly, the development of technology, infrastructure, materials and a trained workforce are lengthy processes, for which contexts with prior production of conventional and unconventional oil and gas resources will have a legacy of tangible and intangible assets which will likely shorten the learning curve and timeframes towards the commercial production of shale gas. Possibly, this legacy industry will have also promoted a larger availability of oilfield and general services and a social environment more familiar with the operations of the natural gas industry.

- Finally, the lack of natural gas demand or market opportunities inhibits the efforts and capital expenditures conducive to shale gas development, even in spite of the mandatory production –and often ambitious– targets established by some governments.

  Although the presence of liquids and heavier hydrocarbons in the production stream has driven the economics of some shale plays in production during the last years and generally improves the economics of prospective projects, the natural gas produced might still be stranded, or worse, flared or vented, in the absence of a clear market for its use.

Governance – (G)

While the first two components in the framework are relatively straightforward, governance is expressed through different institutional arrangements of formal and informal rules which frame the political, economic and social interactions among the diverse governmental and non-governmental actors.

Because of its multidimensionality, governance represents one of the most challenging components of shale gas development Andrews-Speed and Len, 2014; Jarvis, 2014, and in spite of its suitability to bring about a closer collaboration between major stakeholders and foster more favourable results in the first two components, certain features might not be pursued by some economies due to the political cost. The three interlinked governance factors in the framework's governance component are described below.

The first factor **(G1)** refers to the **economic alignment between resource owners and producers of shale gas, in consideration of the natural gas market structure**. As the owner of oil and gas represented is in most cases the State, this economic alignment is defined by the government's recognition of the higher complexity faced in the development of shale gas. To that end, once access rights have been granted for the development of shale gas resources, the fiscal terms established must be different from those applicable to the production of conventional gas. The design of the fiscal regime should reflect the unique risks and the higher economic costs incurred, granting producers more flexibility in their selection of the operational arrangements most appropriate to the geological and commercial uncertainty in place.

While these terms will ultimately depend on prevalent contextual settings, a sound regime for shale gas will aim to reduce the uncertainty across the lifecycle of these projects and provide legal stability to resource owners and developers alike in their respective pursuit of fair returns in consideration of the risks involved. The costs incurred can increase significantly depending on whether extraction costs are considered alone (half-cycle) or in combination with land acquisition, seismic operations and other additional expenses across the entire lifecycle of a project (full-cycle). Some elements to consider are the following:

- Preserving clarity and the rule of law throughout the duration of the binding agreement, to enhance predictability in the decision-making of producers;

- Setting clear fiscal terms based on the time horizons and cash-flow profiles representative of shale gas projects, considering as much as possible the use of actual information on the productivity of the shale play or the project concerned;

- Allowing the economic recovery of upfront investments and operating costs during the early years of projects, to provide incentives for accelerated drilling and the addition of new wells;

- Reducing information asymmetries by sharing and updating geological data;

- Clarifying the responsibilities of the parties responsible for making infrastructure investments;

- Choosing fiscal systems with simplified procedures and requirements to maintain low and efficient administrative costs which facilitate compliance and meet the producers' needs for logistical speed and operational flexibility;

- Reducing transaction costs between the parties by embedding progressive fiscal terms which account for the mutability of the market and international prices without having to renegotiate the applicable regime;

- Setting fiscal terms which reflect the competitive position of the shale play and its jurisdiction against other international references; and

- Specifying different taxation schemes for hydrocarbons co-produced with natural gas with intrinsic higher economic value due to their linkage with oil prices.

As discussed previously, the extent of governmental support might stretch to the infrastructure and operations component, to involve predetermined production goals or an active operational participation through the NOCs, which in turn will influence the economic munificence of the fiscal regime applicable to shale gas production. However, the fiscal terms ultimately implemented are more likely to be driven by the structure of the natural gas industry in place.

- In their initial phase, natural gas industries are typically characterised by non-competitive structures such as monopolies, which rely heavily on government-led prices and economic incentives such as subsidies. Nonetheless, as the demand for natural gas expands, there is a rising need for more operators competing with each other to develop a market with non-discriminatory (open) access to common transmission infrastructure and prices determined through the interaction of the aggregate natural gas supply and demand. In step with this market maturity, certain economic incentives may no longer be necessary to support the development of gas resources.

  Altogether, these issues will promote a shift in the government's role from its active participation in the market's operations to a policy-making and regulatory role (IEA, 1998, 2013).

- By the same token, it is noted (Tian et al., 2014) that when shale gas development and natural gas markets are both in a primary stage, government intervention is likely to be more convenient until the commercial potential of a shale play has been proved, calling then for full market-based measures which will induce industry players to extensively develop production. It is expected that some measures will overlap in the transition between these.

However, *increased competition, open access to pipelines and market-based pricing* will evolve at a more advanced stage of industry maturity. These characteristics of a more competitive market will cause market participants to reflect actual costs more accurately, thereby driving more rational decisions across the industry's value chain. These decisions include investments to address infrastructure bottlenecks more effectively and ultimately promote lower prices to consumers. In this way, a competitive market favours socially optimal prices over prices set deliberately under non-competitive circumstances.

- Moreover, market-based measures promote strategic cooperation between companies as a means to spread their risks, complement their assets, absorb new knowledge and mutually increase their competitive advantages, leading to hubs of innovation and overall gains in cost-efficiency.

Crucial in guiding the structural market shift and reflecting the conditions established in the fiscal regime is the government's regulatory role. An effective regulatory system will nonetheless transcend a market-oriented function to address holistically the matters related to shale gas development in the short and long terms. Policy-making depends on the interlinkage between the political system, the institutional arrangement, the planning processes, the programs designed, and the specific context prevalent (Howlett, 2009). Hence, the resulting regulations for the development of shale gas will vary across jurisdictions, based on the identified risks and the priorities assigned to mitigate each one of those risks.

Potential risks span a variety of market, economic and fiscal issues related to the industry structure and consumers. Technical and safety issues concern the industry's operations, socioeconomic impact local communities, and environmental and public health impacts concern the public interest. In consideration of this, **regulatory effectiveness (G2)** is the second factor in the governance component, in order to provide predictability to the actors involved and reduce possible negative externalities at the lowest cost for taxpayers.

To that end, resulting regulations must be effectively designed, implemented and overseen, in order to strengthen the authority's legitimacy in a way which facilitates cooperation from the industry and other stakeholders. Nonetheless, effective regulation, is not sufficient to address the multidimensionality and diversity of the interdependent actors and interests involved in the development of shale gas.

The co-sharing of risks, decisions and benefits with other stakeholders is not the government's exclusive responsibility, as it also spans the links between the industry and non-governmental actors. In this sense, social environments are becoming more cognizant of the risks and technical processes involved in shale gas production, for which the long-term success of companies hinges on their ability to increase social acceptance of their projects. This is usually expressed in the concept of 'social license', the tacit public authorization of a company's operations by the stakeholders directly affected by these projects, as well as a larger number of those stakeholders not affected locally, but with a compelling reason to be involved anyway (Liss and Murphy, 2014).

In consequence, a **multi-stakeholder engagement** perspective **(G3)** represents the third factor in the governance component, and is likely to foster a more efficient use of resources, a more inclusive and balanced regulatory system, and as a whole, a more effective system of social collaboration to identify and address the trade-offs and risks involved throughout the lifecycle of shale gas projects. More importantly, a proactive multi-stakeholder engagement can contribute to building reciprocal trust amid governmental and non-governmental actors, in order to reduce their transaction costs, increase the predictability of their mutual actions (Davidson et al., 2006) and in the end, promote a virtuous cycle of positive synergies in which social demands improve the performance of companies and government's regulations.

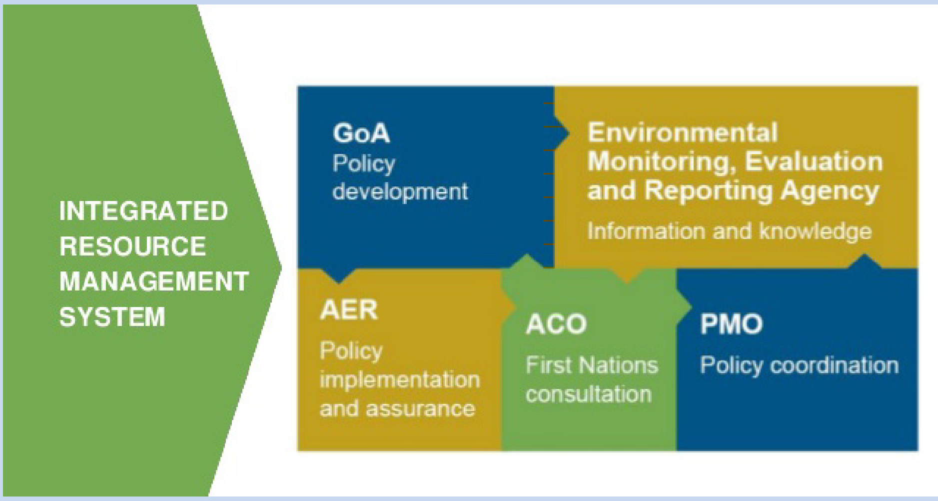
Textbox 4
Shale gas development in Alberta, Canada

To learn about Canada's policy-making and regulatory approach for shale gas, APERC's research team visited Alberta in June 2014. With the kind support of the International Energy Policy Branch of Alberta Department of Energy, this visit allowed APERC to gain valuable first-hand insights from the provincial government and the industry.

Because most energy matters in Canada are under provincial jurisdiction, APERC first visited Alberta Department of Energy to learn more about its institutional arrangements for oil and gas development. It was stressed that the provincial government has recently carried out efforts to streamline its regulatory procedures, in the style of a one-stop-shop through a single agency— the Alberta Energy Regulator (AER).

In a subsequent visit, AER stressed its mandate of ensuring a safe, efficient, orderly, and environmentally responsible development of the entire life cycle of oil and gas resources for the benefit of Albertans. In translating this mandate into action, AER strives to balance social, economic and environmental factors. AER is part of a broader Integrated Resource Management System (IRMS) in the province of Alberta which helps integrate and align resource-based policies around economic, environmental and social outcomes. In this way, the system strengthens regulatory functions while guiding and providing more certainty to the industry and the regulator alike.

Figure 25
Alberta's Integrated Resource Management System



Source: AER

AER's mandate implies regulations proportional to the underlying risks, which in the case of shale gas encompass the most critical areas:

- Water quality and quantity;
- Hydraulic fracturing operations;
- Induced seismicity and emissions;
- Surface infrastructure planning;
- Cumulative effects on air, land and water; and
- Social impacts and stakeholder engagement.

It was emphasised that in Alberta, ensuring appropriate regulations for shale gas development has entailed permanent adaptation to the industry's evolving operations and best practices. There are stricter regulations on hydraulic fracturing, which aim to maximise the recycling of water while minimizing freshwater consumption through the use of sources like saline water. The goal of using alternative water sources would need to take into account a net environmental impact to avoid unintended consequences.

Another example is a forward-looking vision which involves an ongoing shift from prescriptive- to aggregate performance-based regulations, with the aim of implementing a shale-play-level assessment to address cumulative impacts more comprehensively and foster a more effective risk management approach through the collective efforts of incumbent operators. Foremost of these efforts is stakeholder engagement, which includes a consultation process over the life cycle of operations to strengthen relations and mutual understanding. This aims to enhance opportunities to influence decisions on project design and operations where risks cannot be effectively mitigated.

Figure 26
Alberta's Core Research Centre

Photo: APERC

To improve the transparency of its oversight activities and strengthen public engagement, AER provides public access to information, including the disclosure of the chemicals, fluids and water sources used for hydraulic fracturing in each well. AER also levels the industry's competitive field and enhances its technological knowledge through access to its exhaustive collection of historical geologic samples and data stored at its Core Research Centre.

This trip was deliberately timed to allow APERC's research team to attend Calgary's Petroleum Show, in order to get a better understanding of the industry's challenges in terms of access to capital. In that regard, industry experts mentioned that while small- and medium-sized companies have traditionally taken higher risks, the increasing capital profile of shale gas projects is preventing many of them from participating more actively. This has shaped an industry profile with a bigger share of large and medium-sized players, leaving many companies, especially the smallest, to find newer market niches as technology and service providers.

As for the industry's stakeholders, APERC visited a shale gas producer which highlighted the value of best practices as a means of minimising major risks and community consultations to secure a social license for its operations. Additionally, an oilfield service company told APERC that in producing shale gas not only is access to technology essential, but having the knowledge necessary to choose the technology most appropriate to the conditions in place is especially important, given that a bad initial decision might irreversibly affect the reservoir's productivity.

Subsequent meetings with industry associations confirmed these statements and stressed that as the commercial viability of shale gas projects is largely influenced by the regulations in place, firms in Alberta generally look forward to exceeding these regulations proactively, using recommended processes and innovative technologies which not only entail lesser impacts and improve their social license, but help many companies to keep a competitive edge in the market.

For further information on Alberta, please see Canada's section in the Chapter 4 of this document.

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4 Analysis by economy

This chapter presents an analysis of the six economies with the potential to develop or which are already developing their domestic shale gas resources in the Asia–Pacific region. As noted in the introduction of this research document, these economies are Australia, Canada, Chile, China, Indonesia and Mexico.

To that end, each of the following sections is devoted to one particular economy, in consideration of the RIG framework explained previously. Table 7 shows the framework's items considered in this analysis, which have been highlighted with three different colours to account for each of its major components: Access to Natural Resources, Infrastructure and Operations, and Governance.

In broad terms, the two first components refer to the conditions which allow the physical production of shale gas. The third component is far more controversial and politically sensitive, but it has the power to alter the other two components drastically. A useful analogy to express the relationship between these components is to see all of them as complementary links, but while the first two may be thought of as 'hard', governance represents the 'soft' counterpart.

The assessment of each economy is based on the expert insights provided at APERC's initial shale gas workshop and other specific academic and professional events, which were subsequently supported with updated scholarly and official sources. In order to ensure consistency among the different economy analyses, some references were used throughout the discussion of the first component. These main references were the EIA (2013), for the preliminary volume of shale gas resources; the FAO (2014), for total renewable water resources; and the World Resources Institute (2014) for the water stress in the development of shale resources, an indicator defined as "the ratio of total water withdrawals from municipal, industrial, and agricultural users relative to the available renewable surface water" (p. 3). These common references did not preclude the use of other available sources of information specific to these economies.

Other references used for consistent general energy information were taken from the *Oil and Gas Journal* (2013), for the conventional oil and gas reserves; and BP (2014) for energy demand and supply volumes. It is worth mentioning that some of the economy assessments might change in the meantime, contingent upon the turbulence of the energy markets, the uncertainty of major geopolitical events, new geological assessments, and the occurrence of drastic political shifts in individual economies which may considerably alter their energy priorities.

The economy analyses in this chapter have been structured in accordance with the RIG framework's major three components and respective factors, along with a brief introductory overview and a final summary of challenges and opportunities. Information sources appear at the end of each section, in order to allow the individual examination of each economy presented.

Table 7
RIG framework for economy-based analysis of shale gas development

Category	Label	Factor	Additional points to consider	
Access to Natural Resources (R)	R1	Access to shale gas resources	▪ Preliminary assessments of shale gas resources ▪ Political position on shale gas development	
	R2	Access to water	▪ Type and proximity of water resources	
Infrastructure and Operations (I)	I1	Industry's technological and operational capabilities for shale gas	▪ Technological development ▪ Adequate workforce size and skills ▪ Presence of IOCs experienced in shale gas development	▪ Market demand ▪ Access to capital ▪ Legacy of conventional (and possibly unconventional) oil and gas activities
	I2	Oil and gas field services	▪ Presence of IOCs experienced in shale gas development	
	I3	Gas-to-market and auxiliary infrastructure systems	▪ Auxiliary infrastructure for economic development	
	I4	Recommended industry practices	▪ Professional oil and gas associations	
Governance (G)	G1	Dedicated fiscal regime in alignment with the natural gas market structure	▪ Fiscal provisions or regimes accounting for the risks and productive profile embedded in shale gas development. This is usually dependent on the market profile and the following characteristics: □ Policies granting equal operating conditions (that is, barring monopolies or certain companies from holding a dominant industry position) □ Open access to gas transmission infrastructure □ Deregulated natural prices and temporary subsidies	
	G2	Regulatory effectiveness	▪ Capacity and transparency ▪ Scientific- and risk-based information ▪ Holistic and enforceable regulation ▪ Adaptability to industry shifts and mutable stakeholders expectations	
	G3	Stakeholder engagement	▪ Proactive consultation with diverse stakeholders ▪ Industry's social license to operate ▪ Life-cycle engagement ▪ Public access to regulatory and legislative information ▪ Management of public expectations	

Source: APERC

To convey more succinctly all the information discussed and to capture in a single picture the profile of the economy in analysis, a radar graph such as one depicted in Figure 27 is presented at the end of each of the economy sections. The graph is divided into the nine factors of the RIG framework, with three different colours corresponding to their respective major components (green—Access to Natural Resources; blue—Infrastructure and Operations; and red—Governance).

The radar graph is based on a broad assessment of the respective factors within the components of the RIG framework as based on the following quantitative scores:

0—Absent. This score denotes that the factor examined is not at all present in the economy analysed.

1—Partially in place. This score reflects that the factor examined exists in the economy assessed but is not fully operational.

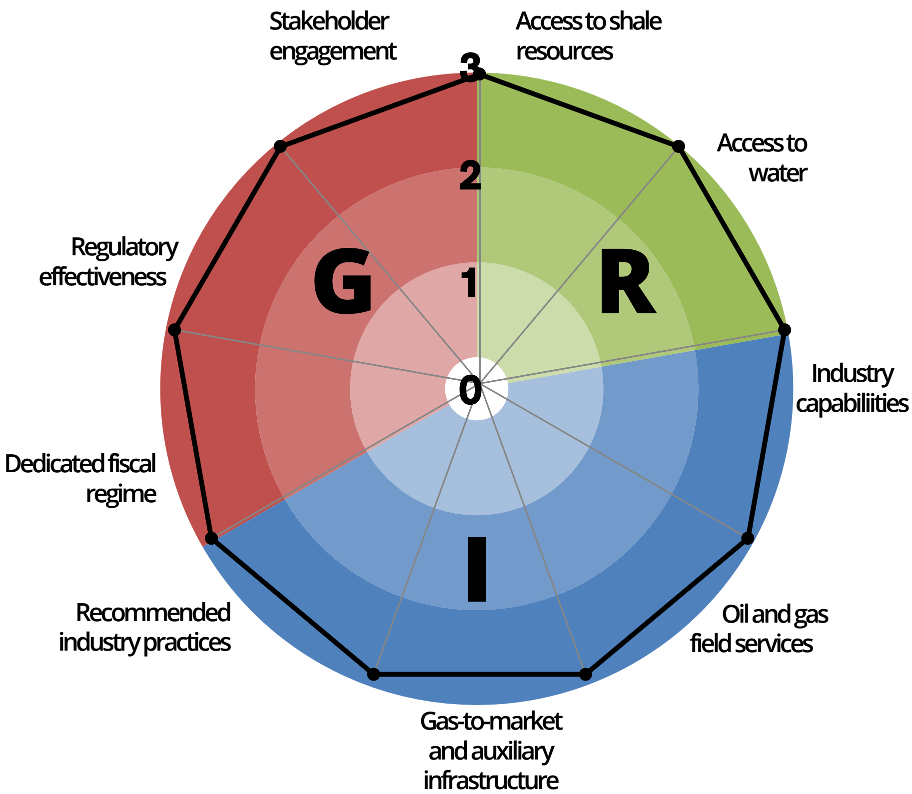
2—Partially in place and in the process of change. Similarly to the category above, this numeral applies to a factor which is not fully operational but which is currently undergoing or is about to undergo a change intended to enhance its efficiency, based on official plans and/or industry evidences.

3—In place. This score denotes that the factor examined is fully present in the economy analysed.

In line with these criteria, the higher the score for an individual economy, the more likely that shale gas can be produced in less time and on a larger scale. This is shown schematically with the colours and sizes of the radar graph's concentric rings; the higher a score for a given factor, the darker and broader the corresponding concentric ring.

Figure 27 shows a schematic representation of the best assessment theoretically possible for a single economy.

Figure 27
Schematic representation of APERC's shale gas policy framework



Note: The figure does not allude to any particular economy; it merely illustrates the maximum possible assessment for each of the factors assessed in the framework.

While the RIG framework is useful as a lens to condense the strategic factors involved in the development of shale gas resources, it must be stressed that the radar graphs do not identify critical elements which could positively or negatively overwhelm the assessed factors.

In consequence, the quantitative scores should be taken only as a general reference, as two or more economies with the same scores will not have the same contexts, motivations, or actors. Because of this, the RIG framework is more useful in combination with the qualitative analysis of the details, opportunities and challenges in each economy, as discussed in each of the following economy sections.

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Australia

Australia is the world's largest island and the sixth largest economy in land area. Australia has a territory of nearly 7.7 million square kilometres divided into six states and two territories, with a population of over 23 million people living mostly in major cities or regional centres along the eastern and south-eastern seaboards.

Australia has a long history of producing natural gas, with the first discovery made in 1964 in the Western Australian Perth Basin. Its plentiful conventional gas resources have historically sustained the growth of domestic and external markets; however, unconventional resources are rapidly increasing their relevance in step with LNG export commitments, which are predominantly oriented to northeast Asia. Even though shale gas production is still minimal, it has achieved commercial status since 2012.

Access to natural resources – (R)

Australia has a robust oil and gas industry which draws on its vast reserves, estimated at 1.4 billion barrels of oil and 1.2 trillion cubic metres (43 trillion cubic feet) of natural gas at the beginning of 2014.The latter represented around 2% of the world's proved reserves of natural gas ('Worldwide look at reserves and production', 2013).

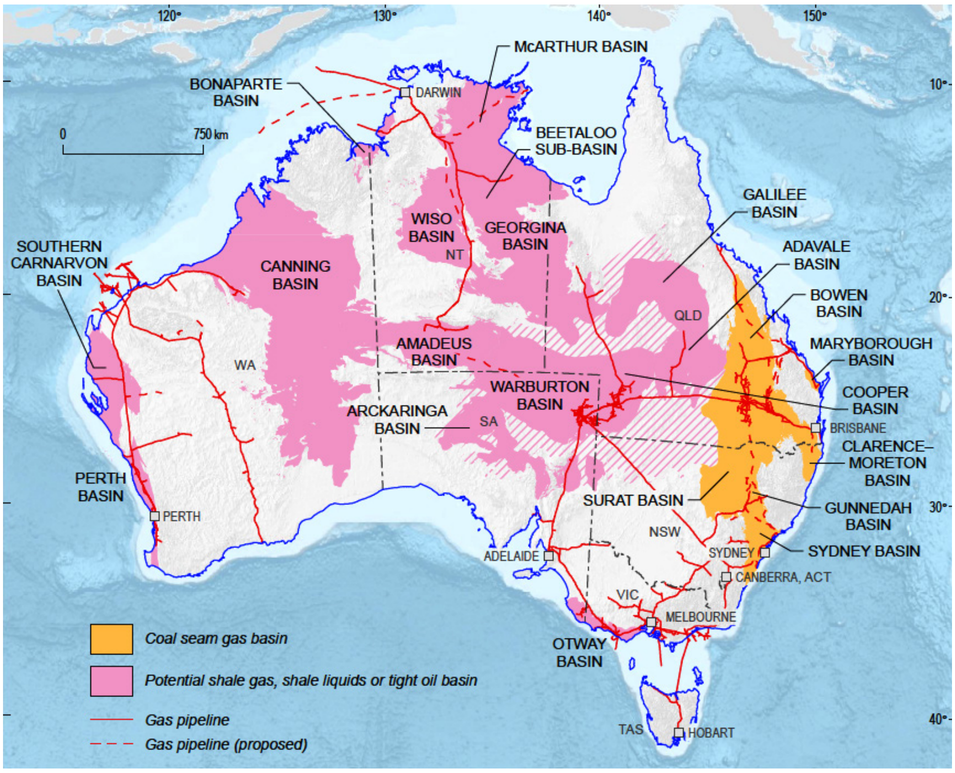
Australian natural gas production has been increasing steadily for decades. By the end of 2013 it reached 42.9 billion cubic metres (1.5 trillion cubic feet), which accounted for 1.3 % of the global output (BP, 2014). Although most natural gas production is derived from conventional resources mostly located offshore, coalbed methane (known in Australia as coal seam gas) has been produced commercially since 1996 and is becoming more relevant as the Queensland LNG projects commence. It is expected that over time, other unconventional gas resources will be commercialized more significantly, including shale gas.

As shown in Figure 28, shale gas basins are widespread across Australia. The economy is considered to hold the seventh position worldwide in terms of the magnitude of its shale gas resources, which were estimated at 12.4 trillion cubic metres (437 trillion cubic feet) by 2013 (EIA, 2013). The following are some of the major shale plays in which exploratory activities are currently ongoing:

- In Queensland and South Australia: Cooper;
- In Queensland: Galilee and Bowen;
- In Queensland and Northern Territory: Georgina;
- In Northern Territory: Beetaloo and McArthur; and
- In Western Australia: Canning and Perth (onshore).

The sizes attributed to Australia's shale resources are quite variable. To provide a better understanding of the potential shale resources and their distribution across the economy, the Australian Council of Learned Academies (2013) carried out a comprehensive examination based on an independent evaluation of 16 shale basins, some of which were not included in the assessment by EIA (2013). As a result, a much larger volume of Australia's potentially recoverable shale gas resources was estimated in comparison to the EIA assessment, with 40.1 trillion cubic metres (1,416 trillion cubic feet). Additionally, the occurrence of wet gas resources estimated in some of these plays is likely to strengthen their commercial viability.

Figure 28
Australia's shale gas resources



Note: Includes coalbed methane (coal seam gas) basins .
Source: Australian Government (2014).

As shown in Table 8, the Canning Basin accounts for the largest share of Australia's total recoverable shale gas resources, with more than 68%. The first commercial shale gas well started production in October 2012 in the Cooper Basin. This milestone led to the report of the first contingent shale gas resources in the Cooper Basin (57 billion cubic metres, or 2 trillion cubic feet), as well as the first shale gas reserves booked by the oil and gas company Santos. In an updated energy resource assessment, the Australian Government (2014) emphasised that the quantification of its shale resources is still undefined and the ultimate size will depend on further exploration.(Australian Government, 2014) .

Similar to many other Commonwealth nations nowadays, Australia's natural resources are owned by the Crown as expressed in the federal and state/territory powers. In this way, States and territories own the petroleum onshore and within their coastal waters up to three nautical miles; the federal government owns all other offshore resources. The governments at the federal and state/territory levels do not develop oil and gas resources by themselves via state-owned companies or other official entities, but grant private companies the rights to undertake those activities.

Notwithstanding the variations across the Australian States and territories, the access to gas resources including shale gas, is awarded in a licensing regime which distinguishes between the exploratory stage from production. Petroleum rights can be obtained by a bidding process in areas open to exploration and development or by proposal, provided that the area requested is available for consideration of other land uses. In most Australian jurisdictions, the holder of an exploration license resulting in a commercial discovery is entitled to receive a production license upon application and is subject to other legal requirements (Crommelin, 2009).

Table 8
Australia's shale gas resources by basin

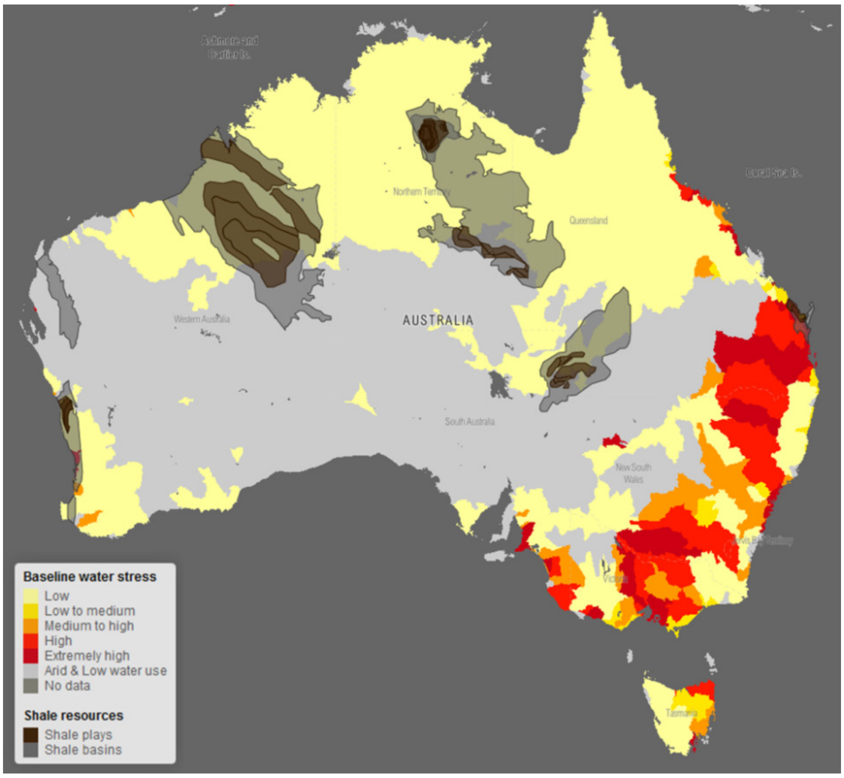
Basin	Play	Area (km^2)	Best estimate recoverable resources - Tcf	Best estimate recoverable resources - Tcm
Amadeus	Horn Valley	7,267	16	0.5
Beetaloo	Kyalla	898	3	0.1
	Velkerri	6,092	16	0.5
Bonaparte	Milligans	2,752	6	0.2
Bowen	Black Alley	51,252	97	2.7
Canning	Goldwyer*	147,305	796	22.5
	Laurel*	48,285	169	4.8
Carnarvon	Byro Group	6,162	9	0.3
Clarence –Moreton	Koukandowie	4,407	11	0.3
	Raceview	4,407	10	0.3
Cooper	Roseneath, Epsilon, Murteree (REM)*	9,106	49	1.4
Eromanga	Toolebuc	93,263	82	2.3
Georgina	Arthur Creek	14,433	50	1.4
Gunnedah	Watermark	8,631	13	0.4
Maryborough	Cherwell	3,264	7	0.2
McArthur	Barney Creek*	2,867	7.4	0.2
Otway	Eumeralla	4,109	9	0.3
Pedirka	Purni	29,357	43	1.2
Perth	Kockatea*	14,123	23	0.7
Total		**457,980**	**1,416**	**40.1**

*This play includes wet gas resources
Source: ACOLA (2013).

Australia is among the driest inhabited continents, and a considerable extent of its shale basins including the Cooper Basin is located in arid to semi-arid areas. Nonetheless, due to its low population density it is well endowed with water resources. On a per capita basis, Australia's total renewable water resources of more than 21,000 cubic metres sit in the second highest decile worldwide, exceeding the global average of 20,000 cubic metres (FAO, 2014). According to the World Resources Institute (2014), As shown in Figure 29, Australia has a low economy-wide profile of water stress for its major shale plays.

The water resource impacts of a larger development of shale gas in combination with other unconventional gas resources such as coalbed methane are expected to represent a major challenge in the future. Not only do both resources overlap in predominantly arid areas, but the water requirements per well of shale gas are on average 20 times fold those of coalbed methane (CSIRO, 2014). In consequence, a more aggressive scenario of shale gas development would drive the industry to use sources other than groundwater and surface freshwater, including recycled water, saline water, and non-water-based fluids for hydraulic fracturing.

Figure 29
Australia's shale gas plays and baseline water stress



Source: World Resources Institute (2014)

Infrastructure and operations–(I)

While Australia's industry has experience in conventional gas production and to some extent in coalbed methane, it still lacks the appropriate expertise for shale gas development. Australia has a 50-year history of drilling for natural gas, yet it has limited experience with hydraulic fracturing, as this process has been carried out only moderately in the Cooper Basin.

Even though Australia's shale gas potential seems quite large, the proper understanding of its geology is a challenge. Despite preliminary geological assessments indicating a large amount of resources, only continued exploration and drilling will confirm whether gas shale formations will support commercial well flow rates. Industry experience in the United States has shown that well performance varies greatly, calling for more exploratory wells across Australia's basins to estimate average flow rates with more accuracy.

Because Australian basins experience higher level of compressive tectonic stress in comparison to shale formations in North America (UCL Australia, 2013), the effectiveness of transferring technologies proved in other locations to Australia is unclear. The Australian government through its Geoscience Australia entity has played a key role in mapping economy-wide natural resources, and housing precompetitive, public geological information accessible to all stakeholders to help reduce the industry's exploration risk.

Significant exploration has been underway in the Canning, Georgina, McArthur, Amadeus, and Perth basins, although the Cooper Basin remains the most economical and has made the most advanced progress. The first commercial shale gas development occurred there in

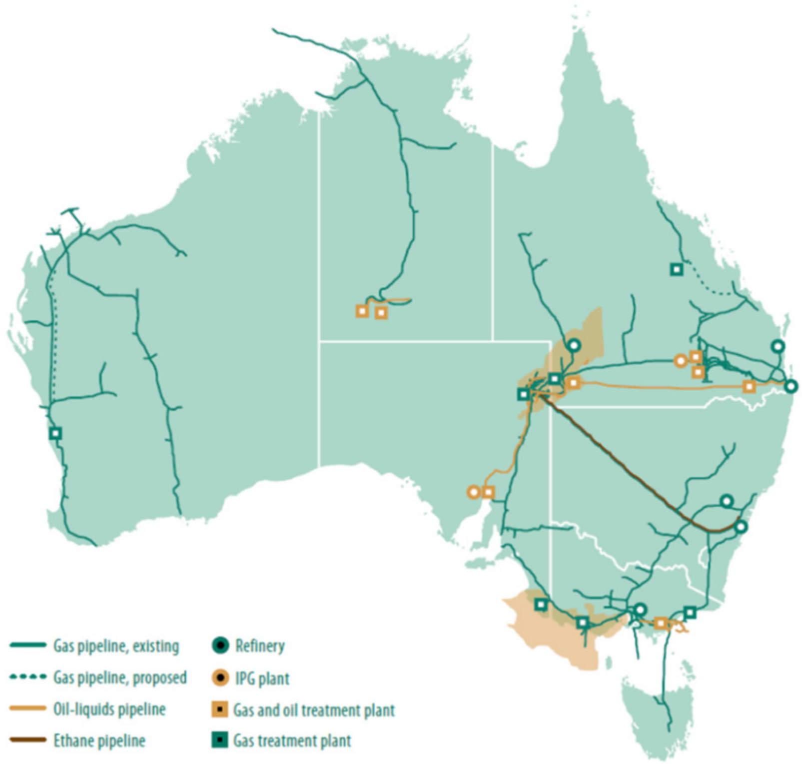
2012 with the Moomba-191 vertical well, which had an initial well flow rate in the range of 1 to 2.6 million cubic feet per day, an output equivalent to successful North American shale developments (UCL Australia, 2013).

A significant proportion of Australia's shale gas is remotely located, making it difficult to bring to markets. In this sense, Cooper Basin's early shale gas success is largely attributed to its legacy infrastructure built over a history of conventional natural gas production since 1969 (Bureau of Resources and Energy Economics, 2014). This existing infrastructure gives the Cooper basin a significant advantage as it enables quick commercialization of smaller pilot projects within current conventional gas plays.

As for infrastructure, as seen in Figure 30, the Australian natural gas pipeline network is very limited restricting access to markets. The Cooper and Perth basins have relatively good networks of infrastructure in place, making them the most readily available to expand shale gas production. However, there are no transmission pipelines in other basins such as Canning and Georgina to existing main transmission lines, creating a large barrier for shale gas development in these regions (ACOLA, 2013). Pipeline access is also constrained by the current regulatory regime of contracted carriage.

Currently, the capacity on most transmission pipelines is fully contracted, restricting the number of new entrants to the markets. Furthermore there are only a limited number of natural gas transmission pipelines which have been regulated and thus allow full third party access; only 11 of the 32 major transmission pipelines are regulated (Australian Government, 2014). Australian natural gas pipelines are privately owned and operated under long-term contracts to ensure recovery of pipeline investment costs, sometimes at the expense of access to other operators (UCL Australia, 2013).

Figure 30
Australia's natural gas pipeline infrastructure



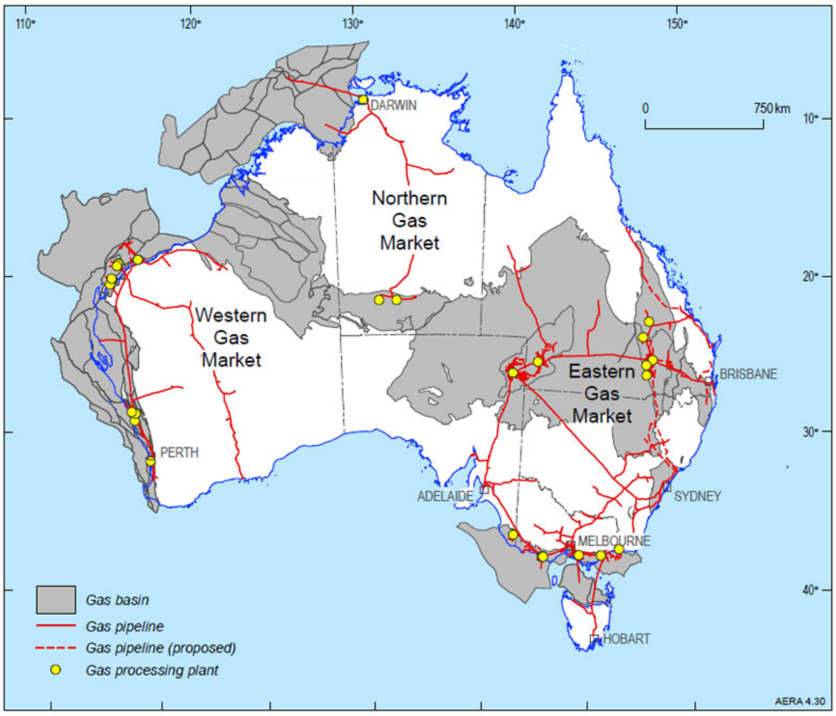
Source: ACOLA (2013)

By December 2014 there were only 13 active onshore rotary rigs in Australia, and only three of them were devoted exclusively to natural gas production. For the sake of comparison, in the same period there were 1,782 in the United States (Baker Hughes, 2014). The availability of experienced crews who can provide hydraulic fracturing and other auxiliary services is also questionable, which may mean longer lead times and higher costs in comparison with other conventional and unconventional gas resources. The prevalence of other auxiliary infrastructure in the form of underdeveloped road networks and a lack of sufficient and trained personnel in remote producing areas will slow the development of shale gas, and although these drawbacks might not be critical in an early stage, they will hinder large-scale production.

The implementation of industry-recommended practices is likely to be strengthened in step with the industry's shale gas learning curve. In that regard, the collaboration of professional organizations such as the Australian Institute of Petroleum to adopt common practices used in well completion and hydraulic fracturing applicable to coalbed methane production will help develop safer and cost-effective operations. Likewise, improving these practices hinges on market demand, and thus they will take some years to develop.

In this regard, Australia has three distinct and physically separated domestic gas markets as seen in Figure 31. The largest gas market is the Western market, accounting for 62% of Australian gas production, followed by the Eastern market at 35%, and the Northern market at barely 3% (Leather et al., 2013). The development of three distinct markets is based on the remoteness of gas supplies from population centres, and low domestic gas demand due to relatively small population and industries (Bureau of Resources and Energy Economics, 2014). In fact, domestic demand for natural gas remained relatively flat after 2007 and started to decrease in 2011 (BP, 2014).

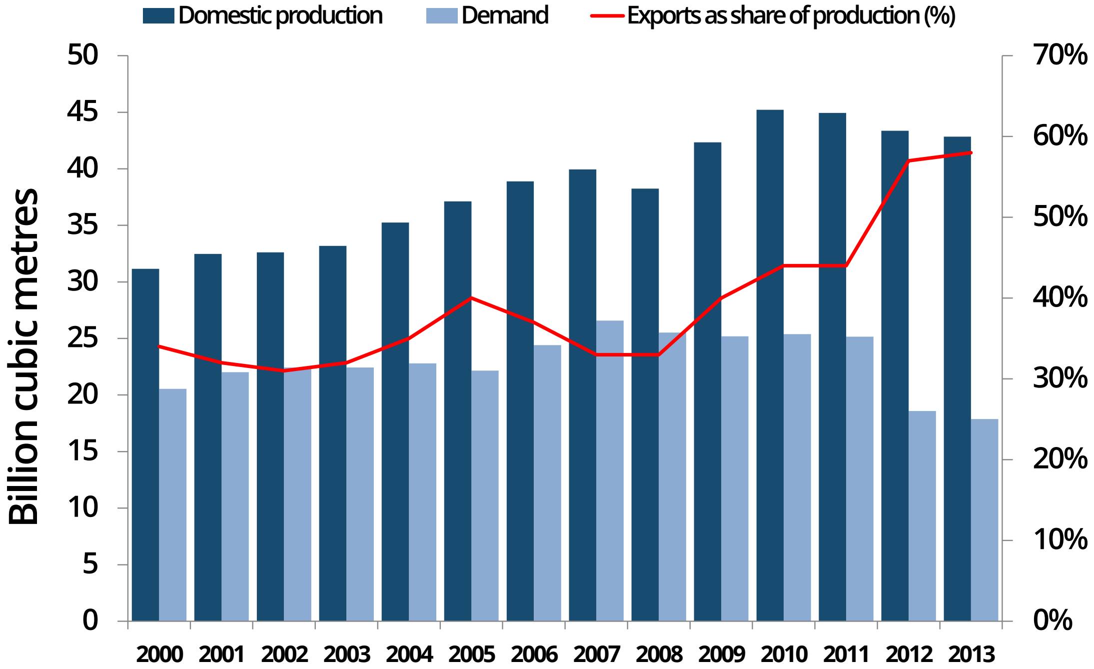
Figure 31
Australia's natural gas markets



Source: Australian Government(2014).

On this subject, Australia is a net exporter of natural gas; Figure 32 shows its main market indicators. By 2013, nearly 60% of Australia's natural gas production was exported (BP, 2014), for which the expansion of its output through the addition of new upstream projects, depend those related to unconventional resources, is dependent on external demand. The intensification of coalbed methane production in recent years for example, has been mostly derived from its potential to meet the LNG demand in Asian natural gas markets(Leather, et al., 2013). It is projected that Australia will become the largest LNG exporter in the world by 2020, supplying approximately 17% of the global demand (Bureau of Resources and Energy Economics, 2014).

Figure 32
Australia's natural gas production, demand, and exports, 2000-2013



Source: BP (2014).

Governance – (G)

Even though fiscal regimes for upstream projects diverge across the state and territory jurisdictions in Australia, they are basically made up of a rent-based tax, a corporate income tax and a royalty-based taxation system. The Petroleum Resource Rent Tax (PRRT) is the main tax collected by the Federal Government from onshore and offshore projects; it is set at 40% of a project's above-normal profits, so as not to discourage investments (Bureau of Resources and Energy Economics, 2014).

Additionally, the states and territories receive a royalty at the wellhead level which usually fluctuates between 10% and 12.5%. To promote investments, some states use a sliding scale with zero royalties during the first five years of a project, which grows to 6% by year six and afterwards increases 1% annually until reaching a royalty of 10%. In Australia there are no special fiscal regimes or terms applicable to unconventional gas or shale gas (EY, 2014).

Speaking of Australia's natural gas market, it is generally deregulated and has open access; however, since 2006 the Western Australian Government has a policy requiring project developers to reserve up to 15% of production to supply domestic energy markets (ACOLA, 2013). As for pricing, the Australian domestic gas market is dominated by bilateral long-term contracts between buyers and sellers, with spot transactions in the Eastern market. The long-term contracts enable large producers and consumers to underwrite large capital investments.

The Western and Northern markets use LNG netback pricing as there are currently LNG export facilities with combined capacity of 24.5 million tonnes per year, with another 36.5 under construction (Bureau of Resources and Energy Economics, 2014). In the Eastern market, it is expected that a similar LNG netback pricing mechanism will be used as more projects come online, and which ultimately may support more shale gas projects in remote basins.

The Australian government has a layered approach to regulating energy, and numerous federal bodies play a role in regulating and administering shale gas development. For the most part, the states and territories retain the responsibility of energy policy and regulation, while the federal government addresses interstate and overseas trade in offshore areas in which it detains ownership rights.

The state and territorial governments have the primary responsibility for shaping policies in their respective jurisdictions, which leads to variable energy policies across Australia. However, in most cases, the regulations in place are largely based on conventional projects, which could overlook crucial aspects of shale gas development, especially those dealing with safety and environmental risks (Hunter, 2014).

One of Australia's most comprehensive regulatory frameworks for the management of large resource development projects is in Queensland, given that state's long history of regulating the exploration and production of oil and gas dating back to the 1960's. Recently, there have been a number of exploratory wells targeting shale gas. The Queensland regulatory regime is responsible for many departments and a diversity of matters which play a unique role in governing oil and gas production. (Department of Natural Resources and Mines, 2014).

In South Australia, the government requires exploration companies to provide samples of cores and cuttings obtained during their activities, and provides public access to those samples and specialized geological information. South Australia's regulated operations are conditional on the prior approval of an environmental impact; and overall, regulations enshrine the principles of certainty, openness, transparency, flexibility, practicality and efficiency (Government of South Australia, 2014).

At a state level, much more work needs to be done to re-evaluate unconventional gas resource regulations to address environmental and public stakeholder concerns. These regulations will be developed overtime, as unconventional gas development gains more momentum and moves from the exploration phase to production. Social license to operate has been a key source of contention in high population density areas in the United States close to shale gas development. Notwithstanding that Australia's source of social conflicts may be currently low as shale resources are often located far from populations, however, companies have grown cognizant of the need to secure and maintain social license in their operations.

Challenges and opportunities

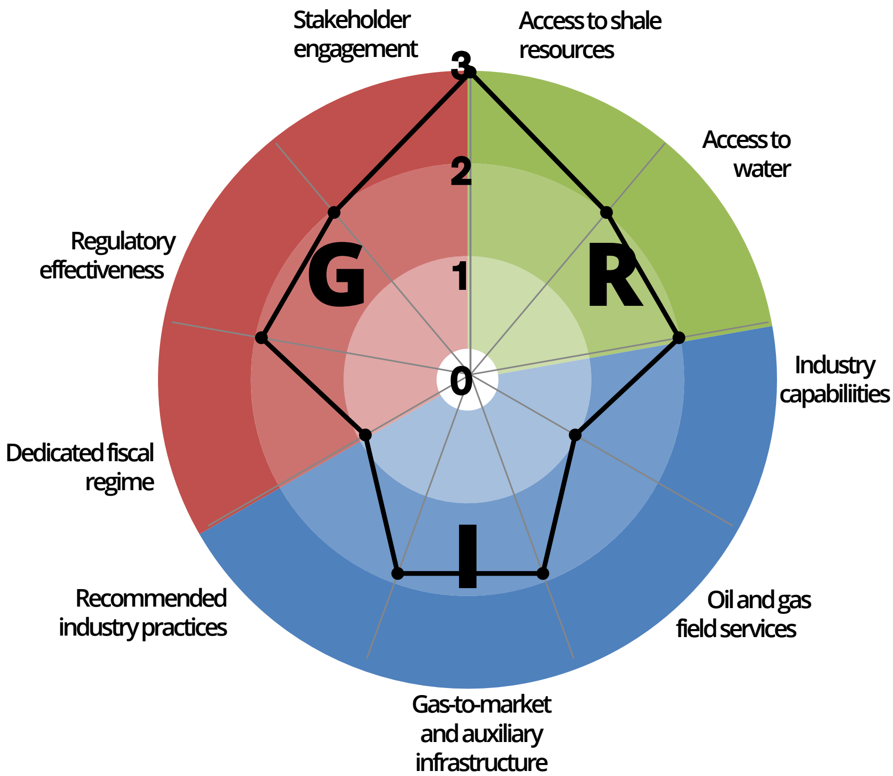
With its strong legacy of mineral extraction and conventional oil and gas production, a great deal of effort is still needed if Australia is to bring its shale gas to markets cost-effectively in comparison with other types of gas resources.

Significant shale resources lie across Australian basins, yet it remains unclear how much of this potential can be brought to markets given their exploratory uncertainty, not to mention technology and capital constraints. Limited access to gas-to-market infrastructure and a shortage of drilling capacity are other major challenges. In some basins, finding adequate water supplies could also delay some projects.

The existence of several conventional and unconventional gas resources produced competitively in Australia might discourage a massive development of shale gas, at least in the short and medium terms or until its cost-efficiency improves and new market demand accelerates its expansion. In this sense, Australia could modify the applicable fiscal regime and the government and companies in tandem could engage stakeholders more actively, with the aim of bringing shale gas to market in a way which protects the environment and results cost-effective.

More importantly, with its profile as net gas exporter economy, much of Australia's shale gas development will depend on external market demand, just as much as its current coalbed methane output is oriented to LNG exports. In light of this examination, Australia's assessment of shale gas development using the components and factors of the RIG framework is shown in Figure 33.

Figure 33
APERC's assessment of Australia's shale gas development under the RIG policy framework



Source: APERC

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Canada

Canada is the second largest economy in terms of land area in the APEC region and the world. Canada's relatively small population (more than 34 million), lives predominantly in the southern cities close to the United States. The economy is well known for its rich supply of domestic energy resources, with abundant reserves of oil, natural gas, coal, and uranium.

With 1.9 trillion cubic metres (66.7 trillion cubic feet) at the beginning of 2014, Canada held a small share of the world's proven natural gas reserves ('Worldwide look at reserves and production', 2013), yet it was the fifth largest producer of natural gas with 155 billion cubic metres (5.5 trillion cubic feet) (BP, 2014). Production has declined by 2.3% since 2012, following its peak in 2006.

This decline is attributed to several factors, including the depletion of conventional reserves, increasing capital and labour costs, skilled personnel shortages, the continuing impact of the global economic recession, and most dramatically, the rapid expansion of the United States shale gas resources. As a result of the increasing domestic production of natural gas in the United States, which represents Canada's only export destination, the market demand for Canadian gas has shrunk.

Even though Canada is one of the few worldwide economies with commercial shale gas production, there are few little economic incentives to support a production burst of similar magnitude to that observed in the United States.

Access to natural resources (R)

Canada has a long history of conventional natural gas production, beginning with its first discovery in Ontario in 1859, although commercial output did not occur until 1884 in Alberta. In comparison, shale gas production is a much younger enterprise, with the first production occurring in the Montney formation, northern British Columbia in 2005 (Rivard et al., 2014). Shale gas drilling activities have expanded ever since, although its production accounted for barely 2.3% of Canada's total natural gas production in 2012 (National Energy Board, 2013a).

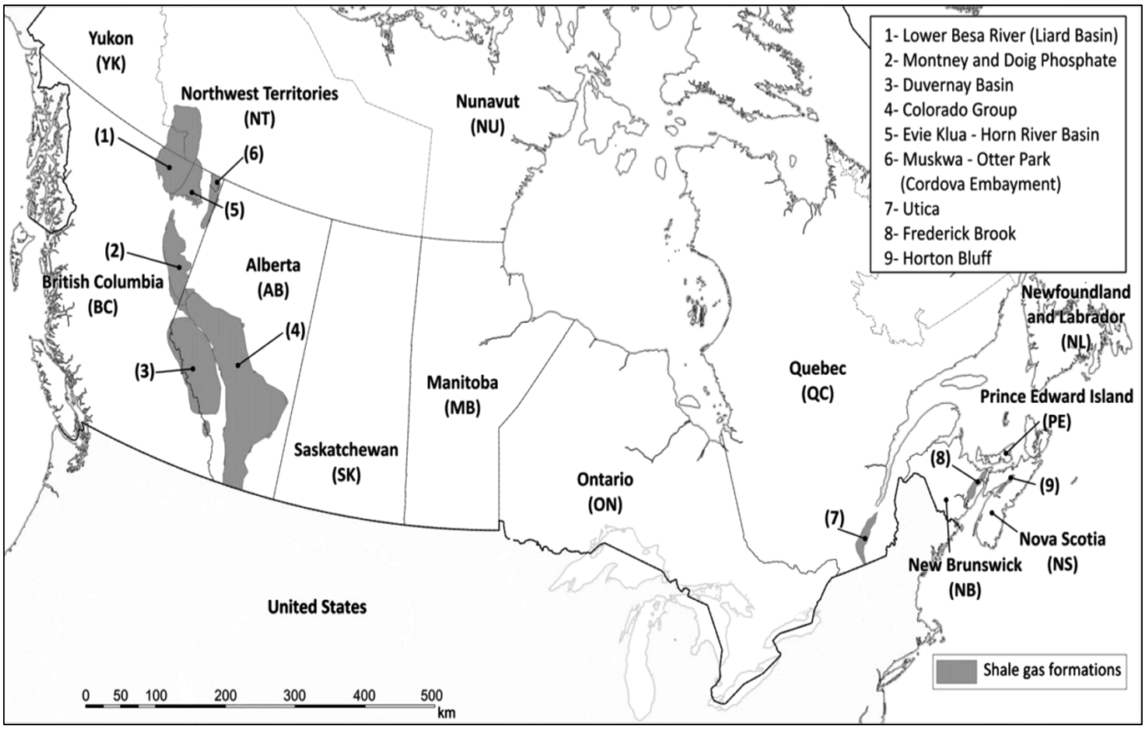
Even though Canada's federal energy regulator, the National Energy Board (2009) initially estimated the economy's shale gas potential at approximately 28.3 trillion cubic metres (1,000 trillion cubic feet), EIA's (2013) assessment inferred Canada's total technically recoverable shale gas resources as 16.2 trillion cubic metres (573 trillion cubic feet). Canadian shale gas is distributed in the provinces of British Columbia, Alberta, Saskatchewan, Manitoba, Ontario, Quebec, New Brunswick, and Nova Scotia. While estimates vary from one agency to the next, Canada's shale gas potential has grown in line with the continuing studies, exploration activities and actual development. These shale gas resources are in a strong position in terms of their size, as they earned Canada the fourth place from among 41 other economies.

Canada has been well known for its rich supply of conventional energy, but it does not lag behind in shale gas, which is mainly located in the Western Canadian Sedimentary Basin (WCSB), with smaller plays in eastern Canada. Similar to the geological properties found in the United States, Canadian shale plays are gas-prone, and some of them also hold liquids which strengthen their possible commercial viability.

As outlined in Figure 34, the WCSB covers approximately 1.2 million square kilometres and is primarily composed of the Horn River basin, the Montney basin, the Cordova Embayment, and the Liard basin (located in British Columbia and the Northwest Territories); the Alberta plays such as Banff/Exshaw, the Duvernay, the Nordegg, the Muskwa, and the Colorado group; and the Williston Basin's Bakken Shale in Saskatchewan and Manitoba. Other promising areas for shale gas recovery include the Utica play in Quebec, the Maritimes Basin in Nova Scotia, the Cretaceous and Devonian formations in the Northwest Territories, and the Arctic islands.

Owing to the somewhat loose industry definition of shale reservoirs, the Montney basin in British Columbia is considered a shale reservoir, but strictly speaking, much of Alberta's significant gas resources in the Montney display different geologic properties with higher gas liquids and oil content. The EIA's (2013) assessment therefore did not include the promising Montney formation in its valuation, as it is geologically classified as tight due to its low organic content (Rivard et al., 2014; Heffernan and Dawson, 2010).

Figure 34
Canada's shale gas resources



Source: Rivard et al. (2014)

Table 9 outlines Canada's shale gas resources by provinces, basins and formations, to provide a better understanding of their economy-wide distribution. The table uses information from EIA (2013) supplemented by data form provincial bodies on the Fredrick Brook Basin and Montney formations, which were absent in the later assessment. The provinces of British Columbia and Alberta hold the largest resource base of technically recoverable shale gas in Canada.

Shale gas is currently produced only in two Canadian provinces, the majority in British Columbia's Horn River basin and the Montney formation, and, to a lesser extent, in Alberta's Duvernay formation (Rivard et al., 2014; National Energy Board, 2013a). Beyond the WCSB, Canada's Atlantic Basins have an extensive history of producing conventional onshore and offshore oil and gas, but it has been difficult to effectively produce shale gas (Popp, 2014). Exploration in New Brunswick and Nova Scotia has produced mixed results (Rivard et al., 2014) and, despite potential shale gas resources in other areas, their commercial viability is challenged by factors such as extremely cold temperatures and remote locations which lack gas-to-market transport systems.

Table 9
Canada's shale gas resources by region and basin

Region	Basin / Formation	Risked technically recoverable shale gas	
		Tcf	Tcm
British Columbia/ Northwest Territories	Horn River (Muskwa / Otter Park)	93.9	2.7
	Horn River (Evie/Klua)	38.5	1.1
	Cordova (Muskwa /Otter Park	20.3	0.6
	Liard (Lower Besa River)	157.9	4.5
	Deep (Doig Phosphate)	25.2	0.7
	Montney [a]	271.0	7.7
	Subtotal	**606.8**	**17.2**
Alberta	Alberta (Banff / Exshaw)	0.3	0.0
	Duvernay Basin	113.0	3.2
	Deep Basin (Nordegg)	13.3	0.4
	N.W. Alberta (Muskwa)	31.1	0.9
	Colorado Group	42.8	1.2
	Montney [a]	178.0	5.0
	Subtotal	**378.5**	**10.7**
Saskatchewan/ Manitoba	Williston (Bakken)	2.2	0.1
Quebec	Utica	31.1	0.9
Nova Scotia	Windsor (Horton Bluff)	3.4	0.1
New Brunswick	Frederick Brook [b]	N.A.	N.A.
Total		**1,022.0**	**28.9**

Source: EIA (2013).
a Montney estimates absent in the EIA (2013) valuation; retrieved from National Energy Board (2013b).
b Fredrick Brook estimates excluded from EIA (2013), retrieved from GLJ Petroleum Consultants (2009).

Concerning the access to these resources, Canada has in place an economy-wide concessionary regime in which mineral ownership exists privately in the lands originally purchased before the ownership of subsurface resources was severed from 1887 (*freehold land*), although nowadays most of them belong to the hosting provinces (*Crown land*). Under Sections 91 and 92 of the Canadian Constitution, the provinces are the owners of ground resources and underground mineral rights within their boundaries, excluding the resources located on aboriginal lands, private lands with freehold rights, federal lands such as national parks, and international waters.

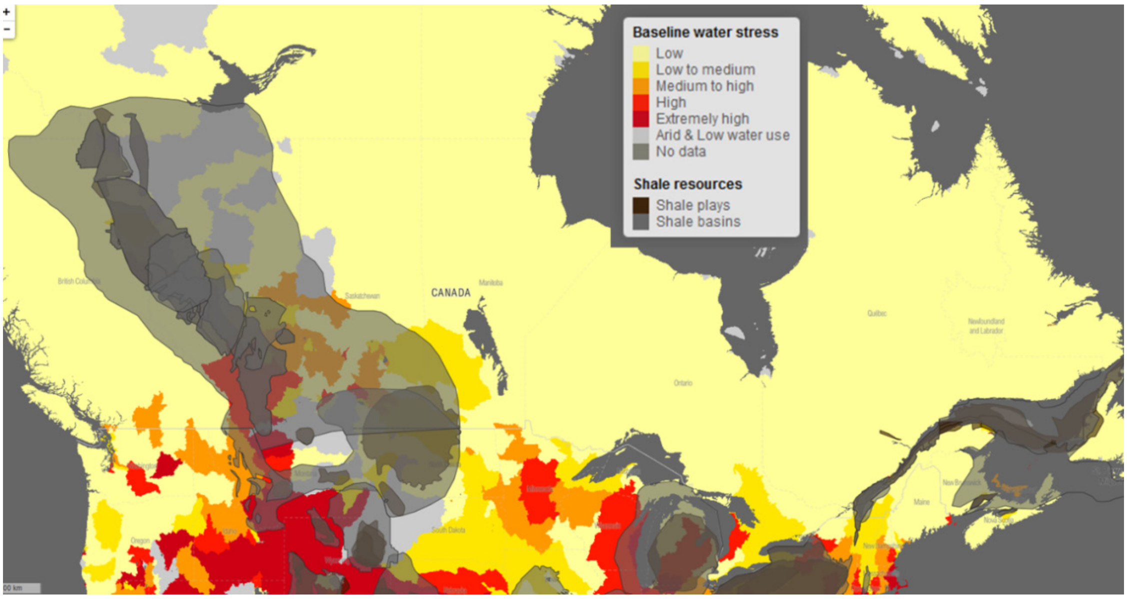
This leads to jurisdictional differences by province. The share of mineral rights owned by provinces alone amounts to 90% and 81% of the land area in energy–friendly British Columbia and Alberta, respectively (British Columbia, 2012; Alberta Energy, 2009). Generally, provincial ownership aligns the economic interests between the government and energy companies, by awarding the latter the rights to explore and develop oil and gas resources through specific licenses. Nonetheless, this mechanism is contingent upon the prevailing political agenda; while Western provinces approve shale gas developments as a means to boost economic growth, some Eastern provinces such as Quebec do not support it due to environmental concerns.

Mineral rights are typically obtained through a bidding process conducted for areas opened to exploration by the provinces. Exceptions to the bidding process include Quebec, which utilises a first come, first served basis for mining claims, and Artic frontier areas, where licenses are awarded to companies with a comprehensive exploration program which exceeds regulatory requirements and encourages exploration in remote areas (Rivard et al., 2014). It must be mentioned that in the two Canadian provinces where shale gas production is taking place, the rights awarded to operators might be restricted to a specific depth interval, in order to optimise the exploration and production of resources in overlapping geologic formations.

Regarding the crucial role of water in shale gas development, Canada has the eighth-largest total water resources per capita in the world, which amount to 83,300 cubic metres (FAO, 2014). As shown in Figure 35, the World Resources Institute (2014), considers that on average, half of Canada's shale resources present water stress levels ranging from medium to extremely high. Nonetheless, the development of shale gas resources underway in the provinces of British Columbia and Alberta is occurring with relatively no major water problems, particularly considering the regulations in place to favour the use of non-freshwater resources.

Despite Canada's abundant freshwater resources, there have been mounting environmental regarding their use. While the industry initially preferred and had access to freshwater, it is increasingly compelled to use brackish or saline water. Technology is playing a big role in enhancing water management and transforming water requirements per well. In Alberta, for example, the natural gas industry is increasing its water supplies from non-freshwater sources as well as its volumes of recycled water. The need to consider net environmental effects helps to identify unintended consequences from alternative water sources.

Figure 35
Canada's shale gas plays and baseline water stress



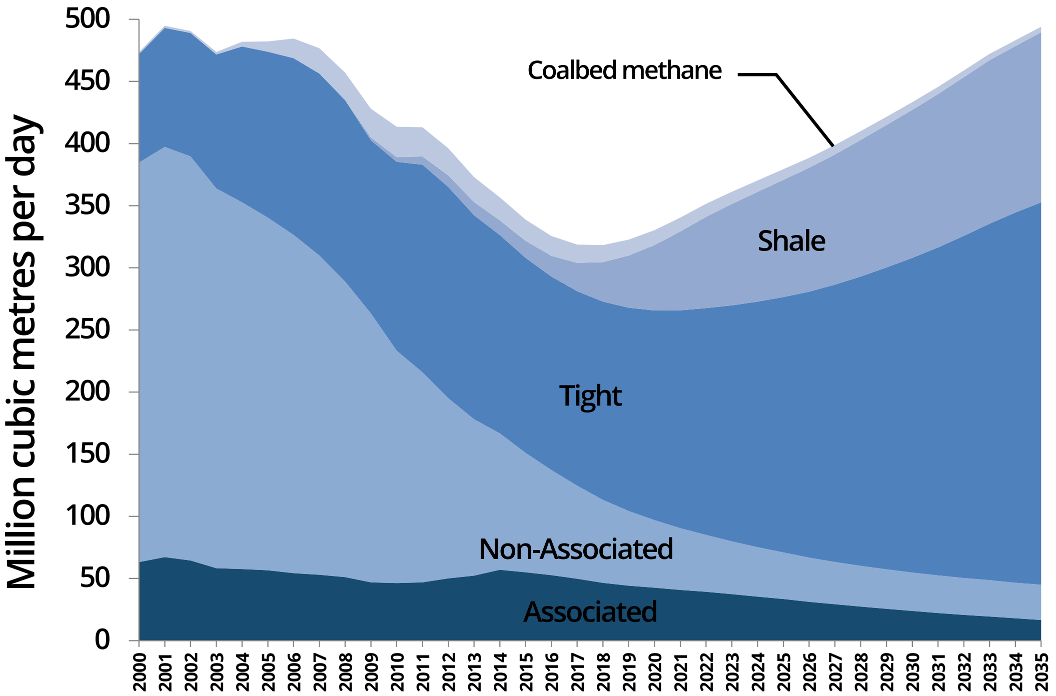
Source: World Resources Institute (2014)

Infrastructure and Operations (I)

Canada was the world's fifth-largest producer of natural gas in 2013 (BP, 2014), but due to the faster depletion of its conventional reserves, its domestic production is increasingly driven by unconventional gas resources, including shale gas.

As a result, the combined share of tight gas, coalbed methane and shale gas in the Canadian natural gas production grew from 19% in 2000 to 51% in 2012. Furthermore, as seen in Figure 36, it is officially projected that the share of unconventional gas resources will be even larger in the long-term. It is expected that unconventional gas resources will represent nearly 91% of total gas production in 2035. Even though shale gas will remain the second gas source in Canada's total gas production by the end of the outlook period, it is expected that it will experience the highest growth, with more than a 13-fold increase from 2012 to 2035. In comparison, for the same period the projected growth for tight gas is 81%, whereas the rest of conventional (associated and non-associated) and unconventional (coalbed methane) sources are expected to decline (National Energy Board, 2013a).

Figure 36
Canada's natural gas production by source, 2000-2035



Data refers to Reference Case.
Source: National Energy Board (2013a).

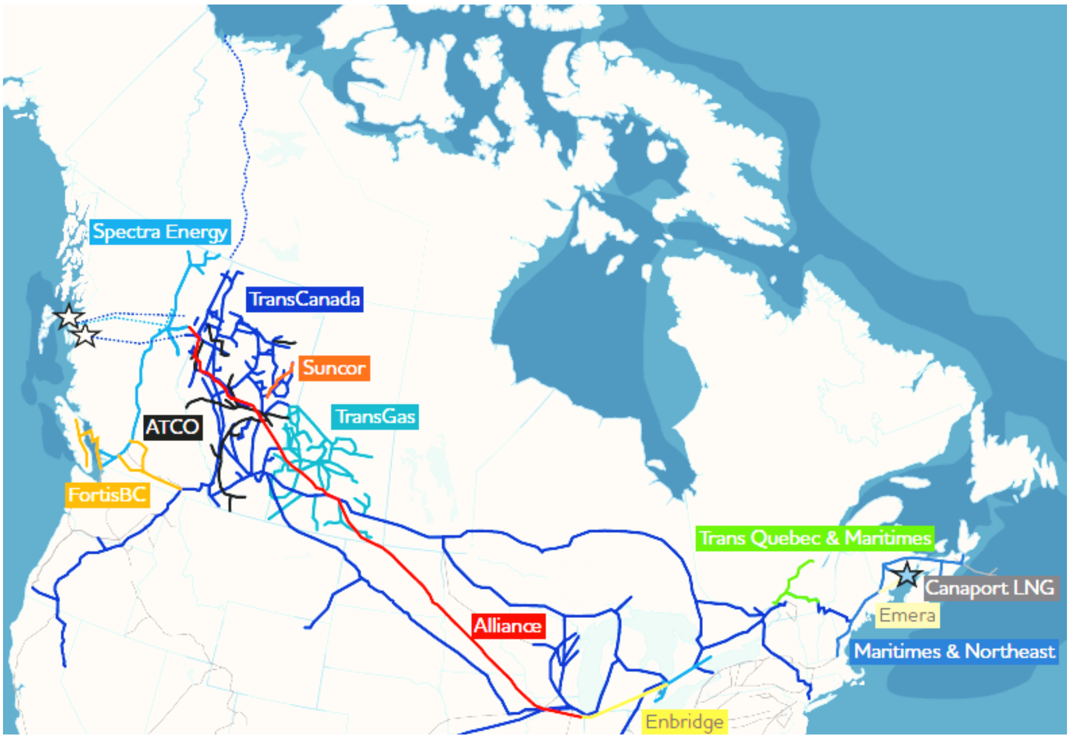
Concerning the Canadian industry's capabilities, its technological breakthroughs have allowed the economic production of a much larger unconventional resource base. Hydraulic fracturing for vertical wells was used for the first time in Alberta in 1953 in the Cardium play (Morgan, 2014), but it was not until recently that its combination with horizontal drilling helped reach a larger payzone per well to improve average profitability.

To a considerable extent, Canada was able to leverage the technological gains developed in the United States for shale gas. Given the proximity of the two economies, Canada's oil and gas industry successfully transferred the technology necessary for the development of its own shale gas resources, the robust geological knowledge in place being crucial to applying this expertise. Canada has developed a thorough understanding and mapping of its oil and gas resources. This undertaking has been led by the federal Geological Survey as well as individual provincial geological bodies which house publically accessible resource catalogues of mineral samples and well. These historical and expansive knowledge repositories are a pillar of Canada's oil and gas extraction, as public geoscience reduces exploration risk and encourages the development of these resources.

Owing to Canada's advanced stage on the shale gas learning curve, the industry has been able to deploy pad operations which bring economies of scale and smaller environmental footprints. These pad operations, which in the Horn River exceed more than ten wells, require in turn more sophisticated technologies, personnel, and materials, which are readily available in Canada (King, 2012). To support these operations, the domestic natural gas industry has sound access to capital markets, and has also benefited from the capital inflows of foreign companies, most of them from Asia, which have taken part in a variety of transactions with Canadian companies in an effort to secure energy resources, get access to technology and knowledge, and refine their operations in other economies.

In step with the historical patterns of natural production, most activities and upstream infrastructure of Canada's natural gas industry are concentrated in the WCSB. Although transmission lines extend up to the markets in eastern Canada, the economy's status as a net natural gas exporter has been traditionally focused on the demand of the Midwest and the West Coast of the United States, which has promoted a sound integration of infrastructure between the markets in both economies as illustrated in Figure 37.

Figure 37
Canada's natural gas pipeline network



*Note: This map is from 2012, and does not include all current proposed LNG terminals
Source: (CEPA, 2012)

Given the physical distance between the natural gas producing markets and the major centres of consumption in eastern Canada, New Brunswick's Canaport LNG import terminal started operating in 2009, with the aim of supplying eastern Canadian and northeast United States markets. In the last few years, however, the advent of rising shale gas production in the United States transformed these market dynamics drastically, resulting in cancelled proposals for more import terminals in North America, a diminished reliance of the United States natural gas markets on Canadian imports, and the proposal of several LNG export plants in Canada to target other markets than the United States.

Canada does not currently have any operational export facilities but according to Canada's National Energy Board, by September 2014 a total of 17 LNG export terminals had entered the corresponding regulatory process to gain official approval. Most of these projects are located in the province of British Columbia near Kitimat and Prince Rupert, and many of them will require new infrastructure to bring the gas from the producing areas and power the liquefaction facilities (National Energy Board, 2014).

As for the last factor in the Infrastructure and Operations component of the framework, industry recommended practices in Canada are considered strong and have aimed to exceed the regulations in place. As a reference, the Canadian Association of Petroleum Producers, a professional association grouping a large number of operators, released a number of guiding principles for the performance of hydraulic fracturing, which economy-wide members commit to. These principles target the needs which tend to be the most notorious and socially sensitive in the process of developing shale gas. The principles look forward to the general issues noted below and delve into specific practices to guide shale gas operations (CAPP, 2012):

- Protecting the quality and quantity of groundwater resources, through efficient water management practices including alternative water sources and recycling;
- Tracking and measuring water quality levels;
- Developing fracturing fluids with the least possible environmental risks;
- Encouraging the disclosure of fracturing fluid components;
- Disseminating best practices and technologies to reduce the environmental risks caused by hydraulic fracturing.

Governance (G)

In line with the rising participation of unconventional resources in Canada's natural gas production, the provinces with ongoing shale gas production have devised fiscal terms adapted to the higher risks and complexity faced in comparison with conventional resources. In this regard, the provisions implemented aim to build a fiscal regime which achieves competitive returns for government and operators alike while encouraging the latter's investments towards the continued development of resources.

In British Columbia, the royalties applicable to natural gas are determined monthly for each well. For such calculations several criteria are considered, including the ownership of the land where the gas was produced; its association or not with oil production; a producer reference price; and inflation adjustments. The co-production of natural gas liquids and substances other than natural gas carries a fixed royalty rate (British Columbia, 2014).

Additionally, there are a number of fiscal instruments in the form of allowances, exemptions, credits and lower royalty rates to account for the diversity of production profiles per well. An example is the Deep Well

Credit, which strives to compensate operators for higher drilling and completion costs incurred in the production of deep formations in active horizontal wells. Another example is the Infrastructure Credit, which provides operators with up to half the cost of the roads and pipelines in producing areas lacking these assets. Depending on contextual characteristics, these provisions could be combined to let some projects become economic (Alberta Energy, 2011).

Similarly, Alberta calculates its natural gas royalties depending on a well's depth and productivity along with price considerations; with propane, butane and heavier hydrocarbons being subject to higher fixed royalties. Other programs provide specific economic incentives and include shale gas. The Shale Gas New Well Royalty Rate establishes a maximum royalty of 5%, which is valid up to 36 months without volumetric constraints for all shale gas wells in production on or after May 1 2010 (Alberta Energy, 2011).

Canada's natural gas industry has a competitive market structure with a mix of small and large players. The industry's capital intensity has been backed by its linkage with international markets. Interestingly, the participation of international oil companies, in Canada's oil and gas sector, both private and state-owned has increased rapidly in the past few decades. These investments may be driven by a number of factors including economic and political motivations, or technological spillover effects which can be applied to conventional and unconventional resources elsewhere. At a federal level, the Investment Canada Act stipulates that any investment greater than CDN 325 million must accrue a net benefit to Canada, signalling possible limits on the foreign control of strategic commodities (Industry Canada, 2014).

Natural gas prices in Canada have been fully deregulated since the conclusion of the Agreement on Natural Gas Markets and Prices between the federal government and the provinces in 1985. The agreement opened up gas markets to greater competition by permitting more exports, allowing users to buy directly from producers and unbundling production and marketing from transportation services. Pipeline infrastructure, made up of gathering, feeder, transmission and distribution lines, may be owned by various entities which support the flow of gas from producers to consumers. Canada's gas pipelines are regulated by provincial agencies within their boundaries, and whenever they transcend provincial or federal boundaries their regulation becomes the responsibility of the National Energy Board. Gas pipeline transmission systems are required to operate on an open access basis, to allow their non-discriminatory use at fair conditions for all interested parties.

Concerning the existence of an effective regulatory system, Canada's energy policy and regulation at the federal, provincial and territorial levels are fundamentally market-based. The basic principles, which are important pillars to energy policy include the respect for jurisdictional power granted under the *Constitution Act of 1867*, as well as targeted intervention in the market process to achieve specific policy objectives through regulation and other means.

Canada has a multi-layered administration in which the policy-making and oversight related to natural gas span a number of agencies at the federal level. The two dominant agencies with a critical role are Natural Resources Canada and the National Energy Board. Natural Resources Canada is mandated to develop policies and broad guidelines which reconcile the responsible development of natural resources with economic competitiveness, whereas the National Energy Board is an independent federal regulator responsible for pipelines, energy development, and trade issues in the Canadian public interest. Other important government agencies may include Environment Canada, Fisheries and Oceans Canada, Indian and Northern Affairs Canada, and Foreign Affairs and International Trade Canada.

In contrast, provincial and territorial governments are responsible for the energy policies within their boundaries, causing initiatives and instruments to differ across jurisdictions. In British Columbia and Alberta, where shale gas is currently produced, regulations have evolved to address more effectively the challenges faced in comparison with conventional gas resources. In this sense, as per the regulatory effectiveness factor, the following actions have been undertaken in each of these provinces.

- In British Columbia, the significance attributed to natural gas is reflected in its Ministry of Natural Gas Development's responsibility for the whole oil and gas sector. The duties of the Ministry include policy design and execution, the awarding of resource rights and their taxation, geoscience programs, and the development of unconventional hydrocarbons. The Ministry is also responsible for the Oil and Gas Commission, which in turn is in charge of the regulations applicable across the value chain of the oil and gas industry with a public safety and natural environment emphasis.

Cognizant of the rising importance of unconventional gas production, namely shale gas, in 2013 the Oil and Gas Commission proposed an analysis to guide the management of cumulative effects at a broader perspective. Set at a basin level, this regulatory approach strives to enhance decision-making by allowing a holistic assessment of shale gas development and its effects as driven by 'changes to environmental, social and economic values caused by the combined effect of present, past and reasonably foreseeable future actions or events on the land base' (British Columbia Oil and Gas Commission, 2014). This approach is visually portrayed in Figure 38.

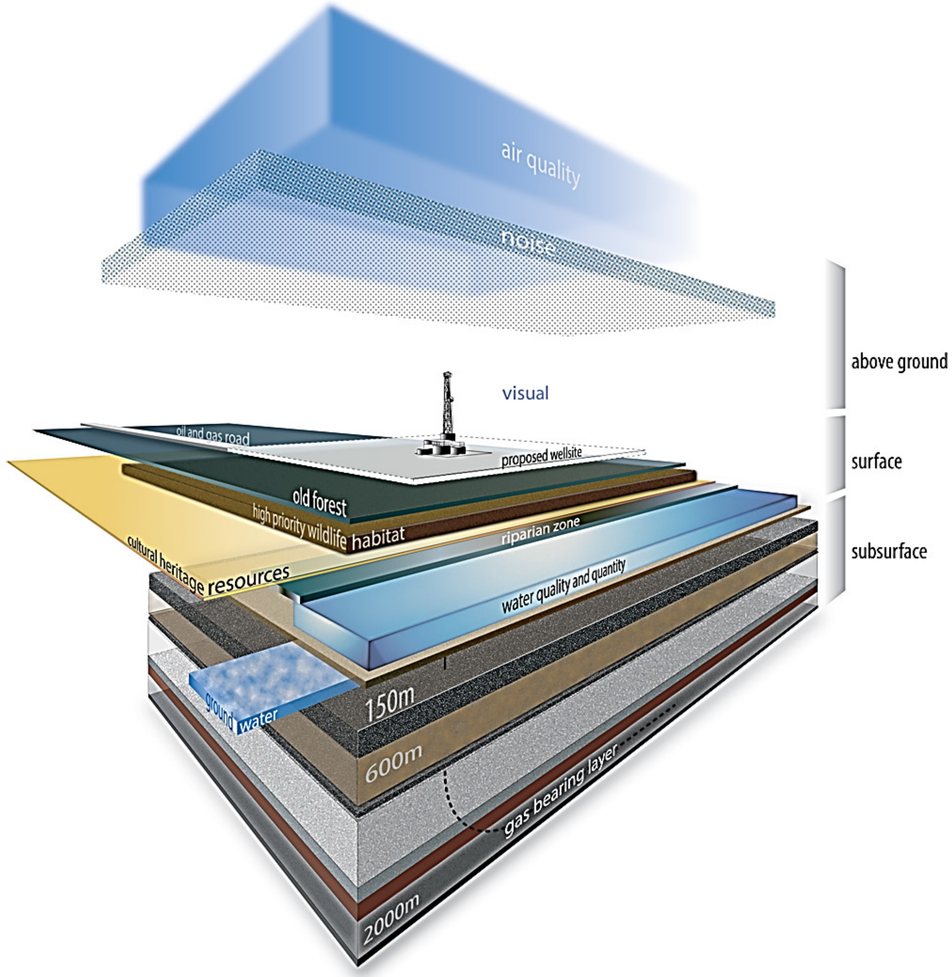
- In Alberta, the regulatory environment has a long history of conventional gas regulation and is experienced in shale gas issues. Energy regulations are mandated and managed by the Alberta Energy Regulator (AER), a single agency created in 2013 by combining the former Energy Resources Conservation Board and the Environment and Sustainable Resource Development division of the provincial government. The evolution of these former agencies into AER looks forward to streamlining and unifying applicable regulations within a single, strengthened agency.

Shale gas development in Alberta is mainly driven by generic natural gas regulations, which comprehensively cover the industry's entire lifecycle, although there are specific regulations addressing the distinctive traits of shale gas, including hydraulic fracturing, water management, and the cumulative social and environmental effects from the more intensive drilling. A recent example of the evolving regulatory structure is the Play-Based Regulation Pilot Application Guide issued at the end of 2014. This pilot model addresses the specific risks developing unconventional oil and gas resources including shale gas.

The advantage of this initiative lies in its tailored approach to set regulations in proportion to the risks assessed at the level of the whole play rather than a single well. This allows for a better management of cumulative risks and provides producers more operational flexibility without the constraints of prescriptive measures.

From another perspective, this adaptive regulation promotes a tighter collaboration between the operators in a common play, which could result in enhanced innovation and cost-effectiveness (Alberta Energy Regulator, 2014a).

Figure 38
Visual representation of an area-based (basin) assessment for gas development



Source: British Columbia Oil and Gas Commission (2014).

In both provinces, the regulations in place for shale gas and other type of unconventional gas resources encompass the disclosure of the water volumes and fluids used during hydraulic fracturing; in Alberta, companies must also report sources of water to assist in regional and sub-regional water management planning and tracking of performance measures. The public dissemination of this information at the FracFocus Canada website, has also improved transparency and outreach to other stakeholders.

These new regulatory approaches to shale gas are prompting the Canadian industry to take a more active role in establishing best industry standards with the aim of strengthening the processes and capabilities directed to address critical issues underlying shale gas development. In particular, the industry has shown greater willingness to engage with stakeholders and gather their insights in order to influence projects and operations, allowing stakeholders themselves to have a better understanding of the full scope of risks and issues associated with the development of a shale play.

Canada's natural gas industry looks forward to developing social license for its sustained operations. In general, most shale gas operators are aware that environmental responsibility and outreach to local communities are key to their own growth and long-term operations. Given the predominant vocation of Canada's natural gas towards export markets, consultation with aboriginal groups, particularly with the First Nations, is a permanent priority in the industry's projects and in the federal and provincial governments' design and oversight of regulations.

Challenges and opportunities

With a strong vocation for the development of energy resources, Canada's natural gas production is progressively made up of unconventional gas resources, including the nascent participation of shale gas.

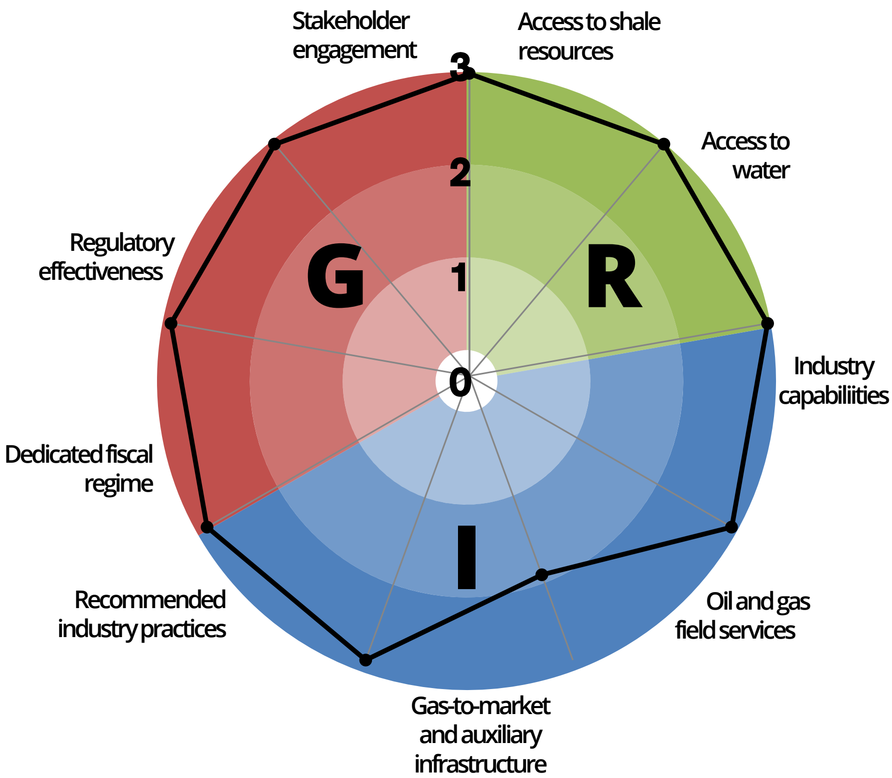
The economy analysis made using the guidance of the RIG framework is depicted in Figure 39 and stresses that although Canada's access to shale gas differs across jurisdictions, in those provinces where this resource is more abundant, there is a firm commitment to promote its massive development to bring about economic benefits. To that end, exploration and production rights are granted to operators through competitive processes. Water is not as much of a problem in the areas where shale gas production is taking place, and major challenges are likely to be alleviated with the application of stricter regulations in combination with a generalised industry shift to water management based on access to non-freshwater sources.

In terms of infrastructure and operations, Canada's long-established oil and gas industry has adhered to widespread practices which comply with or exceed the regulations in place and have developed robust capabilities and oilfield services to support the commercial production of shale gas. Although Canada's natural gas infrastructure is well-developed, its historical focus on the Western and Midwestern markets of the United States has entailed some recent trade-offs, insofar as the expanding gas production and self-sufficiency of the United States has eroded the competitiveness of Canadian natural gas production, leaving Canada with the challenge of finding other markets to sustain its future growth.

Canadian shale gas production will be increasingly driven by other export markets, most likely by those located in Asia, given their rising natural gas demand, their lack of sufficient domestic supplies, and their geographical proximity to Canada's WCSB. Such efforts, however, will require a substantial amount of capital to build critical infrastructure to reach remote areas of Canadian shale gas development and send the resulting production overseas in the form of LNG. As much as this remains a major barrier to more accelerated shale gas production in the short term, as shown in Figure 39, Canadian operators have already taken the first steps to have several LNG export terminals in their Pacific coast.

Finally, in terms of governance, the two Western Canada provinces with ongoing shale gas production have devised fiscal regimes which provide incentives to producers in step with the market's maturity, framed by an effective regulatory system directed to provide certainty and minimise risks. These regulations have given external stakeholders greater influence in the development of shale gas, resulting in more comprehensive regulations and especially a stronger commitment by the industry to secure social license as a means of supporting the long-term viability of its operations.

Figure 39
APERC's assessment of Canada's shale gas development under the RIG policy framework



Note: Given the broadly contrasting political views across Canadian jurisdictions, the figure herein mainly refers to the Western provinces with current shale gas development (Alberta and British Columbia).
Source: APERC

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Chile

Located in South America, Chile is an economy characterized by its open markets and solid growth. The economy is administratively divided into 15 regions which are rich in natural resources suitable for use as renewable energy, although fossil energy resources are scarce.

As a net importer of natural gas, the economy is keen on overcoming the challenges experienced in the past with its natural gas supply through the diversification of its sources and the encouragement of a larger domestic production, which has also targeted unconventional gas resources in recent years.

Access to natural resources – (R)

Chile's commercial oil and gas resources are located in its Magallanes region at the extreme south of its territory, close to Antarctica. Proved reserves at the beginning of 2014 amounted to a rather modest 150 million barrels of oil and 99 billion cubic metres (3.5 trillion cubic feet) of natural gas ('Worldwide look at reserves and production', 2013). Because of this, Chile's domestic fossil production accounted for less than 5% of its coal and oil demand, and for less than 25% of its natural gas demand in 2012 (Ministerio de Energía, 2012).

Chile possesses substantial inferred shale gas resources; according to early assessments (EIA, 2013), its technically recoverable resources amount to 1.4 trillion cubic metres (48 trillion cubic feet), approximately 14 times its proved reserves of conventional gas. As depicted in Figure 40, these shale gas resources are also located in the Magallanes Basin, in a large formation shared with Argentina.

To ensure a steady gas supply, the Chilean government has undertaken two major strategies. The first relates to the introduction and development of the economy's LNG import capacity, which started in 2009 in response to the unreliability of Argentine pipeline imports. The second refers to the expansion of its domestic gas production, including unconventional resources.

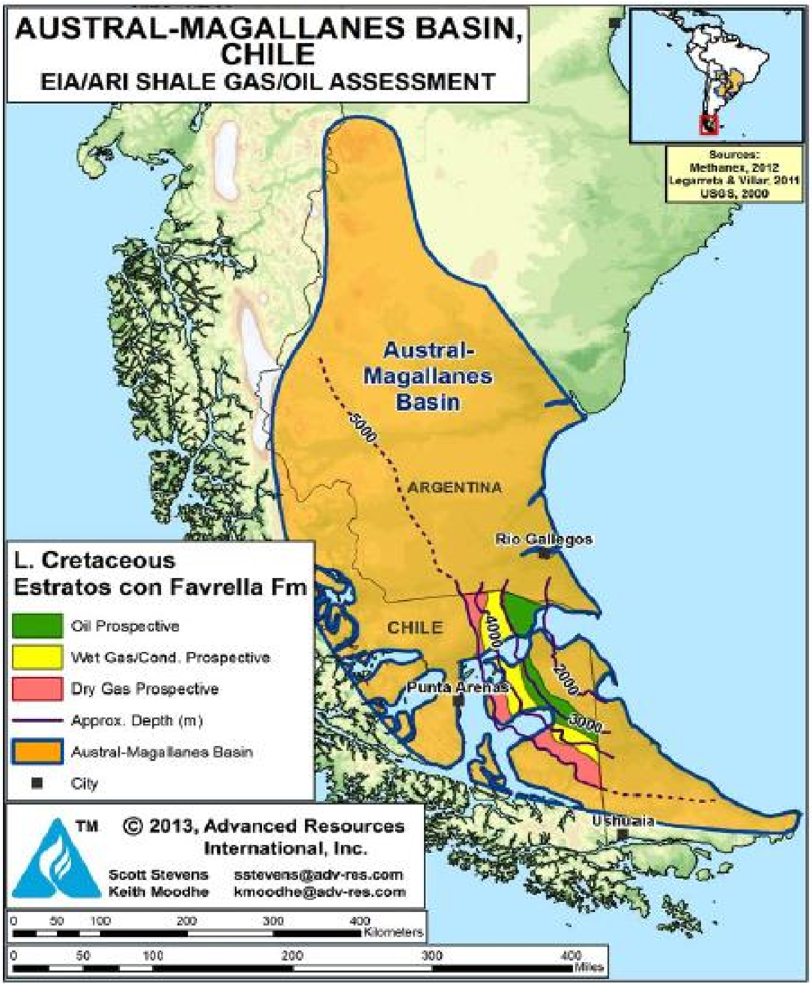
These issues were recognized in Chile's long-term Energy Strategy 2012-2030 and resulted in changes to the business model of the national oil company ENAP (*Empresa Nacional del Petróleo*). This led to the success of several pilot wells of tight gas in ENAP's Arenal block in July 2013 towards the understanding, exploration and development of unconventional gas. Moreover, the current presidential administration took office in March 2014 and soon after presented its energy agenda, which among other major policies, maintained a focus on the development of unconventional gas, and highlighted the role of ENAP as the leader of this effort.

In connection with this, under the Chilean Constitution, the State retains ownership of hydrocarbons and carries out their production through ENAP. Other companies across the gas value chain are granted access solely through special operations contracts (CEOPs) which awarded directly or through a bidding process.

In spite of the establishment of CEOPs in 1975, until a decade ago only a few of them had been signed; however, the faster decline of Chile's natural gas output in the 2000s called for a more aggressive production strategy supported with the aid of other companies (Agostini and Saavedra, 2009). Over the last decade, the Chilean government has encouraged the participation of private companies in exploration activities to boost domestic production. This resulted in the award of nine blocks for exploration and development in 2007, with another five blocks awarded in 2010; all as CEOPs.

Some of these blocks, many of which involve ENAP as a co-participant, are deemed to hold tight gas and shale gas. So far however, the only CEOP devoted specifically to unconventional gas was awarded in 2006 for the exploration and development of coalbed methane (Cuenca Arauco), which incidentally, was not located in Magallanes, and did not succeed in producing those resources commercially. The exploration and possible development of tight gas is expected in the Dorado-Riquelme block, which ENAP operates in partnership with another company under a CEOP exploration contract.

Figure 40
Chile's shale gas resources

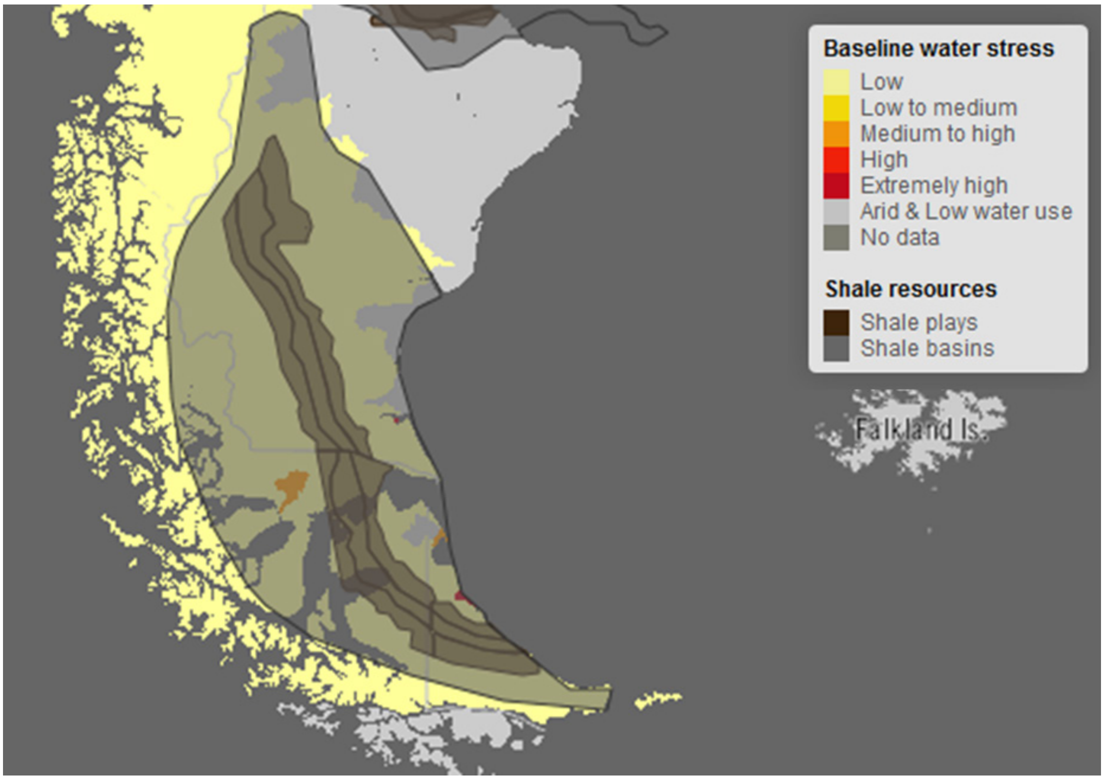


Source: EIA (2013)

Chile's territory is plentiful in water resources, with total renewable water resources per capita of nearly 52,000 cubic metres which place it in the top decile worldwide. Magallanes alone accounts for the largest regional share (34%) of Chile's renewable water resources, defined as the maximum theoretical annual amount of water actually available in an economy at a given moment (FAO, 2014).

As observed in Figure 41, the shale gas resources in Magallanes do not pose significant water challenges nor do they lie in arid areas (World Resources Institute, 2014).

Figure 41
Chile's shale gas plays and baseline water stress



Source: World Resources Institute (2014)

Infrastructure and operations–(I)

Chile's oil and gas industry is relatively small. Most upstream activities in Magallanes are led by ENAP, which carries out its offshore and onshore operations with about 800 employees who make up most of its exploration and production workforce in Chile (ENAP, 2014b). In addition to the capabilities developed in Chile, ENAP has an international presence which includes the Argentine area contiguous to the Magallanes, with several facilities which connect both areas. Some of the largest international oilfield services companies are also in Chile.

The Chilean government has fostered the understanding of unconventional gas issues, particularly shale gas through several events carried out in coordination with the United States. Shortly after presenting its current energy agenda, the Chilean government also expressed interest in increasing its gas supply through LNG imports coming from the United States; and in July 2014, a group of high-level Chilean energy officials visited that economy to have a more comprehensive perspective of shale gas development (Ministerio de Energía, 2014b). This visit resulted in Chile's commitment to receive LNG imports from the Sabine Pass terminal by 2016, and an agreement with ConocoPhillips to conduct a thorough technical study with ENAP, which will better assess Chile's unconventional gas potential.

Nonetheless, the industry's capabilities for shale gas are still at a very early stage of development. Looking forward to filling these gaps and enhancing its technological capabilities, ENAP has performed hydraulic fracturing on some of its exploratory wells since 2011. In 2013, ENAP invested USD 111 million in exploring and developing oil and gas resources, becoming the company's largest investment in 15 years; in 2014, it invested other USD 158 million, a significant portion of which went to develop tight gas resources (ENAP, 2014b). Starting in 2015 and continuing until 2020, ENAP has plans to invest almost USD 300 million per year to fully develop its tight gas reserves in order to guarantee regional supplies.

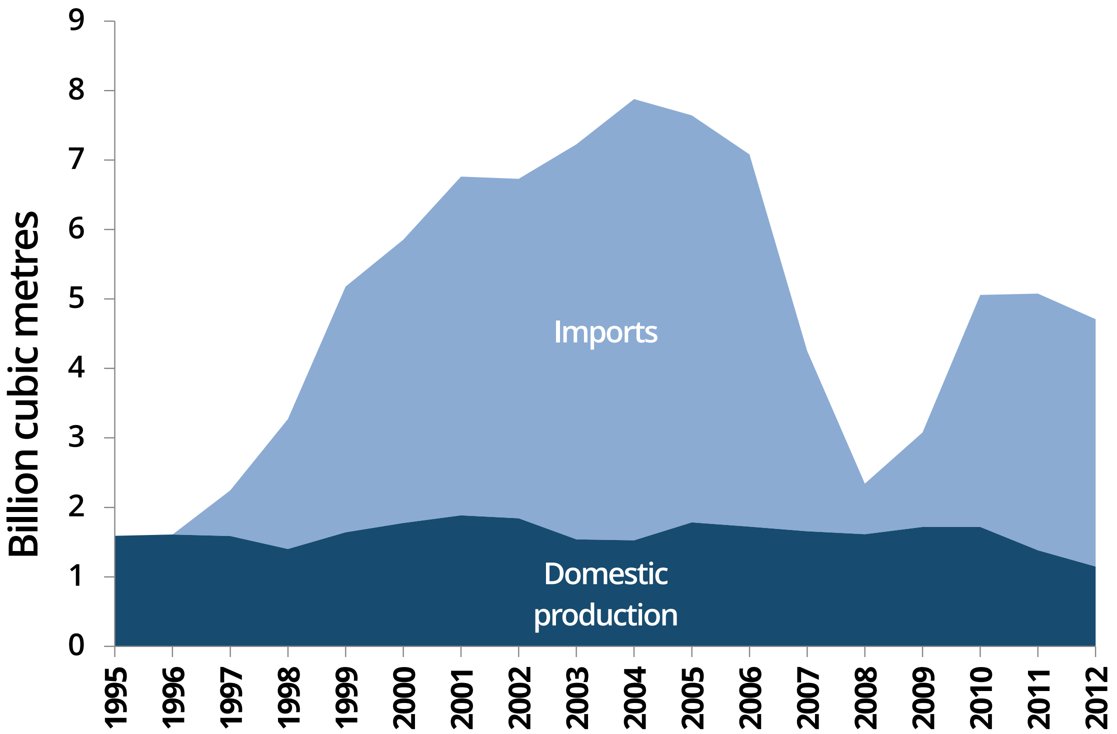
So far, nearly all of these tight gas wells have been drilled vertically in the Arenal block, which advanced from the exploratory to a commercial demonstration stage in August 2014. During 2014 ENAP drilled single vertical wells, but in 2015 it adopted the multiple-well pad drilling technique to hasten the development of tight gas resources.

In 2015 ENAP expects to drill 39 wells in the Arenal tight gas block alone, with the objective of reaching an average daily output of 1 million cubic metres to meet regional demand.

In addition, ENAP has been working with ConocoPhillips to assess shale resources in the Magallanes basin. The confirmation of this potential will leave the challenge of assimilating the hydraulic fracturing of horizontally-drilled wells representative of large-scale shale production to ENAP and the industry as a whole.

In September 2014 ENAP approved its Strategic Plan 2014-2025, outlining its business priorities and commiting the investments necessary to attain its goals. From the company's seven outlined priorities, one is the expansion of oil and gas production in Magallanes, with the goal of doubling the output by 2020; another priority is the promotion of greater natural gas demand in the electricity and residential sectors (ENAP, 2014d).

Figure 42
Chile's natural gas demand by source, 1995–2012



Source: IEA (2014).

In this sense, Chile's domestic production cannot meet its economy-wide needs because of magnitude and reach constraints.

- Regarding magnitude, Chile's domestic gas production accounted for 24% of its gas demand as of 2012. Chile used to be self-sufficient in natural gas in the Magallanes, using LPG (liquefied petroleum gas) in all its other regions. It was the advent of Argentine imports in 1997 which allowed Chile to greatly expand natural gas consumption in the electricity, industry and residential sectors. From 1997 until its peak in 2004, Chile's natural gas demand grew at an annual rate of 25%.

- In terms of reach, Chile's domestic natural gas production in Magallanes is disconnected from other markets in Chile. Owing to this, Chile has several isolated energy systems. As shown in Figure 43, a number of gas pipelines are grouped in four major transmission systems, each of them disconnected from the other. With the exception of the system in Magallanes, all the others were originally built to bring gas from Argentina, and rapidly promoted the development of electricity generation plants and distribution grids.

  As the economy's hub of upstream oil and gas operations, Magallanes has a significant amount of infrastructure inherited from a legacy of activities commenced in the 1950s. This includes more than 1,400 kilometres of gathering lines and gas pipelines, two processing plants, and gas-to-market pipelines which serve Punta Arenas, the capital city of Magallanes(Comisión Nacional de Energía, 2014). Despite its characteristics, the geographical range of this infrastructure constrains the consumption of the gas produced to the regional level.

In fact, the peculiarities of the Chilean territory and its geographical patterns present tremendous challenges for the development of both generic and gas-to-market infrastructure. At 4,300 kilometres long but only 175 kilometres wide, Chile's extreme narrowness hinders the connection of markets and resources. Adding to this complexity, the territorial distribution of the population is very asymmetrical. Half of the Chilean population lives in the Santiago Metropolitan and Valparaiso regions, which barely account for 4% of the economy's territory; in contrast, less than 1% of the population lives in Magallanes, in an area approximately 3,000 kilometres away from Santiago but equivalent to 17% of the economy's total areal extent (Instituto Nacional de Estadísticas, 2012)

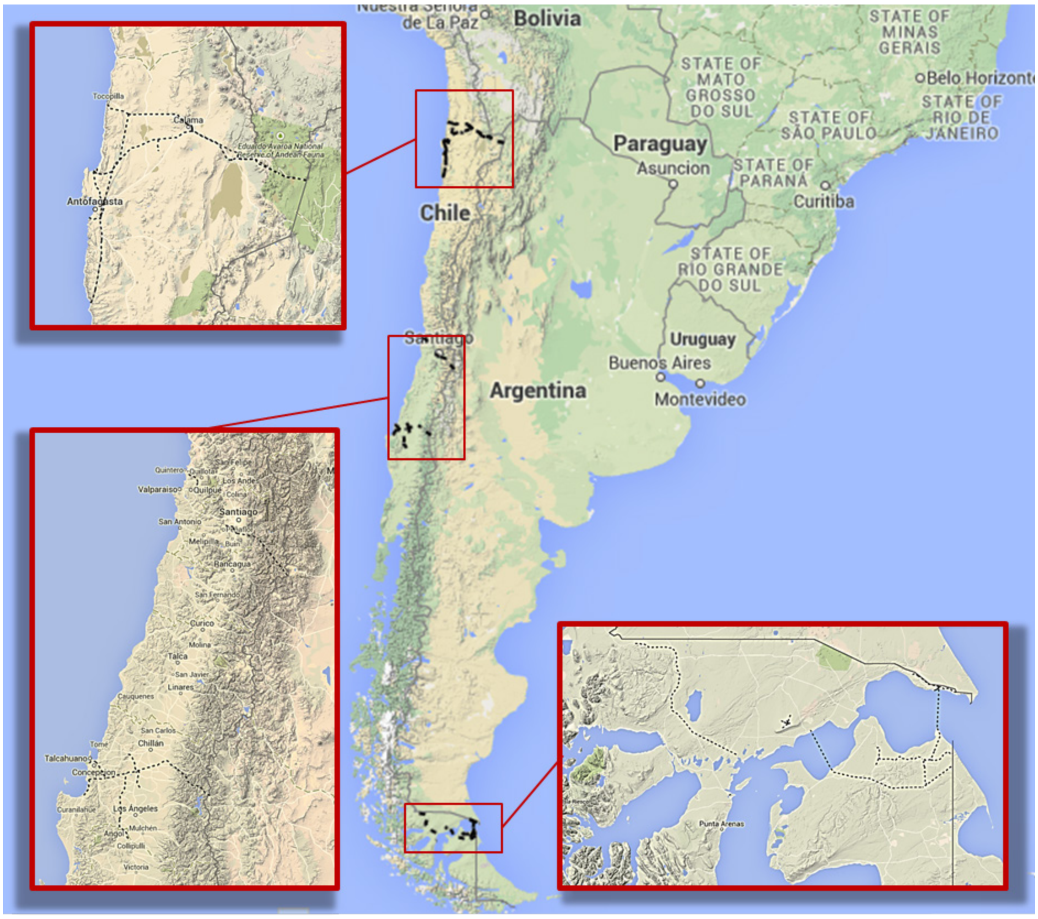
The high dependence on Argentine pipeline gas and its shortages since 2004 shrunk Chile's economy-wide demand for natural gas and made it look forward to more reliable supply sources in the form of LNG infrastructure. This shift led to the construction of the Quintero import terminal in central Chile in 2009 and the Mejillones import terminal in northern Chile in 2010.

The proximity of these LNG terminals to the largest electricity, industrial, commercial and residential markets, combined with the subsequent capacity expansion of 50% in the Quintero LNG terminal have allowed Chilean natural gas demand to grow in recent years, albeit with a smaller share of the electricity generation mix and at higher prices than in the era of Argentine imports (Jiménez and Albornoz, 2013).

Regarding industry practices, a number of technical and professional standards have been adopted in Magallanes to minimize safety and environmental risks. In that regard, ENAP complies with recommended practices which strive to minimise technical and operational risks while permanently;

improving performance additionally, the company observes several environmental protection guidelines. Even though the development of unconventional gas resources is still just beginning, the environmental impact assessments of ENAP's hydraulic fracturing processes were approved by Chile's Environmental Assessment Service (ENAP, 2014c).

Figure 43
Chile's natural gas transmission pipeline network



Note: The red frames highlight four distinct pipeline systems.
Source: Adapted from Ministerio de Energía (2014a).

Governance – (G)

The CEOPs signed with the Chilean government to develop gas resources establish an economic redistribution based on a share of the hydrocarbons produced, payable in cash or in kind. These CEOPs are awarded for a maximum period of 35 years and distinguish exploration from the development phase, establishing minimum investment commitments for maximum timeframes of 10 and 25 years, respectively for each of these phases (OLADE, 2010).

Nevertheless, the CEOPS were designed on the basis of conventional oil and gas fields, with rigid fiscal and contractual terms which do not provide sufficiently strong incentives nor reflect common issues to encourage shale gas development, especially in terms of operational flexibility and higher upfront investments.

In general, Chile's energy policy strives to reduce its economy-wide vulnerability to supply shocks and high dependence on imports, fostering free-market principles driven by economic efficiency and energy security. In line with these broad precepts, the natural gas market in Chile is fundamentally deregulated; since 1995 the law grants non-discriminatory access to the natural gas transmission infrastructure, and given that most gas consumed is imported, prices across the value chain are largely determined by the market.

Ironically, the only exception to this free-market pricing occurs in the Magallanes region, which by law is subject to controlled prices at lower levels than the rest of Chile. This pricing acts as a type of consumption subsidy and hinders the development of positive incentives for increased gas production, particularly from shale gas. Furthermore, the insufficient geologic information on shale gas resources in Magallanes and the dominant position of ENAP in the upstream market leave little room for other companies. For example, it is noted (Agostini and Saavedra, 2009) that ENAP retains the best areas for development and leaves those least attractive or with the highest risk for other participants, but nevertheless, it has the right to join them as a partner or operator once they reach a commercial development stage.

As for regulation, the Ministry of Energy began operations in February 2010 to develop, propose and implement public policies in the energy sector, including defining objectives, regulatory frameworks and strategies. Alongside the Ministry, the National Energy Commission and the Superintendency for Electricity and Fuels are decentralised public entities with a technical character oriented to the oversight of the performance, regulation and technical compliance in the energy sector.

As the main upstream oil and gas operator in Chile, ENAP places high priority to its relationships with stakeholders. To that end, the company's social sustainability policy has developed a comprehensive approach which considers a number of internal and external stakeholders and their interests to serve as a guide for its operations.

These stakeholders include workers, customers, strategic partners, suppliers and contractors, financial institutions, media, communities, academia, and the government. In the case of local communities, the company promotes dialogue as a vehicle to guide social investment, improve the quality of life for its stakeholders, and develop lasting relationships with those most directly affected (ENAP, 2014c).

In connection with this, it is worth noting that the concentration of oil and gas activities in Magallanes led by ENAP has supported the economic growth of the region, by bringing thousands of jobs, an extensive development of generic infrastructure such as roads and telecommunications, the creation of higher education institutions and a gas-based distribution grid for local communities (ENAP, 2014a). It is very likely that the positive support of the Magallanes community to the natural gas upstream activities is also backed by the prevalent regime of lower gas prices, which will represent an issue when a different mechanism more reflective of the costs and risks borne by companies producing unconventional gas is discussed.

Challenges and opportunities

Cognizant of the importance of natural gas in supporting economic development, the risks in ensuring a reliable gas supply, and falling domestic production, Chile has looked forward to supplying its natural gas demand with a more ambitious development of domestic resources, including nascent unconventional gas production.

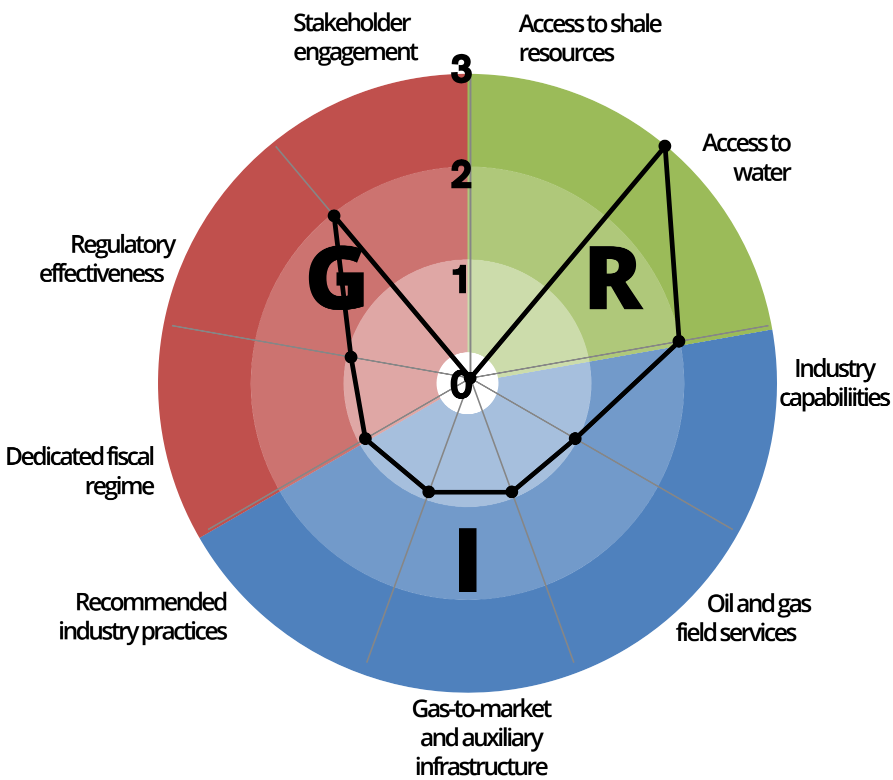
While a robust examination of the quality and extent of Chile's unconventional gas resources will bolster the industry's expertise in a more effective technical development of those resources, increasing production of shale gas will largely depend on the economic incentives granted to producers. These incentives span the fiscal terms established in the CEOPs and the regional gas pricing mechanism in Magallanes, to reflect market conditions more accurately. So far however, no shale gas resources in Chile have been available for exploration or production purposes.

Furthermore, unless the logistic challenges presented by the Chilean territory and its natural gas infrastructure are overcome, its economy-wide natural gas needs will not significantly modify the regional patterns of supply, forcing the economy to explore other options for securing its gas supply more reliably and cost-effectively from external sources. Figure 44 shows the assessment given to Chile for each one of the factors in the RIG framework. The access to resources component is still partial, although water access and infrastructure are considered to be in place.

As for infrastructure and operations, Chile's industry has taken the first steps towards the understanding of its shale gas resources, including the technology necessary to produce them cost-effectively. Nevertheless, oil and gas field services are scarce, industry practices are still incomplete, and gas-to-market infrastructure beyond Magallanes to the rest of Chile in particular remains the largest barrier to increasing shale gas production.

Lastly, in terms of governance, there are no fiscal regimes or provisions which account for the particular characteristics of shale gas; in Magallanes prices are still controlled, and as a whole, the industry is dominated by a single NOC. Regulatory effectiveness is considered to be on a positive path, as it has looked forward to promoting competitive markets and open access, but stakeholder engagement remains partial.

Figure 44
APERC's assessment of Chile's shale gas development under the RIG policy framework



Source: APERC

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China

China is an Asian economy with robust economic growth and rising energy needs. With a total land area of nearly 9.6 million square kilometres, China is among the largest economies in the world, and its nearly 1.4 billion inhabitants make it the most populous, accounting for nearly 19% of the global population.

As a result of several structural reforms implemented since 1978 to open its economy, China has seen unprecedented growth. China's economy increased at an average annual rate of 13% from 1990 to 2000 and at 17% from 2000 to 2013. By the end of 2010, its gross domestic product had surpassed Japan's, making it the second largest economy in the world (The World Bank, 2014). In step with its vibrant economy and huge population, China's energy consumption has risen considerably. From 2000 to 2013, China's primary energy demand expanded 8.6% per year, to represent just over 22% of the worldwide total, making it the top energy consuming economy (BP, 2014).

The composition and magnitude of China's energy demand also make it the largest source of carbon dioxide in the electricity sector worldwide, accounting for as much as 30% of global emissions in 2011 (World Resources Institute, 2014a). China's electricity generation is based predominantly on coal, as the economy is endowed with an abundance of this resource, with reserves of around 114.5 billion tonnes equivalent to 13% of the global total(BP, 2014).

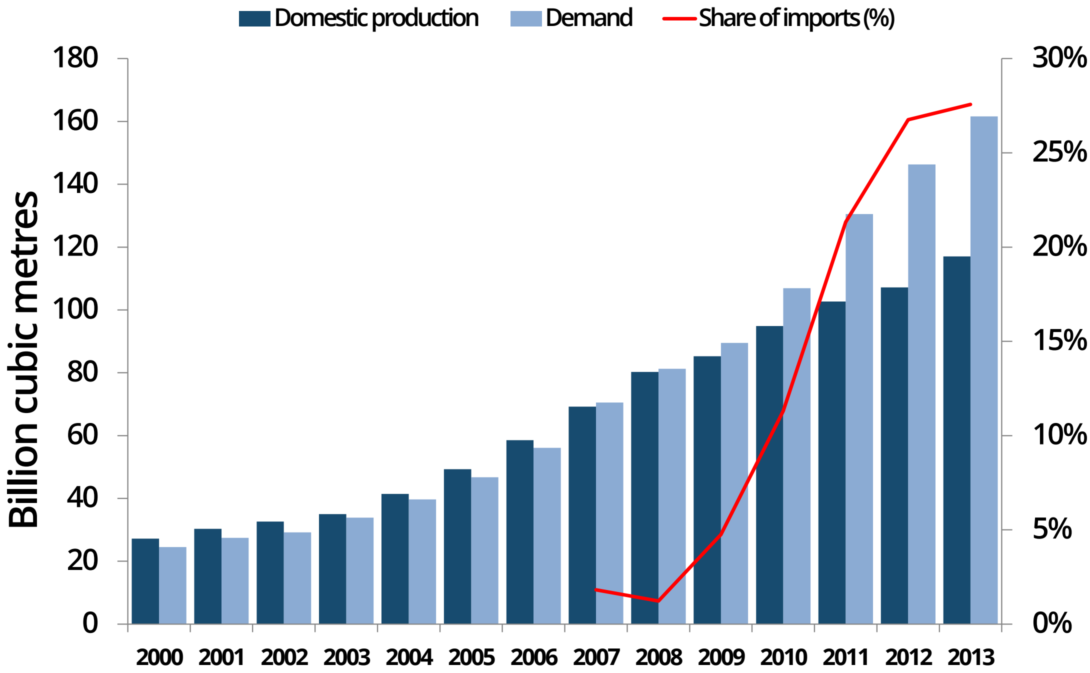
To support its economic development with lower carbon intensity, China is attempting to reduce its use of coal through by taking advantage of other energy resources, including an accelerated use of natural gas. However, the economy has undermined its energy security in step with its increasing dependence on external supply sources. This issue has pushed China to develop its domestic gas resources more intensively, extending in recent years to the exploration and eventual development of shale gas. Notwithstanding the commercial production status reached in 2013, shale gas output remains marginal and at a preliminary stage. China still faces many challenges to develop this type of unconventional gas resources on a massive scale.

Access to natural resources – (R)

China's fossil energy production is insufficient to meet its demands. In 2013, China's domestic oil production represented about 39% of its consumption, and despite its historical coal self-sufficiency, domestic production met only 96% of its demand. Likewise, the fast-growing utilization of natural gas promoted recently by the Chinese government has outpaced the growth of domestic production. As seen in Figure 45, this has led to natural gas comprising an increasing share of imports, growing from barely 2% of demand in 2007 to 28% by 2013 (BP, 2014).

Natural gas production started growing rapidly in 2003, including a small amount of unconventional gas resources in the form of coalbed methane, but it has failed to meet the growth of demand, leaving the Chinese government to explore other ways to enlarge its domestic output, probably compelled by geopolitical considerations affecting the economy's self-sufficiency and energy security. This has resulted in an ambitious drive towards the development of shale gas, which was jumpstarted by a bilateral initiative signed with the United States in November 2009. The aim of that initiative was to accelerate the commercial development of Chinese shale gas resources as a means of bolstering economic growth while attaining an energy supply with lower carbon emissions.

Figure 45
China's natural gas production, demand and external dependence; 2000–2013



Source: BP (2014).

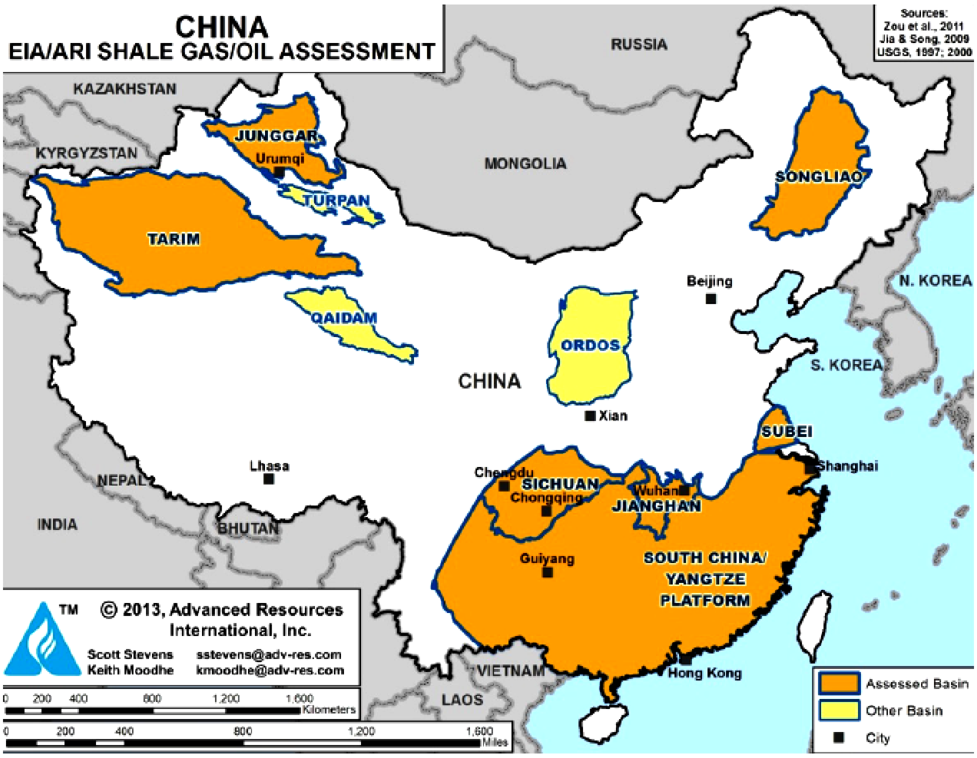
Along with the cooperation established with the United States and the positive results observed in that economy, the optimistic estimates of China's shale gas plays prompted a strong support from the Chinese government to develop those resources.

At the end of 2013 China's proved reserves of natural gas were 4.4 trillion cubic metres (155.3 trillion cubic feet), which represented around 2% of the total worldwide ('Worldwide look at reserves and production', 2013). Nevertheless, China's shale gas resources were expected to be far more prolific. Early assessments (EIA, 2013) estimated its technically recoverable shale gas resources at 31.6 trillion cubic metres (1,115 trillion cubic feet), the largest volume held by any single economy in the world. These resources, equivalent to 16% of the total assessed in 42 economies, are also roughly 8 times the size of China's proved natural gas reserves.

Other preliminary assessments provided similar estimates on the abundance of Chinese shale gas (Nakano et al., 2012): the International Energy Agency, with 26 trillion cubic metres (918 trillion cubic feet); China's Ministry of Land and Resources, with 25.1 trillion cubic metres (886 trillion cubic feet); and the China National Petroleum Corporation, with 30.7 trillion cubic metres (1,084 trillion cubic feet). Irrespective of the different figures, in theory, the magnitude of shale resources in each of these estimations could supply the current Chinese natural gas demand for more than two centuries.

As shown in Figure 46 and Table 10, shale gas is spread across the Chinese territory in seven basins. The largest volumes inferred are located in three basins: Sichuan, Yangtze and Tarim, which together account for nearly 90% of the total technically recoverable resources, with individual shares of 56%, 19%, and 13%, respectively (EIA, 2013).

Figure 46
China's shale gas resources



Source: EIA (2013).

The remainder of China's shale gas resources, equivalent to about 11%, are throughout the Greater Subei and Jianghan basins in the southwest, the Junggar basin in the northwest and the Songliao basin in the northeast. The Ordos, Qaidam and Turpan basins might hold additional volumes of shale gas, but as they were not included in the EIA's (2013) assessment, the confirmation of their resources will depend on further studies. The Ordos basin in particular, has been a major producer of conventional gas and is rich in coalbed methane resources.

Table 10
China's shale gas resources by basin

Basin	Technically recoverable resources (Tcf)	Technically recoverable resources (Tcm)
Sichuan	627.0	17.8
Tarim	215.0	6.1
Yangtze Platform	149.0	4.2
Greater Subei	45.0	1.3
Junggar	36.0	1.0
Jianghan	28.0	0.8
Songliao	16.0	0.5
Total	**574.1**	**16.3**

Source: EIA (2013).

Natural gas is mainly produced by China's three major vertically integrated NOCs: China National Petroleum Corporation (CNPC); the China Petrochemical Corporation (Sinopec); and the China National Oil Offshore Corporation (CNOOC). In addition to these companies and their subsidiaries, other NOCs and private participants can access upstream activities mostly by means of production-sharing contracts (PSCs) or Joint Ventures signed with the Chinese government. In either case, foreign operators are not allowed to undertake any activities alone, but may do so in association with a controlling Chinese partner, typically NOCs.

Unlike natural gas, the access to shale gas resources through the corresponding rights has been granted so far for exploration purposes in two dedicated bidding rounds. In the first round held in June 2011, six domestic companies including the major NOCs were invited to bid on four blocks, but only two of them were awarded: Nanchuan in Chongqing, Sichuan Basin to Sinopec; and Xiushan in Guizhou, Yangtze Basin to a regional operator (Henan Provincial Coalbed Methane Company).

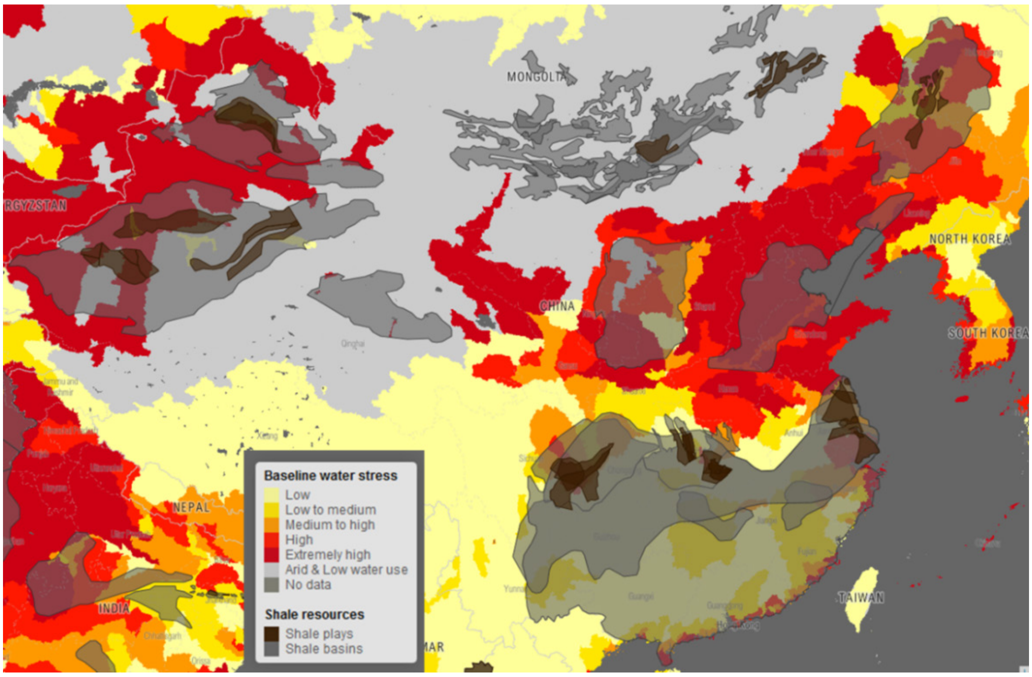
The second round was conducted in October 2012 with 20 blocks located across China's south-eastern shale gas basins. This time, domestic companies as well as international companies in joint ventures controlled by Chinese companies were allowed to participate, contingent on their capitalization and exploration plans. The second round resulted in the award of 19 blocks to 16 Chinese companies, most of them state-owned and none of them foreign (Deemer and Song, 2014; Tian et al., 2014). In both rounds, the tendered areas had not been allocated to the major Chinese NOCs, and the award of the corresponding exploration rights was limited to a three-year period over which certain investment commitments must be met.

In between the two bidding rounds, by the end of 2011, the Chinese government declared shale gas an 'independent' mineral resource, in order to detach it from the administrative procedures applicable to conventional natural gas production and to nurture the participation of private capital in these projects (Jiang, 2015; Sandalow et al., 2014). Also by the end of 2011, the government announced adjustments to the Guidance Catalogue of Foreign Investment and Industry, in order to consider foreign participation in shale gas projects as an 'encouraged' investment category, which basically means that such projects are entitled to preferential administrative and fiscal measures (Deemer and Song, 2014).

In practice, however, foreign investment in shale gas exploration and development projects is minimal. Some foreign companies have been able to engage in the development of shale gas through joint study agreements (JSAs) established in partnership with Chinese companies. These JSAs are oriented to the short-term exploration and eventual development of shale gas, with their use having led to the first shale gas-PSC outside the two dedicated bidding rounds. Signed in March 2012 but approved one year later by the Chinese government, this PSC between CNPC and Shell strives to develop the Fushun-Yongchuan block in the Sichuan basin (Deemer and Song, 2014; Chen, 2013).

Regarding water access, China faces significant constraints. The economy has the fifth-largest volume of total renewable water resources in the world, but due to its high population density, these resources shrink on a per capita basis, amounting to roughly 2,000 cubic metres, which represents barely 10% of the world's average (FAO, 2014). According to the World Resources Institute (2014b) and as depicted in Figure 47, more than 60% of China's shale basins are located in areas with arid settings or with water stress levels ranging between high and extremely high levels. Because of this, the drilling sites and the hydraulic fracturing techniques selected for use in China's shale basins will be critical to determining the water volumes ultimately required and the magnitude of development achievable in each basin.

Figure 47
China's shale gas plays and baseline water stress



Source: World Resources Institute (2014b).

Infrastructure and operations–(I)

For several decades, Chinese natural gas was developed as a by-product of oil. As a result, the industry's capabilities remained somewhat limited, particularly with regard to the development of unconventional gas resources. In the last few decades however, there has been a strong government commitment at the highest level to increase domestic production of a broader base of resources, including coalbed methane and, more recently, shale gas.

China's institutional push for shale gas is largely inspired by the experience of the United States, although there are major differences between the two economies which have prevented a faster pace of development. Above all, the geologic conditions which favoured the commercial production of shale gas in the United States are hardly present in China, where preliminary assessments and exploratory studies indicate more complex tectonics and deeper reservoirs mostly located in areas such as mountains and deserts and therefore more difficult to access. It is estimated that less than 20% of China's shale resources occur in flatlands (Hao et al., 2013).

These geomorphologic characteristics mean higher production costs and have prompted a call for technologies and skills adapted to China's more challenging settings, in order to improve the recovery factors and the commercial potential of existing resources. Research has found (Lee and Sohn, 2014), that China's shale gas technologies are immature, especially in regards to the key technologies of horizontal and directional drilling, as well as hydraulic fracturing. Also, due to China's poor water access, the development of technological capabilities to optimise water resources is critical to increasing shale gas production.

Other challenges remain for China's industry capabilities. The winning companies in the first bidding round, for example, did not have any expertise on shale gas development, the closest being the experience of one of them on coalbed methane production. In the second bidding round, all of the companies that were awarded shale blocks had no experience at all on oil and gas upstream matters, let alone on shale gas (Tian et al., 2014).

The participation of more experienced companies in the development of shale gas beyond the two bidding rounds conducted so far is limited to the PSC signed with Shell in March 2012. CNPC signed another PSC with Hess in July 2013 (Sandalow et al., 2014; Chen, 2013), albeit it is not oriented to the development of shale gas but oil (*tight oil*).

On this subject, as shown in Table 11, several Chinese companies, most noticeably the largest three NOCs, have engaged in substantial overseas investments related to shale gas in the United States and Canada, with the aim of diversifying and strengthening their supplies, but also to enhance their technological and operational capabilities to rush the massive development of those resources in China.

Table 11
China's direct foreign investment transactions related to shale gas

Year	Type of transaction	Investor (Chinese NOC)	Target economy	Transaction amount (USD billion)
2011	Assets and funding	CNOOC	United States	2.3
	Acquisition	Sinopec	Canada	2.1
2012	Assets and funding		United States	2.5
	Joint venture	PetroChina (CNPC)	Canada	1
	Acquisition	CNOOC		18
	Minority stake	PetroChina (CNPC)		2.2
2013	Assets and funding	Sinochem	United States	1.7
	Assets	Sinopec		1

Source: Chen (2013, p. 28).

Chinese companies have started undertaking the manufacture of specific drilling and hydraulic fracturing equipment (Jiang, 2015), including some of the tools actually employed in the Fuling field (Sinopec, 2014). In late 2013, Sinopec, one of the two companies appointed in the first shale gas round, announced that its Fuling shale gas field had been quite successful in its commercial demonstration stage, and would therefore enter full commercial production.

Located in the Nanchuan block, Fuling's average test production was reported to be more than 330,000 cubic metres (11.7 million cubic feet) per day, with one of its 21 exploratory wells having been producing steadily for more than 480 days. The Fuling field is expected to reach 10 billion cubic metres (353 billion cubic feet) by 2017 (Sinopec, 2014). More important, due to this landmark, China became the only commercial producer of shale gas in Asia and one of the very few worldwide, along with the United States, Canada, and Australia.

As for international oilfield services, they are locally available due to previous work in conventional oil and gas projects, but their participation is modest as the market is dominated by Chinese companies (Gao, 2012). Besides, many of these Chinese oilfield service companies are typically small in terms of the magnitude of their operations, and more than 90% of them are owned by the three largest NOCs (Tian et al., 2014). It is unlikely that these equipment manufacturers and service providers can support a larger scale of development in the short term, as they are still at an early stage of the shale gas learning curve.

Natural gas produced in China was consumed locally for many years, owing to the lack of transmission infrastructure between the producing areas and the major demand markets, most of them in the east coast. In step with China's rising energy needs in the 1990s, the Chinese government started promoting transmission pipelines more aggressively, to connect the Ordos and Tarim gas basins with Beijing and Shanghai. This policy orientation and the resulting infrastructure gave the Chinese gas industry an economy-wide reach which was followed by the operation since 2006 of LNG import terminals to support the growing demand (Higashi, 2009). In May 2014, after decades of negotiation, China through CNPC signed a contract with Russia's Gazprom for the long-term supply of natural gas; this deal will strengthen China's natural gas supply and will also extend its transmission infrastructure.

Despite these milestones, China's natural gas infrastructure is immature. Many markets and pipeline systems are still not interconnected, and with more than 40,000 kilometres, the entire transmission system is barely equivalent to 10% of the length of the network in the United States, an economy with a very similar territorial size but far less populous (Jiang, 2015). Aside from pipelines, water-related infrastructure is insufficient in areas with shale resources, and due to the territory's characteristics, the availability of adequate roads in rural areas is poor.

As for the last component of the RIG framework, China's natural gas industry has been introducing international practices, partly because the Chinese government's desire to increase its compliance with international rules and standards, and partly because of the international operations of the major Chinese NOCs. This internationalization has increased the cooperation of CNOOC, CNPC, Sinopec, and other Chinese NOCs with IOCs, allowing them to operate in markets with stricter regulations and more advanced industry practices. It is unclear, though, which methods will guide the development of shale gas in China, owing to the current stage of commercial production at a marginal scale.

It must be noted that in China, the governmental intervention in the natural gas industry and the development of shale gas is deliberate and substantial, due to the economy's political system, which relies on a centralized command-and-control approach. An example of this is the strict planning of the natural gas industry through quinquennial plans. Established in 1953, these plans define the policies to be implemented over five-year periods in order to address several economy-wide priorities and accomplish specific objectives.

In particular, the Twelfth Five-Year Plan 2011–2015 currently in effect aims for the expansion of the natural gas share in the primary energy mix from roughly 4% to 8.3%, and encourages the faster growth of domestic production inclusive of unconventional gas resources like shale gas. Owing to this mandate, two policy instruments were subsequently issued to strengthen shale gas development: The Five-Year Shale Gas Plan in 2012 and the Shale Gas Industrial Policy in 2013 (Deemer and Song, 2014).

Specifically, the Five-Year Shale Gas Plan recognizes the challenges in producing shale gas to a scale sufficiently large to contribute to China's natural gas vision; and thereby sets the following four targets:

- Having a complete economy-wide assessment of shale gas resources which allows the identification of their distribution and most productive areas;

- Achieving recoverable shale gas reserves of 200 billion cubic metres (7.1 trillion cubic feet) and production levels of 6.5 billion cubic metres (230 billion cubic feet) per year by 2015;

- Developing appropriate methods, technologies, and equipment for the exploration and development of those resources; and

- Setting technical standards, specific methods and general guidelines for the exploration and development of shale gas, including those oriented to environmental protection from those activities.

The Five-Year Shale Gas Plan also transcends its time boundaries by envisioning annual production in the range of 60 and 100 billion cubic metres by 2020. This output would be supported on a comprehensive medium-term strategy based on five pillars (National Energy Administration, 2012):

- Increased public investment focused on the appraisal of potential resources and international cooperation;

- Applied technological research and development;

- Better institutional mechanisms to promote the exploration and development of shale gas resources, encompassing the participation of experienced foreign companies and better regulatory arrangements;

- The establishment of economic incentives in line with those established for coalbed methane, and;

- The improvement of related infrastructure, including the development of transmission pipelines and their connections to the main natural gas network, as well as the construction of small gas-based facilities such as LNG terminals and compressed natural gas stations to use shale gas which would otherwise be inaccessible or wasted.

In turn, the Shale Gas Industrial Policy formulates more detailed action lines. Strictly from an infrastructure and operations perspective, these actions encompass the establishment of pilot development zones to master the technology, cost-effective practices and safety measures to let commercial shale gas production take off; the reassertion of the role of foreign operators with experience in the production of shale gas to enhance China's domestic technologies and skills ; and the promotion of new gas pipelines and dedicated infrastructure (Deemer and Song, 2014).

In essence, in the medium term, the objectives and plans implemented by the Chinese central government sustain market demand for natural gas and thus help support the efforts to advance the development of shale gas. This depends nevertheless on the extent to which political support is able to provide the capital and funding required to afford the intensive materials, equipment, technologies, and human resources involved in this task. Just as a reference, it is estimated that at the end of 2013, CNPC and Sinopec together had invested just over USD 1 billion in shale gas development, but had barely recovered USD 54 million (Tian et al., 2014).

Lastly, China has some experience in the development of other unconventional gas resources. Aware of its growing energy needs and leveraging its massive coal resources, China has been engaged in the production of coalbed methane since the 1990s. In spite of its large resource base, governmental support, and development of infrastructure and technology, the commercial production of coalbed methane only started in 2006 and so far has fallen short of achieving the targets established in the government plans.

Some of the main barriers identified for this slow and meagre coalbed methane progress (Andrews-Speed and Len, 2014;

Regan and Chao, 2014) refer to the inadequacy of the prevalent technology used in complex geological settings; the overlapping rights of coal and coalbed methane producers; poor profitability and access to capital; and the institutional inflexibility towards foreign operators, who are prevented from participating in PSCs which are too rigid for their operational requirements.

Governance – (G)

Concerning economic alignment in the development of shale gas, the Chinese central government has established some incentives to address the issues which differ from the production of conventional gas.

To that end, a production subsidy of RMB 0.4 per cubic metre (roughly equivalent to USD 0.06 per cubic metre or USD 1.83 per million cubic feet) was established for the shale gas produced between 2012 and 2015 (Sandalow et al., 2014); additionally, the Shale Gas Industrial Policy issued in 2013 recommended the application of fiscal incentives, the exemption of tariffs from imported equipment and customs to producers, and the reclassification of shale gas activities as a 'strategic emerging industry' to provide it with additional financial benefits (Deemer and Song, 2014).

Nevertheless, some structural deficiencies in the Chinese natural gas market prevent greater shale gas production and a more optimistic outlook. Chinese NOCs, particularly the three largest, exert a dominant market position with preferential rights, geologic data, governmental policies, acreage, infrastructure, and resources which together provide an uneven playing field for other domestic and international operators pursuing the development of shale gas.

Another hurdle is the access to transmission pipelines, which mostly belong to CNPC and Sinopec; even though the Chinese government has declared open access to this infrastructure, in reality there is no specific regulator to ensure its observance (Sandalow et al., 2014). Lastly, natural gas pricing has strived to increase market-based foundations since a reform implemented at the end of 2011. The reform has spurred some progress in the deregulation of wellhead prices, but city gate prices are capped and linked to the import prices of alternative fuels (Tian et al., 2014).

With reference to China's regulatory effectiveness towards shale gas, the assessment is mixed. On one hand, Chinese authorities have regarded shale gas as an economy-wide priority and thus have committed resources designed to reach its commercial production. In an attempt to master the technology and operations required to produce shale gas economically, the policies implemented have encompassed the more active participation of foreign companies as well as overseas investments of China's major NOCs.

Political support for shale gas has gone to the extent of giving it greater weight and more benefits than other unconventional gas resources; for example, the production subsidies given to shale gas are double those of coalbed methane (Regan and Chao, 2014; Hu and Xu, 2013). Furthermore, in November 2014, the Chinese government went as far as imposing a fine on the winners of the first shale gas bidding round (Sinopec and Henan Provincial Coalbed Methane Company) for failing to fulfil their investment commitments. The penalty also included the reduction of the original acreage (Reuters Africa, 2014).

On the other hand, China's regulatory environment for shale gas is characterised by a diversity of agencies with different roles which overlap and conflict with each other. At least seven agencies are involved, some of with unclear responsibilities (Deemer and Song, 2014). More worrisome, though, is the prevalent regulatory ambiguity, insofar as the declaration of shale gas as an independent mineral resource transferred the main responsibility for its development from the National Development and Reform

Commission to the Ministry of Land and Resources. This distinction not only resulted in an administrative change, but caused much uncertainty as to the legal model applicable to shale gas production.

It is uncertain whether shale gas production will be carried out as a joint venture in the vein of the arrangements used by mining activities regulated by the Ministry of Land and Resources, or as a PSC typically used in conventional oil and gas operations and the activities undertaken by the major Chinese NOCs with foreign operators, in which case the National Development and Reform Commission would have regulatory oversight. Owing to these issues, regulatory procedures are likely to become more burdensome.

In addition to these concerns, there is a lack of specific regulations and technical standards. The status of operators is unknown after their exploratory activities determine in the commercial potential of their blocks, and foreign companies are unable to operate without a controlling Chinese partner, which most likely has little or no experience in shale gas operations. These major regulatory considerations hinder the more accelerated development of shale gas. Essentially, despite China's political will and good intentions, there is a prevailing lack of detailed regulations to enforce and translate high-level policies and strategies governing the development of shale gas.

As for the last factor in the governance component, regarding stakeholder engagement, neither the operating companies nor the Chinese government has proactively sought social license with other stakeholders, probably because of the small scale of current operations. Another plausible reason is the Chinese central government's power to override independent environmental movements which conflict with economy-wide priorities (Deemer and Song, 2014).

It must be noted however that the high population densities in areas of concentrated shale gas resources such as the Sichuan basin, the shortage of water resources, the overly lax environmental regulations for oil and gas activities as a whole, and shale gas in particular, and some complaints from Sichuan residents about the noise, dust and environmental consequences of exploratory shale gas activities represent potential risks to a greater shale gas production (Krupnick et al., 2014; Hu and Xu, 2013).

Challenges and opportunities

China is a major economy in the Asia-Pacific region and the world, but the fast growth and composition of its energy demand have resulted in a particularly high carbon intensity which has become a global concern. This has driven an increased use of natural gas to reduce the predominance of coal in the fossil-based primary energy mix; nonetheless, energy security has become critical, as China is increasingly dependent on external sources of natural gas.

To that end, in the last few years the Chinese government has attempted to increase its natural gas resource base with the aid of an ambitious strategy for shale gas development. Notwithstanding the strong political will and efforts expended, production remains marginal. Several challenges must be overcome in order to reach a level which can contribute effectively to China's desired energy transition.

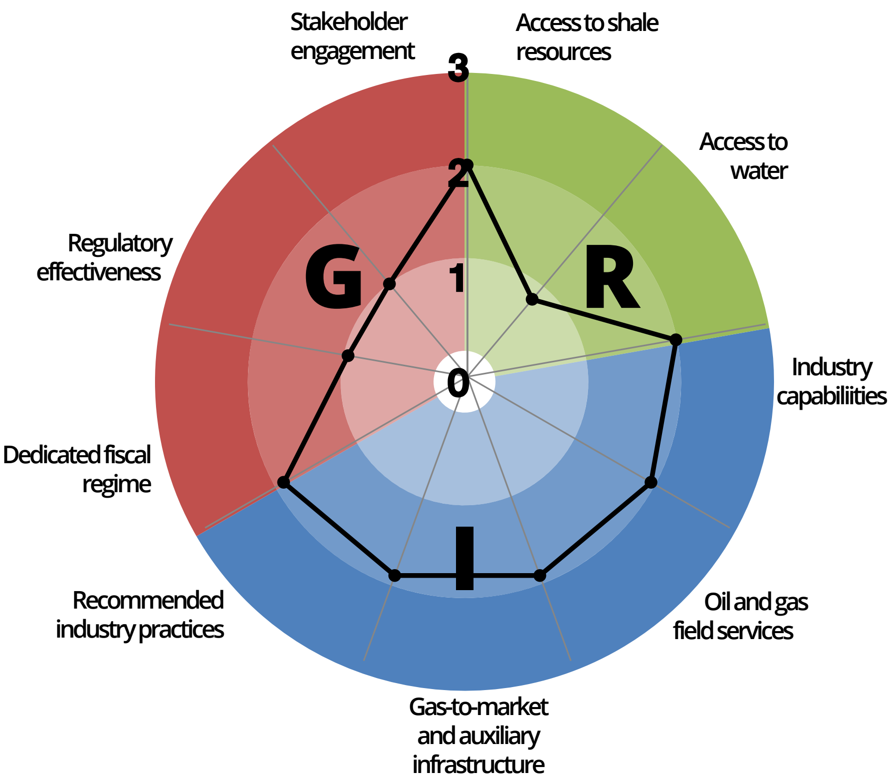
According to the economy analysis based on the RIG framework (shown in Figure 48), access to shale gas resources in China is possible but limited. A few exploration blocks have been offered in two dedicated bidding rounds, but in both Chinese NOCs were favoured. Private participation remains minimal, and the operation of foreign companies is restricted to a single PSC signed with one of the largest Chinese NOCs, albeit there is ambiguity on the legal figure applicable to grant operators' access to the development of shale gas resources.

Additionally, physical access to shale gas resources is complicated due to natural barriers. Because of the high population density across China, there are considerable water access limitations which must be taken into consideration in any scenario of rapid large-scale production. Oilfield services are dominated by Chinese companies, while the interaction with international companies experienced in the development of shale gas and supply chain solutions is minimal.

In terms of infrastructure, China's main barrier is the absence of an economy-wide transmission system which interlinks gas producing areas and markets, especially in the major demand centres located in the Southeast coast. Based on recent events which signal the future construction of cross-border pipelines, China could extend the length of its whole transmission system, in a similar fashion to the kick-starting of its natural gas market some decades ago. On a positive note, the political support for shale gas has sustained a robust economy-wide natural gas demand and allocated sufficient capital to support these efforts at least for a medium-term horizon.

Figure 48

APERC's assessment of China's shale gas development under the RIG policy framework



Source: APERC

The last component of governance might be the most challenging in China. While economic incentives have been implemented to encourage a quicker pace of shale gas production, it must be taken into account that these are only applicable to the productive stage rather than the exploratory stage, which entails higher risks and costs. Additionally, there is much uncertainty on the economic viability of shale gas projects, based on the status of production subsidies during 2015. Although the central government has devised policies to introduce more competition in the natural gas market, including open access to pipelines and the deregulation of production prices, the

Chinese NOCs, particularly the largest three, are dominant market players. Open access to their pipelines is not fully operational, and foreign companies cannot operate if they do not have an association with a controlling Chinese partner.

In spite of China's high-level political support to bolster shale gas production, major regulatory deficiencies persist. Several governmental agencies are in charge of issues related to shale gas, creating not only additional layers of administrative burdens and lengthier procedures, but also leaving some attributions undefined or subject to vague interpretations. Fundamentally, the main hurdle is a generalised lack of regulations to bring certainty to operators; China's strategy has focused so much on the industry that it has overlooked other risks of interest for other stakeholders that if unattended, which if overlooked, could snowball into major future barriers as soon.

It is important to highlight that in their effort to replicate the experience of the United States, the Chinese authorities are also coming closer to reproducing their history with coalbed methane. In this sense, the acknowledgement of the weaknesses experienced in the coalbed methane industry could help the Chinese government avoid repeating them in the development of shale gas.

The milestone of commercial production status achieved with the Fuling field raises the hopes to expand domestic shale gas output; but as long as some challenges are still unattended, it is uncertain whether a scenario of large-scale shale gas development will come in time to meet China's ambitious energy plans and urgent energy needs.

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Indonesia

With almost 250 million inhabitants, which make it the fourth most populated economy in the world, Indonesia is a major energy player in the global arena. In particular, it has long been known as a major producer and exporter of gas resources.

Indonesia is also one of the most important economies in the world for its potential unconventional gas resources, which so far have been developed only in the form of coalbed methane. Recently however, Indonesia has also been recognised as one of the few economies in Asia to have taken the first steps towards the development of shale gas, owing to the combination of its rising natural gas domestic demand, its aging conventional resources, and the inspiration of the positive experience observed in the United States.

Access to natural resources – (R)

Shale-based hydrocarbons are abundant in Indonesia's territory, with many oil and gas basins currently in production from Sumatra to Papua having thick shale formations with appropriate properties for the future development of gas.

According to official data (Sukhyar and Fakhruddin, 2013) based on Indonesia's Geological Agency, the full potential of the economy's shale gas resources originally in place is distributed across 14 basins from Sumatra to Papua and amounts to 16.3 trillion cubic metres (574 trillion cubic feet) of gas in place, as seen in Table 12.

Table 12
Indonesia's shale gas resources by region and basin

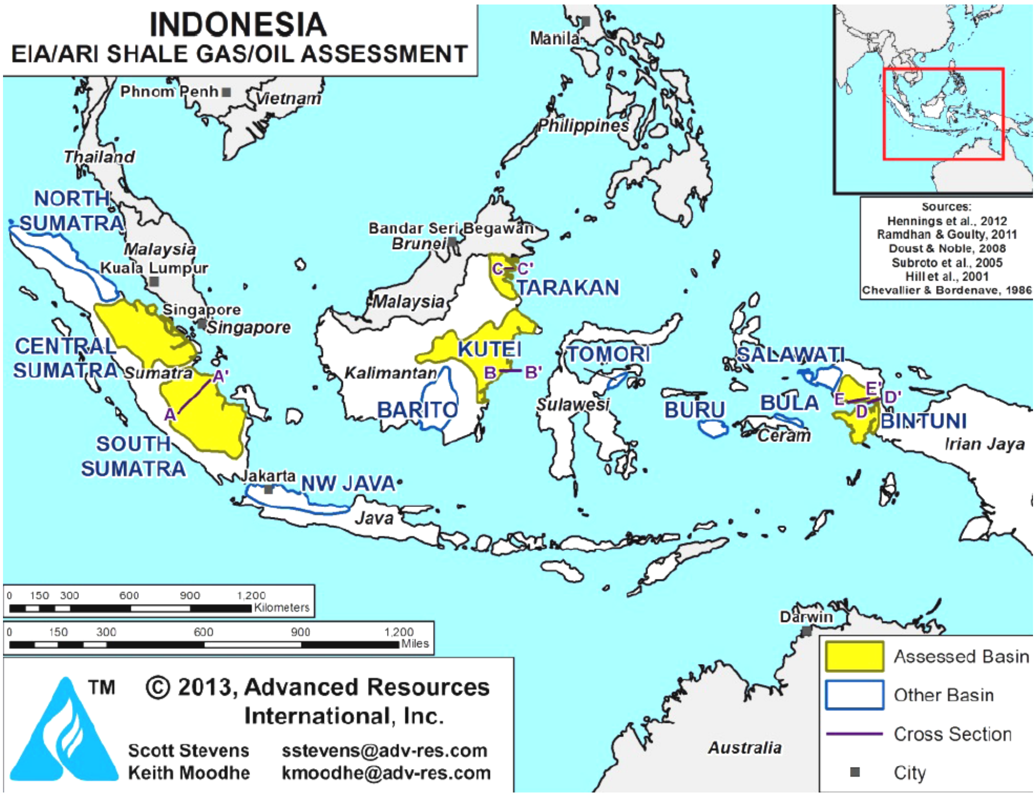
Region	Basin/Formation	Total gas in place (Tcm)	Total gas in place (Tcf)
Sumatra	North Sumatra	1.8	64.8
	Central Sumatra	2.5	86.9
	Ombilin	0.7	25.3
	South Sumatra	1.6	56.1
	Subtotal	**6.6**	**233.1**
Java	Northwest Java	0.2	5.6
	Northeast Java	1.2	42.0
	Subtotal	**1.3**	**47.6**
Kalimantan (Borneo)	Barito	2.1	74.6
	Kutei	2.3	80.6
	Tarakan	0.2	7.2
	Melawi	0.3	11.9
	Ketungau	0.6	19.6
	Subtotal	**5.5**	**193.9**
Sulawesi	**Sengkang**	**0.2**	**5.4**
Papua	Akimeugah	1.8	62.6
	Bintuni	0.9	31.4
	Subtotal	**2.7**	**94.0**
	Total	**16.3**	**574.1**

Source: Sukhyar and Fakhruddin (2013).

The four assessed basins in Sumatra (North, Central, South Sumatra, and Ombilin) make it Indonesia's richest region in shale gas potential, possessing 41% of the total estimated resources. The regions of Kalimantan, Papua, Java, and Sulawesi respectively account for 34%, 16%, 8%, and 1%. These estimates suggest that shale gas resources exceed even coalbed methane, which is estimated at 12.8 trillion cubic metres (453 trillion cubic feet) of gas in place (Sukhyar and Fakhruddin, 2013). To provide a reference for the magnitude of these shale gas resources, Indonesia's proved natural gas reserves reached almost 3 trillion cubic metres (104.4 trillion cubic feet) at the end of 2013 ('Worldwide look at reserves and production', 2013).

In consideration of more precise geologic parameters, the assessment by the United States Energy Information Administration (2013) used five outlined shale gas basins in Indonesia, which are shown in Figure 49: Central and South Sumatra in the Sumatra region; Tarakan and Kutei in Kalimantan region; and Bintuni in Papua. The potential estimated in these basins was much lower, amounting to 1.3 trillion cubic metres (46 trillion cubic feet) of technically recoverable resources, which place Indonesia in control of the largest potential resource base of shale gas in South East Asia.

Figure 49
Indonesia's shale gas resources



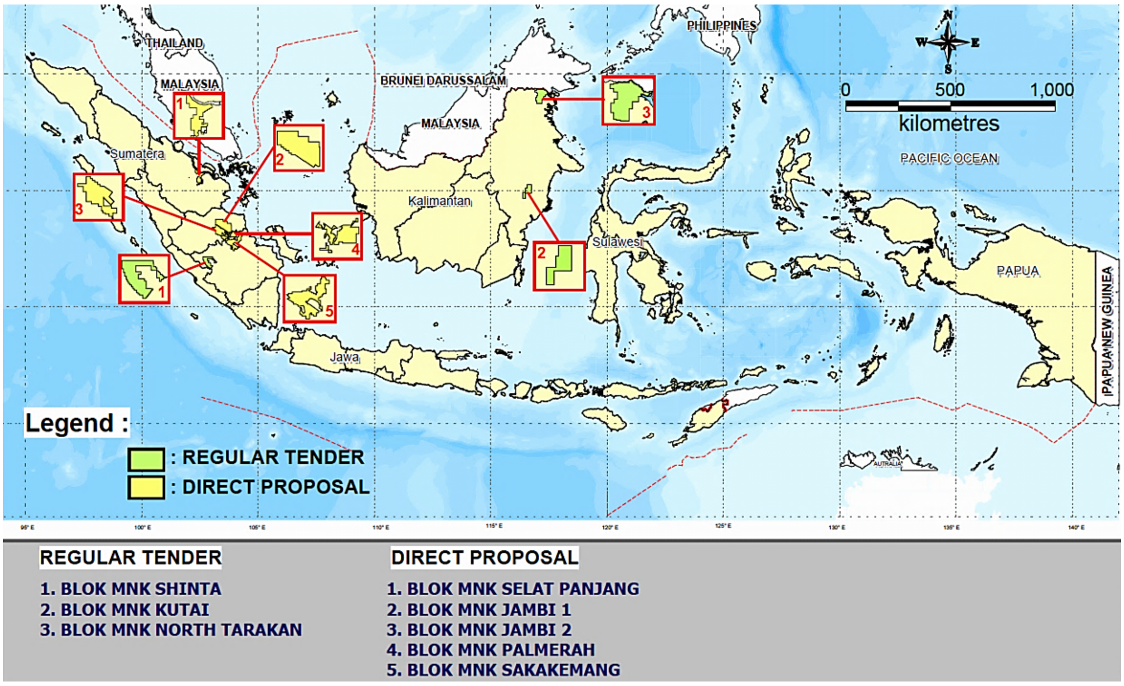
Source: APERC

Besides Indonesia's NOC Pertamina, other operators have access to explore and develop shale gas resources through production-sharing contracts (PSC). Created by Indonesia in the mid-1960s, PSC retain the State ownership of hydrocarbons while granting operators the rights to explore and develop an exclusive area. In so doing, operators bear the operational risks and expenses in the commercial development of resources, with the aim of recouping their costs and making a profit after the resulting revenue has been distributed between them and the government (Bindemann, 1999).

Indonesia has some experience in the production of other unconventional gas resources, with the first PSC for coalbed methane signed in 2008. By the end of 2012 there were 54 coalbed methane cooperation contracts in place, with the government having set production targets of 0.5, 1 and 1.5 billion cubic feet by 2015, 2020, and 2025, respectively (PWC, 2014).

The first shale gas PSC (Migas Non Konvensional, or MNK) was signed in May 2013 with Pertamina, for a working area in North Sumatra (Sumbagut) which is currently in an exploratory stage. In December 2013 two other blocks were awarded (Kisfraran, in North Sumatra and; Tanjung in South Kalimantan), but only the first was awarded to a joint venture of foreign firms, as the second one was declared without a winner. In May 2014, another eight blocks shown in Figure 50, were announced, with two of them being awarded to Pertamina.

Figure 50
Indonesia's 2014 shale gas tender

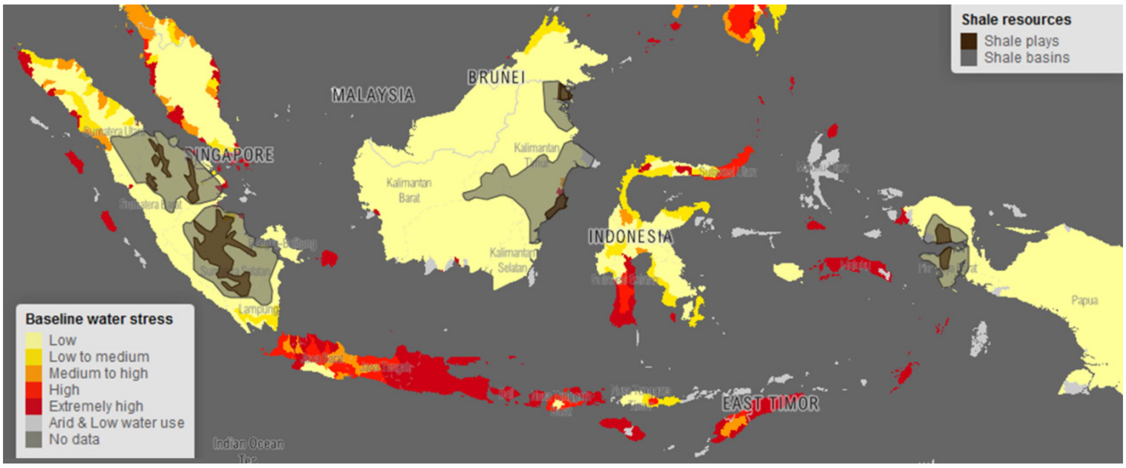


Source: Directorate General of Oil and Gas (2014).

Access to water resources is not considered a major barrier to the development of shale gas in Indonesia. The economy has heavy rainfall and abundant river streams, and even though its total renewable water resources per capita of 8,179 cubic metres are below the world's average (FAO, 2014), the Indonesian regions with the largest estimated shale gas resources in Sumatra, Kalimantan and Papua (EIA, 2013) have adequate water supplies, relatively free of water constraints (World Resources Institute, 2014).

However, being the most populous island in the world, with nearly 60% of Indonesia's total population, Java is likely to experience critical issues regarding water access for shale gas production, as shown in the water stress analysis in Figure 51. Under a larger scale development, economy-wide water access might become more problematic.

Figure 51
Indonesia's shale gas plays and baseline water stress



Source: World Resources Institute (2014)

Infrastructure and operations–(I)

Essential to the understanding and estimation of Indonesia's shale gas potential is the availability of detailed geological mapping and studies. The Geological Agency of the Ministry of Energy and Mineral Resources (MEMR) is responsible for economy-wide data and information services on unconventional gas resources.

To that end, the Geological Agency has established a plan which comprises a survey, research, assessment and pilot program for developing shale hydrocarbons in five areas in Indonesia in the following decreasing order of priority: Sumatra, Papua, Sulawesi-Maluku, Kalimantan and Java. In an effort to favour the commercial production of shale gas to bolster regional and economy-wide development, these basins were selected based on their potential to bear shale hydrocarbons and the adequacy of their infrastructure (Sukhyar and Fakhruddin, 2013). Additionally, there are geologic data for each block explored or developed by operators under the licenses issued by the MEMR. As these data are the product of joint evaluations managed by law as confidential information, access to them is not open and requires official authorization.

To develop better industry capabilities and services, Indonesia has fostered closer cooperation with the United States, in the hopes of increasing its technical and regulatory knowledge to jumpstart the commercial development of shale gas. In February 2012 Indonesia hosted the U.S. Indonesia Energy Investment Roundtable on Unconventional Gas to analyse the challenges experienced by the United States in the development of shale gas, and in May 2013, the two economies co-hosted a regional workshop to discuss public policies and best practices designed to accelerate shale gas production.

As one of the leading industry operators and holders of shale gas blocks, Pertamina started undertaking assessments and studies of this type of resources since 2010 (Alam, 2012). During 2014 it was reported that the company was pursuing a stake in a shale gas play in the United States (Reuters, 2014), probably to strengthen its external portfolio of gas resources but also to improve its technological and operational capabilities. Notwithstanding this effort, a new regulation issued by the MEMR in November 2013, banned oil and gas companies from hiring foreign workers older than 55 years, and established tougher guidelines for the employment of non-Indonesian workers (PWC, 2014). Given the complexity of shale gas production, its predominant focus in North America, and the scarcity of human capital experienced in those operations, this measure is likely to be negative for Indonesia's shale gas outlook.

Indonesia's oil and gas industry is characterised by the active participation of several operators who carry out upstream and downstream operations and have engaged for some years in the production of unconventional gas resources in the form of coalbed methane. This has not been exempt from challenges, though; besides the lack of suitable drilling rigs and specialised expertise (Hewitt, 2014), the inadequate gas-to-market infrastructure has hampered a larger scale of coalbed methane development (Mujiyanto and Tiess, 2013).

These challenges are also applicable to shale gas, as Indonesia lacks a supply chain capable of supporting large-scale development. Specialized equipment, will need to be brought in from elsewhere, which will increase costs. By the end of 2014 for example, there were only five drilling rigs available in Indonesia, and only one was onshore (Baker Hughes, 2014). Additionally, owing to local content regulations requiring a minimum share between 25% (main components) and 40% (including supporting components), the availability of specialised technology and equipment is uncertain.

In addition to the industry's technological and operational challenges, the geographical variation of the potential shale locations in Indonesia entails different challenges. In Kalimantan and Papua for instance, the jungle, hills, and swamps settings in some areas might pose some difficulties to massive logistical activities. This is less of an issue in Java and Sumatra.

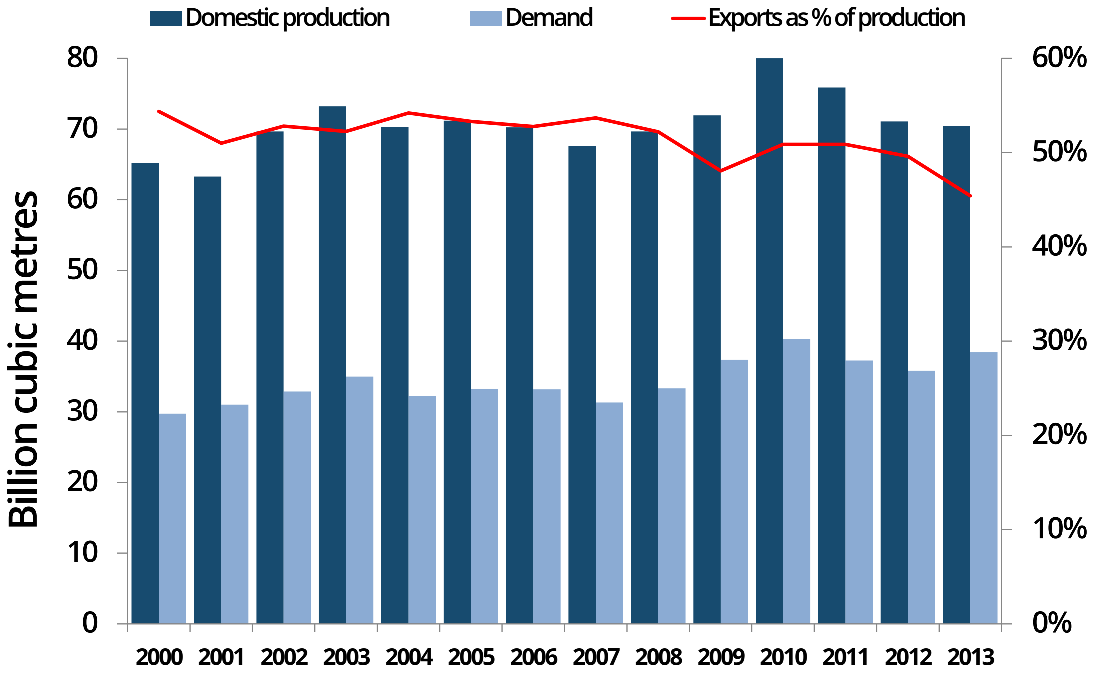
Infrastructure is another major constraint. As a vast South East Asia territory spread over more than 17,500 islands, many of which are inhabited, Indonesia's gas resources and demand centres are disconnected, creating an uneven economy-wide market. So far, gas activities have achieved more progress in the Western islands.

Indonesia has about 4,134 kilometres of gas pipelines with a total transporting capacity of nearly 13.1 billion cubic metres per day (462 billion cubic feet per day). Despite this length, Indonesia's geography has prevented the development of more interconnected regional infrastructure, which has resulted in isolated markets. Java is the largest domestic gas market with a consumption equivalent to 58% of Indonesia's total gas demand in 2013, and is divided into the West Java and Central/East Java markets. Sumatra Island, the second largest gas market, accounted for 31% of total demand and is divided into the Aceh, North Sumatra, and Central/South Sumatra markets. Outside Java and Sumatra, and to some extent East Kalimantan, the available pipeline infrastructure available is very limited (Wood Mackenzie, 2014).

Existing inter-regional pipeline connections include the Grissik-Duri and the Grissik-Singapore pipelines, connecting South Sumatra with Central Sumatra, Batam, and Singapore, and the SSWJ I and II pipelines connecting South Sumatra with West Java. Export pipelines also exist in the Natuna Sea to export gas to Singapore and Malaysia.

Indonesia became an LNG exporter in 1977 and remained the world's leader until 2005; however, the faster depletion of its biggest gas fields and its rising domestic demand represent major challenges to its future supply. The Indonesian government has promoted the domestic consumption of natural gas more aggressively since 2006, setting legal obligations (Domestic Market Obligations, or DMO) which allocate 25% of the gas produced by the PSCs to supply local demand. As a result, the use of natural gas has expanded, particularly in the electricity generation, industry, and residential sectors, which has progressively reduced the volume of domestic production available for exports, as illustrated in Figure 52 (EIA, 2014; Mujiyanto and Tiess, 2013).

Figure 52
Indonesia's natural gas production, demand and exports, 2000–2013



Source: BP (2014).

In order to ensure reliable economy-wide natural gas supply in the face of the logistical challenges imposed by its geography, infrastructure and domestic markets, Indonesia has promoted floating storage regasification units (FSRUs) and LNG regasification terminals to receive gas from the Indonesian LNG export terminals as well as from other economies. At the end of 2013, Pertamina signed a 20-year agreement with Cheniere Energy to import LNG from Texas, United States to Java (Pertamina, 2013). This means that Indonesia will have LNG export and import facilities operating simultaneously.

In Eastern Indonesia, for instance, local demand is marginal, and thereby gas development projects are primarily devoted to export markets through the Tangguh LNG plant in West Papua. On the other hand, market demand in Sumatra and Java is so significant and fast-growing that even the Arun LNG export terminal has been reversed to start receiving gas in order to strengthen the regional supply (EIA, 2014).

In 2014, Indonesia's infrastructure comprised four LNG liquefaction plants and four LNG regasification/FSRU terminals in construction and operation, with a total nominal capacity of 125 million cubic metres per day (4.4 billion cubic feet per day) and little more than 28 million cubic metres per day (1 billion cubic feet per day) respectively (Wood Mackenzie, 2014). New pipeline projects are being developed In line with the projects to expand LNG regasification capacity in Java and Sumatra. These include the Arun–Medan pipeline, the Cilegon-Serpong pipeline, the West Java Ring Lines 1–3 network expansion, and the Simenggaris–Bunyu pipeline in Kalimantan. Once finished, these six pipeline projects will add little more than 1,000 kilometres of length and about 42.5 million cubic metres per day of capacity to Indonesia's gas infrastructure.

Indonesia's long history of oil and gas production has allowed its domestic industry to develop and disseminate robust practices. As Indonesia's NOC, Pertamina's operations are guided by good governance principles which emphasise a cost-competitive performance based on technological and human capabilities, along with other operating companies (including most of the major IOCs) following similar practices. In that sense, most of the oil and gas companies in Indonesia including Pertamina, are members of the Indonesian Petroleum Association, a professional forum which revolves around the exchange of knowledge and education to maximize the economy's hydrocarbon potential (IPA, 2014).

Governance – (G)

Concerning the economic alignment between the State and producers, the shale gas PSCs so far granted by the Indonesian government have allowed some producers to carry out exploratory assessments at their own cost in dedicated blocks (joint study) or in working areas already producing other hydrocarbons or minerals (joint evaluation), with the aim of getting the right to match the highest offers submitted for such areas during the subsequent bidding round for their development.

While the addition of direct proposals to the regular bidding rounds specific to shale gas has allowed the Indonesian government to introduce stronger economic incentives towards the development of those resources, the fiscal terms applicable are still unclear. It is possible that the fiscal regime selected for shale gas follows a similar path to coalbed methane production, which is carried out through PSCs that have slightly departed from the original model, to progressively include enhanced features oriented to encourage a larger development. This has resulted in a PSC version that provides a more generous profit split, and full cost recovery without maximum limits (PWC, 2014; Godfrey et al., 2010).

At the same time, however, the PSC-based approach is pointed out as a (if not the) main barrier to the more accelerated development of unconventional gas resources. Hewitt (2014) noted that, at least for coalbed methane, the fiscal regime established through the PSCs is too rigid for the operational and financial flexibility required, as, unlike conventional gas, producers need to drill more intensively and operate in a more extensive area to attain economies of scale. These characteristics of coalbed methane production—largely applicable to shale gas—preclude companies from recouping the costs incurred beyond the ring-fenced boundaries set in their initial plan of development.

Moreover, the PSC not only forces companies to bear all exploration risks, but requires them to submit a plan of development which must be approved by the authority prior to any production operations. Given that the commercial development of shale gas generally depends on shifting trial and error exercises until cost-efficient operations are achieved, this requirement implies frequent changes to the initial plan of development, which is not only unpractical and uneconomical for producers but also exacerbates the already strenuous regulatory processes they must go through to recoup their costs under PSCs.

Indonesia's gas market has gradually become more competitive. The NOC Pertamina acted as both regulator and operator across the oil and gas sector until 2002, but in order to avoid possible conflicts of interest and to let the company focus exclusively on its role as an operator, its regulatory functions were transferred to two regulatory bodies respectively responsible for upstream and downstream activities. In spite of the legal framework granting open access to pipelines, this was still not fully available across Indonesia in 2014, mainly because of the reluctance of some state-owned gas utilities to allow the use of their infrastructure on the grounds that the third parties benefited did not share any commitments for building or expanding such assets (PWC, 2014).

In addition to state-owned gas utilities like PGN and Pertagas, a number of trading companies have been able to buy and sell gas without owning pipeline infrastructure. These companies, known as 'gas aggregators', have been able to sell gas to industrial users at higher gas prices. In this regard, unlike other heavily subsidised fuels in Indonesia, natural gas prices are settled directly between upstream producers and gas users, under approval of the government. However, The official priority given to the Indonesian natural gas market entitles producers to receive a compensation for the possible differences between their producing costs and the market price when meeting their domestic market obligations.

With reference to regulations, Indonesia has passed a new legal instrument (Regulation 05/2012) pertaining to the procedure and awarding of unconventional gas working areas. The regulation prioritises shale gas over existing oil, gas, and coalbed methane acreages, setting the subsequent highest priority for oil and gas over coalbed methane (Sirait, 2013). The mechanisms of regular bidding and direct proposal in awarding PSCs were also reasserted. This regulation also grants Pertamina a privileged position, allowing it to make a direct offer for the development of shale gas in areas where it might not be operating (Hewitt, 2014).

As the only official guideline for shale gas so far, this regulation leaves out many other risks and thereby falls short of providing more predictability to producers and stakeholders alike. Although the Indonesian government expects to begin shale gas production within five years (MEMR, 2014) it is still uncertain whether and when more elaborated directives will be issued.

In addition, most regulatory processes are burdensome. The approval of development and procurement plans associated with PSCs are lengthy and bureaucratic: environmental permits are predominantly approved by local authorities, and land access is an especially complex process because it involves negotiations with landowners along with the overregulation of authorities at the local and central levels of government (Hewitt, 2014).

Other concerns less salient but equally relevant refer to the MEMR's significant level of discretion in setting the particular terms and conditions applicable to PSCs, a generalised lack of public information about PSCs and the unavailability of official English versions of Indonesian laws and regulations (Godfrey et al., 2010). The regulator in charge of upstream oil and gas created in 2012 (SKKMIGAS) will be a temporary body until a new Oil and Gas Law is enacted, which could exacerbate the regulatory uncertainty surrounding the development of shale gas. Fundamentally, the fact that the regulator is not independent from, but a part of the MEMR, is another plausible cause of concern.

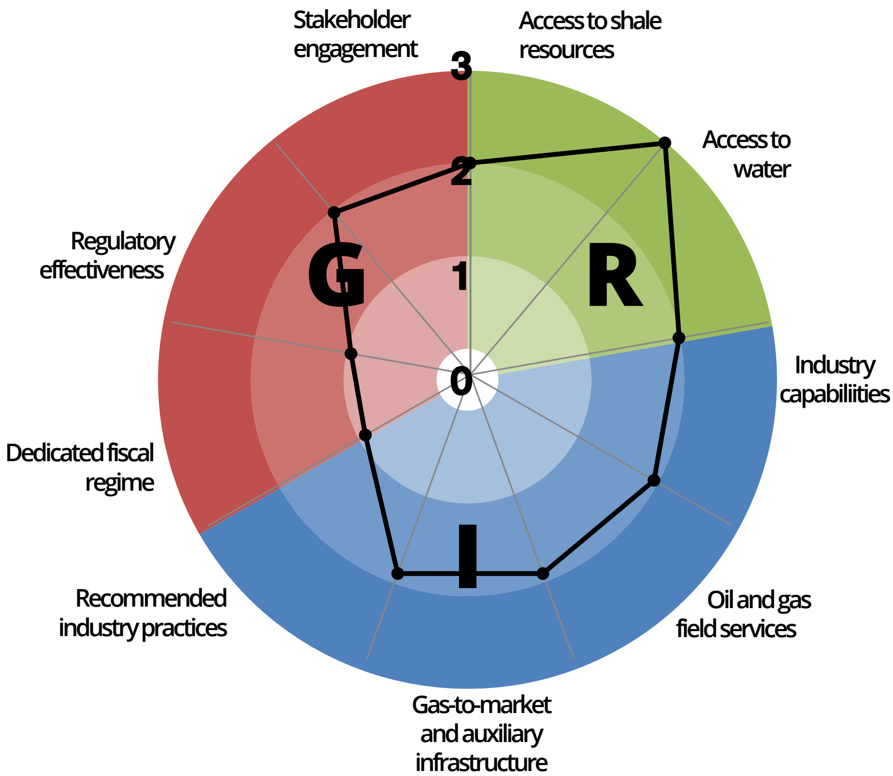
To finish, moderate stakeholder engagement is embedded in Pertamina's corporate social responsibility principles and in the industry as a whole, as expressed by the major activities of the Indonesian Petroleum Association. In Indonesia, there are no generalised social resistance or negative attitudes towards shale gas, probably because of how little activity has taken place and the remote locations of shale formations. Coalbed methane, for example, is the unconventional gas resource at the most advanced development stage, and still has not reached a large scale of activity (Hewitt, 2014; Moore, 2012).

Challenges and opportunities

Indonesia looks forward to meeting its rising natural gas demand while offsetting the natural decline of its aging conventional fields and maintaining its status as an LNG exporter. Owing to this situation, the economy has encouraged a more active development of its vast unconventional resources, which have recently grown to include shale gas.

Indonesia's challenges and advantages in developing its shale gas resources were outlined following the RIG framework; the results are shown in Figure 53. Regarding the access to resources component, Indonesia has demonstrated the political will to develop these resources through the economy's NOC as well through other operators under PSC. As for water access, it does not seem to be a major problem, at least in the near future.

Figure 53
APERC's assessment of Indonesia's shale gas development under the RIG policy framework



Source: APERC

In connection with the factors in the infrastructure and operations component, the industry's technological and operational capabilities are still too far behind to support large-scale production. In this sense, the assessment is mixed, insofar as there is a broad commitment to accelerate the learning curve of shale gas through international cooperation, but in reality, the availability of talent, equipment, and auxiliary services is modest.

Industry practices are considered on par with international standards to address the diversity of risks generated by a larger magnitude of shale gas production. Infrastructure, however, is a significant barrier, given the natural settings of Indonesia's territory, especially its fast-growing internal demand for more dedicated infrastructure. While LNG terminals will correct some issues, pipelines are still a major hurdle to accelerated market development. Indonesia's legacy of unconventional gas development in the form of coalbed methane is expected to provide a foundation for shale gas from a technical and regulatory perspective, but it may also carry over some deficiencies which have blocked a more advanced scenario of coalbed methane development.

Governance as a whole might be the largest deterrent to future shale gas production. Likewise, given the deficiencies highlighted in the coalbed methane industry, the restrictions imposed by the PSC on the financial and operational flexibility required by operators, the exhausting and delaying typical regulatory processes they must endure, and particularly the uncertainty regarding the specific rules affecting shale gas development, provide few economic and institutional incentives to assume an optimistic scenario of shale gas development, at least not in the magnitude necessary to significantly impact Indonesia's natural gas balance in the timeframe expected by the Indonesian government.

Even though shale gas production is still just beginning, its pace of development will ultimately depend on its cost-competitiveness against conventional gas and coalbed methane. Significant development might not occur within the next decade.

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Mexico

Mexico is geographically located and economically integrated in North America, but owing to its culture and history, it is also a Latin American economy. With access to both the Atlantic and Pacific Oceans, Mexico has a land area of nearly 2 million square kilometres rich in natural resources that include oil and gas.

Historically, oil production has bolstered Mexico's economy, but as energy demand keeps growing and stricter environmental policies are implemented, natural gas has become more important. However, given the slow pace of exploration and production caused by the chronic underinvestment in the domestic oil and gas industry, Mexico's natural gas demand has become more dependent on external supply.

With the aim of expanding its domestic natural gas production, Mexico has been pursuing shale gas development for the last few years, prompted by the energy transformation observed in the United States, its shared geologic formations and economic proximity to that economy, and the inferred magnitude of those resources domestically. Although several barriers have hindered this goal, a major structural reform passed in 2013 has brought about more realistic conditions to support an increase in natural gas production, including shale gas.

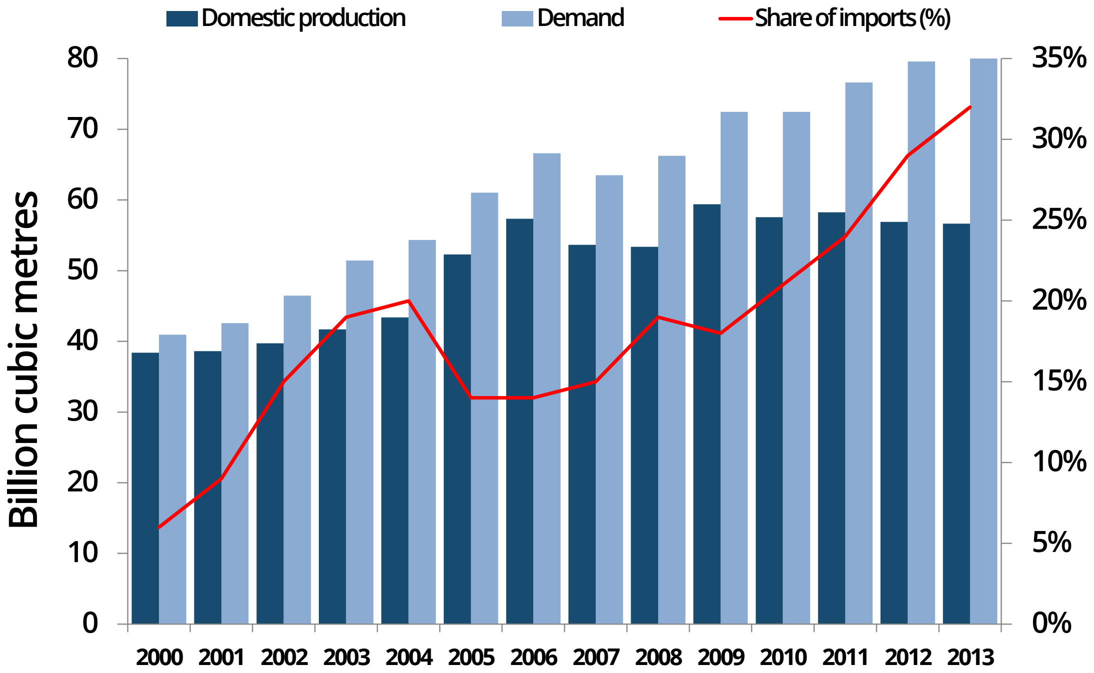
Access to natural resources – (R)

With Mexico's expropriation of the oil and gas industry in 1938, its NOC Pemex became the only operator across the upstream and downstream segments. In addition to granting the absolute ownership of all the oil and gas in the territory to the State, Mexico's Political Constitution also mandated the exploration and production of those resources exclusively through Pemex. This State-owned monopoly remained in place for more than 75 years, largely preventing other participants from access to those resources until the enactment of a landmark reform in late 2013 with the aim of overhauling Mexico's energy sector.

Mexico's natural gas output has increased in recent years, but not enough to catch up with demand. As shown in Figure 54, from 2000 to 2013, Mexico's natural gas production grew at an annual average rate of 3%, while demand grew at a rate of 5.6% (BP, 2014). This has called for a rising pace of imports at an average rate of 18% from 2000 to 2013, LNG imports in particular have risen rapidly, at an average of 38% per year since their start in 2006. This trend has required an increasing share of natural gas imports to meet economy-wide demand, growing from 7% in 2000 to 36% in 2013 (Sener, 2014c).

To reduce this gap, in the last few years the Mexican government has implemented several strategies oriented to step up its natural gas production, which have included the development of its unconventional gas resources. Since 2010, Mexico (through Pemex), has expressed interest in exploring and eventually developing its shale gas potential, mainly because of the positive results seen in the United States and the geological formations in common with that economy. This led to Mexico's first exploratory shale gas well in February 2011, which became a commercial producer of dry gas. This well (Emergente-1) was drilled and completed in the northern Mexican State of Coahuila, contiguous to Texas' Eagle Ford shale play.

Figure 54
Mexico's natural gas production, demand and external dependence; 2000-2013



Source: BP (2014).

Nonetheless, it was EIA's (2011) preliminary assessment of the potential shale gas in a number of economies which spurred interest at the highest levels of the Mexican government, given the suggestion that Mexico possessed the world's fourth largest resource base of shale gas. This generated great expectations about shale gas; the Mexican authorities at that time practically took for granted that the economy would replicate the outcomes seen in the United States. In consequence, shale gas was added to Mexico's energy outlook and priorities, including two long-term production scenarios in which this resource would represent as much as 29% of all the natural gas produced by 2026. In practice however, results were meagre due to a number of technical, economic, and institutional barriers (De la Vega Navarro and Ramírez Villegas, 2015; Lajous, 2013; Lozano-Maya, 2013).

The change of Mexico's presidential administration in December 2012 gave rise to a more realistic position regarding shale gas. The federal government's energy policy initially recognised that despite the lure, shale gas development would need to adapt to contextual settings, for which a faster pace of development would hinge on Mexico's structural conditions (Sener, 2013). Accordingly, a new scenario for shale gas production was presented. This scenario was remarkably different from its predecessors, as it assumed the volume of shale gas production to account for barely 2.6% of economy-wide natural gas production by 2027 (Sener, 2014b).

This policy shift also occurred at the same time as the release of an updated worldwide assessment of shale gas resources (EIA, 2013), which reduced Mexico's resource base by 25%, from 681 trillion cubic feet in the initial version to 545 trillion cubic feet (19.3 to 15.4 trillion cubic metres). This change also implied that Mexico's global position fell from the fourth to the sixth largest.

The approval of a major energy reform in late 2013 transformed Mexico's shale gas outlook drastically, by allowing companies other than Pemex access across the entire oil and gas value chain under a new legal regime. In essence, the reform was designed to improve the competitiveness of Mexico's energy sector for its economic and social benefit, by means of complementing state-owned energy companies with the capabilities and investments from other competitors, especially in the riskiest and most capital-intensive projects, such as shale gas production.

As shown in Table 13, by the end of 2014 Mexico's shale gas resources were officially estimated at 141.5 trillion cubic feet (4 billion cubic metres), a volume 74% and 79% lower respectively than by the EIA (2013, 2011). Despite the downsizing of Mexico's shale gas potential and the fact that current estimates allude to resources lacking any further economic or geologic validations, the inferred scale of magnitude is bolstering the development of these resources, as they are still several times the proved reserves of natural gas. The figures presented in Table 13 show that Mexico's potential shale gas resources are more than eight times its proved reserves, which amounted to 481 billion cubic metres (17 trillion cubic feet) of natural gas at the beginning of 2014 ('Worldwide look at reserves and production', 2013).

Table 13
Mexico's potential shale gas resources by basin

Basin	Potential gas resources (Tcm)	Potential gas resources (Tcf)	Potential oil (billion barrels of crude oil equivalent)
Sabinas-Burro-Picachos	1.9	67.0	0.6
Burgos	1.5	53.8	0.0
Tampico-Misantla	0.6	20.7	30.7
Veracruz	0.0	0.0	0.6
Chihuahua		NA	
Total	**4.0**	**141.5**	**31.9**

These figures refer to undiscovered inferred resources deemed potentially recoverable.
NA: Not available.
Source: CNH (2014).

Most of Mexico's shale gas resources are concentrated along a fringe that spans the northeast and Gulf areas of its territory across five major basins: Burgos, Chihuahua, Sabinas-Burro-Picachos, Tampico-Misantla, and Veracruz. In comparison to the EIA's (2011, 2013) assessments, official Mexican references (CNH, 2014) have added the Chihuahua basin, although no resource assessment is available yet.

The location of Mexico's shale basins is depicted in Figure 55. The Burgos and Sabinas-Burro-Picachos basins together hold more than 85% of Mexico's inferred shale gas resources, with the remainder in the Tampico-Misantla basin. It is noted that the Eagle Ford play extends well into northern Mexico through the Burgos and Sabinas-Burro-Picachos basins, and therefore the two economies largely share geological properties. In fact, most of Mexico's exploratory shale wells have been drilled in the Burgos and Sabinas-Burro-Picachos basins, mainly with the aim of confirming the extension of the Eagle Ford play into Mexican territory.

Mexico's shale formations are also deemed to hold significant oil resources (that is, tight oil), with inferred volumes approximately three times larger than the respective proved reserves of 10.1 billion barrels of oil at the beginning of 2014 ('Worldwide look at reserves and production', 2013, 2013). Nearly all of Mexico's oil-bearing shale formations lie in the Tampico-Misantla basin, which concentrates more than 96% of the total 31.9 billion barrels estimated. The Burgos and Sabinas-Burro-Picachos basins are presumed to have a small amount of oil as well, each one holding approximately 2% of Mexico's inferred tight oil resources. Overall, this characteristic is likely to increase the potential profitability of Mexico's shale resources in the event of commercial development.

Figure 55
Mexico's shale gas basins

Source: CNH (2014).

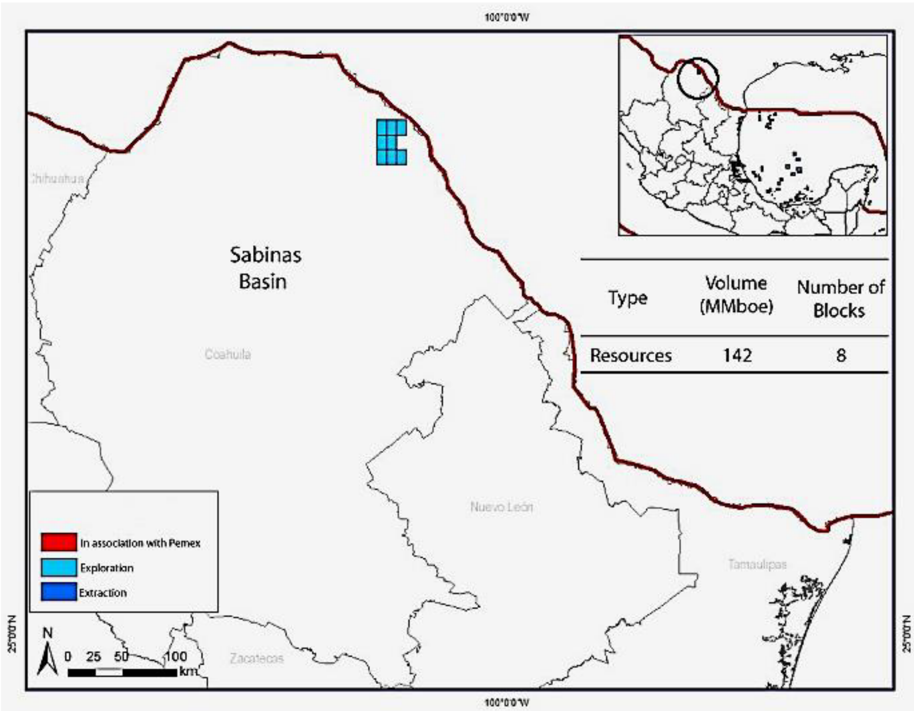
Despite the recent milestone energy reform, access to shale gas resources for other operators apart from Pemex has not yet occurred, as the recent changes in the legal framework and their effects will take time to manifest into an entirely new industry profile. With reference to this, in order to give Pemex an advantage in the face of the competition expected, the reform established a 'Round Zero' mechanism whereby the company is allowed to request the strategic exploration and production areas to retain contingent on its resources and capabilities. As a result of this mechanism, the Mexican government through its Ministry of Energy announced in September 2014 that Pemex would retain all of Mexico's oil and gas proved reserves, 83% of the probable reserves and 21% of the prospective resources.

Pemex was also assigned 9% of Mexico's prospective shale (oil and gas) resources in parts of the Sabinas-Burro-Picachos, Burgos and Tampico-Misantla basins, in a total area of 8,408 square kilometres. This small allocated share strongly suggests that even the development of Mexico's shale gas will rely to a great extent on other companies than Pemex.

Following Round Zero, the Mexican government announced a subsequent 'Round One' for the tender of the oil and gas resources to be explored and produced by other companies. A variety of offshore and onshore resources of diverse quality and nature will be tendered for prequalified companies which meet the Mexican government's financial, technical and operational criteria.

As for shale resources, Round One will assign eight exploratory blocks of dry gas over a total area of 900 square kilometres located in the Sabinas-Burro-Picachos basin in Mexico's Coahuila State. These eight blocks are shown in Figure 56. Another 62 exploratory blocks, equalling 7,410 square kilometres will be tendered in the Tampico-Misantla basin, although these formations predominantly hold tight oil resources (Sener, 2014a).

Figure 56
Mexico's planned shale gas tender



Source: Sener (2014x).

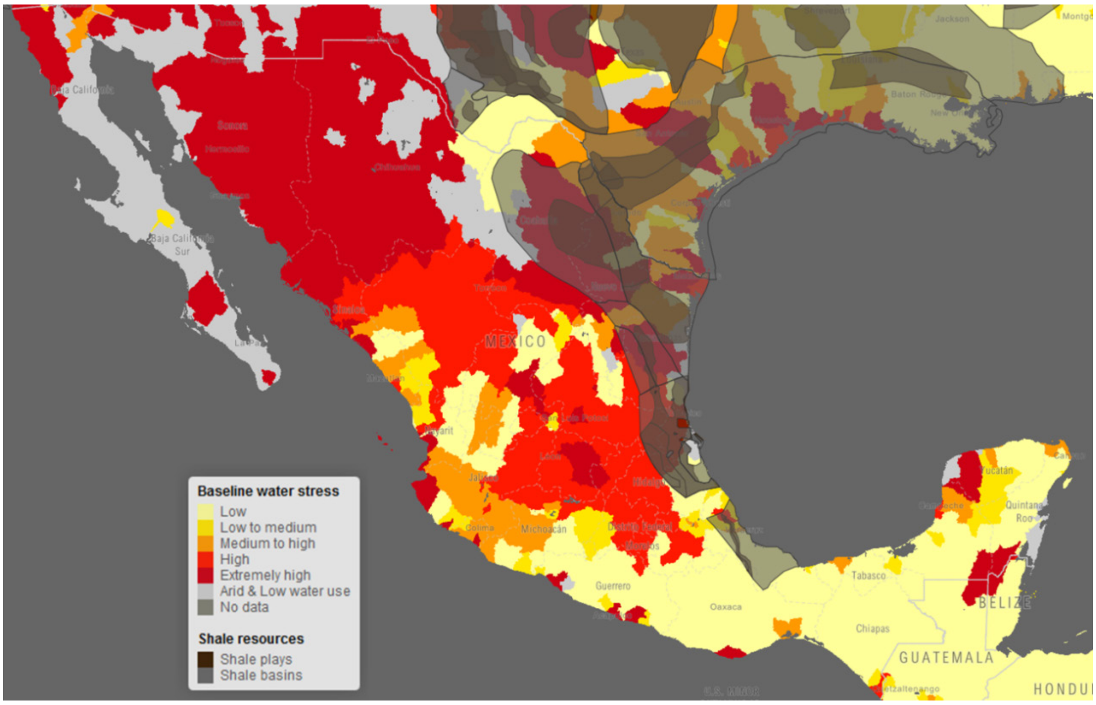
The tender of these shale gas blocks is scheduled for the first half of 2015, but by the end of February 2015, the Mexican government had carried out only two tender phases, concerning the exploration and development of 19 blocks in shallow waters. It was also reported that up to that date, 16 companies had completed the prequalification stage (Sener, 2015a).

Historically, one of the major reasons the Mexican government opposed any legal change to its oil and gas industry was the possibility that other private companies, especially foreign ones, could own those natural resources and in so doing, contravene the State's sovereignty and the tenets enshrined in the Political Constitution. Bearing this in mind, the changes introduced by the recent reform retain the State's ownership of any oil and gas, but grant the Mexican government enough flexibility to establish regimes with characteristics allowing companies to book hydrocarbons for their own accounting and financial purposes.

Besides access to shale gas resources, access to water resources is considered a critical issue in Mexico. With about 3,822 cubic metres, Mexico's total renewable water resources per capita are fairly low in comparison to the world's average of just over 20,000 cubic metres (FAO, 2014). In particular, northeast Mexico, where its most promising shale gas resources are located, suffers from serious water scarcity.

The World Resources Institute (2014) emphasises that around 61% of the Mexican shale basins overlap with arid areas or under high or extremely high water stress. In addition to the scarce rainfall in northern Mexico, the Sabinas-Burro-Picachos and Tampico-Misantla basing face very severe water stress levels, not to mention the seasonal variability of water resources, heavy consumption and other competing uses for the water volumes available. Even the current presidential administration recognised soon after taking office that the location of Mexico's shale gas resources are located in naturally arid settings, for which water management would be critical to the pace and scale of development in the long term (Sener, 2013b).

Figure 57
Mexico's shale gas plays and baseline water stress



Source: World Resources Institute (2014)

Infrastructure and operations–(I)

In terms of the factors within the infrastructure and operations component of the RIG framework, it is fundamental to underscore that in the case of Mexico, its oil and gas industry was for a long time almost exclusively centred on Pemex. Due to this monopoly and the heavy restrictions imposed by the former legal framework on the participation of other companies, the industry's capabilities and infrastructure were largely dependent on Pemex's priorities and resources.

For many decades, Mexico benefitted from highly productive fields with low production costs. Its Cantarell giant offshore field for example, produced at its peak in 2004 almost 2.1 million barrels of oil and 7.8 million cubic metres (275 million cubic feet) of natural gas, volumes respectively equivalent to 60% and 17% of the economy-wide output in that year (Sener, 2015b). Nonetheless, oil and gas production in Cantarell and economy-wide have declined ever since, mainly because of Pemex's weak financial position, and its poor technological and operational capabilities which have been unable to offset the natural aging of many fields.

As Mexico's single operator in the upstream and most of the downstream segments for many decades, Pemex has been subject to increasing challenges and decreasing resources that have worn out its capabilities to support Mexico's energy challenges. Historically, Pemex has been torn between conflicting goals. On one hand, it has strived to maximise the value of Mexico's hydrocarbons to meet rising energy and economic needs under more complex geological, international and environmental conditions; on the other hand, as with any other company of its size, it has strived to improve its performance and capabilities to remain competitive, albeit with very few financial resources left after its bulky pension and heavy taxation payments.

On this subject, Pemex's financial management is largely constrained by the Mexican Ministry of Finance, leading the company to pick the low-hanging fruit, privileging projects with higher profitability and more rapid outcomes, which tend to occur in mature conventional oil and gas fields. This approach has eroded the production of resources with less profitable and longer timeframes, as is the case with shale gas.

Also, a high degree of political interference has traditionally affected Pemex, including the appointment of and close links between its General Director and other top executives with the highest levels of the Mexican federal government. It is also very likely that the company's predominant short-term scope has been deliberate, privileging projects and outcomes occurring within the 6-year presidential term in order to reap political advantages for the administration in place (Stojanovski, 2010).

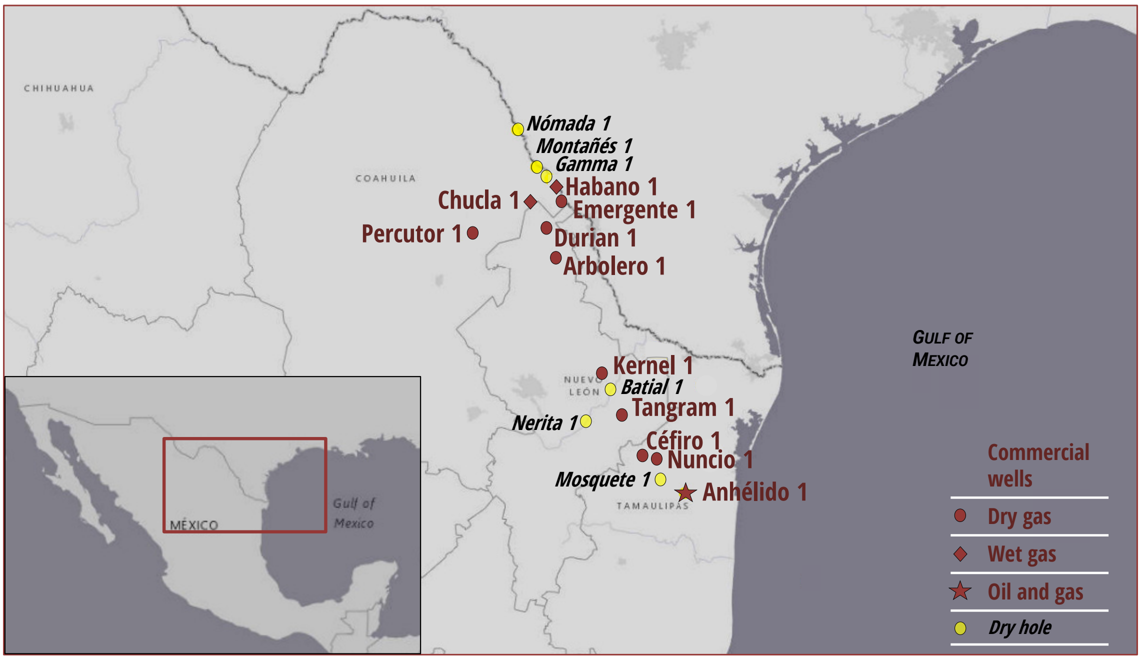
In essence, because of this background, Pemex has been left with little operational and financial leeway to pursue exploration and production projects involving lower profit margins and higher technical complexity. Despite this, Pemex began undertaking exploratory activities targeting shale formations in 2010, and by the end of 2014, it had 17 wells drilled and completed, 11 of which became commercial producers: eight of dry gas, two of wet gas and only one of (tight) oil (CNH, 2014). Figure 58 depicts the location of each one of these wells in Mexico's territory.

To quicken the pace of development and the learning curve of shale gas, in late 2012 Pemex requested Mexico's Petroleum Institute (a public research institution created with the mission to fulfil Pemex's technological demands)– to undertake a comprehensive study of the shale oil and gas in Mexico, in order to refine the assessment of these resources, identify sweet spots, select the most appropriate well designs for their geologic properties, and examine their social and environmental impacts. This project will continue in progress until April 2016, and therefore its outcomes will take some time to manifest.

Also in 2012, Pemex on its own set up five field laboratories to speed up the understanding of shale formations and the development of technical and operational knowledge to produce the oil and gas trapped in them more effectively. These laboratories are located in certain areas of the Sabinas-Burro-Picachos and Burgos basins where shale gas wells have been drilled and are run by private companies, some of them oilfield service companies.

It must be emphasised that given the past legal restrictions to the participation of oil and gas companies, the majority of the industry's technological and operational demands were pragmatically met by service companies under contract with Pemex, which gradually established a robust stronghold in Mexico.

Figure 58
Shale gas exploratory activity in Mexico



Source: CNH (2014).

The advent of the energy reform legally transformed Pemex's into a 'State productive enterprise', to give it more flexibility in selecting the best operational arrangements to meet its goals, whether alone or in association with other companies, for the areas initially assigned in Round Zero or for those which could win in future tenders. In that sense, Pemex has noted that the commercial potential of the shale plays under its control will be key in attracting the interest of more experienced companies with which to form partnerships and enhance its technological capabilities. More important though, is Pemex's acknowledgement that it might fall short of meeting its shale-related goals in the timeframes expected, due to the uncertainty in meeting its considerable anticipated financial and operational needs (Pemex, 2014a). It is uncertain whether other eventual entrants will overcome these hurdles more rapidly to outdo Pemex in producing Mexico's shale gas resources more effectively.

A skilled and sufficient personnel is another relevant issue in the deployment of economy-wide capabilities adapted to shale gas. A larger number of technical and professional individuals with expertise on shale gas matters will be required as exploration and production activities advance. Pemex itself recognized in its initial proposal for Round Zero that the prevalent knowledge of shale formations in Mexico is still poor, and hence efforts needed to focus on a better characterization of shale resources which would lead to the identification of the best potential areas and the design of plans to promote an eventual profitable development on a large scale (Pemex, 2014b).

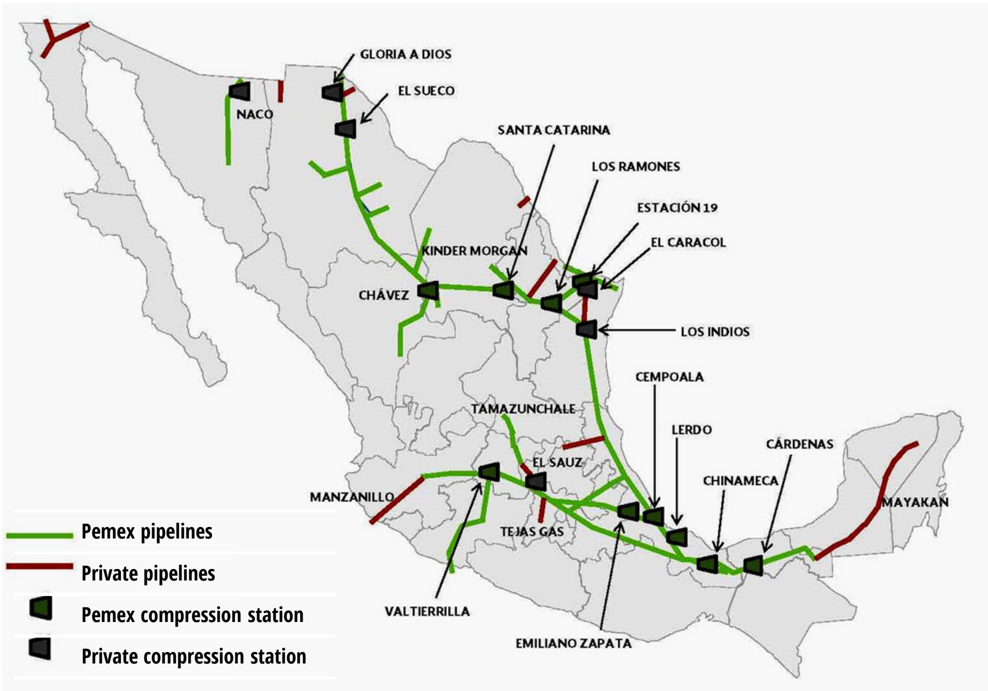
Owing to the long-lasting lack of competition in Mexico's oil and gas industry, Pemex has concentrated much of the specialised labour, most of which is affiliated to Mexico's economy-wide oil union. The unusually strong political power of this union has pushed for overly generous salaries and pensions, resulting in serious overstaffing of many people with political or personal connections. Because of this, labour is costly and has low average productivity; Pemex is among the NOCs with the lowest economic productivity levels per employee (Hartley and

Medlock, 2013). To make matters worse, many experienced professionals are reaching retirement age and replacing them looks more complicated in the long run, given the industry's fast-growing demands and the relative lack of interest in Mexico's higher education system to the study of earth sciences and oil and gas engineering.

As far as infrastructure is concerned, the current length and capacity of Mexico's natural gas transmission system is one of the biggest roadblocks to a more optimistic shale gas outlook. In step with the rising demand for natural gas, during 2012 and 2013, several sections of Mexico's main transmission system for natural gas reached maximum capacity, leading to serious shortages which manifested in a large number of 'critical alerts'. In other words, customers, especially in the industry sector, had their natural gas supplies drastically reduced, incurring significant economic losses and negative environmental effects from the use of more expensive and carbon-intensive fuels.

Official references (Sener, 2013) estimate the economic costs of the 22 critical alerts in 2012 alone to be equivalent to USD 1.5 billion, using the exchange rate at the end of that year. The most serious effect of these gas shortages occurred in the central-western Mexican states which are not reached by the main transmission system (shown in Figure 59) and do not have nearby gas-producing areas.

Figure 59
Mexico's natural gas transmission system



Source: Sener (2014b).

In the aftermath of the critical alerts, the federal government devised a program to strengthen the economy-wide gas supply, including an ambitious expansion of the natural gas transmission infrastructure, which by the end of 2013 had a total length of 13,890 kilometres. Due to this program, more than 6,400 kilometres (an increase of 46%) based on private and public projects are expected to be added by 2018 (Sener, 2014b), with the aim of increasing the natural gas flows and their reach to the largest demand centres. Attention was given in particular to the construction of a transmission line to bring gas from South Texas, passing through

Mexico's major industrial clusters in its central and north-east regions.

As for recommended industry practices, by the end of 2014 there were none, as all shale gas activities had been undertaken mostly at an exploratory level. Nevertheless, it is likely that stricter technical and environmental standards will be enforced once operations are stepped up, especially in light of the prevalent water scarcity in the Mexican shale gas plays and the open door for a rising number of operators, most likely with previous experience in the production of shale gas. It is plausible to assume that new industry entrants will follow practices in areas such as water management, technology and operations, and environmental protection.

The following are some further considerations to the future development of shale gas in Mexico in terms of market demand, capital access and legacy of unconventional gas resources:

- Economy-wide natural gas demand is strong: joint consumption in the electricity generation, industry, residential, commercial and transport sectors grew 64% from 2003 to 2013, and the Mexican government predicts that it will almost double again by 2028. The electricity sector is the largest consuming sector, with 71% of the economy-wide demand in 2013, followed by the industry, with 26% (Sener 2014b).

- Traditionally, access to capital and investments in Mexico's natural gas industry has been less problematic than in the oil industry, partly due to a legal effort in 1995 as discussed in the Governance component below. It must be also taken into account that many large gas-based projects have been typically driven and funded by CFE, Mexico's dominant electricity utility, which is also owned by the State. The Mexican government has set up several trust funds to foster applied research projects, including that currently carried out by Mexico's Petroleum Institute, which will cost over USD 244 million. In any case, one of the energy reform's major tenets referred to the expansion of private investment to allow the use of public resources in higher-priority areas.

- Mexico's natural gas industry has had some experience in developing unconventional gas resources. Pemex has been producing tight gas, and in 2008, coal mine concessions were allowed to develop coalbed methane (referred as *gas grisú*), in an attempt to speed up the economy-wide production of natural gas. With the changes introduced in 2013, holders of coal mine concessions might now be directly awarded the right to produce coalbed methane upon prior request.

  In the state of Coahuila, a group of coal producers in combination with technological research and higher education institutions has recently formed an industrial cluster to lobby at different government levels for more competitive conditions to develop Mexico's shale gas. This issue could create some synergies between mining, coalbed methane and shale gas operations.

Finally and of utmost relevance, Mexico faces critical security issues for its energy industry and economy-wide competitiveness. The diversification of organized crime groups into illegal mining and theft of pipeline oil by-products in northeast Mexico, pose very serious economic and operational challenges in the areas where shale gas activities have been underway or are expected to grow (Payán and Correa-Cabrera, 2014). In fact, this problem has grown so serious that by February 2015, Pemex announced that it would transport its oil by-products—namely gasoline and diesel—in an unfinished state through the pipeline network, as a means to dissuade their theft and sale in the black market (Pemex, 2015). While the global oil industry has been used to operate in areas under conflicts or high security risks, the additional costs incurred are likely to undermine the profitability of Mexico's shale development.

Governance – (G)

Following with the governance component in the RIG framework, Mexico's fiscal details applicable for the legal access of its shale gas blocks have not yet been revealed, although the federal government is now legally able to implement fiscal regimes with concessionary and contractual characteristics.

The two tenders opened so far in Round One for shallow waters are based on a production sharing contract regime in which the bidding variables refer to the State's production share and the amount of investment exceeding the minimum requirements established. Winning bids must include an average of 25% of local content which will rise to 35% by 2025 (2014a). However, it is uncertain whether the Mexican government will use this fiscal regime again for its shale gas acreage or will look forward to profit-sharing or licensing contracts; the latter might be more feasible (Lajous, 2014; Shields, 2013), as the new legislation currently provides a royalty exemption for producing non-associated natural gas under USD 5 per million BTU. In addition, a number of IOCs have signalled their interest on Mexico's shale resources (Kearns, 2014)

The Mexican government is faced with the challenge of designing a fiscal regime that it is attractive for operators but also provides steady revenues, especially considering that Pemex alone is Mexico's single largest taxpayer and accounts for roughly one-third of the economy-wide tax revenue. In this sense the entry of new industry competitors will tend to diminish Pemex's traditional role as the government's cash cow. Overall, the energy reform is indeed a remarkable positive effort to dissolve Pemex's monopoly and allow more competition across the natural gas value chain to accelerate the development of shale gas in Mexico.

In terms of open access, some changes have been accomplished since 1995 to introduce competition in the midstream and downstream segments of the natural gas industry, and to unbundle the related activities to establish non-discriminatory access to pipelines. In practice however, Pemex dominates production and, most of the imports and remains the owner of the majority of the gas-related infrastructure. The 2013 reform created CENAGAS, a state-owned independent operator for the storage and transmission of natural gas whose main duty is to implement effective open access to the economy-wide gas pipeline system, including its planned expansion and excess capacity.

With regards to the industry's competitive and open access, natural gas pricing is critical to Mexico's future shale gas development. The methodology in place since 1995 has linked Mexican prices to the reference market in South Texas, with the intention of reflecting the opportunity cost, although it has resulted in prices based on market conditions which do not reflect those prevalent in Mexico. This mechanism has also led to some problems: when reference prices have been too high, Mexican consumers have expressed their discontent and asked for better conditions, while on the other hand, with much lower prices as of recently, demand has surged, leading to pipeline bottlenecks from an obsolete infrastructure capacity which does not reflect such competitive prices De la Vega Navarro and Ramírez Villegas, 2015; Grunstein, 2014).

Perhaps more relevant, is the point that as long as natural gas prices remain low in the United States and infrastructure is expanded, it is more economical for Mexico to keep importing gas from that economy than to raise its domestic natural gas production.

Because of this, the economic incentives to underpin a faster pace of shale gas development in Mexico are poor in the short term, or at least until more robust infrastructure and competitive pricing are in place to support a more active upstream activity.

As for the second governance factor of regulatory effectiveness, the energy reform brought about major changes in the institutional arrangement, which now involves a multitude of governmental agencies in Mexico's natural gas industry.

At a broader level, the Ministry of Energy guides Mexico's energy policy and designs the general characteristics for the exploration and production of oil and gas resources, leaving the definition of the applicable fiscal terms to the Ministry of Finance. Regulation of the natural gas industry falls under two agencies; the National Hydrocarbons Commission in the upstream segment, and the Energy Regulatory Commission in the downstream segment.

To that end, both agencies acquired a new legal status in order to have budgetary self-sufficiency, and technical and management autonomy. In addition to these bodies, CENAGAS was created as the independent transmission operator, while ASEA will be the agency responsible for addressing the industrial safety and environmental protection related to oil and gas operations. The goal of this arrangement was to address the natural gas industry comprehensively in order to provide it with more accountability, transparency and stability.

Specifically for shale gas, no regulation has been released, but a tripartite group comprising the Ministry of Energy, the upstream regulator, and Pemex (along with other federal agencies in charge of water resources and environmental protection), has been working on this, including visits to and examination of other sites in North America (Martínez Romero, 2014). While details of these regulations are unknown, it is probable that they will include the best international practices and issues. In June 2014, Mexico signed a Memorandum of Understanding with Canada's Alberta Energy Regulator, to share regulatory expertise with emphasis on shale gas (AER, 2014).

Finally, in terms of multi-stakeholder engagement, the legal changes approved grant oil and gas activities the highest priority overriding any other land uses, and aim to align the economic interests of different stakeholders. To that end, while oil and gas remain under State ownership, land owners are entitled to economic compensation. Contingent upon negotiation and the commercial status of projects, these payments might even represent a share of the project's net income, which in the case of non-associated gas –applicable to shale gas– might be in a range from 0.5% to 3%. Likewise, in those cases where local communities are involved, prior consultation will be carried out, and depending on the criteria of the Ministries of Energy and Finance, even certain social benefits to local communities could be demanded to the operating companies.

At the moment, shale gas-related activities have been restrained to a small scale and land footprint, but it must be noted that the social acceptance of these activities could worsen. An ongoing movement against hydraulic fracturing seems to be growing, fuelled by a civil organization and political support. In 2014, a group of legislators submitted an initiative to the Mexican Senate to ban hydraulic fracturing. In January 2015, a more moderate initiative was submitted by a legislator from a different faction, striving to establish the legal right to water for drinking and sanitation purposes as superseding any other uses, even those for oil and gas, as well as making compulsory the disclosure of proppants and chemicals injected in the process of hydraulic fracturing.

Challenges and opportunities

In step with an unprecedented appetite for electricity-generation purposes, Mexico's natural gas demand has grown robustly in recent years, but the economy has also increased its dependence on external sources, due to its inability to expand its natural gas production accordingly. The factors assessed in this section are shown in Figure 60.

In light of this background, Mexico jumped on the shale gas bandwagon with the aim of strengthening its natural gas production. The hype and the hope surrounding this move faced a reality check soon afterwards, and the government realised that no significant progress could be made with the structural conditions at the time. A sweeping energy reform in 2013 transformed this outlook, by opening the door to private participants with the aim of reversing the industry's chronic shortfalls and underinvestment due to decades of monopoly.

As the shale gas learning curve advances, it is very possible that shortages of skilled labour, materials and technology will occur; while these might be brought from the United States, structural conditions in Mexico will call for different logistical arrangements involving cost levels which could compromise the economic viability of many of these projects. In particular, overcoming water scarcity and the capacity and reach in the gas pipelines are critical elements to transport the gas eventually produced up to the markets. The natural gas shortages in recent years not only underscored the vulnerability of the natural gas infrastructure, but also highlighted the weakness of the storage systems and indirectly, that of the pricing mechanism and the planning of the entire natural gas market.

In this regard, Mexico's current pricing methodology and structural conditions in the natural gas industry favours the import of cheap natural gas from the United States, hindering the prospects for increased domestic natural gas production, particularly of resources with higher costs, as is the case of shale gas. In order for shale gas to be produced at a significant scale for Mexico's natural gas industry, long-term efforts will be needed to improve structural deficiencies. Rather than a dilemma, these issues could be an opportunity: in the short and medium terms, Mexico might be better off importing more cheap natural gas from the United States as a means to expand its own market, letting it evolve into a more competitive field capable of supporting expanded natural gas production in the long term, including that coming from shales.

On this point, even after the legal changes introduced, Pemex is poised to hold a major market position in Mexico's natural gas industry and it is still unclear how dominant it will remain at the expense of the market's competitiveness. In many aspects, Pemex still has the upper hand in the industry. Moreover, despite the political success of the reform, its timing could not be worse, as the significant decline of oil prices in late 2014 and early 2015 is exerting additional pressure on the Mexican government to defer or modify the fiscal conditions originally designed to award the exploration and development rights on the shale gas blocks scheduled for tender.

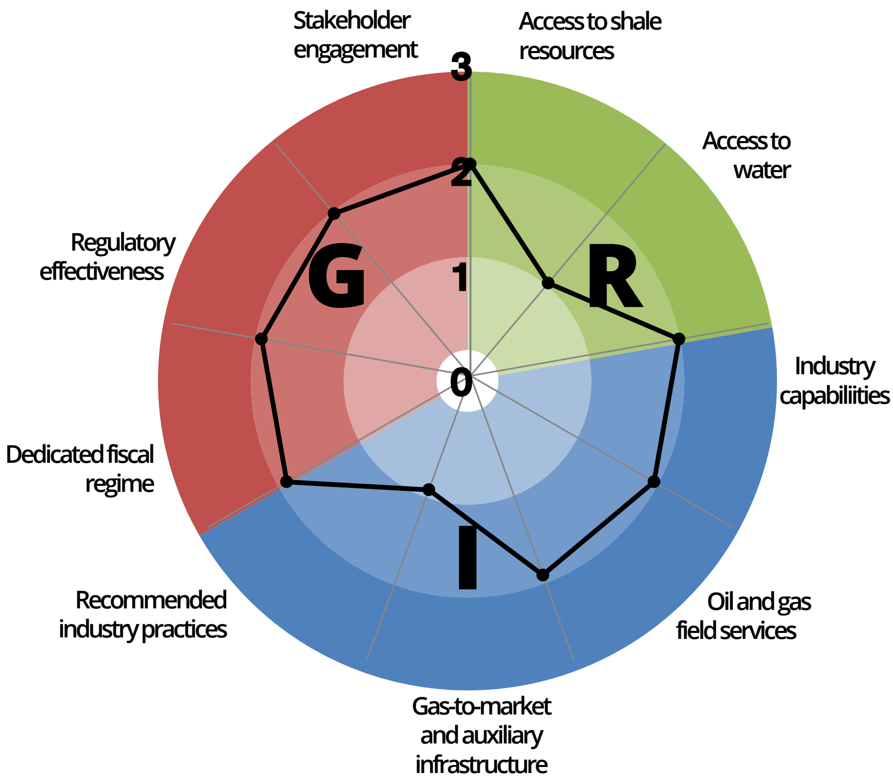
The long-standing weak transparency in Mexico's oil and gas sector, which, prior to the reform had been exclusively—and poorly—managed by Pemex, has imposed very high costs in the institutional and regulatory systems. Due to this, the reform has created a multitude of agencies intended to serve as a system of checks and balances against corruption, but they could lead as well to redundant administrative procedures, unnecessary bureaucracy costs, and an increased difficulty in aligning activities and goals. In addition, if governmental institutions do not pool skilled human resources, the novelty of some regulations could lead to regulatory capture. If unattended, stakeholder issues might also become a significant future hurdle.

While Mexico's energy reform is indeed a remarkable breakthrough, its effects will take years to shape a more competitive industry, including the development of shale gas. It is very likely that the domestic and international natural gas industry will be attracted to develop Mexico's shale gas resources at some point, but this may take longer than official schedules predict, and might not result as competitive as in the United States. Much of Mexico's shale gas development will remain very uncertain until the actual tenders occur.

Now that the energy reform has been legally approved, the largest challenge for Mexico is to make it operational, in order to live up to the expectations of stakeholders eyeing its shale gas resources and of Mexican citizens who want a more reliable, cost-efficient and abundant natural gas supply.

Figure 60

APERC's assessment of Mexico's shale gas development under the RIG policy framework



Source: APERC.

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5

Conclusions

This chapter synthesises the main research outcomes and policy implications presented throughout this document. As noted in the introduction, as the APEC region looks forward to detaching its economic growth from a carbon-intensive energy supply, one of its main strategies is an increased use of natural gas to decrease the predominance of coal and oil in its primary energy balance. A scenario of stronger and more extensive natural gas demand hinges on a robust, growing supply, which is currently constrained by rapid depletion and geographical concentration, as nearly half of the worldwide proved reserves of natural gas are held by three economies alone—two of which are not in APEC.

In recent years, technological prowess has allowed the economic extraction of shale gas, driving the United States to reach unprecedented levels of production which have transformed its energy balance and have defied global industry paradigms. This event, in combination with the inferred magnitude and distribution of shale gas worldwide, have led several economies to explore the development of these resources, as it promises them a larger and broader natural gas supply to support an increased demand over a longer horizon. Nonetheless, many economies within and beyond APEC have faced several challenges which have led them to realise the complexity involved in producing shale gas commercially, let alone at levels similar to that of the United States.

Shale formations are not geologically homogeneous, and thus, the technology and methods which work in one play will not necessarily yield the same results in another. This has been one of the main barriers to increasing shale gas output worldwide, leading several economies to finance research and development activities and even to invest overseas in shale plays in current production, in the hope of assimilating specific knowledge, technology, and practices. In comparison to the production of conventional gas, shale gas generally takes more time, infrastructure and capital investment.

As it was previously highlighted, the absence of private mineral rights in most other legal systems does not prevent other economies from developing their own shale gas resources so long as other mechanisms are implemented to encourage similar risk-taking and entrepreneurial efforts. This means that the scale and pace of shale gas development will be driven by the structural and contextual characteristics of each economy. Absent good governance and effective policies, this will result in longer timeframes, high economic costs, and possibly, sharp social resistance.

While much of the global attention on shale gas has been centred on the United States owing to its role as the pioneer and exemplar model of the industry, other economies currently producing or looking forward to producing shale gas might provide policy lessons and insights with a better degree of transferability. Even though there is no magic formula for shale gas development, some key elements support it and seem to explain the levels of progress and success obtained by different economies. Because of this, it was suggested that APEC economies follow certain pathways which, contingent on their own priorities and settings, will help them make choices more conducive to the development of their shale gas resources,

To that end, a general policy framework was proposed to understand the major components involved in the development of shale gas, and to identify its major underlying barriers. The framework has three components, which derive into nine finer factors to account for the contextual variations among economies. It was also noted that these components and their factors are considered under the control of each economy. This leaves external variables such as geopolitics, disruptive technologies and reference oil and gas prices beyond the framework's scope.

The framework strives to become a common policy lens for shale gas development across APEC, as it outlines three necessary interdependent components: Access to Natural Resources, Infrastructure and Operations, and Governance. Basically, the framework recognises that access to shale gas and water determines the potential of the resource base; infrastructure and operations drive the productivity to develop such a resource base; and governance attains low and predictable transaction costs while fostering social trust among the different stakeholders involved to align their diverging interests. For the sake of memorization, the framework was termed *RIG* in consideration of each of its components and the factors in each one of them:

1. The Access to Natural Resources (R) component encompasses the two most basic factors necessary for shale gas development: the shale gas resources themselves and the water necessary for their economical extraction using the process of hydraulic fracturing. As was emphasised, neither of these resources are considered in terms of their natural endowment, but rather in terms of their accessibility. The notion of these resources expressed through their legal access rather than their natural endowment helps explain why despite having significant shale gas volumes, some economies have not extracted them and will not do so due to the legal prohibitions in place and their political stance on the access to these resources.

2. The Infrastructure and Operations (I) component refers to the critical technology, infrastructure and operations required to support the production of shale gas cost–effectively. This component has four specific factors: the industry's technological and operational capabilities specific to shale gas; the existence of oilfield services to support logistics and operations; the gas-to-market and auxiliary infrastructure to allow the extraction of gas trapped in shale formations and its transport up to major demand centres; and lastly, the industry's adoption of recommended practices to enhance the safety of operations and reduce their environmental and public health impacts.

   Underpinning the factors in this second component is market demand to drive and sustain the economic development of shale gas, adequate capital access, and a legacy industry of conventional—and possibly unconventional—gas

3. The third and last component, Governance (G) is expressed through different institutional arrangements of formal and informal rules which frame the political, economic, and social interactions of the diverse actors involved. This component encompasses three factors related to the economic alignment between the owners and producers of shale

gas resources in consideration of the natural gas market structure; regulatory effectiveness to provide predictability at the lowest cost to the actors involved; and multi-stakeholder engagement which strives to promote positive synergies whereby social demands influence and improve the performance of companies and the government's regulations.

In regards to the market structure, the framework's recognition of the fiscal regime's dependence on the prevalent market structure helps explain the diversity of market arrangements and economic incentives in the economies currently looking forward to developing their shale gas resources. It was stressed that as the industry matures, competition, open access to pipelines, and market-based pricing mechanisms will tend to prevail.

The weights of each of the framework's components and factors will differ across contexts, for which economies will tend to focus first on the weakest. Analogous to the links in a chain which could make it break, the weakness of any of these nine factors will compromise the feasibility of large-scale shale gas development.

Furthermore, while the RIG framework acknowledges that all components and factors are interconnected, it notes that positive characteristics in the governance component are especially desirable to support a long-term favourable environment which reconciles the interests of the different stakeholders involved in the development of shale gas. In this way, governance affects the economic and institutional incentives to foster the development and performance of infrastructure and technology, including those applicable to the value chain of the natural gas industry.

Access to better technology, infrastructure and geological data are likely to result in more efficient operations and recovery factors, which will in turn, increase the size and productivity of the shale gas resources deemed technically developable. Owing to these characteristics, one of the key messages in this research is that governance does matter to bring about more favourable results in the other two framework components for the production of shale gas.

After the RIG framework was explained, it was applied to the analysis of six APEC economies at different stages of shale gas production. According to preliminary geologic assessments, the six economies analysed account for more than 38% of the total shale gas resources assessed in the world. The selection of these economies includes all those with current commercial production, and illustrates the potential global competitive advantage of APEC in the development of shale gas. The following are some key findings:

- Chile is the economy at the earliest stage, having just undertaken the first operations to produce tight gas and start the exploratory assessment of its shale gas resources in order to decide whether or not to pursue large-scale production. Chile's major barrier is the economic deployment of gas-to-market infrastructure given its unusually long, narrow territory and the geographical dispersion of its major markets.

- Indonesia and Mexico are in an intermediate stage. These economies have commenced preliminary exploration and have tendered or are about to tender areas for the exploration and eventual development of shale gas. In both economies, the market is dominated by their respective NOCs, and there are major challenges for commercial production to overcome, particularly in regards to bringing about an enabling environment with experienced players which can produce shale gas more competitively.

- Australia, Canada and China are in the commercial stage of shale gas development, and in all of them the testing of technology adapted to their respective geologic settings continues.
  - In Australia and Western Canada, a more accelerated shale gas production will hinge on export markets; and in the former, it will also depend on the cost-effectiveness of shale gas as compared to the abundant supplies of conventional gas and coalbed methane.
  - In China, industry conditions are significantly different. The major driver to produce shale gas comes from the central government's plans to reduce its dependence on external supply while meeting its rising economy-wide natural gas demand. Given the slow and meagre results so far achieved in comparison to official targets, the Chinese central government has realised the importance of introducing more competitive market conditions, recently deregulating upstream prices and encouraging the (moderate) participation of companies other than its three dominant NOCs, and open access to pipelines.

Policy implications

The development of shale gas in APEC economies is not only expected to increase their domestic supplies to help them support a sustained natural gas demand; it is also expected to enhance their energy security by allowing them to become less reliant on external sources and possibly, to enhance natural gas trade across the region.

Nevertheless, as with any other energy system, shale gas will take time, resources and political will to be developed. Shale gas production could spread to more APEC economies beyond the United States, Canada and China provided that its major barriers are overcome.

This issue brings a key takeaway that shale gas production is ultimately carried out by companies driven by economic profitability. Even in those economies with limited or absent conventional gas resources where energy security is their major driver for shale gas development, the cost-effectiveness associated will largely determine the scale and pace of development.

In that sense, economies must be aware of two fundamental implications. The first is that there is a trade-off between the quality of gas resources and their quantity and cost; therefore, while shale gas is more abundant than conventional gas resources, it comes at a higher cost. The second —and perhaps more important—is that the higher economic costs incurred in the production of shale gas put it at a disadvantage in comparison with conventional gas and other more affordable energy resources; hence, cost-efficiency must be improved, aided by several policies, especially at the early stages of development. This issue is more important under settings of low natural gas prices.

It is in this point that the access to shale gas resources in combination with the industry structure becomes relevant. Given the character of natural gas as a commodity, upstream competition leads producers to leverage their technology, workforce, resources and processes to gain cost-based advantages which collectively lead the industry to improve productivity, achieve lower average costs and standardize regular practices. If shale gas is going to take off on a large scale, economies need to realise these interrelations comprehensively. Promoting competition between gas producers not only reduces costs at company and industry levels, but also decreases the inherent risks in each major area of impact, contributing to create a unified risk approach which increases the net benefits of producing shale gas. In consequence, there is a difference in what policymakers do, as enlightened policies and a better understanding of the elements involved in the production of shale gas will contribute to better decisions.

On this subject, guided by the RIG framework, economies should holistically assess the components and factors involved to define their political position, including the decision to postpone or not pursue the development of shale gas .In some cases the political positions within a single economy differ due to their legal frameworks. In Australia, Canada and even the United States, some states or provinces are in favour of developing their domestic shale gas resources while others are not. In the case of Indonesia, Mexico, and especially China, this decision is largely made unilaterally at the highest administrative level.

In some economies it might be more economical to import shale gas than to produce it domestically. In Chile for example, shale gas will only be produced in the long term, if at all. In Mexico, the current relative abundance of competitively priced shale gas-based exports from the United States provides a remarkable short-term opportunity to expand the share of natural gas in its energy balance while shale gas development matures in the short and medium terms.

In those economies opting to produce shale gas, the political motivation in place will determine the breadth, depth and timeframes of access to those resources, the infrastructure required and the good governance precepts to be implemented. Thereby, despite political sensitivities, and in consideration of economy-wide environmental, economic, social and energy security criteria, good governance measures are key to help APEC economies develop their shale gas resources more effectively.

Unlike the global reach of oil markets, those for natural gas favour its trade in regional hubs, largely due to the intrinsic inflexibility of transport and delivery. In many cases, however, the capacity and geographical extension of the pipeline network is inadequate to transport the gas volumes required between production and consumption centres. In the case of those economies driven by export markets, the infrastructure required will include LNG and storage infrastructure, which are costly and not readily available in every economy.

For gas production to reach the market while preserving this cost-efficiency, producers must be able to access appropriate infrastructure under non-discriminatory conditions, as expressed through the prices set by the market. Prices will then shift in step with the market supplies and transmission capacity. These points illustrate the importance of above-ground considerations to support the economic production of shale gas.

In Australia and Canada, numerous upstream companies operate, but in the other four economies analysed herein, a single or few companies—typically NOCs—dominate the industry These markets led by NOCs usually present more barriers for technological development and assimilation, availability of oilfield services, gas-to-market infrastructure and recommended practices which overall diminish their competitiveness to undertake more complex projects such as shale gas.

Additionally, the strategic role and political links of NOCs typically compel them to focus on more profitable upstream projects, avoiding projects which, while riskier, could enhance their capabilities and shore up the energy security of their economies over a longer timeframe, especially in consideration of the unpredictability of global energy markets. It is possible as well that the rigid, tall hierarchical structures in most of these NOCs hinder the mobility of skilled human resources and the diversification of oilfield service companies as needed for a better execution of shale gas projects. On this subject, governments must decide whether they want their shale gas industry to revolve around one or a few dominant companies, or around several clusters which could enhance competition and innovation by combining different specialised technological, logistical and operational capabilities into a unified supply chain.

In terms of governance, along with access to the exploration and development of shale gas come the fiscal terms applicable, which should ideally have been designed to account for its unique production profile, cost structure and intrinsic risks. To that end, the fiscal regime should strive to give operators flexibility in their selection of the operational arrangements most appropriate to the geological and commercial uncertainty in place. Although the exact terms offered will depend on prevalent contextual settings, and are highly dependent on market maturity, they should strive to reduce the uncertainty across the lifecycle of these projects and to provide legal stability to owners and developers alike in their respective accomplishment of fair returns.

The economies assessed differed in their fiscal regimes: Australia and Western Canada use a license-based concessionary system; Indonesia and China use PSCs, albeit in China there is some institutional ambiguity regarding in the implementation of other models; and while details have not yet been revealed for Mexico, due to the novelty of its energy reform, a concessionary regime seems more likely. With reference to this, governments might want to balance the possible trade-offs in the fiscal revenue obtained from the extraction of shale gas with the positive externalities which such activity could bring about, such as lower carbon dioxide emissions, economic competitiveness and job creation. Even though the co-production of oil and natural gas liquids has strengthened the profitability of shale gas projects in the face of low natural gas prices, economies should devise incentives and mechanisms to promote shale gas production alone.

In connection with this, the regulatory system is key to enforcing the conditions established in the fiscal regime and to promoting more competitive conditions in the natural gas markets. Beyond this function, an effective regulatory system will strive to comprehensively address the diversity of matters and priorities associated with the production of shale gas. This includes several issues that span the access to shale and water resources, the development of adequate infrastructure, and a multitude of stakeholders with different interests. To that end, regulatory policies need to match the potential risks with the prevalent contextual characteristics.

Many governments have introduced significant regulatory changes or, as in the case of Mexico, have gone so far as to overhaul the entire legal framework governing the energy sector. Despite these changes, the capacity of some of these economies to enforce regulations is weak. Regulatory effectiveness is undermined because of cumbersome procedures and a large number of agencies which increase bureaucracy costs and the probability of multiplying similar functions.

In most economies, the regulatory approach implemented is fundamentally prescriptive, insofar as it aims to ensure the fulfilment of specific practices to avoid certain risks; but this may lead to overlooking others. In contrast, in those few economies where shale gas development is at a more advanced stage, regulation has started shifting towards a cumulative performance-based approach, which provides producers more operational flexibility without the constraints of prescriptive measures, although it requires a closer collaboration with the industry operators in a common area to integrate joint operations, which in turn, hinges on better information, coordination, and a more robust energy regulator. In any case, each approach might have its own merits depending on the industry profile in place; some economies might even want to try a combination of both when one alone is not effectively addressing the targeted risks.

For regulations to be effectively designed, implemented and overseen, the following elements are desirable:

- Institutional capacity, in terms of achieving the goals intended by having adequate financial and human resources to design and enforce regulations proportional to the challenges present, and to provide predictability to the industry;

- Independence, to pursue the public interest over any other particular consideration or political interference;

- Fairness, to ensure that regulations are impartial and applied equally;

- Transparency, to allow access to regulations, related processes, and information which enhances understanding and monitoring;

- Accountability, to identify the actors or bodies to be held responsible for enforcing regulations, as a means of preventing abuse of power and corruption;

- Consistency, to harmonise the application and oversight of objectives, programs and regulations between overlapping levels of government; and

- Flexibility and continuous improvement, to ensure that regulations adapt and remain appropriate to evolving settings.

Shale gas has a more visible land and environmental footprint than conventional gas, and tends to be produced closer to human populations, disturbing many stakeholders directly and attracting much larger attention from many people who are not necessarily affected by actual projects but feel compelled to become involved anyway. Hydraulic fracturing in particular, is one of, if not the most controversial issue related to shale gas, probably its most important social deterrent.

Nevertheless, shale gas is more than hydraulic fracturing; actors in the industry, government, and society are involved in different ways in the development of shale gas, for which their common alignment is paramount to support more efficient outcomes. The government in particular is crucial, as in addition to its policy-making and regulatory roles, it is nearly always the holder of mineral rights, and often an industry player through its NOCs. Furthermore, the different levels of government embrace a set of policy and regulatory priorities which encompass a variety of issues spanning energy security, public health, environmental protection and economic spillover effects.

To that end, it was highlighted that regulations are not a sufficient condition to address this multidimensionality. The co-sharing of risks, decisions and benefits with other stakeholders is not the exclusive task of the government as it also includes the links between the industry and non-governmental actors. In this way, governance, manifested through formal and informal rules, fosters a more supportive social attitude conducive to more efficient outcomes for a wider spectrum of stakeholders. Proactive multi-stakeholder engagement can build reciprocal trust amid governmental and non-governmental actors, consequently reducing transaction costs, increasing the predictability of their mutual actions and yielding joint benefits.

In the search for common ground to align their interests, the long-term success of shale gas companies will depend on their ability to gain and sustain social license to increase the tacit acceptance of their projects through engaging a diversity of stakeholders. In some economies, companies strive to stay ahead of current regulations, paving the way for more effective regulatory functions. Reducing information asymmetries, conducting consultations prior to the execution of projects, fostering outreach activities, and establishing baseline indicators to monitor performance, results, and stress levels can help engage stakeholders more positively to build a constructive dialogue that identify further roadblocks and sources of conflict.

In summary, as natural gas demand continues to rise and conventional reservoirs are depleted, the role of unconventional gas sources, particularly shale gas, will be increasingly relevant. While much uncertainty prevails with regard to the pace, magnitude and cost of developing these resources, APERC advocates that a larger shale gas output in the Asia-Pacific region will need to be implemented in a way which is cost-effective, environmentally sustainable and socially responsible, and which ultimately contributes to the energy security of those member economies holding these resources.

Overall, and possibly with the only exception of Chile, there are great opportunities to produce shale gas commercially in the APEC economies assessed in this research, especially in those with large domestic markets with the potential to keep growing—namely China, Indonesia and Mexico. In step with the development of infrastructure, the provision of policy incentives and the implementation of good governance principles, these three economies could leverage the size and growth of their markets to extract their promising shale gas resources, allowing shale gas to become a more significant source in their natural gas and primary energy balances.

Although this document addresses shale gas from a policy angle rather than a technical perspective, it is possible that more APEC member economies than those assessed in this document will want to develop their shale gas resources in step with updated geologic information and technological progress. Nevertheless, economies must realise that despite the global excitement, shale gas is not likely to become a game changer in many of them unless there is strong political will and support, especially in the early development stages of this resource. Moreover, the current environment of low oil and gas prices is putting extra pressure on shale gas production, and even in some plays in the United States, it is proving its long-term viability.

In their quest for energy security, APEC economies must assess all the trade-offs in the use of energy resources available, to realise that as conventional reservoirs are depleted, an increased use of natural gas will be increasingly dependent on the development of unconventional resources, and in particular shale gas In consequence, a key message of this research is that shale gas development risks are manageable and with appropriate governance, in many economies it could pass from being an energy challenge to an energy solution with benefits to many stakeholders. Moreover, if done adequately, the development of shale gas might provide economies enough room to support a less carbon-intensive energy transition towards more sustainable fuel options. An expanded use of natural gas can co-exist with the expansion of renewable energy; for some economies, this could represent an attractive opportunity to turn shale gas into a bridge fuel which contributes to the development of cleaner and more reliable energy systems.

Hopefully, the issues explored in this research guided by the RIG framework will become a stepping stone to intensify regional dialogue and cooperation across the Asia-Pacific region on the development of shale gas. International collaboration on the exchange of experiences, information, expert insights, regulations and industry practices can facilitate, enhance and accelerate results at an economy level that will affect the entire region. Furthermore, the scope of the insights and policy recommendations presented in this research are largely valid to a wide spectrum of unconventional gas resources, as well as to other economies outside APEC.