FLORENCE SCHOOL OF REGULATION

ROBERT SCHUMAN CENTRE

Natural Gas Price Control

Theoretical Issues and World Case Studies

Edited by Sergio Ascari

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Foreword

Sergio Ascari[1]

One of the greatest natural gas experts in the world, in his introduction to a large treaty on the formation of gas market prices[2], has alluded to the need for a similar book on regulated ones, which, in his view, should be even larger. The knowledge gap has partly been filled thanks to the interest and effort of the Public Utility Authority of the State of Israel, who ordered a survey of world regulatory pricing practices that represents the backbone of this Book[3].

However, a mere list of cases cannot be very useful for the regulator wishing to introduce, amend or cancel an existing price control. Therefore, I have provided a theoretical part, which logically precedes the illustration of practical cases, and may serve as a guide to the regulator, and more generally to the reader who is concerned about such topic.

As we will see in the case studies, gas price controls in the past have often been grossly inappropriate, and a source of major distortions, welfare losses and delay of industry development. In turn, these failures have indirectly entailed adverse social and environmental impacts, as other more costly and/or polluting fuels have been burned instead of natural gas. This is probably still the case of many existing controls, so that it would not be surprising if our eager readers included several representatives of the gas industry seeking relief from crippling constraints and looking for solutions to be submitted to their regulators.

On the other hand, the alternative of no control at all can be hardly generalised. This option is actually only open to markets that have been

1 Part-time Professor and Gas Advisor, Florence School of Regulation, RSCAS, European University Institute.

2 Stern, J.P. (ed.), *The Pricing of Internationally Traded Gas*, Oxford: OIES, 2012.

3 The support of the PUA is gratefully acknowledged. Yet PUA is not responsible for any opinion and judgment expressed in this Book.

effectively liberalised, or are subject to genuine inter-fuel competition. A couple of case studies in the Survey show how lack of regulation without a working market leads to high prices and loss of market growth opportunities, with benefits appropriated by few companies rather than consumers.

The experience of markets that have been actually liberalised shows that the emergence of effective market competition is a long process, which can be pursued where some objective favourable conditions occur, and it often takes decades rather than years, even with the best political commitment. Meanwhile, political authorities are not likely to allow market development without price control, and lack of it can be even worse, as gas suppliers may rightly postpone their investment in the fear of the worse. It is striking to see that regulatory errors – and their adverse impacts– can be found almost independently of the political, economic and legal culture of the country, so that no part of the world has been immune – from Northern to Southern America, from Europe to Africa and the Middle East, from Asia to Oceania.

Therefore, the book has been drafted with the certainty that a fair and reasonable price control, albeit never perfect and probably temporary, is much preferable to the disasters of the politically motivated but often economically naïve regulatory solutions. Even where full market liberalisation is the ultimate goal, a fair price control is definitely one of the good medicines for its achievement.

This Book discusses the theory of gas price control, provides some empirical analysis of its usefulness, and describes several case studies. However, a final warning for readers is necessary: the book is not – and cannot be – an up-to-date description of regulatory practices in any country or jurisdiction. Therefore, I apologise in advance to all representatives of regulators as well as market stakeholders who would find that information provided (in particular) in the case studies of Part II is no longer applicable and outdated. Unfortunately, whereas the original Research Report drafted for PUA included current information, this could only be partially updated in some cases, and not at all in others, and important case studies had to be dropped altogether.

Rather, the goal of the book is to provide and discuss examples of (positive and negative) regulatory practices, not to provide any current information, which is inherently impossible for an academic publication.

Thus, the Book focuses on the most interesting experiences, which often occurred in the past, notably in currently advanced markets (USA, The Netherlands, New Zealand).

The interest and questions of many participants to the Courses of the Florence School of Regulation has been a major source of encouragement for this book. The trust of the FSR Director, Jean-Michel Glachant, has been therefore a major fuel for its completion, and that of co-authors for a seemingly endless project deserve just as much praise.

REF-E, the Milan-based consultancy, has kindly provided its remarkable database, which has been the source of elaborations provided in several Chapters. Any data that are not publicly available have been legally acquired by REF-E and are not published in their original form.

As usually, responsibility for the contents lies only with the authors and does not involve the PUA, the FSR, REF-E or any other organisation.

Introduction

Natural gas has been until recently the fastest growing world energy source, and even though it is lately facing a major challenge from the development of renewable energy and the progress of energy efficiency, its consumption is still growing in most of the world. In 2011, the International Energy Agency presented a Study where a "Golden Age of Gas" was described, albeit as a plausible scenario rather than a forecast. In fact, even though the swings of the mature European market and a slower than expected Chinese growth have somehow cooled down some hopes, world gas has increased at a pace of 2.5% in the first fifteen years of this century, and expectations are certainly for its increasing role for several decades to come.

Yet, gas markets are sharply different in the world. Some are mature and stagnating, others are skyrocketing. The composition of markets is very different, with each of the main consumption sectors (power generation, industry and households) playing a very different role as climatic, economic and social conditions differ. Some countries are net exporters, others cover all or most of their demand through imports, often from remote areas, with very different roles of pipeline and liquefied gas technologies. A few are isolated, due to lack of trading infrastructure, or simply because their needs are close to their own production.

In turn, market organisation is quite different, spanning from pure monopoly to full competition. Competitive markets are also organised in rather different way, e.g. in North America, Europe, Russia and Australia. The largest emerging economies (the BRICs: Brazil, Russia, China and India) all see various mixtures of competitive markets and monopolies, though quite different and often less clearly defined than in the mature rich economies of the OECD.

A key factor for any regulatory decision is the role of competition from other fuels (notably oil derivatives, coal, nuclear energy, and renewables), which may be sharply different in relation to the competitiveness of gas itself and to various national policies. *Inter-fuel* competition has always affected natural gas everywhere, but for some time it was supposed to be strong only in less mature markets. In fact, in some cases it has almost disappeared, so that regulators have sometimes regarded natural gas as almost immune from such competition, much in the way of electricity, and applied a similar regulatory approach. However, even the mature European market shows how inter-fuel competition can be born again from its ashes, under the strikingly different characters of coal and renewables, and substantially change the marketplace.

The large variability of market conditions explains how bewildered a regulator[1] (either at a Ministry or a special Agency) may be when she or he must decide whether, where and how, gas prices should be subject to regulatory control. Available information is often scant, and theoretical debates – although surprisingly similar all over the world – may be misleading unless the variability of market conditions is considered. For example, the evolution towards competitive gas markets, at least at wholesale level, has reduced the interest for gas price regulation in the European markets, as well as in Australia and New Zealand, where any such "caps" are mostly regarded as transitional and about to disappear, or have been lifted altogether. In North America, the issue is less obvious, but the bonanza and low prices entailed by the shale revolution has also diminished regulators' interest in containing prices, but has not persuaded them to lift retail price caps.

Given the reduced need to control end user prices in the most advanced economies, the interest of academics and practitioners has fallen, and the solutions adopted by regulators have been subject of limited analysis. The tariff regulation literature has instead largely addressed those areas that are seen as "natural monopolies" and therefore the likely place of permanent regulation, i.e. tariffs and access rules for gas transportation and distribution networks, and in some cases the regulation of storage and LNG facilities. In this book, such issues are explicitly not

1 Throughout the book, we use the term "regulator" to refer to the person or body actually exercising the regulatory functions for gas prices - and possibly also for network tariffs and access, market rules, and quality of service. This is notwithstanding the existence in a jurisdiction of a regulatory agency or authority and its legal status, which depends on the legal framework. Discussion of the legal status of regulators lies beyond the scope of this book.

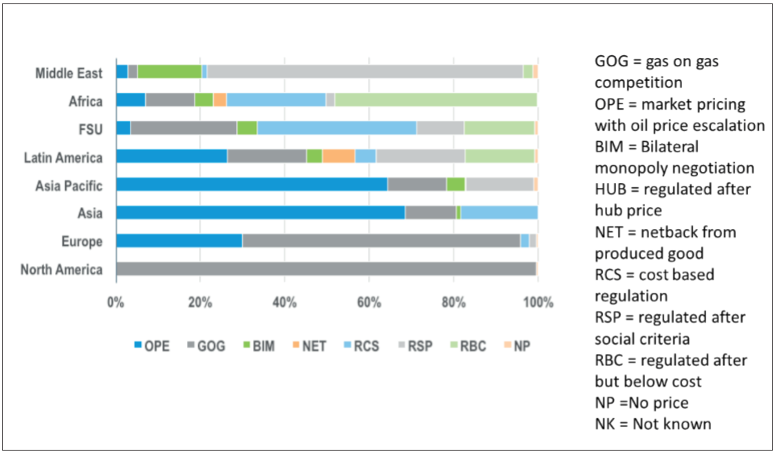
addressed, as they are covered by a significant literature[2].

In other cases, like Japan, South Korea and Taiwan, supplies are dominated by LNG and prices are almost directly linked to international ones, with a limited retail market and regulatory interest. Yet, even if we exclude markets where liberalisation and global integration make gas price controls a topic of declining interest, a number of cases remain where it is still appropriate, as market liberalisation has never started, is lagging behind or is ineffective for a number of reasons, at least at retail level. Yet the large variability of conditions hampers any easy and generalised solution.

A few readers, notably in Europe, may regard the idea of publishing a book about gas pricing regulation as backward looking, due to the perceived spreading of market liberalisation and gas on gas competition, which are often supposed to make controls redundant. On the other hand, the main world survey of gas pricing practices, which is prepared by IGU on an annual basis, finds that regulated gas pricing, even at wholesale level, still accounted for 42% of total consumption in 2019, of which 14% was cost-based, 8% "below cost" and 19% related to "social and political reasons". What is more, in the last fifteen years the share of cost based pricing emerged from almost nothing, whereas regulation below costs or for political reasons declined (see Figure). In turn, pricing based on gas on gas competition has increased from 31 to 47% while oil-based pricing has declined from 24 to just 10%.

2 E.g. Viscusi et al. (2005). This literature is cited where issues overlap, as in the case of rate of return setting.

Wholesale Gas Pricing By World Region, 2016



Source: International Gas Union, Wholesale Gas Price Survey 2017 Edition

Therefore, there is a rapidly increasing demand for cost-based regulation, as the results of a transition from less objective, transparent and predictable criteria. Whether this price control will eventually be lifted as markets are liberalised is not a short term perspective, even though some of the largest markets outside the OECD, like the Russian Federation and China, are actively pursuing domestic market liberalisation.

These figures lead to two important conclusions:

1. Cost based gas price controls are on the rise, and likely to be necessary in several markets for some time to come;

2. Market based wholesale pricing is certainly on a growing path in the world, partly reflecting onto retail markets, at least those serving large customers. Yet market based pricing requires not only political will, but also suitable conditions, notably a significantly large market size, access to multiple sources, and infrastructure to enable trade – and hence competition[3]. Since the development of these conditions requires time and large investments, the development of competitive market will be inevitably slow, and a large scope remains for the illustration and analysis of more rational ways of regulating prices, which is indeed the goal of this volume.

3 For Europe, these requirements have been outlined in the debate about the so called "Gas Target Model". See Glachant et al. (2012), CEER (2015).

An important corollary of these statements is that, where gas price controls are needed, they should be largely market-oriented, possibly with a view to anticipate and smooth the transition towards competitive markets.

Moreover, it is worth mentioning that even in the markets where all end user price controls have been lifted, the debate is far from settled. Controls are still used at least for smaller customers in several European countries and in North America, and even in the UK, the forerunner of energy market liberalisation, unease remains and the main political parties have recently converged towards the reintroduction of some controls.

This book cannot aim at being as comprehensive as the treatise about market pricing edited by J. Stern (2012), but it can help regulators and policy makers, as well as concerned energy companies and other public organisations that are in various way concerned by gas prices, towards more informed and market-friendly forms of intervention.

The general analysis of **Part I** consists of two Chapters, which are written as far as possible in a plain style, with the goal of presenting a list of issues and solutions for concerned stakeholders and regulators, rather than an academic survey. Yet, the most relevant scientific literature has been sought and consulted, and is duly cited in footnotes that non-academic readers may skip.

The first Chapter addresses the key question: should gas prices be regulated? It briefly considers the traditional argument of curbing monopoly power, as well as its theoretical foundations, considering the role of inter-fuel competition in relation to the various market sectors.

In closed markets, where gas to gas competition is prevented by monopolistic control over networks and other facilities, inter-fuel competition is the only market antibody against monopoly. In general, this type of competition is only effective for large customers with redundant, multi-fuel consuming facilities, like power generators and a few cement or steel producers. For most other industrial users - and even more for residential and commercial ones - inter-fuel competition is only effective before users switch to gas, and hence only in the early stages of gasification. After that, smaller users are very unlikely to maintain the capability of switching back to liquid or solid fuels, therefore inter-fuel competition becomes extremely weak.

Environmental policies using tools like differential taxation, emission rights or bans on usage of certain fuels only increase the advantage of natural gas over its traditional fossil competitors, and can even void such competition even in the power sector. The tendency towards a better environment at global as well as local level only adds to this, even though these policies also foster the new, serious challenge from renewable energy. Yet, financial constraints hampering (notably in developing countries) the far higher upfront investment that is often required for the development of wind, solar and hydropower – and to some extent also coal – further restrict the effectiveness of such competition. For our purposes, this means that in closed markets gas price regulation is fully justified. If – as it often happens – the development of the natural gas industry pursues social and environmental objectives – the production of cheaper and cleaner energy – then the regulation of its price is fully consistent, as it aims to avoid that the lower (industrial, social and environmental) costs of gas with respect to other fossil fuels results turns into higher margins for the gas industry, rather than in the desired environmental benefits.

In the open, liberalising markets of advanced economies where customers can actually choose their supplier, the issue of end user price regulation is a different one. It is mostly about the effectiveness of competition, notably in retail markets, where the restoration of some cartel power may dilute or possibly sweep the effects of competition. Ironically, Europe seems to have already decided in principle that end user price controls ought to be lifted, but in fact, several regulators cling on retaining some form of control, and the scientific discussion is lagging. On the other hand, North America seems keener on carefully assessing benefits and costs in each case before results of its successful wholesale competitive market model are transferred to the retailing level, and has kept controls even though a few jurisdictions have been trying retail competition as well.

To address this question, we have chosen an empirical rather than theoretical approach, as no general theoretical answer can answer the question of competition effectiveness. Therefore, most of Chapter 1 is devoted to the illustration of an original empirical study, where industry margins in gas retailing before and after liberalisation are analysed. The study is undertaken for a sample of European countries. Results of studies undertaken in North America on the same issue are also compared.

Chapter 2 discusses "how to do it", focusing on the main specific issues of gas price regulation. The price regulation of utilities like water supply, telecommunication, railways, sanitation, and others is nowadays a rather consolidated matter, and the same can be said also of substantial parts of the electricity and gas industry, like transportation, distribution and storage, notably where these are unbundled from supply and retailing services.[4].

What all these industries have in common is that their activity is largely based on capital and labour services, the prices of which do not change very quickly. To some extent, short term variations of such prices (like those of interest rates) can be neglected, as they are usually offset in the long term, or can be regarded as part of the normal risk of the utility.

After a brief outline of the main consensus criteria that are used by worldwide regulators for the setting of regulated tariffs, the Chapter focuses on the specific problems that make natural gas prices so hard to regulate.

Unlike the previously mentioned regulated industries, gas supply is concerned with a natural product, which is subject to price fluctuations depending on often volatile markets. Costs of the supplies cannot be easily determined, as they include a premium, or rent, which is not related to an industrial activity but rather to market conditions. This is a key fact of energy economics, and indeed of political economy since David Ricardo first detected the concept of economic rent from a natural resource, almost 200 years ago. Yet, despite its being far from new, this issue is still neglected and challenges regulators, who are often tempted to ignore it, thereby prompting the regulated market towards serious failures.

This type of difficulty does not apply to natural gas only, but it can also affect industries where gas, oil or other natural resources play a key role so that their value is a substantial part of the good (or service) final price. It happens notably in the power generation industry, wherever thermal generation covers a significant share, as well as in air, railway and local transports that are subject to the fluctuations of oil derivatives used as fuels.

4 This statement does not mean that the all regulatory problems of network industries have been solved and that the same criteria are used everywhere. In fact, world practices differ regarding the setting of the asset base, the update criteria of regulated tariffs and their incentive properties, and other issues.

Any attempt to set the price based on costs, as is the case with utilities that do not significantly depend on natural resources, is bound to fail. The correct value of the natural resources cannot be defined by regulators, as it is affected by variations of natural conditions, but also of demand (or simply demand expectations) facing a (temporarily) less flexible supply. Hence, prices of products embodying a large natural component (mostly agricultural and mineral commodities) tend to fluctuate sharply. This is also the case of natural gas, irrespectively of whether it is priced in independent and competitive markets or (in case these are not established) it is linked to those of competing or related energy sources like oil, coal, or electricity.

In other words, cost based regulated prices are normally wrong (except by good luck) and different (usually lower) than those resulting by international markets. Thus, they will be either too high (damaging consumers) or (most likely) too low, prompting the flight of investors towards more profitable jurisdictions or at least the postponement of development and production to better times; hence a decline of the resource base, lower than expected market development, or even the shutdown of production. The numerous, and often tenacious attempts by regulators to enforce such price controls again market logic are constellated by legal battles, and have often resulted in the nationalisation of resources, with the creation or expansion of the role of national companies. Yet the latter have often faced similar problems (sometimes on top of those characterising long term nationalised industries in general): uneconomic production has required mounting state subsidies or cross subsidisation at the expense of other, profitable sectors, leading to the loss of cost and benefit transparency that is a typical breeding ground of inefficiency and corruption.

Our analysis is limited to natural gas, but may nonetheless be of interest also for the regulation of power generation and other services, notably where fossil fuels represent a significant share of their costs.

On the positive side, the Chapter shows how sensible regulators can accept the reality of fluctuating resource markets, by including related (wholesale) prices into regulated tariffs. This has been done in several ways and countries, yet the particular specifications depend on the type of wholesale as well as retail markets. Therefore, even within the same country, arrangements have changed over time, following the evolution of gas markets. For other countries, significant adaptations are necessary. For example, the best known cases of end user price regulation are aimed at markets of households and other small users, but these solutions are not directly applicable to markets consisting mainly of power generation or other primary industries. Nevertheless, excellent models can be found in the experience of both developed and emerging economies, even though implementation is not always consistent and often hampered by political fears.

Two less traditional and interrelated solutions are then considered, which somehow depart from pure cost based pricing. First, the social and environmental reasons for providing gas (or possibly, gas-generated power) at subsidised prices are discussed. This allows us to briefly mention the rather large literature about energy subsidies and their merits, as well as to remind their (probably better known) drawbacks. It could allow to understand how dominant policy prescriptions are so rarely followed, yet much of the explanation probably lies in the political economy of price regulation.

Second, there may be an industrial policy as well as a socio-political rationale behind energy subsidies, notably in the case of natural gas. Subsidies may be justified to kick-start the industry and allow it to achieve the remarkable economies of scale that arise only once a certain market maturity is achieved. In this sense, subsidies are simply introduced to anticipate long term price levels, which are expected to be achieved from economies of scale. The point is even stronger if economies of scale from gas and electricity market development are jointly considered.

In each case, the argument must be carefully articulated in relation to the consuming sector, as subsidies to (e.g.) power generation rather than households may have a sharply different rationale. Likewise, subsidies allowing prices below average costs may apply to a wholesale rather than retail level, with rather different impacts.

The risks of price controls are of course emphasised. It will be shown that they can block industry development, scare investors, and even lead to supply shortage. Yet, some of the practical examples of Part II illustrate these risks most effectively, as such disasters have indeed occurred in the most different economic, social and political environments, from the U.S. and New Zealand to Egypt and Argentina.

Part II reports several case studies, with the analysis following as far as possible a common scheme for all countries: investigating the regulatory framework, the nature of the regulator, the scope, methodology ad main parameters of the regulation of prices and ancillary conditions, and the prevailing price levels. The considered countries are: U.S.A; Europe (overview and selected Member States: Italy, France, Netherlands); Middle East and Africa, (overview and special sections on Algeria, Nigeria, Egypt, Israel); Indonesia; New Zealand[5]. These countries cover over 50% of the world gas consumption.

There is a world tendency towards deregulation of gas prices, starting from the wholesale level and from larger customers. However, most countries retain some form of price control for residential and other small customers (mostly the commercial sector and public services), and in several cases even wholesale markets are not open and their prices are regulated.

Most gas importing countries have linked wholesale price regulation to market prices (*hub based regulation*). On the other hand, most exporters (notably outside the OECD) are still under different kinds of wholesale price regulations, often broadly cost related; yet most of them have national gas companies with a monopolistic or leading role in the market and widespread cross subsidies between customers, often opaque and managed by the national company. Countries that are at the same time important producers and importers may have mixed cost-based wholesale price regulations and market based gas prices.

Several advanced economies (OECD Members) have opened their wholesale markets and phased out their gas price regulation, even though they generally maintain the regulation of network services like transmission, distribution and (in some cases) also storage and LNG regasification.

Full cost transparency of the kind usually delivered by modern electricity and gas regulation is rarely found in the upstream gas regulatory regimes, where a strong influence of large state owned companies prevails. On the other hand, criteria for regulated price update, where applicable, are mostly transparent and both indicators and frequency are well known. Criteria point to oil derivatives (Russia, China), to liquid

5 The original Survey also included Argentina, Brazil; China, India and the Russian Federation, but adequate Chapters could not be prepared for such countries. Some information about these countries is provided in the final summary.

gas markets (U.S., Italy, France), or to a mix of both (India). Updating frequency varies between quarterly and yearly.

Price levels in the world are very variable, as LNG trade is still too limited and costly to bring about their alignment, at least when markets are tight. Exporting countries and integrated markets (including North America as a whole) feature lower wholesale prices, usually below $5/MMbtu, and often as low as $2 or less. On the other hand, net importing areas (including the EU as a whole) usually have higher prices, normally above $5/MMbtu, but up to 25$/MMBTU and more for consumers relying mostly on LNG imports under tight supply conditions. Currently isolated countries like Israel and New Zealand typically lie in between, around 5-6$, and feature a lower variability.

For *retail*, several OECD countries (like U.S., France, Italy) still keep some type of price control, particularly for smaller customers, even though the outreach of controls is shrinking and Europeans are all committed to phase out the remaining caps. In other cases, there is no control even for retail prices, and prices are only subject to ex-post control from competition regulators. The remaining regulated retail prices are increasingly linked to gas hub prices rather than to competing fuels. In a few cases, if there is a specialized energy or gas regulator, it retains a market monitoring and advisory role towards the government or the Competition regulator.

A typical example of a country that has phased out all price controls is the Netherlands. In the past, in this country – as well as in most of Western Europe – prices of natural gas were related to those of competing fuels, notably oil derivatives, with some margins aimed at maintaining some competitiveness for gas. Lately, the Dutch market has been fully liberalized, with no wholesale price regulation, and integrated to those of neighboring countries of North-Western and Central Europe, with prices defined mostly in market hubs.

The **U.S.** has phased out wellhead and wholesale price wholesale regulation since the early 1980s. It was a complex and burdensome practice, which had been lasting for several decades and has been widely seen as partly liable for the shortage that affected America's gas industry in the 1970s. This important historical case shows how regulatory practices that may be suitable for other industries are hardly applicable to gas production. Yet, controls are retained for customers supplied by franchised local distributors, even though in a few States some competitive options are available.

The three largest African gas producers (Algeria, Egypt and Nigeria) as well as most Middle Eastern countries all have a dominant national company, acting as a "single buyer" that purchase gas from producing joint-ventures (where the private sector usually prevails) at various conditions. Gas is then re-sold to consumers at regulated prices, which may be related to political priorities rather than cost. However, this model is being revised, at least in Egypt, where production stagnation and fast demand increase have turned the country into a net importer and huge consumer subsidies have become unsustainable for public finances. Nigeria has also increased its prices for power generation, bringing them almost in line with production cost, with a view to fix its power generation deficit. Israel, a new gas power and a potential exporter after huge recent finds, is currently revising its regulatory system, which is now extremely simple and has resisted calls for price control in the (disappointed) hope that competition may emerge. However, regulatory controversies have been widely held responsible for postponed development and the prospects for exports are increasingly uncertain amid an international low pricing environment.

Another case where regulation has not been able to curb monopoly power is Indonesia, a large producer and exporter. In its internal market, uncertainty between the choice of a competitive or monopolistic regime for gas transmission, political interference in gas allocation and questionable regulatory practices for infrastructure have led to relatively high prices for a self-sufficient country, and presumably curbed the potential development of the industry.

Finally, New Zealand, now a fully liberalized market in spite of its small size, has also undergone a period of regulated prices, indexed to inflation, which were introduced after 1996 as a remedy against the market dominance by a single gas field. However, the rigid price control led to reduced exploration and development and a demand supply imbalance, followed by a sharp production decline. Ensuing price increases and liberalization – allowed by a much less concentrated supply – have slowly restored the equilibrium.

Other important cases have been analysed but could not be reported in the book with adequate detail.

For instance, both China and India have various and complex regulatory regimes, mixing cost based cases with market-oriented ones. In both cases, official policies aim to bring prices in line with market levels, notably with oil derivatives in China and with import prices in India. Yet implementation is slow, particularly in India.

In Brazil, prices are generally driven by inter-fuel competition, but some special programs reduce the price for power generation. Regulatory criteria are cost based for network services but less clear for the commodity price, which is generally in line with import costs.

In Argentina, a prolonged price freeze after the country's 2001 default and high inflation has led to stagnation of upstream investments, production decline since 2005 and a shortage that is now covered by costly LNG imports. Price levels are well below any cost definition. However, some supplies have lately been made available at market prices.

Russia and Ukraine share several features, as both had to face a long evolution from Soviet time, when natural gas (and gas-fired heat generation) were almost free for households, to a market based system. Russia has long aimed at bringing gas prices for households up to the "netback" level where they were aligned with those of exports minus export transportation costs. Yet, despite some improvements, this pricing parity between exports and the residential internal market has never been achieved – except probably very recently, due to the sharp downfall of international gas prices of 2019-20.

As for Ukraine, the achievement of cost reflectivity has long been officially endorsed by the government, under pressure from international financial institution. The IMF has notably included gas price cost reflectivity as a key condition for support, and the World Bank has long worked on how to combine this achievement with the support of poor and vulnerable consumers, with the "monetization" of subsidies as a key intermediate step. Further pressure came after Ukraine joined the Energy Community (of South-East Europe), as a step towards its long hoped EU candidate member status. Successive Ukrainian governments have resisted these calls for gas price increases, fering the backlash of a largely deprived population facing harsh winters with poorly insulated homes. Yet, a few steps have been done in 2015, 2016 and 2018, which have almost achieved the results, leading to significant demand reductions.

A final Chapter compares the cases, draws the main lessons and relates them to the general part.

PART I

THE ECONOMICS OF NATURAL GAS PRICE CONTROL

1. END-USER PRICE LIBERALIZATION VERSUS REGULATION. LESSONS FROM ADVANCED MARKETS

Alessandra Motz[1]

1.1 Introduction

Regulated end-user prices, i.e. prices that are "*subject to regulation by a public authority, as opposed to a price set exclusively by supply and demand*" [7], have been widely used in the natural gas industry in most countries in the world, and are still adopted in several areas, particularly – but not only - where the liberalization process is lagging behind.

End-user price regulation was first introduced in the energy industry in response to the monopoly pricing problem [20], although other reasons were often present (see Section 2.1). The natural gas industry was, indeed, characterized by vertically integrated state-owned monopolies. The integrated firms carried out production and retailing activities, which nowadays are often opened to competition, together with transmission and distribution activities, which show instead a monopolistic cost structure and are thus generally subject to regulation. In the absence of a trading place for gas, the wholesale cost of the commodity was often defined either by means a cost-plus approach, or with reference to the prices of alternative fuels, picked among those that were either complements to gas in the production phase, or competing with gas in the consumption phase. Regulated prices were adopted as a way to ensure a

1 Institute for Economic Research, Università della Svizzera italiana, Lugano, Switzerland.

fair price to end-consumers, while guaranteeing the coverage of the costs for supply, transmission, distribution and marketing activities, and promoting efficiency along the whole supply chain.

With the liberalization waves of the 1980s and 1990s, gas retailers in Europe, North America, Australia, and other countries were gradually allowed to design customized offers for an increasing share of end-consumers. Nonetheless, regulated prices were maintained in most countries for several years at least for some consumption classes, or as an alternative for those consumers who opted out of the liberalized market. The goal was to facilitate the transition phase, protect small consumers, and deal with the initially slow progress in the formation of a reliable wholesale market price for the commodity. The practical ways in which end-user price regulation was put in place are discussed and analysed in the rest of the present book, from a theoretical (Chapter 2) and empirical (Part 2) point of view.

In recent years researchers, analysts, and stakeholders have started to debate the advantages and disadvantages of retail price regulation, trying to evaluate the benefits and costs of retaining price regulation within liberalized, competitive gas (and electricity) markets. The difficulty in defining a clear counterfactual [17] has generally hindered an evaluation of both the welfare or efficiency gains, and the distributional effects of the retention or removal of regulated prices within competitive markets. The same holds for the impacts of the liberalization itself. Indeed, the gradual liberalization of the whole supply chain, the spreading of new production and consumption technologies, the increasing integration of wholesale energy markets, and finally the changing market and regulation environment have introduced several confounding factors into the picture.

To our knowledge, no conclusive evidence regarding the net impact of end-user price regulation on the general welfare in liberalized gas markets is yet available. The work of researchers and analysts studying the gas market and, to a deeper extent, the neighbouring electricity market, has however provided several suggestions and at least some partial evidence in this respect. Building on these hints, this Chapter aims at understanding if, and to what extent, the liberalization of the retail gas market and the dismantling of regulated end-user prices have actually generated some advantages for end-users so far.

Our work starts with a review of the analyses and findings from the economic literature concerning end-user price regulation and the liberalization of the retail segment in the gas and electricity markets, with a focus on advanced liberalized markets. Based on these contributions, we try to assess the impact of end-user price regulation on consumers' welfare by means of an econometric analysis of an original panel dataset, covering eight European countries during the years 1991-2015. The results of our analysis support the view that dismantling the regulated end-user price system might actually generate significant benefits for both industrial, and residential consumers, at least in sufficiently competitive markets.

1.2 Advantages and disadvantages of end-user price regulation in a liberalized market

The main rationale for retaining price regulation within liberalized gas markets has historically been linked to consumer protection goals, in light of the long lead time needed for the liberalization process to be implemented and generate an impact, and for actual competition to develop. The latter phaenomena partly depend on the generally low rates of energy literacy among small consumers, facing proportionally higher transaction costs than large consumers to access the market.

Regulated end-user prices have been used, indeed, as a tool to protect consumers from unduly high prices both during the transition phase, when some consumption segments are open to competition and some are not, and where the liberalized retail market still hosts a dominant player or a small number of big competitors, able to (jointly) exert market power and erode the consumer surplus ([9], [22]).

Even where the market structure is reasonably competitive, though, the time and effort required for collecting information and evaluating the available offers are often such that only large and medium consumers can timely select the cheapest deals. Small consumers might end up cross-subsidizing larger ones: economic theory suggests that suppliers will apply higher mark-ups to those consumers that show the lowest price elasticity of demand. As this is the case for small firms and households, regulated prices can be used within competitive markets to prevent undesirable distributional consequences of the retail market liberalization [22].

The low switching rates observed among households and small firms confirm, indeed, that proportionally higher transaction costs may discourage small consumers from exploiting the free market. By failing to engage in the market, however, these consumers reinforce the market power of the dominant players, and expose to a worsening of supply conditions [6]. By publishing reference end-user prices and/or providing price comparison tools, energy regulators can foster energy literacy and protect consumers from the consequences of large information asymmetries.

Consumer protection goals, however, can also be pursued by means of "social tariffs", i.e. special regulated prices reserved to vulnerable consumers only ([1], [9]), or by creating last resort suppliers, i.e. retailers in charge of ensuring access to energy to all passive consumers until they are able to engage in the market [6].

A different reason to retain regulated end-user prices can be found in the fact that retailers often fail to incorporate the external costs of energy provision into the marginal price. Whereas small consumers tend to react to the monthly cost of energy, rather than to its marginal cost as economic theory would suggest, large consumers could indeed reduce or reshape their consumption if exposed to the marginal cost of energy supply. Hence, large consumers could contribute to the reduction of the aggregated cost – and environmental impact - of energy provision [20].

By a similar reasoning, price regulation has also been used, in (liberalized) electricity markets, as a way to promote consumption reductions during certain time spans by means of time-of-use tariff structures, in which the variable components reflect the average cost of providing electricity during specific hours of the day [20]. As the electricity system is traditionally characterized by very limited storage capacities, the provision of real-time scarcity signals to the downstream market can lead to a more efficient balancing of demand and supply. The magnitude of the demand response expected from small consumers is often questioned by researchers, but the spreading of metering and demand response technologies could, indeed, allow a more optimistic view ([4], [15], [21]). In the natural gas sector, a similar argument applies: the main demand fluctuations that could justify time-of-use tariffs are seasonal ones, at least in temperate and cold climates where winter consumption greatly exceeds summer consumption. Daily fluctuations are instead an issue in emerging markets with limited storage capabilities. In the gas sector, pricing is often used as a tool to promote switching from more polluting fuels to natural gas, notably to curb local air pollution in urban areas. In principle, this goals could be more efficiently pursued by means of different policy tools, like differential taxation or tradable emission caps (see Section 2.1).

Further reasons to regulate prices - irrespective of the structure of the retail market - have often been suggested by policy makers: income redistribution, inflation containment, support to nascent industries. The usefulness and efficiency of price controls to pursue these objectives has been questioned by several economists and international organizations: this topic is addressed in more detail in Section 2.1.

Despite its advantages, however, price regulation has started to show some limitations: this led to the decision of gradually opening retail markets to competition in some countries. The rest of this Section summarizes the main advantages that recent economic literature associates to the liberalization of retail markets and the removal of price controls, as well as the main disadvantages that may be connected to the existence of regulated end-user prices in a liberalized setting.

The liberalization of the retail segment was introduced based on the hypothesis that its benefits would have outweighed the sum of the costs of attracting end-users on the market on the one hand, and the transaction costs faced by consumers for engaging in the market on the other hand. As retail margins usually represent a small fraction of total energy costs, the net benefit stemming from competition among retailers alone was expected to be nearly negligible [6]. The advocates of liberalizations argued however that competitive retailers could also be better buyers on the wholesale markets. Increases in the consumer surplus could be expected from the retailers' influence on the upstream segment, as well as from the fact that the savings obtained in the upstream segment would have been transferred on the competitive downstream markets through more cost-reflective prices [6]. The exposure of end-consumers to liberalized energy prices was also expected to positively influence the wholesale market by increasing the responsiveness of demand to prices, and contributing to the development of forward markets [6]. In sum, liberalized retail markets were introduced since they were expected to provide better incentives for all players along the supply chain to keep end-user prices below the levels that monopolies could achieve [22].

Some analysts and stakeholders are now supporting the removal of regulated prices, arguing that the survival of regulated end-user prices within competitive markets can actually induce severe distortions, and hence hinder the achievement of the above-mentioned general welfare goals ([1], [3], [15]).

Indeed, they provide some descriptive evidence that regulated end-user prices generally act as “focal points” around which supply offers tend to cluster: according to their view, this further reduces the consumers’ propensity to switch below the physiological level given by inertia and transaction costs [1].

They also hypothesize that regulated prices, if set at artificially low levels, could send incorrect signals to market players. When observing low or negative mark-ups, indeed, the active market players tend to delay investments, while prospective new competitors are discouraged from entering the market. These trends might even result in a threat to the long-term security of supplies ([1], [9]).

Distortions from end-user prices set below the cost level also affect the consumers’ side. Indeed, low regulated prices can disengage consumers from looking for cheaper supply offers, and hence reinforce the market power of the existing dominant players [1]. Several countries have been using low regulated prices for household consumers as a tool to temporarily manage a widespread fuel poverty, or gain political consensus. Household prices below the cost level have however promoted an inefficient use of energy, and led large consumers to either cross-subsidize small ones, or switch to suboptimal energy sources [16].

Based on the above-mentioned findings and on some descriptive evidence comparing liberalized energy markets to markets that still host regulated end-user prices, some stakeholders ([1], [3], [15]) recently came to the radical hypothesis that “*in countries where regulated end-user prices exist, competition is compromised*” [1], particularly if regulated prices are set below the long run marginal cost of supply. These stakeholders call for the abolition of regulated end-user prices, further arguing that a low level of competitiveness is often seen as a signal that the market is not mature and regulated prices should be maintained, so that the market is caught in a vicious circle that ultimately harms consumers [1].

Finally, an additional reason in favour of liberalized retail markets with no regulated prices lies in the fact that competing retail suppliers are, in general, able to better fit the needs of consumers by providing a wider set of customized offers, ranging from risk management to "green" options, from demand management to lower risks of interruptions, etc. ([3], [6], [15]). Recent analyses regarding the electricity markets [15] stress the importance of the availability of a wide set of offers, in light of the need of enabling and incentivizing demand response, and subsequently contributing to the security, affordability and sustainability of supply. Several of these side benefits are also available for natural gas, other less so – for example, there are fewer green options in gas supply, although some are developing.

The next Section is devoted to an attempt to assess whether claims in favour of lifting price controls are supported by evidence, at least in a few European countries where such controls have been removed for several years, or have never been formally imposed.

Before starting the analysis, it is worth recalling that for both electricity and gas, few empirical studies have tried to actually compare retail prices across jurisdictions, and assess the impact of the retail market liberalization on consumers' welfare.[2] Indeed, remarkable differences in supply conditions make the benchmarking very demanding, and the lack of necessary data makes the rest, so that full cost-benefit analyses of the introduction of retail price competition and the lifting of any price control could not be properly undertaken. Our contribution is a preliminary attempt to draw some conclusions from the available European data.

2 A comprehensive quantitative analyses of the impact of regulatory reforms and cross-subsidies on the retail margins in the electricity sector has been carried out on a panel of 63 countries for by Erdodgu [8]. Waddams Price [22] provides some descriptive evidence of the impact of the market liberalization on retail prices in the United Kingdom. A benchmarking, descriptive analysis of retail electricity and gas prices in several European countries is available in the 2012 study by London Economics [19]. A descriptive analysis of the market competitiveness and its impact on retail prices for Georgia can be found in Costello [5]. A study by Woo et al. [23] measures the pass-through of wholesale costs in the retail market for natural gas in the United States of America, but without focussing on the presence and impact of price controls. Finally, Hortacsu et al. [13] investigate the impact of frictions, such as consumers' inattention and brand loyalty, on the development of the retail market for electricity in Texas.

1.3 Did European consumers benefit from a liberalized gas market? An empirical analysis

Our empirical analysis starts by defining an index of the share of the consumer surplus that the retailers are able to extract from end-users. Consumer surplus, as Chapter 2 discusses in greater detail, can be defined as the extra value individuals receive from consuming a good over what they pay for it: its value measures the aggregate welfare of consumers under the given market equilibrium. If the market equilibrium departs from the ideal conditions for perfectly competitive markets, the suppliers can be able to charge a unit price that is higher than the marginal cost of the commodity: this means that part of the benefit consumers would get from consumption in an ideal, perfectly competitive market can be extracted and go to the benefit of suppliers.

After defining a proxy for the part of consumer surplus that is extracted by suppliers, we look for the drivers that, according to existing research, may influence its value together with the presence or absence of regulated end-user prices. By means of sound econometric techniques, we try to isolate the impact of each individual driver on the index of surplus extraction, and assess the effect of retaining or removing regulated prices on its final value.

1.3.1 The mark-up as a measure of the consumer surplus extraction

In line with previous contributions (0, [8]), we select the mark-up that retailers are able to charge above the wholesale cost of gas as a proxy for the share of the consumer surplus that the retailers are able to extract from end-users. The mark-up, also called "price-cost margin", measures the percentage difference between the unit price charged to consumers and the unit cost to supply them: the higher its value, the lower the surplus that consumers are able to extract from the retail market. The mark-up index we were able to compute based on available data has some intrinsic limitations with respect to the scope of our analysis:

- it neglects the costs implied by distribution and retailing activities, as well as the impact thereon of increased service quality or specific regulatory provisions. Hence, contrary to what economic theory suggests for perfectly competitive markets, our mark-up is not expected to be close to zero in very competitive markets, as it includes the costs of retailing activities for the average market player, as well as the cost of transporting gas along distribution grids;

- it does not capture the impact that an increased competitiveness of the retail market could have on the wholesale market, although this effect is often mentioned as one of the positive side effects of liberalization in the retail segment.

Nonetheless, by choosing the mark-up as our dependent variable, we are able to disentangle the impact of wholesale market trends from the retail market's dynamics, and hence to isolate and evaluate the contribution of individual policies affecting the margins on the retail market.

1.3.2 The drivers of the mark-up index in a liberalized setting

According to the sectorial economic literature, several drivers may have an impact on the mark-up index:

1. An increased retail market competitiveness is expected to exert some downward pressure on the profits achieved by market players, and hence on the mark-up they are able to apply on the wholesale cost for gas (0, [22]). Market competitiveness can be measured in terms of:

   a. Market concentration – usually expressed as the market share of the former incumbent, or the three biggest players [11]. It is worth noting that, due to the fact that retailers are often rooted within specific regions, the concentration measures, although informative of the number of players that are active within a certain market, may hide higher concentration levels on a regional scale [11];
   b. Competitive constraints from consumer behaviour, e.g. low switching rates, revealing high transaction costs, legal obstacles to switching, or regulated end-user prices set below the cost level [11];

2. The presence of cross-subsidies across different consumption segments can impact the mark-up charged on each individual segment [8]. More in detail, the consumption segments that pay the cross-subsidy will show higher mark-up values, whereas those that benefit from the cross-subsidy will show lower mark-up values.

Indeed, the former might be the case of residential customers that, due to the lower elasticity of their demand for electricity (e.g. due to their higher transaction costs), might subsidize the medium and large industrial consumers;

3. Individual reform steps are expected to increase market competitiveness, and hence reduce the price-cost margin. Among these we can list ([8], [11]):
   a. the creation of a wholesale market, which should help reducing the mark-up by making wholesale prices more transparent to end-users;
   b. the creation of an energy regulator, whose regulation and monitoring activity should help decreasing the mark-up by increasing transparency, and detecting and removing distortions;
   c. the liberalization of the retail market, which is the focus of our analysis. Our hypothesis is that the opening of the retail market to competition and the gradual removal of regulated end-user prices help reducing the mark-up index, thereby increasing the consumer surplus.

The inclusion of all the above-mentioned drivers within the econometric analysis is, to some extent, limited by data availability. Nonetheless, we try to account for all available information, coherently with the suggestions from the economic literature, and we use sound econometric techniques in order to avoid omitted variable biases.

1.3.3 Dataset

Our analysis is performed on an unbalanced panel[3] of eight European countries, which we are able to follow from 1991 to the first semester of 2015 (S1 2015). The countries we include in the panel are: Austria (AT), Belgium (BE), Germany (DE), France (FR), Italy (IT), the Netherlands (NL), Spain (ES), and the United Kingdom (UK). The choice of these countries was driven by two kind of reasons:

- As Western European countries and Member States of the European Union, they share a similar regulatory framework, and have com-

3 A panel dataset is called "balanced" if there is the same number of observations for all individuals in the panel, and "unbalanced" if this is not the case. As the rest of the Section will show, our dataset includes a few countries for which we have fewer observations, particularly as regards the wholesale cost of gas.

parable economic conditions and energy markets. Their national gas markets, moreover, have been following a roughly similar path from vertically integrated, monopolistic markets to liberalized gas markets;

- There is a sufficient amount of publicly available data, providing comparable information of reasonably good quality.

The dataset we were able to assemble collects information on the mark-up index and its drivers, as well as a few control variables, such as yearly national gas demand, production, imports and exports. The inclusion of the relevant control variables is not linked to any specific hypothesis concerning their influence on the price-cost margin. It is rather due to the fact that, by deciding a priori to exclude from the analysis one or more variables that could have an impact on the price-cost margin, we could neglect some information concerning unknown factors that do, indeed, affect the margin, and hence obtain biased estimations for the coefficients of the explanatory variables we are interested in.

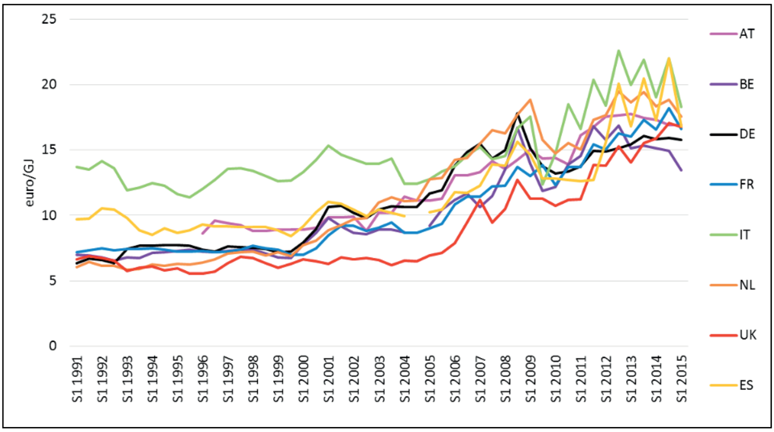
A list and description of the information we gathered follows in the rest of the Section.

1. Gas prices for household consumers

We took as a reference the Eurostat biannual gas prices, net of VAT and other recoverable taxes and levies, for household consumers for the years from 1991 to the first semester (S1) of 2015 (from 1996 onwards for Austria). Coherently with the latest "ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2014", we assumed that the representative consumption class is D2, with yearly gas consumption between 526 and 5260 cubic meters (cm). This class corresponds to consumption class D3, with an average annual consumption of 2200 cm, in the Eurostat classification that was adopted until mid 2007.[4] Figure 1.1 reports the development of biannual prices for households in our sample in the years 1991-2015.

4 In energy terms, class D2 corresponds to the consumption class between 20 GJ and 200 GJ per year (i.e. between 5556 kWh and 55556 kWh per year), while class D3 corresponds to a yearly consumption of 83.70 GJ (23250 kWh per year). Coherently with Eurostat dataset, we always refer here to the gross calorific value of natural gas.

Figure 1.1 – Household gas prices, excluding VAT and other recoverable taxes and levies.



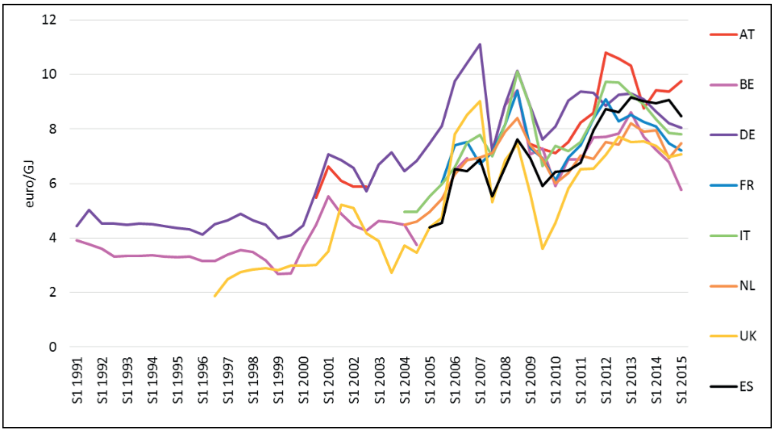
Source: Eurostat

2. Gas prices for industrial consumers

In line with the "ACER/CEER Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2014", we assumed that the representative consumption class for European industrial consumers is I5, with yearly gas consumption between 26 and 105 million cubic meters (mcm) – corresponding to class D3, with an average annual consumption of 11 mcm, in the Eurostat classification adopted until mid 2007[5]. The prices we took as a reference are, again, net of VAT and other recoverable taxes and levies, and cover the years from 1991 onwards for Belgium and Germany, from 1996 onwards for the United Kingdom, from 2000 onwards for Austria, from 2004 onwards for Italy and the Netherlands, from 2005 onwards for France and Spain. Figure 1.2 provides information on the development of biannual prices for industrial customers in our sample in the years from 1991 to S1 2015.

5 In energy terms, class I5 corresponds to yearly consumptions between 1000 TJ and 4000 TJ (i.e. between 278 GWh and 1111 GWh). Class D3 corresponds to a yearly consumption of 418.6 TJ (116 GWh).

Figure 1.2 – Industrial gas prices, excluding VAT and other recoverable taxes and levies.



Source: Eurostat

3. Wholesale cost of gas

The choice regarding the index for the wholesale cost of gas was one of the most complex decisions we had to take while assembling the dataset, due to:

- The general lack of transparency on the cost side in the natural gas industry, hampering an official assessment of the average cost of gas on the wholesale market in most individual countries, at least until the development of national gas hubs;
- The changes occurred in the pricing mechanisms during the selected time span, with the shift from oil-indexation to spot and forward pricing on national or regional gas hubs (see Part 2, in particular Section 5.1, for the trends in the pricing of internationally traded gas in Europe);

We decided to balance the need of using reliable, publicly available information collected with consistent criteria for each country, and the need of minimizing gaps and missing values for the sake of representativeness of the econometric analysis. Hence, our database comprises independent assessments for both the average import cost of gas, and the spot prices on some national gas hubs for those countries for which import cost assessments were not available or less reliable than hub prices. More in detail, the series we took as a reference in the wholesale cost index are:

- Biannual averages of Platts daily quotes for day-ahead prices at the Central European Gas Hub (CEGH) from S1 2010 to S1 2015 for Austria;
- Biannual averages of monthly import costs as quoted by World Gas Intelligence (WGI) from S1 2002 to S1 2015 for Belgium. This time series is not perfectly in line with Platts day-ahead quotes for the Belgian gas hub Zeebrugge, which is only available to us starting from S1 2008; the correlation between the two series for the available semesters is slightly above 75%;
- Biannual averages of the monthly average import cost to Germany, as quoted by the Bafa index. The Bafa index is the only official assessment of the average import cost of natural gas to a Western European country. The index is published by the German Federal Office for Economic Affairs and Export Control, and measures the average cost of the gas crossing the German borders every month. The Bafa index shows reasonably high (88%) correlation values with the biannual averages of day-ahead prices on the two German hubs, GasPool and NetConnect Germany (NCG);
- Biannual averages of monthly import costs as quoted by WGI from S1 2002 to S1 2015 for France. As with the Belgian gas prices, this time series is not perfectly in line with Platts day-ahead quotes for the French PEG Nord, which is only available to us starting from S1 2008. The correlation between the two series is around 88%;
- Biannual averages of monthly import costs as quoted by WGI from S1 2002 to S1 2015 for Italy. The correlation between the import cost and the biannual average of day-ahead prices published by Platts for the Italian gas hub, the PSV, is around 54%: lower, indeed, than the corresponding value for France, Belgium and Germany;
- Biannual averages of quotes for day-ahead prices on the TTF hub for the Netherlands, as published on a weekly basis by WGI from S1 2006 to S2 2007, and on a daily basis by Platts from S1 2008 onwards;
- Biannual averages of day-ahead prices on the NBP hub for the United Kingdom, as quoted (on a yearly basis) by the BP Statistical Review of World Energy from S1 1999 to S2 2007, and by Platts (on a daily basis) from S1 2008 onwards;

- Biannual averages of monthly import costs as quoted by WGI from S1 2002 to S1 2015 for Spain.

The EUR/USD exchange rate, where needed, was computed as a biannual average of the daily quotes published by the European Central Bank (ECB).

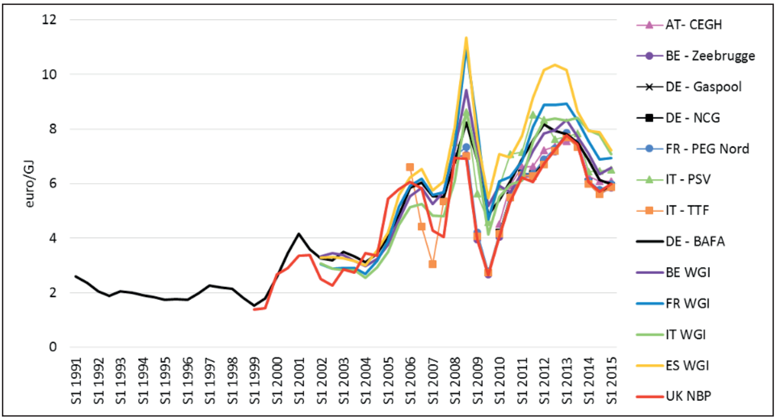
As a further consistency check, we computed the correlation between the Bafa index for the average import cost of gas in Germany and the import cost indexes published by WGI for the same country. The correlation value is around 98% for the years 2002-S1 2015: this confirms the reasonably good quality of the WGI import cost assessment as a proxy for the wholesale cost of gas, at least for this country.

Figure 1.3 describes the trends and levels of all the above-mentioned wholesale price indexes, including those that were not directly used for the analysis, i.e. the biannual averages of day-ahead prices on the Zeebrugge, GasPool, NetConnect Germany, PEG Nord and PSV gas hubs.

As a preliminary analysis, we computed the correlations between the above-mentioned end-user prices and the wholesale cost indexes for each individual country over five-year periods, for all the periods where data is available.

Table 1.1 collects the correlations between end-user prices for households and industrial consumers. The table shows generally positive values, suggesting that industrial and household prices tend to move together. There are, however, significant differences between countries, as well as time spans with negative correlation values, suggesting that for some reason the prices for industrial and household consumers followed different trends over part of the observed period.

Figure 1.3 – Wholesale gas prices: biannual averages of hub prices and import costs.



Source: Bafa, Platts, own calculations on WGI, BP, and ECB data.

Table 1.1 – Correlation between end-user prices for households and industrial customers.

Years	AT	BE	DE	FR	IT	NL	UK	ES
1991-1995		-17%	-40%					
1996-2000		98%	89%				64%	
2001-2005		100%	92%				77%	
2006-2010		72%	52%	23%	54%	71%	-20%	41%
2011-S1 2015	76%	69%	-58%	-17%	40%	47%	45%	73%

Source: own calculations.

Table 1.2 shows instead the correlations between the cost index and the household price for each individual country. The correlation values are, again, generally positive, but with significant differences across countries, and with some negative values. The case of Germany is, indeed, striking, as the country shows high positive values in the period 1996-2010, but negative values in the years 1991-1995 and 2011-S1 2015, possibly suggesting that household prices followed the wholesale cost increases observed in the years 1996-2010, but not the subsequent decreases of the 2011-2015 period.

Table 1.2 – Correlation between the cost index and end-user prices for households.

Years	AT	BE	DE	FR	IT	NL	UK	ES
1991-1995			-66%					
1996-2000			97%					
2001-2005		92.5%*	81%	48.1%*	-6.2%*		65%	41.4%*
2006-2010		90%	80%	41%	66%	9%	-9%	77%
2011-S1 2015	66%	54%	-28%	52%	69%	39%	-20%	2%

** Starting from S1 2002. Source: own calculations.*

Finally, Table 1.3 collects the correlations between the cost index and the end-user price for industrial consumers. The values are all positive and show less variation across different countries. Industrial customers seem, indeed, able to obtain supply offers in line with wholesale costs, probably due to lower transaction costs and, possibly, more frequent bargaining of supply contracts.

Table 1.3 – Correlation between the cost index and end-user prices for industrial customers.

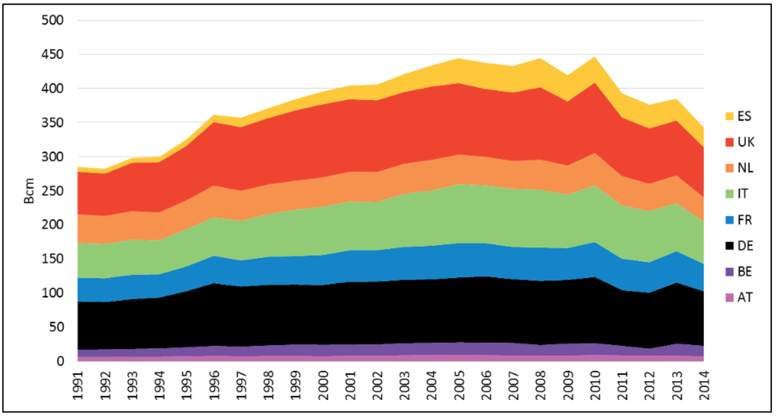
Years	AT	BE	DE	FR	IT	NL	UK	ES
1991-1995			47%					
1996-2000			90%					
2001-2005			85%				26%	
2006-2010		80%	38%	75%	91%	40%	63%	76%
2011-S1 2015	34%	86%	77%	72%	82%	62%	70%	29%

Source: own calculations.

4. National demand, import, export and production

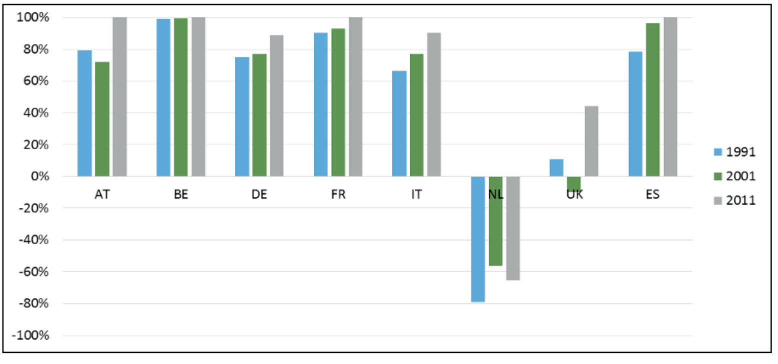
The dataset also contains biannual values of natural gas demand, import, export and production as published by Eurostat for the eight countries. Figure 1.4 depicts the yearly demand for gas in each individual country over the years 1991-2014, while Figure 1.5 provides information on the net imports of each country, as a percentage of the national gas demand, in selected years.

Figure 1.4 – Yearly demand for natural gas.



Source: Eurostat.

Figure 1.5 - Net imports as a percentage of the national gas demand (selected years).



Source: Eurostat.

5. Individual reform steps

The dataset contains a few dummy variables representing individual regulatory reform steps. Each dummy variable takes value 0 before the implementation of the specific reform step in each individual country, and 1 in the semesters after the implementation. The reform steps covered within this part of the database are:

- The liberalization of the household market, i.e. the entry into force of the regulatory or legislative provisions according to which household consumers became eligible to choose their supplier. This variable was reconstructed thanks to the comprehensive cross-country analysis of London Economics [19];
- The liberalization of the industrial market for the relevant consumption segment;
- The creation of a wholesale gas market. This variable was computed based on the rich overview of the history and liquidity of the main European gas hubs provided by Heather in [12];
- The creation of an energy regulator.

Table 1.4 collects the information we were able to assemble on each individual reform step.

Table 1.4 – Date of implementation of individual reform steps.

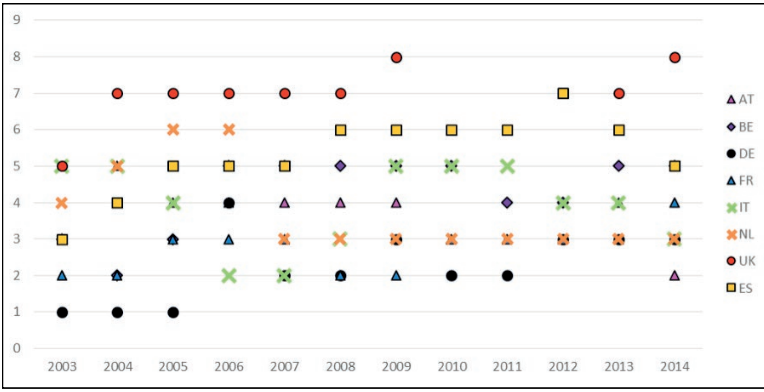
Country	Creation of an energy regulator	Liberalization of the household market	Liberalization of the industrial market	Creation of a wholesalemarket	Status of wholesale market in 2015 (Heather, 2015)
AT	2001	2002	2002*	2005	poor
BE	1999	2007	2004**	2000	poor
DE	2005	1998	1998*	2009	active
FR	2000	2007	2003	2004	poor
IT	1996	2003	2000	2003	poor
NL	1998	2004	1998	2003	mature
UK	1986	1998	before 1992	1996	mature
ES	1998	2003	2000	(2004***)	inactive
We assumed that the industrial market was liberalized in the same year as the household market					
*** We assumed that the industrial market was liberalized pursuant to Directive 2003/55/EC*					
**** As the Spanish gas market is inactive at the time of research, the corresponding dummy variable takes value 0 for the years 1991 - S1 2015*					

Source: own research, London Economics [19] and P. Heather, 2015 [12].

6. Competitiveness indicators

In the absence of lengthy time series for traditional competitiveness indicators, such as the switching rates, or the market share of the dominant player or the three biggest players, we included the only information available for approximately 10 years in all the eight countries, i.e. the number of players with a market share above 5% in the retail market for gas (Figure 1.6). This information was only available on a yearly basis for the period 2003-2014, and is a less satisfactory measure of market competitiveness, as it completely neglects the actual market share in the hands of the biggest retail suppliers.

Figure 1.6 – Number of players with a share above 5% in the retail gas market.



Source: European Commission Energy Datasheet, June 2015

1.3.4 Econometric model

The models we estimate belong to the fixed effects family [2]. The general formulation for fixed effects models takes the form:

$$Y_{it} = \Sigma_j^J \beta_j X_{jit} + \alpha_i + u_{it}$$

Where subscript *i* stands for each individual country, subscript *t* stands for each time period, and subscript *j* stands for each explanatory variable X_j impacting the dependent variable *Y*. Fixed effects models typically decompose the error term into two addends: an individual-specific, time-invariant term a_i, and an individual-specific, time-variant term u_{it}. The term a_i, the "fixed effect" of the model, is treated as an individual-specific intercept, and is computed through the estimation process. Adding this term into the model allows us to exclude any distortion in the estimated b_j parameters due to the omission of country-specific, time invariant variables, on which we might have no information. In particular, in our case fixed effects are most likely to account for structural differences across the countries included in the panel, such as differences in logistic costs between different jurisdictions. As long as we include all time-varying explanatory variables in the analysis, the b_j parameters are consistent estimates of the average impact of a variation in each independent variable on the dependent variable.

Under the general – and quite restrictive – conditions of homoscedasticity and strict exogeneity of the error terms u_{it}, the fixed effects model can be safely estimated by ordinary least squares. After rejecting the validity of these hypotheses through appropriate statistical procedures, we decided however to account for heteroscedasticity, cross-sectional dependence and autocorrelation of the error terms u_{it} by means of Driscoll-Kraay standard errors [14].

We specify two different fixed effects models: one for the residential sector, and one for the industrial sector.

In each model the dependent variable is the mark-up on the relevant consumption segment (*mh* for households, *mf* for firms). The mark-up is defined as follows:

- Mark-up for the household market: *mh = (household price – cost index) / cost index*;
- Mark-up for the industrial market: *mf = (industrial price – cost index) / cost index.*

Tables 1.5 and 1.6 collect information on the average value of the mark-up indexes in the residential and industrial sectors over five-year periods. The mark-up measures the difference between the end-user price and the wholesale cost of the commodity in percentage terms: a mark-up value of 150% suggests, for example, that the end-user price amounts to 250% of the wholesale cost index for the same time period.

It is important to remind here that, given the available data, the mark-up index also includes the costs of distribution and retailing activities that are charged above the wholesale cost of gas. Recent estimates ([1], [19]) show that network costs, which include distribution costs, vary significantly across countries. 2014 figures for the countries included in our panel show, for example, that network cost vary between 12% and 32% of the final household price (including VAT and other taxes and levies), with a cluster of countries showing network costs between 20% and 24% of final household prices. Distribution costs, that are charged to end-users on top of the wholesale cost of the commodity and are hence included in our mark-up index, represent the largest share of total network costs. A comprehensive study [23] based on 2013 data for a wider sample of EU Member States shows that distribution costs paid by households in the same year lied in a range between 0.6 €/GJ and 4.1 €/GJ, corresponding to approximately 3%-23% of the average household price in the same year. Distribution costs for industrial customers are expected to be significantly lower than those paid by households, as a consequence of the fact that industrial consumers are often connected to higher pressure grids. Unfortunately, however, no information regarding the historical development of distribution costs for households and industrial consumers was available at the time of the study. We accept this limitation and account for it in the analysis and interpretation of the results, and rely on the fixed effects structure of the model to correct at least for the time-invariant differences in the magnitude of distribution and retailing costs across countries.

Table 1.5 - Mark-up in the household sector. Source: own calculations on Eurostat, Platts, Bafa, WGI, BP and ECB data

Average mark-up in the household sector	AT	BE	DE	FR	IT	NL	UK	ES
1991-1995			262%					
1996-2000			267%				236%	
2001-2005		159%*	198%	182%*	340%*		104%	189%*
2006-2010		104%	142%	95%	172%	252%	131%	91%
2011-S1 2015	153%	112%	115%	106%	157%	177%	129%	98%
** Starting from S1 2002*								

Table 1.6 - Mark-up in the industrial sector. Source: own calculations on Eurostat, Platts, Bafa, WGI, BP and ECB data

Average mark-up in the industrial sector	AT	BE	DE	FR	IT	NL	UK	ES
1991-1995			126%					
1996-2000			118%				57%	
2001-2005		34%*	90%				26%	
2006-2010		16%	51%	14%	37%	54%	32%	-5%
2011-S1 2015	40%	1%	24%	2%	11%	15%	9%	-2%
** Starting from S1 2002*								

In both the residential, and the industrial model we explain the magnitude and variation of the mark-up index through some or all of the available variables:

- a dummy variable representing the liberalization of the relevant market segment: *liberalization_h* (for the residential market) or *liberalization_f* (for the industrial market), equal to 1 if the consumers belonging to each market segment can freely choose their supplier, and 0 otherwise;
- a dummy variable *regulator*, equal to 1 if there is an energy regulator, and 0 otherwise;
- a dummy variable *trading_point*, equal to 1 if there is a wholesale trading point for natural gas, and 0 otherwise;
- the continuous variable *cross_subsidy*, defined as *cross_subsidy = (household price / industrial price) – 1*. The cross-subsidy index is positive if households pay higher prices than industrial customers, negative if the reverse holds, and zero if both categories pay the same price. Household prices are generally higher than industrial prices in our sample, since they also cover at least higher distribution costs. Hence, we use the index as a proxy of the trends in the spread between household and industrial prices, rather than as an

accurate measure of the magnitude of cross-subsidies across consumption classes;

- the discrete variable *competitiveness*, standing for the level of competitiveness of the retail market, and corresponding to the number of players with a market share above 5% in the retail market for gas;
- a set of control variables, i.e. national demand, production, import, exports, and net imports. A derived variable *import_dependency*, standing for the degree of import dependency of each country, is computed as: *import_dependency = (import – export) / demand*.

The most general formulation of the models we estimate takes the following form:

$$\text{mark\_up}_{it} = \text{constant} + \beta_{lib} * \text{liberalization}_{it} + \beta_{reg} * \text{regulator}_{it} + \beta_{tp} * \text{trading point}_{it} + \beta_{cs} * \text{cross subsidy}_{it} + \beta_{comp} * \text{competitiveness}_{it} + \beta_{imp\_dep} * \text{import dependency}_{it} + \beta_{dem} * \text{demand}_{it} + \alpha_i + u_{it}$$

If the estimated coefficient for the *liberalization* dummy has a negative and significant sign, we can conclude that the opening of the retail market to competition is correlated with significant advantages to the consumers, as the switch from 0 (no liberalization) to 1 (liberalization) is associated to a decrease in the mark-up index, which measures the extraction of consumer surplus from gas retailers. By accounting for all other potential drivers affecting the magnitude of the price-cost index, we are able to disentangle the part of the variation that is due to all the other reform steps and changes occurred in the wholesale and retail gas market.

1.3.5 Results

The household market

The first set of models we estimate relates the mark-up in the household market to the individual reform steps that have been implemented in the natural gas markets of the eight European countries during the time span covered by our dataset. Table 1.7 collects our estimates for the five specifications we tested.

The simplest model, MH_0, includes the liberalization dummy and a constant intercept. The negative sign of the estimated liberalization coefficient suggests that the retail market opening is associated with a strong negative impact on the mark-up. The positive sign of the constant suggests instead that the average mark-up has a positive value, net of the impact of the liberalization: this result is in line with our expectations, as our information concerning the retail prices is not net of retailing and distribution costs. This simple model seems to confirm the hypothesis that the retail market's liberalization reduces, indeed, the ability of retailers to extract consumer surplus through the application of a higher mark-up.

The negative coefficient for the liberalization dummy is however halved in model MH_1, which also accounts for the cross-subsidies and all other reform steps, i.e. the creation of a trading hub and of an energy regulator. According to MH_1, both the creation of an energy regulator, and the development of a trading point are associated with a reduction in the mark-up, whereas the presence of a cross-subsidy from household to industrial players is, as expected, associated with an increase in the mark-up on the household market.

The estimated coefficients remain roughly stable in the other specifications. MH_2 and MH_3 improve on MH_1 by adding two control variables, namely the national gas demand and the import dependency index. The former has a slightly positive coefficient, whereas the latter does not have any significant effect. Although there is no theoretical assumption regarding the impact of a larger gas demand or an increased import dependency on the price-cost margin, it is important to include these two controls, as they provide some time-varying, country-specific information that cannot be captured in the country-specific fixed effect, and whose exclusion could bias the other coefficients.

In MH_4 we try to further improve the specification by including information on the competitiveness of the retail gas market, as measured by the *competitiveness* index. The coefficient for this last variable is negative and significant, in line with the suggestion that a more competitive market tends to yield lower mark-ups to the competing market players. Due to the fact that this index is only available for the years 2003-2014, however, several periods are dropped from the estimation procedure, and the model fit is significantly worsened.

The specification we choose is hence MH_3, which provides significant parameters, coherent with our expectations, and a satisfactory fit, with an adjusted R-squared around 0.415. The values of the MH_3 estimated coefficients suggest that:

- The liberalization of the retail market for households is associated to a reduction of the price-cost margin. Ceteris paribus, the variation is 0.425, significant at a 5% level: this corresponds to an average decrease in the percentage difference between the household price and the wholesale cost of gas around 42.5 percentage points;
- The development of a trading point is also associated with a negative variation on the mark-up: the percentage difference between household prices and the wholesale cost of gas is expected to decrease, on average, by approximately 31.8 percentage points (significant at a 10% level);
- The presence of an energy regulator is associated with the highest reduction in the mark-up: on average, the percentage difference between household prices and the wholesale cost of gas is expected to decrease by 82.8 percentage points (significant at a 1% level). This result has to be interpreted carefully, given the fact that we are not able to disentangle the impact of the dynamics of distribution costs on the price-cost margin. Indeed, the negative and significant coefficient associated to the *regulator* dummy may be linked to the fact that market oversight by a sectorial regulator has led to a reduction in the surplus extraction, but also to the fact that the presence of an energy regulator has led to a decrease in the distribution costs, which are actually subject to regulation in all the eight countries under analysis;
- A 1% increase of the cross-subsidy index is associated to a more than proportional (1.2%) increase in the price-cost margin (significance level 1%);
- The constant term signals that, in the absence of any reform, the price-cost margin is strictly positive. Indeed, as we pointed out when describing the mark-up index as a proxy for the amount of consumer surplus that the retailers are able to extract in the form of a profit, the available data are such that we cannot expect zero profits (or zero price-cost margins) even under a perfectly competitive market, because Eurostat data for retail prices are not net of distri-

bution fees and retailing costs. Although we might expect a decrease in the mark-up index if the regulatory reforms achieve their goals and contribute to the competitiveness of the retail market, a positive mark-up will always be needed to cover distribution and retailing costs.

Table 1.7 – Estimation results for the household market

Y = mark-up in the household market					
Explanatory variable	**MH_0**	**MH_1**	**MH_2**	**MH_3**	**MH_4**
liberalization_h	-0.78***	-0.370**	-0.428**	-0.425**	-0.3534*
cross_subsidy		1.089***	1.185***	1.199***	1.116***
trading_point		-0.385*	-0.324*	-0.318*	-0.3475*
Regulator		-0.770**	-0.841***	-0.828***	-0.704***
demand_TJ			0.001*	0.0005*	0.0003
import_dependency				-0.238	-0.017
competitiveness					-0.018
Constant	2.271***	1.829***	1.195**	1.361***	1.369***
Goodness of fit					
R-squared	0.1378	0.3971	0.4099	0.4153	0.3131
Model features					
maximum lag	3	3	3	3	2
nr of observations	218	199	199	199	155
nr of groups	8	8	8	8	8

** significant at a 10% level; ** significant at a 5% level; *** significant at a 1% level*

The industrial market

The second set of models we estimate replicates a similar analysis for the mark-up that retailers make in the industrial market.

As Table 1.8 shows, the simplest model, MI_0, detects a strongly negative correlation between the liberalization of the industrial market on the one hand, and the mark-up that suppliers are able to get on the other hand, as suggested by the negative and significant coefficient for the dummy variable *liberalization_f*. As in the model for the household segment, the constant term is still positive and significant, confirming our expectation of a positive mark-up.

The inclusion of additional explanatory variables significantly improves the model fit, and halves the magnitude of the coefficient for the liberalization of the industrial market opening. In all the estimated models (MI_1, MI_2, MI_3, MI_4) the liberalization, the introduction of a trading point, and the creation of an energy regulator have a negative and significant coefficient, whose magnitude decreases slightly when accounting for additional time-varying control variables. The coefficient for the cross-subsidy index is instead negative, as expected, but not significant, suggesting that the price-cost margin that retailers make in the industrial market is not affected by an increase or decrease in the difference between household and industrial prices. The estimated coefficients for the control variables demand and import dependency are not significant as well; nonetheless, we retain these variables in the models with the purpose of avoiding the risk of omitted variable biases, in line with what we did for the household models.

The competitiveness index included in model MI_4 has a negative, but not significant coefficient. Its inclusion induces however a worsening of the model fit, as all periods before 2003 are dropped from the analysis. Hence, we retain MI_3 as our preferred specification.

The estimated coefficients of the MI_3 model suggest that:

- The liberalization of the industrial market is associated, on average, with a reduction of 25.2 percentage points in the percentage difference between the industrial price and the wholesale cost of gas. This effect is significant at a 5% level;
- The development of a trading point is also associated with a compa-

rable decrease in the mark-up: on average, the percentage difference between the industrial price and the wholesale cost of gas decreases by approximately 24.0 percentage points (significance level 10%) after the opening of a wholesale trading point;

- The presence of an energy regulator is, again, associated with the highest decrease in the price cost margin; on average, the percentage difference between the industrial price and the wholesale cost of gas drops by around 82.8 percentage points (significance level around 1%). Similarly to what we underlined in the household models, we are not able to disentangle what share of the impact of the presence of an energy regulator is due to a lowering of distribution and retailing costs and what share is due, instead, to an increased competitiveness of the retail market;
- An increase of the cross-subsidy index does not have any significant effect on the mark-up index;
- The constant term is, again, positive and significant, with a value slightly below the one we observed for the household market. This suggests that distribution and retailing costs are still present in the industrial market, but lower than in the household segment.

Table 1.8 – Estimation results for the industrial market

Y = mark-up in the industrial market					
Explanatory variable	**MI_0**	**MI_1**	**MI_2**	**MI_3**	**MI_4**
liberalization_f	-0.499***	-0.229**	-0.257**	-0.252**	-0.264***
cross_subsidy		-0.134	-0.096	-0.089	-0.105
trading_point		-0.269*	-0.243*	-0.240*	-0.257*
regulator		-0.44**	-0.465***	-0.459**	-0.424**
demand_TJ			0.0002*	0.0002	0.0001
import_dependency				-0.133	-0.16
competitiveness					-0.012

constant	0.817***	1.260***	1.003***	1.096***	1.156***
Goodness of fit					
R-squared	0.1676	0.3762	0.3852	0.3922	0.2034
Model features					
maximum lag	3	3	3	3	2
nr of observations	200	199	199	199	155
nr of groups	8	8	8	8	8
* significant at a 10% level; ** significant at a 5% level; *** significant at a 1% level					

1.4 Conclusions

The results of our empirical analysis seem to confirm the hypothesis that the liberalization of the retail gas market is generally associated with a reduction in the spread between end-user prices and the wholesale cost of gas, both in the household, and in the industrial segments. This suggests that in liberalized markets, the fraction of consumer surplus that the retailers are able to extract from both residential, and industrial consumers decreases by a significant amount, to the benefit of the relevant class of consumers.

Our analysis allows us to disentangle from the price-cost margin dynamics the impact of other reform steps, i.e. the creation of a wholesale market and a sectorial regulator. Both the creation of a wholesale trading point, and the creation of an energy regulator are correlated with a sizeable effect on the mark-up index, although in the case of the energy regulator is it not possible to disentangle the share of the effect which is due to a decrease in the regulated distribution costs.

The impact of the individual reform steps on the mark-up is consistent across the two consumption segments, and stronger in the household segment with respect to the industrial one.

Our findings are coherent with previous research for the gas and electricity sector. Our econometric models are not meant to detect causal relationships, but rather correlation values, net of the impact of other relevant variables. Nonetheless, our results tend to support the view that liberalizing the retail market for gas, and hence allowing for privately contracted end-user prices, generates significant benefits for both household and industrial consumers, at least in reasonably competitive markets as those that are included in our panel.

The available information is not sufficient to shed some light on the impact of reference prices published by energy regulators in fully liberalized markets for certain consumption classes that are already open to competition, e.g. the benchmark prices published in order to guide households in the choice among the numerous available offers. These benchmark prices, although published with the aim of improving energy literacy and reducing transaction costs, might indeed favour the clustering of supply offers around the reference level, and thus indirectly hamper competition. As no information was available thereon, however, we were not able to evaluate this measure, nor to compare its outcome with that of the price comparison tools often provided by consumers associations or energy regulators to the benefit of small consumers.

Further research could improve on our results by expanding the dataset to wider set of countries and, where available, better indicators for some key drivers, e.g. the competitiveness of the retail market or the above-mentioned reference prices. Moreover, the availability of long time-series for the distribution costs in each individual country could help disentangling from the variable of interest the impact of variations in the regulated components of the retail price. Finally, the availability of data with a higher frequency would allow for richer analyses, such as those addressing the possible asymmetries in upward and downward variations of retail prices in response to a similar movement in the wholesale cost. A typical case of such asymmetries, often studied in the gasoline market, is the “rocket and feather effect”, that describes the situation in which retail prices rise fast in response to an increase of wholesale prices, and fall slowly after wholesale prices slumps. This is probably the next topic worth analysing in this research area.

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2. OBJECTIVES, ISSUES AND METHODS OF GAS PRICE REGULATION

Sergio Ascari

2.1 From objectives to methodologies

Price regulation is the traditional solution to the market power problem, including its extreme version, where gas is sold by a monopolist in the relevant market. This is the solution addressed in this book, but certainly not the only one. Where a competitive and liquid wholesale market already works, policy makers and regulators[1] often try to boost retail competition. This book does not address the complex issues related to the implementation of competitive markets, which have been the subject of a vast literature, notably in Europe, North America, and Australia.[2] As noticed in the previous Chapter, the debate on whether retail competition can be successfully introduced in electricity and gas markets is still open, and even more open is the answer to the (possibly more relevant) question: whether

1 It is worth recalling at this stage that, in this Chapter, the term "regulator" does not identify a specific legal body or person. It is referred to the legal entity (or entities) that has the power to set, modify or remove gas price controls, within the specific legal framework of each country or jurisdiction. For example, the regulator may be a public utility Commission, a Minister in charge of energy, etc.

2 In the European Union, where competitive wholesale markets have been recently developed, the Council of European Energy has identified the following conditions for a wholesale market to be competitive: (i) a market size of at least 20 Bcm/year; (ii) access to at least three different supply sources; (iii) a Herfindahl-Hirschman Index of supply concentration below 2000. See Glachant et al. (2013), CEER (2015). Within the academic literature, a typical example of the answers to competition difficulties is provided by Joskow (2008) for power.

the remarkable costs that the introduction of retail competition entails[3] are overcome by the benefits of the actual retail competition.

On the other hand, regulators may have different objectives, apart from – and alongside – controlling monopoly or market power, which may be involved in their choice of regulating prices. For example, they may want:

- To redistribute income between consumers
- To curb consumer price inflation
- To attract private and/or foreign capital
- To reduce the environmental impact of energy production and consumption
- To boost the competitiveness of national industry in international trade

A basic economic policy principle reads that one tool cannot in general pursue different goals. Other tools are available to pursue some of these goals, like (e.g.) income taxes, transfers, public expenditure, monetary and policy, capital flow controls, trade standards and tariffs, environmental taxes, emission standards and tradable rights, and others. It is certainly too hard to discuss the best allocation of tools to objectives, as interrelationships and feedbacks are so wide to almost prevent such analysis. In case, the right way of analyzing it would be by means of computable general equilibrium models, which may allow a comparative analysis of several policy tools.[4]

It may worth noting that regulators and international institutions often take for granted that income redistribution is better achieved by the tax and transfer system, that inflation is better checked by monetary policy, and that environmental policies should be pursued by their own tools, preferably pollution taxes and tradable emission mechanisms. Therefore prices, the dominant consensus goes, should be cost-reflective, notably

3 In the EU experience, the highest costs of generalized retail competition where no leading regulated supplier is identified are probably those entailed by the balancing system. In particular, the implementation of retail competition requires sufficiently precise procedures for the metering, allocation and settlement of gas flows transiting common interconnection points, like those between different transportation operators, and the "city gates" where gas is transferred to distribution operators.

4 See Bhattacharrya (2011), Chp. 17 for an overview of these methodologies.

with a view to attract capital, notably foreign capital in poorer countries. Pricing policies that fail to cover costs instead result in *energy subsidies*, which have been the target of long campaigns, notably by major international organization, often supported at national level by independent agencies and management of energy companies.

For example, the IMF (2013) claims that energy subsidies depress economic development in a number of ways, including discouraging foreign and local private investment, crowding out more productive public expenditure, encouraging energy waste and smuggling, and worsening energy related polluting emissions at local, regional and global level. Moreover, it can be shown that energy subsidies are socially regressive, as energy consumption by the rich in most developing countries are more than proportionally higher than the poor's. The deep interest of the IMF into this topic testifies of its general relevance, going well beyond the energy industry. In some countries energy subsidies have overcome public expenditure on key items, like defense, education, or health services.

However, all of these conclusions are not generally valid but should be assessed for each country. For example, the ability to attract foreign capital has often been questioned, as well as the opportunity of providing subsidized electricity as a basic good, or of privatizing its supply, notably in the least developed countries.[5]

A large literature has estimated the benefits of removing energy subsidies in several countries, with generally positive results. A related literature has addressed strategies that are advisable for subsidy removal, given the remarkable public and political opposition that this measure has often met (IMF, 2013; Vagliasindi, 2012).

This book is neither about energy subsidies nor their removal. It will briefly show the basic theory underlying the prevailing view that energy subsidies should be removed, or at least limited to selected groups of more vulnerable customers, but the empirical estimation of the their costs and benefits is to be found in the above cited literature. Instead, this Chapter shows the practical way of actually implementing cost reflective pricing policies.

At the same time, several difficulties of defining a concrete reference

5 On these issues see Wamukonya (2003); Hall, Lobina, de la Motte (2005).

several crucial cost concepts, notably as regards the price of gas resources – as opposed to those of the infrastructure built and operated to produce, treat, haul and distribute the fuel.

Therefore, it is worth looking at other pricing policies, although not strictly cost based, may nonetheless be *broadly* cost reflective and be preferred by policy makers in specific countries, with the reasonable claim that these may even be superior to strict cost reflectivity, and easier to implement. In particular, three such policies are worth mentioning:

1. Regulation after competing fuels: this approach amounts to setting prices at such levels that consumers prefer switching to gas away from competing fuels (mostly oil derivatives, sometimes coal or electricity), but without an excess margin;
2. Regulation at netback value from goods and services produced from natural gas: this approach can be used if the destination industries cater into competitive markets, which is rarely the case. It may happen for electricity and – more often – for fertilizers;
3. Regulation at long term cost: this methodology anticipates cost reductions that may be reasonably expected in network based services.

Theoretically, these policies can be shown as being optimal under certain conditions, notably in the early stages of market development. We will analyze them after cost based pricing policies.

Thus, we assume that the reader entering this Chapter has solved the question of whether to regulate end user gas prices, discussed in Chapter 1, but has already accepted that this is necessary, at least temporarily. Indeed, before we start discussing how to do it and as a final bridge from the previous Chapter, let us notice that the regulator or policy maker may decide to do so:

- On a permanent basis, as no transition towards retail competition is envisaged. In this case, regulation applies to the monopolist in the relevant jurisdiction (town, district, state, country, etc.);
- As a near-permanent measure, ensuring the protection of customers while retail competition is encouraged to develop and achieve better prices. This is the typical case of regulated prices for *suppliers of last resort*, which in turn are often the former monopolists (*incumbents*).

In such cases, competitors are allowed to challenge the regulated prices and usually (but not always) incumbents may react. A price control holds at least for the latter, but its relevance is expected to diminish over time, as consumers turn to competitive supplies;

- As an explicitly temporary measure, in case retail competition is being introduced, with a view to protect customers during the transition, but with a clear expectation that caps will be lifted after a predetermined period, or when sufficient competition has developed.

These different setting do in fact have their consequences on how to regulate prices. However, these differences are more in the regulatory practice than in the most general theory. We now move to the theoretical part of the study, but the differences entailed by the various competitive framework should not be neglected and will be discussed in the following sections, where necessary.

2.2 The basics of optimal pricing theory and its practical meaning

Whenever gas price control is suggested as a solution to monopoly or market power problems, economists have consistently suggested that prices should be aligned with the marginal cost of supplies, which is the cost of providing further (new) supplies. This results is presented in nearly all economics textbooks, and can be also understood as the suggestion that regulation should as far as possible imitate the outcome of competitive markets.

In a competitive, unregulated market, as shown in the well known graph of Figure 2.1, the equilibrium price P^C would prevail: the (inverse) aggregated demand function[6] would cross the aggregated supply curve[7] at a price equal to both the marginal cost, and the average cost of production.

6 The inverse demand function expresses the solution to the consumer's utility maximization problem as a relationship between the demanded good's price and the desired quantity of the good.

7 The aggregate supply curve is the horizontal sum of the individual firms' supply curves, which in turn represent the solution to each firm's profit maximization problem. As a necessary condition for profit maximization states that the marginal revenue must equal the marginal cost of production, the supply curve coincides to the portion of the marginal cost curve that lies above the average cost curve. The last statement must hold since any firm selling its product at a price below its average production costs would incur a loss, and would eventually leave the market.

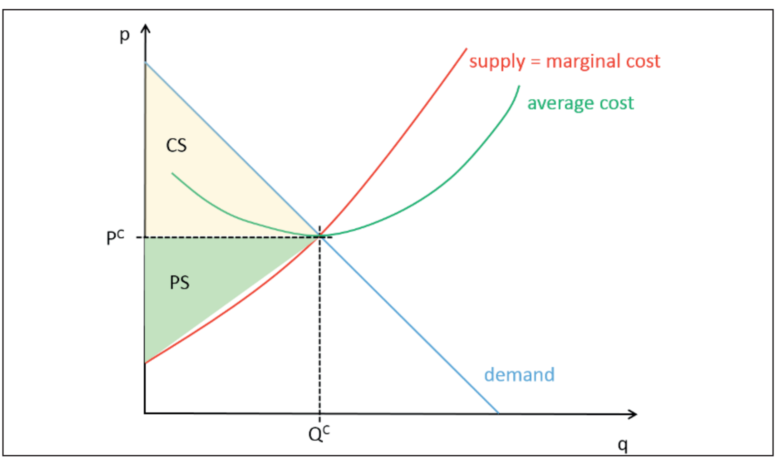
Since the marginal cost function always crosses the average cost function at its minimum[8], the competitive market equilibrium ensures both productive efficiency, as the average cost of production is minimized, and cost coverage, as the unit price is always equal to the average production cost. Productive efficiency is ensured because if the unit price were higher than the marginal cost of production, than the active producers would make positive profits, new entrants would be lured into the market, and the equilibrium would adapt to a lower price level. At the same time, firms with average costs higher than the equilibrium price would not be able to compete and should exit the market, so that only the most efficient producers could survive. Similarly, cost coverage is ensured because if the equilibrium price were lower than the average cost of production, then some firms would exit the market, supply would decrease and a new equilibrium with a higher price would be set. The equilibrium market price also represents the *opportunity* cost of the resource or the value that gas is given by consumers. This is often a fairly generic concept in economics, but in energy economics it often has a clearer meaning: since an energy product is usually interesting for its energetic (or calorific) value. Therefore, the market value (and hence the demand) of natural gas is related to the price of producing the same useful energy by alternative fuels, notably oil derivatives, coal, or electricity. This has long affected market pricing criteria and contractual formulae, and still affects several markets.[9]

8 The intuitive reasoning behind this fact is the following. The marginal cost corresponds to the cost of producing one additional unit of the good, given the production level already reached, Q. If the marginal cost of production is above the average production cost when the firm produces quantity Q, any unit produced above Q level would cost more than the previous unit: hence, if the firm should expand its production beyond the level Q, the average cost of production would increase. By a symmetric reasoning, if the marginal cost of production is below the average cost when the firm produces quantity Q, then any unit produced above Q would cost less than the previous unit, and by increasing production by one additional unit beyond level Q the firm would actually decrease its average cost of production. Hence, if for quantity Q the marginal cost equals the average cost, any variation from the Q production level determines an increase in the average production cost: hence, the marginal cost curve can only cross the average cost curve at its minimum.

9 In fact, the value of o fuel in terms of its pure calorific value is hardly the only relevant decision factor. The opportunity cost of a fuel is also affected by related factors, like the associated costs (e.g. for operation, maintenance, environmental protection, storage, appliance conversion) and the quality of derived products, which is often higher for gas than for other fossil fuels (but lower than for electricity). Yet, once the equilibrium between the value of different fuel is defined in a certain market, it can remain stable for several years, hence the indexation of gas price to other fuels in case of interfuel completion is justified. See below, section 2.9 for more on this logic.

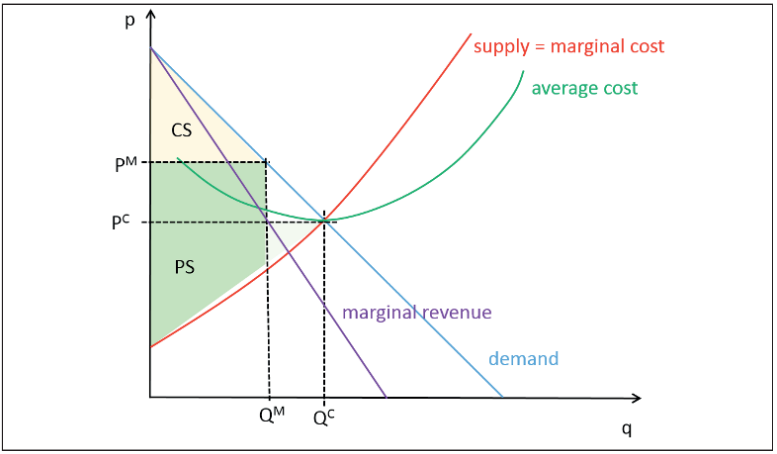
In this graph, economists notably point at two values: the "consumer surplus" (CS), which is represented by the area below the demand curve and above the market price equilibrium; and the "producer surplus" (PS), which is the area below the market price equilibrium and above the supply (marginal cost) curve. Consumer surplus can be defined as the extra value individuals receive from consuming a good over what they pay for it, or equivalently what people would be willing to pay for the right to consume a good at its current price. Producer surplus can instead be defined as a measure of the extra value producers get for a good in excess of the opportunity cost they incur by producing it, or as the amount that all producers would pay for the right to sell a good at its current market price. The sum of consumer surplus and producer surplus, corresponding to the shaded area between the demand and supply curves, is called aggregate or social welfare: its maximization is generally the target that policy makers and regulators try to reach if the market is not competitive and an external intervention is needed. Figure 2.1 intuitively shows, indeed, that a perfectly competitive market spontaneously maximizes the sum of producer and consumer surplus: this is not the case, however, if competition is distorted.

Figure 2.1 - Outcome of a competitive market



However, in markets that are dominated by a reduced number of suppliers (and even more if by a single monopolist), it is likely that the pricef is set at a higher level P^M (Figure 2.2). In this case, indeed, profit-maximizing producers, such as pure monopolists, participants in a cartel, or large market players abusing their dominant position, would try to set prices above the average and marginal cost of production, in order to exploit the reduced competition and earn a positive profit.

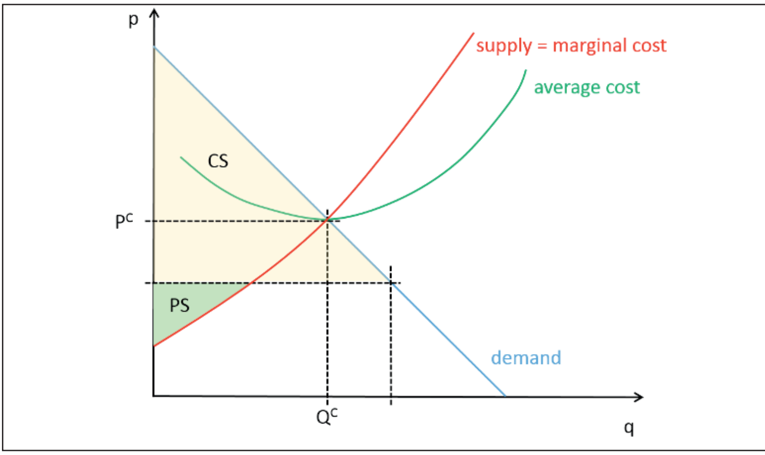
Figure 2.2. Outcome of a monopolised market



Conversely, in a market that is regulated by a public authority on behalf of consumers, it is possible that the price is set below the equilibrium competitive price, for example at a level that is too low to cover the average production cost (P^R). In this case, the producer would just cover part of its total costs, usually their variable component: this equilibrium can only be sustained if either the policy maker subsidizes production through general taxation, or the producer exploits cross-subsidies across the different markets it is serving. In the natural gas case, this can happen if the producer internally cross-subsidizes more costly resources (gas fields, producers) by cheaper ones.[10] In this way, the consumer surplus is maximized, but consumers' gain are outweighed by the loss of producer surplus, hence total social welfare is not maximized (Figure 2.3).

10 This has indeed happened in the U.S. under wholesale price regulation. See above, section 2.2.8.

Figure 2.3. Outcome of a market with equilibrium price below the average



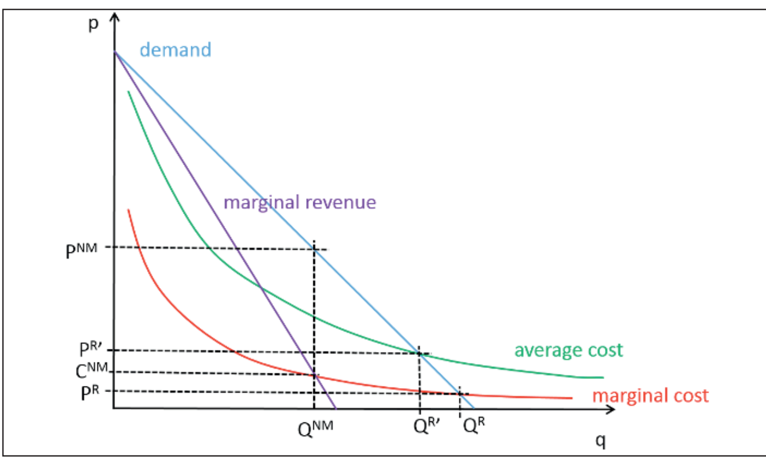
From a purely theoretical point of view, price regulation should be introduced for two main reasons: either when the competitive structure of the market is such that perfect competition cannot display and lead to its typical optimal outcome (e.g. because a small number of big competitors create a cartel or barriers to entry); or because the cost structure of the industry is such that a natural monopoly is in place, at least given the size of the market.

The case of the natural monopoly gives interesting hints for the topics that are addressed in the rest of this chapter.

A natural monopoly arises when the productive structure of the industry shows increasing returns to scale: the larger the quantity produced, the lower the average production cost, as it may happen, in practice, in those industries that show very large fixed costs. In this case, the entry of new competitors would actually decrease productive efficiency, since small firms would not be able to achieve a cost level as low as that of a single, big producer. The presence of one single producer, i.e. a monopolist covering the whole market, is indeed the best solution under the productive efficiency point of view.

Figure 2.4 shows the typical market structure in the presence of a natural monopoly, and the problems that price regulators face under this hypothesis. The profit-optimizing monopolist would ideally produce the quantity Q^{NM}, for which the profit-maximizing condition "marginal revenue equals marginal cost" is satisfied. However, the monopolistic market equilibrium defined by quantity Q^{NM} and price P^{NM} yields a loss in terms of consumer surplus: the monopolist earns a positive profit equal to the difference between P^{NM} and C^{NM} on each unit sold, and the consumer surplus is reduced, as the equilibrium price is set above its optimal level (i.e. the marginal cost) and the equilibrium quantity is smaller than the optimal level. This situation calls for price regulation, in order to restore the allocative efficiency that the monopolist has altered. On the other hand, if the regulating authority sets the price P^R at a level equal to the marginal cost - a condition that ensures allocative efficiency in a perfectly competitive market, then, in a natural monopoly - the producer cannot recover its production costs, as the average cost for the corresponding production level Q^R would be higher than the (regulated) price. A second-best solution for maximizing social welfare, while ensuring cost coverage, is setting the regulated price at level $P^{R'}$, i.e. a level that ensures the recovery of the average production costs.

Figure 2.4. Market equilibrium under a natural monopoly



Economists criticize both the monopolistic pricing, and the average cost pricing solution. In case a regulated price is necessary, they recommend regulating near the marginal cost of supplies, which is in practice (for gas supply) the cost of the marginal fields or imports, usually those that enter the market at a later stage. Several countries (or other jurisdiction) start their gas market by using own domestic resources but are later forced to become importers due to falling reserves, inadequate investments production and/or booming demand: in such cases the marginal resource would "make the price" in a competitive market and represent the true cost of more gas supplies at the margin is imported gas. Since, even in buyer market conditions like those of mid-2010's, the price of imported gas is nearly everywhere higher than the cost of domestic one, the theory would recommend substantial gas price hikes as a consequence of imports, a suggestion that is rarely accepted by regulators (at least in the short term).

In general, the reasons why both the monopoly and the average cost pricing are criticized are twofold. In the short term, both such solutions would not maximize the total (consumer and producer) surplus, which is a measure of total welfare. There would be a "welfare loss", also known in the literature as *deadweight loss*. Whereas this argument is true in principle, what really matters is the size and meaning of the deadweight loss. Therefore, this point has often been overwhelmed by other arguments, notably: (i) the distributional impact that may be achieved through lower energy prices; (ii) the opportunity to foster the development of national or local industries; and more recently (iii) the case for an accelerated role of natural gas in the energy transition that is required to contain global warming.[11]

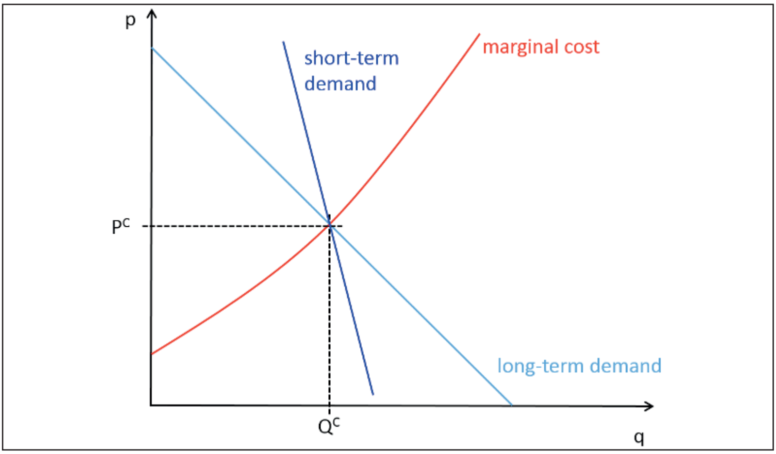
In the long term, the adverse consequences of wrong pricing are much more serious. In fact, energy demand is normally rather price-inelastic in the short term. In other words, demand does not react significantly to price changes. This is true for electricity[12], and a little less true for gas and oil products. However, in the long term, when consumers and producers have had the time to adjust their facilities and appliances, things differ

11 Griffin and Steele (1980:Chp. 8) present an example of these calculations for the US after the oil price hikes of the 1970's, showing that the deadweight loss of oil price controls and the related import limitations could be estimated to about 6 billion US$ (in today's money), or about 0.03% of US GDP.

12 The traditional view of an almost inelastic demand for electricity in the short-term could indeed be challenged by the recent spreading of smart technologies, that could enable load shifting and demand response among small-sized consumers as well. The expected magnitude of demand-side reactions to price variations is questioned by researchers, but this topic is expected to gain increasing importance in those countries where volatile renewables are adopted on a larger scale and the energy transition is already being implemented.

(Figure 2.5). For instance, if the gas price is high, a power generator is likely to push more on other energy sources and/or to introduce more fuel-efficient technologies, but it takes time to achieve it. Commitment is also important, as major investments are unlikely if prices are seen as temporary.

Figure 2.5. Market demand long term and short term

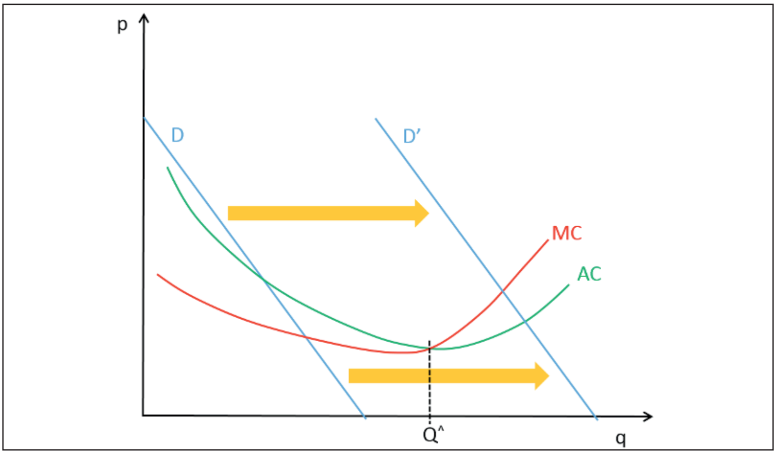


Conversely, if the price is regulated at a level that is too low for new developments, like the "average cost", the market could be rationed on the supply side. An example of this situation is depicted in Figure 2.5, which shows what may happen under significant demand increases. When both the marginal, and the average cost functions are increasing (for production levels larger than Q^), setting regulated prices at the average cost level would actually hinder the development of new capacities. This may happen both under natural monopoly conditions (as it typically happens in gas transportation and distribution) or under normally decreasing returns, as it normally the case of production, storage, and the LNG industry. The natural monopoly problem arises, in general, every time the average and marginal cost functions are steadily decreasing within the relevant market size, as it is the case, in Figure 2.6, under the (inverse) demand function D. Sometimes even under a natural monopoly, if the demand for the relevant good experiences a significant increase, as shown in Figure 2.6 with the rightward shift from demand D to demand D', then the natural monopolistic features of the market are lost. For example, a large, low cost production field may monopolize a market, but lose this property as demand increases and smaller and costlier fields are required to match it.

In such case, if prices are regulated after the cost of the larger field, companies would probably refrain from developing new fields, which are typically costlier than older ones. International companies have the option of investing their development resources in other, more profitable basins, and are likely to do so. That would reduce investment in the country, jeopardizing further production, or forcing state owned companies to cross-subsidize the development of new fields by older ones.

In fact, even state-owned companies are typically reluctant to invest in such situations: they know that their need for subsidies is bound to increase if the economy (and hence the main demand factor) is on the rise. However, as older fields are depleted, more subsidies are needed to cover the costs of marginal ones, and the state is likely to delay the award of new subsidies as competing public finance needs present their cases. Hence the reluctance of the NOCs to invest (unless in very rich countries).

Figure 2.6. Scale economies under changing demand conditions



To understand what this mean in practice, it is worth departing from a pure theoretical analysis and anticipate a short description of two practical cases, which are discussed in more detail in Part II.

The first such case is New Zealand, a relatively small market (between 4 and 6 Bcm/year) that has long suffered from dependence from a large single gas field. In fact, the large offshore Maui field was able to almost monopolize the market after its development, and the market was not large enough to develop more. Therefore, its price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years. This blocked the discovery of new reserves, and the reserve/consumption ratio fell from 14.6 years in 1997 to 7.4 in 2002, when the cap was eventually lifted. Demand kept increasing, peaking at 5.9 Bcm in 2005, but growing prices and lack of available reserves saw consumption falling to its historical minimum of 3.6 Bcm in 2005, and only slowly recovering after that.

A second interesting case is Egypt, where the wholesale gas price has long been fixed (for most gas production) at the level of $2.65/MMbtu. Such price was reasonable for some time but came to be regarded by international oil & gas producers as too low for the development of new deepwater fields, and production stalled after 2009. At the same time, gas has been sold at heavily subsidized prices to the internal market, notably to the power generation sector, which covers about 65% of the market. At the same time, Egypt, like other countries that are mentioned in the next section, has been unable to raise domestic prices, with few exceptions. Subsidies were growing with consumption, which increased by over 7%/year between 2002 and 2012. This led to a huge imbalance, which has eventually forced Egypt to suspend all its exports, even in break of contractual obligations, in spite of its huge reserves. Only recently, some new fields have been awarded higher prices, but the positive consequences will not appear for several years. Since consumer prices have not been raised for most sold gas, the subsidy burden on the State has boomed, and is regarded now as unbearable.[13] Costly LNG imports have been activated but this has not avoided gas rationing, and the ensuing power shortages in the peak consumption months.

13 Among countries described in detail in the second part of this book, other similar cases are found in Argentina, Algeria, and to some extent also in China, India and (in the past) the United States.

Generally speaking, regulated prices below marginal cost or market levels are most feared by international producers, who are often more aware than governments of the unsustainability of subsidies as well as of the political difficulties of lifting them. Hence, the issue of removing (explicit or implicit) energy subsidies has become a major concern of many governments, as well as of world environmental policy for negative impact on emissions. A number of countries have been struggling to lift prices towards levels that are necessary to boost new exploration and production. A few examples are reported in Part II (China, Egypt, India, Nigeria, Russia).

The above theoretical cases are based on the assumption that the market is transparent, so that a single price prevails.[14] On the other hand, the typical solution for buyers in case they feel to be under a market power by producers is by forcing *price discrimination*. If buyers can pay different prices, in relation to the marginal costs of supply, all producer surplus can in principle be transferred to consumers (and/or to the State). However, to achieve this it is necessary to have either a single buyer, which is the most typical solution (Algeria, Egypt, Nigeria, and others) or by regulating the prices at different, cost based levels (Argentina, China, India). Yet, this approach does not necessarily solve all problems, as producers must get a sufficient return to incentivize them to keep investing in the country. Whereas previous (sunk) investment may lead governments and regulators to expect them to keep producing in the country, competition between countries (and other jurisdictions) may yield different outcomes. The cases of Algeria, Argentina, New Zealand and (in other periods) even Russia and the United States show that the risk of loss of investments, and hence of production decline, should not be underestimated.

2.3 Optimal pricing solutions.

In general, economists recommend that, if prices ought to be regulated, they should be set at the level of marginal cost. A large academic literature has analyzed this concept, mostly focusing on electricity, which is of some use for natural gas distribution, provided that the different relevant

14 This means that the same price obtains for similar services. The price could be actually differentiated by time of the year or day, quality of service, location, or size of the consumer.

cycles are considered. However, the key concepts are very relevant for upstream as well, as we see shortly. Good summaries for electricity are in Greer (2012), Turvey (2000). The key issues are:

(i) The relationship between long run marginal cost (LRMC) and short run marginal cost (SRMC);
(ii) The relationship between marginal and average cost.

LRMC is the cost of increasing supply by a unit when there is no spare production capacity, hence it includes the cost of expanding the capacity. From a practical perspective, there are several loopholes in this concept, which the regulator may have to deal with. In fact, some spare capacity is often available, therefore there are often consumers or users claiming that increasing supply does not require any new capacity, so that the right price is the SRMC. However, this amounts to excluding almost all capital cost from the price, which means that capacity costs are not covered.

The simple textbook example of such case is an industry where the cost function can be described as follows:

$$C = F + v\,Q \qquad (1)$$

Where C is total cost, F is a fixed cost that is independent of actual production, v is the variable cost of production, and Q is production. In this case, the marginal cost is v, but if price is set at such level, i.e. if:

$$P = v$$

Then it is clear that price falls below average cost, fixed costs are not covered and the company would lose money. It is easy to understand that this would lead to the flight of any private capital from the regulated industry. This case, though very simple, may be assumed to recall the typical situation of natural monopolies, like energy and gas networks. If networks are not unbundled and separately regulated, integrated gas supply may also fall into the same problem.

Some economists, claim that even in such cases it is optimal to set prices at the marginal cost level, and cover the gap by means of public funds (or taxpayer subsidies).[15] However, this solution raises eyebrows, especially among policy makers of developed countries, where the idea of raising taxes or issuing public debt in order to subsidize the energy industry is hardly popular. [16]

In order to maximize welfare but avoiding any cross-subsidization from taxpayers (or other industries), economists have long proposed the concept of optimal pricing to be declined in such way to cover corporate (or industry) costs. The basic idea is to create the lowest distortion of resource allocation that is necessary to cover costs, by setting prices above marginal cost (*Ramsey pricing*).[17] The key concept is to charge higher prices where the price impact on demand (elasticity) is *lower.* The intuition is that, where demand elasticity is lower, consumers are ready to pay more for the good, and their consumption will be affected less. This solution is interesting wherever more goods are produced by the same cost functions or in the case (more interesting for this book) that gas can be sold at different prices to different classes of consumers, even if costs are the same.

Formally, optimal price discrimination is generated by solving the problem:

$$\text{Max } U(q_1, \dots q_N)$$
$$\text{s.t.}$$
$$p_i = p_i\,(q_i) \text{ for } i = 1, \dots N \qquad (2)$$

and

$$C \leq \Sigma_i p_i q_i \qquad (3)$$

15 For example Lucas and Muehlegger (2010), in spite of commenting on a broadly liberalized market, where a similar call on public funds seems rather unlikely.

16 In a more academic language, it could be said that the marginal cost of public funds is seen as higher that the welfare cost of increasing prices above marginal costs.

17 This solution was proposed by Baumol and Bradford (1970), but it basically follows the same approach that was proposed by Frank Ramsey in 1927 to address the problem of a multi-product monopolist and is also known for its application to optimal indirect taxation.

Where

- there are N separate customers (or customer classes)
- p_i (q_i) is an inverse demand function (as depicted in Figures 2.1 – 2.5 above).
- C is total supply cost

Optimal prices p_i* are higher than marginal costs to cover the fixed cost F, and the required uplift is shown to be proportional to the inverse elasticity of demand:

$$p_i^* = v + \mu \frac{\partial p_i}{\partial q_i} \frac{q_i}{p_i}$$

Where is a Lagrange multiplier associated with the cost covering constraint (3). Price discrimination is a well known topic of monopolistic behavior, widely discussed in microeconomics textbooks, like Varian (2010: Chapter 25). In fact, the more precise the discrimination, the better is the resource allocation.

However, Ramsey pricing is not always popular among energy regulators. In fact, regulation is not normally aimed only at efficient resource allocation, and even less at the distributional impacts of pricing. Price discrimination is often seen as “unfair” even if efficient and could be challenged in courts as inconsistent with general and specific principles of equitable cost sharing among customers.

Furthermore, the distributional impact of efficient price discrimination may not be politically desirable. In the natural gas case, suppose that the supplier can discriminate between households, industry, and power generation. It is likely that households have a less elastic demand than industry, and even less than power generators, because they have less fuel switching chances. Therefore, a discriminating monopolist would overcharge their prices[18], which is probably not what regulators would like. For these reasons, Ramsey pricing is not likely to be an explicit regulatory choice.

On the other hand, some forms of Ramsey pricing may be implicitly practiced in the world of regulated gas pricing. One solution is for the regulator to set an average regulated price level and allow the supplier to set (or propose) price levels, for example defined by consumption blocks or including some standing (fixed) or price blocks.[19]

Another approach that yields similar results is to allow pricing in relation to competing fuels. Since gas demand is related to its price towards competing fuels, this can be a seen as a way to follow demand elasticities. For example, prices (excluding transportations and distribution costs) could be lower for power generators than for the steel industry in relation to the different prices of substitutes. Here we see that approach of pricing gas after substitutes is not only useful to promote natural gas for social and environmental reasons, but it could be also consistent with economic efficiency. This option is not necessarily cost-related and is discussed in more detail in section 2.8 below.

Despite these cases, regulators often prefer to refer to costs as the basis of their pricing decisions, and in several cases are bound to do so by their statutes or by other legal obligations[20].

The typically used cost concept is LRMC, which includes all capacity costs.

Energy industries, including the exploration, production and transportation of natural gas, are capital intensive industries, where labor input is limited. Moreover, most labour costs are actually part of capacity costs and often cannot be cut even if production is temporarily suspended. Therefore, variable costs in the gas industry are usually limited to own consumption of energy and raw materials, which are necessary for the operation of plants.

In gas production, variable costs are a rather limited share of the total,

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19 Price structure issues are mostly related to the network components of tariffs and prices and therefore beyond the scope of this book. See Greer (2012). For a description of actual distribution tariffs in the E.U. see AF-Mercados et al. (2015). It shows that block tariffs, based on annual consumption, are the most common approach for small customers in Europe, whereas for larger end customers a capacity term also often applies. Objective criteria are rarely used for the calculation of block tariffs and standing component, therefore it is likely that distributors and dominant suppliers follow market preferences in the definition of market structures, rather than costs.

20 For example in the EU, Directive 2009/73 requires the avoidance and cross subsidies between different stages of the value chain and the remuneration of efficient investments. Regulation 715/2009 (Article 13) specifically prescribes that tariffs for access to networks "reflect the actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator and are transparent, whilst including an appropriate return on investments". In the US, regulators normally include prudently incurred costs in the rare base.

typically less than 10%. A higher share is found in gas transportation, notably where liquefaction is required, but rarely exceeding 20% even in high price times. On the other hand, the variable cost share of pipeline transmission and distribution is also tiny, usually less than 5%.

In practice, SRMC generally coincide with variable costs, for example gas transmission losses, fuel gas of compressors where necessary, and own consumption of supply facilities. There may be cases where this does not apply, for example where for some reasons supply falls short of demand, so that it is necessary to expand capacity to cope with demand. This case is neither common nor easily matched in gas supply.

An important part of the literature on marginal cost pricing considers its impact in network industries. The transmission and distribution of electricity, gas, water as well as telecommunication networks, roads and railways have a typical and peculiar cost structure, with remarkable economies of scale. In these cases, an increase of delivered services often leads to diminishing average costs. This is indeed a key reason why such industries cannot stand competition (except in special cases, notably in very large markets). Indeed, they fall in the category of *natural monopolies* (see Figure 2.4 above). Pricing in these industries can be tricky as pricing at LRMC is lower than the average cost (AC), so that either the marginal cost pricing rule is abandoned or some subsidy must be provided to cover losses. Again, these issues are only mentioned here to avoid misunderstanding but are fortunately hardly relevant for gas supply - even if they are for domestic transportation and distribution.[21]

On the contrary, natural gas supply into a market, either from domestic production or from imports, is no natural monopoly. In principle, different suppliers can compete. Market size is obviously very important, as larger markets are more likely to be competitive. However, the case of New Zealand (Part II, Chapter 18) shows that even at just over 3 Bcm/year a market can be competitive if supply is sufficiently scattered. In fact, monopolistic conditions may arise because a single supplier may be so large that he can cover all market demand at the best prices, so that no competition occurs: a few such cases will be shown in Part II. In this case, some type of regulation is necessary.

Before considering the practical meaning of LRMC in gas supply, let

21 These issues are abundantly treated in public sector economics textbooks, like Tresch (2008) or in more specific electricity economics books like Greer (2012).

us finally recall that a substantial part of marginal cost pricing literature is devoted to the problem of pricing supplies against a *cycling* demand: for example, demand for electricity and gas networks services follow daily, weekly and annual cycles, entailing rather different supply costs along the cycle. In these cases, application of marginal cost pricing can be complex.[22] Again, this is hardly a problem in gas supply, even though a perfectly isolated, monopolistic market may reasonably consider some time of use pricing rule. However, such cases are not common in this world, and the tendency is towards international market integration rather than isolation.

2.4 Marginal cost pricing in practice

Let us now move towards regulatory practice, and describe the typical way regulators address cost based tariffs. This is the practical equivalent of the LRMC concept.[23]

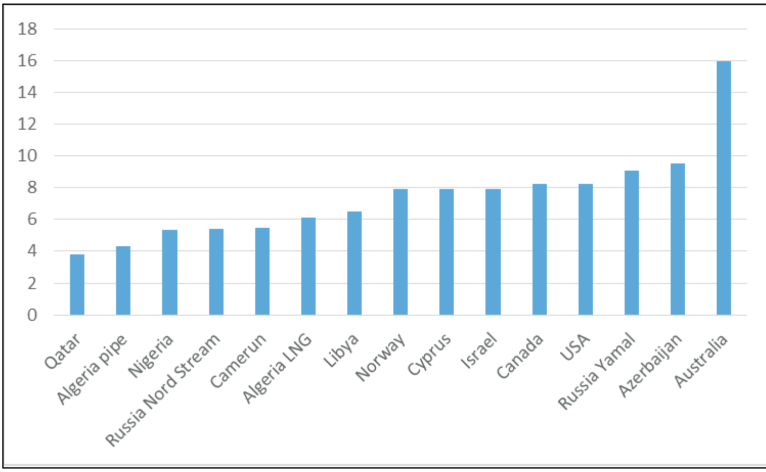
In the following, some readers may be puzzled by the fact that the "marginal" part of the concept seems to disappear, so that someone in the regulatory business may think that the "marginal" is just a theoretical "decoration". However, we will see that the choice of a LRMC concept (rather than for example an average cost concept) is in fact crucial for gas supply.

In gas supply, each market or jurisdiction normally faces several – domestic or foreign - suppliers, characterized by different cost levels. Many practical studies present examples of consistent (*levelized*) cost estimations for different supplies, as in Figure 2.7. Marginality typically refers to the highest cost, which is logically purchased last, as necessary to match market demand. Thus, the LRMC is the calculation of costs for the marginal gas *source* (domestic or imported). Accordingly, to follow the marginal cost pricing rule amounts to select a marginal supply *path*, which will then be used as the reference supply chain in all its components. If market fluctuations make the choice of the marginal supply source uncertain, a pool of marginal supplies could be identified (e.g. all imports, LNG imports, imports from a certain region etc.).

22 The typical approach is to charge capacity costs to peak periods. In the gas industry, the seasonal cycle is the most relevant one. Daily or weekly fluctuations can normally be addressed by changes in line pack, storage or production, with limited costs.

23 For more on these topics see Turvey (2000).

Figure 2.7. Estimations of long-run marginal costs for supplies to European borders ($/MBtu)

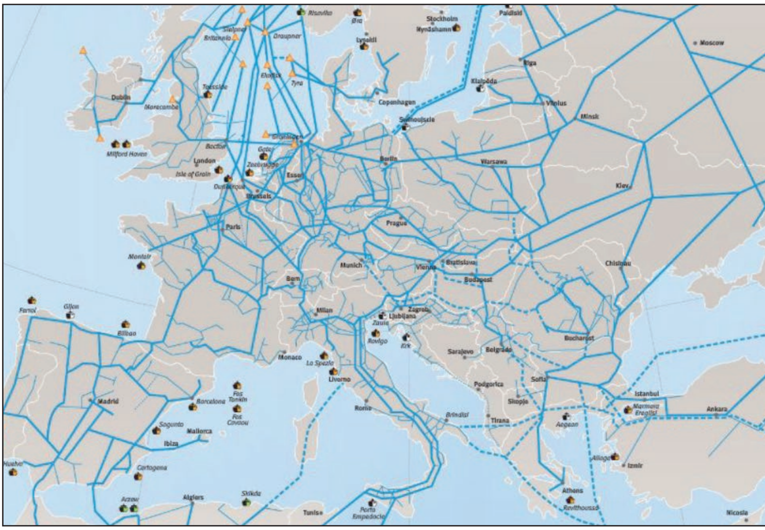


Source: REF-E/Mercados Study for GME, 2013.

The principle of long run marginal cost pricing refers not only to the inclusion of costs that must be borne to ensure that supplies can be obtained in the long run, that is including all capital costs needed to sustain supply capacity. It also means that supplies are those that can reasonably be assumed to be necessary in the long run. For example, the inclusion as reference marginal supply of temporary LNG imports by a country that is normally self-sufficient may not be a reasonable estimate of its marginal costs. On the other hand, taking the average of all supplies, including cheap domestic production that are clearly not sufficient in the long run, would not be consistent with the LRMC principle.

Figures 2.7 and 2.8 provide a (rather stylized) example of how this problem could apply for Europe. In fact, the solution recently adopted in Europe do not require such choice by regulators (see Part II, Chapters 10-12), but the problem may be serious in other regulatory frameworks.

Figure 2.8. Supply paths for Europe: which one is "marginal"?



Once the marginal supplies have been identified, in the common regulatory practice the price is set as:

$$P = AR / Q$$

where AR is the allowed (or "required") revenue of the supplier and Q is the relevant quantity. The denominator (Q) is normally defined as forecast, possibly subject to correction after actual data are available. Let us however focus on the AR.

The Allowed Revenue is normally defined as:

$$AR = RAB * RoR + DEPR + OPEX$$

Where:

RAB = regulated asset base (capital) = Gross RAB (GRAB) – cumulated depreciation

DEPR = annual depreciation

OPEX = operating cost

RoR = rate of return

Each of these components must be analyzed. However, to understand the issues of gas supply pricing, it is necessary to distinguish between two fundamental types of assets, and their related costs:

- Infrastructure, which is essentially a collection of industrial products that can in principle be replicated: wells, rigs, treatment plants, pipelines, etc.;
- Natural gas in the fields, which is essentially a natural good and cannot in principle be replicated (even though some more can be found).

We should therefore split the above definition as follows:

$$AR = AR_i + AR_g = (RAB_i * RoR + DEPR_i + OPEX_i) + (RAB_g * RoR + DEPR_g + OPEX_g) \qquad (4)$$

Where the suffix *i* indicates industrial infrastructure and the suffix *g* refers to natural gas extracted from the ground. As we will see, the treatment of these two classes of assets must be rather different. In fact, attempts to treat natural gas in the same way as industrial products incurs into remarkable difficulties, which have been at the root of important regulatory failures in the past.

The next section is devoted to the infrastructure part of the allowed revenue calculation. It will briefly summarize the typical modern regulatory practices, paying some particular care to criteria that are applicable to the gas upstream (Exploration and Production, or E&P) industry, and to the emerging and developing countries where most of such production currently occurs and the need to regulate is more common[24].

The following section will show the difficulties of applying the principles of cost based regulation to natural gas E&P, but also (where relevant) to supplies of imported gas, where the same issues apply even though they are apparently located in producing countries. In fact, oil & gas assets are producers' most important assets (PWC, 2011) and this is just another justification for their different treatment.

24 In Europe, North America and the Pacific countries of the OECD, competitive markets are more common so that regulation of gas prices is less frequent.

We will finally suggest different approaches, which are more practical and may inspire regulators of jurisdictions where gas price regulation is required.

2.5 Valuating costs of industrial infrastructure

This section evaluates the allowed revenue that covers costs of industrial infrastructure required for gas supply. In case the evaluation is based on domestic production, these assets include:

- exploration and appraisal investment, including test wells;
- production facilities
- treatment plants
- dedicated storage capacity
- pipelines connecting gas fields to treatment plants and the latter to the market.

We assume that the regulator has identified a marginal cost supply chain. In the case of importing countries, the reference supply is likely to be imports, or a selected import source. Once the marginal source(s) are defined, all infrastructure valuations should refer to them. However the regulator may also consider an average cost approach, including imports, even if this is not recommended for reasons illustrated in section 2.2 above[25]: in such case all supply routes will be considered and an appropriate (weighted) average will be calculated. For imports, the shares of pipeline and/or LNG transportation may be much higher, except in case imports are from a neighboring and relatively close origin[26]. Therefore, shares of the infrastructure component of final price is certainly higher for importing countries, the higher the farther gas travels.

25 As noticed in section 2.1, regulators are not likely to accept this approach, at least overnight, if a country moves from self-sufficiency to exports. See section 2.5 for further discussion.

26 Examples of such close trades could be exports from Norway to Britain, or from Qatar to the UAE. Full costs of long distance transportation may vary between 1 $/MMBtu for pipeline distances of a few hundreds and 4 $ for distances of 3-4000 Km, like the connections between Siberian fields or the Caspian and Central Europe. For LNG transfers costs vary between 3 and 9 $/MMBtu for distances between 500 and 5000 nautical miles. The reader may notice that the highest values of the range actually exceed the wholesale price of gas that prevails in 2015 in Europe as well as in North-East Asia.

The reader may think that the valuation of regulated assets is just an application of ordinary accounting principles and that the relevant methodology can be found in valuation handbooks. However, the intention of regulators is often different from that of the company's accountants. The main objective is less to offer investors the most objective information about the company's financial status and performances than to calculate supply costs that convey the right message to consumers, with a view to resource allocation: in particular to calculate the marginal (or in some cases, the average) cost.

Moreover, in general, the valuation of assets amounts to finding their most appropriate market value, but in the case of utilities such assets are often not separately tradable. Therefore, the valuation of assets by special methodologies (other than market value), which is not commonly used in accounting, is often necessary. This methodology is known as *depreciated replacement cost*[27]. Yet, a key accounting principle always applies: the search for the best approach of defining the replacement cost of the assets, which is indeed the best estimation of the marginal cost that should be paid (eventually) by consumers to obtain their services.

For utility asset valuation, regulators normally consider the following main approaches:

1. Current cost. It amounts to reevaluating the original cost data by means of a suitable cost inflation index. This yields the current equivalent of the original value of the asset. However, to obtain a current value, depreciation of each asset should be also considered. Assuming linear depreciation along the useful life of each asset (UL), this approach amounts to the following calculations:

$$GRAB = \sum_{t,k} I_t^k P_t$$

$$RAB = \sum_{t,k} I_t^k P_t \left(1 - \frac{T_0 - t}{UL^k}\right)$$

where GRAB is the gross value and RAB is the net value of the assets, also known as *regulatory asset base,* and:

t = year of entry into service (> T_0-UL)
T_0 = first year of tariff period
UL^k = useful technical or legal life of cat. k items
k = item category
I_t^k = sum of original values of investments of cat. k entering service in year t
P_t = price deflator

Implicitly, the cumulated depreciation of the asset is the difference between its gross and net value:

$$DEPR = \sum_{t,k} \frac{I_t^k P_t}{UL^k}$$

This basic approach can have a number of variants. Most of them are related to depreciation, which can be nonlinear. For example, in order to stabilise revenues, regulators may prefer a French depreciation pattern, where the sum of the annual depreciation and of returns is kept constant for a constant gross base.

Further, either by regulator's choice or by law, depreciation may follow a different (usually faster) pattern than its technical useful life. This is more common- and consistent – if the book value approach is chosen (see below, #4).

If available data for individual assets (pipelines, stations, buildings, software…) cover a large part of the RAB, the current cost methodology may be used and is the preferred one. This is likely for production assets, which are normally relatively "young" (compared to transmission and distribution facilities) and their values are often made public. The high internationalization and stock exchange exposure of the oil&gas industry (compared to national or local utilities) requires high transparency levels and lack of information about key investment costs is unusual. On the other hand, in case of imports, regulators may have to estimate costs of assets that lie outside national territory and may have been laid in rather old times, subject to different accounting principles and denominated in foreign currencies. In these cases, the definition of current cost may not be easy.

2. Modern Equivalent Asset Value (MEAV). Assets are valuated at their replacement costs (or the cost of their modern equivalent). If cost data are only available for recent investment, these should be collected anyway, to be used under MEAV: simple statistical techniques will then be used to calculate costs of assets that are not available. Data could also be integrated by reference to international experience or by literature models.

The MEAV involves several difficulties as the right type of assets or its valuation may be controversial. Moreover, technical change may lead to a fall of replacement values with respect to those of original assets. For upstream assets, difficulties may be even larger than (for the relatively standardized) pipelines, compressors and meters that make up the bulk of transportation and distribution companies. For the above mentioned reasons, resort to MEAV for the valuation of upstream assets is neither likely nor desirable. In practice, MEAV can often be an appropriate integration of current costs, rather than an alternative, to be used to integrate where accounting costs are missing, with a view to provide the best estimate of the replacement cost.

3. Independent appraisal. An audit company may be appointed for the appraisal of the network. This approach has been proposed within EGAS. However, the appointed auditors are likely to apply similar methodologies, like current cost or MEAV, therefore this approach is not a real alternative but rather a choice to externalize the implementation of one of the existing methodologies. If this is chosen, consultants should provide information from specific comparable cases and not limit themselves to calculate current costs or MEAV. Independent appraisal can be quite costly.

4. Book Value. This may also be taken as an estimate of the RAB. The advantage is that it is a value calculated in line with the fiscal and accounting rules of the country, hence it is stronger from a legal perspective. In other words, there is a lower risk that the regulator's valuation may be challenged in Courts. However, European regulators rarely use book values, with the agreement of regulated companies, because they feel that book values are usually underestimating the real economic value of networks. This is often related to legal depreciation rules, which often allow (or require) a faster depreciation than would be implied by the assets' physical and technical life. This is a benefit for the company in the short term, as it allows lower corporate tax outlays, but also leads to a faster fall of the residual asset value of the balance sheet, and hence of the future RAB.

Moreover, rules for re-evaluation of assets are not internationally consistent, and can be confusing for foreign investors.

The book value is often an estimate of assets above the depreciated historical cost but somewhere below their current or replacement value. On the other hand, the book value may duly consider the asset value reduction that may arise from write-offs or lump sum payments received from consumers and from public bodies, and represent therefore a fair estimate of actual shareholders' outlays. Yet, even if the current cost or MEAV methodologies are followed, such estimation should be performed anyway[28].

5. The market value of asset holding companies could be used as well, but it is logically questionable. This is particularly the case of companies that have been (or are about to be) sold or privatized. When this happens, politicians, with specific goals in their minds, often define the value at which companies are sold. For example, in the U.K. of the 1980s the push towards extensive privatization of state owned activities led to low sale prices, with valuation well below those attained by the above methods[29]. On the contrary, privatisations undertaken by cash-stripped governments of peripheral European economies occurred at high prices, with a view to maximize Treasury revenues, even at the cost of privatizing monopolies and their profits. Understandably, when regulators had to price the services of such companies, they found that market valuations had been embarrassingly high.

The logical flaw of this approach is that normally investors' valuations are based on discounted cash flows of the companies, which in turn depend on their tariffs and prices. Therefore, trying to base the calculation of such tariffs on asset values defined in this way is a logical

28 According to Hayward's (2008) handbook, "failing to reflect the economic and functional obsolescence of assets adequately" is one of the most common errors of depreciated replacement cost practice.

29 Jones et al. (1999) in study of 630 privatization IPOs, find that governments consistently underestimate the value of privatized companies, triggering significant windfall gains by subscribers. This may be related to the political will of favoring the latter, or more generally to spread equity ownership among citizens.

circularity. However, this does not apply to valuations that were defined in special cases, like those of privatization, where prices were affected by political objectives. The possibility for regulators to modify such valuations and use one of the above criteria depends on the legal system, and differs in each jurisdiction.

It is hard to pick up the best approach in general, as it depends on the quality of available data. Current cost is more objective, but its outcome often depends on the choice of the cost inflation indicator, notably if this must cover periods of high inflation. Very general indicators (like the Consumer Price Index, CPI) may be inappropriate, but very specific industry indicators may reflect the market power of the monopolists, or regulatory and government interference. Intermediate indices, like a Wholesale or Producer Price Index, are preferred but not always available.

On the other hand, the MEAV is in principle a better indicator of the replacement cost, as it is the cost that should be spent now to achieve the same services. However, in case of industries subject to substantial technical progress, it may lead to significantly lower asset prices than the original ones. Adopting the MEAV in such cases would transfer the benefits of technical progress to consumers, whereas shareholders would suffer an implicit partial impairment of their original investments.

Book value in the accounting systems of several jurisdictions is fairly aligned with current cost. In others, it is much lower. In such cases, regulators must be aware that its adoption follows a principle of fairness rather than economic efficiency, as the best way of transferring to investors only their actual current asset value (and its remuneration). Therefore, as new investments are necessary, values are likely to increase, albeit often (but not always) slowly.

Market values, notably those arising from privatization, are not the first choice of regulators, for the above reasons. However, it may be mandatory, or it may be acceptable if the value is determined well before any tariff setting process is started so that the market value is reasonably independent.

Each of these main methodologies has therefore its role, and, as Frontier Economics' survey (2003) already noticed, every regulatory case is unique. However, after considering all these issues, the regulator who faces the task of defining costs of gas supply should be relieved to learn that difficulties in this case are comparatively lower than for transportation and distribution utilities, for several reasons:

- Unlike monopolistic utilities, oil & gas producers are subject to fierce competition, therefore their choice of inputs is normally aimed at achieving the best cost efficiency;
- The oil & gas industry is generally more transparent than local utilities and its costs must be promptly disclosed if companies wish to maintain high credit record, which is crucial for their sustainable operations. For example, at least rough and aggregate figures about major investments and their key performance indicators are always communicated to the press and the financial world and available in specialized magazines. Even more than in the case of utilities, financial analysts are among the regulators' best allies, given their professional interest in the transparency of accounts, and a potential source of useful information;
- When gas is imported, even though some transportation assets may suffer from the same difficulties as other utility assets, competition between gas sources and routes is also likely to play a role in ensuring significant transparency and efficiency of investments;
- Most investments that must considered, notably to define the costs of reference marginal supply chains, are relatively recent. Hence, lack of historical data and the impact of the choice of re-evaluation indices are less serious problem.

To sum up, finding the values for the relevant supply investments is an easier task in gas supply than in gas transmission or distribution. It may be a little harder for imports, notably if aging foreign pipeline or LNG facilities are concerned, but even in such cases a suitable MEAV can usually be estimated.

2.6 The rate of return

2.6.1 Overview

The careful reader may have noticed that in the above formula of the allowed revenue (4), the rate of return (RoR) does not carry a suffix for infrastructure investment or for the gas value. In fact, there is no possible separation, as any market based analysis of the rate of return of the gas supply industry cannot be undertaken by separating its gas assets from others. In fact, observable returns accrue to the industry and cannot be attributed to either component. From the theoretical economist's perspective, the returns provided by natural, limited and potentially exhaustible resources are rather different from those of an industrial activity, and amount to what energy economics calls *Hotelling's rent*. Since this is a key issue for pricing a natural resource, the theoretical discussion is postponed to section 2.7. For the time being, let us address the practical ways of calculating the right rate of return, which also represents the cost of infrastructure capital invested in the activity.

Most modern regulators calculate the RoR by the Capital Asset Pricing Model (CAPM). This method is used by the vast majority of European regulators (CEER, 2011) and by many outside Europe, even though other methods are also adopted, notably the DCF in the U.S.(see below). The CAPM defines the rate of return as a Weighted Average Cost of Capital and uses the formula:

$$WACC = \frac{K_E}{1-t_e} \cdot \frac{E}{D+E} + K_D \frac{D}{D+E} \cdot \frac{(1-t)}{(1-t_e)}$$

where:

$K_E = r_f + \beta$ MRP is the cost of equity, where:

r_f is the "free risk" rate (government borrowing cost)

β is a measure of the industry risk

MRP is the Market Risk Premium, or the difference between the expected return of capital invested in the stock market and the "free risk", and is also known as Equity Risk Premium (ERP)

K_D is the cost of corporate debt for the industry

t is the debt tax shield

t_e is the corporate tax rate.

The DCF method (also known as Dividend Growth Model), is the main alternative to the (CAPM based) WACC. Its starts from the idea that the cost of equity capital (Ke) can be detected in actual financial markets, as it can be shown to amount to:

$$K_e = \frac{D}{P} + \dot{D}$$

where D are dividends, P is equity price and is the time evolution rate of dividends.

This approach is still recalled in handbooks, but rarely used especially outside the U.S.[30]. In fact, in principle all market data to calculate the cost of capital can be found, but in practice it shares almost the same open issues as the CAPM: in particular:

- Should use current (latest) data or a longer term average, and in the latter case, how long?
- Should choose a general (market) cost of capital, or choose the cost for the specific industry in view of its peculiar risk pattern (and in the latter case, how specific)?
- What is the relevant reference market to assess capital costs? (National, regional or global, or other)
- Use nominal or real values, and in the latter case, how to deflate nominal yields?

DCF/DGM offers a different framework to address these issues, but does not facilitate the solution of any of them. Therefore, almost all Europe (and probably most of world regulator) shares what Jenkinson (2006) noticed for Great Britain: regulators pay just some lip service to DGM but in fact prefer referring to WACC, as defined by CAPM.

In fact, the rate of return is largely the biggest single item of the regulated revenue for a gas company. Operational costs rarely exceed 2% of RAB even for distribution and meshed transmission systems, but are typically lower for upstream activities like E&P and for long distance transmission, where they range between 0.5 and 1.5% of RAB, depending mainly on distance and the price of gas itself. Variable costs are higher when the LNG chain is involved, as typically between 12 and 20% of gas is burnt in the liquefaction, shipping and regasification process. Depending on the price and distance, this cost can be up to 5% of the total.

Depreciation depends on several criteria: in several jurisdictions its terms are dictated by tax law: in a few cases special norms for fast depreciation, which enhances costs and profits in the short term. If regulators are free to set their preferred rates, any technically meaningful depreciation is usually based on the useful life of assets, which normally lies between 2 and 5% of the assets' original costs.

The rate of return rarely falls below 7% before tax even in the most stable countries and activities like distribution, and is normally in the double-digit zone for riskier exploration, production, and long distance transportation. Therefore, it is normally larger than the sum of operational costs and depreciation for regulated activities, including gas supply. This justifies a more thorough attention to this component.

Whatever RoR methodology is chosen, any regulator will face a number of choices in its actual calculation. The following sub-sections illustrate problems and solutions adopted for the calculation of the various WACC component.

2.6.2 Risk free and market risk premiums

In several cases, the risk free and market risk premium are defined separately. However, if for a number of reasons no proper estimation of MRP is available for a country, their determination is actually a joint one.

To understand this complex financial issue, one should consider that these parameters are often estimated by rating agencies or international financial institutions (IFISs), with a view to define what returns is deemed necessary to invest in any (including riskier) countries or sectors. This perspective is the basis of some international finance analysis, but it is not necessarily the perspective of the national regulator, who could also follow a similar methodology but with a national perspective and data.

Since financial markets are usually well connected and at least some funds move quickly across borders in search of arbitrage opportunities, all approaches should in principle lead to similar results. However, barriers to capital movements and enhanced risk perception (which is typically triggered by political uncertainty) may lead to rather different valuations for sustained periods, for some countries. Therefore, we describe both the international (or *global*) and the national (or *standard*) perspective in this analysis[31]. The analysis starts from the global approach, which is more relevant here: it can be used also in emerging markets where the implementation of the standard approach may be harder due to lack of national data; yet most regulated gas supply occurs in these markets.

The global approach would assume that the correct remuneration of the risk of investing in the gas industry of a country Z would amount to:

$$K^{Z}_{E} = r_f + \beta \, MRP^{Z}$$

In this approach, the choice of a free risk rate is straightforward, as it can be taken from long term government bonds of a low risk country (typically, a country rated AAA by the main rating agencies). However, the choice of the MRP is trickier, as it combines the risk of investing in the country (country risk) with that of investing in its equity market (market risk).

For the estimation of MRP^{Z}, one of the following approaches may be adopted:

(1) The "Country Risk Management Model", which is often used by large financial institutions. Its ratio is to calculate MRP^{Z} as a sum of the expected loss and the unexpected loss arising from a possible default:

31 This sub-section is partly based on Gözen (2012)

$MRP^Z = PD^Z * LGD + (PD^Z (1-PD^Z))^{½} * LGD$

where PD^Z is the Probability of Default of country Z implied by Credit Default Swaps market, and LGD is the expected Loss Given Default, assumed at 45% in the practice of large financial institutions. For countries that are perceived as politically or financially unstable, the resulting MRP^Z calculated with this approach may be quite high, and this is often unacceptable for regulators and actually above yields actually earned by oil&gas companies in these countries.

(2) The *Damodaran* model assumes that the difference between the total MRP of two countries represents the country risk premium. Such difference can be divided between a "risk free" spread (spread between risk free yields in national currencies) and the Equity (Market) Risk spread. Hence, the Emerging Market (EM) MRP could be estimated starting from that of a high rating country, like the USA:

$MRP^{EM} = MRP^{US}$ + Country Risk Premium = MRP^{US} + Equity Risk Spread + $(r_f^{EM} – r_f^{US})$

This is a formula where all values are known, as the CRP can be derived from the default spreads, which are provided by Moody's as a function of the country's sovereign debt rating[32]. For example it amounts to 7.50% for a Moody's Caa1 sovereign country rating (as of January 2016). Since the MRP at the same time for the US (and other top rating markets) was estimated at 5.75%, the derived MRP

32 This is the first equality of the text: $MRP^{EM} = MRP^{US}$ + Country Risk Premium. The second equality $MRP^{EG} = MRP^{US}$ + Equity Risk Spread + (R_F^{EM} - R_F^{US}) is provided only to illustrate the meaning of the formula. Damodaran actually suggests "two choices, one based upon the local currency sovereign rating for the country from Moody's and the other is the CDS spread for the country (if one exists)". It is also useful to check that country risk is not added twice, a rather common mistake.

for the country would amount to 13.25%.[33].

The criticism against the global approach consists of three basic remarks, which unfortunately lead often into opposite directions:

(i) It has been noticed that this approach considers the perspective of an international investor entering an emerging market economy, rather than that of a domestic investor. This is reasonable if foreign capital is involved, but mat overestimate the cost of capital if the foreign risk perception of the country is overrated. In such cases, if domestic capital is available, the standard approach maybe more appropriate;

(ii) International investors may be larger than domestic ones and hence have access to cheaper sources of finance. This may lead to underestimation of the cost of capital and lead to acquisition of domestic assets by foreign investors. Yet, if governments seek foreign capital, this is of course the price to pay.

(iii) Several authors notice that the approach of turning higher default risk into higher rates is questionable: a better way would be to downgrade expected cash flows instead. However, most financial analysts prefer the (easier?) interest rate adjustment.

The solution depends on specific financial market conditions. Regulators may also follow the *standard* approach, focusing on the national financial market and ignoring the analysis of country risk and its estimation compared to low risk countries. In other words, they may assume that national markets can actually estimate the risk in the country.

Under the standard approach, the valuation of "free risk" rates requires collection of data about maturities and yields of national debt in local currency, which are normally provided by Central Banks. For the estimation of the free risk rate, long term government bond matu-

33 This approach basically amounts to adding the typical risk of a high rating country's stock market to a country's measure of risk. However this may not be a proper evaluation of the country's stock market volatility. A simple way to consider such volatility is to compare the equity market volatility (measured as the standard deviation of stock prices, σ_E) with that of the bond market (measured as the standard deviation of bond prices, σ_F), and take the ratio of the two. Hence the formula becomes:
$MRP^{EM} = MRP^{US}$ + Country Risk Premium (σ_E/σ_F).

rity (e.g. 10 years or more) are normally used, provided that transparent and relatively stable results are found. Even more than under the global approach, it is often preferable to choose an average yield of bonds issued in the last years, notably if the latest data are affected by instability that is deemed to be temporary (for example, as it may happen in a period of political turmoil).

This approach would directly use a national valuation of free risk (as provided in the previous section) and define the cost of equity in the country as its own national currency free risk rate plus the MRP or (if that information is missing) that of an high rating country like the US. In formulas:

$$K_e = r_f^{EM} + \beta \, MRP^{US}$$

In principle, all approaches should yield similar results. However, current market valuations of bonds and spreads are probably affected by the general uncertainty perception arising from the political and macroeconomic situation, which affects in particular the default spread estimation, the sovereign debt rating, and the long term sovereign bond interest rates. Capital flow limitations and active monetary policies may also limit market convergence. Poor correlation between emerging and mature markets[34] is seen as proof of limited convergence, but is also a hedging opportunity for global investors.

Consistency is often more important than the choice of approach. If (e.g.) a 5-year average is used for risk free rates, the same should occur for the inflation rate. Likewise, if the standard (national) approach is chosen, all valuations should be in national currencies, with the international investor bearing the exchange rate risk in return for (probably higher) nominal yields. On the contrary, if a global approach is chosen, all calculations are probably better done in hard currency.

34 Gözen (2012), p. 151

2.6.3 The Beta factor.

The WACC formula includes Beta, a measure of the volatility level of a company's shares profitability compared with the volatility of all shares in the market. Risk of shares is determined by such factors as the existence of sudden fluctuation of the share rates, compliance of share rate to the market index, possibility of abrupt falling of the rate, etc. The lower company's risks are- the lower is β. If the risk of company shares equals the risks of the market portfolio, β = 1.

Generally, rates of shares' profitability and return on the market index are used for β calculation. Beta Levered is indeed usually calculated as a correlation index and it is equal to the following:

β = Covariance (Stock market index; share price) / Variance (Stock market Index).

If the regulated company is not an independent listed company, it is not possible to calculate its actual Beta. Facing the same problem, several European regulators have commissioned studies to estimate a typical Beta of peers, with a view to apply it to their regulated utilities. Since Beta represent a feature of the industry (i.e. gas transmission) rather than a specific national characteristic, it is reasonable to use an international average, as it may be reported in studies. The calculation is not difficult but time consuming: market values are "levered", which means that they are affected by the leverage condition of the listed companies. For comparison, they must be "unlevered", that is the equivalent must be calculated by the formula[35]

Beta unlevered = Beta levered / [1+(1-T)*(D/E)]

with symbols defined as above[36].

35 The levered Beta is also known as Asset Beta, whereas the unlevered Beta is also known as Equity Beta.

36 For example, the Damodaran Tables (http://pages.stern.nyu.edu/~adamodar/) provide information on Beta's by industry. The latest unlevered Beta for integrated oil&gas industry is 1.31.

2.6.4 Other issues: current values vs. averages, nominal vs. real

For any rate component, reference should be to the level that is expected to prevail in the long run, or at least during the period when the price control holds. For gas supply, multi-year price controls have rarely been introduced, as Part II will show. In fact, multi-year price controls are typical of network tariff regulation. In Europe, where end user price liberalisation is the rule and controls are seen as temporary exception, regulators have not usually bothered to establish multi-year controls, with incentive regulation, even though this would be justified in case controls do in fact survive for several years. The (rather limited) theoretical and practical discussions about price controls has so far followed different paths, which will be discussed in more detail in the next section.

In order to provide a reasonable information about the long term costs of capital, regulators should use averages of at least five years. This is naturally achieved for variables like the risk factor (Beta) or the MRP, which are typically estimated as statistical means (or medians); but it is less obvious for "risk free" government bonds or for inflation rates.

Lately, faced with extremely low risk free rates and volatility, regulators of mature markets have introduced rate of return indexation, with RoRs recalculated on a yearly basis after a predetermined formula, where the free risk is the main (or the only) changing variable (Langset and Syvertsen, 2013). This approach may offer a fairer rate of return but reduces the incentive properties of the regulation.

Another controversial issue is whether to use real or nominal values. Again, consistency is the key: a real RoR should apply to a real RAB, whereas a nominal RoR may be more appropriate for a nominal value of assets. The choice is therefore primarily driven by the outcome of the discussion that is carried out in sub-section 2.6.2 above. If a real value is chosen as calculated by the current cost or MEAV approach, it is obvious to apply a real WACC, whereas a nominal value would be better for a book value. In fact, the book value must be carefully evaluated, as the reasons behind its relatively low value may be various.

Since the use of a real RAB value is recommended in most cases, the RoR should be real: again, this a difficult valuation, albeit less so in low inflation economies. The normal prctice is to subtract an expected inflation level (taken from financial market or official forecasts), over the reasonable duration of the price control[37].

2.6.5 Debt/equity ratio

The D/E ratio is an important component of a company's financial costs. Again, there are several approaches.

The easier way is to use the current ratio of the company or (if this has no independent financial structure) of its parent company. Oil&gas companies in the world can afford lower gearing ratios than normally regulated utilities, as their activity is inherently more competitive and risky.

In most utility cases, European regulators have chosen not to use actual D/E ratio. The reasoning behind this choice is that, particularly in the case of currently state-owned companies or in that of recently privatised ones, D/E are likely to be very low – in other words, such companies have very low debt. Whereas this may look like a virtue at first glance, this is not actually the case if one thinks that equity financing is normally more expensive than debt. This is not perceived by state –owned companies, as the state normally pays lower borrowing rates than any of its controlled companies, therefore it is better for the state to "centrally" borrow on the market and then transfer funds (as equity) to its companies. However, once companies are (at least partly) privatised, this is no longer true: on the contrary, it is cheaper for them to borrow, and they can borrow at relatively low rates if they are regulated in such a way as to protect them from risks, which are normally relatively low in businesses like electricity and gas transmission and distribution.

Therefore, regulators have often decided to set the D/E ratio to a level that is regarded as efficient, e.g. to 1 or a higher level, as found in the international experience. Typical gearing rates of the integrated oil&gas supply industry in advanced country are about 20%. However in the U.S., where the end user supply industry is regulated and its risk is comparatively lower (with unlevered Beta of 0.65), gearing of retail suppliers increases to 95%, not far from network and power utilities.

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37 In any case, the utmost care should be used to clarify that the values are properly calculated, i.e. to avoid any mix-up of nominal and real values.

For regulated supply, the argument used for utilities is hardly applicable. Suppliers are likely to carefully choose their gearing level, as they are under close scrutiny from the financial community. It would be hard claim that a systemic bias may occur, even though fully state owned producers are certainly less bothered by the need to raise external finance. Very low gearing can be found in state owned or recently privatised companies: in that case the target gearing could be moved up to industry averages. However, gearing that companies can afford also depends on factors like size, geographical exposure, ownership, and others (Weijermars, 2011). Benchmarking in this area is difficult, and keeping the suppliers' original value is recommended unlike strong special reasons apply.

2.7 The value of natural gas

2.7.1 Gas price regulation and the problem of exhaustible resources.

In section 2.4 above, we suggested that the value of natural gas requires a treatment different from the costs of infrastructure developed for its production and commercialization. The application of regulatory criteria that have been developed for industrial infrastructure to natural gas is not actually feasible, because the *v*aluation of natural gas (and hence its depreciation) is inherently unstable and only partly related to costs, with the relationship often limited to the long run. A cost based price would only consider a limited part of the gas value, which depends on the relations between demand and supply. Whereas this is in principle true of any good, the basic difference between natural gas itself and the infrastructure used for its production and supply is that the former is not built by human industry, but it is a gift of nature. It is true that gas is found through the exploration process, but this is a relatively uncertain venture, and results may be extremely satisfactory or disappointing irrespectively of the spent effort[38].

38 It has been noticed that one reason the shale gas industry of the U.S. has changed the economics of natural gas is the much lower uncertainty of the exploration process. Once a shale "play" is detected and appraised, its exploitation by actually investing in reserves resembles more a traditional industrial investment process than the exploration of conventional gas, as the success rate is comparatively higher. However even in this case not all wells hit "sweet spots", i.e. the profitability of each well or area is rather uncertain, and the total amount of the resource remains limited.

The analysis of exhaustible resources is clearly the core of energy economics[39]. The traditional theory of exhaustible resources was developed by Hotelling (1931). It started by assuming that at a certain point in time available resources could be regarded as fixed, and showed that in such case the resource commanded a scarcity premium above production costs, known as *Hotelling's rent*. The theory has shown that such premium is expected to grow in line with the resource holders' discount rate, and that the growth path is affected by (real or perceived) changes of the resource availability and of its demand, so that sudden shocks may occur if any of them obtains. The intuition is that the producer would abstain from using a given resource today, and keep it for tomorrow, if its appreciation increases at least as much as the long term rate of interest.

Since the theory suggests a growth path but does not explain the price level, the introduction of several constraints has been suggested so that the problem is "closed" and a determinate solution is identified. For example, a popular view since the 1970s suggested that prices of fossil fuels should be such that all known resources are exploited by the time they hit those of an alternative, infinite energy source (e.g. solar energy) (Figure 2.9). Identification of the backstop fuel and of its cost and time has proven elusive, but the view is still common. If costs of alternatives are driven down by technical progress, so are the prices of fossil fuels.

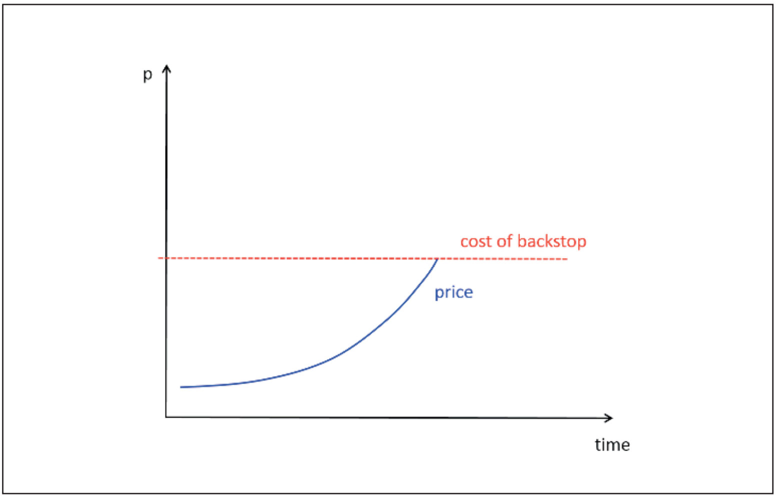
The literature about exhaustible resources is extremely large and far beyond the scope of this book. Energy economists have discussed not only the availability and identification of backstop fuels, but also other issues that may sharply affect price paths, like the role of exploration; the causes and features of resource price cycles; the objectives of producing countries and companies; market power and the role of cartels; and the impact of technological change (Krautkraemer, 1998).

A remarkable part of the literature has been devoted to identifying the optimal pricing policies of resource holders, of which domestic pricing is one instrument – but not the only one, and not the main one for coun-

39 Current as well as most of the past energy consumption has been based on exhaustible mineral resources (fossil fuels). Even though the recent agreement in Paris may have marked the beginning of the end of their era, about 86.3% of primary 2014 energy consumption currently consisted of fossil fuels (BP, *Statistical Review of World Energy 2015*). The long lasting dominance of fossil fuels in energy consumption is only partly mirrored by the relevance of resource analysis within the energy economics profession.

tries that export most of their production. Since fossil fuel markets are mostly traded in open and competitive markets, albeit possibly affected by cartels and collusive behaviour, end user price regulation has received less attention.

Figure 2.9 Exhaustible resource price with a backstop technology



For the objectives of this book, however, it is sufficient to highlight a key conclusion of the theory: the mineral resource will in general yield a scarcity premium, leading to prices above marginal production costs. The fact that theory predicts (and empirical experience indeed confirms) significant price changes, often in the form of sharp swings, confirms the inadequacy of cost-based regulation. Cost based regulated prices are typically stable, or are adjusted after a predictable path (like the RPI-X criterion). They do not match market price swings but by chance.

The impact of a regulated price that does not follow market fluctuations would be almost inevitably damaging. If the price is too low, it would discourage production, and even more investment, possibly triggering shortages beyond the short term: It the price is too high, it would be challenged by unhappy customers (and by regulators and politicians), who would inevitably compare it with other countries where market prices prevail. In perfectly isolated systems, a purely cost based assessment of the gas value is more tempting; but market isolation may end, and the forecast of such event may already affect gas valuation in the country; or indirect connection may occur as international companies choose between development in the isolated jurisdiction or in others, where prices are aligned with international markets. Companies would always prefer to invest where prices are allowed to follow market trends, which would make them at least not worse off than their competitors.

Part II of this book will show how prices below (and occasionally also above) international market levels have damaged industry development in very different economic and political systems, and of very different size. The only sustainable discrepancies between domestic and international prices are those justified by transportation costs, including those of the LNG chain, which may indeed be remarkable but can be reasonably evaluated by methods similar to those used for domestic transportation, albeit with a few specific features.

Perhaps, the biggest single mistake that is shared by many cases of inappropriate regulation is the idea that regulation can impose a behavior (low pricing) that is systematically at odds with the behavior dictated by economic opportunities. A regulated company (like a network operator) can normally accept to work under a regulated return that forces it to forsake supernormal profits but ensures a protected status. A supplier of a mineral resource that sees its peers operating in competitive markets – and is also often selling itself in competitive markets, e.g. by exporting – can hardly accept to sell permanently below what it sees as the fair value of the resource. Regulators often seem to neglect the problem known in the economic literature as moral hazard: the company may formally accept the regulation but practically reduce its efforts to offer it to the regulated market. It will either cut investment, neglect productive opportunities, or divert its best efforts to more profitable markets like exports, where available.

2.7.2 Market based regulatory options

Since the value of natural gas, due to its exhaustible nature, is normally larger than the sum of its production, transport and distribution costs, and cannot be defined by a cost based methodology, the alternative is to consider its market value. There are three basic options that must be considered and are applicable in different realities. The theory is however partly similar and several considerations are applicable to all cases, with the appropriate adjustments[40]. The three cases are:

(1) Gas is priced at the wholesale level in a connected market, plus the import or upstream cost that is necessary to bring it to the regulated market. In this case, the problem is simply how to appropriately transfer (or consider) the wholesale price in the gas value of the regulated selling price. In turn, this regulated price is applicable either to power producers or utilities, or regulated gas distribution or retailing companies, or other end users. This definition is mostly applicable where retail markets are regulated but interconnected wholesale markets are not. This concept is often referred to as the **pass-thru** of wholesale gas prices.

(2) If there is no functioning upstream wholesale market, but there is a connected downstream competitive market, gas can be priced at the value it would have if sold to the interconnected competitive market. This definition is particularly relevant for (net) exporting countries, or potential exporters. In particular, if the country is tied to international markets, its opportunity cost is the price at which the gas would be valued on international markets minus the transportation cost[41]. This is known in the industry as the **netback** price of gas for the exporting country.

(3) If there is neither an upstream nor a downstream gas market to be considered, the reference could be the price of another fuel with comparable performances. This definition is particularly relevant for self sufficient and isolated countries and for net importers from non-competitive origin markets. In fact, this concept has been originally conceived as a way of finding a reasonable compromise for cases of bilateral monopoly, where no other price reference was possible[42]. It can be applied provided that substitution between natural gas and alternative fuel(s) is feasible. Even though this pricing concept used to be also named “netback”, a more appropriate description refers to the idea of **parity**, as it is based on the

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40 It is of course excluded the case where an effective and competitive retail market is at work, because that would of course rule out the need for regulation.

41 Transportation cost would include liquefaction and re-gasification if gas is transported as LNG. In the following we will discuss the netback concept in more detail.

42 The original developers of this pricing methodology were the Dutch government and state companies, who historically pioneered gas pipeline exports.

principle that a similar energy output should have the same value.

For each case, prices – like any regulated tariffs – cannot be separated from the key contractual conditions, which represent the "quality" of the product and should be associated to the regulation. Section 2.9 below will briefly discuss the main non-price conditions of the gas sale contracts.

The section proceeds as follows. In the following sub-sections, we assume that gas procurement costs that are included in the price control are allowed to vary by some pre-determined formula, or "passed through" by the utility to its customers. The key concepts and issues are discussed in relation to the pass-thru problem. We will see that in fact the actual pass-thru of wholesale market prices, even if available, is just a particular solution, and not necessarily the most desirable one. The regulator may well ask the usual questions: notably whether, how much, and when such pass-thru should be allowed, and which alternatives are available.

Later, the discussion is extended to the netback concept, where some of the issues and solutions discussed for the pass-thru problem are also applicable, with the necessary adaptations.

Even more complex is the following discussion of the parity concept, where reference is made to indices that do not directly represent gas procurement costs. In fact, this approach has a long history and may also represent the basis for an effective gas price regulation. Therefore, this approach is analyzed in more detail in a separate section, under the heading of non-cost based regulation. In fact, it aims at slightly different goals than cost-based regulation.

It is worth remarking that all these issues are clearly related to private sector pricing practices. Since in general competitive markets are efficient, so that one option for regulators is to try to "mimic" their outcomes, it will be appropriate to refer to practices that are found in gas markets in the world, as described e.g. in Stern (2012). When regulators set rules and criteria for gas purchasing on behalf of captive end customers, their objectives and behaviour may not differ from that of a private buyer under competitive conditions. However, institutional constraints and political objectives may also lead to different choices.

2.7.3 The pass-thru problem

Let us discuss the problem of a regulator who needs to set pricing rules for natural gas purchased by a utility, either for distribution or retailing to end users[43], or for transformation into other products of regulatory interest (typically power). In general, the problem can be formulated as follows:

$$P_t^R= P_0+a I_t \qquad (5)$$

where P_t^R, the regulated price at time t, is calculated as a basic price P_0 plus a fraction *a* ($0<a\leq1$) of a price index I_t , representing the share of the price index changes that are born by consumers. If $a < 1$, the utility bears at least part of the variation of the price index, and can therefore see its profits diminish if the index increases, and increase if the index falls[44]. In turn, a general form of the index can be:

$$I_t^{\wedge} = bC_t+(1-b)\ B_t \qquad (6)$$

where C_t is the actual weighted average cost of gas purchased by the utility (WACOG), B_t is a pricing benchmark and *b* ($0<b\leq1$) is a parameter that splits regulated price indexation between actual cost and the benchmark. This is the incentive approach, originally suggested by Shleifer, where the company retains a share of the difference between its actual purchasing cost and a benchmark. In the early formulations, the typical benchmark

43 The institutional framework, and even the (English) language to identify it, may be misleading, notably as the largest English-speaking countries (U.S. and U.K.) have rather different institutional settings and use different definitions. In North America, a *distributor* is a company that performs a regulated, integrated service of local transportations and sale of natural gas to franchised customers. This market can be open to retail competition, where customers can also buy gas from other marketers, but the distributor normally remains regulated for both its local transportation and gas sales. For updates about the spread of retail competition in the U.S. see www.eia.gov
In the U.K. as well as in the rest of Europe, a distributor is instead an unbundled operator of local transmission services, and is therefore known as a *distribution system operator (DSO)*. Retailers may be DSO affiliates but should be legally unbundled in the E.U., except those serving less than 100,000 end customers where accounting and functional unbundling are enforced. DSO tariffs are always regulated, while selling prices may be regulated, and indeed are in several countries: see Part II, Chapter X for the U.S. and Y for Europe.

44 Asymmetric variants also are possible, as in the British Gas case that will be shown shortly.

was simply an industry average of actual costs, but later more complex proposals have emerged (see below).

The special case where a = b = 1 is the pure pass-thru model, where actual costs are included in the regulated price. This approach amounts to the traditional, U.S. style rate of return regulation, where costs are included in the rate base provided they have been "prudently incurred".

The pure pass-thru approach has been criticized as a general way of setting regulated prices, by a stream of criticisms originating from the seminal article by Averch and Johnson (1962). Under RoR regulation, the utility has no incentives to cut costs: on the contrary, it could even be interested in increasing the cost of inputs, as its returns are proportional to them. Under the RoR approach, the regulator must undertake an extremely careful analysis of the "prudence" of incurred costs, which is never fully satisfactory, which is hard even for the large and qualified staff of North American regulators, and even more elsewhere. Therefore, economists have looked for alternative approaches to incentivizing the utility to reduce its costs, building on the suggestions proposed by Shleifer's (1985) benchmarking concept.

In the area of infrastructure regulation, the most popular approach is certainly the well known "RPI-X" or *price cap* rule, requiring prices to be increased by the inflation rate minus a pre-determined productivity improvement factor. Discussion of this approach in its details lies beyond the scope of this book, as it is mostly related to infrastructure components. In fact, it can in principle be applied to purchasing costs as well, and one of the earlier attempts did actually include it. In this case, the above formula, after merging (5) and (6), becomes:

$$P_t^R = P_0 + a[bC_t + (1-b)\,B_t]\,I_t\text{-}xP_{t-1}$$

This approach was actually followed in an early price control in the U.K. (Ofgas, 1991, 1997; Marshall, 2003). Lately, this price cap approach has become less popular. This is possibly due less to its theoretical properties and more to the institutional evolution in Europe, the region where the multi-year regulatory periods where prices follow the RPI-X logic have been appreciated more. However, since Europe has also gone for full unbundling of network services, it has actually created network operators (TSOs and DSOs), which have very limited control over the traded quantities. For such network operators a *revenue cap* regulation is more suitable, where regulated revenues are raised from forecasted quantities. Under this approach, the capping incentive applies to total allowed revenue of the operator rather than to each tariff item:

$$AR_t = AR_{t-1}\ (1+RPI - X)$$

and the total revenue is the basis for the setting of (often complex) sets of tariff items[45].

On the contrary, outside Europe integrated distribution and supply are much more common, but the revenue cap approach does not fit such services, as it may actually lead to replication of the monopolistic behavior (Crew and Kleindorfer, 1996). On the other hand, the multi-year regulatory period approach has had limited success in North America, where it is normally listed as one possible way of providing incentives, among the most general heading of *Performance Based Regulation* (PBR). Most actual caps are hybrids, including revenue caps, price caps and pass-thru components[46].

Performance Based Regulation is a more general concepts than RPI-X incentive regulation, and under this heading scholars and practitioners have actively addressed the issue of providing incentives for the purchase of inputs by regulated utilities, including fuels with their own peculiarities. Since the case of power (or gas & power) utilities is far more common than that of pure gas distributors, it is not surprising that most theoretical as well as applied literature refers to power.

Basically, the problem considered by the literature envisages a regulator maximizing a "welfare function" on behalf of consumers, while the utility maximizes profits complying to the constraints set by the regulator. The typical welfare description is an inverse function considering

45 Revenue cap regulation is often integrated by an "error correction" or similar mechanism, reconciling ex-ante forecast and actual values so that the allowed revenue is almost exactly matched.

46 This clearly emerges from AF-Mercados et. al. (2015) review of European regulatory experiences for distribution.

not only of the mean price paid by the utility, but also of its variance:

$$W = W[E(P^R_t),Var(P^R_t)]$$

This is a reasonable approach, as consumers and politicians alike are often afraid of swinging prices, not less than of high prices. Moreover, since the "mean-variance" approach is also used in financial portfolio analysis, theoretical work has been able to use techniques and results already used in finance. However, since reduction of price variability comes at a cost, theoretical analysis will be looking for optimal mean-variance frontiers rather than price minimizing strategies.

Theoretical analysis has been carried out for both power and gas purchases. The typical framework is that of a regulator that looks for an optimal benchmark, which is described as a set of public products that are available on physical and financial markets. Such products may include spot and future purchases, long term contracts, storage, and related options. The utility in turn can resort to public products, but also to a few more that are known to her only, for example *over the counter* trading. Finally, the game can be repeated, with the regulator learning from previous utility behavior.

Theoretical contributions are of limited help to practitioners, but could be the basis of computational exercises that could be arranged by experts on a case by case basis and become a useful practical tool. Theoretical economists have criticized pass-thru clauses, as part of the general criticism of rate of return regulation[47]. However, no general conclusion can be drawn regarding the optimal values of the key *a* and *b* parameters. An interesting conclusion by Muthuraman, Aouam and Rardin (2008) states that once a regulator has set an optimal policy, it is not efficient to change it after the utility has made its choices.

This statement leads to address what is at the core of this Chapter, i.e. the advisable regulatory approach. If academic theory does not provide very detailed and general suggestions to regulators, some literature have described and discussed mechanisms that have been proposed in practice.

47 According to Isaac (1982), fuel adjustment clauses distort the allocation of resources between fuels and other inputs.

In fact, the choice of *a* and *b* parameters is affected by legal constraints. In Europe, where even regulated suppliers have long enjoyed "light hand" regulatory regimes and preserved confidentiality of their purchase contracts, regulators have normally been forced to set b = 0, i.e. to leave to the supplier all savings that it could achieve by buying gas below benchmark levels.

To our knowledge, only the original 1991 British price control tried to transfer systematically at least a small share of the gains to customers, but this was later dismissed. A likely reason for this was the limited effectiveness of the incentive in a transition period towards a competitive market: under previous monopoly conditions and with limited cost-cutting incentives, the incumbent had high supply costs, often embodied in legacy contracts, that could be easily beaten under new, competitive conditions in the wholesale market. The limited (1%) annual improvement requirement turned out to be negligible in comparison with the cuts offered by competing suppliers.

As a consequence, European regulators have rather focused on establishing aggressive benchmarks (see Part II, Chapters 10-12 for an overview and detail cases). This has represented a good incentive and certainly a benefit for economies that have managed to see reduced supply costs. However, benefits for consumers have been mostly indirect: in fact, the pressure on markets resulting from the liberalization processes – and possibly also from the incentivizing regime based on benchmarks - has triggered a substantial evolution of markets, with a conspicuous development of ever more liquid hubs (Stern, 2012; Heather, 2015; Rogers, 2015). Together with the explosion and resilience of North American unconventional production, this has reduced prices as well as margins of upstream suppliers. As far as liberalization has worked for end consumers, they have benefited as well (see Chapter 1).

In the U.S., costs of gas purchases by regulated utilities are transparent, and regulators have been able to provide some profit sharing provisions for the gains triggered by PBR.

The most interesting period of regulatory activity on these issues has occurred between 2000 and 2006, when an increasingly tight US market has triggered gas price increases that have worried several state regulators and encouraged them to take action[48]. An overview is provided by Yu and Yu (2005).

Approaches that have been implemented or at least proposed in the U.S. include:

- Encouraging and/or auditing improved supply portfolios;
- Allowing utilities to hedge against price increases by means of suitable financial products, like futures and options;
- Allowing utilities to buy or develop more storage;
- Requesting utilities to present their strategies aimed to curb price increases and auditing them on a case by case basis;
- Allowing costs based partly on benchmarks, i.e. setting $b < 1$. Typically b has been set to 50% but some Commissions[49] have devised more sophisticated algorithms, e.g. with the recovery rate a decreasing as a function of the difference between benchmarks and the average actual purchase cost.

In the U.S., benchmarks have typically been identified as spot prices on key hubs, notably those closer to the utilities. The Kansas regulator took care to apply benchmarks to spot purchases only, excluding longer term contracts. In Texas, the benchmark has been set as the average of national purchase costs by utilities: this is an almost exact implementation of the original Schleifer (1985) proposal, but has been criticized as it fails to allow for the specific supply conditions of the State, which is the largest single producing State.

Some Commissions have considered PBR but have dismissed it, preferring to establish a retail competition program (not mandatory in the U.S), and claiming that aggressive regulation of gas pass-thru costs for incumbent supplier would jeopardize its development. This position is akin to that of several E.U. Member States.

48 After 2006, the (then largely unexpected) shale revolution has overturned the North American market and watered down the urgency of cutting utilities' gas purchasing costs.

49 In the U.S., these arrangements are the responsibility of Public Utility Regulatory Commissions, which have various names and organization but are always established at State level.

The World Bank has carried out interesting analyses of several world experiences, notably for the power sector, which are clearly relevant for natural gas purchases, including by regulated gas distributors or retailers[50].

Traditional ex-ante analysis and control of purchase contracts are not advisable, as they involve long and demanding effort as well as limited transparency. The same, and even more, could be said of ex-post controls, which amount to questioning the acceptability of deals after they have been concluded. Resort to ex-post control is a potential source of litigation and regulatory uncertainty and should be limited to cases where there is clear evidence of wrongdoings, like corruption or conflict of interest.

As far as possible, benchmarking should be based on existing competitive and (if possible) liquid markets. This can be achieved in three basic ways:

(1) *Requiring that supplies should be purchased by public auctions*. This is sometimes possible and often implemented for LNG purchases, and sometimes for pipeline supplies in competitive markets, like in Europe. However, gas markets are not generally liquid outside a few regions, and many deals are less transparent. For example, a long term contract may be cheaper than a spot supply for relatively large amounts but can only be stipulated under confidentiality. Thus, if supply alternatives are very tight, transparency may damage the buyers' interests[51].

(2) *Referring to benchmarks from liquid gas markets*. It is interesting to note that the increasing availability of the LNG chain is dramatically widening the availability of this option. A liquid market in Europe or North America can now represent a useful benchmark even for supplies to remote emerging markets: the logic is that suppliers optimize their sales and purchases worldwide, so that (for example) the selling price at a Gulf of Mexico hub of supplies heading for Asia, Europe, or inland America should be roughly the same. This

50 The following analysis mostly follows Arizu, Maurer and Tenenbaum (2004).

51 In fact, transparency has been higher for (mostly LNG) supplies to North-East Asia than for (mostly pipeline) supplies to Europe. Yet prices have been generally lower for the latter.

helps the supplier, who is sure to be earning a satisfactory price. On the other hand, the buyer may be exposed to closer and less costly competition (as it happens in Europe as of early 2016), but may benefit in the long term, and has remarkable hedging opportunities, offered by the liquid reference market.

In fact, this approach is now spreading into the remaining supply price controls of Europe. Examples are France and Italy, which are documented in the II part of this Book. In these cases, the preferred reference is the most liquid continental European hub (the Dutch TTF). Several interesting proposals have also been formulated in India, where competing gas supplies may now come from the Middle East, Australia, the U.S. and other producers, who are also selling in Europe or East Asia. This justifies reference to multiple world hubs.

However, reference to such hubs requires careful analysis of the supply chains by regulators, who must be able to estimate reference supply paths and the related costs.

(3) *Referring to benchmarks of alternative fuels*: these are taken mostly from the oil market (crude and derivative prices), and occasionally from coal. This option has long been preferred, as dominant supplies were indexed to alternative fuels, and substitution between fuel was important in end user markets. However, the world picture is now rather different and complex. Several studies have documented that in Europe substitution of natural gas by oil products is now minimal (Stern and Rogers, 2014), and price correlation between oil and gas prices is relaxing, as already happened in North America[52]. Therefore, European and North American regulators have largely switched to price benchmarks taken from gas hubs. In fact, benchmarks from the oil (or coal) market are mostly justified as a way of ensuring gas competitiveness against other fuels. Therefore, they are more properly discussed under non-cost-based regulatory approaches (see next section). In fact, for many years upstream suppliers have shared the goal of ensuring gas competitiveness, and have therefore accepted to stipulate contracts where

52 Substitution and hence competition between gas and coal has actually been rising in the last decade, even though most observers expect its future weakening as policies towards climate change strengthen. However, since prices for power generation are less frequently regulated, linkage between gas and coal prices is found in private contracts but rarely in regulatory clauses. However, there is no theoretical reason against the inclusion of coal prices alongside those of oil products.

> prices were indexed to those of competitive fuels. This was indeed the traditional arrangement in the European market, and fostered the development of the gas market as its competitiveness reduced demand swings. This arrangement involved a reduced demand risk for suppliers – and hence higher load factors of their costly infrastructure – in return for a higher price risk – as prices were to follow the oil market, albeit with some delay.

Arizu et al. (2004) see a mix of auctions and market benchmarks as the best solution for fuel purchases by electricity utilities, but reckon that it all depends on the features of the fuel market. For power generation, where only one supplier is available, no benchmarking seems feasible and ex-ante controls are necessary.

More than ten years later, and considering more specifically the natural gas market, it seems likely that a few benchmarking opportunities are normally available. The convergence of natural gas prices and the current (2016) oversupply of the LNG market show that a significant share of world markets are supplied by companies with a global outreach, which have been able to substantially unify the world market, reducing price differences among the main markets to those justified by transportation costs. Excellent market liquidity in North America and increasingly integrated and transparent European markets have led private players to more and more base their contracts on such hub prices, rather than the (increasingly divergent) benchmarks of the competing oil and coal markets (Rogers, 2015). Hence, prices in key world markets may have become good benchmarking points for regulators as well, in the respective markets. Referring to netbacks from existing competitive markets as domestic price regulatory criterion for exporters has also been analyzed from a theoretical perspective and found to be efficient (Brito and Rosellon, 2005).

However, price alignment is limited by the existence of remarkable transportation costs. In turn, such costs have uncertain impacts, which should be carefully considered in the definition of any regulatory formula based on hub benchmarks.

A difficulty stems from the fact that the benchmark rarely consists of a pure market price, but some transportation costs must be normally added (for net importers) or subtracted (for net exporters). However, the assessment of transportation costs present two types of problems.

First, international transportation costs are usually not transparent, as services are provided by pipeline companies or LNG carriers that may not be regulated, depend on foreign jurisdictions, and are often affiliates of suppliers and/or buyers. In all such cases, regulators probably either do not have the legal power to collect cost information, or such data could be distorted by the interest of the supplier (or the buyer) who controls the carrier.

Second, costs are themselves significantly variable, notably in the LNG sector, where integrated control over the chain by large operators competes with specialized services. Both liquefaction and regasification terminals are often joint ventures of several operators, ships can be chartered even on a spot basis, and large integrated operators encompass supply, destination and storage portfolios, allowing them to optimize their logistics.

In the pipeline sector, third party access and increasing availability of short term contracts and of (virtual or physical) reverse flow, alongside long term contracted capacity, heavily affect the suppliers' business.

In both cases, companies consider transportation costs in a very different way from regulators. Under a buyer's market, a company is likely to neglect any fixed costs that are "sunk", but expects (or at least hopes) to recover such fixed costs in the long term, when the business cycle reverts and the seller's market allows supernormal profits. However, regulators normally estimate full (long term) costs, which may therefore diverge from private players' estimations. The next Box illustrates such difficulty in more detail.

Generally speaking, the principle of long run marginal cost pricing would take regulators to use them to calculate the transport infrastructure components of costs – including the case where it must be subtracted to define a netback value. However, this can be at odds with the logic of suppliers – and particularly of traders – who take into account full costs only when the market is able to pay for it.

As the role of LNG tends to increase and the world market becomes more integrated, it is likely that LNG supplies will become the marginal reference supply for many (both importing and exporting) countries. This would facilitate the market valuation of shipping costs, but would not solve the issue of whether to include in the calculation the huge capital costs of liquefaction and regasification. However, many regulators are not ready either to follow a marginal cost principle or to follow market swings, where those of shipping would only add to those of the commodity. This is a difficulty that regulators have to address and could be a source of tensions between regulated prices and market tendencies. It would have a proportionally higher impact under buyers' markets, where transportation and other logistics costs have a proportionally higher role

BOX: ISSUES IN THE ESTIMATION OF TRANSPORTATION COSTS: A NUMERICAL EXAMPLE

Let us consider the case of two different imaginary countries without liquid markets: a net exporter and a net importer. Let us assume that their markets are not directly interconnected, but that both can sell into (or buy from) two other imaginary countries with liquid wholesale markets. All these markets are geographically separated, but connected by transportation routes (either as LNG or via pipe). Transportation costs consist of a fixed (long run) and a variable (short run) component.

To further facilitate understanding, let us call the four countries: "RF", "BIC", "US" and "EU". Any resemblance to actual country acronyms is (as usual) purely fortuitous[53], but may help the reader. The features of the countries are summarized in the following Table:

	Net Importer	Net Exporter
Liquid market	EU	US
No liquid market	BIC	RF

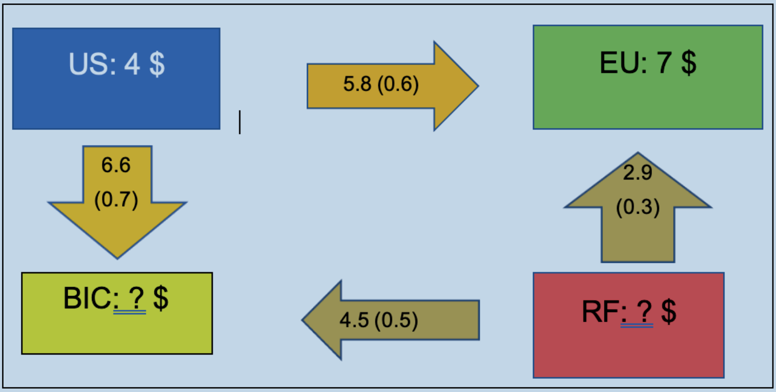
Dominant trading flows are shown in the following Chart. Numbers near the arrows represent the purely indicative long term[54] and (in brackets) short term transportation costs. Short term costs only include

53 BIC can be thought of as a "BRIC" without the "R", which in gas can well stand alone as "RF".

54 The recently commissioned new export terminal in Sabine Pass, Texas, operates (on a fob basis) with a tolling contract that has a fixed component of 3.5$/MBtu and a variable component estimated at 15% of the Henry Hub price (Source: World Gas Intelligence). However, this does not mean that the contract correctly reflects the shares of fixed and variable costs.

the variable cost of gas consumption and losses for liquefaction, shipping, regasification and (for pipelines) compression and leakages. The 10-year average prices at the main liquid hubs are also shown (in US$/MBtu).

Assuming that US is the marginal supplier (notably for BIC), and EU is the marginal destination (notably for RF), the regulated price based on



long run marginal cost would be calculated as follows:

In BIC (as cost): Price (US) + Transportation (US→BIC) = 4 + 6.6 = 10.6

In RF (as netback) = Price (EU) - Transportation (RF→EU) = 7 – 2.9 = 4.1

However, in a buyer's market, suppliers would be ready to forego capital costs to protect their market shares. Therefore, the calculation would be

In BIC (as cost): Price (US) + Transportation (US→BIC) = 4 + 0.7 = 4.7

In RF (as netback) = Price (EU) - Transportation (RF→EU) = 7 – 0.3 = 6.7

This example shows the difficulty that regulators would find in establishing regulation based on benchmarks if the evaluation of transportation is cost-based. In fact, at least for LNG, market conditions reverberate on transportation costs, which tend to share at least part of the ups and downs of LNG markets. In the last 10 years, charter rates have fluctuated between 40,000 and 150,000 $/day, against a full cost estimated at 70-80,000[55].

55 Estimation courtesy of David Ledesma.

2.8 Non-cost-based regulation

2.8.1 Subsidies: definition, rationale, and criticisms

The regulatory frameworks of OECD member countries always require regulated tariffs and prices to cover costs, and recommendations issued by multinational bodies like the International Energy Agency, the World Bank and even the International Monetary Fund are based on this same principle.

On the other hand, governments, notably in producing countries, often hold different view, leading to set regulated prices natural gas somewhere below cost. The typical reasons for this attitude can be broadly summarized as follows:

1. Natural gas, as a gift of nature, belongs to the country's people and must be used by and/or for the people, notably as a development tool. This attitude is related to the legal principle that underground natural resources belong to the state and that private intervention in their exploitation is only by state' concession. This legal principle is shared even by market oriented countries, as in Europe, but has remained stronger in developing energy exporters, with a tradition of centrally planned economies and a weak private sector.
2. Since gas is "by the people and for the people", a key principle of the (explicit or implicit) gas regulatory policy is that the gas rent should be set to zero for domestic consumers (either households or productive uses). If public budget requirements prevent a zero rent pricing, gas is anyway charged with a view to provide a competitive advantage for domestic gas-intensive industry and power generation vis-à-vis importing countries.
3. Since the above mentioned policies can hardly be pursued in a competitive market economy framework, where industrial players would have appropriated at least part of the rent, most gas rich countries have nationalized the industry, or entirely developed it from the beginning by means of public bodies and companies. In several cases, the key role of national oil companies (NOCs) in gas development is assured by its right of being a single or priority buyer of gas produced in the country. The key role of state-owned NOCs in gas

markets occurs not only in developing countries, but also in several European countries[56]. This case has interested almost all examined countries of Part II, as well as others (e.g. Norway, almost all Central-Eastern producing countries, Middle-Eastern, Asian and Latin American exporters, and even some Australian states.

The above attitudes explain why formal regulation of gas prices is not common in many self sufficient and exporting countries. In such cases, price setting is actually delegated to the NOCs, acting as a single buyer or at least as market leader, with the NOC's supervisory bodies (typically Ministries or the Cabinet) sanctioning them, or exercising pressures for their change. The most remarkable exception is of course North America, with the U.S. case discussed at length in Part II (Chapter 5). In other cases, cost based regulation is officially enforced, but implementation is often not transparent, and heavily influenced by political opportunities, with due price increases cut or postponed. Examples can be found in the Russian Federation, China, India, Argentina – also described in detail in Part II - and others.

Whoever the regulator and whatever the price setting process, there are several cases where prices are typically below costs. The IGU (2015) Report about gas pricing distinguishes between "Regulation Below Cost" where prices are explicitly subsidized and "Regulation after Social and Political" where this is not explicit but in fact "low prices" prevail. It is likely that the differences in the Report are more about how regulators define their approach than with the substance.

Let us briefly recall from previous sections that, even if several studies typically mention "pricing below cost" or "subsidized", this definition is rather ambiguous. A market price is usually defined by the marginal supply source and includes a premium, or royalty, as appropriate for exhaustible resources. Thus, the price can be logically split as follows:

P = Exploration & Production Cost + Transport Infrastructure Cost+ Marginal Rent + User Cost

56 It could be recalled that the energy industry, including natural gas, sees a comparatively high state involvement even in countries like the U.S., Canada and Australia, both in terms of ownership and of regulatory influence. In Europe, market liberalization has led to an often slow and painful decline of the NOCs' supremacy in the gas market, but several have remained as market leaders (incumbents) in their markets.

In this definition, E&P as well as infrastructure costs also include a normal profit component. However, debates about subsidization often refer to a cost definition that includes only the first two components. In fact, in several cases prices fall short even of such definition. Costs of different reservoirs are likely to be rolled in, so that reference to costs usually means the average costs. User costs that are included in international market prices are not usually considered in this cost definition. On the other hand, for the regulation theory (see Section 2.2 and Figures 2.1-2.3) efficient pricing is related to marginal supply, includes its user cost: this maximizes welfare for the concerned country.

Pricing at international prices is often criticized on distributional grounds. Politicians (and regulators if that is their mandate) may have a preference for a redistribution of the welfare, for example from producers to consumers. In other words, they may prefer a smaller total welfare, but a larger one for consumers. In most countries, producers (even including workers) are seen as a limited group, whereas consumers are the large majority of the population.

As a rejoinder, economists suggest that such redistribution is more effectively achieved by other solutions, notably what is known in the literature as "tax and transfer system". The strength of this argument has been long discussed in the economic literature, and cannot be solved theoretically, but it depends on how effective is the tax and transfer system in each jurisdiction. For example, use of electricity prices below costs has been advocated for very poor countries, as they are not likely to have an effective tax and transfer system, so that delivering electricity (or other basic products) below cost may be an effective way to redistribute income. Furthermore, access to electricity at very low prices is often the only way to provide several electricity-based basic services to the largest population. Pricing gas at the lowest feasible level when gas is an important fuel for power generation is just another way of achieving the same goal.

However, in countries with a higher per capita income, such approach easily carries the risk of providing subsidies even to a relatively affluent part of the population, which is highly inefficient. For these reasons, most international organizations like the International Monetary Fund, the World Bank and the International Energy Agency have consistently criticized energy pricing below marginal cost as a way of redistributing income, unless this is limited to groups of vulnerable customers, or for basic consumption levels (and hence, for limited consumption blocks). This point is even stronger in case prices are directly subsidized, and set even below the average cost (IMF, 2013). In fact, energy consumption in almost all of its forms – from electricity to gas to oil derivatives – increases more than proportionally with income. Redistribution from pricing energy below cost is therefore actually regressive, or is a redistribution *towards the rich* rather than the poor.

Moreover, in the case of the upstream oil and gas industry, the tax system works fairly well even in relatively undeveloped fiscal systems, as oil and gas production can normally be tracked. A large international practice of upstream taxation exists, based on royalties and profit taxes, ensuring that most revenues from oil and gas exports are taken by the state. Therefore, taxation difficulties are not an important point against cost reflective pricing of natural gas.

A large literature has discussed energy subsidies, which have become such an important macroeconomic issue to become the subject of several World Bank and IMF studies and position papers. Criticism of energy subsidies is based not only on the two above arguments – allocative inefficiency and regressive distributional impact –but also on the adverse macroeconomic and environmental effects. The macroeconomic effect is actually another way of describing the allocative inefficiency, but points to its size, which has become impressive in some countries. In Egypt, until the 2014 reform, energy subsidies exceeded the size of major public expenditure items, like defense, education or healthcare. The amount of resources wasted in underpriced energy has become a major obstacle for several developing economies.

Another major issue is the environmental impact. Energy waste also leads to higher environmental impact at local, regional and global level. The impact is just the opposite of that of policies aimed at containing climate change. In the longer term, subsidies to fossil fuels jeopardize not only energy efficiency, but also the growth of more sustainable energy production from renewable sources.

Natural gas is part of the picture, even though natural gas subsidies are lower than those provided to electricity and liquid fuels and are estimated by the IMF at 112 $ billion/year, or about 23% of the total. However, the environmental impact of natural gas subsidies is not so clear: whereas they directly or indirectly stimulate energy consumption, the impact could be positive if they manage at least to offset those provided to higher impact liquid and solid fuels, or even to displace some of them.

The case against energy subsidies is so clear that the debate is now focusing on how to reduce and eventually erase them, rather than about their worthiness. A few governments that have introduced them in the past are now struggling to phase them out against a reluctant public opinion. These discussions are very important, but beyond the scope of this book and covered by a significant literature, including several national case studies. The interested reader is referred to IMF (2013).

In the next subsections, we will instead focus on special cases where a pricing policy that is not directly based on costs may be appropriate. These policies may generate supernormal profit or require some subsidies, but certainly not of the size triggered by the above reported, and much criticized, energy subsidies. The key policies that are worth considering are:

- Pricing after long term costs, with a view to anticipate economies of scale;
- Pricing after competing fuels, with a view to ensure the competitiveness of natural gas.

Although the basis is different, these policies may lead to similar results: in both cases, the goal is to expand gas consumption at the expense of other fuels. In turn, this aims at two other objectives:

- Improve the efficiency of energy supply by properly exploiting the economies of scale in gas transportation and distribution;
- Reduce the environmental impact of energy supply by substituting a cleaner fuel to dirtier liquid and solid ones.

2.8.2 Prices, costs and economies of scale

Gas is transported and distributed mainly[57] by networks, and therefore shares with electricity the possibility to exploit remarkable economies of scale. As consumption grows, the increase in transmission and distribution costs is very small. The most significant example is gas distribution in cold and temperate climates, where an important share of natural gas consumption is for residential and commercial space heating. In fact, the network that can supply basic cooking fuel to households requires only limited enhancements to be used for the much larger heating consumption. Hence unit distribution costs can be greatly reduced by winning the heating market, but this requires low prices (to beat competition from other fuels) and time: a new heating customer is normally won only when his appliances need renovation, which may take between 10 and 20 years.

Similar economies of scale occur even for large industrial customers, which may exploit natural gas for different purposes. However, the share of high pressure costs is smaller for transmission than for local distribution (typically less than half), therefore the possibility of cutting costs by expanding consumption and load factors are limited. When gas is used mostly by large users, like power generation or primary industries, the scope for cost cutting from the achievement of economies is rather small.

Other economies of scale, albeit of limited relevance, can be achieved by increasing consumption *density*, which may be defined as the ratio between consumption and network lengths. For example, pipelines that have been originally built to supply few large customers (*anchors*) may also be used to supply smaller ones, including local distribution. The very high economies of scale in gas transmission justify building oversized pipelines whenever the perspective of expanding consumption of neighboring customers obtains. Such multiple usage of pipelines reduces unit costs for all connected customers, including original anchors.

Regulators should carefully consider these opportunities. In the long term, when all potential market opportunities are exploited, the costs of gas supply to end users may be significantly lower thanks to the exploita-

57 Lately, the expansion of the small scale LNG business is foreshadowing a future where natural gas can extend competition with oil derivatives to the transportation sector, starting from bigger users like ships and trucks, and other areas that are not reached by pipeline networks. However at present this promising demand sector is in its infancy.

tion of network economies of scale and higher consumption density. On the other hand, in the short term, when these cost cutting factors have not been achieved, gas supply costs for end users may be higher, which weakens their competitiveness towards liquid and solid fuels, featuring lower economies of scale. Setting prices strictly in line with present costs may be myopic and ignore the increasing competitive strength of natural gas when its consumption increases.

The most efficient exploitation of gas possibilities, faced with significant competition from other fuels, may require a flexible pricing policy. Suppliers may well agree to sell gas below cost, in order to promote consumption and achieve economies of scale and density. Discounts may be useful for a few years, notably for selected customers. However, suppliers must be sure that such losses and discounts are recovered in the longer term, which may last well over the typical 3-6 years periods that tariffs are revised in the European and North American regulatory practice.

Therefore, if the regulator is willing (or instructed) to promote gas consumption expansion, its pricing policy must be very flexible in the short term. Ideally, he may allow the supplier the right to accumulate some losses to be recovered in the longer term, once costs have fallen and gas competitiveness becomes easier.

It is worth recalling that such suggestions are provided in case a regulatory regime is maintained even under a significant interfuel competition. In such conditions, price control is hardly justified and regulation is more likely to be damaging than useful. The risk is that regulators may prevent the suppliers to take losses in the short term and recover them later – or perhaps just the latter – discouraging private players from entering – or expanding - the market.

The analytical basis for such regulation could be the price that can be achieved in the long term, after a certain market size is reached. In principle, the regulator may ask the supplier to provide such estimates and allow the recovering of short term losses over a sufficiently long period. In practice, such schemes are more likely to be managed by state owned companies, yet the potential for more transparent and efficient implementation of gasification programs could be envisaged.

2.8.3 Pricing after competing fuels

The most common, traditional way of promoting gas penetration vis-à-vis other fuels is by keeping its price aligned with them in terms of equivalent useful energy, with a certain, rather stable margin that encourages switching towards gas. This approach has been long pursued in the early stages of gasification – i.e. in conditions of high natural gas demand growth. It is worth recalling that in the early stages of natural gas penetration in the energy market, competition from other fuels is quite effective so that containment of gas suppliers' market power is not of the utmost urgency, even though prices are sometimes subject to formal regulation[58].

On the other hand, pricing after competing fuels has effectively served another, different purpose. In markets with a limited number of (possibly foreign) suppliers and one or few local marketers, lacking any significant liquidity, a serious bilateral monopoly problem occurs. In such conditions, the definition of the price at which gas is transferred from producers and upstream suppliers to retailers and other traders is rather uncertain, as is the definition of a rule for price updates. The linkage with competing fuels, notably with oil and its derivatives, provided an effective way of solving this problem, because the oil market is always so large and liquid that its outcomes can be regarded as independent of the actions of any gas supplier, and provided therefore an independent reference to solve the inherent uncertainty of bilateral monopoly pricing. Moreover, this approach provided a rather clear split of the commercial risks of the deals: suppliers take the price risks, as the oil market can suffer from significant fluctuations; but they know that the cyclical nature of commodity markets, including oil's, makes it very likely that a remunerative average price can be achieved in the long term.

On the other hand, this approach[59] ensures natural gas competitiveness so that the volume risk is greatly reduced. In return for taking up the price risk, the gas buyer – usually a midstream company that in turn sells gas to local distributors and large end users – takes most of the volume risk by subscribing take or pay contracts, where gas must be paid even if not actually consumed. In case gas demand falls for any reasons - from

58 For an example of discussion of interfuel competition and its impact on price regulation see Casarin (2013).

59 This methodology has been originally conceived in the Netherlands for the first pipeline gas exports to neighboring countries in the 1970's. See Part II, Chapter 13.

macroeconomic crises to overwhelming competition of other sources - the buyer must pay at least a certain share: this is the well-known *take or pay* percentage clause. Several variations and complex clauses have been elaborated starting from this basic model (see next section).

In the most advanced markets, this approach belongs to the past: it is history in North America and is being phased out in Europe, where only legacy contracts are mostly oil-related, and are often reformulated to include hub-related components. The rationale for the oil-gas price linkage is reduced by the sharp reduction in the substitutability between gas and oil derivatives, which has been fostered by technological evolution and environmental regulations. What is more, the emergence of liquid and relatively independent gas markets strongly reduces the need to find an external anchor for gas prices (Stern and Rogers, 2014). Therefore, even where gas price controls are retained, the linkage has been generally moved towards hub prices (see Part II, Chapters 10-12). In private contracts, links are sometimes provided to coal, which has actually returned as a major gas competitor in power generation, or even to prices of traded goods produced by means of gas, like electricity or fertilizers.

In practice, the calculation of gas prices equivalent to those of competing fuels is not directly used for regulatory purposes. Rather, it is the basis for a calculation of consistent wholesale prices, which may be used in the calculation of end user gas prices. The typical rule amounts to setting the wholesale gas price equal to the weighted average price of competing fuels, calculated as equivalent energy, and subtract a weighted average of transportation costs from the wholesale price location (hub) to the gas end users, and a margin:

$$P_g^W = \Sigma_i F_i S_i - \Sigma_i L_i S_i - M$$

Where is the regulated wholesale gas price, F_i is the (energy equivalent) price of an alternative fuel for market sector i, L_i is the logistics (transportation, distribution, storage) cost of delivering gas to market sector i, and S_i is the share of the gas market belonging to sector i.

Apparently, difficulties are similar to those of defining regulated tariffs for the logistics component of the gas value chain, i.e. of establishing regulated transportation, distribution and storage tariffs. However, a further difficulty occurs: that of defining reference conditions for delivery. Regulated transportation and distribution tariffs normally include several components, which may be related to capacity, peak, user, or commodity indices. For a gas price value, these must be turned into an commodity-based price, which is usually calculated under reference conditions, e.g. for the load factor and profile of a typical or average consumer. However, errors can be significant as demand conditions change for natural and economic reasons.

Likewise, the margin to be left should be related to a competitive advantage that natural gas is supposed to maintain, in order to encourage customers to switch towards natural gas, which often requires some investment costs on the consumer's side.

However, the regulator need not necessarily embark on the difficult calculation of what is the right margin, or the right mix of consuming sectors and load profiles. Rather, the logic of alternative fuels is mostly applied as an indexation (escalation) criterion rather than to set the base price. The logic is that the supplier knows better what price, and hence what margin, is needed to ensure the desired natural gas competitiveness. The regulator's goal is to ensure that consumers retain this (or at least some) advantage after they have switched to gas and have lost the power they had towards the supplier before switching. Hence, all the regulator must do is to ensure that price changes occur in accordance with those of competing fuels.

Thus, this approach aims to protect customers but is not cost based. Suppliers face a fair pricing rule, but are allowed to accept the original deal on which the price updating is based, and take full risk for losses that may arise in case the market is not won, e.g. because prices of competing fuels fall below levels that cover gas suppliers' costs. In these cases, the rationale of the regulation is often not clear: the purpose may be either to ensure gas competitiveness against other fuels, as well as to follow supply costs, which are in turn linked to prices of competitors. This double purpose may be at the root of the historical success of oil indexation formulas, which are still widely used even though they are declining in advanced Western markets. On the other hand, the ambiguity could be a source of legal difficulties, as regulators may be bound by primary law principles and their decisions may be challenged before the relevant courts or appeal bodies. In the regulatory arena, multi-faced approaches may be a source of uncertainty and litigation.

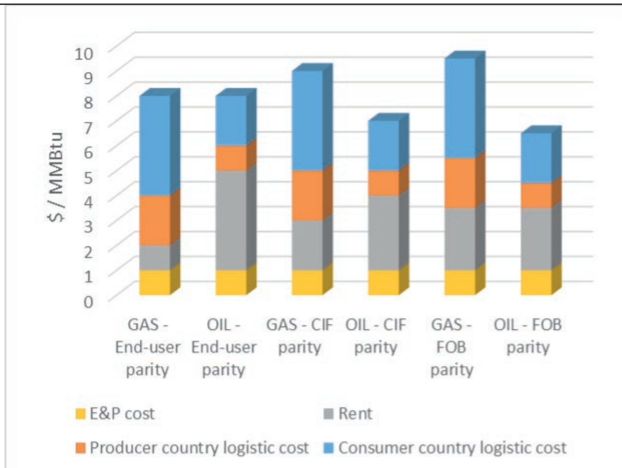
A further practical difficulty of linkages between prices of gas and those of competing fuels is the time lag that applies to the former, as implementation requires acquisition of competing fuel price data. Historically, this time lag in commercial contracts and regulatory implementations alike has been between 3 and 9 months[60]. An alternative is provided by oil future prices, which are now available and reasonably liquid, but may grossly miss actual oil price development. Yet, it is hard to find an approach that can properly face price routs like those of 2008-9 or 2014-15.

In practice, the parity concept is often used simply as a way of approximately mirroring costs of gas supply, which is in turn related to those of competing fuels, e.g. by an S-curve (see below).

The parity concept has not always been defined starting from end user markets. In some cases, producers (notably producing countries and their NOCs) have tried to establish an upstream parity concept towards oil. Originally, the concept involved parity of the energy equivalent price of oil and gas at delivery from the exporting country – a concept known as fob parity. A variant was to allow for different international transportation costs, which are typically larger for gas than for oil, and establish a parity after including such costs (*cif* parity). Larger gas logistics costs are partly offset by efficiency gains allowed in the final consumption stage: the best known case is power generation, where a state of the art combined cycle gas fired power station allows an energy recovery efficiency of over 60%, against about 45% of the most advanced coal fired stations.

60 It may be claimed that, apart from the practical problem of getting data, the typical 6-month delay between oil and gas prices fitted with markets conditions, as gas consumption tends to peak in northern hemisphere winters whereas oil demand tends to peak in northern hemisphere summers, due to the "driving season". This linkage does not fit with the needs of gas markets that peak in the summer due to the increased air conditioning demand, like those of the Middle East and others.

Figure 2.10 – Parity pricing



Since gas logistics cost are larger than those of oil or coal, a *fob* parity entails a higher final price of gas than an end user parity, with *cif* parity in the middle. Therefore, an oil parity would restrict the gas market, by pricing it above competing fuels.

In modern commercial practice, S-curves are the common way of linking oil and gas prices: the gas price is a linear function of an index, typically a basket[61] of oil crudes and/or derivatives. The linear function normally includes a constant term, usually between 0.5 and 1 $/MMBtu. However, the indexation mechanism only holds within a certain range, with a floor protecting the producer against too low prices, and a ceiling protecting symmetrically the buyer.

Thus:

$$P_g^W = C + s\, I_f$$

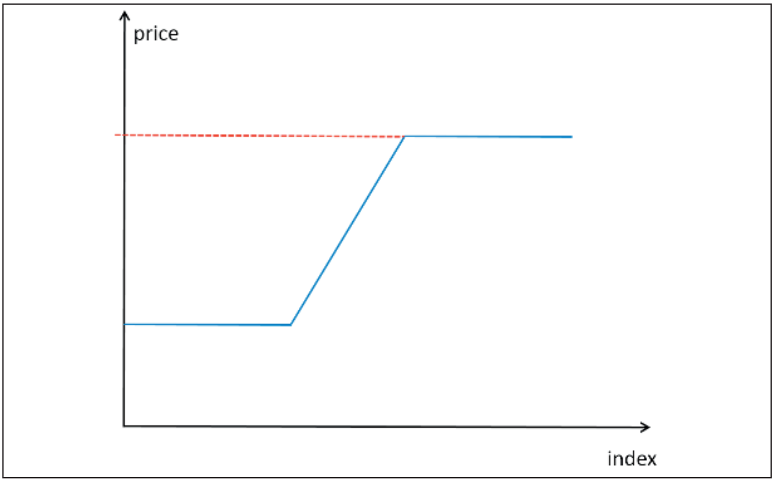
where C is the constant term, s is known as the slope and If is an index of alternative fuel prices or their mix.

In fact, current commercial practice hardly refers to a parity concept. However, since reference to oil is still important in less developed mar-

61 The best known and used index is the Japanese Crude Cocktail (JCC), but the British Brent, originally a single crude, is now also a cocktail of crudes.

kets – notably where oil products are still significantly used to generate electricity – the slope of a contract is a typical measure of the state of the market. Slopes involving prices close to parity[62] indicate a seller's market whereas in the 2015-16 excess supply market conditions they are often as low as 60-70% of the fob parity.

Figure 2.11 – S–curve pricing with floor and ceiling



In principle, the S-curve concept can be a sound basis for a regulatory approach aimed at including in regulated end user prices an international market-based natural gas value, while at the same time offering a basic protection to both producers and consumers. If independently defined by market parties, such agreement could be sanctioned by regulators, with a view to avoid regulatory uncertainty that may prevent investments and the development of markets. Basically, parties can agree and regulators can sanction that, in energy markets affected by latent volatility and deep uncertainty, traditional risk allocation is no longer the only and best solution. Both quantity and price risks must be shared by both buyers and sellers, who may agree on minimum and maximum prices to reduce risks from investments on each side.

62 In commercial practice, where gas prices are set in \$/MMBtu and oil prices in \$/bbl, parity is indicated by a slope of 0.166 with a constant term of 0.5 and an oil price in the 80-100\$ range. These levels are rarely achieved in practice, with slopes more commonly between 0.14-0.15 in seller's market conditions and 0.11-0.13 in buyer's markets.

Examples of practical details of this approach are presented in the historical experience of European countries in part II. Their experience may still be useful, even though they are phasing out price controls or moving price linkages to gas market hubs. However, if this experience has to be applied to other markets in emerging economies, substantial adaptation is necessary. In particular, the latter's markets are typically dominated by power generation and heavy industry, therefore the reference fuels differ.

2.9 Non-price regulation

It is reasonable for a regulator to define not only regulated prices, but also other contractual conditions, as no price has a meaning if the characteristics of the traded good and supply conditions are not accurately described. Contractual conditions are usually defined in contracts that have been stipulated before a price control is introduced, in such case the regulator may simply require them to be left unchanged. However, worsening of the quality of service or other performance indicators is a typically feared reaction of suppliers to price controls, therefore regulators are understandably interested in keeping at least the main non-price conditions of deals under control, and should know their efficient ranges.

In particular, the gas regulator may be concerned about:

- Load factor clauses:
    - o *take or pay*: percentage of contracted gas that must be paid for even if not withdrawn;
    - o *make-up gas*: amount of gas subject to take or pay, the withdrawal of which can be postponed to later periods;
    - o *carry forward*: amount of gas beyond take or pay obligation that, if withdrawn, can be used towards a reduction of take or pay obligations in the next period (usually year)

- Technical performances:
    - o *load factor*: ratio between the average and the maximum allowed daily (or hourly) quantity;
    - o *swing factor*: ratio between maximum and minimum (daily or hourly) withdrawal rates;

- o *ramp-up and ramp-down rates*: speed at which a certain (e.g. the maximum or average) withdrawal rate can reached starting from zero, and vice versa;
- o commissioning period;

- Delivery conditions:
    - o gas and service quality;
    - o destination and re-delivery clauses.

Unfortunately, whereas clear illustrations of contractual clauses are available (Roberts, 2011), theoretical discussion and international experience on such issues are not very helpful. There is little publicly available information on such conditions, for several reasons:

1. Natural gas production is related to natural conditions of the reservoir, hence performances may be very different, for similar investment costs. It is difficult to require certain performances, which may entail significant cost increases, and it is difficult for the regulator to assess whether such costs are justified[63].

2. In the regulatory history, price regulation has normally come first, taking for granted that the characteristics of the service should be at least as available before the price regulation was introduced. Only later regulators have tried to introduce other rules, for example in terms of quality of service, technical performances, and contractual conditions, usually starting from those applicable to small customers. On the other hand, in the upstream and supply gas field this has not generally happened, because deregulation and liberalization have generally voided the scope of such regulations[64]. Thus, regulatory experience in (non-price contractual regulation is very limited.

3. In several cases, notably for E&P, governments rely on NOCs,

63 In the few cases of underground storage regulation, an activity that is technically similar to production, the same problems arise. Storage site performances (including depleted fields, which the large majority of them) have rather different technical performances e.g. regarding injection and withdrawal rates. Regulators usually require transparency but do not set the performance standards.

64 Non price-regulation is normally limited to transportation and distribution. For high-pressure transportation, it is particularly developed in Europe, but mostly aimed at ensuring fair access to networks.

which actually play the role of the upstream industry regulator. This is justified by the technical complexity of the details, as well as by the above mentioned difficulties of assessing the relationship between performances and related costs. The NOC, being itself endowed with in depth technical expertise, can perform this job better than the regulatory agency, but is less transparent, often in order to better discriminate between suppliers.

4. In several cases, regulation of gas supply is directly performed by Ministries, and follows more political and less transparent criteria. Ministries tend to rely on operators for more detailed technical issues.

5. Since both Ministries and NOCs in producing countries tend to maximize revenues and minimize IOC's profits, they have developed a complex set of tools to achieve such goals. However, this toolbox usually does not include only technical conditions of supply, but extends to taxation, exploration and drilling efforts, bonuses to be paid to win the concessions, duration of the permits, development times etc. The disclosure of details is seen as damaging for the achievement of the above mentioned NOC revenue maximization as well as IOC profit minimization goals, and expertise that is necessary for this approach is generally regarded as a valuable asset of NOC staff and management, not to be easily shared.[65]

However, in principle expertise of NOCs and Ministries could be transferred to regulatory agencies. Yet extending the formal regulatory approach applied to prices and quality of service for small customers, notably in electricity, is hardly advisable. Before undertaking this type of efforts, the regulator should always consider that conditions may change faster than the time needed to open and implement a procedure to cope with them. For example, changes in the market or unexpectedly poor or good reservoir performance may justify contractual adjustments that private parties can quickly enforce but regulators cannot. The resulting regulatory uncertainty may jeopardize the development of resources.

65 It is worth recalling that oil&gas producing countries are typically competing for exploration and development investments by IOCs. This does not solve the problems of market power, but helps achieving reasonable contractual conditions.

Considering these difficulties, for a country without a NOC, a procedure in line with transparency criteria of Western style regulation to address these issues could be as follows:

- Open a consultation about the possible parameters to be subject to regulation, focusing on a limited number;
- Once these have been identified, ask operators and other stakeholders to present proposals and related costs. This may lead to some disclosure of foreign experience as well;
- Hire a technical consultant to assess the proposals, e.g. whether the cost of adding more wells to a reservoir to improve flexibility and deliverability is reasonable;
- Enforce a limited number of technical provisions, allowing for price increases as necessary to fund the approved investment.

Some parameters may be subject to preliminary assessment before a detailed technical assessment is carried out. For example, the regulator could assess costs of a lower take or pay threshold by using different quantities in the same financial model that is used for cost assessment. A reduction of the take or pay gas, or a rescheduling of supplies over a longer period, leads to a cost increase, which could be taken as a measure of the cost of requiring a lower take or pay level.

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PART II

WORLD CASE STUDIES

3. THE UNITED STATES

Jeff Makholm

3.1 Introduction

The gas industry in the United States is more than a century old—and for about half of that time the federal government was involved in some form of gas price regulation as part of its efforts to organize and regulate the gas pipeline and distribution industry.

Today, the natural gas industry in the United States has reached a kind of regulatory equilibrium. Free of major controversy or initiatives for change, modern gas industry exhibits the following attributes:

a freely competitive gas production sector with spot and futures markets throughout the continental United States (extending into Canada) unlike any other regional gas markets in the world;

cost-based regulation of gas transmission services provided under federally-licensed pipeline capacity and capacity contracts between pipeline companies (who own no gas themselves) and shippers;

unregulated sales contract capacity rights to the existing licensed pipeline capacity, creating a competitive market in pipeline "space";

largely passive regulatory certification/licensing of a vigorous and genuinely competitive market in pipeline capacity expansions; and

a state-regulated distribution and retail supply sector that collectively is the largest collection of gas buyers in the country, and that passes those gas commodity and pipeline transport costs to their connected users at actual invoiced cost without margin, as they pass through their other purchases (such as labour and materials), at actual cost.

The most striking element of gas pipeline regulation, compared to Europe for example, is the lack of non-contractual "common carriage" or "third-party access" obligations on US gas pipelines. Gas pipeline regulation formed around pipeline contracts, instead.

The transition to open pipeline access and deregulated wholesale gas prices was not smooth or deliberate in terms of gas market regulatory policy. But the political and institutional story is critical to understanding the development of the world's only unregulated gas pipeline capacity market and its accompanying highly competitive gas market.

Creating contract-based gas transport companies was an important step towards the current regulatory framework. However, the construction of a genuine market in capacity rights was defining. In the end, a "Coasian" market in the legal rights to capacity on the US pipeline system developed, worked, and survived the various energy "crises" of the 21st century, including hurricane Katrina and the Californian Electricity Crisis.[1]

Gas pipelines now exist in a market with unusual regulatory equilibrium, which has overcome the certification/monopoly problem. The market determines who will use the nation's gas transport capacity. Further, it has allowed FERC action over regulated prices to recede to the point where it is little more than background noise. The development of modern gas pipeline regulation in the US ultimately demonstrates how hard it is to create regulations that satisfy the competing objectives of the critical interest groups.

The regulation of gas prices in the United States consists of the following reasonably well-defined periods:[2]

No federal gas or gas pipeline regulation before 1938: Increasing concentration of the gas industry into multi-state holding companies formed to evade the state regulation of local gas companies as those companies switched form locally-produced coal gas to natural gas. The period ended with Congress passing - as part of a common legislative initiative - two important laws: (a) the Public Utility Holding Company Act (PUHCA) in 1935 unbundling (i.e., forcibly separating) state-regulated local gas companies from federally-regulated interstate pipelines, and (b) the Natural Gas Act (NGA) of 1938 regulating the interstate gas industry using the accounting and administrative tools developed by state regulators in the prior decades.

Increasing gas commodity price regulation from 1938-1954: Uncertainty over whether the NGA permitted the Federal Power Commission (FPC) to regulate the price of gas in addition to pipelines ended when the Supreme Court in its Phillips Decision directs the FPC to engage in such regulation, which the regulator did with the cost-based accounting and administrative tools that it applied to pipelines.

Regulation and constant industry and political disputes from 1955-1978: Cost-based regulation of individual, and then field gas prices, partly leading to a shortage of interstate gas shipments as within-state gas shipments were not subject to federal regulatory caps. All through this time there were unsuccessful legislative efforts in Congress to deregulate gas prices. 1978 marked the passage by Congress of the compromise Natural Gas Policy Act (NGPA) of 1978 that loosened the regulation of gas prices in response to perceived shortages of interstate gas shipments.

Phased deregulation of gas prices from 1978-1989: wellhead prices gradually loosened and then eliminated completely by Congress with the Natural Gas Wellhead Decontrol Act of 1989.

Phased unbundling and creation of "Coasian" pipeline transport market from 1985-2000: overlapping with loosening wellhead gas prices regulations, the Federal Energy Regulatory Commission (FERC — successor to the FPC) in various orders and actions unbundled the gas market from the pipeline transport market and created a competitive market in capacity rights, permitting shippers to access competitive gas prices with transparent, flexible and tradable cost-based-regulated pipeline capacity rights.

Vigorous and unregulated gas commodity market after 2000: The competitive gas market exhibits some pricing fluctuations, and shippers took some time to learn how to adapt to flexible open access, but since 2008 the gas market has been vigorously competitive, with prices that have permanently split form oil equivalent prices (which are maintained in the rest of the world). Competition encouraged the application of new technology to the production of unconventional supplies at increasingly low costs. Contracts may be signed for long terms of several years as well as for periods that are as short as the day, or even fractions. The U.S (and the interrelated Canadian) markets are the most liquid in the world.

3.2. The infant unregulated industry

Prior to 1906, the US natural gas industry, and its supporting pipeline infrastructure was small and limited to the regions adjacent to the gas fields due to limitations of the materials pipelines were constructed from. The physical limitations of the infant gas industry meant it grew up, along with the oil industry as unregulated.

New technology, particularly the introduction of welding, combined with strong economic conditions meant gas pipeline construction grew rapidly in the 1920s. Gas was now able to be shipped between municipalities, leading to the rise of state based regulators to oversee regulation.

It was during this time that the long distance transport of gas from the Hugoton-Panhandle basin in Kansas/Oklahoma/Texas Panhandle to markets in the Midwest was first accomplished. Figure 3.1 shows the major gas producing basins and gas pipelines in 1930.

3.3 Federal Jurisdiction

During the gas pipeline boom of the 1920s and early 1930s, before the Depression halted all gas pipeline construction until the mid-1940s, state regulators tried repeatedly to exercise a measure of control over the gas prices charged by their local distribution companies. Local distribution companies had increasingly become integrated, either by contract or consolidation, into national gas pipeline businesses. The charges for wholesale gas delivered to local distributors increasingly became a function of the gas and pipeline fees charged by companies outside state jurisdiction.

Starting in 1910, the Supreme Court used a series of interstate commerce cases to clarify and re-affirm the necessary role of Congress in regulating gas pipelines. For example, in 1924, the Supreme Court struck down an order issued by the Kansas Corporation Commission that fixed city gate rates charged by the Cities Service system. The Court stated:

> The transportation, sale and delivery constitute an unbroken chain, fundamentally interstate from beginning to end, and of such continuity as to amount to an established course of business. The paramount interest is not local but national—admitting of and requiring uniformity of regulation. Such uniformity, *even*

> *though it be the uniformity of governmental non-action*, may be highly necessary to preserve quality of opportunity and treatment among the various communities and states concerned.[3] (*emphasis added*)

Figure 3.1. Major Vertically Integrated Gas Pipelines in the US, 1930

Despite having jurisdiction over gas pipelines, small profit margins in the industry during the 1930s meant Congress delayed regulating the industry until there was more pressing concern about rates abuses by holding companies. Congress then passed two pieces of legislation. The first to restructure the holding companies; the Public Utility Holding Company Act, and the second to regulate interstate gas pipelines; the Natural Gas Act.

3.4 Abuses of Integrated Holding Companies

The holding company structure adopted by electric and gas utilities in the US during the 1920s and 1930s enabled a number of abuses. The holding companies' primary abuse of power involved using regulated franchises to cross subsidize non-regulated franchises, exposing regulated franchises to extraordinary risk of financial collapse with even the slightest non-performance. This allowed holding companies to earn excess returns on non-regulated franchises.

This kind of exploitation can occur in any regulated company, though modern accounting regulations and meticulous scrutiny of affiliate transactions by experienced regulatory jurisdictions ensures that many abuses do not take place. Until the 1930s, however, US regulatory methods were not equipped to handle such problems.

In February 1928, the Senate asked the Federal Trade Commission (FTC) to conduct an investigation of the public utility holding companies. The report showed the degree of market concentration, highlighting that over half the gas produced and more than three-fourths of the interstate pipeline mileage in the US was controlled by 11 holding companies. The four largest holding companies controlled 58 percent of the pipeline mileage. The holding companies had also branched out into manufactured gas, electricity, oil production, and coal.[4]

The FTC report highlighted many gas market abuses perpetrated by the holding companies, including monopolistic control of gas producing areas, unreasonable differences in wholesale gas prices, pyramiding investment schemes in gas enterprises, excessive profits on transactions between affiliates, inflation of assets and stock watering, and misrepresentation of financial conditions.[5]

3.5 Restructuring of the Holding Companies and Interstate Gas Pipeline Regulation

Congress dealt with the abusive market behavior of the holding companies by passing the Public Utility Act in 1935. Title I of the larger act (known as the Public Utility Holding Company Act or PUHCA) gave the Securities and Exchange Commission (SEC) jurisdiction over public utility securities. As part of their new jurisdiction, the SEC was given the power to simplify the holding company structures of gas and electric utilities.

The SEC's goal was to establish integrated distribution systems that were confined to a single regional area, and to ensure that no holding

4 Sanders, *The Regulation of Natural Gas*, p. 28.

5 Castaneda, *Invisible Fuel*, pp. 33-34.

company was so large as to impair local management, effective operation, or effective regulation.[6] In passing the Holding Company Act, Congress effectively ended the vertical integration of gas pipelines and gas distributors. The relationship between companies holding extensive relationship-specific investments became clearly defined and almost purely contractual.

The Public Utility Holding Company Act was a very strong piece of legislation, as it prescribed an unprecedented structural reorganization of the US utilities. It was the last time that Congress was willing to bypass widespread industry opposition to take such strong action regarding the corporate structure of interstate pipelines.

The PUHCA did not provide for the regulation of the interstate gas pipeline industry (although it was part of a broader legislative initiative that included that subject). To govern the interstate pipeline market, Congress had to deal with powerful political and economic constituencies, including state regulators who objected to ceding any jurisdiction over local gas companies; gas producers who wished to avoid commodity price regulation; and the gas pipeline companies themselves, who feared the potentially destructive consequences of common carriage and the potentially cut throat competition of a highly capital intensive business.

Congress avoided direct confrontations with each of these three groups as it crafted the far-reaching legislation known as the Natural Gas Act, which became law in 1938. That the Natural Gas Act is still in force today is a testament to its underlying durability and effectiveness.

Importantly, the Natural Gas Act 1938 gave the Federal Power Commission (FPC), now the Federal Energy Regulatory Commission, the power to regulate the sale and transportation of natural gas. There are several sections of the Act that distinguish it from any other federal regulation of inland transportation, namely the Act:

- satisfies the States by stating that Federal regulation will only occur if in the public interest and that Federal regulation "shall not apply … to the local distribution of natural gas or to the facilities used for such distribution or to the production or gathering of natural gas";[7]
- rejects common carriage to satisfy existing gas pipeline users by

6 Phillips, *The Regulation of Public Utilities*, p. 634.

7 Hooley, *Financing the Natural Gas Industry*, p. 37.

stating that the gas pipeline companies commitment to existing customers has to come first;

- limits entry to satisfy incumbent pipelines by requiring the FPC to judge the economic need of any interstate gas pipeline;
- invokes a "just and reasonable" rate (tariff) standard, giving the FPC full power to investigate and adjudicate the rates of interstate gas pipeline companies; and
- allows the FPC to control accounts for ratemaking purposes preventing companies abusive accounting practices.

The Natural Gas Act also contained provisions concerning:

- the abandonment of lines (Section 7(b));
- regulation of depreciation practices (Section 9(a)); rules pertaining to administrative procedures (Section 15(a));
- procedures for re-hearing and appeal of Commission orders (Section 19(a)); and
- issues pertaining to the FPC's enforcement powers (Section 20(a)).

In all, the Act provided an effective framework for regulating price and entry for gas pipelines as interstate gas pipelines. It resolved the issues raised by the state commissions, the gas pipeline company interests, and pipelines customers and, importantly, it relied on the quasi-judicial powers of the FPC, to deal with issues arising from the collision of interests between pipelines, their customers, and the public interest.

3.6 The Administrative Burden of the Natural Gas Act

Congress intended the Natural Gas Act (NGA) to fill a vacuum in the federal regulation of the fast-growing gas pipeline industry.[8] The NGA provided for utility-style rate regulation, which, by the late 1930s, had developed into a form very similar to what it is today.

When Congress passed the Natural Gas Act, it did not anticipate that the Courts would determine that the regulatory body, the FPC (now the FERC) had to regulate both wholesale gas prices and transportation costs. Combined with the new regulatory accounting procedures, the resulting administrative burden led to gas price freezes and an apparent shortage in gas supplies sold to pipelines for delivery through interstate commerce.

New Regulatory Accounting Procedures

The Natural Gas Act tasked the FPC with regulating gas and pipeline charges, certifying new entrant pipelines, and defining its accounting methods for its various duties. None of these assignments had firmly established regulatory precedents that the FPC could reference, so the FPC had to set its own standards, with mixed results. While the FPC succeeded in creating accounting practices on its own, it required the Supreme Court to sanction its procedures for basic ratemaking, including the setting of the value of the "rate base," due to opposition from the gas pipeline industry.

Throughout the US, regulators and legislators alike came to accept the impossibility of effectively controlling utility rates without a separate, detailed set of accounting guidelines specifically targeted at the commissions' rate regulatory duties. Regulatory accounting methods had been developing in the US for at least 20 years prior to the passage of the Natural Gas Act. In 1923, the Supreme Court had ruled that the US Constitution required regulators to set regulated charges in a manner that would not deprive investors of the value of property devoted to serve the public[9]. However, by 1938 there was still no definitive standard for determining the value of the rate base, or utility property, then defined as part of a highly complex valuation equation[10].

The test case for the FPC's new powers to define the rate base came in 1942, with the *Hope Natural Gas* decision. There, in the first fully-litigated case filed immediately after the passage of the Natural Gas Act (NGA), the city governments of Cleveland, Toledo, and Akron, Ohio challenged the rates of the Hope Natural Gas Company, a Standard Oil subsidiary that sold West Virginia gas to distributors in Ohio. Using its new accounting methods, the FPC decided the case in favor of the city governments to value the asset based at actual recorded nominal book cost. Hope appealed the FPC decision to the appellate court, where Hope prevailed on the question of the valuation of its rate base (i.e., a "fair value" valuation substantially higher than actual recorded nominal book cost). The FPC then appealed further to the Supreme Court, which confirmed the FPC's 1942 ruling and defined the "opportunity cost" standard for providing a return to the investor owners of regulated businesses based on the nominal book cost of the capital devoted to providing regulated services.

The NGA was a highly advanced and concise (13 pages) legislative advance. Testifying to its brilliance is the fact that it could deal effectively with both the infant US gas industry of the 1930s (as reflected in Figure 3.1) and the competitive, technologically advanced gas industry of 2014. It is indeed a masterpiece of regulatory legislation deserving of more widespread emulation as other countries and regions attempt to pursue their own efficient gas markets.

Despite its brilliance, however, the Supreme Court had to specify how to value the capital devoted to the public service — rejecting intangible costs or circular notions of "fair value" for the purposes of computing regulated prices. These hard-won advances worked in setting pipeline prices — based as they would be on steel, construction costs, labor costs and objective measures of interest costs and paid-in equity costs.

But such tangible, cost-based measures for regulating pipeline prices did not work for regulating the price of gas as a depleting commodity resource—where the intangible costs and expectations drive market values for petroleum-based fuels; then as now. The FPCs' tools for reg-

10 The value of utility property was considered to be a function of the earnings that investor-owners could make from the property, which itself depended on the rates that were charged, which depended on the valuation of property in a cost-of-service formula, and so on in a logically circular loop.

ulating prices, based on the 1938 Uniform System of Accounts and the 1944 Hope decision were thus a failure in dealing with the federal regulation of gas commodity prices when the Supreme Court ordered the agency to do so in 1954.

3.7 Wholesale Gas Price Regulation

The issue of field gas price regulations proved to be a particular problem. The FPC had no desire to regulate the field price of natural gas. However, the Supreme Court interpreted the Natural Gas Act to extend FPC jurisdiction over gas sales to companies affiliated with regulated interstate pipelines.

In the Phillips Petroleum Co. v. Wisconsin (1954), the Court declined to make a distinction for affiliated interest transactions in interpreting the FPC's jurisdiction to regulate gas prices in either the Natural Gas Act or the Congressional debate leading up to it, and the Court would not read such a distinction into the NGA, a move that left the job explicitly to Congress.

Congress did not wish to direct private markets, preferring to leave that job to regulators and their industry experts. In addition, the Natural Gas Act was crafted during an era when it was assumed that a close affiliation existed between gas pipelines and production. In repeatedly turning aside calls for common carrier regulation of gas pipelines, Congress acknowledged that the pipelines owned the gas they shipped. The case was remanded to the FPC for the regulation of all gas prices sold to interstate pipelines, thereby sparking 40 years of controversy.

The stance that pipelines owned the gas they transported created problems for determining an appropriate rate of return in accordance with regulatory accounting standards. The main issue was the cost of production. The economists of the 1950s ran into insurmountable problems associated with two cost questions. The first was apportioning joint and common costs to regulated gas prices.[11] The second was the question of depreciation, or depletion as it is known in natural resource matters. The FPC could deal with neither source of cost as a practical matter.

11 For an enduring description of the economics of joint and common costs, see: Kahn, *The Economics of Regulation, Volume 1*, pp. 77-86. Professor Kahn devotes two of only four graphs appearing in the text of the entire volume to this particular issue (other graph appear in footnotes, but the cognoscenti would not count those).

It is important to understand the impossible administrative and legal burden that the FPC faced when the Supreme Court told it to regulate the price of a depletable fossil fuel. Regulating any private industrial activity in the United States is very difficult, for the US Constitution has definitive protections (in its 5th and 14th amendments) to the "taking" of private property without due process of law. Given this high barrier, no important piece of US regulatory legislation takes hold until it survives constitutional challenge in the courts (perhaps up to the Supreme Court) by those affected. And since the tools of regulating (accounting and administrative) can affect private property also, those tools also need to survive challenge in the courts (hence the Hope decision coming out of a challenge to the legality of the accounting tools for applying the NGA).

Thus, when the FPC was directed by the Supreme Court to regulate the price of commodity gas, it was going to use the tools it had based on the Uniform System of Accounts and the importance of nominal book costs in establishing equity values for the owners of gas wells, including book depreciation to record the expense of capital spread over the life of that capital. But commodity markets for fossil fuels, like prices in other commodity markets, are often only distantly related to tangible costs of any sort—either operating costs or some notion of the cost of capital. Commodity prices are driven by intangible expectations of both producers and consumers on a large scale.

Trying to tie regulated gas commodity prices to some tangible measure of recorded book costs, book depreciation and operating expenses was bound to be a failure. But one remedy to that predictable sort of failure—simple wellhead deregulation by legislation—was viewed as totally unacceptable by the distributors and representatives of consuming states in a world where gas pipelines simply re-sold gas at cost to captive consumers. So the application of unsuitable regulatory tools to forming wellhead gas prices continued.

The sheer volume of rate cases brought on by the Phillips decision drew attention to the unmanageable administrative load carried by the FPC. By 1960, the FPC had received more than 2,900 applications for cost-based price reviews but had completed only ten. Each application required the FPC to find the original cost of producing gas for the particular producer and the particular field in question. The FPC itself estimated that it would not complete its caseload until the year 2043.[12]

In an effort to economize on administrative resources, in 1960 the FPC decided to set regional average gas prices on the basis of regional average production costs, a move that basically froze gas prices at a 1958-1959 level. The freeze was designed to be temporary, so that the FPC could begin "area rate" proceedings in order to set permanent prices. The area-rate proceedings lasted 10 years, however, so the prices of existing gas supplies did not change significantly until the 1970s. By that time, the FPC's effort to regulate returns on investments in the gas production sector resulted in an apparent shortage in gas supplies sold to pipelines for delivery through interstate commerce.

All the while, producers could either sell gas to intra-state markets and avoid federal regulation altogether or could hold gas in the ground on the expectation that the "area rates" would ultimately be thrown out and the value of gas in interstate shipments would rise to a broader market level. Therefore, based on expectations of the futility of regulating wellhead prices based on the FPC's practices for assessing costs, the perceived interstate shortage of gas was self-supporting. All the oil companies had to do was to wait, and the longer they waited the worse the situation became.

The Phillips decision came under withering criticism later when it was clear that wellhead price control was causing significant problems in the marketplace. Most of this criticism faulted the Supreme Court for failing to recognize that the market power problems in the interstate gas pipeline business lay in the pipeline component of the service, where significantly concentrated markets existed at the origin and destination of those pipelines, not with the sale of gas. In essence, the Supreme Court was being censured for not taking a more economic view of the Natural Gas Act.

In reality, the complaints over regulating the price of gas were mostly misplaced. Gas price regulation would end when pipeline companies left the gas business entirely. Yet that was an unthinkable requirement in the 1950s. It would take a complex series of events, and another 50 years, to make that change in the market possible. In the meantime, the social costs of trying to regulate an essentially impossible to regulate sector were what they were.

12 MacAvoy A. and Pindyck R., *Price Controls and the Natural Gas Shortage*, p. 12.

3.8 The Techniques of Gas Price Regulation

For those considering regulating gas prices elsewhere, it is probably helpful to look specifically at how the FPC tried to accomplish that task—apart from the wider issue of whether there was any realistic prospect for such regulation to be effective in a volatile fossil fuel market.

- **Costs**: The FPC was tied to assessing tangible and recorded costs of producing the fuel. Its Uniform System of Accounts had no realistic way of dealing with "depletion allowances" that might have some usefulness for corporate accounting or tax purposes.
- **Depreciation**: Depreciation is always apt to be a confusing issue in international discussions of accounting. For the accountant's view of depreciation is to the past (to spread one large book entry into a number of smaller book entries over some projected life of capital facilities) — or as one economist wrote, "a special method of writing history". The economists' view of depreciation is generally to the future, taking into account replacement and opportunity cost. Depletion accounting, for natural resource extraction, is a forward-looking economic concept; but the FPC, in history and today (through its successor, the Federal Energy Regulatory Commission) uses a strict accounting interpretation of depreciation.
- **Rates of return**: The modern methods for computing the market's view of a risk-adjusted rate of return (e.g., CAPM or DCF) had not been developed in the 1950s. Analysts at that time used comparable-profitability benchmarks of various sorts based on existing accounting methods applied to what they considered reasonable groups of peers. There is little in the details of "rate of return studies" in the 1950s that would look familiar, or be considered credible, from the perspective of modern financial analysis and it would not be very helpful to dig deeply into the methods employed at the time, even if the basic pursuit, under Hope standard was the opportunity cost of capital.
- **Trading margins**: There was no conception that either gas producing companies or the pipelines that bought gas at regulated prices from producers (and re-sold mostly to gas distributors) were entitled to a "trading margin." If there were any costs to "trading" (e.g., personnel, equipment and other costs), then those costs would be

recorded like any other cost under the Uniform System of Accounts.

- **Incentive regulation for performance**: Modern conceptions of incentive regulation did not exist in the 1950s in the United States. Price regulation was tied strictly to measure of recorded costs, using accounting conventions to do so.
- **Pass-through of costs**: Both federally-regulated pipelines and state-regulated distributors passed-through the cost of gas without mark-up. Pipeline profitability, just like distributor profitability, was tied to the return gained on the capital devoted to the business, not margins on operating costs.

3.9 Redefining the FPC's Regulatory Functions

The slow administration of field price regulation was widely believed to have contributed to the gas shortages that developed in the early 1970s, as energy prices increased following the 1973 Oil Embargo. In 1978, Congress responded with a gradual and complicated partial deregulation of gas prices via legislation.[13] However, the shortage situation had already been alleviated by dampening demand or increasing supply. It was clear, though, that the FPC was incapable of effectively regulating the returns to gas producers.

Circumstances were different when it came to gas pipeline capacity. There, the FPC had full control of the quantity in the market and the cost of that capacity to the pipeline company owners, which made it possible to regulate rents. The FPC would demonstrate in the 1990s that it had the power to regulate the economic returns flowing to pipeline owners, thereby facilitating a competitive market for pipeline capacity. In that market, the traditional holders of capacity rights kept the rents controlled in a way that has not distorted the market in either the use or expansion of the nation's pipelines.

Embedded in the NGA, a type of standardized utility regulation, were three market distortions that loomed large for the interstate pipeline companies:

- the licensing/certification process for local gas or electricity distribution companies meant competitors would not enter the market;

13 The legislation was the Natural Gas Policies Act of 1978 (15 USC. 3301 *et seq.*).

- gas pipeline companies averaged the price of wholesale gas, removing the incentive to contracting for supplies at prices above what the market would generally bear; and
- pipeline companies could pass through the cost of gas, meaning gas pipeline companies were rewarded through the movement of gas, not through the acquisition and resale of the gas itself. [14]

From the 1950s through the 1970s, these mutually-reinforcing incentives, discussed respectively throughout this Section, damaged competition in the gas fields and led pipelines companies into such an overextended position in the 1980s that the FERC was able to restructure the gas pipeline market without a fight from the pipeline companies.

Uncompetitive Certification and Licensing

Under Section 7 of the Natural Gas Act, four standards had developed for controlling competition through certification of competing lines. The new entrant must show: (1) material benefit to the public; (2) the inadequacy of existing facilities; (3) that it will not duplicate existing facilities; and (4) that it has the financial capacity to render the service.[15]

The FPC developed its own criteria in a landmark case involving the Kansas Pipe Line and Gas Company, in which the FPC specified that it would certify a new entrant to a market containing an existing pipeline company if the entrant had secured adequate gas supply, had reasonable costs of construction, displayed adequate physical facilities and financial resources, proposed to charge cost-based rates, and could demonstrate market demand for the new capacity.[16]

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14 It is well known that under the more less standard regulatory model, utilities generate profits to their owners through the returns on invested capital, not on sales margins or the mark-up of operating expenses (like labor, fuel, etc). Perhaps the first comprehensive economic investigation into how such a regulatory model affected owners' incentives was by Professors Harvey Averch and Leland Johnson in a famous 1962 paper (known internationally as Averch-Johnson). (See Averch, H., and Johnson, L.L., "Behavior of the Firm Under Regulatory Constraint," *US Economic Review*, Vol. LII, No. 5. (December 1962), pp. 1052-1069.) It is clear under the Averch-Johnson that for company subject to traditional regulation, profit-making incentives do not apply to operating costs. To the extent that those costs are subject to some control, it is either by regulatory fiat (i.e., prudence examinations) or ultimately the market itself (despite the presumption that a market exists for the regulated product).

15 Clemens, *Economics and Public Utilities*, pp. 92-93.

16 2 FPC 29 (1939).

In order to receive certification, rival pipeline companies had to go before the FERC with plans demonstrating both their financial ability to build a line and their acquisition of the gas to fill it. The issue of gas sourcing gave prospective pipeline developers an unusual incentive to secure large blocks of supply for a product that they merely proposed to transport through their pipeline for resale to local utility monopolies, which put upward pressure on gas prices.

Problems with Averaging Gas Prices

In 1942, Congress amended the Natural Gas Act to require certificates for all new construction, extension, or acquisition of gas pipelines.[17] Rising gas prices led the FPC set split regulations for "old" and "new" gas prices in 1965 to elicit new gas production for a rapidly-expanding market while continuing to regulate economic rents associated with gas flowing under old contracts. But by creating "old" and "new" gas prices, and allowing the pipeline companies to mix various gas streams to re-sell at an average cost to gas distributors the FERC created incentives encouraged another set of problems.

The regulatory formulae in the Uniform System of Accounts for gas pipelines specified that gas purchased for resale carry a single weighted average cost of gas (WACOG) for ratemaking purposes.[18] The WACOG was the price that pipeline customers paid their suppliers for gas, and it was problematic. Using the WACOG, gas pipelines could purchase certain "new gas" supplies at prices that themselves would have been above what buyers were willing to pay.

Incentive Problems with Cost Pass Through Arrangements

The next incentive issue for gas pipelines buying gas had to do with the nature and design of regulated pipeline rates themselves. Pipeline rates were designed in a way that gave the companies an incentive to push gas through the pipeline. The practice originated in the two-part tariffs with "demand" and "commodity" components; the former is a fixed charge

17 Troxel, *Economics of Public Utilities*, p. 96.

18 See US Code of Federal Regulation, Title 18, Part 201: Uniform System Of Accounts Prescribed For Natural Gas Companies Subject To The Provisions Of The Natural Gas Act.

independent of the volume delivered, and the latter varies by the amount of gas sold.

Pipeline companies could under recover on fixed charges but stand to make extra profits if the quantities delivered were higher than those used to set the volumetric rates.[19] Between the 1950s and the 1980s, when gas prices were regulated, commodity loading was imposed on gas pipeline prices, skewing pipeline incentives toward shipping gas and away from the potential problem that buying too much expensive "new" gas might cause.

3.10 Deregulating Gas Prices

By the early 1970s, the problems in wholesale gas price regulation had reduced interstate shipments and contributed to the perception of a gas shortage in the north. As a result, many large gas users and industrial customers were unable to receive reliable gas supplies.

The 1978 Natural Gas Policy Act (NGPA) was Congress's attempt to separate gas and transportation prices in order to help alleviate the interstate gas supply shortages.[20] Congress perceived that the shortage had developed in response to the rigidly controlled wellhead gas prices and declining reserves of the early 1970s, and increased oil prices following the 1973 Arab Oil Embargo. The process Congress used for deregulation was both complicated and gradual.[21]

One of the NGPA's major features was a legislative version of the "two-tier" pricing system already imposed by the FERC. These two-tiered regulated prices exacerbated an existing problem. Because the pipelines combined their "old", regulated and "new", decontrolled gas into a single

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19 This is a common issue for regulated utilities when fixed costs are collected according to volumetric a tariff (which is generally the case for most local distribution utilities where billing is unavoidably tied to volumetric meters). Ratemaking requires some "test year" volumes. When the volumes delivered during the period of time that those rates are in effect is greater than the test year, utilities profit. This gives utilities a powerful and unavoidable incentive to minimize those test year volumes, just as utility customers have an incentive to maximize them. The fight over the denominator of volumetric regulated rate calculations (where costs are the numerator) is one of the main administrative headaches of regulators around the world.

20 An extensive analysis of the origin and politics of the NGPA appears in Sanders, *The Regulation of Natural Gas*, Chapter 7 (pp. 165-192).

21 See Pierce, *Reconstituting the Natural Gas Industry*, p. 11.

average price, the effective price of new gas could rise above levels that would clear the market.

However, by the time Congress passed the NGPA in 1978, several factors in the gas market had brought the shortage to an end by reducing gas demand or increasing gas supply, including the increased price of “new” gas authorized by the FERC; the purchase of large volumes of unregulated imported gas; the increased supply of gas from the intrastate market; and increased Canadian supplies and offshore production. As a result, the NGPA, which was intended to spur production, actually contributed to overproduction and surplus. A number of market factors already at work also contributed to the overproduction that began to occur after the NGPA’s passage.[22]

The gas surplus was further fuelled by the popular notion that gas prices would increase steadily throughout the 1980s. As a result, interstate gas pipelines engaged in an energetic round of purchasing “new” gas in the late 1970s and early 1980s. Gas and oil prices did not increase in the 1980s as many had expected, and by the middle of the 1980s gas demand had actually declined as oil prices dropped from their post-Arab Oil Embargo levels. As a consequence, the interstate gas pipelines that had been vigorously purchasing new, expensive gas supplies found themselves in financial straits as demand for natural gas fell and the weighted average cost of gas supplied by interstate pipelines rose.

In response to the rise in interstate pipelines’ prices, many interstate pipeline customers (particularly industrial customers) tried to avoid buying expensive pipeline gas. Instead, these customers pursued certificates for “transportation” of cheaper gas through the pipelines than the pipelines themselves were able to offer. This caused the pipelines to act less frequently as merchants and more frequently as transporters of third-party supplies, which amplified the pipelines’ difficulties by shrinking their captive gas markets even further.

The gas pipeline companies responded to their shrinking captive market by levying a charge for gas not taken by their customers, creating

22 These factors included: (1) the recession of the period in the US, which dampened demand; (2) the sharp decline in world oil prices, which also dampened demand for gas because its substitute in many applications—oil—became less expensive; (3) increased conservation efforts by gas consumers due to higher energy prices in general, which also reduced gas demand; and (4) unusually mild weather, which reduced the demand for space heating supplies.

a parallel "take-or-pay" type of liability on the customer's part that would help the pipelines offset the risk of their gas purchase contracts. These "minimum bill" provisions in the pipelines' gas sales contracts required customers to pay for a percentage of the gas they could demand, even if they did not actually take the gas.

The FERC's abolished minimum bill provision exposing the interstate pipeline companies to the consequences of their own high-cost and high volume commitment gas purchasing practices. By 1986, the total take-or-pay liability for gas that pipeline companies could no longer bill to their connected customers was approximately $11.7 billion.[23] The resulting threat to the pipelines' financial integrity gave the FERC the opening it needed to compel the pipeline companies into offering contract carriage service more widely.

This is actually the start of the modern part of the U.S. gas industry history, which is characterized by competition in gas supply and (albeit under tighter control) in gas pipeline capacity as well. As such, this part of the history is beyond the scope of the present Report. The interested reader may see Makholm (2012).

3.11 Concluding remarks

Overall, the era of gas price regulation in the United States can be described as a slow-motion failure representing the unfortunate application to fossil fuel markets of a style of regulation that was, and still is, very well suited to pipeline markets. Indeed, the style of regulation that Congress crafted for the pipeline sector in the 1930s has proven to be a masterpiece: capable of dealing both with the young interstate gas industry of that time and the high-technology industry of today.

The failure of regulating US gas prices reflects the futility of using accounting methods to assess tangible costs (that inherently focus on the past) in an extractive resource market where values and prices are driven by intangible expectations of the future. The predictable results of applying misapplied regulatory methods to the gas sector were fuel shortages, various other social costs, heavy litigation and almost constant legislative action (successful or not). Those problems ended when methods

23 See: "Pipeline Take or Pay Costs Continue to Mount," *Oil & Gas Journal*, August 10, 1987, p. 20.

were devised to incentivize the voluntary exit from gas market by pipeline companies ("voluntary" because the US Constitution prohibits peremptory regulatory action that affects property) and the making of a competitive pipeline transport sector that could deal with volatile gas markets.

Thus, the history of how US federal regulators dealt with a court order to regulate gas prices is a record of what did not work—and could not work given the regulatory and governance institutions that those regulators had at their disposal. There is never any reasonable prospect that federal pipeline regulators could successfully regulate the commodity price of gas in the public's interest. Given the legislation that they worked under, as interpreted by the Supreme Court, the only choice was to try to moot the question of gas price regulation by pursuing open access in interstate gas transport — and the ultimate deregulating of the commodity.

4. EUROPE

Beatrice Petrovich[1]

4.1 Overview of gas pricing regulation in Europe

Gas prices along the value chain are mostly liberalised in Europe. This is the result of the EU Energy Package liberalization measures[2]. Such measures also apply to the Energy Community Contracting Parties[3], although with an extended time schedule for implementation.

At the wholesale level, the EU liberalization process brought about the principle of market liberalization and introduction of competition on a free single market by eliminating entry barriers for newcomers, allowing third party access to infrastructure and requiring the unbundling of the network from energy suppliers. At the retail level, the prin-

1 University of St. Gallen, Switzerland.

2 The European legislation on the creation and development of the electricity and gas single market is grouped into three different Packages. The First Energy Package was issued in 1996-8 and comprises: Directives 96/92/EC for electricity and 98/30/EC for gas). The Second Energy Package was issued in 2003 and includes: Directives 2003/54/EC for electricity and 2003/55/EC for gas, Regulations 1228/2003/EC for electricity and 1775/2005 for gas. The Third Energy Package was issued in 2009 and includes: Directives 2009/72/EC for electricity and 2009/73/EC for gas, Regulations 713/2009, 714/2009, 715/2009 for the creation of Agency of the Cooperation of Energy Regulators (ACER) electricity and for gas, respectively. EU Member States were obliged to transpose the 3rd Package into national law by March 2011.

3 Contracting Parties of the Energy Community are: Bosnia and Herzegovina, Serbia, Montenegro, Kosovo, FYR of Macedonia, Albania, Ukraine and Moldova. In the area of gas, the Contracting Parties of the Energy Community implement the Third Energy Package legislation since 2011. With the exception of Article 9 (Unbundling of transmission systems and transmission system operators) and 11 (Certification in relation to third countries) of Directive 2009/73/EC, the general implementation deadline is 1 Jan 2015. For Contracting Parties of the Energy Community, the deadline for the market opening for households is 1 Jan 2015. Whilst the general implementation deadline of market opening for non-households was set for 1 Jan 2008, it is 1 Jan 2013 for Moldova and 1 Jan 2012 for Ukraine.

ciple of free supplier choice for end consumers was introduced by the 1998 Gas Directive, but only the Second Energy Package in 2003 (notably Directive 2003/55) set the deadlines for the full opening of gas retail markets, namely July 2004 for non-household customers and July 2007 for households.

The EU explicitly chose to regulate network access rather than pricing. The rationale behind the full market opening - and avoidance of price regulation- is that it generates benefits in terms of efficiency gains, price reductions, higher standards of service and increased competitiveness. In particular, the full extension of retail competition is a peculiar characteristic of the European liberalised market model (as opposed to the North American one). In the world, only Australia and New Zealand have achieved a similar liberalisation.

Nonetheless, the European legislation also ensures protection of small consumers in a fully open market by setting service obligations on suppliers and allowing limited price regulation.

Public service obligations usually include rules for the connection of users, continuity of service and stability of pressure in the grid, price transparency, fairness in commercial clauses (like regular frequency of invoicing, maximum supplier switching time, disconnection rules for lack of payments). Special provisions (including reduced prices and special protection against disconnections) may apply to low-income and other vulnerable customers[4].

Additionally, the legislation allows that some retail prices may be regulated for consumer protection aims, on a temporary basis[5]. Member States may impose public service obligations which may relate also to the pricing of supplies, on the ground of the general economic interest, provided that such obligations are clearly defined, transparent, non-discriminatory, verifiable and able to guarantee equality of access for all EU gas companies to national consumers.

However, the European Commission as well the Council of European Economic Regulators have consistently criticised the regulation of end

4 Member States have different understandings of what a concept of vulnerable customers entails.

5 Ruling of the European Court of Justice, Grand Chamber, 20 April 2010, case C-265/08.

user prices. In their last Market Monitoring Report[6], The Agency for Coordination of European Energy Regulators and CEER note that "Artificially low regulated end-user prices, although set above energy costs, discourage market entry and innovation, increase suppliers' uncertainty regarding their return on investment in the long term and consequently hinder competition in retail energy markets". They also recall that in the recent 'Energy Union' communication[7], the European Commission identified regulated retail prices as an obstacle to demand-side participation and retail competition...[which] can constitute a strong barrier to competition if they are not limited in time or applied to exceptional cases based on socio-economic criteria.

In fact, as of 2016, 13 out of the 24 EU Member States with gas supply maintained regulated end-user prices for (at least part of) households, and 6 also for at least some industrial customers. However, the trend, albeit slow, is towards phasing out of price controls. The share of European households that is subject to price controls has fallen from 49% in 2008 to 25% in 2015.

The Report divides countries in the following way:

- Regulated prices for the entire retail market: Bulgaria, France, Greece, Hungary, Latvia, Poland Slovakia;
- Regulated prices for the entire retail market with roadmap for their removal: Denmark;
- Regulated prices for the household segment: Croatia, Lithuania, Northern Ireland;
- Regulated prices for the household segment with roadmap for their removal: Portugal, Romania, Spain;
- Non-regulated prices with (a potential) ex-ante intervention in price setting: Belgium, Italy;
- Non-regulated prices: Austria, Czech Republic, Estonia, Finland,

6 ACER/CEER, *2015 Electricity and Gas Market Monitoring Report – Retail Markets,* November 2016, http://www.acer.europa.eu/en/Electricity/Market%20monitoring/Pages/Current-edition.aspx

7 European Commission, "A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy, February 2015, http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM%3A2015%3A80%3AFIN.

Germany, Great Britain[8], Rep. of Ireland, Netherlands, Slovenia, Sweden.

In a few cases, consumers can choose between the regulated price and a "free market" offer: in these cases, consumers tend to sick to regulated prices.

While regulated retail prices are quite common in Europe, there are few exceptions to the price liberalization at wholesale level. The price for domestic gas production in Poland, Bulgaria and Hungary as of 2013 was regulated on an irregular basis, mostly in response to political/social needs. In the last two cases, there have been complaints that prices may have been set below the cost of service. In addition, Romania still has regulated pricing for domestic production.

Overall, wholesale prices in Europe are not only liberalised, but also increasingly determined in competitive markets. The traditional linkage to oil market prices has sharply declined and hubs have become increasingly liquid and reliable (Petrovich, 2015; Heather, 2016).

The interested reader is referred to ACER (2016) for an analysis of the mark-ups between wholesale and retail prices in regulated and unregulated regimes. ACER points at the fact that margins are very low, or even negative in a few countries where retail prices are regulated, mostly located in the Eastern part of the EU (Slovakia, Poland, Lithuania, Bulgaria, Latvia, Hungary). For a more thorough analysis of the evolution of retail margins and the role of regulation, the reader is referred to Chapter 1.

Regulation methodologies are not well known at EU level. We present in detail two ongoing cases (Italy and France), plus an interesting one from the past (the Netherlands: see Chapter 11).

8 Price controls have since been established for about 1/7 of British households.

4.2 Italy

4.2.1 Introduction

In Italy, import prices, wellhead prices as well as wholesale prices are fully liberalized, being the outcome of bilateral negotiations between the parties or the result of the interplay between demand and supply on the wholesale market. A relatively liquid virtual hub (known as PSV) also exists, where transactions have been increasing.

Price regulation concerns only retail prices, although to a limited extent. In fact, gas retail prices were fully liberalized since the 1st of July 2003, following the implementation of the First EU Energy Package[9] and anticipating the mandatory deadline set by EU law. However, exceptions to this general rule are allowed on the ground of consumer protection. In fact, regulated retail prices are currently in place only for protected gas end-users (also known as "safeguarded gas end-users"), who have the right to opt-out of the liberalized market and opt instead for "reference price conditions" set by the independent Energy Regulator. Only households and residential buildings consuming less than 50,000 cubic meters per year are eligible for the regulated retail gas prices. In 2013, a law made the conditions for being protected consumer stricter; before 2013 non household users consuming less than 50,000 cubic meters per year and public service users were also eligible for the regulated retail prices.

As of 2013, about 74% of the Italian gas customers were under regulated prices, while in terms of volumes, gas sold at regulated prices represent 23% of the total[10].

Reference price conditions for protected consumers are expected to set a maximum fair price level. Unlike in the Italian power sector and in other countries, there is no single buyer to supply protected consumers: as far as protected consumers are concerned, all the gas retail suppliers are bound to include the regulated reference prices in their commercial offers along with their free market sale offers.

4.2.2 The legal basis for the regulation

The legal basis for the regulation of the retail gas prices for protected consumers is a 2007 law[11], entitling the Italian Energy Regulator with the power to define ‘reference prices’ for the sale of gas to “protected” customers, based on the actual costs of the service. The Italian legislator, when implementing the Third Energy Package[12] in 2011, confirmed this provision and specified that the Regulator should do this on a transitory basis.

In the past Italian suppliers appealed against the power of the Regulator to set reference prices arguing that it was a breach of Community law requiring the full opening of gas retail market by 1 January 2007 for household consumers. The European Court of Justice[13] rejected the argument and ruled that national price regulation through the definition of ‘reference prices’ was not a breach of EU law provided that such intervention pursues a general economic interest, features proportionality, holds for a period that is limited in time and it is characterized by transparency and non-discrimination. According to the Italian Courts, the regulated prices set by the Italian Regulation meet these criteria. Currently, regulated prices for protected consumers still exist, although there is a tendency towards narrowing the perimeter of users allowed to stick to the regulated price. A debate on whether to maintain this form of price regulation is currently going on, but the Regulator has no explicit plans to phase out regulated prices.

4.2.3 The institutional framework and the regulator

Regulated prices for small residential gas users are set by an Independent Energy Regulator (ARERA), who sets determination criteria (pricing methodology) by issuing resolutions and also is responsible for price update. A consultation process is adopted to foster the transparency and inclusions of all stakeholders’ interests. When the need for a relevant change in the design of protected gas prices arises, the Regulator usually issues a first publicly available consultation paper illustrating broadly its intentions and, usually, one or more proposals. Stakeholders are called for participation in the consultation process and may reply to the consultation paper issued by the Regulator within a predefined timeframe, then

11 Decree-Law n.73 , 18 June 2007 converted into a Law, after amendment, by Law n. 125, 3 August 2007.

12 Legislative Decree n.93, 1 June 2011.

13 Ruling of the European Court of Justice, Grand Chamber, 20 April 2010, case C-265/08.

the Regulator issues a second consultation paper taking into account received feedback. Final criteria often results from compromises.

Unlike network tariffs, which are issued for fixed regulatory periods, there is no schedule set in advance for the review of the protected price design.

The key principles inspiring the decisions on price regulation are:

- Stability of decision principle, which translates into changes put forward gradually
- Cost reflectiveness
- Incentives towards efficiency, which translates into the identification of costs incurred by an efficient market player, rather than the actual costs incurred by the supplier
- Economic sustainability both on the side of consumers and retail companies

Companies have the right to challenge ARERA resolutions in front of the administrative court (*Tribunale Amministrativo Regionale*, TAR). The administrative court sentences can be grounded both on the basis of merit (e.g. resolutions were unreasonably detrimental) and procedural arguments (e.g. lack of a proper motivation or missing consultation process). In fact, the issue of regulated end user gas prices has been a major source of litigation: a number of cases have been raised in the past, and many sentences have voided previous regulatory decisions. The TAR repeatedly confirmed that the price regulation is lawful but, even in presence of incentive mechanisms, should ensure the recovery of the actual costs. This is a crucial issue as the regulator often privileged incentive mechanisms over cost reflectiveness in the past, which has triggered the most important lawsuits (see Sub-section below).

4.2.4 The basis for the regulation and the structure of the regulated price

When setting regulated prices for the protected segment, the aim is allow the coverage of costs incurred by an efficient supplier, including both infrastructural costs and commodity procurement costs (cost of service regulation).

Accordingly, the structure of protected regulated prices foresees different components, encompassing all activities of the gas value chain: commodity wholesale procurement, transportation, storage[14], distribution and retail marketing[15]. Tariffs for transport and distribution are differentiated geographically and retail prices also for different user clusters.

The components reflecting the costs of retail marketing and distribution networks are fixed (expressed in € per year per user), while all others are variable (i.e. depend on consumed volumes).

Infrastructural cost components depend on network tariffs and the Regulator makes some assumptions in order to convert the fixed network charges into variable components[16]. The retail marketing component includes: costs related to customer service, information management costs including invoicing costs, costs for acquiring new customers such as promotion and advertisement (only starting from October 2013), costs of unpaid bills[17]; the corresponding values are assessed by the Regulator also on the basis of yearly data collection concerning a sample of suppliers. Determination criteria concerning the wholesale procurement component are presented in the bext Subsection.

All the components of the regulated end user price are cashed in by the supplier, except for the distribution component, which is collected by the supplier and then passed on to the distribution system operator.

4.2.5 Main criteria used for price adjustment and indexation

Here we focus on the wholesale gas procurement component of the regulated price, which is a single national one and is composed by:

- a pure "raw material" or gas cost component, being the value of the gas molecule located at point where the title is transferred from the wholesaler to the retailer, either the border flange or the virtual trading point[18];

- a component for other procurement costs such as operating costs, including the fair margin allowed to the wholesaler, and costs related to hedging and portfolio management[19].

The latter is assessed by the Regulator. No detailed criteria have ever been published for the determination of the fair margin and operating costs allowed to the wholesaler, anyway their joint level has been unchanged since 2009 and equals about 0.67 \$/MMBtu[20], which over the 2009-2013 period corresponded to about 5%-8% of the whole wholesale procurement component of the regulated price. Costs relating to hedging and portfolio management were introduced in October 2013 and remunerate costs for the activities carried out by the supplier (directly or indirectly) to hedge the risk to procure on the wholesale market additional gas volumes compared to the planned ones, which may result for instance from exceptionally low winter temperatures. These values are assessed applying standard national criteria based on the Regulator's expert judgement and historical data.

The value of the gas cost component is updated on a quarterly basis. The cost of gas in the protected prices is based on a formula, which is designed to correctly reflect the efficient (rather than the actual) average import price[21] to Italy. It is very important that the formula avoids the risk of being based on benchmarks which may be easily manipulated in their favour by suppliers to the Italian protected consumers, like those of national markets that may not be aligned with international ones. Explicit inflation indexes have never been adopted, as international prices are not related to domestic inflation.

The Italian regulatory approach consistently pursued the objective of

18 First known under the acronym of QE and currently C_{MEM}. QE was the estimate of the price of gas at the Italian border flange, while C_{MEM}, currently in place, is an estimate of the price of gas already injected into the Italian high pressure grid (including entry costs to Italy, which is part of the transmission tariff).

19 First known under the acronym of QCI and currently CCR. QCI was the estimate of the international transport costs plus fair wholesaler margin and operating costs, while CCR, currently in place, is an estimate of the non-commodity costs related to the procurement of gas on the wholesale markets.

20 0.47 €/GJ. An exchange rate \$/€ equal to 1.37 \$/€ is assumed.

21 The reference is to import prices as Italy is highly dependent on import, with a very small share of domestic production, which is nonetheless priced very similarly to imported gas.

incentivising efficient gas procurements by suppliers, notably by avoiding the pass-through of actual costs, and preferring the use of an objective cost-of-gas formula. The incentive consists in the fact that suppliers may keep any gain resulting from lower procurement cost with respect to the formula. However, they know that such gains could eventually be partly or totally transferred to end users. The reliability of the gas cost benchmark, in fact, is checked over time through constant monitoring by the Regulator. Inquiries are used to fine-tune the formula and to prove its robustness.

Such formula has evolved over time to reflect changes in supply conditions. Initially it was updated using an indexation basket including only oil derivatives, representing the prevailing fuels competing with gas in Italy. More specifically, the formula was such that the value of gas evolved consistently with the changes in an index defined as the weighted average over nine month moving averages of the monthly quotations of selected oil crudes and products, with the weights reflecting the importance of such products in the Italian fuel mix. The adoption of a moving average aimed to smooth and delay the impact of monthly highs and lows. The weights were:

- 49% light fuel oil (Gasoil);
- 13% Brent, which replaced in 2004 a basket of eight crude oils;
- 38% low sulphur fuel oil (LSO).

Following the shift away from oil-linked long term contracts and the spread of hub-indexation and procurement on the European "spot" markets, starting from 2012 the Regulator, prompted by a Decree Law[22], gradually phased out the link to oil product prices, which ended on the 30th of September 2013. As of July 2014, the gas cost in the protected gas prices is based exclusively on prices for the gas delivered at the Dutch wholesale market TTF, to which costs of transport to the Italian hub (PSV), as determined by the Regulator, are added. The TTF is chosen as it is by far the most liquid hub in Continental Europe. More specifically, the reference for the TTF price is the monthly average of daily OTC price assessments for the Q+1 product for delivery in relevant quarter at the TTF hub, referring to the second to last month before the relevant

22 Decree Law n. 1, 24 January 2012.

quarter, as published by a leading Price Reporting Agency[23].

The long term objective is to take the prices quoted by the Italian physical future exchange (MT-GAS) as a benchmark. MT-GAS was launched in the second half of 2013 but it was not used by any trader yet as of July 2014. The Regulator proposed and consulted on some criteria and thresholds to decide when (and whether) the Italian exchange becomes liquid enough to be considered a reliable (manipulation-free) price benchmark for the protected prices.

Instruments, such as price ceilings, are envisaged to protected consumers from hub price spikes but are neither fully determined nor in place yet.

In Italy, there is a lack of publicly available detailed information on gas pricing and price level for the main large consumers, who are free to choose their supplier on the liberalized wholesale market. This is due to the sensitiveness of information perceived by these consumers.

However, aggregate data are published on an annual basis by the Italian Energy Regulator. In general, price spot supplies to large consumers are very close to hub prices.

4.3 France

4.3.1 Scope of price regulation

In France, import prices, wellhead prices as well as wholesale prices are fully liberalized, being the outcome of bilateral negotiations between the parties or the result of the interplay between demand and supply on the wholesale market. Price regulation concerns only retail prices.

As of 1 January 2014 users consuming up to 100,000 MMbtu/year (no matter whether they are households or small businesses) are always

23 Platts until September 2014. Then starting from October 2014 the benchmark will be computed based on ICIS Heren price assessments. Price assessments may slightly differ across provides. In fact, as OTC trades are concerned, there is no obligation for transparency in the disclosure of the prices of trades. In this context, one price discovery service that is used very much is that provided by specialist agencies ("price reporting agencies"), which furnish surveys of prevailing prices on markets, based on interviews with a panel of traders. These are increasingly accompanied by the calculation of the average weighted price of a certain number of transactions.

eligible for regulated prices (*tarif réglementé*, TRV), while those consuming more than 100,000 MMbtu/year are not allowed to opt out the free market when they sign a new supply contract[24].

Until mid-2014, France was one of the very few countries (along with Poland, Romania, Bulgaria, and Latvia[25]) where regulated prices persist for large industrial consumers. However, in March 2014 the Government passed a plan for the progressive phasing out of price regulation[26] for non-household gas consumers. By the 19th of June 2014 all the consumers connected to the high pressure grid should buy gas at market prices. Non-household end users consuming more than 67,500 MMbtu/year (200 MWh/year) and non-household end users consuming more than 100,000 MMbtu/year (30 MWh/year) should choose a free market supplier by January 2015 and January 2016, respectively.

Any household who chooses a free market offer retains the right to return to regulated prices at any time. Only customers featuring a consumption level of 100,000 MMbtu/year are legally prevented from switching back to regulated prices.

In additional to this, there is a solidarity tariff applicable in situations of fuel poverty.

Regulated gas prices dominate the households and small businesses market in France. As of 31th December 2013, 75% of French consumers opted for the regulated prices, accounting for the 34% of total gas consumption in France[27]. More specifically, in 2013 77% of residential and 50% of non-residential customers were in the regulated regime (Table 4.1).

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24 However, users consuming more than 2.8 mcm/year can maintain the regulated prices if they opted for them in the pre-liberalization period.

25 CEER (2013), P.163.

26 LOI n° 2014-344 du 17 mars 2014 relative à la consommation, article 25, http://www.legifrance.gouv.fr/affichTexteArticle.do?idArticle=JORFARTI000028738295&cidTexte=JORFTEXT000028738036&dateTexte=29990101&categorieLien=id

27 http://www.cre.fr/marches/marche-de-detail/marche-du-gaz

Table 4.1 - French Retail gas market structure as of 31/12/2013 (%)

	Residential		Non-residential	
	N.users	Annual Consumption	N.users	Annual Consumption
Regulated prices	77%	77%	50%	19%
Free market prices	23%	23%	50%	81%

Source: CRE (2014)

Only the incumbent suppliers (*fournisseurs historiques*), namely GdfSuez, Total Energie Gaz (Tegaz) and the local distribution companies (*entreprises locales de distribution*), such as Gaz de Bordeaux and Gaz Electricité de Grenoble, supply consumers who choose the regulated option. All other suppliers are referred to as alternative suppliers (*fournisseurs alternatifs*) and supply only free market consumers.

Engie accounts for the majority of total selling to end users opting for regulated gas prices. In fact, the only important areas where the incumbent differs from Engie are the districts of Bordeaux, Strasbourg and Grenoble, which were originally supplied by local companies.

There is a public service contract between Engie and the French State.

4.3.2 The regulatory framework

The decree n° 2009-1603 dated 18th December 2009[28] requires that the Ministry of the Economy and the Ministry of Energy decide on regulated tariffs, by accepting or rejecting a CRE proposal.

In May 2012 the European Commission once again called[29] on France to bring its legislation on regulated gas prices for non-household end-users in line with European Union law. The main argument against French price regulation is that regulated prices eventually set by the Government are artificially too low and discourage GDF Suez's competitors from entering the retail market.

Basically, regulated prices are ultimately set by the French Ministries for Economy and Energy, after a proposal by the independent Energy

28 http://www.legifrance.gouv.fr/affichTexte.do;jsessionid=76F8783A060DDB-15F1C5CB2D116DD69F.tpdjo17v_3?cidTexte=JORFTEXT000021504554&dateTexte=20130806.

29 Infringement proceeding was opened in 2006.

Regulator CRE. In 2012 France, Spain and Hungary were the only EU gas markets where the government still has the final say on regulated prices[30], while the Regulator provides a consultative opinion only.

However, in practise the setting of regulated gas retail prices is a complex procedure. First, a cost formula is set for each supplier by the relevant Ministers after consulting with the CRE. This formula specifies the gas procurement and non-gas procurement (i.e. infrastructural) costs for each supplier (GDF Suez is by large the most important one).

Then, a decree by the Energy and Finance Ministers, after a proposal by the CRE, sets the rate of change for regulated prices. It is therefore the Ministry who eventually sets the regulated price, also discretionally deviating from the objective application of the formula. For instance, in December 2011 under the existing formula the regulated prices should had gone up by 10%, but the Prime Minister opposed a 10% rise and preferred a 5% maximum. In the past, the Government had ruled for price freezes, for instance in autumn 2011, when the government of the day blocked a 6% increase cleared by the Regulator, and in 2012 when a government decree[31] capped GDF Suez's October 2012 price hike at 2%.

More than once in the recent past suppliers appealed against Government decrees setting the rate of increase in regulated prices and the State Council (Conseil d'Ètat), France's top administrative appeals court, overturned the government decisions on gas regulated prices. This happened in 2011, twice in 2012 and three times in the beginning of 2013. The State Council cancelled the Ministerial decrees setting the increase in regulated prices on the grounds that they did not fully cover GDF Suez's average costs[32].

Pursuant to the law[33], the Regulator shall carry out any consultation with energy market players that it deems useful before formulating its opinion or proposals, including those regarding regulated natural gas retail prices.

The French regulated price allows the full coverage of costs (cost of service regulation), including both infrastructural costs and commodity

30 CRE(2013), P.169.

31 Decree 26th of September 2012.

32 Conseil d'Etat 10 July 2012 decision.

33 Article L.445-2 of the French Energy Code.

procurement costs, incurred by the energy companies supplying users opting for regulated prices.

Infrastructural costs include the cost for the use of the grid (transport and distribution) and the cost of access to storage. The former is set by the Government after the proposal of the Regulator and is differentiated among different consumer classes, while the latter is set by the storage companies.

The procurement cost (*tariff de fourniture*) is added to the infrastructural cost component to make the regulated price that is set by the Ministry.

4.3.3 Main criteria used for price adjustment and indexation

Here we focus on the gas procurement component of the regulated price.

Gas procurement cost component is reviewed at least annually if necessary, in the past it has been updated on a quarterly basis and, since January 2013, on a monthly basis. Any change in this component of regulated price should be consistent with changes in the supplier's procurement costs. In fact, it should allow the full coverage of procurement costs. Suppliers may propose changes in the regulated price to the CRE, together with a justification of the proposal. The CRE either approves or rejects the proposal on the basis of whether the requested change mirrors an actual change in their procurement cost.

Supplier's procurement costs are assumed to be correctly represented by the procurement cost formula that is approved by the Energy and Finance Ministers after consulting with the CRE. More specifically, the procurement cost formula should provide an accurate estimation for GDF Suez's and other incumbent suppliers' gas procurement costs, otherwise, as repeatedly noted by CRE, this may jeopardise the offers from alternative suppliers as well as a fair comparison by end customers; moreover, the benefits from any improvement in procurement strategies should be transferred to end customers. The CRE regularly audits the adequacy of the formula with regard to GDF Suez's actual supply portfolio costs. In March 2009, the formula was published in order to increase the transparency. It is interesting to notice that this was actually seen as an important decision, and not a straightforward one: this shows how sensitive are any issues related to price gas formation.

Until 2010, the procurement cost formula was fully indexed to oil products, reflecting the structure of Gdf Suez's portfolio, featuring virtually only long term oil-linked contracts (see Section XX). The recent change in procurement strategies (see Section XX) triggered a progressive revision of the formula structure, supported also by the ruling issued by France's top administrative appeals court[34].

In 2011, the French Ministry of the Economy requested the Regulator to provide its expert judgments on actual GDF Suez's procurement costs so that a new formula could be envisaged. The CRE carried out an audit of GDF France portfolio to define the incumbent's costs[35]. Accordingly, the procurement cost formula was adjusted with the step-wise inclusion of a spot-related component, namely the monthly average of the forward products delivered at the Dutch TTF[36].

In 2011, wholesale hub prices accounted for 9.5%; this share was increased to 26% in January 2012, and to 36% in January 2013. In mid-2013 the share indexed on the wholesale natural gas market in the GDF Suez procurement cost formula was set at 46% and on the 1st of July 2014 the weight of this component rose to 60%

The latest decision was taken following the publication of the CRE's audit of GDF Suez' long-term contract portfolio in June 2014[37]. CRE concluded that gas hub pricing accounts for 60% of the costs, up from 45.8% in 2013, due to renegotiations of GDF Suez' long-term contracts, which now include more, and sometimes full, indexation to hubs. The CRE has also showed that the "gas-year-ahead" and indexing to prices recorded at PEG Nord (the most liquid French wholesale market) gained an increasing weight in the indexing of Gdf Suez's contracts. Accordingly, CRE recommended taking into account these facts in the formula. However, while the price of the gas-year-ahead product with delivery at TTF was added into the formula approved by the Government in July 2014,

34 On 29th of November 2012 the State Council (Conseil d'Etat) required the Government to come to a new decision on the criteria setting regulated sales gas prices.

35 CRE press release, *CRE has released its report on GDF SUEZ's supply costs which it submitted to the Government on the 28 September 2011*, dated 24 October 2011, available at: http://www.cre.fr/en/documents/press/press-releases/cre-has-released-its-report-on-gdf-suez-s-supply-costs-which-it-submitted-to-the-government-on-the-28-september-2011.

36 http://www.cre.fr/marches/marche-de-detail/marche-du-gaz

37 CRE Press Release *La CRE publie son rapport d'audit sur les coûts d'approvisionnement et hors approvisionnement de GDF SUEZ*, dated 4 June 2014, available at: http://www.cre.fr/documents/presse/communiques-de-presse/la-cre-publie-son-rapport-d-audit-sur-les-couts-d-approvisionnement-et-hors-approvisionnement-de-gdf-suez.

the PEG Nord prices were not included.

As of July 2014, the formula that sets the rate of change in the Gdf Suez's procurement costs, is the following[38]:

$\Delta m = \Delta FOD€/t*0.00546 + \Delta FOL€/t*0.00431+\Delta BRENT€/bl*0.05597+ \Delta TTFQ€/MWh*0.11292 + \Delta TTFM€/MWh*0.45572 + \Delta TTFA€/MWh*0.02936 + \Delta USDEUR*1.16332$

Where:

- FOD€/t: light fuel oil with 0.1 sulphur content quotation recorded over the eight month period ending one month before the date of the update, in €/tons;
- FOL€/t: low sulphur heavy fuel oil quotation recorded over the eight month period ending one month before the date of the update, in €/tons;
- BRENT€/bl: Brent crude quotation recorded over the eight month period ending one month before the date of the update, in €/barrel;
- TTFQ€/MWh: quotation of the quarterly product delivered on the Dutch TTF in the quarter of the update, recorded in the one-month period ending one month before the quarter of the update, in €/MWh;
- TTFM€/MWh: quotation of the monthly product delivered on the Dutch TTF in the month of the update, recorded in the one-month period ending one month before the month of the update, in €/MWh;
- TTFA€/MWh: quotation of the annual product delivered on the Dutch TTF in the year of the update, recorded in the one-month period ending one month before the month of the update, in €/MWh;
- USDEUR: exchange rate €/$ recorded on the eight-month period ending one month before the date of the update.

38 Arrêté du 30 juin 2014 relatif aux tarifs réglementés de vente du gaz naturel fourni à partir des réseaux publics de distribution de GDF Suez, http://www.legifrance.gouv.fr/affichTexte.do;jsessionid=DCF5BE7A22B36886B0A6189F49B5452C.tpdjo17v_3?cidTexte=JORFTEXT000029167907&dateTexte=20140701

5. THE NETHERLANDS

Aad Correljé[1]

5.1 Introduction

From the early 1960s onwards, the Netherlands benefited from the exploitation of its large natural gas reserves. At the end of 1963, the first delivery of gas took place and by 1968 all municipalities and most households were connected to the national grid. Yet, Dutch gas was not only of influence in the national energy sector. The manner in which Dutch gas was exported to and marketed in neighbouring countries has been of decisive importance for the development of the mainland European gas market from the mid-1960s onwards. First of all, it permitted the construction of a trans-European gas transportation network that connected most of the main centres of consumption and thus laid the foundation for an integrated gas market. Secondly, it ensured the creation and expansion of a European gas sector which otherwise might have been thwarted by the over-supply of oil products in Europe at the time. Thirdly, it established the principles and patterns of an 'orderly' and controlled European gas trade. Despite adjustments arising from the emergence of new suppliers, the institutional framework and the principles that governed gas production, marketing and pricing and the distribution of the profits have prevailed until the turn of the century.

Since the late 1980s, the European Commission has pursued policies which seek to liberalise the energy sector. This process slowly gained momentum and in December 1997 the Council of EU Energy Ministers signed a Gas Directive to secure a gradual liberalisation process in Euro-

1 Part-time Professor, Florence School of Regulation, RSCAS, European University Institute. Technical University of Delft, The Netherlands.

pean gas markets. Prior to this, in December 1995, the Dutch Minister of Economic Affairs had published his Third *White Paper on Energy Policy (EZ 1995)* including new liberal guidelines for electricity and gas policy. This not only anticipated a liberalized European energy market but was also a response to changing circumstances in the supply of energy, especially gas and electricity. These proposals implied a radical alteration to traditional Dutch gas policy.

This section examines the regulation of prices in the Dutch gas sector in the period preceding the liberalization post-1998. Subsection 2.10.2 describes the development of the Dutch institutional framework and natural gas policy since the early 1960s and subsection 2.10.3 provides an account of the main changes proposed in the White Paper on Energy Policy, the later elaboration thereof in a policy paper, *Gasstromen* and the proposals for a new *Gas Law* and a *Mining Law*.

5.2 Development of the economic and institutional framework

In essence, the economic and institutional framework of the Dutch natural gas sector has experienced a high degree of continuity over the post-1962 period. Nevertheless, the changing perceptions of the situation in the energy market, by 1974 and again by 1983, have induced a number of important adjustments. These are reflected in pricing decisions, in the origins of the gas purchased by Gasunie and in shifts in the volumes of gas sold to the several types of customers (Correljé et al 2003).

Three years after the discovery of the large Groningen gas field in 1959, the Minister of Economic Affairs, De Pous, established the main principles of Dutch gas policy in the *Nota inzake het aardgas* (Kamerstukken II, 1961-1962, nr. 6767). Firstly, in order to generate a maximum of revenues to the state and the concession- holders, Minister De Pous – on the advice of Exxon - introduced the "market-value" principle. The gas price to the various types of consumers was linked to the price of the most convenient substitute fuels, i.e. gas oil for small-scale users and fuel oil for large-scale users. Consumers would thus never have to pay more for gas than for alternative fuels. Yet the market value principle also ensured that they would not pay less and thus enabled the concession holders, Shell, Exxon and the Dutch state, to secure high revenues, compared to a situation in which the consumer price was related to the low production costs of gas from the Groningen field. An essential precondition for maintaining the 'market value' principle was that no alternative supplies of low-priced gas could reach the market - a condition which was fulfilled until recently in the Netherlands and until the early 1970s in Europe.

Secondly, the *Nota De Pous* stated that the exploitation of the Dutch gas resources should proceed in harmony with the sale of the gas, in order to avoid disruptions of the energy market. Thus, control over the supply of gas was seen as a government task. Yet, it was also stated that the exploitation and marketing of the gas reserves should be undertaken by the private concession owners, Shell and Exxon, in order to benefit from their knowledge, experience and financial resources.

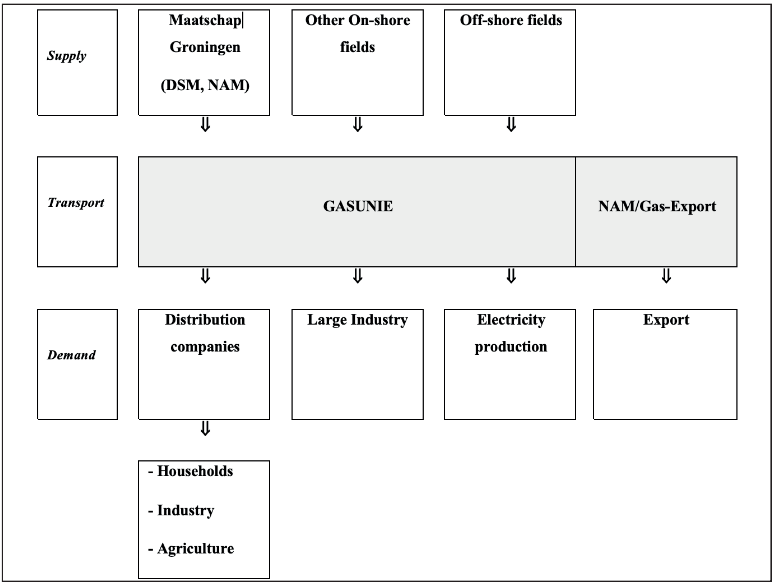
In 1963, the Dutch government and both companies agreed upon a structure that effectively united these principles (see Figure 5.1).

The holder of the Groningen concession, the *Nederlandse Aardolie Maatschappij* BV (NAM), a 50/50 joint venture of Shell and Exxon, undertook the production activities.

Gasunie was established as a joint venture owned by the *Dutch State Mines* (DSM) (40%)[2], the Dutch State directly (10%) and Exxon (25%) and Shell (25%). Gasunie was given the responsibility to co-ordinate the commercialisation of Dutch natural gas resources on behalf of the State and the concession-holder NAM in the Netherlands. NAM/Gas-export - operating on account of Gasunie - was established to co-ordinate the sale of Dutch gas to foreign markets.

2 In 1972, in response to the increasing number of participations, a separate entity was established: *DSM Aardgas BV*. In 1989, *Energie Beheer Nederland BV* (EBN) replaced DSM Aardgas when DSM was partly privatized. EBN has remained a part of DSM, surrounded by a so-called Chinese Wall. The state pays DSM a management fee.

Figure 5.1 Structure of gas sector 1963 – 1974



The state, via the *Staatsmijnen* (later Dutch State Mines or DSM), participated in the costs of the exploitation of gas from Groningen field and in the flow of revenues through a financing partnership, known as the *Maatschap* (40% DSM, 60% NAM)[3].

Thus, though direct state ownership/control of Groningen gas was avoided, the state's direction of the financial flows emerging from gas production and the management of the state's interest by DSM established a kind of arm's length relationship with the gas industry. State revenues were collected in several ways: first, through the dividends paid to the state by Gasunie and DSM; second, through corporate taxes (48%) on the profits of the Maatschap, Gasunie and DSM; and third, by a 10% royalty on the profits of the Maatschap (Wieleman 1982a, 12).

The role of the Ministry of Economic Affairs was confined to the responsibility for formally approving decisions proposed by DSM and Gasunie, in respect of prices, production and trade volumes and the construction of transport and storage facilities.

3 See Correljé et al (2003). Peebles (1980), Stern (1984), Kort (1991) and Ausems (1996) for a detailed account of the development of the institutional structure and the government's policy. The older concessions, remained outside this new concession regime.

After its establishment in 1963, Gasunie handled virtually all natural gas produced in the Netherlands (apart from exports until the mid-1970s) plus most of the volumes that have been imported since the 1980's. Over the 1962-1974 period, gas policy was driven essentially by, on the one hand, the fact that the declared gas reserves in Groningen increased year by year and, on the other, by the perception that these reserves as declared should be produced and sold before the expected widespread use of nuclear energy would make the gas redundant. This objective was reflected in the pricing policy, in the rapid expansion of the national distribution grid and in the search for new markets in the Netherlands. Markets abroad were selected by NAM.

Yet, after 1974, government policy reduced the amounts of gas available for export because of fears of scarcity. In the inland market, Gasunie, after initial restrictions, sold the gas to all potential consumers (including electricity producers and large scale industrial users). In export markets, however, the level of border prices, through the influence of Shell and Exxon, restricted the sales of gas to so-called high-value markets, in which natural gas would not have to compete with cheap fuel oil or coal. As a consequence, inland sales increased rapidly and exports peaked in 1976, when commitments under contacts negotiated in the 1960s/early 1970s reached maximum volumes agreed (Gasunie 1988; Ausems 1996, p. 17). This is illustrated in Figure 5.2. In this period most gas originated from the Groningen field.

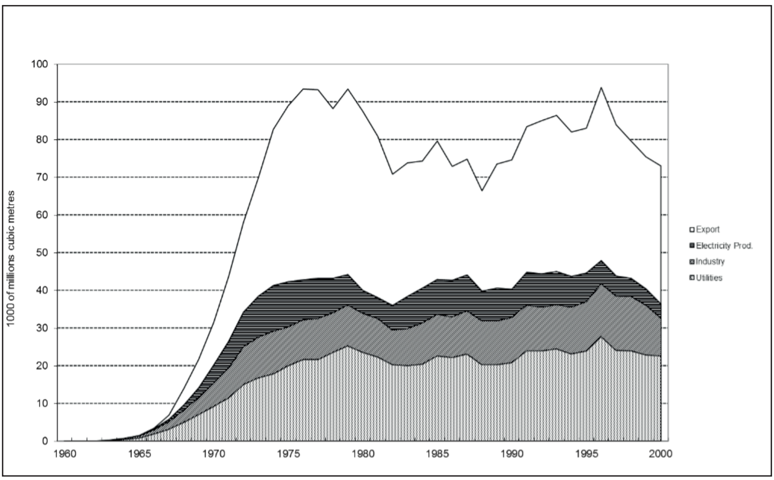
The successful exploitation of this field had induced further exploration activities elsewhere in the country and offshore. This inspired the development of a new oil and gas regime under which new concession owners were required to seek state participation through a joint venture with DSM, while Gasunie was given the right of first refusal regarding the purchase of the gas they produced, as was determined in new legislation governing exploration and production activities on the Dutch continental shelf and the mainland (Mijnwet Continentaal Plat, 23 september 1965, Staatsblad 428; KB 27 januari 1967, Staatsblad 24; Wet Opsporing Delfstoffen, 3 mei 1967, Staatsblad 258)[4]. Towards the end of the 1960s, small volumes of gas were being purchased from new on-shore locations (Figure 5.3).

The 1973/1974 oil crisis gave rise to the first revision of the Dutch

4 The older concessions, under which - most importantly - Groningen remained outside this new concession regime.

gas policy, as documented in the first *White Paper on Energy* by Minister Lubbers. In the atmosphere of perceived energy scarcity at the time, the government primarily sought to achieve security of supply - defined as Gasunie's guaranteed capability to satisfy the foreseen demand of its customers for the following 25 years on the basis of the Dutch reserve position. In order to achieve this objective, on the one hand, consumption of gas was discouraged. Gas sales to the electricity production sector and large scale consumers were reduced and additional export contracts were prohibited. The increase in gas prices - linked with the price of oil - in combination with the economic recession at the time, brought about a decline in household and industrial consumption (Figure 5.2).

Figure 5.2 Natural Gas Sales by Gasunie/Gasterra



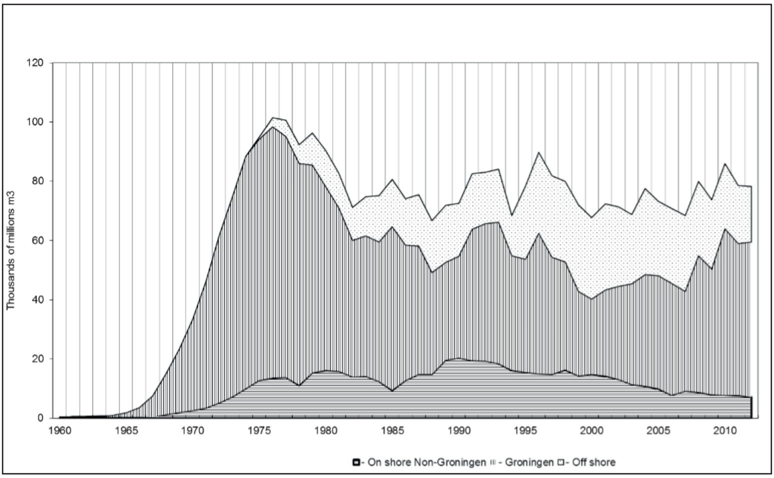
On the other hand, the sources of gas supply changed. The depletion rate of the large low-cost Groningen field was brought down while, at the same time, the search for and the development of new on- and off-shore deposits was encouraged by assurance given to the operators of these fields that Gasunie - having the right of first refusal - would purchase the gas they offered based on optimal depletion rates against acceptable prices. As a result, from the mid-1970s onwards, increasing volumes of gas were supplied from off-shore fields in the Dutch part of the North Sea. Altogether around 600 billion cubic metres (Bcm) (on-shore) and 500 Bcm (off-shore) of gas were discovered and taken into production

(Oil and gas in the Netherlands 1996, p. 25). In fact, the large low-cost Groningen field became the marginal source. As a swing producer it supplied the volumes of gas that filled the gap between the increasing production of the small fields and Gasunie's falling total requirements. From around 85 Bcm in 1976, production from Groningen fell to 45 Bcm in the early 1980s and to only 30 Bcm in the early 1990s (Figure 5.3).

The details of the agreement between the state and Gasunie and NAM have never been revealed. It can be assumed that it involved a trade-off between, on the one hand, the reduction of highly remunerative production at the extremely low cost Groningen field and, on the other, the fact that unit price paid by Gasunie for gas from the Groningen field was high enough to sustain both NAM's and the government's revenues. The link between oil and gas prices had already induced an enormous expansion of the revenues to Gasunie and the NAM (Tweede Kamer, zitting 1974-1975, 13109, nr.1), as a result of which the tax rate on gas from the Groningen field had been increased.

Following the 1979/80 oil shock and the *Second White Paper on Energy*, by Minister Van Aardenne, this policy was continued even more vigorously. Moreover, the Dutch state succeeded in negotiating higher export prices from most of the importing countries - albeit at the expense of sales which were stretched out over an extended period. Additional windfall profits were however now left untouched, in return for which Exxon and Shell agreed to the government's demands that they must reinvest the large profits originating from the second oil shock in expanding their activities in the Netherlands so as to benefit the Dutch economy.

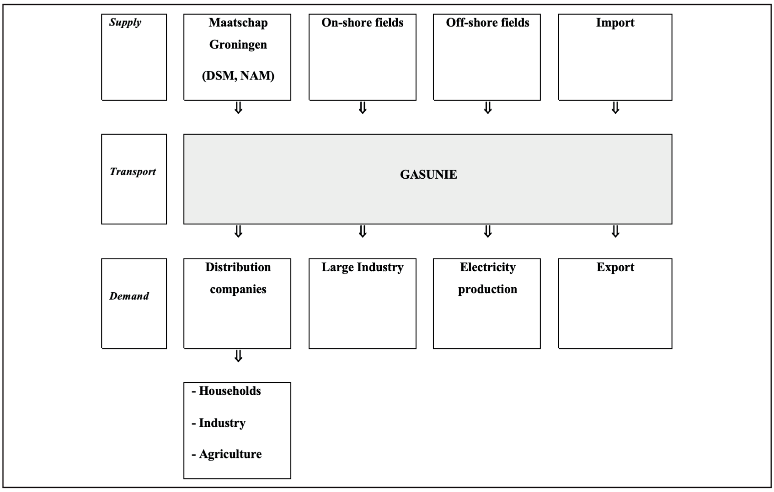
Figure 5.3 - Natural Gas Supply



Consequently, from 1974 onwards, Dutch natural gas functioned under two separate regimes: the regime for the large Groningen field, operated by NAM/de Maatschap, and the regime for the small on- and off-shore fields, operated by a variety of consortia (but dominated by NAM to which most concessions had been allocated). This is illustrated in Figure 5.4. Within the context of very high oil and hence gas prices from 1974 to 1985, the Dutch state collected large revenues from the exploitation of gas reserves. In the early 1980s, the aggregate state revenues from gas amounted to around 15 - 16% of total state income (exclusive of social security contributions). Currently, this share is around 4%[5].

5 Calculations based on data from: *Oil and gas in the Netherlands*, 1985, 1996; *Jaarverslag De Nederlandse Bank*, 1991, 1994.

Figure 5.4 Structure of gas sector 1975 - 1997



From 1983 onwards, the objectives of energy policy were gradually adjusted to the then emerging perception of abundance in energy supply and to the falling sales of gas at both home and abroad. In particular, the decline in sales diminished the output of the Groningen field and therewith threatened the state revenues - badly needed to reduce the state deficit at the time. Thus, in 1983, Minister Van Aardenne lifted some of the restrictions on the use of gas in industry and electricity production and allowed the renewal of export contracts.

Towards the end of the 1980s, with low oil prices and an increasing supply of natural gas from Norway and the Soviet Union to Europe, Minister De Korte acknowledged the need to re-establish the status of Gasunie as a gas exporter. Nevertheless, the yardstick by which the government decided whether or not to authorize additional export contracts was kept in place. Gasunie had to guarantee that it would be able to continue to supply its inland customers for at least 25 years, on the basis of the Dutch reserve position and the estimated evolution of demand (Nota De Korte, 1989). In spite of this restraint, regular additions to proven reserves at this period subsequently allowed for new export contracts, particularly after 1989 (Figure 5.2).

5.3 Pricing of natural gas

As stated above, Gasunie's pricing policy was based on the principles set forth in the 1962 *Memorandum concerning Natural Gas*. In practice, this means that the market value was taken as the basis for determining the price of gas. The value of gas is based on the costs that consumers would incur if they were to use a substitute fuel. The gas price is in most cases linked to the price of oil products. For most industrial users, this means heavy fuel oil; for domestic consumers, heating gas oil. In both cases, the fuels used as the reference are the cheapest alternatives to gas. Although the importance of gas oil and fuel oil declined in the Netherlands over the years, these fuels nevertheless continued to provide benchmarks.

For example, on 1st July 1999 the (delivered) commodity price of gas to consumers supplied by Gasunie was calculated as follows:

Table 5.1 - Gasunie's price formula, third quarter 1999

For each m3 between:	Zone	Dutch cents/m3
0 and 800	a1	"domestic price" = 38.607
800 and 5,000	a2	"domestic price" = 54.587
5,000 and 170,000	a3	"domestic price" = 49.047
170,000 and 1 million	b1	P* x 38.2 + 7.35 = 25.218
1 million and 3 million	b2	P* x 38.2 + 7.35 = 24.508
3 million (m.) and 10 m.	c	P* x 38.2 + 3.60 = 20.758
10 m. and 50 m.	d	P* x 38.2 + 1.80 = 18.198
above 50 m. (plus transport)		P* x 37.2 -).80 = 13.075
(One m3 = 9.769 kWh = 27.8 MMbtu and 1 € = 2.204 NLG = 220.4 Dutch cents		

5.4 Prices to domestic and small commercial consumers

The threshold for to Domestic and Small Commercial Consumers is 170,000 m3 of 8,400 kcal (1.66 GWh) per year. The prices at which the distribution companies purchase from Gasunie are ultimately related to a formula (supervised by the Ministry of Economic Affairs).

This formula starts with the mean of the high and low FOB Rotterdam Platt's barge prices of gasoil in the half-year up to two months before 1 January and 1 July (e.g. the gas price for January to June is related to gasoil prices from May to October) converted to Dutch guilders (later Euros, 1 EUR = 2.204 NLG) using average monthly exchange rates against the U.S. dollar.

To the resulting guilder price were added excise duties of NLG 10.26/ hectolitre (EUR 46.56/ m3), compulsory stock cost of NLG 1.10 per hectolitre of (EUR 5.90/ m3) and a distribution margin of NLG 100/ton (EUR 45.38/ton), giving a value known as G.

If G was less than NLG 550 (EUR 250)/ton, then 0.8 of G plus 0.2 of 550 (EUR 250) is taken to calculate a new G; between NLG 550 (EUR 250) and 750 (EUR 240) per ton, the actual G is used but if G is above NLG 750 (EUR 340)/ton, then 0.8 of G plus 0.2 of 750 (EUR 340) is applied.

G is then multiplied by 37.2 to give a price in Dutch (or Euro) cents per cubic metre (ct/m3) and a "market value" supplement of 1.70 (EUR 0.77) ct/m3. A price change during the year (i.e. at 1st July under the formula) was limited to a maximum of 3 1.36 c (EUR ct)/m3 after which it was "capped" at that level for the next period. So, the gas price followed oil prices with a delay.

This cap means that increases which would have been more than 1.36 cEUR/m3 can be carried forward, as was the case in January 2002, when the gasoil prices were lower than in the previous six months.

The price paid by the distribution companies is calculated by subtracting a margin from the Gasunie formula level described above. This margin is negotiated with the distribution companies, but we estimate that it is around 2.54 €c/m3, plus the standing charge. Within the total tariff, the purchase price of gas has to be passed through with no mark-up but non-gas costs (transport and distribution) are subject to maximum price control by the Ministry of Economic Affairs (later DTe). The following examples for the second half of 2002 show typical regional differences between the companies (Table 5.2).

Both the standing charges and the proportional charges contain the transport and distribution elements, which are subject to the maximum price control by DTe. These elements can vary widely: for example in 2001 NUON's standing charge was 86% transport and 14% distribution while that of Essent Nord was 98% transport. REMU's proportional charges were 14% transport and 86% distribution, while those of ENECO Rotterdam were 93% distribution.

The averages of all 29 tariffs in the second half of 2002 were EUR 51.64/year for the total standing charge and 24.35 cEUR/m3 for the total proportional charge, including excise duty.

Gasunie's formula price on the same basis was 24.65 cEUR/m3 for the same period.

P* is the Platt's mean quotation for 1% sulphur heavy fuel oil in barges fob Rotterdam, averaged over the previous six months, plus NLG 48.00/metric ton and divided by 500. The U.S. dollar value is converted to Dutch guilders using average monthly exchange rates and the charge of NFL 48.00 allows for excise duty of NLG 34.24 and average transporatation costs within Holland of NLG 14.00 (rounded down to NLG 48.00). No account is taken of the "voluntary" charge of NLG 10.00/ton for compulsory stocks, which we understand is paid by most large fuel oil users. The value of P for the third quarter of 1999 was 195.79.

Table 5.2 - Representative prices charged by Netherlands' LDCs, second half 2002

Company	Standing Charges	Proportional Charges
	EUR/year	cEUR/m^3
Essent Noord	45.88	24.81
REMU, Utrecht	35.01	25.41
NUON Zuid Holland	114.52	24.75
ENECO Midden Hol-land	60.10	24.52
Eneco GMK	41.65	24.45
Eindhoven	40.23	23.85

Source: EnergieNed
Prices include excise duty (Brandstoffenbelasting) of 1.06 cEUR/m^3 but not the eco-tax (REB). NUON's standing charges for the second half of 2002 were originally 67.66 EUR/year, but these were recently almost doubled (the amount shown above is after deduction of a special rebate of EUR 10.96/month for the months of September to December 2002.

The prices in Table 5.2 above include taxes. Consumers supplied by Gasunie do not pay any MAP regional levies. In the three northern provinces of Groningen, Friesland and Drenthe, plus a small part of Overijssel, there is a discount of 0.85 ct/m3.

Following an agreement signed in 1994, all new gas customers are supplied by the distribution companies if their annual use is less than 10 million m3 (97.69 million kWh) per year and by Gasunie above this threshold. Existing customers (e.g. those of Gasunie below 10 million m3/year) remain subject to the pre-1994 conditions. We estimate that about 100 of the total of 250 consumers in Zone c (between 3 and 10 million m3/year) are still being supplied by Gasunie.

5.5 Prices to Small Industrial Consumers

The Gasunie formula for consumption between 170,000 and one million m3is

P = P* x 38.2 + 3.34 (cEUR/m3)

Where:

P* is the Platt's mean quotation for 1% sulphur heavy fuel oil in barges fob Rotterdam (P), averaged over the previous three months, plus EUR 22.00/metric ton and divided by 500(*). The U.S. dollar value is converted to Euros using average monthly exchange rates and the charge of EUR 22.00 allows for excise duty of EUR 15.54 and average transportation costs within Holland of EUR 6.35 (rounded to EUR 22.00). The value of P* for the fourth quarter of 2002 was 0.3446, compared with 0.2778 in the first quarter.

38.2 is a conversion factor from tons to m3

3.34 is a "market value" supplement for small industrial users

Thus the Gasunie formula price excluding tax is 16.50 cEUR/ m3 in the fourth quarter of 2002. The distribution companies' average price in this sector of the market is normally below the formula calculation (e.g. in 2001, by 1.03 cEUR/ m3)

5.6 Prices to Larger Industrial Consumers

Transport tariffs now apply above firm annual volumes of one million m3 of 8,400 kcal (there are no interruptible supplies to industry).

With the partial deregulation of the Dutch market in January 1999, tariffs for transportation and associated services (until end-2002 the so-called CSS system) have been published since then by Gasunie (since January 2002 by the Transportservices division, later GTS). The gas price in both the CSS and the new entry/exit system is made up of three main components: commodity, transmission and other services.

The commodity price is either calculated each quarter from the formula

P* x 37.4 - 0.363 (cEUR/ m3)

where

- P* is as defined above in Section 5.5
- 37.4 is a conversion factor from tons to m3
- 0.363 is a fixed discount, or at a fixed price, generally for a year (see example below), or at a price related to spot market levels of coal (mostly for power stations)

Our research has revealed the following types of pricing in the market in the period around 2000:

1. Gasunie's direct sales: no negotiation, either on the fuel-oil related price per quarter, or on the other alternatives.
2. Essent, Nuon and Eneco purchasing from Gasunie: final price can be up to 0.5 cEUR/m3 lower (usually achieved through careful attention to offtake patterns etc)
3. Essent and RWE Gas imports (from the UK and elsewhere): between 0.5 and 1.0 cEUR/m3 below the Gasunie commodity price, depending on the indexation formulae in purchasing contracts; we are of the opinion that such imports are almost certainly linked to Continental pricing and Euro rather than p/therm and the NBP
4. Other importers from Germany, Norway, etc (e.g. Duke), at discounts of up to 1.5 cEUR/m3, although we understand that some potential customers have doubts about security of supply and/or difficulties in obtaining adequate or correctly-located transportation capacity, especially because the DTe is unable to intervene to any extent

We have been able to examine a fixed-price contract for the year 2002 (dated 30 January) between Gasunie and an industrial consumer of 3.5 million m3 per year. This specifies a fixed commodity price of 11.13854 cEUR/m3, compared with the formula price of 10.02670 in the first quarter of 2002, i.e. a "premium" of 1.11184 cEUR/m3.

When the fixed price is compared with the average of the four quarterly formula prices in 2002 (11.18368 cEUR/m3), the consumer in this case had a price advantage of 0.04514 cEUR/m3, or 0.4%. It is thus very important for suppliers to estimate correctly how the formula price will move over the year, especially if they do not hedge their offers.

5.7 Prices to Power Stations and for Co-generation

Prices to power stations supplied by Gasunie were on the same basis as those to large industry until the end of 1998, except that the indexation (known as Pc) is based on a six-month period starting seven months previously, i.e. for July to September the P value is calculated from fuel oil prices from November to May (instead of January to June as for industrial prices).

There are also upper (+$4/ton) and lower (-$1/ton) limits to the value of Pc, which is first calculated from the mean of the high and low Platts quotations for heavy fuel oil, cargoes fob N.W. Europe (1% sulphur). If the mean of the high and low quotations for the same grade of fuel oil, barges fob Rotterdam, falls within the range as calculated above, then the barges value is taken as Pc; if it is higher or lower, then the upper or lower limits from the cargoes calculation is taken.

This calculation resulted in a Pc value of 185.80 for the third quarter of 1999, compared with a P of 195.79 for normal industrial consumers, giving a typical price of 16.42 ct/m3 including tax.

The special terms which existed for power stations until the end of 2000 have been abolished and from then onwards prices became subject to the Entry/Exit system rather than the old zonal structure with a special P value. However, from the beginning of 2001 gas to power stations has been exempt from the Brandstoffenbelasting (the REB did not apply because it is levied on electricity). Gas used in co-generation has been exempt from the Brandstoffenbelasting and the REB, provided that an efficiency of at least 65% (as defined by complicated rules) is achieved.

5.8 Other special prices

Prices of gas used mainly as feedstock by the chemical industry are normally about 1.00-1.05 cEUR/m3 below those to large industry, because of

- a rebate equivalent to the fuel oil excise duty on 70% of the volume (deemed to be the non-energy part)
- no brandstoffenbelasting on the non-energy part
- load factors higher than a typical large industrial user

Greenhouse growers using more than 30,000 m3 per year received special terms laid down in a tripartite contract between EnergieNed, Gasunie and the Produktschap Tuinbow (Greenhouse Growers' Association). Their prices were about 30% less than to commercial consumers of comparable volume.

There are special rules for greenhouse growers, who have regulated prices in two tranches: up to 170,000 m3/year and from 170,000 to 835,000 m3 (not 1 million m3). For the first quarter of 2002, for example, the prices have been set (excluding tax) at 15.53 cEUR/ m3 in the first tranche and at 15.04 cEUR/m3 in the second. These are the maximum controlled prices for the country as a whole; by distribution company they can vary by less than 1%.

These prices compare with an estimated 22.90 cEUR/m3 to domestic and commercial consumers in the first tranche and 12.91 cEUR/m3 in the second.

Greenhouse growers pay the full Brandstoffenbelasting but much less REB than other consumers, namely 0.165 cEUR/m3 for the first 5,000 m3, 0.077 cEUR/m3 from 5,000 to 170,000 m3 and 0.014 from 170,000 to 1 million m3. They also pay only 6% recoverable VAT instead of 19%.

Above 835,000 m3, greenhouse growers are subject to the Entry/Exit system, but with the above concessions on REB.

5.9 The liberalisation after 1995

By the end of 1995, the Minister of Economic Affairs, Wijers, proposed a number of changes designed to liberalise the organisation of the Dutch energy sector in his White Paper. This was followed in December 1997 by the specific paper on gas *Gasstromen* (EZ 1997) These changes originated in the wish to adapt the sector to future EU regulations and from the pressures from large energy intensive industry for lower energy prices (EZ 1995; SIGE 1995). In the electricity sector, however, liberalisation was also seen as an instrument to force efficiency upon the sector. This allowed the government to present the restructuring of the sector as an objective of 'national interest' (Correljé 1997). In the natural gas sector, the situation is much more complicated. As shown above, Dutch gas policy has always been associated with objectives such as the generation of state revenues, security of supply and at a later stage also protection of the environment. Hence, until mid-1996, the Netherlands was among the fiercest opponents of the several initiatives of the EU Commission for a liberalisation of the gas market.

The first actual alteration to the Dutch gas regime took place in 1994, when Gasunie's right of first refusal to Dutch gas producers was terminated, by accepting the EU Hydrocarbons Directive (RL 94/22/EG. PB, 1994, L164).

In 1999, a new Gas Law started the liberalisation of the industry, in line with the 1998 EU Directive:

- Customers obtained free choice regarding their gas supplier(s), with large consumers, accounting for around 46% of Gasunie's home market sales, explicitly allowed to seek alternative suppliers immediately[6]. In 2002, medium sized users, representing 16% of the market, followed. Small users were explicitly made dependent on the regional distribution companies[7], but they were allowed to shop around freely by 2007.

6 Dutch definitions are as follows: *large users* have an annual consumption of above 10 mln. m^3 annually; *medium-size* users, between 10 mln. and 0.17 mln. m^3; *small* users, less than 0.17 mln. m^3.

7 In the future, these distribution companies will be free to purchase their gas requirements from other (non-Gasunie) suppliers, provided that they present a robust *dekkingsplan* (plan of supply), showing their capability to supply their customers over a specified period (EZ 1995: 131, 132).

- New suppliers and traders were given the right of negotiated access to the transport and distribution networks.
- Gasunie and the distribution companies were required to establish Chinese walls between their trading and transport activities and to publish separate indicative prices for the services provided. Later on Gasunie was separated in Gasterra, as the commercial gas wholesale company, and Gasunie Transport Services (GTS), the regulated transmission system operator (TSO).
- The Minister of Economic Affairs established a controlling agency DTe - within the Competition Authority (NMA) - to correct collusive behaviour and to guarantee the interests of the small consumers in particular.

The basic structure of the industry, with a key role for Gasterra and De Maatschap/NAM - including a cross shareholding - was maintained. This is because, as was argued, it provides advantages of scale and organisation and allows for the continued co-ordination of gas sales and purchases from Groningen and the small fields.

Thus on the demand side, notwithstanding the fact that initially only large consumers are allowed to negotiate with other suppliers, eventually all Gasunie's current customers will be free to 'shop around' for lower cost gas supply - either on an individual basis or as part of a gas buyers' consortium[8]. On the supply side, both internal as well as foreign suppliers had already been given the right to sell gas to others than Gasunie. Thus, with the new Gas Law, the combined monopoly-monopsony position of Gasunie had been legally terminated.

The more recent part of the Dutch experience falls in line with general European liberalisation, with regulated access to both transmission and distribution tariffs and legal unbundling of transport companies from suppliers[9]. Unlike several other EU Member States, the Netherlands have not maintained any gas price regulation.

8 Until then, it was not determined by law that small - or any - consumers were tied to Gasunie. Yet, the fact that Gasunie was always able to underbid other potential suppliers *de facto* gave Gasunie the supply monopoly. It should be noted that, over the past ten years, the Dutch distribution sector went through a process of extensive vertical and horizontal concentration. Only a few large integrated companies now supply the country (Correljé, 1997).

9 The interested reader may consult Correljé (2005).

Thanks to its natural resources, his long history in the gas industry, as well as the quick adaptation to a new regulatory framework, the Netherlands have managed to maintain a leading position in Europe, in spite of market integration forbidding any discrimination within the EU, based on national borders. Indeed, the Dutch gas hub (known as Title Transfer Facility or TTF) has become the leader in continental Europe, is often seen as a pricing benchmark and has challenged the primacy of the British hub.

Current gas pricing in the Netherlands is an example of how gas pricing works in integrated markets. Prices are not very different depending on whether gas is produced locally or imported, as efficient markets tend to generate a uniform price. The only price advantage for consumers of an exporting country like the Netheralds is related to the lower average transportation cost, but this gap is small, as transportation cost to neighbouring countries is rather small. Even for farther importing countries like Italy, which is over 1200 Km away, the transportation cost is about 2 €/Mwh (0.7 $/MMBtu). On the other hand, benefits of local gas production are much larger for the Dutch taxpayers, rather than consumers. Natural gas is a major source of state revenue, both from royalties, excise and profit taxes and due to the direct interests of the Dutch government in Gas Terra, the wholly state owned company that sells most gas produced in the country.

5.10 Summary of key issues[10]

1. Dutch price regulation covered wellhead, wholesale and retail prices.
2. Consumer price regulation distinguished power generation, medium and large industry, three segments of residential & commercial users, feedstock, and the greenhouse sector.
3. Prices were determined on the basis of established formulas, adapted at fixed half year intervals by Gasunie in coordination with the SEP (cooperating power producers) and the regional distribution companies, eventually approved by the Ministry of Economic Affairs. Overall competition control over the sector was carried out by the Competition Authorities.

10 referred to the Netherlands before full liberalization.

4. Dutch price regulation covered wellhead, wholesale and retail prices, according to the market value principle for distinguished segments of national consumers, combined with cost plus remuneration for the distribution companies and the Gasunie transmission function, resulting in a netback price to the producers. A similar mechanism applied to export contracts, in which the extra costs of transmission beyond the Dutch border were deducted from the revenues.
5. The upstream part of the value chain received netback values.

   a) criteria for capital valuation; n.a.

   b) rates of return and their main component; not explicitly but part of the cost plus allowance for the transmission function in Gasunie and the distribution companies.

   c) depreciation rates; idem

   d) operational expenditure; idem

   e. use of benchmarking techniques; n.a.

   f) exploration costs and their evaluation criteria; n.a.

   g) depletion fees, royalties, or user costs; 10% royalty to the Dutch state, in addiction to profit sharing regimes: A (40%) for small fields, and B from 70 up 90% for gas supplied from Groningen, depending on the price level.

   h) social or environmental fees and subsidies; guaranteed off take of gas from the small fields, above supplies from Groningen.

   i) reference to competing fuels; Net back, based on cost plus and market value pricing.

   j) reference to international gas prices; n.a.

6. Main criteria used for price adjustment and indexation?

   a) Adjustment frequency (if any) and trigger rule: Half yearly adjustments, with a capped pass through factor.

   b) price indicators of competing fuels and/or market or other gas prices; For most industrial users, this means heavy fuel oil; for domestic consumers, heating gas oil.

   c) inflation index or other macroeconomic indicator; n.a.

d) ceilings and floors; Only in the speed of adjustment of gas prices to changes in oil product prices.

e) role of incentive or performance –based regulation. n.a.

7. Structure of the regulated price for the main consuming sector? Are there…

   a) Commodity charges only? Lump sum charge to consumers, including all costs.

   b) Capacity related charges? Tariff structures established on the basis of consumer segment and maximum contracted annual off take.

   c) Standing (fixed) charges? As an element in the pricing formula

   d) Decreasing or increasing blocks? n.a.

8. Relevant authority for price update: Gasunie and Ministry of Economic Affairs. Pricing methodology is negotiated between Dutch government and Exxon and Shell, pre-1962.
9. Legal basis for the regulation: Until 1998 the legal basis was the Policy paper covering natural gas, the Nota inzake het aardgas (Kamerstukken II, 1961-1962, nr. 6767). This was not a law. Moreover, relations with the oil companies were arranged under private law in contracts with DSM/EBN, representing the State.
10. Main non-price provisions of regulation that are tied to the price control:

    a) production performances like available capacity, ramp-up, ramp-down, swing factors; Such aspects were incorporated in the pricing formula

    b) take or pay clauses that may be subject to the regulation and related flexibility arrangements (e.g. make-up gas); Such aspects were incorporated in the pricing formula

    c) price review clauses; Each half year.

    d) destination clauses (by sector or country); Applied in (export) contracts to both sectors and countries.

6. THE MIDDLE EAST AND AFRICA

Sergio Ascari

6.1 Overview

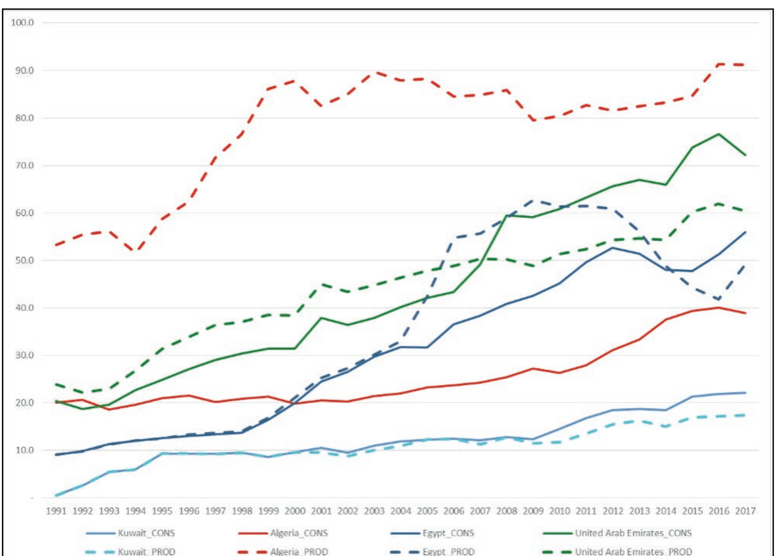
The Middle East and North Africa have been a major source of natural gas demand growth in recent years, due to a rising population, economic development and the related energy hunger. Some infrastructure has also been developed in a few Sub-Saharan African countries (Nigeria, South Africa, Ghana) where demand has also grown. In these countries, warm climate and limited widespread industrialisation lead to power generation and fertiliser production being by far the main use of natural gas.

A frequent feature of the gas industry development in several Middle Eastern and North African countries is the fast growth of consumption, which has often outpaced production, despite significant development of the latter (Figures 6.1 – 6.2). This has led several countries to turn from net exporters to importers (e.g. Kuwait, UAE, Egypt) or to reduce the share of their exports (Algeria, Iran). Even Saudi Arabia, which is an isolated system without imports or exports, has seen a relatively low growth with respect to expectations and resources.

In some cases, production growth rate have been relatively low and some stagnation periods can be clearly identified. However, this is hardly related to unavailability of resources: as Figure 6.3 shows, in most cases Reserve/ Production ratios remain well above those of other world areas. Since in most cases gas production is associated to that of oil (and/or condensates), it has often followed the latter, which are normally a better source of export revenues for the producing countries. Yet in several countries gas production, driven by that of oil and gas liquids, cannot be used due to lacking treatment and transportation infrastructure, and several MENA countries have some of the worst gas flaring records in the world.

Inadequate development of the gas industry, despite strong demand growth, may depend on political reasons (like continuous warfare in Iraq and sanctions on Iran), corruption protecting vested interests (like those of competing fuels), and financial constraints. However, inappropriate regulation is also a major suspect. The regulation of the gas industry is often strictly related to that of electricity, and is often heavily influenced by the political willingness to provide cheap power (and fertilisers) as a way of fostering economic and social development. Moreover, the legacy of joint oil & gas production has traditionally entrusted the vision of natural gas as a "free by-product" of oil, which can be priced at very low levels. Once prices are set at such levels, and the resulting electricity and fertilisers are priced accordingly, it becomes politically hard to raise them and the country may end up in a spiral of low prices, fast growing consumption, loss accumulation by public sector enterprises, lack of resources for industry development, and shortage. It is likely that several MENA countries may have followed this spiral, despite their remarkable financial resources (as in the case of Gulf countries).

Figure 6.1. Gas production and consumption in selected MENA countries



Sub-Saharan Africa has so far seen a very limited gas industry development, although more and more countries are joining thanks to local resources or imports. Yet the main producer (Nigeria) has partly followed a similar pattern, followed by its interconnected West African neighbours, with inability to develop power generation equipment going hand in hand with that of gas industry development. This has however left more gas for export, with economic benefits (possibly for the few) rather than social development.

On the other hand, Israel is by all respects a very different society, yet its gas industry development may have been slower than expected (and justified by resource availability), for very different reasons. The emergence of a private monopoly and the authorities' inability to promote competition or control prices have led to very high prices, which have in turn triggered a regulatory dispute, which has led to the postponement of developments, notably in the upstream sector of the industry. This case shows that too high prices may damage the industry just like too low ones. Whereas such errors have been recently partly fixed, industry observers widely believe that Egypt, despite its past mistakes, is now far ahead in the race to exploit the large resources of the Eastern Mediterranean basin, and may hold the key even to further Israeli development as a gas exporter.

Figure 6.2. Gas production and consumption in Saudi Arabia, Iran and Nigeria

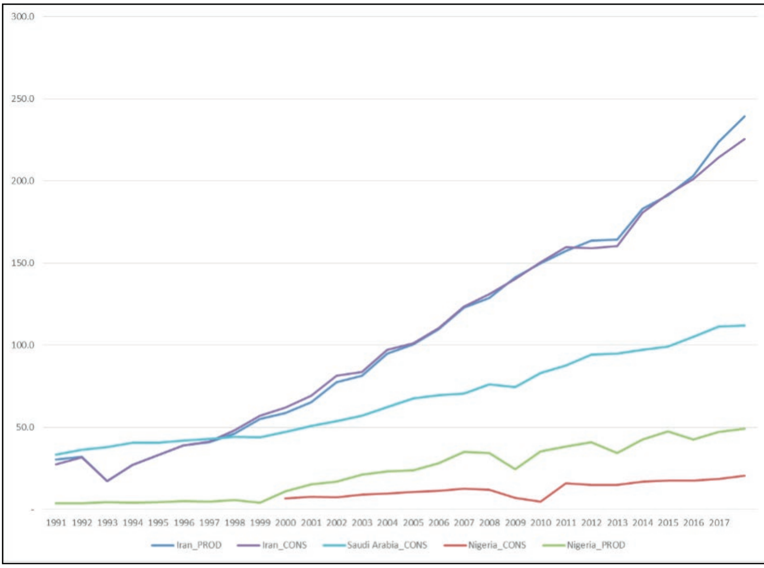
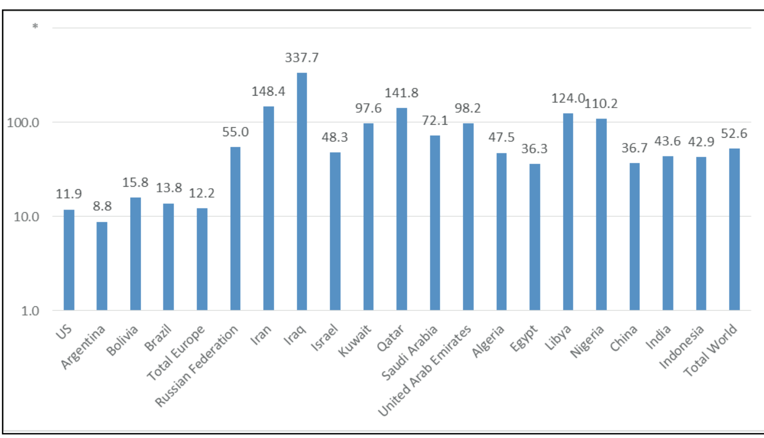


Figure 6.3. Reserve/production ratios as of end 2017 in selected countries (logarithmic scale)



The rest of this Chapter will focus on four case studies, trying to understand their differences and to draw lessons from their experience, notably regarding gas price regulation.

6.2 Algeria

6.2.1 Overview of the market and regulation

Algeria is an historical exporter, as it pioneered LNG exports in the 1960s, and offshore pipeline exports in the 1980s. In 2015, it exported 41 Bcm, of which 25 by pipeline and 16 as LNG. Figure 6.1 shows the evolution of production and domestic consumption. The balance is composed mostly of exports, with some gas used for reinjection into oil fields and own industry consumption (compression, losses and liquefaction fuel).

In the last 15 years, domestic production has stagnated, while domestic consumption has remarkably increased, notably since 2010. As a consequence, exports have been shrinking, and international observers have often pointed to the inability of Algeria in maintaining its share of the world gas market. In particular, the creation of the gap has been blamed on inappropriate conditions for international investments (Darbouche, 2011), which have jeopardised the development of the large national resources, leading to a fall of the reserve-production ratio in the last decade from around 50 to 33 years. A timid recovery seems to be on its way in the last two years.

The consumption growth has been driven by both power generation, which is 90% fed by natural gas, as by other sectors. As of 2015, power and water generation only represented 42% of total demand, with industry at 30% and local distribution at 27% (Aissaoui, 2016). However, power generation has been the most dynamic growth sector, even though the government is now promoting a shift towards renewables.

Domestic gas prices in Algeria are regulated in both upstream and downstream markets. Sonatrach, the national oil company, produces its own gas or buys from international oil companies (IOCs) at the wellhead at netback export prices and sells it domestically on the wholesale market to power generators and heavy industries at regulated prices. The retail market is controlled by Sonelgaz, Algeria's state-owned utility, which purchases gas from Sonatrach and sells it to domestic and commercial users at regulated prices.

Regulation covers all downstream consuming sectors. There has been a debate in recent years in Algeria about the level of the price of gas sold to heavy industrial users owned partially or wholly by foreign investors and whose output is marketed in export markets, but that debate never extended on to the subject of full liberalisation of domestic gas prices.

Different regulators are involved in the regulation of gas prices in different market segments in Algeria. Prior to 2006, the ministry of energy was the only regulator in the upstream and wholesale segments of Algeria's domestic gas market. However, with the introduction of a new Hydrocarbon Law (05-07) in 2006, regulatory powers were given to two new nominally independent agencies, namely ALNAFT (*Agence nationale pour la Valorisation des Ressources en Hydrocarbures*) for the upstream and ARH (*Autorité de Régulation des Hydrocarbures*) for the wholesale market. Given that wellhead prices are based on netback export prices achieved by Sonatrach, ALNAFT's role is essentially to provide IOCs with monthly notices of the reference export price. ARH for its part is charged with adjusting domestic wholesale gas prices annually based on a formula (see next section for details).

Prices in the retail consumer market are set by downstream gas and electricity regulator CREG (*Commission de Regulations de l'Electricite et du Gaz*), which was established by the 2002 Electricity and Gas Law. This law was designed to liberalise the electricity market and gas distribution, but it has so far only succeeded to introduce a limited degree of liberalisation in the generation segment of the power market. Distribution and pricing of gas and power remain heavily controlled and regulated by the State.

6.2.2 Regulatory criteria and price levels

In the upstream segment, gas prices are based on netback export prices. Since IOCs are not actually allowed by Sonatrach to market their gas production entitlements on export markets, the national oil company buys such gas quantities at a negotiated price based on netback export prices. More recently, Hydrocarbon Law 13-01, which was introduced in February 2013 as an amendment to Hydrocarbon Law 05-07, established a *domestic market supply obligation for IOCs*. Such quantities are sold to Sonatrach at the wellhead, based on the volume-weighted average of the prices realised by IOCs in their sales contracts with Sonatrach for the volumes that do not fall under the domestic market obligation. This is meant as an incentive to IOCs given that domestic gas prices in Algeria remain well below international prices.

The wholesale market is controlled by Sonatrach. Prices are fixed by ARH on the basis of Article 10 of Hydrocarbon Law 13-01, which stipulates that wholesale gas prices should only cover:

- the cost of production;
- the cost of the infrastructure used specifically for the domestic market;
- the operating costs of the export infrastructure used in part to transport gas dedicated to the domestic market;
- a reasonable profit margin for each of these activities.

The above costs should also cover the return on existing investment, as well as new investments needed to maintain supply activities. Executive Decree No. 07-391, dated 12 December 2007, which aimed to define the modalities and procedures of wholesale gas price regulation, states that the supply price is based on the "cost of economic returns" plus a "premium to cover the additional cost of mobilizing new resources to meet long-term demand". This cost concept may be understood as similar to the theoretical long-run marginal cost of supply (LRMC), yet this interpretation is not obvious.

Furthermore, as already noted, the latest revision of the 2005 hydrocarbon law has introduced the concept of export-based opportunity cost of gas for remunerating Sonatrach's foreign partners relinquishing their share of gas to the domestic market. To let domestic prices evolve towards that level in time, a "depletion premium" would have to be added to the LRMC in order to factor in the opportunity cost of consuming an exhaustible resource now rather than in the future.

In fact, retail market prices are based on social affordability given that the residential and commercial segment accounts for an insignificant share of domestic consumption.

However, wellhead prices, which are negotiated between Sonatrach and its foreign partners with reference to Sonatrach gas export prices, are based on the company's unstated objective of limiting IOCs' profits (rates of return) in the relevant ventures in which the Algerian national oil company is a mandatory partner with minimum equity of 51%. Thus, depending on the size of the reserves under development, Sonatrach decides the rate of return IOCs will reasonably require for their investment and concede a gas price accordingly.

The formula used to define domestic gas price adjustments by ARH is outlined in Executive Decree No. 10-21, dated 12 January 2010 and is as follows:

$$P_n = P_i\,(D_n / D_i)\,(1+R)^n$$

Where:

P_n: is the adjusted pre-tax gas price (in Algerian Dinars AD per 1000 m^3) for year n;

P_i: is the pre-tax gas price for the base year;

D_n: is the parity of USD relative to AD as quoted by the Bank of Algeria on the first Business Day of year n;

D_i: is the parity of USD relative to AD as quoted by the Bank of Algeria on the first Business Day of the base year;

R: is a constant rate of inflation, currently fixed at 5%.

The base price is adjusted every five years by the ARH, except in the event of an important variation in one of the parameters of the above formula. At the beginning of each of the intervening 5 years, the ARH issues a notice to gas producers (essentially Sonatrach), providing an update based on the AD/USD exchange rate and the 5 percent fixed inflation rate. As the Algerian economy is structurally dependent on large imports, the 'pass-through' of exchange rates and import prices to domestic inflation is fairly strong. Most frequently, a decrease in the exchange rate (depreciation) and a rise in foreign prices lead to an increase in domestic prices in nominal terms.

Aissaoui (2016) tries to estimate:

- the production cost
- the relationship between prices and costs
- the relationship between the declared price updating rule and actual prices.

As for the first, he estimated by a Delphi process an average cost of about 0.6 – 0.7 $/MMBtu and a cost of the hardest field at 4.70. Even if we trim the estimates to exclude the 10 most extreme values, a reasonable estimate of marginal cost is probably around $3.

As for the other issues, he finds that prices have been “lagging behind” both the adjustment formula and average cost, let alone marginal cost.

ARH’s notifications pursuant to the relevant Executive Decrees referred to above have been sporadic rather than annual as required by law. Of the four price notifications made to the date of Aissaoui’s study, the first, which came in decree 2005, set a dual supply price, one at DZD780/1000m3 ($0.28/MMBtu) for the power generators and public distribution, the other at DZD1,560/1000m3 ($0.56/MMBtu) for the industrial sector. The second notification, which was made by ARH in 2008, set the supply price at DZD828/1000m3 ($0.33/MMBtu) and the wholesale price at DZD1,203/1000m3 ($0.48/MMBtu). The third in 2011 set the supply price at DZD1,024/1000m3 ($0.37/MMBtu) and the wholesale price at DZD1,404/1000m3 ($0.51/MMBtu). Finally, CREG Decision D22-15CD of 29 December 2015 increased prices by 15 – 40% depending on consuming sector. However, considering the low starting level, increases are not so large in absolute size and hardly modify the previous picture.

Whatever the pace and modalities of successive adjustments, primary gas prices in Algeria have remained very low by any standard. They are lower than costs and are also the lowest across the MENA region.

6.2.3 Price structure and other provisions

According to Chapter X of the Electricity and Gas Distribution Law of 2002, "Activities contributing to … gas supply shall be paid on the basis of legal provisions based on objective, transparent and non-discriminatory criteria. These criteria shall favour the improvement of management efficiency, technical and economic profitability of activities as well as the improvement of the quality of the supply." Gas transportation and distribution tariffs, which feed into retail prices, include also incentives for the reduction of costs and the improvement of the quality of the supply. There are no known destination clauses in domestic gas supply contracts in Algeria. Even in Sonatrach's gas export contracts, pressure from EU competition authorities led in 2007 to the removal of destination clause restrictions for European costumers.

The following Table shows prices that have been enforced in Algeria since January 2016.

Table 6.1. Gas prices in Algeria since 1 January 2016

User	Fixed	Capacity	Energy
Unit	$ / month	$/cm/h/ month	$c/cm
High Pressure / high load	608.60	0.45	0.96
High Pressure / low load	80.46	1.17	1.93
Middle Pressure / high load	66.24	0.96	1.59
Middle Pressure / low load	6.62	0.23	3.30
Low pressure (< 543 m3/y), residential	0.24		1.30
Low pressure (< 1087 m3/y)	0.24		2.51
Low pressure (1087-3260 m3/y)	0.24		3.11
Low pressure (>3260 m3/y)	0.24		3.56

Source: Elaboration on CREG Decision D22-15CD. Conversion rate $ = 119 Algerian Dinars

Overall, these tariffs are below costs (as noticed above) and among the lowest in the world. The energy component for small customers is progressive) increasing with volumes. Their structure looks well balanced and relatively advanced, as it included a fixed term, a capacity related component, and an energy-related component. Customers supplied at high and middle pressure can also choose between high and low load tariffs.

However, prices for small customers are more heavily subsidised as even fixed charges are clearly very low and not likely to cover distribution costs.

6.2.4 Final comments

Algeria is indeed a model in which export prices and domestic gas prices are quite different. Domestic gas prices are very low compared to export gas prices. This fact as such has not created problems for bringing investors to the Algerian gas market. However, Algeria as a producing region is suffering from a rather long lasting crisis. Production of oil and gas fields has been mostly declining in the last ten years, and even recent rounds for new exploration acreage have hardly raised IOC interest. Therefore, it is dubious that the country can recover and possibly overcome its past peak production levels for several years. Its resource base has been recently revised downward to 2745 Bcm (33 years of current production) whereas demand development, notably for power generation, is skyrocketing. It is feared that persistently low energy prices may push demand in such a way that an Egyptian style shortage may emerge by the end of the decade. The government had started to lift subsidies for the (less politically sensitive) industries that are partly controlled by foreign interests, but this process has been halted in the last three years. Subsidies to natural gas also prevent the development of other power sources, with natural gas accounting for about 97% of generation, despite the remarkable renewable potential of the country.

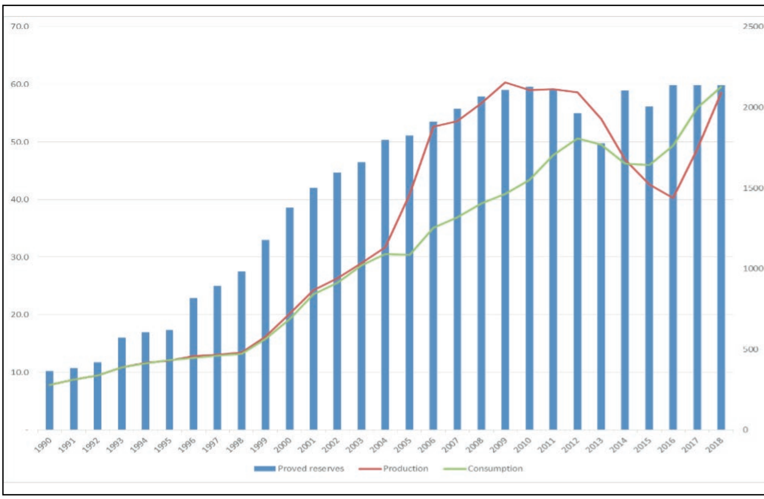
On the supply side, only a substantial reform of the tax regime would probably bring back IOCs, which are necessary to invest in the development of new resources, including unconventional ones. The U.S. Energy Information Administration has estimated Algerian shale gas resources at over 25 Tcm, which would put the country among the top 5 world resource holders. Yet remarkable difficulties, including water management, may hinder the actual development of such huge wealth. For further details see Darbouche (2012, 2013), Aissaoui (2016).

6.3 Egypt

6.3.1 Introduction: the Egyptian gas industry

The Arab Republic of Egypt ranks among the 20 largest countries in the world by proved commercial reserves and current gas production (58.6 Bcm in 2018). The origins of its gas industry date back to the 1960s, but production has taken off mostly in the 1980s and 1990s.

Figure 6.4. Gas production, consumption (left scale) and proved reserves (right scale) in Egypt, 1990 – 2018 (Bcm).

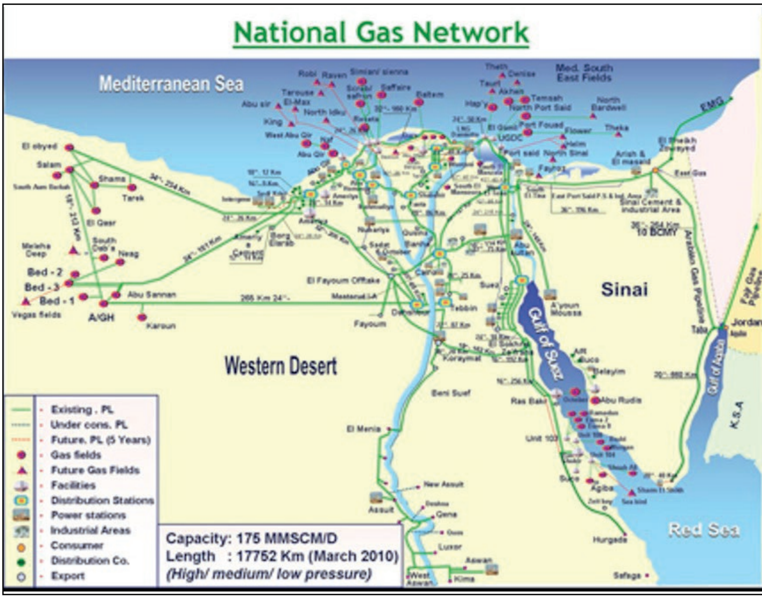


Source: BP, Statistical Review of World Energy, 2019.

EGAS sells gas to end users. However, it is not a fully integrated company: transmission is operated by its subsidiary GASCO, and local distribution is operated by 16 local distribution companies. EGAS pays fees to both GASCO and distributors for their services, but retains the gas retailer position.

The gas network has been extended to almost all governorates, with a total length of nearly 50000 Km, of which about 3500 of high pressure transmission (Figure 6.5).

Figure 6.5 – Egypt's gas production, treatment sites and transport network



Source: EGAS

Most of natural gas production has always been consumed locally. The market mainly consists of power generation (61%), however industry plays an important role (34%). Local distribution (4%) and the transport sector (1%) are still minimal, even though the gas network has over 8 million connected households and other small customers (All market data from the 2016-17 fiscal year).

Exports have started in 2003 by the Arab Gas Pipeline to Jordan, followed in 2005 by LNG from the Damietta liquefaction terminal in the Nile Delta Region. Later, a second terminal has been opened in Idku LNG terminal near Alexandria, and pipeline exports have been extended to Israel, Syria and Lebanon. However, since 2009 a stagnation of production and reserve finds, together with a continuous fast growth of domestic consumption have led to the mothballing of Damietta and later of Idku LNG plants, and them to the disappearance of exports altogether, which are now reduced to a minimum.

For some years, despite the suspension of exports, the country has been effectively short of gas, and has contracted two floating LNG gasification and storage units, becoming an LNG importer. However, important finds have recently reverted this trend. In particular, the discovery of the giant Zhor field and its fast development have allowed to stop imports as of late 2018, and the restart of LNG exports is expected soon.

6.3.2 The market and pricing

EGAS has actually the pivotal role in the system: it sells gas to the domestic market, which is supplied through Production Sharing Agreements with International Oil Companies. Such agreements are negotiated in bidding rounds, and involve a common structure:

- A share of production, known as *cost gas*, covers the operator's costs;
- The remaining (*profit gas*) is shared between all joint venture participants, among them in Egypt there is always EGAS or another National Company, usually with a 50% share[1];

Any gas that EGAS needs (for domestic consumption) in excess of its share of profit gas is purchased at an agreed price. This price was originally linked to crude oil, with a floor and a ceiling, through a mechanism, widely used in international trade, known as S-curve. However, since the ceiling of 2.65 $/MMbtu was related to a Brent crude of $22/bbl and above, in fact this is the price at which EGAS purchased most gas. The S-curve had a floor at 1.50 $/MMbtu for Brent below $10/bbl, with linear interpolation within these thresholds[2].

The ceiling price is regarded as adequate for old fields, but not for new ones, which are mostly in the Mediterranean deepwater offshore.

It is clear that the gas price formula has been set at a time when oil and gas market prices were much lower: Brent crude prices in the 10-22 $/bbl range date back to the 1990s. However, this fixed price could adequately serve the upstream Egyptian market even later, because flexibility and competition were provided by other conditions of the Concession Agreements. In particular, EGAS/EGPC and the Contractors (IOC's) could bargain on items like:

- The share of cost and profit gas (with the former typically around

2 The Euro-Arab Mashreq Gas Market Project, Egypt Diagnostic Report, December 2006, MEDA/2004/016-703.

35%);

- The shares of the JV, and hence of profit gas (usually, but not always, at 50%);
- The duration of the concession and the possibility of extension;
- The minimum required seismic exploration and drilling efforts;
- Rates of return, usually comprised between 12 and 16%;
- The "bonuses", or lump sums paid by the Contractors upon obtaining the Concession.

In fact, several clauses are defined in a separate PSA, negotiated and signed once a commercial discovery occurs, yet its terms are related to those of the original Concession Agreement. In particular, the development and production duration and its possible extensions are defined considering the characteristics of the field.

Besides these negotiated clauses, others have remained fixed: among them, not only the gas prices, but also (most importantly) the fiscal terms, and the take or pay conditions, which are typically set at 75% for the NOCs' purchases.

This model and its related conditions have allowed a superb development of the Egyptian gas exploration and production for several years; so that they have been taken as a model by other countries (see e.g. the next section about Nigeria). In particular, experts regard Egypt's fiscal terms and take or pay conditions as slightly more producer-friendly than the average international standards.

Formally, the Egyptian oil and gas policy envisages that resources should be split as "one third for domestic use, one third for export, and one third for future generation". Yet it is not clear what this means in practice, If resources kept for the future are related to new additions, the policy is clearly neglected since 2009 at least, as reserves have been mostly stagnating or even shrinking. Furthermore, exports have never reached more than half the level of domestic consumption.

However, the rapidly increasing domestic consumption has limited the availability of gas for export, jeopardizing the economics of the IOC's projects in the country. Moreover, the cost of most new offshore development clearly exceeds the maximum allowed price level of 2.65 $/

MMbtu. Whereas EGAS and the Egyptian Ministry of Petroleum have lately accepted higher prices for selected projects (reported up to $4), the loss of profitability and increasing delays in the payments owed by EGAS to IOC's has led to a stagnation of investments, which in turn has led to stalling reserves. For some years proved reserves have actually been eroded, and the natural decline of older fields has led to a reduction of production, now entirely dedicated to local consumption. Although the political upheaval of 2011-13 has also been blamed for the crisis of the Egyptian gas industry, it is worth noticing that the decline of investments, reserves and production actually started before such events.

More recently, facing the very high costs of imports and the payment of high penalties for its failure to meet export contracts, Egypt has further increased its upstream pricing flexibility. This has allowed the remarkable recovery of production since 2016.

EGAS' single buyer role leads to complete independence between the price at which gas is purchased (upstream) and the prices at which it is sold to domestic customers.

As a World Bank – ESMAP Report[3] explained a few years ago:

"Egypt has no specific gas law. The policy and regulatory roles are not clearly defined and separated, and third party access to transmission networks and independent regulation of gas prices are not currently in place. Egypt does have a functionally separate transmission system operator (GASCO). The Ministry of Petroleum is aware of the shortcomings of the gas market and is in the process of making changes, including plans to establish an independent gas regulator". This institutional situation has been eventually addressed in 2017, through a gas market law including the setup of a separate gas regulator and partial market opening, at least for industry[4].

A number of policy decisions have led to the prominent rise in domestic gas consumption in Egypt. In the early 1990s, attractive fiscal and gas pricing terms were introduced on the supply side, creating the incentives necessary for upstream producers to develop existing reserves and explore new gas reserves. However, domestic gas tariffs have remained heavily subsidized, funded through the State's share of the nat-

3 World Bank Energy Sector Management Assistance Program, *Potential of Energy Integration in Mashreq and Neighboring Countries*, Report No. 54455-MNA, June 2010.

4 https://www.gasreg.org.eg/law-for-gas-market-activities-regulation/

ural gas rents. World Bank estimates indicated that natural gas subsidies ranged between 32% and 85% depending on the customer class, with the largest subsidies provided to the residential sector. It is understood that the Government intends to phase out subsidies over time, while establishing other social protection measures that target the truly needy. Such actions will dampen the rate of growth in domestic gas demand".

As part of this approach, retail prices have been largely maintained below supply costs, with a view to:

- promote gas usage in residential sector
- attract energy intensive industries like cement and steel;
- ensure competitiveness of local fertilizer production; and in particular:
- generate cheap electricity, with an average price (also through further subsidies) of 3.5 US cents/kWh.

In fact, this situation had already lasted for several years. A previous and accurate Report, sponsored by the European Union[5], had concluded that:

"The retail pricing of domestic gas sales (and electricity and petroleum products) is below economic levels. EGAS buys gas for \$2.65/MMbtu and sells for \$1.25/MMbtu in the domestic market (FY2005/06 rates). The \$1.40 difference is covered by the State's share of natural gas resource rent. As in any energy market, persistent sub-economic pricing leads to increased and affordable energy access; but it also leads to wasteful consumption, misallocation of resources, underinvestment and the need for subsidies. As one would expect, the suppression of energy prices for the domestic market has led to consumption in excess of the economic norm. In the current cost environment, increased retail prices are almost certainly required to minimize the extent of subsidy required". For example, the role of the combined cycle technology in the Egyptian power generation is still very limited, with most plants featuring a rather low efficiency. The role of renewables is also a minor one despite the remarkable solar and wind resources that are available.

Only eight years after the EU Report and four years after that issued by the World Bank, the situation has started to change. Meanwhile, only very limited increases have been reported, particularly for energy inten-

5 See fn. 152

sive industries (like cement or steel), which cover about 10% of total consumption. As the domestic consumption now requires (and is about to fall short of) all production, the export gas rent has all but vanished and the burden of subsidies that are necessary to keep prices below costs are clearly unsustainable. It has been estimated that such burden amounts to 14 $ billion, which is more than the Egyptian state spends on defence, education, or healthcare. Of these, annual subsidies for natural gas only could be estimated at between 3 and 4 Bn. $.

A July 2014 Government decision has imposed a substantial correction of these practices, with significant price hikes for most consumption categories, including power generation. In this way, prices would be on average close to cost reflective levels, although significant subsidies remain notably in the residential sector.

Table 6.2. Consumer prices in Egypt ($/MMbtu)

	Before May 2008	After May 2008	2013	Since July 2014
Energy intensive industries	1.91	3.01	4.00	7.00 – 8.00
Other industries	1.32	1.32	1.25	4.50 – 5.00
Residential	0.80*	0.80*	0.80*	1.55 - 5.81
CNG	2.38	2.38	1.75	4.26
Power generation	1.32	1.32	1.25	3.00

However, it could be noticed that prices for power generation are probably still below the long run (i.e. full) marginal costs of new fields

6.4 Nigeria

6.4.1 Facts and Plans

Nigeria, a historical OPEC Member State, has the 9th largest proved commercial reserves in the world (5200 Bcm) and is the 17th current gas producer (49.2 Bcm in 2019). The rapid growth in gas production in the last 20 years has been mostly driven by exports, particularly LNG (27.8 Bcm in 2018), with minor quantities delivered to neighbouring countries through the West African Gas Pipeline.

Gas production is dominated by international oil&gas companies, including several majors and a few independents. The Nigerian gas is on average rather rich in gas liquids, and often associated with oil. Production has often been driven by the need to commercialize these liquid products, therefore associated gas production that cannot be reinjected is flared. The share of flared gas has however declined in Nigeria, from 46% in 2003 to less than 12% in 2018.

The Nigerian Gas Company (NGC), a subsidiary of the Nigerian National Petroleum Company, plays a major role: it is a producer as it enters into joint ventures with several international companies, and is the owner and operator of the national transmission grid. Two other companies (Shell Nigeria and Gaslink) operate local distribution and supply.

Natural gas is a major source of tax revenue for the Federal Government of Nigeria (FGN). The total government take is estimated at 93% for onshore and 91% for offshore fields, one of the highest values in the world.

Domestic gas consumption is mostly for power generation (about 80%), but important shares are also utilized as feedstock for the production of fertilizers and methanol, and for consumption by other industries. The residential and commercial sector represent only a tiny share. Overall, natural gas covers 13% of national primary energy requirements but over 45% of its commercial energy.

Whereas exports have taken off, with an average growth rate of 14%

since 2000, domestic gas trade and consumption have lagged [6]. The problem has been also exacerbated by unavailability of power plants, due to lack of maintenance, and by sabotage of pipelines and unrest in the main producing region (Niger Delta) The rich condensate content of Nigerian gas has fostered such sabotage, alongside that of oil pipelines, aimed at condensate theft, as well as a form of political pressure in the long lasting struggle of Niger Delta tribes to enhance their share of the oil and gas take and to improve environmental protection.

Yet, inadequate gas transportation and processing infrastructure, and an history of commercial poor performance of the domestic gas and power sectors – with low price, unpaid bills, weak and unenforceable supply agreements (GSPAs) – have been also blamed for slow growth[7]'.

To avert this situation, the Federal Government has adopted since 2008 a new gas policy, which has been translated into a Gas Master Plan and embodied into the National Domestic Gas Supply and Pricing Regulation 2008 (NDGSPR), aimed at boosting the national use of gas resources. The pillars of this policy are:

- a legal obligation to reserve 40% of the production for domestic use (Domestic Gas Supply Obligation or *Domgas*);
- a price reform, aimed at ensuring commercial viability of domestic gas market, and eventually bringing prices in line (on average) with those of gas aimed at LNG export.

Both pillars aim at avoiding that companies privilege the export market, curbing supplies to the domestic one. A peculiar way of implementing this goal is the establishment of an *aggregator*, or single buyer, known as Gas Aggregation Company of Nigeria. Legally, it is a joint venture owned by the country's gas producers, but in fact it acts as a public body under FGN control. This is a most interesting feature of the Nigerian case.

The Aggregator has several roles, expected to evolve over time. In the

6 Nigerian Electricity Regulatory Commission (NERC), Multi-Year Tariff Order for the Determination of the Cost of Electricity Generation for the Period 1 June 2012 to 31 May 2017, 1st June 2012, www.nercng.org

7 D. Ige (2010), "Strategic Aggregator" Roles and Functions in the Nigerian Domestic Gas Market, www.gacn-nigeria.com ; T.O. Okenabirhie (2009), "The Domestic Gas Supply Obligation: Is this the Final Solution to Power Failure in Nigeria? How Can the Government Make the Obligation Work?", University of Dundee, Centre for Energy, Petroleum and Mineral Law and Policy;

short term, it deals with demand management, including the rationing of inadequate resources. Its most interesting role is however indicated as Aggregate Price, Securitization and Escrow Management.

In fact, the Aggregator buys gas from producers, taking it from their quotas pertaining to the Domgas and from other sources, like excess gas or currently flared gas. A public purchase procedure is envisaged.

For these purchases, the Aggregator negotiates pricing and commercial conditions pursuant to the Pricing Regulation principles outlined by the NDGSPR. This is not however a detailed price control order, nor does it define prices. It is rather a general policy requiring that projects maintain an internal rate of return of 15%. Since gas production sites are very different for their costs, location (and hence transportation costs), and particularly for their contents in liquids, actual prices and their escalation clauses can be rather different, but they are normally related to the prices of natural gas liquids. For example, for some Niger Delta fields that are very rich in gas liquids, the production cost of residual (dry) natural gas can be as low as 0.1 $/MMbtu. For this reason, this approach is also known in Nigeria as “liquids based pricing”.

The Aggregator is not a regulator, although its institutional goals include the optimal protection of both producers and consumers, and it is the only body that is actually involved in the negotiation of prices with producers. However, the official natural gas regulator is the Department of Petroleum Resources (DPR), under the Ministry of Energy.

A consequence of this approach is the lack of information about contractual details. In fact, in order to maximize its bargaining power, the Aggregator would not reveal the details of prices and indexation clauses that are negotiated in each case.

The purchased gas is then sold to the domestic market, which is segmented into three sectors for the sake of price regulation. Hence, gas prices are fully regulated in Nigeria, but regulatory criteria differ by consuming sector:

1. For power generation, the largest consuming sector, the price is assumed to be based on the cost of supply (*regulated pricing regime*). Since about 80% of domestic consumption is for power generation, it is understandable that a cost based pricing of such gas should not be far from the average production cost. This approach seems to

have been roughly followed for some time, with costs evaluated by the "liquids" method, i.e. with costs netted of the liquids' sale revenues.

However, a progressive upward price review is now envisaged, bringing prices towards the export parity target. Therefore, regulated prices are not apparently fully based on cost, but seem to be the outcome of a political decision aimed at incentivising gas domestic use. The original plans are illustrated by the following Figure 7.5. The target price for this sector was $2/MMbtu for 2014.

These plans have been included in the electricity regulator's Multy Year Tariff Order (MYTO 2012-17), which reads:

"Gas prices have been regulated since the adoption of the MYTO in 2008 and the regulated prices as applied in the 2012- 2016 tariff are as follows:

	2012	**2013**	**2014**	**2015**	**2016**
Price	1.80	1.80	2.30	2.37	2.44

Gas prices are pass-through costs for the electricity producers. Where there is a material change in the price, the NERC will effect a commensurate change to the wholesale contract price".[8]

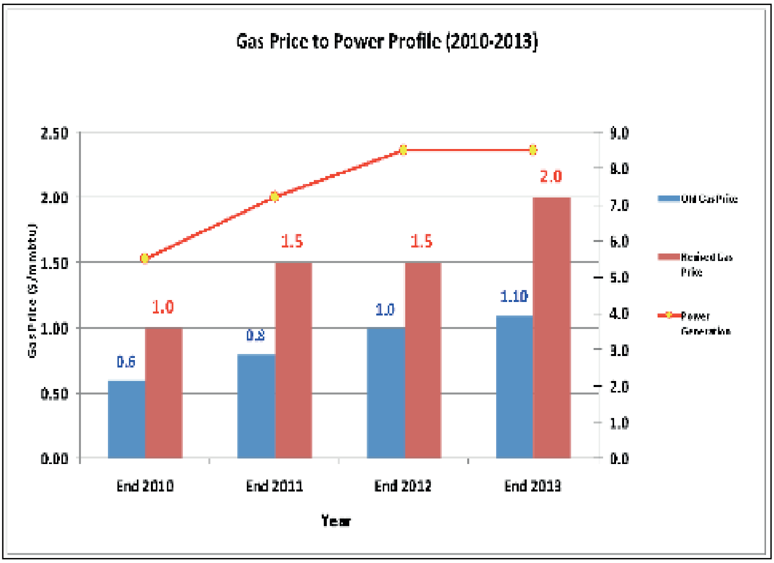
The upward revision of gas prices for power generation has also been part of the process that led to the electricity industry reform of 2013, where the former state-owned monopoly has been split into 5 generation and 10 distribution companies, all sold to private owners, whereas the state retained control of the transmission companies, one generator and one distributor.

To understand the problems of Nigeria's domestic gas sector, we should consider its extremely strong linkage with the power industry. In fact, power covers 60% of domestic gas consumption, and gas in turn represents about 80% of primary generation capacity. Yet Nigeria has one of the lowest per capita generation levels in the world, and access to electricity is estimated at 61% on average but only 34% in rural areas%. It is widely agreed that both modern renewable energy and natural gas are

8 See fn. 156. A "material change" is defined as a change in any cost item of more than ± 5%.

necessary to improve this record[9].

Figure 6.6 – Actual gas price and power generation (RHS, TWh)



Source: National Electricity Regulatory Commission of Nigeria

In the other main consuming sectors, other approaches are adopted:

2. In the "gas based" industries that use gas mainly as feedstock (methanol and fertilizer production), prices are indexed to those of the end products, which are largely traded in international markets. This is defined by the NDGSPR as *pseudo-regulated pricing regime*.
3. In the other industrial sectors, where gas is used to produce heat or to (locally) generate electricity, prices are defined in relation to those

9 U.S. Energy Information Administration, Country Analysis Brief: Nigeria, 2016; Occhiali, Giovanni; Falchetta, Giacomo (2018), "The Changing Role of Natural Gas in Nigeria: A policy outlook for energy security and sustainable development, *Working Paper No. 010.2018*, Fondazione Eni Enrico Mattei (FEEM), Milano.

of competing fuels, typically on a useful energy equivalent basis[10].

In both cases, the Aggregator is in charge of negotiating exact prices but, as in the case of the gas purchase price, details are not known for confidentiality reasons.

6.4.2 Comments

It has been noted that the Domgas obligation has in fact been hardly implemented by the IOCs that it targeted. Whereas several of them have pledged to devote more gas to domestic use, including by building new gas fired power stations, these plans have not been implemented, and the growth of gas exports has clearly exceeded that of domestic consumption, even after the NDGSPR has been enforced in 2008. Delays in the implementation of the pricing part of the Policy and political problems including terrorist attacks in the Delta have been blamed for this outcome, but the majors allege that burdensome details of the Policy have jeopardized its implementation, and that its direct application under the current resource availability would lead to breach of their take or pay commitments towards foreign customers. In fact, it is likely that the hunger for tax revenue has led to preferring higher exports as the domestic development plans were lagging behind.

Despite some delay, the gas-to-power price seems to have been broadly aligned with the plans, and to have made a substantial contribution towards alignment with export parity. Faced with substantial inability to force IOCs to abide by the domestic gas obligation, the FGN seems to be playing the card of incentives, raising the domestic prices towards export parity. It is interesting that this has happened in spite of the availability of a National Gas Company that was involved in many production JVs.

Unfortunately, the policy of pricing production on a case by case

10 This is a traditional practice of the gas industry in less developed markets and has been long used in Europe as well before gas market liberalization. It is also known as the approach where prices to each sector (or in some cases even to each individual consumer) are adjusted to the "bearing capacity" of the sector (consumer). This approach is also close to what is known as "Ramsey pricing" in theoretical economics, where prices are related to inverse demand elasticities. Yet the idea of bearing capacity includes not only the capacity of the demand side to react to higher prices, e.g. by improving efficiency or switching to other energy sources, but also the politicial capability of consuming sectors to accept higher prices.

basis prevents the definition of clear criteria. The official rate of return is known and rather high at 15%, which is understandable given the general risk level of this country.

However, a full alignment of domestic prices to export parity is hampered by the remarkable payment difficulties of the main customers, notably power generators, which are in turn related to those of distributors and of end customers. In fact, a debt chain extends over the whole gas and power industry of Nigeria. A further increase of prices may not increase revenue, but rather debt as well as litigation, further exacerbating the companies' weaknesses.

In turn, these payment difficulties reduce actual average revenues, hampering creditworthiness and hence the development of new projects that are critical to reduce gas flaring, increase gas to power conversion and the availability and reliability of power supplies. The non-completion of critical projects is often mentioned as a key reason for the slow development of gas fired power generation in Nigeria.

On the other hand, as noticed by Oyewunmi and Iwayemi[11], "from a government perspective, the trade-offs are more complex and involves striking a pragmatic balance between maintaining investment incentives for producers, maximizing state revenues and ensuring the much-needed energy supply increases while reducing pass-through costs to final consumers in the power market".

6.4.3 Regulatory and institutional issues

In the Nigerian gas industry, the regulator is the Ministry of Petroleum, through its Department of Petroleum Resources. The Minister is also Chairman of the Board of NNPC, of which NGC is a subsidiary. Therefore, some authors have pointed at a lack of regulatory transparency, as the regulator in fact coincides with the regulated company. This may have discouraged foreign investment in the domestic gas sector, which has not helped addressing the infrastructure inadequacy that has slowed its development. For example, fines are envisaged for companies that violate the gas flaring reduction obligations, but most of the breakers are controlled by NNPC itself, so that in a sense the regulator should have fined

11 Tade Oyewunmi, Akin Iwayemi, "Energizing Emerging Economies: The Role of Natural Gas and Renewable Energy", The 9th NAEE/IAEE International Conference, 24th – 26th April 2016, Abuja, Nigeria.

himself[12]. This problem has been addressed by the Petroleum Industry Governance Bill, which has been passed by both Houses of Parliament and waiting for the President's signature as of early 2019. By comparison, power sector regulation is in the hand of an independent agency.

In fact, gas pricing is largely a political decision, under the responsibility of the Federal Government and subject to very limited constraints. The National Domestic Gas Supply and Pricing Policy 2008 requires a floor price of 0.40 $/MMBtu for power generation and 0.80 for other users, of which 0.30 is reserved as transmission fee. It is not surprising that this hardly encourages the implementation of domestic obligations by suppliers, which has in fact been poorly implemented (Figure 6.7). As of 2017, the performance of the Domgas supply obligation was 41%, with lack of infrastructure mentioned as key reason for failures.

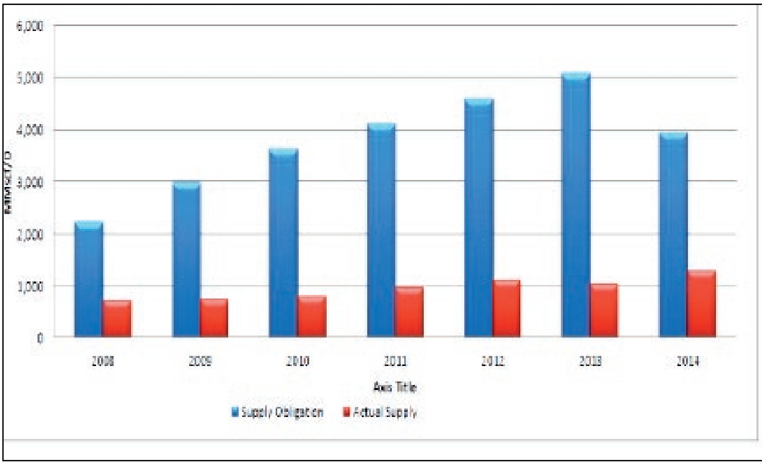
Since 1 January 2016 the gas price for power generation has been lifted to 2.50 $/MMBtu and the gas transmission price to 0.80 $/MMBtu[13].

Information about actual prices is scant and not fully transparent. In their cited paper, Oyewunmi and Iwayemi conclude that "an often arbitrary, opaque, state-cantered regulated pricing approach which is still applicable to the Nigerian gas supply industry further complicates the expected gains of the incentive-based price-cap related model being adopted in the power sector through the MYTO".

12 Occhiali and Falchetta, cit.;

13 Latest update provided by the Nigerian Electricity Regulatory Commission, see various Tariff Orders on https://nerc.gov.ng/index.php/home/myto/406-generation-tariff

Figure 6.7. Industry Compliance with Domestic Gas Supply Obligation 2008-2014



Source: DPR 2014 National Oil and Gas Report, pg. 1 - 85 available at <https://dpr.gov.ng/index/wp-content/uploads/2016/01/2014-Oil-Gas-Industry-Annual-Report-1.pdf

6.5 Israel

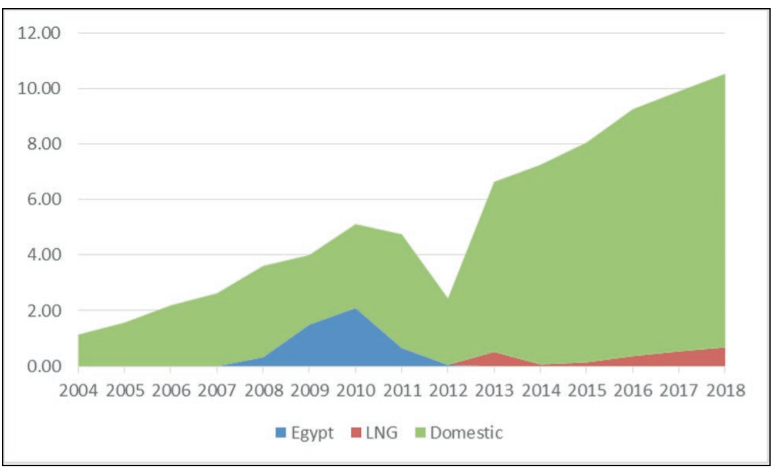
6.5.1 Brief description of the industry

The State of Israel developed its gas market only recently, after its first important find in the Mediterranean offshore the Yam Tetis and Mari B fields. Yet consumption has grown quickly and has reached 930 cubic meters/pc, a remarkable level for a mild climate country where space heating is very limited. Most gas is produced domestically, but the country has been importing from Egypt by pipeline – the only international connection of its system. After the decline of the original fields and the abrupt interruption of pipeline imports triggered by the Egyptian 2011 revolution and the ensuing Egyptian gas crisis (see section 7.3), consumption has fallen, and small amounts of LNG have been imported by means of a floating re-gasification terminal, which is also used as a small storage (FSRU). Since 2013, the large Tamar field has come on stream and consumption has strongly recovered (Figure 6.8).

After the discovery of another huge field (Leviathan) and a few smaller ones, proven reserves have taken off, exceeding 400 Bcm, but estimates are as high as 900-1100 Bcm, or 300 years' consumption). This bonanza has raised the issue of exports. After long discussion and a reform of fiscal treatment[14], implemented in 2012, the government has decided that up to 40% of resources can be exported, although it is not clear how (and on which time span) this percentage will be calculated.

Plans about exports have been hampered by the difficult geopolitical situation of the country, surrounded by hostile or troubled neighbours. As of 2019, limited exports to Jordan have been agreed, and the start of some sales to Egypt are expected, which would be hauled by reversing the old import pipeline (EMG). Talks have been also held with other potential partners, including the possibility of a liquefaction facility in Cyprus, and an offshore pipeline connecting Israeli offshore fields with Cyprus and on to Greece. However, high costs and security concerns have slowed the process.

Figure 6.8. Israeli gas supplies, 2004-18 (Bcm).



Source: PUA; BP Statistical Review of World Energy.

14 Known as Shishinsky Reform from the name of the Chairman of the special Committee that has inspired it

The structure of the Israeli gas industry is rather uncommon. There is no integrated national gas company, but a transmission and distribution company (*Israeli Natural Gas Lines*), which is state-owned and subject to regulation by the Natural Gas Authority at the Ministry of Energy and Water Resources. The transmission system is 650 Km long and growing in line with expected demand.

The market mostly consists of power generation (around 80%), of which most is purchased by IEC, the National Electricity Company. However, a growing share is purchased by independent power producers, who benefit of a lower price (see below), with a view to foster diversification of power supply. Other uses include limited supplies to large industrial customers. Local distribution has also been planned but its development is just starting.

Availability of natural gas and the willingness to reduce pollution from coal burning has led to a sharp increase of natural gas in the country's energy supply mix, from just 12% in 2004 to 64% in 2017.

Whereas the market is organised as a competitive one, since Egyptian supplies vanished (around 2011-12) there was basically one supplier. Consortia of several companies control both active fields (Tamar and Yam Tetis, where the latter is almost depleted), are dominated by two companies, U.S. Nobel and the Israeli Delek Group, and market gas together. The same companies also controlled the majority of the huge new Leviathan and of the smaller Karish and Tanin finds[15].

In the early years, competition between domestic production and imports from Egypt ensured prices aligned with international levels in the Mediterranean basin, therefore no further regulatory or structural provisions were enforced. However, after the suspension of Egyptian supplies around 2011 there was a *de facto* monopoly in Israel, which could not be challenged by the limited LNG imports that started in 2013, priced in line with international markets, often higher than previous Israeli prices. Moreover, LNG import capacity is limited to less to 2.5 Bcm/year, but this threshold has never been reached.

Therefore, regulators started to request a rebalancing of the industry. In particular, the Israeli Antitrust Authority (IAA) had initially required that the two combined dominant companies should sell their interests in

15 Shares vary across fields, but Noble and Delek jointly control substantial majorities. Smaller companies hold minority shares.

the smaller Karish and Tanin fields. However, these fields do not comprise more than 7% of Israeli reserves and were not expected to be commissioned before 2018, therefore the Public Utility Authority for Electricity (PUA, see next section) saw market competition as inadequate and requested a substantial supply price regulation. The issue has become very controversial in the country.

More recently (2015-16) and after a dramatic confrontation leading to resignation of the Head of the Antitrust and of PUA, a deal was defined requiring Nobel and the Delek Group:

- To sell their interests in the smaller Karish and Tanin;
- To market gas separately to new customers;
- To offer to new customers the option to choose among four pricing options, including a linkage to oil (Brent), one to international prices and a weighted average of existing contracts (see below for more).

This proposal was agreed and enforced in December 2015 and became known as the New Gas Framework (NGF). However, it was challenged before the Supreme Court, which required a change in the "stability clause". Yet regulatory stability was not achieved despite this agreement. As of 2017, a class action had been launched, but limited effects arise from its conclusion. Yet regulatory uncertainty is lingering and the political instability of the countries, with general elections held in 2019, does not seem to help. Eight years after its discovery the development of giant Leviathan field is still pending, in stark contract with the fast take-off of neighbouring Egyptian Zohr[16].

6.5.2 Scope of price regulation, legal basis and responsibilities

Transmission tariffs and distributors' prices are regulated by the Israeli Natural Gas Authority. The price is nationally uniform and related to capacity and volume.

Gas suppliers are not regulated other than technically and operationally by the terms included in their reservoir's licenses. These terms

16 For more see Renelle Joffe and Elad Sharabani, "Israel's Upstream Natural Gas Sector Against The Backdrop Of The New Gas Framework", 5 May 2017, www.mondaq.com; Athanasios Dagoumas, Floros Flouros, "Energy Policy Formulation in Israel Following its Recent Gas Discoveries", *International Journal of Energy Economics and Policy*, 2017, 7(1), 19-30.

include the amount of gas they are supposed to send to acceptance terminals in Israel, the size of pipelines they are supposed to construct to the Israeli shore and maximum quantities to be produced on an hourly basis from the reservoirs.

However, most gas is sold to the power generation industry, which is currently fully regulated and only in a very initial stage of market opening. It is dominated by the state –owned IEC, with a few IPPs running their (almost entirely gas fired) CCGT or cogeneration plants. Therefore, the PUA can actually regulate the price at which gas is purchased by IEC as well as by IPPs.

The PUA is not in fact a fully independent regulator. Since the Ministries of Finance and of Energy and Water Resources are represented in its Board, decisions are actually taken by consensus with these Ministries. Coordination with the IAA is also actively pursued.

In fact, after substantial consumption started in 2004, gas prices have not been under supervision or regulated due to the assumption that competition between gas suppliers could set competitive terms for Israeli consumers. As long as there were two gas suppliers to the Israeli market (EMG from Egypt and domestic gas from Yam Tetis) gas prices and terms were competitive and in line with international standards. While gas prices started to climb around 2008-2009, EMG raised their gas prices including to existing consumers, but Yam Tetis did not.

However, when the Tamar reservoir was discovered and EMG stopped selling gas to Israel, prices offered by Tamar's partners to the Israeli consumers increased significantly. Due to the fact that the Israeli market was in shortage of gas, with just one supplier and one reservoir that was supposed to be developed very quickly, and pending government decisions regarding the taxation of gas to be paid by reservoir owners, the PUA together with the IAA and Ministry of Finance decided not to force price control over the Tamar reservoir.

The assumption at that time was that additional drillings for gas that took place would generate additional reservoirs that would be able to compete with Tamar, so that governmental intervention would not be required.

Since all non Delek and Noble exploration failed to find commercial gas, and the same partners discovered another huge reservoir (Leviathan), partly supposed to serve for export, the relevant government parties have been reconsidering gas regulations, including price control. Proposals have been put forward for prices to be aligned to those of alternative power generation fuels (like coal) or to alternative markets where Israeli gas could be sold, like Europe or Japan (via LNG). However, none of these proposals have been adopted.

It is important to notice that recently Tamar partners jointly signed several contracts with small IPP's for gas (actually reaching the maximum capacity they have) at prices that are higher than the previous prices signed two years ago. The base prices were increased by 4.7% compared to prices of contracts that were signed two years earlier. The indexation of the gas contracts has been changed to follow IEC's basic gas contract with Tamar (see next section for details).

6.5.3 Pricing and indexation criteria

Since prices are not regulated, this section analyses how prices appear to have been set by private contracts.

The basic price of Tamar gas for IEC, which covers about 70% of the gas market, amounted to 5.04 $/MMBtu as of 2012. Contractual prices for IPPs are related to the average electricity wholesale price of the country, in such a way that they are normally slightly lower than IEC's, but with a floor at 4 $.

Considering their lack of market indexation, prices may be regarded at first sight as roughly cost-based. However, analyses by J.L. Smith as well as by the author of this Chapter show that such prices involve a rather large rate of return (22-23%) for the Tamar partners, which is clearly above the average standard for the upstream oil and gas industry[17]. Moreover this price is the world highest for countries that are self-suffi-

17 This conclusion has been reached by Professor James L. Smith of the Southern Methodist University, Dallas, Texas in his testimony in a lawsuit promoted by a customer against Noble Energy Ltd., where he estimated that the cost of the Tamar gas lies between 2.34 – 2.47 $/MMBtu. Professor Pyndick in his Report to the "Shishinsky Committee" that advised the Israeli government on gas taxation issues estimated the average rate of return of oil & gas exploration and production at between 8-10%, with a best estimate of 9.2%. The popular Damodaran Tables (cited by J.L. Smith) (http://pages.stern.nyu.edu/~adamodar) show the E&P industry average cost of capital at 9.3% for their sample of companies that operate in this sector, including all main international companies.

cient, after New Zealand.

The price of Tamar gas for IEC, which covers about 70% of the gas market, is indexed only to the Israeli (30%) and US (70%) price indices, with no reference to any gas or oil market. This makes it rather unusual (see Chapter 8).

Prices for IPPs are indexed to the average wholesale electricity supply price, which is calculated by the PUA and is affected partly by supplies from coal, renewables and (marginally) oil products. It is however kept above a floor of 4 $.

Price levels and indexation criteria for thermal use by other industries are not public.

Figure 6.9. Recognized Cost of Gas from Tamar Reservoir $ per MMBtu and comparison with key world prices

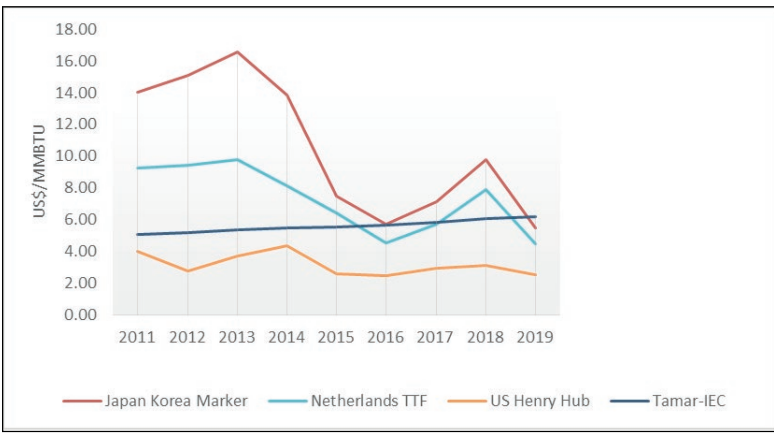


Figure 6.9 shows that the Israeli price remains stable and is not affected by international market fluctuations. Overall, Israeli prices remain usually well above the typical levels of net exporting countries, but often below those of net importers like the European Union.

It is hard to foresee whether this decoupling from international prices could be sustained once the country starts exports, notably if international (and hence export) prices remain lower than those paid by Israeli customers.

Indexation has led to IPP enjoying lower prices than IEC, which may favour competition in the power industry. However, since this is actually almost entirely governed by a system of long term contracts, such impact looks unlikely.

6.5.5 Main non-price provisions of regulation

There is no formal regulation of non price contractual clauses, except for technical and safety provisions. However, it should be considered that Israel's gas infrastructure currently lacks almost all flexibility tools. The only flexibility sources are the FSRU off the Hadera coast, with a storage capacity equivalent to almost 80 million cubic meters, and the limited line pack. The former could cover about three days of peak consumption, the latter just a few hours.

In this situation, contractual arrangements are rather important. Swings in electricity demand and hence in gas demand for power generation may well lead to further increases of fuel costs if not matched by limited contractual flexibility. In particular, contracts include:

- Maximum offtake rates;
- Take or pay (TOP) clauses (ratio between the average and maximum offtake rate): comprised between 60-77%;
- Carry forward provisions (possibility to calculate gas taken in excess of TOP towards TOP obligations in following years : 2-5 years;
- Make-up provisions (possibility to transfer part of the gas not taken to the next contractual period, thus recovering part of the TOP penalty): up to 4 years;
- Swing factors (between the highest and lowest hourly offtake rate): 1.8 for the largest contract (IEC), no limit for others;
- Run-up and run down rates (speed at which the requested offtake rate can be reached): only for the largest contract;
- Re-nomination provisions (size and required advance notice).

All contracts are long term (15-17 years). Only the largest one includes reopening clauses, which are however not related to market conditions but only point at the possibility to cover costs as required by an "anchor buyer" in the Israeli market. These reopening clauses apply after 8 and 11 years of contract implementation.

Non-price contractual conditions are related to technical factors and are therefore hard to compare among different reservoirs and systems. To some extent, further investment in wells, connecting pipelines and gas treatment facilities allow larger flexibility[18]. Yet, the reported Israeli values are interesting and indicative.

6.5.6 The political economy of gas pricing regulation in Israel: some lessons

In many cases, gas pricing regulation is mostly undertaken and decided by political authorities with a view to check the market power of monopolists and dominant operators. In producing countries where industry operators are largely controlled by international companies, this issue frequently overlaps with the partition of gas rents between domestic and foreign stakeholders.

In Israel, the situation is more complex, as already illustrated in previous sections. The country is a mature and vibrant democracy, with elections based on proportional representation and a political system characterised by high fragmentation. Cabinets are often the results of difficult coalition agreements between several parties, which are necessary to achieve often precarious parliamentary majorities, so that early polls are rather common.

In this situation, regulation of gas prices and of the related electricity prices has been often a major field of political infighting. Regulators have played important roles, normally in line with their institutional duties but possibly also stressed by politicians (from government or opposition parties) and highlighted by the press. In particular, the PUA has fought to protect electricity consumers and IAA has tried to check gas market cartels. However, the independence of these bodies is limited in Israel: for example, the PUA includes Board Members that represent concerned Ministries. The head of the IAA resigned after clashes with the Cabinet.

18 In most advanced and complex systems, the gas industry prefers a steady production flow, with flexibility provisions moved downstream. In other words, flexibility is often better provided by underground or LNG storage and by interruptible end users, as well as a by a suitable combination of supplies. Only in systems with very abundant capacity (often because of declining production) it may be appropriate to use partly depleted reservoirs as a source of flexibility.

More recently, consumer associations have also played an important role through the opening of a class action.

In turn, the Cabinet in Israel has not systematically sided with domestic customers, but has rather been trying to strike a balance between consumers and producers, also with a view to ensure security of supply and to develop discovered resources.

Ironically, the vibrant democratic scene of the country, its western-style system of checks and balances and the rule of law, with their ramifications in the regulatory world, have been regarded by foreign observers mostly as a source of regulatory uncertainty. Legal procedures have led to decisions being changed or at least questioned, and this may have led to "loss-loss" outcomes: high consumer prices and slower resource development. This shows the importance of ensuring a clear framework, where regulatory responsibilities are well defined.

In the Israeli case, problems are further complicated by the difficult security situation of the country. The involvement of an American company for a country that crucially relies on U.S. support in international relations and in key military supplies further complicates the gas pricing issue. The U.S. government intervened to request the upholding of regulatory decisions taken towards American interest in the Israeli gas industry.

The Israeli case is interesting particularly as it shows the effects of the lack of price regulation in a market where monopoly positions have emerged. Prices are consistently higher than reasonable cost estimates, and allow twice as normal rates of return. What is more, they are subject to very limited indexation, which is not market related, and could make prices inconsistent with those of competing fuels as well as triggering tensions between domestic and export markets when sales to foreign markets start[19].

Finally, even ancillary contractual conditions are tight: take or pay provisions are not particularly demanding by international standards, yet they could lead to unnecessary and inefficient costs for consumers. In particular, price reopening clauses are either missing or very limited, and not in line with international practice where reopening normally occurs

19 In fact, Israel is already connected by pipeline to the Egyptian system and there have been proposals to use this connection, already used for imports, in reverse mode to feed the gas hungry Egyptian market, and possibly its currently idle liquefaction terminals.

every 3-5 years and is related to market conditions.

Whereas in many cases (reported in this book) price controls have been criticised for being too tight and hereby discouraging investors by inadequately covering their costs, Israel shows clearly that the opposite case does not necessarily lead to better results. In fact, if prices are too high, regulatory and/or political forces are likely to complain and put pressure on the status quo, with good points. Long discussion about taxation and about the split of resources between domestic market and exports – often hard to monitor and implement for a country that has not even started exporting – have also played a role in delaying development approvals, so that the very development of the Leviathan reservoir is currently at risk after an LNG major withdrew, no firm contracts have been signed and the export logistics has not yet been decided.

Thus, regulatory uncertainty could be a brake on investment just like too low prices, as investors perceive the situation as unstable, are busy fighting regulatory pressure, and hold off actual resource development as their main tool to force the hand of the government.

The key lesson of the Israeli case is that, whereas too tight price controls may discourage resource development, lack of a sensible regulation is also a problem, notably in an open and democratic society where economic and social forces are likely to oppose the exploitation of monopoly positions.

Moreover, Israel has not only neglected a proper price regulation, but has not even considered a broad market design. World experience shows that, if details of the market design are better defined by market forces, at least a broad framework must be defined either by legislation (as in Europe, Russia, Australia or China) or by a powerful, independent industry regulator (as in the U.S.A). Particularly in a small market like Israel, lack of counterbalancing market forces hamper the development of the market, which is entirely dominated by colluding suppliers, with little annoyance from far smaller competitors. Authorities should define not only a reasonable and balanced price setting and indexation methodology, but also the main pillars of a market, like balancing responsibilities and a (physical or virtual) market hub where resources that are necessary for flexibility and balancing are fairly traded, without unnecessary contractual obligations.

Israel's case is however rather peculiar, both for its lack of a national gas company and for its special security position and political relationship with the U.S.A. Whereas the latter is a special case that goes far beyond energy policy, the effects of the lack of a national gas company may be worth thinking over. The Israeli case certainly represents a blow for those arguing that market competition can work even in a relatively small market. On the contrary, Israel shows than in a small market even production can be a dangerous monopoly, which must be tackled either by a national company or by a strong and stable regulatory framework, covering wholesale as well as retail gas prices, as far as no effective competition prevails.

7. NEW ZEALAND

Sergio Ascari

7.1 The market and its regulation story

New Zealand is indeed an interesting case in gas pricing regulation[1]. It is a relatively small and isolated market, with consumption and production fluctuating between 4-6 Bcm in the last 20 years). Nowadays, in spite of its small size, it is a very competitive market, with several suppliers at both wholesale and retail level.

The industry started in the late 1960s with the discovery of two fields, Kapuni and Maui. In particular, development of the large offshore Maui field brought consumption beyond the 4 Bcm/year threshold as early as 1986. Most gas I now used by the petrochemical industry (51%) and power generation (27%).

In fact, the Maui field almost monopolised the market after 1985, with a market share over 90%. On the other hand, the market was not large enough to develop more fields. As a consequence, its price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years, at a level of about US $3.2/MMbtu.

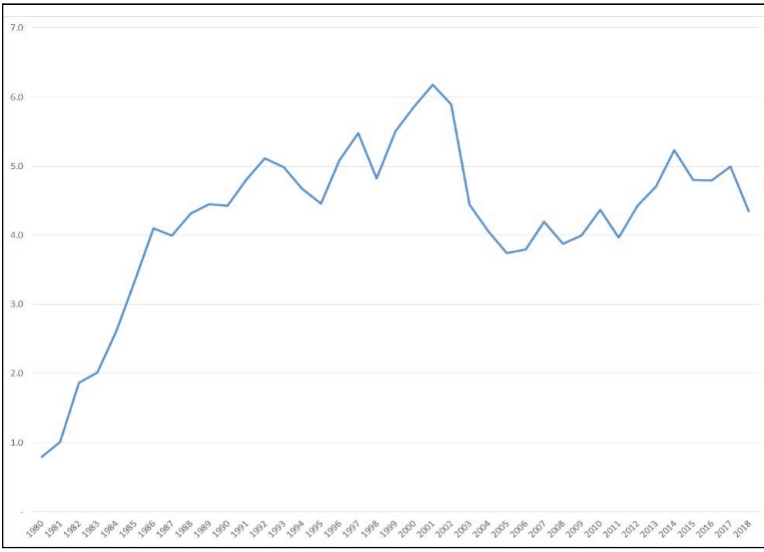
Little information could be detected online about details of such regulation. Apparently, the Commerce Commission did not calculate the costs but used a legacy contract that was deemed to precede the rise of Maui's market power, and mandated its application to the wholesale market. The mechanism was a compulsory purchase of the gas by the Government, which in turn sold it to power generators and retailers.

1 For details please see "The New Zealand Gas Story. The State and Performance of the New Zealand Gas Industry, 2nd Edition – April 2014, http://gasindustry.co.nz/publications/new-zealand-gas-story-second-edition.

The contract ensured a reduction (in real terms) of the price, as this was supposed to increase by the larger of 50% of the inflation rate, or the inflation rate itself minus 3% (see Figure 2.15.2). However, this price was too low to clear the market. It triggered consumption growth but did not foster the discovery of new reserves, thus the reserve/consumption ratio fell from 14.6 years in 1997 to 7.4 in 2002, when the cap was gradually lifted. Demand kept increasing, peaking at 5.9 Bcm in 2001, but after the cap was lifted increasing prices and lack of reserves led to a slump. Production fell to a historical minimum of 3.6 Bcm in 2005, and only slowly recovered after that[2].

"The original Maui contract had minimum take or pay provisions, but it also allowed buyers to bank gas paid for but not taken – known as prepaid gas. Maui take or pay quantities also applied over a 12-month period, allowing buyers to balance their obligations across different seasonal demand periods. So long as the buyer had taken the minimum take or pay quantity at the end of the 12 month period, the average price would match the marginal price (i.e. fully variable). […] The Maui contract enabled buyers to uplift gas paid for, but not taken, at a later date for no cost apart from the Energy Resources Levy. As such, it gave buyers flexibility to vary their daily offtakes to match their demand within minimum and maximum quantities, while guaranteeing producers a stable income to underwrite their investment in the field"[3].

Figure 7.1. New Zealand's gas consumption (Bcm/year)



Source: BP Statistical Review of World Energy

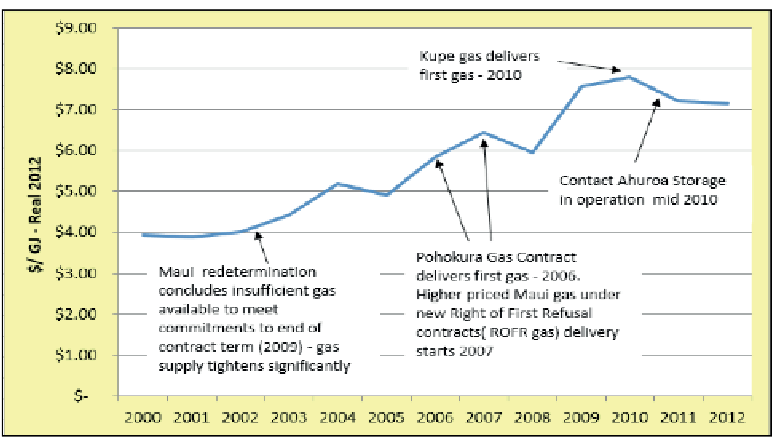
Since New Zealand's gas market is isolated, consumption is also a good measure of the trend of production. In fact, the difference between production and consumption is only the industry's own use (including reinjections) and transportation losses.

As Levin and Duncan[4] explain, "In 2003, the Maui supply contract was re-determined. A portion of the gas was removed from the supply agreement and allowed to be sold at market prices. […] the prevailing market prices for gas after 2003 were considerably higher than the price under the legacy contract. With the increase in wholesale prices following the Maui re-determination, producers undertook significantly more investment in exploration and development of reserves. Subsequently, proven reserves have increased significantly with large new discoveries" These have eventually ended Maui's market dominance, which had already lasted for nearly 15 years. At that point, the Commerce Commission managed to open the market and established a limited control on transmission pipeline tariffs and quality, which has lasted to date.

After the liberalisation, both E&P investments and production have recovered. Production has increased by 19% between 2006 and 2012. Several international gas companies have entered the market, and reserves have increased to reach a level of nearly 55 Bcm as of January 2017, which is more than in 2006 and equivalent to more than 12 years of current production. Yet reserves are too small to justify export projects.

After the depletion of the Maui field, competition has increased, but reliance on smaller fields has led to price increases, which have however eased after 2011. New Zealand's wholesale gas price in 2013 averaged 6.15 US$/MMBtu, a relatively high level for a self-sufficient country. At present, several fields are serving New Zealand, with different operators and interests and no dominant suppliers. The Commerce Commission has currently limited regulation to the transmission and distribution business.

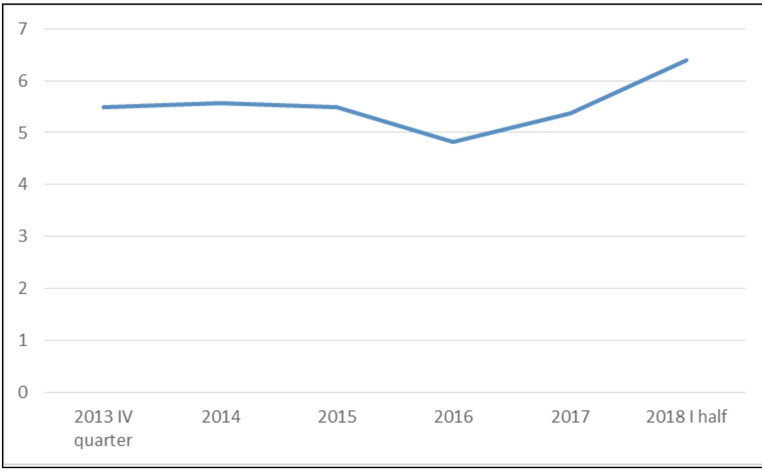
Figure 7.2. New Zealand's wholesale gas price development, 2000-2012



Source: Gas Industry Company of New Zealand, The New Zealand Gas Story 2nd ed., 2014.

Since 2013 a wholesale market based on a trading point has also been established alongside bilateral contracts, which has gained ground, reacing a size comparable to annual internal consumption. Weighted average prices on such markets are shown in Figure 7.3.

Figure 7.2. New Zealand's wholesale market average price development, 2013-2018 (NZ$/GJ)



Source: Gas Industry Company of New Zealand, Annual Report 2017-18.

7.2 The regulatory framework

New Zealand is also interesting for its peculiar regulatory model. It has no national company, and government interests in the industry were sold in the early 1990s. Also, there is no sector or energy regulator, but a model known as co-regulation. The actual regulator is the Commerce Commission, which acts both as a Competition Authority and as a sectoral regulator wherever necessary, i.e. where competition is found as inadequate after a due process. In such cases, the Commission declares control and a regulated regime is established.

On the other hand, there is an industry body, the Gas Industry Company, which is in charge of proposing several industry standards and to provide technical expertise to the Regulator, to which it is tied by a Memorandum of Understanding. The Gas industry Company also undertakes a detailed industry monitoring, following Guidelines from the regulator.

8. INDONESIA

Sergio Ascari[1]

8.1 Introduction

Several countries outside North America and Europe have tried to open gas markets, by following either the European model of Third Party Access to transportation pipelines and other essential facilities, or the North American approach of strong unbundling of network facilities from supply. Yet some of them have chosen an intermediate approach.

Indonesia is an interesting case. It owns large reserves and has long been a net gas exporter. Yet the development of the domestic market has been limited, and probably well below its potential.

This Chapter aims to show how this outcome may be the result of a lingering uncertainty in the choice of a market model, as well as of a regulatory framework that has kept infrastructure use tariffs and gas prices at high level, while at the same time it has not allowed the development of competition.

Regulatory uncertainty has discouraged the development of infrastructure. At the same time, high costs and prices are both a consequence of this limited development and of inadequate regulation, and the cause of its slowness, as they hamper effective competitiveness of gas versus other energy sources and the achievement of significant economies of scale.

In order to assess the effects of this market design, the main focus is on prices. The paper analyses two classes of prices:

1 This Chapter is largely based on "Uncertainty in Gas Market Design and Regulation. The Case of Indonesia", Paper presented by the Author at the 6th IAEE Asian Conference, Wuhan, 2–4 November 2018.

- Network tariffs for access to transmission and distribution pipelines;
- End user prices.

In both cases, prices as well as key cost drivers are compared in detail with those of similar operators in other countries and with other relevant benchmarks[2].

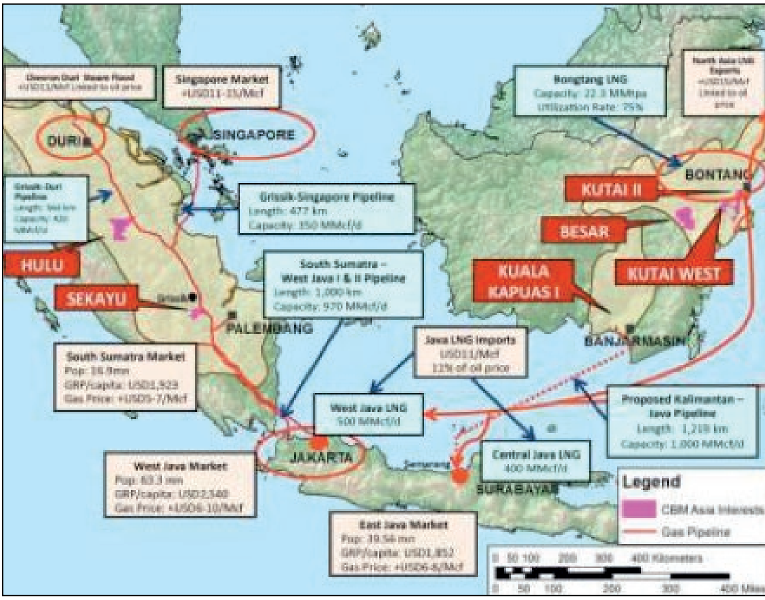
The analysis considers in detail the key price components, i.e. the asset base, rates of return, depreciation, operational expenditure, upstream gas purchase prices and trading margins. Each component is compared with the corresponding values of several operators, having regard for the operational conditions of the companies, or with the approach that would be adopted by regulators of advanced liberalised markets. Some attention is also paid to tariff design, which is analysed towards cost-reflectivity as well as the provision of incentives for consumers and network users.

Finally, the paper considers other market results, which can be partly seen as related to market design and regulation: in particular pipeline congestion and network development.

8.2 Background: Natural gas in Indonesia

Indonesia is endowed with large gas reserves, which have been developed rather early and used for exports, originally of LNG towards the East Asian market, and later by pipeline to Singapore. Domestic consumption has developed, with a transmission network largely covering the most important energy consumption areas of Western Java and Southern Sumatra. Other, smaller network exist in other parts of the country (Figure 8.1).

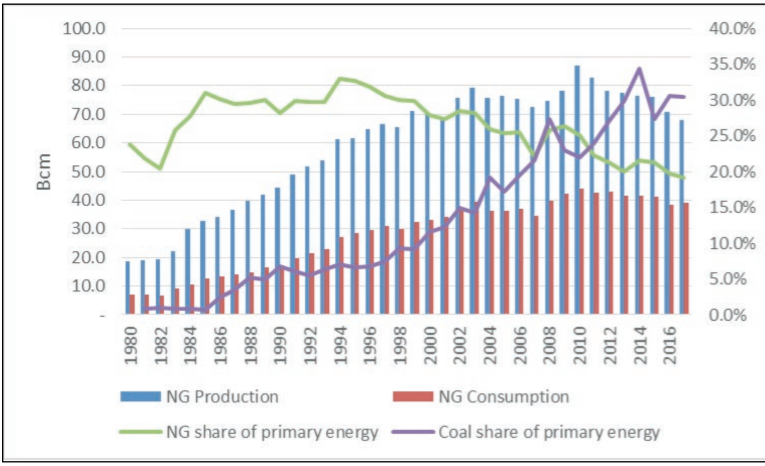
Figure 8.1 - Gas pipelines in Indonesia



Source: CBM Asia http://www.cbmasia.ca/Indonesia-Gas-Market

Production and consumption have grown steadily until around 2000, leading to an increasing role of natural gas in the country's energy balances. However, steady growth has turned into a more uncertain and swinging path after 2000, and after the 2010 consumption has been mostly declining. Since total primary energy use has kept growing, the share of natural gas in Total Primary Energy Supply has fallen from over 30% to just about 20% (Figure 8.2).

Figure 8.2. Development of the Indonesian gas industry



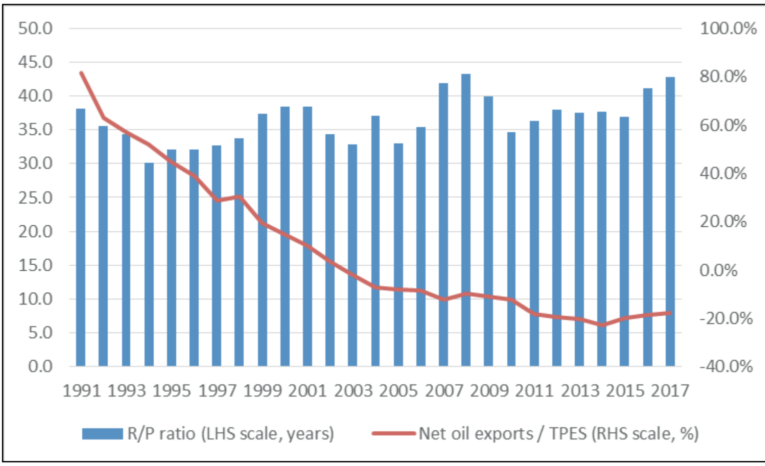
Source: BP Statistical Review of World Energy

The decline does not depend on lack of resources: as Figure 8.3 shows, the Resource/Production ratio has remained between 30 and 43 years, just under the world average. The fall of the gas consumption share of TPES has entailed a significant cost for the Indonesian economy, as the country is a net oil importer since 2002 and any lack of gas is mostly leading to further oil imports[3]. However, gas has lost its market share notably to coal, which has become the backbone of the Indonesian energy industry, with exports that in 2017 have reached 122% of Indonesian TPES (170 MTOE).

The Indonesian gas domestic market is rather complex, also due to the huge size and insular nature of the country. A significant part of domestic consumption is physically separated and consists of own consumption by oil and gas producers, mostly for oil lifting, LNG production, and own use power generation. About 40 Bcm are transported and traded by the interconnected transmission system, which is run by the main, state owned gas transmission, distribution and supply company, PGN[4].

The upstream sector has been historically open to international companies and is fairly competitive. The main state owned Indonesian companies have a combined market share of about 33%.

Figure 8.3. Gas Reserve/Production ratio and Net Oil Exports



Source: BP Statistical Review of World Energy

The downstream industry is dominated by state-owned PGN, which sold 22.3 Bcm in 2017, or 57.2% of total domestic consumption. This amount represents 51.4% of gas transported in the main ntegrated transmission network of Central-Southern Sumatra and East Java.

8.3 The regulatory framework

Several gas market designs have been developed in the world. It is possible to cluster them into three fundamental models:

1. The *traditional monopolistic model*, where at least transmission and wholesale supply are controlled by a dominant company. This company is often state owned but may be partly or totally private and subject to formal regulation. Other gas activities, like production, treatment and/or storage may be more or less competitive even within this model, as the dominant company acts as a "single buyer", purchasing gas and other services from their suppliers, possibly at discriminatory prices. Distribution and retail supply can be pro-

vided by the same companies or by other ones, often with a regional or local outreach, which all depend on the dominant one for their gas supplies.

2. The *North American competitive model*, where gas transmission is a potentially competitive activity, albeit formally subject to tariff regulation. Transmission companies (as well as providers of other market services) are fully unbundled, as they are not allowed to engage in any trading activity. The only fully price-regulated sector of the gas industry is local distribution, which is normally bundled with retail supply.
3. The *European competitive model*, where both gas transmission and distribution are regarded as natural monopolies, are unbundled from supply and trading and subject to tariff regulation. In turn, supply, trading and (in most cases) other services like storage and LNG activities are competitive. Thus, in this model, competition usually encompasses retail supply as well. Yet, particular cases of this model are often found outside the European Union, where competition is limited to the wholesale market and large customers, while smaller ones cannot choose their supplier but are protected by price regulation (e.g. in the Russian Federation).

It is beyond the scope of this paper to discuss the relative merits of these models. Theoretical and applied literature (Glachant et al., 2013) explains the rationale behind each models, which is often related to risk sharing among market players. For example, reduced risk in distribution activities in the North American model may offset higher transmission risk, whereas higher retail competition risk in Europe is partly offset by the regulatory protection of transmission and distribution operators' incomes.

Tariff and price regulation is often related to risk taking of the market players and infrastructure operators. Companies that are protected from volume risk, like European Transmission System Operators (TSOs) and Distribution System Operators (DSOs) are typically awarded lower returns, are allowed longer depreciation periods, and their costs are more thoroughly scrutinised, possibly by means of benchmarking techniques. On the other hand, in North America, such scrutiny has remained important for Distributors (which are also locally monopolistic retail suppliers), but has become largely redundant for TSOs (pipeline companies), where pipe to pipe competition has side-lined regulatory activities: in fact, no rate case for tariff re-setting has occurred in the U.S. gas transmission industry in the last years (Makholm, 2012).

Several countries outside the European Union, Australia, the U.S. and Canada[5] have lately tried to liberalize the gas industry, in the hope of achieving more consumer value, as lower supply prices or better purchasing terms, e.g. more flexibility of consumption patterns[6].

If we analyse Indonesia's gas industry regulation towards the above models, we find that it is formally quite free. Companies can develop their own resources and supply them by either building their own transmission and distribution infrastructure or by agreeing on the use of existing infrastructure, owned by other companies. However, use of gas is subject to administrative authorisation after government-mandated allocation criteria, which may hamper the workings of the market.

End user prices are mostly free, although some informal control may occur as part of the supervisory role of government on state owned companies like PGN and Pertamina. Formal regulation is limited to households and CNG for road transport, which represent less than 1% of the domestic market.

Transmission and distribution pipelines are formally regulated and subject to Third Party Access. Transmission and distribution prices are regulated for TPA purposes (see below). However, there is no formal unbundling and infrastructure owners can reject access due to lack of capacity or inability of the company to cover its costs, e.g. if capacity is booked by long term gas supply contracts.

Currently, Indonesia uses about 4000 MMscfd of natural gas, of which the majority (about 2900 MMscfd) is directly transported and used or sold by producers, mostly for oil lifting, fertilizer production and power generation. This separate gas supply system is not further analysed here.

About 1505 MMscfd (15.9 Bcm) were transported by PGN and its affiliates in 2017. The PGN transmission system is by far the largest in the country and is largely open to TPA: about half of gas is transported on

5 Canada broadly follows the U.S. model, whereas Australia's (South-East) gas industry is somewhat closer to the European one, notably in the State of Victoria.

6 In many cases, gas consumers are subject to tight withdrawal patterns, e.g. high take or pay levels, limited make-up / carry forward allowances, tight ramp up / rump down paths and swing factors, minimum withdrawal rates on a daily or monthly basis.

behalf of other shippers. Moreover, PGN hauls its own gas, which is then transferred to the distribution network or to end users who are directly connected to transmission pipelines.

On the other hand, distribution is essentially closed to TPA, with the exception of small quantities sold for road transport as CNG. Distribution also includes gas sale; gas cost and retail margins are discussed in section 8.5 below[7].

The tariff for infrastructure use is entirely volume-related and is computed by directly dividing the cost of service by the total contractual volume.

All tariffs are calculated and defined in US dollars. Hence, the local customer bears any risk arising from exchange rate swings between USD and the Indonesian rupiah (IDR).

In principle, the transmission tariff can be determined by a postage stamp, distance based or entry-exit methodology. However, no cost allocation criteria are defined and in practice only a volume –based postage stamp, with few zonal components, is used for gas transmission.

It is important to notice that the tariff is calculated *for each pipeline*, as a single, volume related postage stamp. The PGN Group has 6 pipelines, partly shared with other owners; one of them has been idle in the last two years (Table 8.1). The longest pipelines have zonal tariffs, broadly considering distance.

Table 8.1. Main transmission pipelines of the PGN Group

Pipeline	Operator	Length [km]	Capacity [MMscfd]	Volume [MMscfd]	Price [$/MMBtu]	Load factor*	Price/km
Wampu – Belawan	PGN	37	40	0	0.400	*0%*	*10.8*
South Sumatra – West Java Phase 1	PGN	378	275	125	1.550	*45%*	*4.1*
South Sumatra – West Java Phase 2	PGN	626	440	450	1.470	*102%*	*2.3*
Grissik – Duri	TGI	536	427	272	0.466	*64%*	*0.9*
Grissik – Batam – Singapore	TGI	470	465	414	0.740	*89%*	*1.6*
Kepodang – Tambak Lorok	KJG	201	150	92	2.326	*61%*	*11.6*
Total / Average	-	2248	1797	1353	*1.110*	*75%*	*2.6*

Source: PGN; own elaboration (last two columns); (*) on a daily basis

The methodology for the setting of the cost of service looks aligned with the practice of mature markets, and in particular it is consistent with the U.S.-style Rate of Return (cost plus) methodology. The average tariff is defined as:

$$P = (RAB \times WACC + OPEX + DEPR) / Volume \qquad (1)$$

The regulated cost of services is defined by a discounted free cash flow model. The Regulated Asset Base amounts to actual capital expenditure or its valuation (to be interpreted as Modern Equivalent Asset Value). Thus, the RAB is probably a mix of book value, current cost and MEAV. In fact, different valuation criteria are specified by the regulation, depending on whether the facility is built by the operator or purchased from another owner.

Depreciation follows the straight line approach. The economic life of assets is related to that of Gas Transportation Agreements (with a minimum of 15 years) or follows the technical lifetime (with salvage value). Although precise data about the duration of GTAs are not available, they are likely to be far lower than the technical lifetime. Hence, depreciation values are probably much larger than those used in the official accounts, which imply an average duration of 33.5 years under a linear depreciation method.

The allowed rate of return is defined as a Weighted Average Cost of Capital (WACC). Costs of equity and debt as well as the D/E ratio are reported as the actual ones. The risk-free rate r_f is taken from the latest USD denominated 10-year government bonds. The equity cost is calculated as:

$$Equity\ cost = r_f + \beta \cdot (ERP + ICRP)$$

Where ERP is the equity mature market premium and ICRP is Indonesia country risk premium.

The overall result for nominal WACC is around 11%. Our independent calculation in line with world practices is performed in Table 2 below to provide a comparison. A further incentive is provided to new investments and amounts to

Incentive = 1% + 2% x %D ;

hence the incentive should be about 2% as the current D/E factor implies a debt percentage of 48%.

OPEX is capped to 10% of RAB for new facilities, but normally the actual value is used. An escalation with the inflation rate of the U.S. is foreseen, as all tariff values are set in U.S. dollars. The volume used in the calculation amounts to 90% of the ship-or pay level.

The tariff regulation process follows the U.S.-style "rate case" approach: a tariff review occurs upon request of an interested party. Hearings of key stakeholders are held. Result of the tariff decisions for PGN pipelines in 2017 are shown in Table 8.1. The same tariffs also applied in 2015 and 2016. The average for pipelines operated by PGN parent company was

1.5 $/MMscfd[8] in 2016, but the weighted average for the PGN Group pipelines of Table 8.1 was 1.11 $/MMscfd.

For distribution, tariffs are defined by distribution zone and by consumption blocks. There are three Regional Distribution zone, essentially covering West Java and South Sumatra, East Java, and North Sumatra. However, no TPA to distribution is currently active, except for small CNG quantities. Distribution tariffs are included in the final retail price for end customers (see section 5). The average distribution tariff is estimated at 1.5 $/MMBtu. In fact, this value is included in the regulated price for end customers, but not used for TPA (as of 2017).

8.4 Assessment of the transportation tariff regulation

The assessment of this regulation results starts from comparing several partial, simple indicators. It would be theoretically preferable to undertake a formal benchmarking exercise, e.g. by a COLS, SFA or DEA methodology, as it is often practiced by regulators. On the other hand, there are few attempts to undertake such formal benchmarking at international level for gas transmission and distribution, as differences in regulatory frameworks and input costs make results hardly reliable (Jamasb et al., 2008). Moreover, available data do not allow such exercise, as the sample size is too small. Therefore, we follow a different approach: we compare in turn each component of the tariff formula (1) to assess how Indonesia's main transmission and distribution company compares with available peer data. A general comparison of overall tariffs follows.

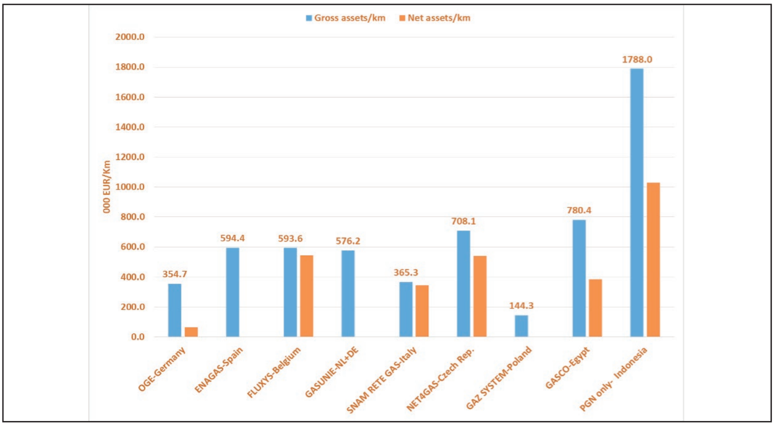
Concerning **RAB**, it is customary to compare the value of assets divided by network length, as distance is the main cost driver. A preliminary comparison is provided by Figure 8.4. PGN transmission assets per km, evaluated by current cost, look much higher than those of the peers. Historical reasons may explain this fact. Faced with such situation, a regulator would probably further investigate the reasons of high past investment costs, and also possibly check whether they are reflected in stock market valuations. Past depreciation practices should also be considered. For example, if the regulator found that accelerated depreciation has been allowed in the past, so that consumers have actually already substantially paid for the assets, it may well decide that the book value

8 Million standard cubic feet per day

is a more appropriate measure of the current assets' value and reduce the RAB accordingly. Likewise, the RAB could be reduced if government grants have contributed to pipeline construction.

On the other hand, labor and hence pipe-laying and operational costs should be far lower in Indonesia than in Europe.

Figure 8.4. Benchmarking of transmission assets.



Source: Own elaboration based on company reports, 2013, for PGN: 2016

For the **WACC**, a direct comparison with rates of return allowed in other countries is not applicable, as general country risk conditions vary. Moreover, European TSOs usually face a very limited volume risk, with few exceptions. Instead of comparing rates of return, we calculated a range for WACC, based on reasonable estimates of the relevant financial parameters, as provided by Aswath Damodaran[9]. Such calculation is shown in detail in Table 8.2.

Table 8.2 - WACC estimation for Indonesia, 2017

	Low	**High**
Group tax rate – T	25.0%	25.0%
Interest charge tax rate – t	25.0%	25.0%
Risk free – Nominal	4.58%	6.66%
Indonesia Country Risk Premium (CRP)	1.87%	2.54%
Cost of Equity		
US Equity Risk Premium	5.00%	5.00%
Equity Risk Premium	6.87%	7.54%
Beta – Levered (actual 2016)	77.29%	80.00%
Ke - Cost of equity, nominal	9.89%	12.70%
Ke - Cost of equity, nominal, pre-tax	13.19%	16.93%
Cost of debt		
Kd - Cost of debt = Risk free + CRP	6.45%	9.20%
Kd - Cost of debt = Risk free+CRP after tax shield	6.45%	9.20%
D / (D+E)	46.5%	48.6%
E / (D+E)	53.5%	51.4%
D/E	87.0%	94.7%
WACC NOMINAL before tax	**10.06%**	**13.17%**
WACC NOMINAL after tax	8.29%	11.00%
Retail Price Index (expected)	3.50%	3.50%
WACC REAL before tax (expected)	6.56%	9.67%
WACC REAL after tax (expected)	4.79%	7.50%

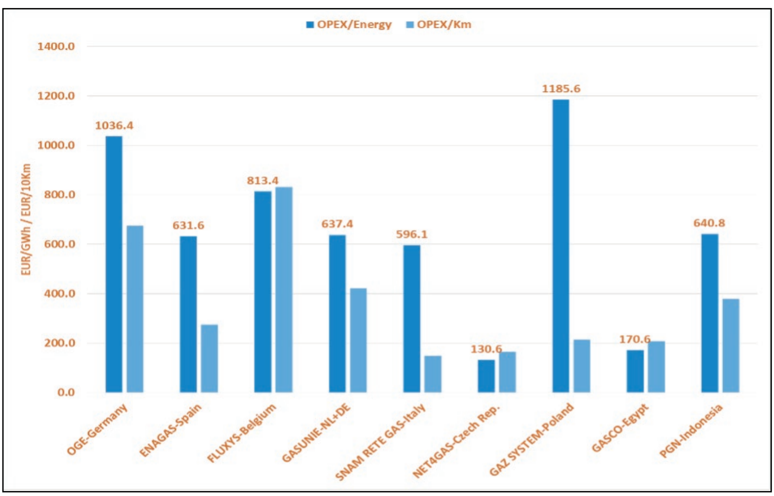
Source: Own elaboration based on Damodaran and PGN data

We find that that the reported rate of 11% (nominal, before tax) is within the range that we have calculated. In fact, the reported Indonesian methodology is close to the low assumption of our estimates, which is based on the Damodaran model, starting from the U.S. free risk and adding the appropriate country risk, equity and debt premiums. The high assumption is based on the Indonesian dollar-denominated 10-year Government bonds as “free risk” and on international parameters for equity premium, while PGN’s actual average borrowing cost is used as debt cost. Differences between our values and those defined by the Indonesian regulator depend more on the different timing of the decision than on methodology.

Application of the nominal WACC is normal if the chosen regulatory model is the traditional US-style Rate of Return, with no built-in adjustment of prices to inflation.

On the other hand, OPEX looks comparable to peers, if evaluated either in relation to pipeline distance or volumes (Figure 8.5)[10]

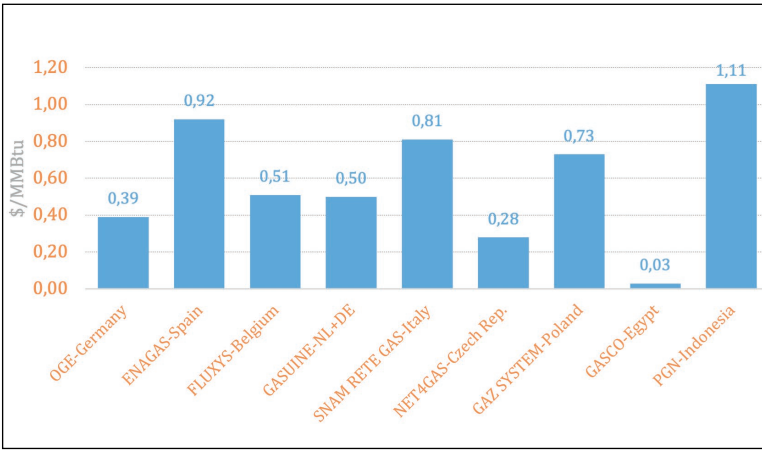
Figure 8.5. Benchmarking of operational expenditure



Source: Own elaboration based on company reports, 2013, for PGN: 2016

Let us move to the comparison of average transmission tariffs (Figure 8.6). PGN Group average transmission tariff of 1.1 \$/MMBtu (and even more the value of 1.5, applicable for pipelines operated by the parent company) is the highest of the sample.

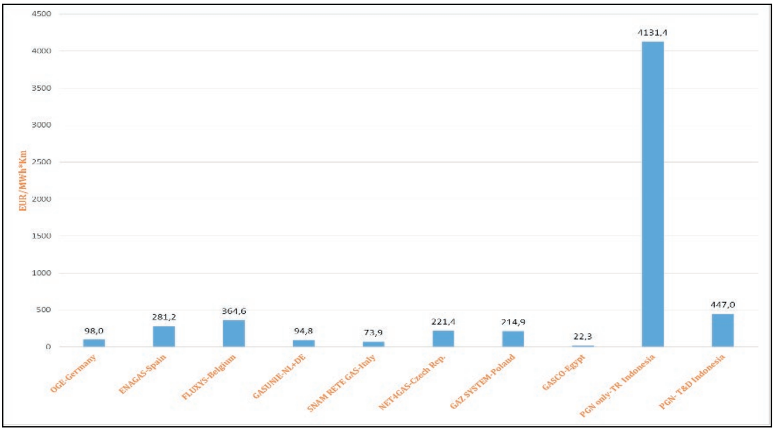
Figure 8.6. Benchmarking of average transmission tariffs



Source: own elaboration. Company reports, 2013 (2016 for PGN). Note: GASCO tariff is subsidized; a cost-reflective tariff is estimated at about 0.27 $/MMBtu.

Whereas multivariate analysis cannot be tried due to the low sample size, a simple benchmarking of overall tariffs (rather than their components) can be performed by dividing total revenue by an index of transportation activity i.e. the product of volume and distance (Figure 8.7).

Figure 8.7. Transmission revenues by volume and distance



Source: Own elaboration on company reports, 2013 (2016 for PGN).

Similar results obtain by showing prices in relation to the product of transmission distance and capacity (Not reported for space reasons). As we have outlined above, distance and capacity are actually the main drivers of transmission costs.

The very high value of PGN tariffs seems to depend largely on asset valuation. Other reasons may include unusual depreciation criteria: depreciation in relation to transportation contracts is regarded as prudent by accountants but is not usually accepted by regulators, as natural gas is likely to be transported well beyond the end of current transmission contracts. Moreover, useful lives in Europe are typically far longer for buildings (50 vs. 20 years) and pipelines (40-50 vs. 16 years).

Depreciation values that are used in PGN Annual Reports are not unusual and in line with the sample average (3.1% of gross assets vs. 3.5%). However, it is reported that depreciation criteria used for tariff setting are much faster, although no precise values are available.

For distribution, quantitative benchmarking is harder, due to limited data availability. Unlike for transmission, the main driver of distribution costs is the number of connected customers, but network length also plays a significant role. On the other hand, as for transmission, volume is hardly a cost driver.

Table 8.3 shows the different figures of PGN and of the distribution service in two mature European markets. It shows that the distribution service is in a very different stage of advancement, but few conclusions can be drawn from it. Further analyses are necessary for an assessment of the PGN efficiency and development potential.

Table 8.3. Key distribution network data for France, Italy and Indonesia, 2016.

Indicator	France*	Italy	Indonesia**
Customers [Thousands]	10 900	23 398	169
Volume [MWh]	277.0	326.4	87.6
Net Revenue [M€]	3029	3117	386
Net Revenue / customer [€/year]	277.9	133.2	2 283.3
Network length [km]	197 928	258 466	3 995
Customer density [meters/customer]	18.2	11.0	29.6
Revenue/Volume [US$/MMBtu]	3.80	3.32	1.53

Source: Gas Réseau Distribution France (GRDF), PGN Reports, Annual Report of the Italian Regulatory Authority for electricity, gas and water (ARERA). (*) GRDF only; (**) PGN only.

Let us now turn to the **tariff structure**. This is the most striking peculiarity of the Indonesian system. It is mostly a pipeline-based regulated tariff, consisting of volumetric charges. Such tariffs are postage stamps, in the sense of being the same for the whole pipeline, although the longest pipelines have some zonal (broadly distance-based) component.

This structure is most unusual in world markets, although similar volumetric tariffs are also found, e.g. in Russia and China.

Table 8.1 shows some key features and indicators of PGN six pipelines. Indonesian pipeline tariffs do not show apparent relationships with distance, load factor as well as with any market features. Such tariffs hardly provide signals about the transmission costs, and may foster shippers to avoid using some pipelines while leaving other shippers use them at too low price. Thus, this tariff system ultimately does not favor the further spread of natural gas in the country. Tariffs should deliver a cost signal that is related to objective characteristics of the service provided to each shipper, and not be based on the pipeline's past amortization policy or the subsidies it may have received in the past.

In the U.S., tariffs are mostly distance- and capacity-based. They are formally regulated, but in fact the very large market dimension (over 15 times Indonesia's) allows for a significant pipe-to-pipe competition. Several competing pipelines often serve large consumption areas. Therefore, pipelines tend to set their actual tariffs below regulated ones, and no rate cases on gas transmission have been reported for several years (Makholm, 2012).

In Europe, during the fast market growing years before market liberalization (starting about 2000), EU Member States developed their own transmission networks, mostly through national integrated companies. Such companies were either *de jure* monopolists or *de facto* dominated the market. They were mostly subject to limited or "light-handed" regulation and no TPA (except for cross border transit). This situation allowed them to essentially cross-subsidize new developing areas by margins attained in more mature ones, and to price each customer (or customer class) in relation to its ability to pay, which was in most cases related to the price of competing fuels, with premiums depending on the technical characteristics of usage. The rationale behind this approach was the strong competition by other fuels (oil derivatives, coal, electricity) and limited regulatory capabilities (unlike in North America).

A few countries like France, Germany, Austria, Italy had important alternative transmission operators, but they rarely competed with dominant ones and were mostly forced to accept the leading role of the largest operator, from which they often depended for essential services like flexibility, reserves and some maintenance services.

After market liberalization was slowly introduced in most countries in the 2000 decade, European gas TSOs were almost everywhere fully unbundled and turned into low risk / low revenue ventures, acting under close regulatory supervision. A model of increasing continental co-operation prevailed, officially endorsed by the creation of a coordination body (ENTSO-G). On the other hand, transmission competition was hindered by limited continental market integration, and political wariness to lose control over key domestic assets. Thus, in Europe, tariffs are tightly regulated and increasingly streamlined, with a view to avoid discrimination, but also to enhance cost reflectivity, so that competition for the most profitable market segments (*cream-skimming*) is avoided.

In Indonesia (as in any single European country), limited market size prevents the success of the U.S. model of pipe-to-pipe competition. On the other hand, current regulation seems to hamper the resort to the EU model of cross-subsidizing market growth. Even under a TPA regime, this could be achieved by a tariff system offering remuneration to the pipeline company independently from sales revenue. Tariffs should be network-based rather than pipeline-based, offering integrated transportation across interconnected pipelines.

Serious problems derive from current, pipeline-based, purely volumetric tariff:

Customers benefit or suffer from a peculiar cost structure of the pipeline to which they are connected, possibly depending on its depreciation history, past subsidies, or consumption density of the region, but without any reference to distance, capacity, their ability to pay, congestion or to the replacement cost of the service.

With the current tariffs system, higher load factor customers may cross-subsidize those with low load factors, as the purely, single volumetric tariff neglects unit cost differences that are related to the different use pattern of transmission capacity. Moreover, large customers cross-subsidize small ones, as the tariff is not related to transportation amount so that economies of scale in gas transportation are neglected.

Furthermore, customers located near gas sources (production fields, LNG terminals) cross-subsidize those located far from them, as the distance factor in transmission costs is only partly reflected in tariffs.

In mature markets where pipe-to-pipe competition exists (as in North America), pipeline companies act to avoid such developments by offering tariffs that reduce the appeal of building new infrastructure, which is in most cases inefficient for the system as a whole. Moreover, regulators often prohibit the development of merchant infrastructure which is not in the general interest, e.g. if it duplicates costs, or if facilities risk being stranded.

In tightly regulated transmission systems (as in Europe) the construction of such merchant lines is sometimes forbidden; in other cases it may be allowed, notably as a by-product of larger, long distance projects. However, TSOs often propose and regulators allow the setting of special tariffs (e.g. "short haul" tariffs) to avoid the construction of inefficient local bypasses.

Similar comments apply to distribution pipelines. Normally, distribution tariffs are postage stamps, as it is hardly possible to identify the distance that gas travels in distribution systems. Such postage stamps are usually defined for interconnected distribution systems, i.e. for systems that are not connected to other distribution systems except by transmission pipelines, upstream pipelines or LNG routes. Sometimes a political decision is taken to socialize costs across larger areas, but this requires transfers among areas and may be technically complex if several operators are involved. If the goal is to favor gas use spreading in new areas, it is probably better to provide a tax and subsidy scheme, preferably for a limited time.

8.5 Distribution and the selling price

In Indonesia, like in the U.S., distribution includes both local transportation through distribution pipelines and the sale of gas to end customers. Although such pipelines area in principle open to TPA, in fact this has not been allowed yet, except for very small amounts used for road transport.

At present, in Indonesia, the end user gas price is regulated only for small customers (households and small commercial users).

PGN calculates the gas price for its customer as the sum of (1) the cost of gas; (2) the cost of transmission and distribution: (3) the cost of selling the gas (*retail margin*).

We have already commented in the previous section about the pricing of transmission as well as local transportation services by distribution pipelines. This section focuses on the other components.

The cost of gas varies among the three distribution regions, and even among several areas of the same distribution region (there are 3-9 areas within each distribution region). The gas cost is the cost of buying and taking the gas to the entry point of the distribution network (City Gate).

On the contrary, the cost of distribution pipeline including end user connection is the same throughout Indonesia. End user connection costs are included in the distribution cost.

The cost of selling the gas (sales & marketing activity, customer handling, etc.) and other general and administrative costs is the same throughout Indonesia, and is capped at 7% of the gas cost.

Based on the above arrangements, the price of gas varies among distribution regions and areas, because different gas sources have different prices, and the cost of bringing gas from each gas source to the city gate differs.

Besides the gas price difference between regions and areas, there are different prices for different segments, based on the amount of gas consumption. In general, customers with large consumption pay less than the small ones. In some cases, prices differ by consuming sector as well.

On average, the reported value of the various components in 2016 is ($/MMBtu):

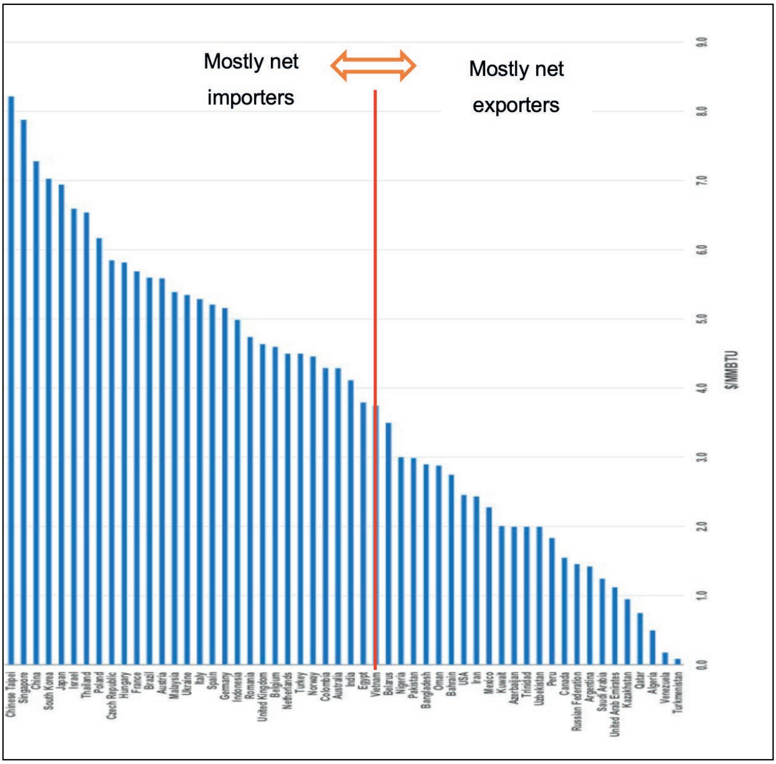
Gas price (9.4) = Gas cost (6) + Transmission (1.5) + Distribution (1.5) + Retail margin (0.4).

In general, it is reported that gas purchase costs are related to contracts. Detailed information about such contracts (e.g. size, duration, price re-opening and escalation clauses, destination constraints, take or pay and related arrangements like make-up and carry-forward clauses, ramp/down rates, tax provisions) are not available.

Based on the available information, it is possible to notice that the purchasing price (gas cost component), reported at around 6 $/MMBtu, is high for a net exporting country. Even the (lower) average wholesale price that is reported by IGU for 2016 (about 5 $/MMBtu: see Figure 8.8) shows that Indonesian prices are unusually high for a net exporter or self-sufficient country.

This judgement is reinforced if we notice that the average Japanese LNG import price in 2016 was $6.89. Since the full cost of the LNG chain is at least $2.5, the export price from Indonesia (for which Japan is a key export market) should be around $4.5/MMBtu.

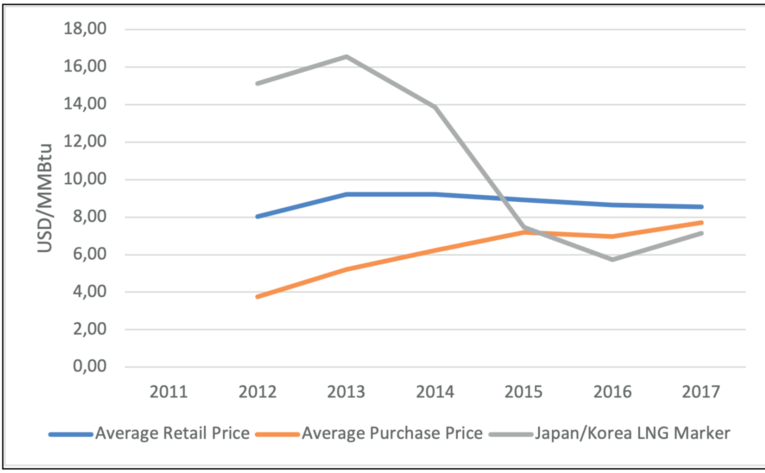
Figure 8.8. Wholesale price levels by country, 2016



Source: International Gas Union, Wholesale Gas Price Survey, 2017

Figure 8.9 shows that this high domestic price is a relatively recent feature. Until 2015, the average gas purchase price for PGN was well below the typical prices in the East Asian LNG market (here represented by the "Korea Japan Marker". Only in 2016-17, PGN's average gas purchase cost has exceeded the KJM.

Figure 8.9. PGN's prices vs. East Asian LNG



Source: PGN Annual Reports, 2013-17. BP for KJM

There may be a few reasons for such relatively high prices:

1. Indonesia is more than self-sufficient, but is a very large, insular country where consumption areas do not always match productive ones. In fact, most consumption occurs in Western Java and Southern Sumatra, but significant production is from Kalimantan (including offshore) and the Eastern provinces, which are not currently interconnected (except by LNG). Since some gas is actually transferred from producing areas to the main consuming districts as LNG, the reported price level is probably close to the marginal cost of LNG supplies, even though it is clearly higher than the average purchase cost of Indonesian gas.

2. It is likely that some gas supply contracts are set at a fixed price, which is a commercial practice used in a minority of contracts. PGN in its 2016 Annual Report (p.122) claims that "the stability of natural gas prices made easier for customers to conduct production planning and to calculate operating costs". Such strategy is confirmed by the chart (p.123) that shows that gas prices are much more stable than those of rival fuels, and by comments about loss of natural gas competitiveness as oil prices declined.

3. Even if contracts are indexed to oil or other market indicators, they may have had a floor set during high price period (before 2014), so that such floor may currently apply, which is above current world spot prices. Nevertheless, many Asian LNG importers have been able to lower their procurement cost after the oil and gas price collapse starting in 2014. For example, according to World Gas Intelligence, the average Japanese purchase price has fallen to 9.77$/MMBtu in 2015 and 6.86$/MMBtu in 2016. On the other hand PGN purchase cost was 6.95$/MMBtu in 2015 and 5.76$/MMBtu in 2016, which is high because most gas is local and does not use the LNG chain.

It is not surprising that suppliers may accept a fixed purchasing price formula, notably if it allows for some correction for cost inflation and/or exchange rate swings. However, this is at odds with the prevalent practice of large, integrated gas companies in the world. In general, such companies prefer to stabilize relative prices (in relation to competing fuels) rather than absolute levels, by linking their purchasing prices to those of gas hubs or of oil. In this way, they can be sure that, except in extremely low price scenarios, gas is competitive towards other fuels. This approach stabilizes natural gas demand growth and load factors of infrastructure remain higher. In other words, the price risk is limited, and most of it is transferred to upstream suppliers.

To sum up, PGN supply costs, which are included in their reported average domestic price (9.4$/MMBtu in 2016 including T&D and the retail margin) are now high by international standards. Moreover, they do not follow world price trends. In fact, whereas world gas prices have been falling between 2013 and 2016, Indonesia's have increased (Figure 8.9). It is hardly surprising that Indonesia's gas consumption has been decreasing in the same period (Figure 8.1), despite strong economic growth.

As for the retail margin, it is capped at 7% of the gas cost. This percentage share is lower than in the above mentioned European cases (10%-13%); however, it must be considered that retail costs largely consist of labour, which is certainly cheaper in Indonesia than in Europe. Therefore, the cap looks set at a reasonable level.

To sum up:

- Network tariffs are high in comparison with those of Europe, notably for transmission. Regulation has set a reasonable rate of return, but the cost base is inflated, notably because:
    - Asset values are very high on a unit basis;
    - Depreciation is much faster and aligned with durations of contracts rather than the physical life of infrastructure;
    - Tariff structures are fully commodity based and hardly cost reflective, providing inadequate market signals and possibly triggering cross-subsidies between consumers of different capacity size and load factor.
- Market prices have recently increased, even against the world trend. They hardly follow either the world gas market or prices of competing fuels. Prices have lately grown above LNG netback levels (calculated with respect to the East Asian market).

Thus, we can conclude that:

- Regulation has not been substantially able to check the market power of dominant companies, even though it is formally aligned with the Rate of Return approach. The Averch-Johnson effect seems to prevail, leading to cost inflation, which in turn entails higher profits (Averch & Johnson, 1962).
- Market prices are relatively high and do not behave as they would in a competitive market.

8.6 Beyond prices: market design issues

Whereas this Chapter focused on Indonesian tariffs and prices, this is just a limited part of the implementation of a market model. Other authors have addressed more general issues and discussed how the market design may have hampered the development of the Indonesia gas industry, despite the availability of natural resources and a vibrant demand, boosted by fast economic growth. Herewith we summarise their main points (Glachant, Hallack and Vazquez, 2013).

Indonesia chose a centralized mechanism based on a merit order to allocate the gas from the upstream, i.e. contracts between producers and the rest of the chain. In other words, contracts stipulated between producers, traders and customers must comply with a gas allocation defined by the government. This is of course a major source of uncertainty for investors and a potential source of market distortions. Yet, this is not necessarily the only problem. For the sake of discussion, let us ignore the administrative gas allocation process for the rest of this section.

Indonesia has an ambitious plan to increase the participation of gas in the energy mix, which requires (i) substantial investment in exploration and production as well as in network expansion; (ii) to maintain affordable prices, allowing gas to compete against other energy sources.

At the same time, Indonesia has decided to introduce competition in the market, allowing users to choose their supplier.

There are two types of contracts for gas supply from producers to retailers and distributors:

- "Contracts to develop", usually 10+ years long, with take-or-pay obligation. They are defined in a way to allow financing of infrastructure, i.e. they provide an anchor to develop the infrastructure required to reach new customers;
- "Contracts to trade", usually for not more than 5 years.

On the other hand, PGN has chosen to offer end users just one type of contract (probably to avoid issues in the management of contracts), always below 5 years[11].

These contractual arrangements are potentially at odds with the TPA policies aimed at introducing market competition. To understand the main issue, let us briefly remember the features of the main competitive market models, recalled in section 8.2 above.

In the U.S. model, pipeline investments are fully covered by pipeline companies' tariffs. Since their transmission rights are firm on a long term basis, financing is ensured. Any change of suppliers due to market competition does not harm the pipeline business. Network tariffs are checked by regulators as well as by pipe-to-pipe competition.

11 PGN manages imbalances caused by take-or-pay provisions by using minimum quantity provisions for end users. Consumers' consumption is mostly flat within the year, with some variability on a weekly basis. The PGN contract is designed on a monthly basis, giving consumers flexibility for their gas usage within each month.

In the E.U. model, pipeline investments are proposed by TSOs and approved by regulators after a market testing process and/or Cost-Benefit Analysis. Once they are approved, costs are included in the tariffs and paid by all network users, with costs spread over the whole technical duration of the assets. Regulatory protection allows to set relatively low return rates. In the few cases of merchant pipelines, most of gas transmission rights are protected for a reasonable amount and time (usually at least 20 years), so that pipeline investors can reasonably depreciate their assets without overcharging. In both cases, as in the U.S., payments to transmission operators and owners are not affected by changes in the gas suppliers chosen by end users or downstream retailers.

In Indonesia, pipeline companies partly recover infrastructure costs through retail prices. Thus, any loss of customers would lead to inability to adequately cover such costs and fully depreciate assets. Hence, the risk of seeing customers switching to other suppliers is a major problem for investments, and experience has shown that such risk is real, notably by the largest customers[12]. Not surprisingly, dominant companies prefer to reduce their investments vis-à-vis such risk, and some key pipelines are now heavily congested.

Moreover, vicious circles are probably generated:

1. Given the risk of losing customers, companies (backed by regulators) tend to reduce their depreciation time, and the built-in activity risk increases. Both such shifts increase tariffs, and hence end user prices, strengthening the interest of end users to switch away from the dominant company (or from gas altogether, where possible).
2. The risk of losing customers reduces the incumbent's incentive to expand and invest in new infrastructure, and incentivizes PGN to increase its revenues by raising prices in the short term.

On the other hand, the Indonesian market remains essentially too small for the full development of a US-style market model. With such gas flows and a limited geographical dimension of the main market (South Sumatra & West Java), it is very unlikely that a substantial pipe-to-pipe competition can develop. In fact, as it happened in Europe before TPA-based

12 As noticed almost 48% of gas transported by PGN is now on a TPA basis. For example, gas-fired power plants initially contracted with PGN, now they have mostly direct contracts with producers. They also threaten to build their own infrastructure, bypassing PGN Group's network, notably if for short distances.

market liberalisation started, lack of a transmission licensing regime has led to the development of several, though often inter-related pipeline companies, which do not compete with each-other. Some cream-skimming competition only occurs by large customers that are located close to production areas, or by the (threat) of developing independent LNG regasification facilities, but no general market competition appears.

8.7 Concluding remarks

In Indonesia, energy policy allows and promotes competition among gas market players and only envisages some limited, traditional (Rate of Return) regulation of network tariffs, whereas end user prices are controlled only for a very small part of the retail market. Yet, while market competition is promoted in principle, gas allocation to end users is subject to government authorization.

The actual mix of incentives entailed by the current market design, as well as by regulation, not only impedes the establishing of a set of efficient and transparent pricing and investment decisions, but also increases uncertainty among the players.

Regulation of network tariffs has essentially failed, despite being in principle aligned with the North American model. Unit costs of laid pipelines and other assets are comparably high with respect to those of similar companies in Europe and Middle East. Depreciation periods adopted by the dominant company (and supported by the regulator) are unusually short and contribute to very high network tariffs, even if the rate of return is consistent with the regulatory practice of more developed markets (but remains higher due to macroeconomic factors).

Tariff design occurs on an individual pipeline basis, but no substantial pipe-to-pipe competition occurs; in fact tariffs are entirely volume-based and are not related to the key cost drivers (pipeline distance and capacity), thereby triggering further distortions and exacerbating the interest of some end users to activate their own supply chains. Pipelines are not run as a network, thus losing the network economies that have characterised the development of pipeline networks in Europe.

Under the threat of TPA and no guaranteed returns on network investments, dominant as well as other companies reduce investments and charge high network tariffs and gas prices. On the other hand, entry into the market by either TPA or construction of competing infrastructure is prevented by the market power of the incumbent, administrative gas allocation constraints, and limited regulatory control. This restricts the opportunity to invest to large consumers (notably power generators, oil companies and fertilizer producers) satisfying their own needs, and prevents the development of effective competition.

To sum up, Indonesia's market design regulation and regulation seems to lay half-way between the European and the U.S model, but it does not enjoy any of the positive features of either of them. Moreover, it does not have the main common feature of both competitive market models, i.e. the unbundling of transmission from supply. On the contrary, infrastructure depreciation depends on revenues of supply, so that the threat of losing end users by TPA reduces the incentive of infrastructure based companies to further invest.

Under this condition, Indonesia is experiencing stagnation of pipeline investments, relatively high prices (among the highest of self-sufficient countries) and low market growth rates.

The potential of Indonesia' gas market growth could be better exploited if:

- the country chose a clear market design model, which could be either the establishment of a European style regulated transmission operator or of a U.S. style separation of current dominant companies so as to promote pipe-to-pipe competition between unbundled companies. Market size suggests a preference for the European model;
- regulation of transportation tariffs was aligned with technical and economic criteria adopted in advanced markets, with a view to reduce them in return for much lower risk. A multi-year tariff reduction process (possibly based on benchmarking with international pipelines) would reduce regulatory uncertainty;
- Investments were enhanced by protecting the capacity rights of investors for a suitable time;
- competition by gas suppliers were encouraged by establishing a level playing field, as well as clear access provisions to networks and gas supplies.

8.8 References

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9. SUMMARY AND CONCLUSIONS

Sergio Ascari

9.1 Regulatory models in the world: an overview

As the International Gas Union Surveys1 show in general, there is a world tendency towards deregulation of gas prices, starting from the wholesale level and from larger customers. As of 2018, 47% of traded gas was priced based on gas-on-gas competition.

In the sample of our case studies, only the African countries still have regulated wholesale prices, including for the larger consumers, which are mostly power generators. On the other hand, some regulation of prices for residential and other small customers (mostly the commercial sector and public services) is still found in the U.S., in Europe (where it is being phased out) and in Indonesia. However, the sample is deliberately biased, as it has been selected with a view to study regulatory practices.

Table 9.1 - Regulation and other pricing mechanisms by sector

Country	Wellhead / Wholesale	Residential & Commercial	Industry	Power generation
United States	GOG	HUB/RCS	GOG	GOG
Netherlands	GOG	GOG	GOG	GOG
France	GOG	HUB/RCS	HUB/RCS	GOG
Italy	GOG	HUB/RCS	GOG	GOG
Algeria	RCS	RSP	RSP	RSP
Egypt	RCS	RSP	RSP	RSP

1 Wholesale Gas Price Survey, various years, www.igu.org

Nigeria	RCS	RSP	RSP	RSP
Israel	GOG		GOG	GOG
Indonesia	GOG	RBC	GOG	GOG
New Zealand	GOG	GOG	GOG	GOG

For definitions: see Annex 1.

The pattern is relatively simple. The most advanced economies (OECD Members) have all phased out wholesale gas price regulation, even though they often maintain (and have indeed enhanced) the regulation of network services like transmission, distribution and (in some cases) also storage and LNG regasification. However, the regulation of networks, which are often monopolies in each market or jurisdictions (sometimes on a local basis), must not be confused with that of gas prices, and is outside the scope of this book.

For retail, several OECD countries (US, France, Italy) still keep some type of price control, particularly for smaller customers. In other cases, there is no control even for retail prices, and prices are only subject to ex-post control from competition regulators (Netherlands and several other EU countries, Israel, New Zealand). In a few cases, if there is a specialized regulator, it retains a market monitoring and advisory role towards the government or the competition regulator.

In fact, the US have phased out wellhead and wholesale price wholesale regulation since the early 1980s. It was a complex and burdensome practice, which had been lasting for several decades and has been widely seen as partly liable for the shortage that affected America's gas industry in the 1970s. Yet the US, unlike Europe, has not mandated retail competition and the distribution and retail sectors of the industry are usually bundled and regulated by State Public Utility Commissions. The cost of gas is however normally taken from wholesale markets and passed through to end customers.

The European Union countries have liberalized their markets in different steps, but all of them had to comply with an EU Directive, requiring the liberalization of the wholesale market by 2004 – even though some have kept some price controls for years, and implementation has often been slow. After 2007, all end users are eligible to choose their suppliers, the market is in principle fully open and wholesale as well end user price caps should be lifted as well. However, in fact national markets are not always fully competitive, as limited infrastructure or contractual arrangements still limit the interconnection of national markets, particularly in the Central-Eastern and South-Western part of the Continent. Therefore, several regulators have actually maintained price controls, particularly for smaller (residential and commercial) customers, and in a few cases also for larger ones.

Regarding retail gas market control, the main issues that are discussed in the EU are the conditions for competition enhancement and removal of the caps, and the wholesale markets to be chosen as benchmarks or indicators for gas wholesale costs. In most cases, regulators do not control the price at which wholesale suppliers procure their gas, which is mostly imported and traded in increasingly competitive hubs.

For jurisdictions with limited market competition, the main interest of European cases lies in how, in some of them, regulators have defined the way gas costs are recognized. Wholesale costs to be included in retail prices are often taken from spot markets; and price escalation of remaining control formulas is now linked to gas market rather than oil market indicators.

It is also interesting to see how such definition of indicators occurs in practice, and how escalation works, for example in terms of frequency, the choice of indicators, the use of moving average rather than point values, and the responsibility and clauses for price adjustment. The issue has been a frequent source of litigation in Italy, as linkage to foreign hubs like the Dutch TTF could have led to losses by suppliers that were not able to procure gas at hub prices, due to their legacy contracts. Likewise, in France the government has often tried to lower prices (or to avoid price increases) by referring to a basket of supplies which could be cheaper than the actual one. In a couple of cases, the Ministry has been defeated in lawsuits, with the energy regulator (which is not formally in charge of end user prices) providing its advice to the Court, and has been forced to adjust its regulation.

Unlike these cases, the Netherlands are an historical exporter, and were actually the first important exporting country in the world, starting in the 1960s after the discovery of the huge Groningen field. The Dutch market is today fully integrated within Europe and the home of the most liquid trading hub alongside the British one. Yet, it is interesting to consider how prices were regulated for the domestic market before liberalization was implemented, starting in the late 1990s.

The fundamental approach of the Netherlands until full deregulation was to price gas after the competing fuels, with some discount. Price escalation followed similar criteria, mostly following market prices of oil derivatives, with some delay. This approach was applied to all sectors, with the appropriate benchmarks, and also to exports, after allowing for transportation costs.

The rationale for this approach was to use gas also as a source of state revenue, and as a way of boosting security of energy supply and of reducing environmental pollution. This choice was made possible by the existence of a state-owned monopolist, which purchased gas from the Groningen field (operated by a joint-venture of the state and two large IOCs), and later from smaller fields as well. As a consequence of this policy, gas use was quickly expanded in the country, which came to use gas as a primary energy source more than any other European country.

Let us also summarise trends of the large emerging markets of the BRICs2, where the tendency is also towards market based pricing although China (a net importer) is moving towards links to oil derivatives (in line with the Dutch approach). Russia, the largest world exporter, has planned (but not fully implemented) an export parity principle, where domestic gas should be priced at the export price minus export transportation costs. Since Russian exports prices are in turn related mostly to oil derivatives', this may end up as a similar approach. However, Russian gas' export prices have in fact slowly moved towards hub based pricing, and their domestic pricing may also reflect this tendency.

Domestic gas pricing in the Russian Federation was historically cost-based, with subsidies benefiting in particular households' consumption. On the other hand, liberalization in the last decade has led to a vibrant market for power generation and large industry customers, even though regulated prices still exist for the smaller customers. An official policy has long existed (and has been to some extent been implemented) to increase prices towards the "netback" (or export parity) levels, where they would be aligned with those of exported gas, minus the transport cost. However, when international gas prices increased, regulators have been wary of reaching the netback levels.

A somehow similar pattern occurs in China, which (unlike Russia) is

2 Case studies of Brazil, Russia, India, China, Argentina and Australia could not be included in this book but are available to the author from private and public sources.

a net importer. Domestic production has been mostly regulated on the basis of individual field costs. The industry has been offsetting high cost of imports with low costs of domestic production, but it is now suffering rising losses as the share of imported gas has increased. Therefore, a pilot mechanism has been introduced in two provinces and later extended to the whole country, where prices are related to those of competing fuel. Despite efforts to promote stronger competition, lingering control of the large state-owned majors on main pipelines has so far maintained Chinese prices at relatively high level. Central and (in particular) provincial regulators have therefore tried to protect smaller customers, by neglecting due hikes when the reference oil market indicators increased. In fact, households are still largely cross-subsidised by larger customers. A more general reform towards a more competitive model based on unbundled transmission networks is under development.

India has also often cross-subsidized imports with the low costs of domestic fields, yet this has slowed down the development of marginal ones. Heavy litigation between the government and suppliers in Courts and arbitrations have increased regulatory uncertainty. A policy of raising prices towards market levels has been announced, but implementation is lagging behind.

Brazil is in an earlier market development stage, and a net importer. Prices are not regulated in the wholesale market, which is dominated by a state-owned company, therefore interfuel competition is the main factor affecting pricing practices. The reform process towards reduction of the incumbent's influence and increasing competition is under development.

All of these countries have started from more or less subsidized prices, or at least from cost based regulation that led to prices below market levels. Yet such pricing regulation practices are often not transparent, and little information is available about their details.

Although it is now fully liberalized, an interesting case in historical perspective is New Zealand, a small market (4-6 Bcm/year) that has long suffered from dependence from a large single gas field. In fact, the large offshore Maui field was able to almost monopolize the market after its development, and the market was not large enough to develop more; therefore, its price was regulated by the Commerce Commission in 1996 and remained almost constant for 6 years. This has slowed the discovery of more costly new reserves, and the reserve/consumption ratio fell from

14.6 years in 1997 to 7.4 in 2002, when the cap was gradually lifted as shortage was looming. Demand peaked at 5.9 Bcm in 2001, but increasing prices and lack of reserves led to a market slump, where consumption fell to a historical minimum of 3.6 Bcm in 2005, and only slowly recovered after that.

Whereas New Zealand may have largely overcome such difficulties, a similar (and more difficult) case is Argentina, where prices have long been kept below import and even domestic field costs for a long time after the 2001 sovereign default and the ensuing macroeconomic disaster. Even though the Argentinean market is larger and has not suffered from serious monopoly problems (but only from YPF dominant position) the very low price ceiling has cut all new exploration incentives and led to reserve decline and wasteful consumption, with the country having to fill the gap by costly LNG imports. The subsidy burden is among the main causes of the further deterioration of the State's public finances.

These risks have been so far avoided in Australia, where a rather competitive market has always prevailed. Regulation is limited to a few pipelines, and some distribution and retail markets. Prices have been historically low due to abundant local resources, but a major change has recently occurred as the development of a large LNG export industry has in fact connected the market with the rest of the world, raising domestic prices from cost levels towards export netbacks. Volatility has also grown, as any delay or restriction of LNG exports has triggered domestic oversupply and price crashes, followed by spikes. Despite these swings and the ensuing consumer complaints, no price controls have been introduced, but Government's moral suasion (and regulation threat) has so far ensured that producers have pledged a significant share of their output to the domestic market, albeit at prices that are now aligned with export netbacks.

The book has also analysed two cases of light regulation, which have been far less successful than the U.S., Europe or Australia. In both Israel and Indonesia, pipelines are regulated and open in principle to third party access, and price controls are limited to a small part of the market.

In Israel, a rather small market, a consortium of private producers has managed to impose rather high prices, lower than those of competing fuels but clearly above costs. As competition has almost vanished after the end of Egyptian supplies, regulators and consumer representatives have fought hard to impose some control. The ensuing regulatory battle has been a loss for all, as the policy framework has become controversial and investment decisions on major finds have been delayed. Yet producers have certainly managed to increase their sales, but possibly to make as much money as it could have been possible if production and exports had started earlier.

In Indonesia, another gas-rich country and historical exporter, rather loose regulatory and price-setting criteria have in fact led to surprisingly high domestic prices, which in turn have slowed market development. In fact, state-owned industry has been allowed to behave as a dominant supplier, so that gas could be a government cash cow. On the other hand, inadequate TPA enforcement and lack of appropriate incentives and guarantees have curbed investments, leading to congestion of key long-distance pipelines. The country has some of the highest domestic prices among exporters, and seems to have enjoyed neither the benefits of competition nor those of protected monopolies.

Let us now turn to cases of tight regulation. This book includes case studies of three African countries (Algeria, Egypt and Nigeria) that are historical gas exporters. All of their market models have “single buyers”, tasked of producing or negotiating and purchasing from foreign companies and joint-ventures. In fact, such buyers share some regulatory role, even though a separate gas regulator exists in Algeria and Egypt. Negotiations in such cases are based on price as well as on a number of other features, including take or pay, swing and ramp up/down factors, but also exploration efforts, production bonuses, pricing of natural gas liquids, and taxation.

It is not surprising that large gas producing countries have chosen this regulatory model. It is related to the fact that gas production has different and specific features in each field, which are not easily standardized and understood. The establishment of a National Oil (and/or Gas) Company allows governments to maximize their revenue, first by acquiring a deeper knowledge through its direct involvement in exploration and development of mineral resources and secondly by defining tailored purchase conditions for each field3.

For many years, Egypt actually set the wholesale gas price at the then

3 The main risks of such models are the establishment of large and powerful bureaucracies that may propser on their exclusive knowledge of valuable insider information.

reasonable level of $2.65/MMbtu. However, such price was later been regarded by oil&gas producers as too low for the development of new deepwater fields, and production development has stalled after 2009. At the same time, gas has been sold at heavily subsidized prices to the internal market, notably to the power generation sector, which covers about 65% of the market. At the same time Egypt, like other countries that are mentioned in the next section, has long been unable to raise domestic prices, with few exceptions. This has led to a huge imbalance, which has eventually forced Egypt to suspend all its exports, even in break of contractual obligations, despite its huge reserves. Only recently some new fields have been awarded higher prices, and positive consequences have quickly (and somewhat luckily) emerged with new finds that have allowed the return of net exports. Only in 2015, consumer prices have been raised for most sold gas, to curb the boomed State subsidy burden, widely regarded as unbearable. This hike has not ensured cost-reflectivity of domestic prices yet, but the gap has sharply narrowed. Moreover, after the establishment of a regulatory body, a limited market opening is happening for industrial customers.

Nigeria has explicitly followed the Egyptian model, but has recently separated the single buyer role, which has been attached to a special body, jointly owned by oil&gas companies and regulated by the Ministry. Yet, unlike Egypt, Nigeria's market has always been dominated by exports. Potential demand is large, as a large share of the population still lacks access to electricity, yet the slow development of pipelines and power plants has not allowed the exploitation of the huge gas resources of the country, which are still partly flared, although with a decreasing trend. The attempt to regulate prices below those of exports has been also regarded as responsible for a vicious circle, with international oil&gas companies (IOCs) often failing to implement their pleas.

Thus, although Egypt and Nigeria have a similar institutional model and are both formally following a policy of resource partition between domestic consumption and exports, both of them have actually failed to implement it, but in opposite ways. In Egypt, domestic consumption has left less and less available gas for exports, and currently all production is absorbed by the domestic market. In Nigeria, the downstream infrastructure development has lagged behind exports. In both cases, inadequate pricing policies may be partly responsible, with too low upstream and far too low domestic prices in Egypt (with few exceptions) triggering the growing imbalance, and too low domestic prices in Nigeria hampering the development of infrastructure. Both countries are now actively trying to fix the problems.

In Algeria, a similar pattern also occurred, with slow updates of upstream prices, whereas those of the domestic market are kept well below costs. However the larger reserve base of the country and its smaller domestic absorption have managed to keep enough exports to subsidize domestic consumption. Yet, recent tenders for exploration acreage have not been very successful and the country is struggling to maintain its export levels.

9.2 Regulatory responsibilities and criteria

The next Table summarises how regulatory responsibilities are assigned to institutions in each country. Institutional settings of countries are very different, as so are the power separation, and transparency standards, hence the independence of formally separate regulatory bodies may be very limited in several cases.

Even among Western style democracies, responsibilities are very different. Whereas independent energy regulators are normally in charge of setting network tariffs, in a few cases the responsibility with gas prices has remained with the government. The same happened in the past, when more OECD countries had gas price regulations:

Nevertheless, in the U.S., before controls were abolished in the early 1980s, prices were set the Federal Energy Regulatory Commission, and by State level Public Utility Commissions for the retail market. Gas prices in the past were set the Commerce Commission in New Zealand4, but by relevant Ministries in the Netherlands and (even now) in France. In Russia and China, tariffs are formally issued by a Government Agency, but this is hardly independent from central Government.

The Ministry is also the regulator of the gas industry in large producing countries like Egypt and Nigeria, and is in fact the regulator in Argentina as well, leaving to the official regulatory body that was in charge in the 1990s a mostly advisory role.

4 The Commerce Commission of New Zealand is mainly a Competition Regulator, but has also the power to regulate utility tariffs where necessary.

Table 9.2 - Regulators in charge of gas pricing mechanisms by sector

Country	Wholesale	Power generation	Retail (industry)	Retail (Residential & Comm.)
US	None	None	None	State PUCs
Brazil	None	Special program (Govt)	None	State regulatory Agencies
Argentina	Energy Secretariat (Ministry of Energy), Regulatory Agency			
Netherlands	None	None	None	None
France	None	Ministry of Energy		
Italy	None	None	None	Energy regulator
Algeria	Upstream regulator (ARH)	Energy regulator (CREG)		
Egypt	Ministry of Petroleum			
Nigeria	Ministry of Petroleum			
Russian Federation	Various	GOG	Federal Tariff Service	
China	Pricing bureau of National Development and Planning Commission			
India	Ministry of Petroleum & NG	Petroleum & Natural Gas Regulatory Board (PNGRB)		
New Zealand	Commerce Commission (if necessary; transportation control applies)			
Israel	Cabinet	PUA	N.A.	N.A.

Source: own research

In general, the regulation of natural gas prices is far less widespread, transparent and standardized than that of the electricity industry. This is not necessarily true of networks, but it is particularly true for gas prices, notably where natural gas is domestically produced rather than imported.

This situation is not necessarily the result of political choices, but is probably related to the "natural resource" character of gas, which, unlike industrial products like electricity5, is produced in each field under almost unique circumstances, which cannot be properly benchmarked against those of other fields. Therefore, the regulator is not usually able to properly assess the costs, e.g. by comparing them with those of akin plants, as it happens in power generation.

This is true not only for costs, but even more for the quality of services parameters. For example, the duration (depletion time) and the performances of the field in terms of peak and flexibility (ramp up or ramp down rates) can hardly be properly assessed by the regulator, and their negotiation is subject to a serious information asymmetry in favour of the company. The regulator's ability to benchmark the production site performances and their costs are also hindered by the high confidentiality of the industry: most companies or even their clients or regulators would not disclose field or treatment plant performance data, as this may damage their international market competitiveness.

Difficulties that are even more serious emerge in the assessment of some specific cost items of gas productions. In particular:

1. Since any gas field is exhaustible, its use has a certain "user cost", which can also be seen as the opportunity costs of producing the gas now rather than "leaving it in the ground", or keeping it as an asset for the future. This is known as Hotelling's rent in the economic literature and its analysis dominates the economics of exhaustible resources. There is a general agreement that the user cost of mineral resources is positive, but its level and trend is uncertain. From a practical perspective, neglecting it would be wrong, but its actual value can hardly be estimated (as the U.S. experience of 1950s and 1960s shows), as it is related to the evolution of technology, demand, resources and regulation.
2. The twin problem of the above is the uncertainty about depletion – and hence depreciation rates of the fields. Prices can widely change if different depletion rates are used, yet this is far from certain for the regulator. This problem has also been noticed in the U.S. experience.
3. A substantial part of the oil and gas industry's costs lies in the

5 Hydro and other renewable sources of electricity are more akin to oil and gas fields on this respect.

exploration stage, which is not always successful. It is not clear and not internationally agreed how to charge such costs on successful investments.

4. There is often some natural gas liquids production that is associated to that of gas, and is highly valuable. Its share is very variable and even uncertain across time, and its value is strictly related to the trend of oil prices. Any properly cost-based regulatory mechanisms should therefore be related to oil markets, at least through this way.

All of these difficulties help explaining why cost based regulation is not common in the more advanced regulatory systems, and why it is not transparent in others.

Some more information exists about rates of return that are allowed on upstream investments, which are typically in the 12-15% range. They are somehow related to the "country risk", and this explains why these rates are above the average yields of the oil and gas industry, which are in the 9-10% range[6]. On the other hand, if depreciation is a problem for upstream resources, the valuation of capital is less so than for networks, or for aged power generation equipment. Most assets are relatively young and most investment costs are recent, therefore CAPEX valuation is less problematic if company accounts are available.

9.3 Price levels

The IGU Survey annually publishes a chart of world wholesale gas prices, which is not entirely transparent, but covers a much larger number of countries (see Figure 9.1)[7].

Looking at Figure 9.1, it is clear that a basic difference exists between self-sufficient countries and net exporters on one side, and net importers on the other side[8]. There is indeed a gap in the Chart between the lowest level importing country (Belarus), which lies above 3 $/MMbtu, and the

6 Pindick, quoted by Smith (2012).

7 Later surveys are available at https://www.igu.org/resources/ but cannot be reported here.

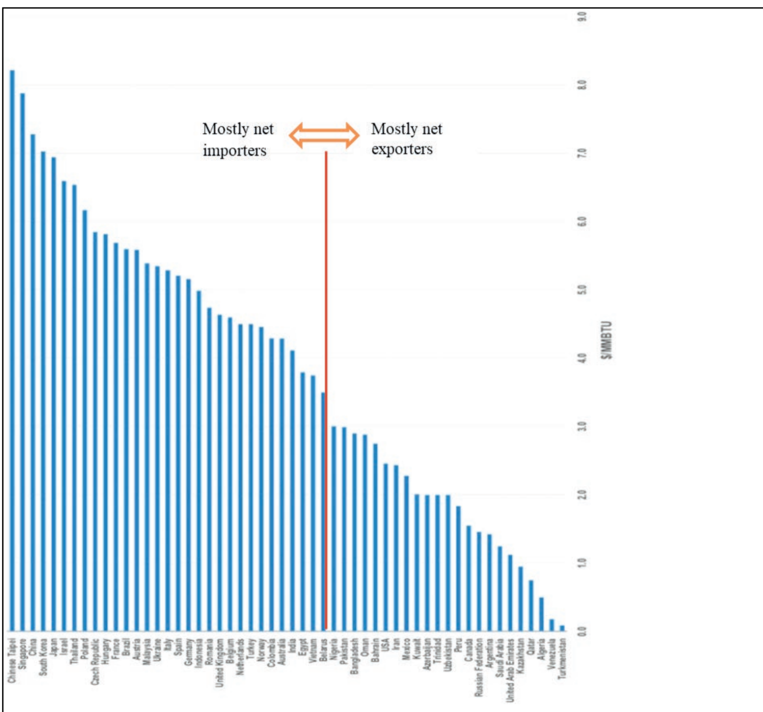
8 Since the U.S. and Canada are a fully integrated and liberalized market, they can be regarded as a single market, and are now (if taken together) a self-sufficient area, with minimal external trading flows. Likewise, the EU is now an almost integrated market, with limited internal price differences, and is a net importing area. Therefore, even an exporter like the Netherlands has now the typical price levels of net importers.

highest level self-sufficient country (Nigeria), which is well below that level. This gap is partly explained by transportation costs, which can be as low as a few tens US¢/MMbtu for pipeline connection between small neighboring countries, but may exceed $6 for LNG transportation at long distances.

In fact, prices depend on a number of features, among which regulation plays a limited role. Among them, different competing fuels; location with respect to gas sources; and domestic market structure and power. Understanding price levels in the world is beyond the scope of this book.

Yet, it is striking to find that countries like Indonesia and Israel, which are self sufficient and net exporters but lack a proper price regulation, show prices that are often higher than those of net importers, and sometimes even above the levels at which they export gas.

Figure 9.1 – World Gas Prices (2016)



Source: IGU Wholesale Gas Price Survey - 2014 Edition

9.4 Concluding remarks

We have explored gas price controls, both from a theoretical and an empirical side, with case studies taken from all continents. Let us draw some general lessons, as answers to two key questions:

(1) Are gas price controls necessary?

(2) If yes, how should they be designed?

Gas price controls are not always necessary. In fact, gas markets can be competitive enough, so that market power is checked and no controls are needed. Competition can come from other energy sources, but this is more likely for power generation and large industrial customers, and it is not always the case even in these sectors. On the demand side, the benefit of using natural gas compared to alternative fuel can be so large that inter-fuel competition is weak and ineffective.

On the supply side, several bottlenecks can prevent competition from being effective: this can happen in production (as shown by the Israeli case); lack of unbundling and inadequate regulation of the more naturally monopolistic sectors, like transmission and distribution (as was the case almost everywhere before stark reforms requested unbundling in North America, Europe and Australia, and still happens in several countries); cross-border transmission, storage or LNG regasification (where these are essential facilities, as was the case of some European countries).

On the other hand, Chapter 1 has shown that, where unbundling and network regulation are effective and other bottlenecks are removed, gas-to-gas competition drives down prices towards competitive, efficient levels: this has been the case in Europe after the implementation of the Third Package, but also of North America, Australia, and New Zealand, at least in the wholesale markets. Less unanimous are the opinions regarding retail markets, notably for smaller customers, where several jurisdictions In North America, Western Europe – and even more in Eastern Europe and Asia – retain price controls. Complexity of price structure and determinants and the limited appeal of alternative bids – beyond a price component often burdened by significant taxes and levies – can reduce the effectiveness of competition and preserve the market power of incumbents – or of new oligopolists.

Thus, if barriers to effective competition cannot be removed (at least for a while), it is almost inevitable to resort to some control of retail prices. Those unwilling to implement it have seen high prices, as the case studies of Indonesia and Israel in this book have shown: their prices are among the highest of self-sufficient countries, are often above netbacks from export markets (so that domestic customers may in fact cross-subsidise exports) and clearly exceed production costs, including normal industry profits.

Nevertheless, cases of missing or ineffective price controls are certainly outnumbered by those of suffocating regulation. The world has seen – and still sees – several cases where price controls have resulted in prices well below cost-reflectivity levels. These price controls foster excess consumption, discourage investments in all sectors of the industry, destroy competition, and may create the basis for shortages and government subsidies, which in turn are the basis for higher costs that may be necessary to address the shortage and activate emergency supplies, resort to more expensive and polluting alternative fuels, strained public finances and – last but not least – higher carbon emissions.

It has been a remarkable discovery how the tendency to cap prices below efficient levels (i.e. the levels that would result from healthy competition) has been common to all continents, political and economic systems, although in different historical phases. Controls consisting of a complex and burdensome methodology have created a backlog of delayed price increases in the United States, hereby contributing to the shortage of the 1970's (Chapter 3).

On a smaller case, the same happened in New Zealand at the end of 1980's, when prices were frozen at levels that were not adequate for the development of new resources, triggering a long-lasting damage to the industry (chapter 8).

Similar problems occurred, and are still happening, in some key producing countries of North Africa (Chapter 6), with great damage to the industry and the economy, as shown in the case of Egypt. However, similar problems are found in the literature and in our research in a number of other countries, which have not been analysed in detail in this book. Let us mention Argentina; P.R. of China, the Russian Federation and other former Soviet republics (at least for the household sector); India, Saudi Arabia; and several European cases where governments managed at least to delay retail price hikes driven by international market swings.

As for the latter question, Chapter 2 has explored (and section 9.1 above summarised) the theoretical difficulties of cost-reflective price controls. The US' case of the 1960-70s and other countries' more recent experience showed how these difficulties are far from purely theoretical, but can results in market distortions, shortages, or inadequate industry development. The best solutions seem to rely on the abandonment of any cost-based estimation regarding the price of produced or imported gas, which is instead taken from a liquid and sufficiently competitive market hub; whereas cost based components may be included for the (usually smaller) shares of international transport, where relevant. These solutions are adopted typically in the U.S. and in few EU Member States that still feature regulated prices, and have been aimed at also in emergeing markets like China, India and Russia. Yet, even these type of control must solve several problems, like the choice of the relevant markets and their weights, the definition of trading routes, and the regulatory lag between hub an regulated prices.

Annex 1. International Gas Union's Definitions of main price formation mechanisms

Oil Price Escalation (OPE)	The price is linked, usually through a base price and an escalation clause, to competing fuels, typically crude oil, gas oil and/or fuel oil. In some cases coal prices can be used as can electricity prices.
Gas-on-Gas Competition (GOG)	The price is determined by the interplay of supply and demand – gas-on-gas competition – and is traded over a variety of different periods (daily, monthly, annually or other periods). Trading takes place at physical hubs (e.g. Henry Hub) or notional hubs (e.g. NBP in the UK). There are likely to be developed futures markets (NYMEX or ICE). Not all gas is bought and sold on a short term fixed price basis and there will be longer term contracts but these will use gas price indices to determine the monthly price, for example, rather than competing fuel indices. Spot LNG is also included in this category, and also bilateral agreements in markets where there are multiple buyers and sellers.
Bilateral Monopoly (BIM)	The price is determined by bilateral discussions and agreements between a large seller and a large buyer, with the price being fixed for a period of time – typically this would be one year. There may be a written contract in place but often the arrangement is at the Government or state-owned company level. Typically there would be a single dominant buyer or seller on at least one side of the transaction, to distinguish this category from GOG, where there would be multiple buyers and sellers.
Netback from Final Product (NET)	The price received by the gas supplier is a function of the price received by the buyer for the final product the buyer produces. This may occur where the gas is used as a feedstock in chemical plants, such as ammonia or methanol, and is the major variable cost in producing the product.

Regulation: Cost of Service (RCS)	The price is determined, or approved, by a regulatory authority, or possibly a Ministry, but the level is set to cover the "cost of service", including the recovery of investment and a reasonable rate of return.
Regulation: Social and Political (RSP)	The price is set, on an irregular basis, probably by a Ministry, on a political/ social basis, in response to the need to cover increasing costs, or possibly as a revenue raising exercise.
Regulation: Below Cost (RBC)	The price is knowingly set below the average cost of producing and transporting the gas often as a form of state subsidy to the population.
No Price (NP)	The gas produced is either provided free to the population and industry, possibly as a feedstock for chemical and fertilizer plants, or in refinery processes and enhanced oil recovery. The gas produced maybe associated with oil and/or liquids and treated as a by-product.
Not Known (NK)	No data or evidence.
Hub indexation (HUB)	The price is explicitly linked to those reported at a major (physical or virtual) gas hub.

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