Regulation and Incentives for Investment in the Colombian Gas Transport Network *

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Abstract

Recent events in the distribution of gas supplies in Colombia, caused by the 2009-2010 El Niño event, have led to controversy concerning the effectiveness of the existing regulatory regime in eliciting timely investments in gas pipeline infrastructure. The Colombian Comisión de Regulación de Energía y Gas (CREG) consequently commissioned Market Analysis Ltd, assisted by the Brattle Group, to undertake an economic study of the current proposals for regulating gas pipeline charges, and specifically to consider: (i) the price incentives required to ensure timely and efficient investments in gas transport infrastructure; (ii) the appropriateness of adopting measures to reduce the risk of stranded assets; and (iii) whether the current controls on vertical integration in the gas industry should be relaxed. Taking account of the views expressed by both market participants and government agencies, our study concludes that the regulatory regime is working broadly as intended, and that no major overhaul of the existing regulatory framework is either needed or desired. The most urgent issue may be the concentration in upstream gas supply, which has led to claims of an undersupply of long-term firm gas supply contracts in the market. During the course of our consultation, we nevertheless received numerous detailed proposals for improvements in the regulatory regime, from both market participants and the CREG, and a number of these appear to have merit. We therefore recommend that the CREG consider adopting many of these proposals, in some cases after a further period of detailed study and consultation has taken place.

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1 Introduction

The Comisión de Regulación de Energía y Gas (CREG) regulates the prices which gas pipeline companies (Transportation System Operators, or TSOs) can charge for the use of their pipeline systems by gas shippers in Colombia. It also imposes strict limits on vertical integration between gas producers, transporters (TSOs) and distributors. After a recent consultation which closed on 21st July 2009, the CREG was set to finalize new five-year price controls for TSOs, as well as adopt some minor variations in the current regulatory regime. Recent events in the distribution of gas supplies, however, caused by the 2009-2010 El Niño event, resulted in renewed controversy over the effectiveness of the regulatory regime in eliciting efficient and timely investments in gas pipeline infrastructure. In particular, constraints on the Ballena – Barrancabermeja pipeline in the TGI system, caused by the running of gas-fired power stations in the interior of Colombia to supply the electricity market, led to gas supplies being interrupted for some consumers on interruptible contracts, especially industrial plants located around Bogota, and taxi drivers in large urban centres. In October 2009, the Colombian Ministry of Mines and Energy intervened in the market to reallocate gas supplies irrespective of prior contractual commitments. Various market participants as well as government agencies - such as the National Hydrocarbon Agency (ANH) - have since presented their views on the causes of the current problems, and the regulatory measures and reforms that may be needed to remedy them.

The CREG therefore decided to commission Market Analysis Ltd, assisted by the Brattle Group, to undertake an economic study of the current proposals for regulating gas pipeline charges. The purpose of the study is to analyze the gas transport market and the current regulatory framework in Colombia, taking international experience into account, and specifically to consider:

1. The regulatory price incentives required to ensure that investments in gas transport infrastructure are made in a timely and efficient manner;

2. The appropriateness of adopting measures to reduce the financial risks placed on TSOs by the regulatory regime, especially the risk of stranded assets, even where TSOs faced these risks at the time investments were made; and

3. The appropriateness of revising or relaxing the current controls on vertical integration in the gas industry.

The study was required to take account of industry views, and the CREG's own perspective on the current issues in Colombian gas transportation and regulation.

After fairly lengthy and detailed consultations with the industry, the CREG and other government agencies in Bogota, our study concludes that the current regulatory regime in Colombia is working broadly as intended, and has led to no significant or identifiable problems in the gas transport system. Although Colombia has adopted a more "decentralized" or "market-based" approach to gas transport regulation than that currently found in many European and North American markets, as evidenced by the Brattle Group report it is nevertheless within the mainstream of international best practice, where market mechanisms and private (or "merchant") investments are increasingly being relied on to provide for new gas transport infrastructure. Although a number of market participants (as well as consultants to the ANH), have called for Colombia to adopt a more "European-style" approach to regulation, European regulators themselves have recently been moving in the opposite direction. And the recent gas supply interruptions to more than 100 industrial customers in the United Kingdom, brought on by a spell of particularly cold weather, reminds us that such events can occur even in an archetypal "centralized" regulatory regime, in which the regulator takes on more direct responsibility for ensuring that adequate investments in pipeline infrastructure are made.

Importantly, however, the response of the regulatory authorities in the UK has been to allow the market to function as intended, rather than intervene to redistribute gas supplies. No market - regulated or otherwise - will be able to function effectively in the long term if political lobbying can predictably result in government intervention in favour of certain market participants who become dissatisfied with their contractual positions. If the recent El Niño event has revealed there to be a shortage of gas transport capacity in Colombia - and this remains entirely unclear to us - its proximate cause has been a failure of the market participants themselves to signal the need for system expansion via a demand for long-term, firm capacity contracts.[1] Now that such demand has come forward, major new investments in pipeline capacity are under way. But the system will be unable to operate efficiently in the future without a commitment on the part of government to allow the market mechanisms already put in place to operate, so that participants understand that it is via their own market behavior, rather than political lobbying, that demands for new pipeline capacity will be met.

Where recent stresses to the gas transport system have revealed problems, these appear to lie primarily in upstream gas supply which is very concentrated, and which has led to claims that long-term firm gas supply contracts are being with held from the market. Problems have also arisen downstream in the regulation of taxi fares, leading to considerable dissatisfaction when gas supplies were interrupted. These upstream and downstream issues lie outside our terms of reference in (1) - (3) above. We nevertheless suggest that the relevant regulatory authorities in Colombia investigate them, and consider mechanisms for addressing them where warranted.

[1] As we point out in Section 6.3 below, prior contractual commitments from market participants are typically required before capacity expansions are approved, or remunerated, even in regulatory systems where the regulator is responsible for overseeing capacity investments.

Our study therefore concludes that no major overhaul of the regulatory regime for gas transmission is either needed or desired. Indeed, an abrupt change in the regulatory framework at a time when very significant new investments in pipeline capacity are being made would risk creating even more uncertainty and delay, as well as upsetting existing long-term contractual commitments between market participants. As the Brattle Group report confirms, no drastic changes to the regulatory framework would appear to be called for.

During the course of our consultations, however, numerous detailed proposals for improvements in the regulatory regime have been made, both from industry participants and the CREG, and a number of these appear to have merit. We discuss these proposals in Sections 6 below and, where appropriate, recommend that the CREG consider adopting them. Some of these proposals could potentially be implemented quite quickly, when the new price controls are adopted. Others will require more detailed thought and development, possibly accompanied by a further consultation exercise with the industry.

Section 2 of our report provides a brief overview of the Colombian gas market, and Section 3 describes the current regulatory framework in some detail. Section 4 discusses the recent events and controversies. Section 5 asks whether there has been too little investment in gas transport infrastructure in Colombia, and if so, what the causes of this are. Section 6 considers various proposals for reforming, or refining, the current regulations, and recommends that the CREG consider adopting many of them. Section 7 concludes.

2 Overview of the Colombian Gas Market

This section provides a brief overview of the gas production and transport market in Colombia.

2.1 Production

Roughly 90% of Colombia's gas supply comes from two main fields: Guajira on the Caribbean coast and Cusiana in the interior. Several minor fields account for the remaining 10%. Guajira has about one-half of Colombia's reserves (but this is declining over time), and currently provides 65% of production. The field is jointly operated by Ecopetrol, the State-owned oil company, and Chevron Texaco. In 2009, average production of the Guajira fields was approximately 640 GBTU per day. Gas from these fields is delivered to the entry point of Ballena, and is shipped to the inland part of the country, the Atlantic/Caribbean coast, and to Venezuela.

Cusiana has about 50% of total Colombian gas reserves and currently provides approximately 25% of production. The field is operated jointly by Ecopetrol, BP, and Total and produces approximately 220 GBTU per day. Other minor fields produce around 80 GBTU per day: La Creciente, 40; Payoa, 20; other, 20 . There is also a new field in Gibraltar, expected to produce

30 GBTU per day by the end of 2010.[2]

Upstream gas production in Colombia is therefore highly concentrated. Table 1 shows production by company in January 2008. The Herfindahl-Hirschman Index (HHI) for gas supply is 4357, and the degree of concentration is set to increase when Ecopetrol acquires complete control over the Cusiana field in 2016.

Table 1. Gas supply by company in January 2008[3]

Company	GBTUD	Share
Ecopetrol	518	62%
Chevron	185	22%
BP	53	6%
Total	33	4%
Pacific Rubiales	27	3%
Others	25	3%
TOTAL	841	100%

Gas from the Guajira field is sold at a regulated price, currently $2.76 per MBTU (US), using a value estimated in the 1970s and indexed twice a year with the New York fuel oil price. Gas from other fields is unregulated. Auctions for 32,821 MBTUD of long-term, firm gas contracts were held for production from the Cusiana field in December 2009, resulting in a price of $6.14 (US) per MBTU.

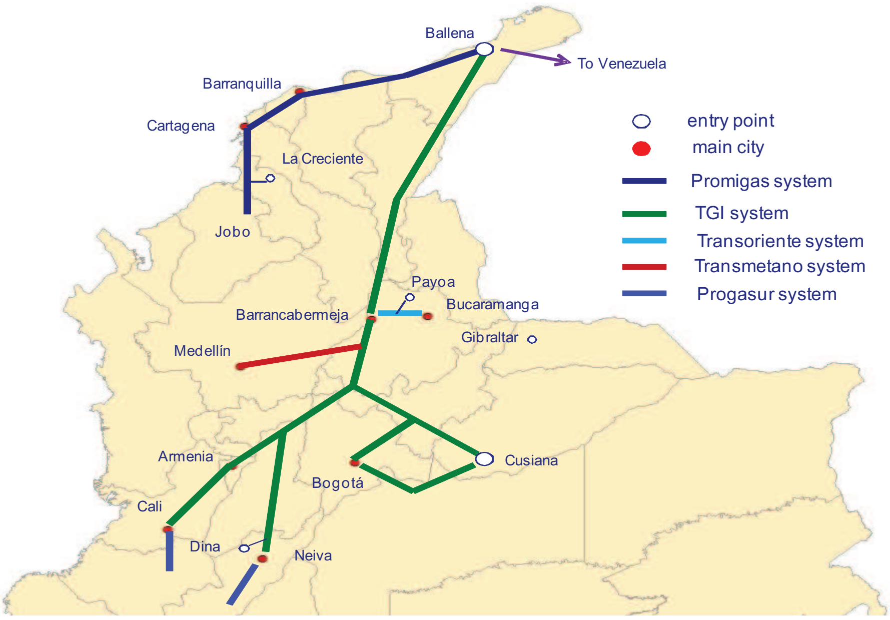
2.2 Transportation

Colombia has two large Transportation System Operators (TSOs): Promigas on the Atlantic/Caribbean coast, and TGI in the inland part of the country. The Promigas system's Ballena – Barranquilla – Cartagena – Jobo network is 590 kilometers long with a capacity of 540 GBTUD. The TGI has two interconnected pipelines systems: the Ballena – Barrancabermeja pipeline which runs for 580 kilometers and has a capacity of 190 GBTUD, and the Cusiana – Bogotá – Vasconia – Cali – Neiva pipeline (1700 kilometers long) with a capacity of 220 GBTUD. Other minor TSOs deliver gas from the TGI system to local markets such as Medellín and Bucaramanga (see Figure 1).

The TGI purchased its pipeline network from the state-owned EcoGas in an auction in 2006 for a price of $1.4 billion (US). The other pipeline networks have been developed under private ownership.

[2] In addition, a mining company that operates close to the Ballena – Barrancabermeja pipeline has recently announced the existence of coal-bed methane reserves that could be developed in the near future. There is also offshore exploration activity in the Caribbean that appears to have significant potential for future gas production.

[3] Source: Cramton (2008), p. 3.



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2.3 Demand

Demand for gas in Colombia falls into four main categories: residential and commercial (19%); industrial (45%); electricity generation (24%); and vehicles (11%), located on the Atlantic/Caribbean coast (34%) and in the interior (52%). Exports to Venezuela currently account for 14% of demand. Approximately 49% of demand on the north coast comes from thermal electricity generators. The interior also has significant gas-fired generation capacity, but these units generate little or no electricity in a typical year, since hydro resources are less expensive when there are sufficient water resources.

The main consumption points are located in the major urban centres (e.g. Bogotá, Cali, Barranquilla, and Medellín among others), and where gas-fired power plants and refineries are located. These plants are located in the southern part of the country, near to Barranquilla, and in the central interior region near to Barrancabermeja.

In the Atlantic/Caribbean region, the Promigas pipeline network appears to have sufficient capacity to deliver all of the gas currently demanded. In the inland part of the country, supply is constrained during Niño periods when the gas-fired power stations near to Barrancabermeja produce electricity under their reliability charge obligations.[4] Hence existing pipeline capacity in the TGI system is insufficient to meet peak demand in such periods. The current supply deficit (in December 2009) is approximately 80 GBTUDs on average.

Capacity on the Ballena – Barrancabermeja pipeline is currently 190 GBTUD and capacity on the Cusiana – Bogotá – Vasconia – Cali – Neiva pipeline is 220 GBTUD. So total capacity

[4] These are known as "Firm Energy Obligations", or OEFs. See Harbord and Pagnozzi (2008) for a description.

of the TGI network is at most 450 GBTU.

Demand in normal times is 363 GBTUs, so there is typically spare capacity of approximately 87 GBTUs. During El Niño periods, however, gas-fired power plants demand an extra 175 -182 GBTUDs, so there is excess demand of up to 90 GBTUDs. During El Niño periods, gas-fired power plants demand up to 93% of the Ballena – Barrancabermeja pipeline capacity, and 45% of all available capacity on the TGI system. They sign firm contracts to reserve this capacity, and re-sell it in the interruptible market during normal periods.[5] Supply is thus interrupted for a proportion of demand during El Niño events.

The market is unconcentrated on the demand side (see Cramton 2008, Table 3). The vast majority of Colombia's gas is settled according to firm gas contracts with terms much longer than the daily spot market. Current gas contracts are mostly take-or-pay with a high minimum percentage over the month or year (often 100%). Most contracts are for one or two years, although there are some that are much longer. There is a large variety of contracts.

3 The Current Regulatory Regime

The CREG has had responsibility for regulating charges for the transport of gas since 1994. Resolution CREG 001 of 2000 defines the methodology used which consists of:

- a regulated charges scheme which sets average-cost based price caps for pipeline segments calculated from investment costs using 20 year demand forecasts;
- an option for shippers to negotiate the split in regulated charges between capacity and commodity charges, and a method for resolving disagreements over this split; and
- a methodology for calculating the regulatory asset base (investment costs) and Administration, Operation and Maintenance (AOM) costs.

There are also restrictions on the degree of vertical integration between gas transporters, producers and distributors established in the 1990s. We describe each of these elements in turn.

3.1 The Charges Scheme

The regulated transport charges are set every five years, and consist of the following:

- average-cost based maximum charges for shipping gas in each pipeline segment for each TSO ("Cargos de Paso") to remunerate investments or recover fixed pipeline costs; and

[5] Since 1996 they have done this largely via a gas and transport contract with Ecopetrol, which is discussed further below.

- fixed charges to remunerate Administration, Operation and Maintenance (AOM) costs.

For each pipeline segment, the CREG defines an array of fixed (capacity) and variable (commodity) charges, in the form of a menu of two-part tariffs. So if, for example, the capacity charge remunerates 80% of investment costs, the variable commodity charge should remunerate the remaining 20% (an "80-20" charge). Two-part tariffs are defined for the pairs: 0-100, 20-80, 40-60, 50-50, 60-40, 80-20, and 100-0.

Shippers may either agree on the split between capacity and commodity charges for a pipeline segment with the relevant TSO, or use an "ordinal approximation procedure" defined by the CREG when agreement cannot be reached. Non-regulated users and marketers selling gas in the non-regulated market are free to negotiate their own charges.

The regulated charges apply to contracts for firm capacity only. For a contract for X units of firm capacity, the shipper thus pays:

- the annual capacity charge times the contracted maximum capacity, X;
- the amount of the variable charge multiplied by the volume transported; and
- the annual fixed charge remunerating AOM expenses, times X.

Under a firm capacity contract the shipper is entitled to use all the contracted capacity at all times, independently of the pair of capacity and commodity charges paid. The duration of firm capacity contracts is not regulated and must be agreed between TSOs and shippers. Contracts for interruptible capacity are unregulated, and sold both by TSOs and by shippers who have acquired firm capacity contracts.

Since the regulated maximum charges are fixed for a five-year period, the risk that actual demand differs from expected demand is borne by TSOs. If actual demand exceeds expected, the TSO may recover more than its investment costs; if actual demand is less than expected the TSO may under-recover its costs. No adjustments are made ex post, or in subsequent regulated charges, to account for either over or under-recovery in previous price control periods.

3.2 Methodology for Assessing the Regulatory Asset Base

The price caps are calculated taking account of the costs of existing and new pipeline investments over a five-year period, assuming a "depreciation" period of twenty years. The NPV of investment costs is calculated using: (i) different costs of capital for new versus existing investments; and (ii) different costs of capital for fixed capacity charges versus variable commodity charges.[6] These NPVs are then divided by the NPV of average capacity or commodity demand over a

[6] The CREG is currently proposing to use the same cost of capital for new and existing investments.

twenty year period, to arrive at the prices required to remunerate the investments, assuming utilization factors exceeding 50% (see immediately below). Expected demand is estimated by combining 3 - 5 scenarios submitted by TSOs with a CREG scenario, with the latter being given a 20% weight.

Utilization Factor (UF) The CREG applies a minimum efficiency standard to pipeline investments. Capacity and commodity charges are calculated by dividing the NPV of total investment costs by the NPV of “adjusted demand” for either capacity or volume. The level of adjusted demand depends on forecast pipeline utilization:

- Where forecast average utilization, i.e. the ratio of forecast volume demand to pipeline capacity, exceeds 50% over the twenty-year forecast period, adjusted demand is set equal to forecast demand. In this case, the regulated charges recover costs if realized demand equals forecast demand, and the TSO is exposed to demand risk only to the extent that realized demand differs from forecast demand over the five-year period.

- Where forecast utilization averages less than 50%, adjusted demand is set higher than forecast demand so that the adjusted demand results in a 50% utilization factor. This reduces the regulated charges, so the TSO will under-recover its total investment costs even when realized demand equals forecast demand.

The UF adjustment thus prevents the full remuneration (on average) of expenditure on pipelines which are under used according to this criterion, by preventing prices from increasing as utilization falls below 50%. Assets which effectively become "stranded", in the sense that they face little or no future demand, receive little or no remuneration via the regulated charges.

Network Expansion Expansion of, or new investments in, the pipeline network is carried out by private companies, with no direct CREG oversight or involvement. Remuneration of new investments occurs either:

1. Via inclusion in the “New Investments Program”, in which case the CREG reviews the investment in order to establish the “Baseline Investment”; or

2. The TSO may choose to:

- – apply the current regulated charges for the gas pipeline or group of gas pipelines from which the investment is derived; this alternative applies to cases where the incremental average cost of the investment is lower than, or equal to, the average cost approved by the CREG for the corresponding stretch of gas pipeline; or

– request independent regulated charges to remunerate the corresponding investment; this option would be applicable to those cases in which the incremental average cost is higher than the average cost approved by the CREG for the corresponding stretch of gas pipeline.

3.3 Vertical Integration Rules

A number of rules concerning vertical integration in the gas industry were established in the 1990s:

1. Gas producers may not own more than 25% of gas transport or distribution companies.
2. Gas transporters (TSOs) may not own more than 25% of gas production or distribution companies
3. Gas distributors may not own more than 25% of gas transport companies.

On the other hand, gas distributors and retailers must be integrated the for purposes of selling to the regulated market.

Companies created prior to of 1994 are exempt from these vertical integration rules and may continue with the activities they were carrying out prior the law coming into effect. This particularly affects the activities of Promigas and Progasur.

4 The Current Controversies

The El Niño event in 2009-2010 has meant that gas-fired power stations in the interior of Colombia have been called upon to generate electricity under their reliability charge obligations. As noted above, during El Niño periods, these power plants demand an extra 175 -182 GBTUs of gas per day, accounting for up to 93% of the Ballena – Barrancabermeja pipeline capacity, and 45% of capacity on the TGI system as a whole. The power stations sign firm contracts to reserve this capacity, and re-sell it in the interruptible market during normal periods. Hence, during El Niños, excess demand on the TGI system can be as much 90 GBTUs per day (although it is typically slightly less than this), and gas supplies may be rationed for that proportion of demand with interruptible supply and transport contracts.

Supply interruptions duly occurred in October 2009, particularly affecting some industrial plant and taxi cabs in major urban centers (e.g. Bogota). These interruptions resulted in a political controversy, and the Ministry of Mines and Energy subsequently intervened in the market to rearrange who received gas supplies independently of their previous contractual positions. This has also led to claims that the CREG's regulatory framework was itself causing, or exacerbating, the supply shortages by providing inadequate incentives for new infrastructure investments.

Additional problems were caused by the fact that the interior gas-fired power stations had contracted for 182 GBTUDs of gas via their historic contract with Ecopetrol, the formerly vertically integrated gas producer and transporter (see Table 2), but EcoPetrol contracted for only 144 GBTUDs of transport capacity with the TGI.[7] Since Ecopetrol's contract with the power stations evidently included only weak incentives to avoid breach, the power plants did not receive all of their contracted gas supply, even before the intervention by the Ministry of Mines and Energy. The rationing imposed by the Ministry has meant that the gas-fired power stations have increasingly switched to more expensive liquid fuels to generate electricity.

Table 2: Power Station Gas Demand

Power Station	**GBTUD**
Termovalle	36
Merilectrica	32.8
Termocentro	48
Termosierra	55
Termodorada	10
Total	**182**

Finally, there are claims that gas distributors and retailers have faced difficulties obtaining firm gas supply contracts from the upstream gas producers, in the Guajira and Cusiana fields in particular. This may have made them less willing to sign firm transport contracts with the TGI.

As a result of these controversies, a number of companies and government agencies have questioned whether the CREG's regulatory regime is providing adequate incentives for pipeline investment and expansion, and have suggested both major and minor changes to the regulatory regime. The more detailed proposals have included:

- changing the way in which the regulated capacity and commodity charges are calculated or negotiated, as commodity charges may not be remunerating pipeline investment costs as intended;
- eliminating, or altering the operation of, the capacity Utilization Factor;
- adopting more transparent and open procedures for allocating or selling firm pipeline contracts; and

[7] In addition to its supply contracts for 182 GBTUDs with the thermal generators, Ecopetrol's refinery in Barrancabermeja demands up to 90 GBTUDs. Hence Ecopetrol was potentially under-contracted with the TGI for up to 137 GBTUDs.

- relaxing some of the rules on vertical integration, and allowing for the recovery of some transport investments over a shorter time frame than twenty years, where justified by demand.

While most market participants have not suggested wholesale changes to the existing regulatory framework,[8] there have been proposals for the CREG adopt a ‘common carriage’ or ‘centralized planning’ approach to gas infrastructure regulation, similar to that applied to the electricity transmission network in Colombia, and to gas transmission in some European countries, so that:

- TSOs do not face either short-term or long-term demand risk, and transport infrastructure investments are planned by a centralized regulatory agency;
- regulated prices be permitted to increase to signal gas pipeline congestion, possibly via the use of ’Ramsey prices’ of some kind; and
- a ‘reliability charge’ be introduced to ensure that pipeline assets which are required only occasionally recover their costs.

In subsequent sections of this report we address all of these issues and proposals, and make some suggestions for adapting regulated prices to provide better cost signals for usage, location and investment decisions. Section 5 first considers, however, whether there is any evidence of underinvestment in gas transport infrastructure as a result of failings in the current regulatory system.

5 Has There Been Too Little Capacity Investment in the TGI System?

All of the recent controversy concerning gas transport infrastructure relates to the TGI system, and in particular, to capacity constraints on the Ballena - Barrancabermeja pipeline. This is because the TGI system faces a relatively unusual pattern of demand, with gas-fired generators contracting for, but not requiring, a large proportion of total pipeline capacity in most years, while demand exceeds current capacity in El Niño periods. The Promigas system on the Atlantic coast has a much less variable pattern of demand, and has not faced similar capacity constraint issues. Hence for more than half of the current pipeline network (in capacity terms), there is no evidence of any underinvestment in network capacity, and investment in the capacity of the

[8] Indeed, at least one TSO we spoke with was strongly opposed any large-scale changes in the regulatory regime at a time when it was making large new investments in pipeline infrastructure.

Promigas system has been taking place.[9] Progasur, in the southwest region of Colombia, has also been making substantial new capacity investments in recent years.[10]

Neither is there any clear evidence of underinvestment in the TGI system. Until recently (i.e. spring 2009), demand for firm transport contracts on the Ballena - Barrancabermeja pipeline has been slightly less than total pipeline capacity. The gas-fired power plants contracted for 144 GBTUDs via their contract with Ecopetrol, and others contracted for approximately 45.5 GBTUDs (see Table 3). The Bogota distribution company GasNatural, and some large industrial consumers, evidently chose to sign cheaper, interruptible contracts. Hence the TGI did not see a demand to expand firm capacity in the Ballena - Barrancabermeja pipeline. As noted above, this was at least partly due to the failure of Ecopetrol to contract for sufficient transport capacity to meet its own gas supply obligations, and may have been exacerbated by an inability of GasNatural, amongst others, to obtain firm gas supply contracts from producers. Nevertheless, given the demand for firm capacity it faced, the TGI's decision to maintain its current levels of pipeline capacity made economic sense.

Table 3: Balance contratación gasoducto Ballena - Barrancabermeja

Capacidad nominal	**190 GBTUDs**
Distribuidores Guajira y Cesar	6
Compresores transporte	8
ECOPETROL	144
Otros	26
ISAGEN	5.5
Total	**189.5**

In 2009, however, the TGI began an $570 million investment program to:

- increase capacity on the Ballena - Barrancabermeja pipeline to 260 GBTUs by July 2010 (i.e. to increase capacity by more than 35%); and to
- increase pipeline capacity from the Cuisiana field to 280 GBTUs by mid 2010, and to as much as 390 GBTUs by early 2011 (i.e. by more than 75%).

These large increases in TGI system capacity amount to an incremental financial investment of some 40%-70% overall,[11] and are the result of GasNatural and other companies requesting long-term firm capacity contracts with a high proportion of capacity charges.[12]Hence, now that

[9] Promigas has invested more than US $100 million in its network since 1998.

[10] Since 2007, Progasur has invested US $26.3 million in its pipeline network.

[11] TGI purchased the EcoGas pipelne system in 2006 for a cost of approximately $1.4 billion (US). The system is valued for regulatory purposes at approximately $800 million (US).

[12] Gas-fired power plants have reduced their contracted firm capacity in the Ballena - Barrancabermeja pipeline from 2012 from 145 GBTUDs to less than 60 GBTUDs.

firm demand for transport capacity has come forward, new investments in pipeline capacity are taking place. To have undertaken such large investments earlier, in the absence of firm demand, would have risked creating excess capacity desired by neither gas shippers nor consumers.

A number of the recent criticisms of the CREG's regulatory regime appear to be based on the belief that pipeline capacity should always be expanded to meet peak demand, especially during El Niño periods, which historically occur every eight to ten years. On the TGI system, a large proportion of pipeline capacity is contracted for by gas-fired power generators which use the system relatively infrequently. It may or may not make economic sense to ensure that pipeline capacity is sufficient to meet these periodic demands. But whether it does or not is probably best determined by the market participants themselves, via their demand for firm capacity contracts.

During normal weather conditions, gas-fired power stations in the interior of Colombia resell their unused capacity in as interruptible contracts in the unregulated market. Given the large proportion of unused firm capacity in most years, this is likely to be extremely efficient, especially for demand which is able to make use of alternative energy sources when pipeline capacity becomes scarce.[13] Since in normal periods, interruptible contracts will be less expensive than firm capacity contracts, gas shippers and purchasers must trade off the costs of occasional supply interruptions against the additional costs of contracting for firm capacity. Such trade-offs are again best left to the market participants who have the relevant information.[14]

An increase in capacity to meet all peak demand could have some negative consequences. It would result in an increase in average regulated charges for all users, and it might reduce, or even choke off, demand for interruptible contracts from the gas-fired power stations. As a result, the costs of obtaining firm pipeline capacity for the gas-fired power stations would increase, possibly dramatically. One consequence of this could be to make the interior gas-fired power generators uneconomic in the electricity reliability market.[15]

Evaluating the merits and demerits of increasing pipeline capacity therefore requires a great deal of detailed information not readily available to either the regulator, or to any single market participant. The purpose of a more decentralized regulatory regime is to allow market par-

[13] Taxis, for example, are for the most part able to switch to petrol when gas is not available.

[14] It is interesting to note that some hospitals in the UK choose to sign less expensive, interruptible gas contracts, precisely because they have an ability to switch to alternative fuels when necessary. See, "Cut-price gas deals 'put patients at risk'", Guardian, 17 January 2010.

[15] The gas-fired power stations in the interior of the country were originally located next to a developing gas field (Opón), which contained much less gas than originally estimated. Consequently, they are now located far from any gas fields, and hence reliant on the TGI pipeline network to a degree not originally planned for. An interesting question is whether it would make more economic sense for these power plants to relocate closer to the currently productive gas fields, rather than expand gas pipeline capacity. While we are unable to answer this question directly, a pipeline charging system which correctly signals the costs of pipeline capacity should permit the power stations themselves to make the most cost effective location or relocation decisions.

ticipants to express their demands based on their own private information, thereby allowing more efficient infrastructure expansion decisions to be made. As noted immediately above, recent history does not suggest that this approach has failed to deliver additional capacity when needed.

It is also useful to observe that even in archetypal "centralized planning" or "rate of return" regulatory regimes, such as in the UK, in which the regulator is responsible for eliciting and approving investments in gas transport infrastructure, the same types of controversy which have recently arisen in Colombia can also occur. Gas supplies were interrupted for up to a hundred UK businesses which had signed cheaper interruptible contracts during the unusually cold weather in January 2010. While this had led to some predictable hysteria in the British press concerning energy security,[16] the government has pointed out that the market operated exactly as intended in these circumstances.[17]

Whatever view one takes of the current UK controversies, it is clear that a centralized planning system, in which the regulator oversees investment decisions, guarantees neither uninterrupted supplies in all circumstances, nor that there will be any more consensus concerning the regulators' capacity and investment decisions than there is in Colombia where capacity expansion decisions are made by the TSOs.

Conclusion. There seems to be no reason to believe that either the gas transport market, or the CREG's regulatory framework, have failed to provide adequate incentives for investment in gas transport infrastructure in Colombia. The TSOs are currently making substantial investments in new capacity within the existing regime. Some issues of concern have arisen, however, especially on the TGI system. In particular:

- gas-fired power plants in the interior of Colombia have not directly contracted for the amounts of firm transport capacity they required to meet their demands, thus reducing the demand for firm capacity contracts below what it otherwise would have been;
- some companies have regretted signing cheaper, interruptible contracts and appealed (successfully) for government intervention;
- upstream gas producers may be withholding firm gas supply contracts from the market to exploit their market power, making consumers less willing to contract for firm pipeline capacity; and

[16] See, for example, "Gas row hots up as Labour calls Tories scaremongers," The Independent, 14 January 2010; and "Industry warns of looming gas crisis as big freeze sends demand soaring," Daily Mail, 13 January 2010.

[17] As the energy minister Lord Hunt noted, *"this is a period of exceptionally high demand. The system is coping as it should. These sort of arrangements have been commercially entered into."* See, "Energy security questioned as National Grid cuts off gas to factories," Guardian, 7 January 2010.

- taxis appear to be regulated in a manner which does not allow their fares to rise when they are forced to switch to more expensive fuels.[18]

The first two issues are essentially historic in nature, and unrelated to the regulation of gas pipeline infrastructure. The latter two issues are upstream and downstream of the transport system, and do not relate to the regulatory system itself. Nevertheless, they will probably need to be addressed if the gas market is to function efficiently in the future.

6 Issues with Current Regulations

This Section considers the various proposals for reforming the current regulatory regime enumerated above.

6.1 Reliability Charges and Total Revenue Regulation?

A number of proposals have been made which combine suggestions for adopting "rate of return" or "total revenue" regulation (as in much of Europe), so that TSOs face neither short-term or long-term demand risk, and the planning or oversight of transport infrastructure investments by a centralized, regulatory agency. There have been related demands for the introduction a 'reliability charge' to ensure that gas pipeline assets which are required only occasionally (e.g. during El Niño periods), recover their costs.

Proposals to switch from price cap to rate of return or "total revenue" regulation have little merit in our view. While Colombia's price cap approach places more financial risk on TSOs than is currently common in many European and North American markets, there is no real evidence that this creates inadequate incentives for new investments in pipeline capacity, nor that it has so far led to any underinvestment. The TSOs are undertaking large investments in network capacity under the current price cap regime, and all expect these investments to be adequately remunerated by it. We therefore see no reason to believe that centralized oversight by the CREG of capacity investment decisions will lead to more timely, or more efficient, investments being made. As evidenced by the Brattle Group report, the use of market mechanisms and private (or "merchant") investments to elicit efficient capacity expansion decisions in gas infrastructure is becoming increasingly common in Europe. A move in the opposite direction in Colombia would likely be a backward step.

In addition, the TSOs already receive a "reliability" charge indirectly from electricity consumers, especially from the gas-fired generators located in the interior of the country. In TGI system this currently finances up for 45% of total system capacity, and up to 76% of the Ballena

[18] One possibility might be to change the way in which taxi fares are regulated. Another would be require distributors to buy firm gas and transport contracts to supply taxis.

- Barrancabermeja pipeline. Given that we have seen no evidence of capacity shortages in either the TGI or Promigas systems, and that large investments in new capacity are currently under way, there appear to be no strong arguments for introducing a separate gas pipeline reliability charge.

6.2 Commodity and Capacity Charges

A number of TSOs have expressed dissatisfaction with the calculation of the regulated commodity and capacity charges, as described in Section 3.1 above, and the method employed to determine the split between these charges for particular users. The capacity and commodity charges are calculated on basis of the average load factor for each pipeline segment, and consequently only necessarily result in expected cost recovery if all pipeline users pay exactly the same combination of charges. However, users with higher than average load factors will typically prefer to pay capacity charges, while users with lower than average load factors will prefer commodity charges. If users' preferences are respected, this can easily result in under-recovery of investment costs.

This issue is of particular significance for the charges paid by gas-fired power plant with extremely low load factors, and which typically pay 50% commodity charges. Such power plants are arguably obtaining their firm capacity rights too cheaply, and users with higher load factors who pay the same combination of charges will, in effect, be paying more to obtain exactly the same capacity rights. Since it is the gas-fired power plants' extremely low average load factors which create particular "stress" in the pipeline network, it is important that they face the actual costs that their location and gas consumption decisions impose. It appears likely that they are currently paying too little for firm pipeline capacity rights.

One solution for this would be to use commodity charges solely to remunerate the variable or marginal costs of gas transmission, and use 100% capacity charges for the purchase of firm capacity rights. Another possibility would be to directly link the capacity/commodity charge split obtained by any particular user to their own (expected) load factor (e.g. by making the proportion of capacity charges inversely related to the load factor). A third would be to calculate the regulated capacity and commodity charges using information on the actual split between these charges obtained by users, so that overall investment costs would be remunerated in expected terms.

In our view, either of first two options are more likely to address the current problems with these charges, and we recommend that the CREG consider implementing one or another of these approaches.[19]

[19] We note that the TSO, Progasur, expressed satisfaction with the current system, and told us that both they and their customers valued the availability of combinations of capacity and commodity charges. This may be

6.3 Utilization Factor

As described in Section 3.2 above, the CREG applies a Utilization Factor (UF) to determine the amount of capacity investment to be remunerated by the regulated charges. For pipeline segments with a UF exceeding 50%, the TSOs entire investment cost will be recovered in expected terms. For pipelines with lower utilization factors, demand forecasts are adjusted upwards so the regulated charges are set "as if" the pipeline achieved a 50% utilization factor.

It is common for regulatory authorities to apply efficiency criteria of some kind in setting regulated tariffs for network infrastructure, under both price cap and total revenue forms of regulation. In the regulation of mobile telecoms operators' termination charges in the UK, for example, Ofcom calculates five-year price caps by allocating the fixed and common costs of *a hypothetical efficient network operator* over mobile retail and wholesale services.[20] The European Commission (in EC 2009a) recommends applying this approach to both mobile and fixed telecommunications networks. Similarly, Article 13 of the European Commission's regulation on conditions for access to gas transmission networks (EC 2009b) states that:

> *"In calculating tariffs for access to networks, it is important to take account of the actual costs incurred, insofar as such costs correspond to those of an efficient and structurally comparable network operator."*

Clearly, "*a hypothetical efficient network operator*" and "*an efficient and structurally comparable network operator*" are closely related concepts.

How these efficiency criteria are applied to the regulation of gas transport infrastructure varies across European countries. As explained in the Brattle Group report, in the UK Ofgem approves new capacity investments by the National Grid company only if the net present value of the contractual commitments sold to shippers in long-term capacity auctions exceeds 50% of the cost of the new capacity. Ofgem can (and has) used information from long-term auctions to decide that certain investments should not be guaranteed a return, because of the lack of supporting commitments from shippers.[21] In the United States, some regulators also apply a 50% rule, whereby the pipeline must have sold 50% of the capacity in advance before it is allowed to build the line and add the costs to the rate base. US energy infrastructure regulators have

because there are no gas-fired power plant connected to Progasur's system, so the load factors of its industrial and domestic users differ little from the average.

[20] See Ofcom 2007 (also Harbord and Pagnozzi, 2010). That is, Ofcom constructs a model of an efficiently-sized and configured mobile network given its demand forecasts, and uses the associated costs to set maximum wholesale charges for interconnection. It makes no attempt to reimburse mobile networks for their historical investment costs.

[21] For example, in the 2007 price control, Ofgem disallowed £17 million of capital expenditure undertaken by Transco at the St Fergus entry point, equivalent to 3.6% of the total allowed capital expenditure on entry points. The basis for Ofgem's decision was lack of demand for capacity in the long term entry capacity auctions.

traditionally applied a "used-and-useful" test for investments, which can prevent recoupment of the costs of assets which are no longer competitive, even if they were “prudent” when incurred.[22]

The CREG’s Utilization Factor is a similar efficiency criterion for pipeline cost recovery, and therefore lies within the mainstream of international regulatory practice. To impose no such efficiency criterion, as some TSOs have suggested, would place the CREG outside of the mainstream, and potentially create incentives for inefficient investment. Nevertheless, some legitimate questions concerning the precise application of the CREG’s utilization factor have been raised, and are worth addressing. [23]

First, utilization factors are calculated using a pipeline’s expected volume demand over a twenty year period. Hence it is possible that a pipeline with a large proportion of contracted capacity could still fail the UF’s 50% test, if shippers used their contracted-for capacity fairly little, or less than expected. If a TSO is able to find willing purchasers of pipeline capacity, however, there would appear to be no rationale for penalizing it if the pipeline is little used.[24] It has therefore been suggested that the utilization factors be calculated on the basis of some measure of capacity, as opposed to volume, demand. It is our understanding that the CREG is already considering this proposal and how it could be implemented.

Second, the utilization factors are calculated using expected demand volumes for twenty years, and re-evaluated each five years. This means that a pipeline investment which was undertaken on the basis of expected demand forecasts which resulted in a UF above 50%, can be penalized later if these forecasts are not realized. It has been suggested that the UF rule be applied only once, when investments are made, rather than re-evaluated at five-year intervals. In this way, if the regulator agrees that a pipeline investment appears to be economic initially, it will not "revisit" the issue in subsequent years when demand forecasts change.

In our view, this issue can be argued either way. Firms in competitive markets make (what appear to be) efficient investments on the basis of future demand forecasts, and suffer the consequences if these forecasts turn out to be optimistic. Nevertheless, since the CREG’s utilization factor rule operates asymmetrically, in the sense that it does not reward pipelines with higher revenues for achieving utilization factors above 50%, we are persuaded that there may be some merit to this suggestion, and that the CREG should give it consideration. This might apply particularly to pipelines or infrastructure developed under competitive conditions, e.g. awarded

[22] See McArthur (1998) for a discussion.

[23] We note, however, that the application of the utilization factor has rarely resulted in any TSO receiving reduced revenues, and that it does not appear so far to have jeopardized investments in network expansion.

[24] For example, it is theoretically possible that a pipeline segment is 100% contracted for by a gas-fired power station, but has a utilization factor based on shipped volumes below 50%. This could be the result of the power station being unable to find willing purchasers of interruptible pipeline contracts, for instance. Nevertheless, so long as the power station remains willing to pay for the installed pipeline capacity, there is little reason for the regulator to second-guess these market decisions.

by an auction (see Section 6.5).

6.4 Price Signals for Usage, Location and Investment

A number of features of the Colombian regulatory system give rise to concerns about the adequacy of the price signals it induces for both short-run usage and longer-run location decisions.

First, pipeline investment costs are recouped by the regulated charges over a 20 year period, and subsequent charges are set using a different (forward-looking) cost methodology. This may be overcompensating TSOs for their investment costs, and hence result in regulated average charges which are too high. The European Regulators' Group (2007) recommends that regulated tariffs for gas infrastructure be calculated based on the expected economic lifetime of the asset,[25] and that a depreciation method be used to keep tariffs constant in real terms over the life of the asset. Whatever view one takes of the relevant depreciation period, however, it is evident that the two different price caps applied by the CREG can't both give correct cost and location signals to pipeline users.

Secondly, as discussed above, the regulated capacity and commodity charges don't necessarily repay TSOs' investment costs, and some users with low load factors (such as gas-fired power plants) may be acquiring firm capacity rights too cheaply. They can also lead to different users paying different amounts to purchase the same firm capacity rights.

Third, for regulatory purposes the TGI system is valued at 70%-80% of its historic costs. This potentially results in average regulated prices which are too low, and may potentially encourage inefficient usage and location decisions.

Finally, average-cost based charges, by their nature, result in lower prices for pipelines with higher utilization factors. This makes uncongested pipelines more expensive than congested pipelines for users who, other things equal, will prefer to locate on more congested pipelines. But pipeline capacity should in principle be less expensive where it is in excess supply, and more expensive where it is not.

It is difficult to know if, on balance, the regulated charges under- or over-recover TSOs' investment costs. Nevertheless, it seems clear that the price signals induced by the regulated average charges probably provide inadequate incentives for efficient usage and location decisions. As observed in Section 5, this is a key issue for the gas-fired power stations in the interior of Colombia which are currently located far from any productive gas fields for historic reasons.

We have already suggested reforms to the capacity and commodity charges in Section 6.2 above. One proposal for inducing better regulated price signals generally, advocated by Alcogen (2009), is to introduce Ramsey pricing of some form. It is not clear that Ramsey prices would

[25] A lifetime of 40-60 years for pipeline-related assets is commonly assumed.

necessarily lead to better congestion and location signals, however, nor that they would be practical to implement.[26] A more practical (and well-tested) solution would be to introduce periodic auctions for pipeline capacity, similar perhaps to the entry capacity auctions currently used in the UK. The National Grid holds auctions for long-term firm capacity contracts and short-term (i.e. day ahead) firm and interruptible capacity rights.[27] Using auctions to allocate pipeline capacity in Colombia would ensure that shippers faced the "market-determined" opportunity cost of their usage decisions, provide better information for location and investment decisions, and introduce more openness and transparency to the market, as advocated by some users and by Poyry Energy Consulting (2009).

While auctions are probably the best means of providing both short-term and longer-term price signals, they would need to be made consistent with the current price-cap methodology, and with existing long-term contracts between TSOs and shippers. Numerous other issues would also need to be addressed prior to their introduction. For example: How should the auction revenues be treated for the purposes of regulating the maximum charges or revenues recoverable by the TSOs? (AOM charges?). What products should be offered, and how frequently should auctions be held? What is the best auction design and what reserve prices should be used? Etc.

Addressing these issues is beyond the scope of this report. We recommend, however, that consideration be given to using auction mechanisms in the future as a means or resolving most, if not all, of the price-signalling issues described above.

6.5 Vertical Integration Rules

7 Conclusions

In this study we have considered:

1. The regulatory price incentives required to ensure that investments in gas transport infrastructure in Colombia are made in a timely and efficient manner;

2. The appropriateness of adopting measures to reduce the financial risks placed on TSOs by the regulatory regime, especially the risk of stranded assets, even where TSOs faced these risks at the time investments were made; and

[26] The practical implementation issues are well known. Since Ramsey mark-ups are levied primarily on services or consumers with inelastic demands, they are not necessarily related to system usage or congestion. And, as pointed out by Laffont and Tirole (2000, Section 2.2), the mark-ups can sometimes fall more heavily on poorer consumers, with fewer alternatives to the service in question. Finally, it would seem to make little sense to apply Ramsey mark-ups to regulated firm capacity contracts only; interruptible contracts and contracts for unregulated users would need to be priced accordingly, adding new layers of regulation to the existing framework.

[27] Some of these auctions are described in the Brattle Group report. See also National Grid (2009).

3. The appropriateness of revising or relaxing the current controls on vertical integration in the gas industry.

Following consultations with the industry, the CREG and other government agencies in Bogota, we have concluded that the current regulatory regime in Colombia is working broadly as intended, and has led to no significant problems in the gas transport system. Although Colombia has adopted a more "decentralized" or "market-based" approach to gas transport regulation than that currently found in many European and North American markets, as evidenced by the Brattle Group report it is nevertheless within the mainstream of international best practice, where market mechanisms and private investments are increasingly being relied on to provide for new gas transport infrastructure.

In the preceding sections we have considered a number of proposals for the reform or improvement of the existing regulations in Colombia. We remain unconvinced by arguments for a major overhaul of the established regulatory framework, including the adoption of a reliability charge for gas transport infrastructure to reduce the risk of stranded investments, as explained in Section 6.1. A number of the more detailed proposals and suggestions for reform appear to have merit, however. Specifically, the calculation of commodity and capacity charges (discussed in Section 6.2); the operation of the Utilization Factor (Section 6.3); the need to provide better price signals for usage, location and investment decisions (Section 6.4); and some minor relaxation of the rules governing vertical integration (Section 6.5). We recommend that the CREG consider adopting these proposals, in some cases after a further period of detailed study and consultation has taken place.

The recent controversies in Colombia arose when demand from gas-fired power stations led to gas supply interruptions for some consumers on interruptible contracts. This ultimately led to intervention in the market by the Ministry of Mines and Energy, to reallocate gas supplies irrespective of prior contractual commitments. As we observed in Section 5, such supply interruptions occur even in archetypal "centralized planning" or "rate of return" type regulatory regimes, and are not specifically associated with the more "decentralized" Colombian regulatory system. Interruptible contracts can be extremely efficient, especially for consumers with alternative sources of energy.[28] But as the name implies, consumers on interruptible contracts must occasionally bear the costs of having their gas supplies interrupted. It will be important for the future operation of the Colombian gas market that the government allow the market mechanisms put in place to operate, so that market participants understand that it is their own market behavior, rather than political lobbying, that results in demands for new pipeline capacity being met.

[28] Such as some hospitals and industrial plant in the UK, and taxis in Colombia.

If the recent El Niño events have revealed there to be a shortage of gas transport capacity in Colombia, its proximate cause has been a failure of the market participants themselves to signal the need for system expansion via demands for long-term, firm capacity contracts. Gas-fired power plants in the interior of Colombia, for example, have not contracted for sufficient firm transport capacity to meet their own requirements, reducing the demand for firm contracts below what it otherwise would have been. Other companies have signed cheaper, interruptible contracts which they subsequently regretted. There have also been claims, however, that upstream gas producers may be withholding firm gas supply contracts from the market, making consumers less willing to contract for firm pipeline capacity. While we have seen no conclusive evidence for this, the concern has been repeatedly expressed. It is probably important that this issue be investigated, and further regulation of upstream gas supply be put in place if warranted.[29]

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[29] We have also been made aware of concerns that the market for unregulated, interruptible contracts may have been subject to manipulation, or abuse of market power, by TSOs and shippers. Again, we have seen no evidence of this, but recommend that the issue be investigated and appropriate regulatory controls be introduced if needed.

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