Designing and Structuring the Secondary Market, Short-term Markets and their Management Mechanisms

Task 6 Report

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Contents

1 INTRODUCTION

The Comisión de Regulación de Energía y Gas (CREG) has retained Market Analysis and *The Brattle Group* to advise on the design of secondary markets for the trading of gas and gas transport capacity in Colombia, and their management mechanisms. Our first substantive report addressed Tasks 2 and 3 of the project, introducing the relevant analytical framework and international experience.[1] Our second report, responding to Task 4, described different options for developing secondary and short-term markets for gas and transport capacity in Colombia. Our Task 4 report did not make specific recommendations, but rather defined objectives and criteria to assess the pros and cons of the alternatives identified. Following further consultations with the CREG and the industry, our Task 5 report described in greater detail the markets to be introduced and their management mechanisms.

In this Task 6 report, we describe the following issues in greater detail:

- The standard contracts – which contracts should be introduced, delivery points and trading windows;
- Issues surrounding the role of the market operator (MO), including incentives and payment;
- The details of the Market Maker role
- The Use-it-or-lose-it (UIOLI) rules, both short-term and long-term

2 BACKGROUND

There are currently no organized markets for secondary or short-term trading of gas or transport capacity in Colombia. Nor are there any organized methods for collecting and disseminating information on such trading activities, which occur on a private, bilateral basis. Nevertheless, a significant amount of secondary market trading does take place, mostly driven by the need for gas-fired power plants to resell gas and transport capacity purchased under firm contracts for the firm energy market. Approximately 45% of Colombia's available gas is purchased by power plants for the firm energy market and is available for resale. Some power companies sell most of their surplus gas in conditional firm contracts, while others sell only 10-15% this way, and the rest in shorter-term transactions.[2] One distribution company told us that it purchases up to 20% of its gas supply requirements in the secondary market from the gas-fired power plants.

There appears to be a clear demand for the creation of more organized markets or trading platforms for gas and transport from both producers and consumers in Colombia. Producers, for instance, have argued for need for more transparent information on market transactions and transport capacity availability, and for improved supply-transportation coordination. Other companies argue for organized and administered short-term and secondary markets, which exclude or limit the participation of the large producers. While there is currently no consensus on

1 "Designing and Structuring the Secondary Market, Short-Term Markets and Their Management Mechanisms, Task 2 & 3 Report," 17 February 2011, Market Analysis (David Harbord and Marco Pagnozzi) and The Brattle Group (Paul Carpenter, Dan Harris and David Robinson).

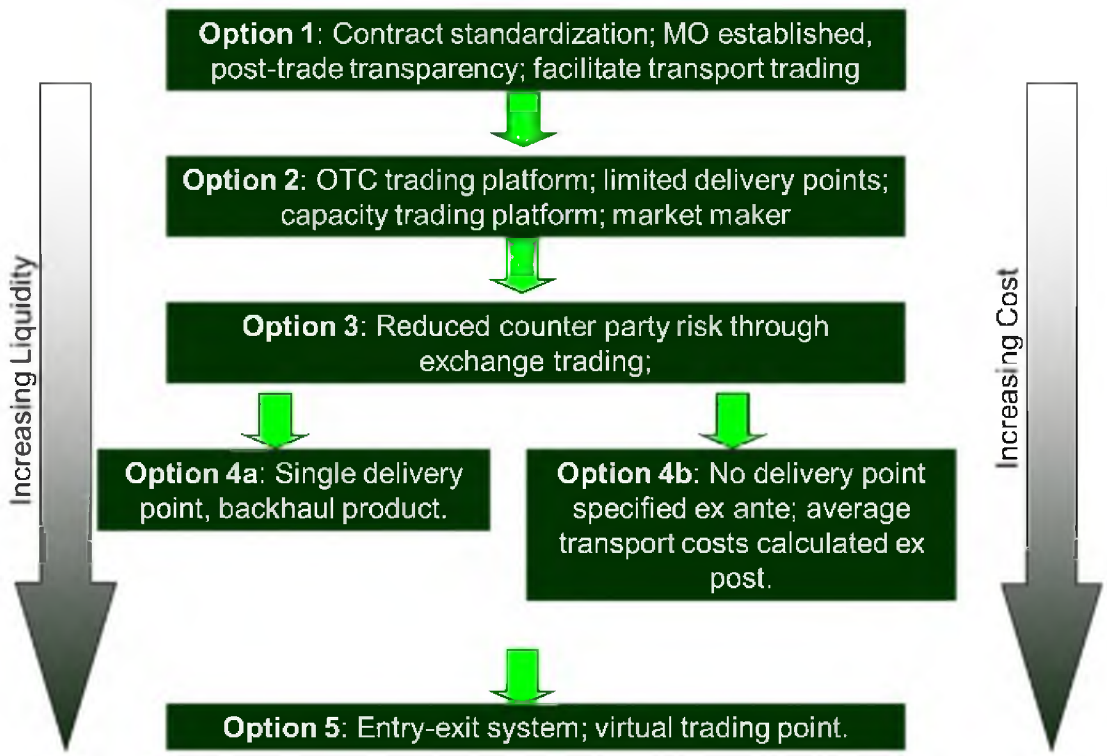
2 For example, Isagen has recently introduced daily "Subastagas" auctions for 24 hour firm gas and transport contracts.

the exact market reforms required, most if not all market participants in Colombia appear to believe that their trading opportunities will be improved by greater market transparency and organization of one type or another.

In our Task 4 report we identified a number of possible combinations of natural gas physical markets that might be developed in Colombia, presented as a number of 'nested' reform options, or policy packages, involving increasing degrees of regulatory intervention, organization and changes to the status quo. The reform options described were:

- Option 1: Gradual Market Evolution.
- Option 2: OTC Trading and Development of Trading Points
- Option 3: A Gas Exchange
- Option 4: A Single Trading Point or Physical "Hub"
- Option 5: Entry-Exit Charges and a Virtual Trading Point

The figure below summarizes the main options considered in order of increasing costs associated with the change, market liquidity and competitiveness. Option 1, for instance, introduces relatively few changes to the status quo, while Option 5 requires fairly radical changes to current regulations and market organization.



Following our consultations with the CREG and the industry a consensus emerged in favour of implementing Options 1and 2. Our Task 5 report is described in much greater detail the necessary changes and reforms to be adopted in implementing these options. We also recommended that the CREG set up an industry group to consider the desirability of implementing more comprehensive reforms, such as those described in Option 5, over a longer time horizon.

1.1 OPTIONS 1 AND 2: SUMMARY

Option 2 contains a number of elements, including all of the features of Option 1, which we briefly summarize here.

A Standardization of contracts and delivery points

Gas supply and transport contracts in secondary and short-term markets would be standardized to make bilateral trading more practical and allow fast, low-cost bilateral trades to take place. By standardized contracts, we mean:

- the basic terms and conditions of all contracts would be identical[3]
- a menu of standard contract durations and start dates
- the delivery points of the contracts will be partially standardized, so that all secondary gas contracts would specify delivery at one of three or four locations where most gas is already traded

Contracts for a given standard duration and start date would therefore only need to specify the counter parties, the price, the quantity and one of the standardized delivery points.

B Establishment of a Market Operator (MO)

An MO will be established whose role is to:

- Develop more liquid and transparent OTC trading by creating trading platforms or "bulletin boards" where:
  - Traders can make bids and offers for the standardized gas and transport products;
  - The TSOs post information on available primary capacity and offer to sell primary transport capacity at regulated prices; and
  - Un-nominated gas and transport capacity be offered to the market on a daily basis by the MO, possibly by holding a simultaneous one-hour auction at the end of the nomination period ('use if or lose it' rules)
- Collect and publish aggregated information on the prices and volumes of traded gas contracts, as well as collecting data on primary gas contracts and primary and secondary transport contracts.
- Monitor the market for signs of market abuse.
- Manage the Use-it-or-lose-it process.

C Establishment of a market maker

Liquidity is to be stimulated on the OTC gas trading platform by creating a market maker and/or by mandating the sale of specific volumes of gas, e.g. 'royalty' gas, on the OTC platform. The bid-ask spread of the market maker could be capped to provide strong incentives for market maker to attempt to "bracket" the "real" market price, or determined by a competitive tendering process. The role of the market maker is to support trading in the main standardized gas contract categories.

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3 As determined by the results of the companion study on standardizing contracts by Auctionomics and FTI Consulting.

D Market power and related issues

- Voluntary trading: An important issue is whether secondary trading on the OTC trading platforms should be voluntary or mandatory. If the OTC market is well-designed, it will be attractive to market participants, so mandatory participation may be neither necessary nor desirable. We recommended that participation in the OTC trading platform be voluntary.
- Limitations on producers: Market participants have expressed concern about producers' participation in secondary markets. One concern is that producers will offer less gas in the primary auctions in order to sell it under long-term contracts in secondary markets. Producers have legitimate reasons for trading in secondary markets, for example to replace lost production. We recommended that large or dominant producers be limited to trading in shorter-term products in secondary markets.
- Transport capacity release: Numerous concerns were raised about the availability of gas transport capacity, and the potential for this to become a bottleneck for both primary and secondary market trade in gas. Short-term and longer-term "use it or lose it" rules are proposed for transport capacity to ensure that gas trading is not limited in this way.

2.2 TERMS USED

Throughout this project we have referred to the 'secondary gas market' in Colombia, meaning a market where buyers and sellers trade standardised gas contracts. During our consultations some parties noted that this term was confusing and misleading, since gas producers would be able to sell their gas directly in the form of standardised contracts, and these are primary not secondary trades. Similarly, pipelines will offer primary capacity via the capacity trading platform. Nor can the market be defined as a 'short-term' market, since some of the gas contracts could have duration of a year and transport contracts even longer.

Nevertheless, for consistency we will continue to use the term 'secondary market', while noting that this does not preclude producers or pipelines selling gas or pipeline capacity using the trading platforms that we describe. This definition is consistent with markets in other jurisdictions, where for example producers are free to sell their gas directly on a trading platform or exchange.

3 STANDARDIZED CONTRACTS AND LOCATION OF THE TRADING POINTS

As described in our previous reports, the gas supply and transport contracts should be standardized to make OTC trading more practical and allow fast, low-cost bilateral trades to take place. The OTC contracts should include:

- A within-day gas and transport product
- Daily, weekly and monthly products
- Longer-term quarterly, annual and multi-year contracts

The standardized gas products should be for Firm, Interruptible and Conditional Firm and Options contracts as recommended by the related consultancy for physical delivery of the gas, rather than contracts that are financially settled (financial contracts). Financial contracts are not practical in the early stages of the market because they require an underlying liquid physical market against which they can be valued.

Within-day products: Within-day contracts should follow the daily renomination cycle and be for constant amounts of gas to be delivered hourly over the remaining gas day. For example, a within-day product traded at 00:00 at the beginning of the gas day could be for 100 MBTUs of gas to be delivered at a constant hourly rate from 06:00 until 00:00, *i.e.* an 18 hour contract. Similarly, a contract agreed at 06:00 could specify 100 MBTUs to be delivered at a constant hourly rate from 00:00 until 12:00, *i.e.* an 12 hour contract, and so on.

Daily products: Daily, or day-ahead, products are 24 hour contracts for the following gas day. They should be traded by 14:00 on the previous gas day. For example, a day-ahead product traded by 14:00 on Tuesday could be for 100 MBTUs of gas to be delivered at a constant hourly rate from 00:00 on Wednesday until 00:00 on Thursday and covers 24 hours. Note that this trading schedule leaves some time between the final trade taking place (14:00) and the deadline for nominations to gas producers (15:30). This is so that there is time for trades to be confirmed and sent to the MO (discussed below), and any mistakes to be corrected before nominations take place. However, the period between close of trade and the nomination deadline could be shortened over time as the MO and the market participants gain more experience.

Weekly products: Weekly products are seven-day contracts all of which specify a constant rate of delivery from 00:00 on Monday until 00:00 the following Sunday. Such contracts must be traded prior to 14:00 on Sunday for delivery beginning 10 hours later.

Monthly products: Monthly products specify a constant rate of delivery from 00:00 on the first day of the relevant month until 00:00 on the day after the last day of the relevant month. Such contracts must be traded prior to 14:00 on last day of the preceding month for delivery beginning 10 hours later.

Quarterly products: Quarterly products specify a constant rate of delivery from 00:00 on the first day of the relevant month until 00:00 AM on the day after the last day of the relevant month. Quarters will run from December to February inclusive, March to May inclusive, June to August inclusive and September to November inclusive. Such contracts must be traded prior to 14:00 on last day of the month preceding the first month of delivery for delivery beginning 10 hours later.

Annual products: Annual products specify a constant rate of delivery from 00:00 on the 1st January of the relevant year until 00:00 on 1st January of the following year. Multi-year contracts are defined analogously. Such contracts must be traded prior to 14:00 on last day of the preceding year (e.g. 31st December) for delivery beginning 10 hours later.

At least at the beginning of the market's development, sellers in secondary markets should be required to hold primary gas or transport contracts to cover their positions. That is, there would be no short selling. We recognize that short selling can be a legitimate speculative exercise – for example a market participant may wish to sell gas month ahead that it does not have in the hope that it will be apply to meet its obligation by buying, for example, cheaper day-ahead gas. However, clearly such a strategy is risky, and raises the risk of financial distress and default if the bet on lower prices is wrong. Such episodes could be damaging to confidence in a young market, and so we recommend ban on short selling at least for the first few years of the market's development.

Experience in international markets suggests that short-term products tend to be more popular initially, because these products require less collateral and involve less counter- party risk. For example, if party A sells gas to party B under a one year contract at a fixed price, there is ample time for prices to move significantly and the volumes of gas involved are usually large because of the time period involved. This means that while longer term products could be offered, initial trading is likely to involve short-term products.

3.1 LOCATION OF THE TRADING POINTS

The delivery points of the contracts will be partially standardized, so that all secondary gas contracts would specify delivery at a limited number of locations. Following our recent consultations with the industry consultation, we recommend trading points at Ballena, Cusiana, La Creciente, and Barrancabermeja. Absent a physical connection, Ballena contains two delivery points, one for the TGI system and another for the Promigas system.

4 THE MARKET OPERATOR

Parallel to the preparation of this Task 6 report, we have also prepared a 'Request for Proposal' (RFP) document for the MO. The RFP MO is aimed at parties that might want to submit an offer to become of the MO. In this section we provide a commentary on some aspects of the MO RFP and the MO functions.

4.1 INCENTIVES FOR THE MO

Clearly the MO needs incentives to perform its duties effectively and to give a high quality of service. Many regulated entities, in particular networks, are given incentives via an 'RPI-X' regime, in which the firm's revenues change (usually decrease) at a given rate relatively to inflation over the price control period. If the firm can reduce costs faster than its revenues decline, then it is able to keep the savings. This gives strong incentives for the firm to reduce costs.

However, to implement a RPI-X price control the regulator must first make a forecast of costs and allowed revenues. In the case of the Colombian MO such a forecast is not possible, since we do not know how much the MO will cost to establish and operate.

Similarly, one could imagine Key Performance Indicators (KPIs) for the MO, based on factors such as availability of the system, time taken to publish data or register platform users. We could set financial incentives around these KPIs based on exceeding or underperforming against certain targets. However, the difficultly is in deciding what target is reasonable, and what level of fine or reward is appropriate. Moreover, the risk is MO duties that are important but hard to measure via a KPI could be neglected so that the MO exceeds at the financially incentivised tasks.

Accordingly, we have opted for three broader classes of incentives for the MO:

1. Probably the most important incentive is that the MO's term is limited, but the MO is an advantageous position to be re-appointed at the end of the term. This gives the CREG a powerful 'lever' with which to incentivise generally high levels of performance from the MO across a broad range of areas, since the MO would prefer to be re-appointed without competition at the end of the its term. The period of the contract needs to be long enough

that the MO has time to establish its operations, but short enough that the prospect of being dismissed at the end of the term provides a strong incentive for good performance from the beginning of the contract. We think that four years provides the right balance for these objectives.

2. The MO will share the costs of any cost overruns. This gives the MO an incentive both to provide a realistic initial bid for the costs, and to manage the business so as to maintain fixed costs within the annual allowance.
3. The MO will face some financial penalties for certain KPIs. For example the MO will face a reduction in its annual fixed fee if it brings the trading platforms into operation later than promised. We are also asking bidders to specify the amount of time that the platforms will be unavailable, and there are financial bonuses and penalties associated with the over or underperforming against the target levels.

4.2 Payment of the MO

Who will pay for the MO function, and how? Broadly speaking we see two options:

1. Users of the trading platforms pay;
2. The costs are somehow socialised among all market participants.

We see a number of significant disadvantages with option 1. Most importantly, the MO will have a high proportion of fixed costs. If its payment depends on the volume of trading or number of users that trade on the trading platform, there is either a risk of very high fees per market participant – which would put people off using the platforms – or a revenue shortfall for the MO. A second disadvantage for option 1 is that the MO would be exposed to the credit risk of market participants – in other words that users are not able to pay, or that they are late in paying fees and the MO must pursue payment. For an MO that is not familiar with the Colombian market and legal system, relying on payment from multiple counter parties of unknown credit quality could represent a large risk. The MO might respond by insisting on a high level of credit quality before market participants could use the trading platform, and/or large upfront payment of fees, which may preclude some potential traders. This would harm liquidity which would be undesirable. The MO would also require a higher level of working capital to account for late payments, which would increase its costs.

In contrast, there are good reasons why the costs of the MO should be spread or socialised among all gas market participants. First, two of the main functions the MO performs – being market monitoring and publication of prices and volume data – benefit *all* market participants regardless of whether they are actively trading gas or not. The presence of trusted, publically available prices allows parties to negotiate a fair price for their gas from producers, and eventually to index their price to the prices published by the MO, even if they are not active in the secondary market. In this sense the prices that the MO generates are a 'public good'. Most importantly, an accurate price which indicates the value of gas at any point in time enables efficient allocation and production decisions – for example whether to use gas to generate power or another fuel – at any point in time. Similarly, the parties that are actively trading gas and capacity on the platforms are generating this public good by their trading activity. Making the users of the platform pay for the MO's costs – in effect 'taxing trading' – will provide a strong disincentive to use the trading platforms, and reduce market liquidity to the dis-benefit of all gas users.

One could respond to the disadvantages of option 1 by simply making use of the trading platforms mandatory, and this is indeed the direction that the CREG prefers. We discuss this issue in more detail in the following section. Mandatory use of the trading platform would broaden the number of users that have to bear the MO's costs. But charging the MO's costs directly according to use of the trading platform would still reduce the number of secondary trades, since market participants could avoid paying a share of MO's costs by avoiding or minimising secondary trading. Allocating all the MO costs to parties using the trading platforms would also dissuade players from entering the market purely to carry out trading for profit in the secondary gas market, which would reduce liquidity.

Accordingly, our preferred option would be to collect the MO's costs from a surcharge on either pipeline capacity or primary production. The advantage of this is that a) all users of the gas system that benefit from the price data and market integrity also pay for the MO, roughly in proportion to their use of the system b) payment of the MO's costs are not dependent on trading activity, so there is no financial disincentive to trade gas. Further, the risk to the MO is minimised since its cost recovery is not dependent on trading volumes.

Moreover, both the pipelines and the producers have an established billing relationship with market participants, and so arranging payment of the MO's costs in this way should be relatively simple.

The pipelines or the producers would collect the MO surcharge and pay this to the MO. The advantage is that the MO then only has to deal financial with a smaller number of counter parties (the pipeline or the producers, of which there are around 8-9). This is preferable to collecting the fees from around 40-50 market participants directly. The pipeline or producers would be responsible for collecting payments from the participants, and would be required to pay the MO regardless of whether they had in turn been paid by the market participants, thereby covering any temporary shortfall between the MO's fees and payments by market participants.

Acting in effect as guarantors for the MO's fees would impose an additional risk on either producers or the pipelines. However, we expect that this incremental risk would be relatively minor. Both producers and pipelines are already exposed to the credit risk of the market participants, and we expect the additional amount of money that would need to be collected to pay for the MO to be relatively minor compared to both transport costs and the price of the gas sold in primary contracts.[4] However this role could create costs both in terms of debt collection and eventually some debts may be written off. For the pipelines, these costs could be passed through as a legitimate operating expense that should be allowed for in the price control. For producers there is no obvious way in which they could recover these costs, although they would presumably be tax deductible. In this sense the pipelines would be a better agent for collecting the MO's fees than the gas producers.

The arrangements above – where the MO has a limited number of counterparties that guarantee its payments – will make the MO role more attractive to potential bidders who are unfamiliar with the Colombian investment environment and legal system. By avoiding a 'tax on trading' and

[4] For example, assuming daily gas consumption of 900 GBtu, or about 330,000 GBtu per year, and supposing that the MO's costs were $4million per year, the MO's fees would amount to an average additional cost of $0.012/MMBtu.

making use of the trading platforms free they would also maximise the chances of developing a liquid secondary market.

The arrangements described above are consistent with practice in other jurisdictions, or where they differ there are good reasons to do so. For example, market monitoring is, in the EU and US gas markets, performed by the energy regulator, which is in turn paid for either by general taxation or from surcharges on electricity and gas system users. In US electricity markets, the market monitor is a private party appointed by competitive tender. But all system users pay for the costs of the market monitor, regardless of whether they trade or not.

Pricing information is usually made available by private parties and can be obtained by paying a subscription fee. These services have been developed by the market over time. However, in this case the CREG wishes to accelerate the process of price transparency, and so it seems reasonable to socialise the costs. Moreover, it is highly likely that all market participants would in any case which to buy such data – but our proposed system makes sure the costs fall on the same group of people but that the payment risk and costs of collecting payment for the MO is minimised. Finally, trading platforms would usually be self-financing, in that the users pay for them. But as we discuss above in Colombia there are good reasons to justify the socialisation of the trading platform, because doing so creates prices that are useful to all market participants. The Brattle Group has recommended socialising the costs of exchanges and trading platforms in new, illiquid EU markets, for the same reasons as given above.

4.3 INFORMATION REPORTING AND VERIFICATION

In the MO RFP we have specified that the details of all the trades should be reported to the MO within a certain time period. The purpose of this is twofold. First, so that the MO can verify that the pricing information supplied is accurate and consistent with the signed contracts. Second, so that the MO can monitor each market player's position in the market for the purpose of market monitoring.

An alternative would have been for each market party to simply report each day the average value of its trades, and for the MO to carry out 'spot checks' or audits to check that the reported prices match the underlying trades. This would reduce the volume of information and data that has to be transmitted from the market parties to the MO. However, we see two main disadvantages with this approach. First, it could take some significant period of time to discover discrepancies between reported market prices and actual trades. This could undermine confidence in market prices. Second, the MO needs details of each market parties trading position so that it can effectively carry out its market monitoring role.

Moreover, the greater availability of trading information to regulators and authorities is consistent with the latest legislative developments in EU gas markets. Specifically, the Regulation on Energy Markets Integrity and Transparency (REMIT) states that market participants must report the precise identification of the wholesale energy products bought and sold, the price and quantity agreed, the dates and times of execution, the parties to the transaction and the beneficiaries of the transaction and any other relevant information. Market participants must also report information related to the capacity and utilisation of facilities for production, storage, consumption or transmission of electricity or natural gas or related to the capacity and utilisation of LNG facilities, including planned or unplanned unavailability of these facilities.[5] The purpose of reporting this information is to enable effective market monitoring. These are essentially the same types of information that we recommend by made available to the MO to assist in its market monitoring role.

4.4 MANDATORY OR VOLUNTARY PARTICIPATION

In section 6.1 of our task 5 report, we discussed the advantages and disadvantages of making secondary trading using the OTC trading platform, as well as the associated platform for trading transport capacity, mandatory. Mandatory trading would mean that it would not be possible to conclude bilateral deals outside of the trading platform, so for example the Subastagas auctions, or any other bilateral selling arrangement outside of the trading platform, would no longer be permitted.

It is important to stress that regardless of whether use of the trading platforms is voluntary or mandatory, trading data would still be reported to the MO. Accordingly, it would make no difference to the MO's ability to monitor the market. However, mandatory trading would make the market more transparent, since all gas for sale or bids to by gas would be visible to all market participants.

The case for voluntary participation is that there seemed to be no compelling need to restrict alternative forms of gas transaction – be they bilateral of platform deals or auctions. The ability of market participants to transact off the platform would encourage the MO to make the platform service as attractive as possible. On balance, we recommended that the use of the trading platforms should be voluntary.

Since our Task 5 report the CREG has concluded that it would be advantageous for the market to be mandatory. This requirement relates partly to an issue that we had not considered in our task 5 report, which is that allocating the MO's costs to all market participants – as discussed above – would be less open to challenge if all the market participants were required to use the trading platforms. Given that the original recommendation for voluntary participation was finely balanced, we agree that the CREG's preference for mandatory use of the trading platforms seems reasonable.

4.5 VIABLE CANDIDATES FOR THE MO ROLE

In section of our Task 2&3 report,

5 THE MARKET MAKER

Section 5 of our task 5 report described the role of the market maker. The report indicated some alternatives for the way in which the market maker is appointed. The CREG could simply appoint Ecopetrol in the role or appoint the market maker by a tender process.

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5 For details see European Parliament Report on the proposal for a regulation of the European Parliament and of the Council on energy market integrity and transparency A7-0273/2011 Committee on Industry, Research and Energy, 15.7.2011, Article 7.

In this report we make some further comments and refinements based on comments received during industry consultation.

5.1 QUESTIONS REGARDING THE MARKET MAKER'S ROLE

Several parties have expressed concern with Ecopetrol acting in the market maker role. Presumably the concern is with the dominant party having a prominent role in the secondary market. However, it should be noted that the differences between the market maker's buy and sell offers (the spread) will be fixed, either by the CREG or by a competitive process. Therefore it would not be possible for the market maker to, for example, demand a very high price to sell gas, because it would also be obliged to buy gas at a similarly high price. Fixing the spread will compel the market maker to offer to buy and sell gas at close to the true market value of gas at any point in time. As we described in our Task 5 report, in other markets the incumbent firm has been given the role of market maker with a regulated or fixed price spread. No issues of market abuse were reported, and indeed the participation of the incumbent firm in a market is generally accepted to be important to build liquidity.

Another issue that was raised is whether the market maker should only be introduced if it seems to be required, for example if liquidity is low. Our view is that it is important that the secondary market gets the best start possible, since it could be damaging to the success of the secondary market if there is a prolonged period of illiquidity at the beginning. The market maker role is a low cost policy option that could significantly boost liquidity, especially in the early days of the new secondary market. There is little or no cost in introducing the market maker function – indeed in other markets agents perform this role voluntarily as a profit making function. Therefore there seem to be no advantages and clear disadvantages in delaying the introduction of the market maker role.

5.2 CONTRACTS FOR WHICH MARKET MAKING WILL OCCUR, SPREADS AND VOLUMES

We recommend that, to simplify the introduction of the market maker role, the market maker initially offers to buy and sell only the day-ahead gas product, at each of the delivery locations.

Based on international experience and the likely size of daily trading in the Colombian gas market, we recommend that the market maker should have present on the OTC trading platform offers to sell and bids to buy day-ahead 1 Gbtu of gas at each delivery point/location. The market maker would have to make standing bids and offers – that is bids and offers should always be there. As soon as a market participant has taken up one of the market maker's offers to buy or sell gas, the market maker would post a new bid or offer on the trading platform.

The market maker will both buy and sell gas. However, so as to enable the market maker to manage its gas supply needs, we recommend that the market maker has a daily limit on the volume of gas that it is required to sell. Specifically, when the net gas volume sold, that is, gas sold less gas bought by the market maker, over all locations has reached a cumulative volume of 100 Gbtu within the gas day, then the market maker is no longer required to make bids and offers on the trading platform for the reminder of that gas day. So assuming five trading points (counting Ballena East and Ballena West separately), this would mean that the market maker makes 20 trades of 1 GBtu each at each trading point during the day. The minimum number of trades would be 100, spread over all trading points. In reality we expect some trading points to be more popular than others, and the market maker will also be buying gas which will enable it to make more than the minimum number of trades described above. The CREG should modify the market maker's parameters – for example the size of the market maker's 'standing' bids and offers – depending on experience and market needs.

In our task 5 report we recommended that the market maker be appointed by a competitive process, and the role could be awarded based largely on the bid-offer spreads the market maker is prepared to accept. We also noted that it would be wise for the CREG to set a maximum bid-offer spread in this process, to cater for the event that there is insufficient competition to result in an acceptable bid-offer spread. Based on trading in US and EU markets a reasonable maximum bid-offer spread for the market maker would be 0.15 \$/MMbtu.

6 THE SHORT-TERM USE-IT-OR-LOSE-IT PROCESS

In our task 5 report we identified the need for both short term and long term use it or lose it rules (UIOLI). In section 6.3.1 of our task 5 report we explained that there should be a short-term UIOLI process both for gas transport and for gas (commodity). In this report we describe the proposed rules in more detail and describe some of the main issues.

6.1 GAS UIOLI PROCESS

Any gas that is available under a primary contract but not nominated for production by 15:30 on the day before delivery (D-1) would 'roll into' the UIOLI process. At 15:30 producers would inform the MO of unnominated gas volumes, the delivery points for that gas and the buyer of the gas under the primary contract (hereafter the 'primary buyer'). The MO would then auction the unnominated gas volumes between 17:00 and 18:00 on D-1. The MO would hold a separate auction for each delivery point. Since the auction needs to be completed within a specified time period, a single-round sealed bid auction would be the most appropriate. All persons qualified to use the trading platforms would qualify to participate in the UIOLI processes. Since the gas is lost if it is not nominated, there would be no reserve price for the sale of UIOLI gas – on the basis that any revenue would be better than none for the primary buyer.

Ideally, we would prefer the primary buyers to actively sell any unnominated gas themselves, rather than rely on the MO to sell this gas for them via the UIOLI process. At the same time, it would be disproportional to encourage this behaviour by denying the primary buyers any revenue from the gas sold in the UIOLI process. Therefore, we propose that the primary buyers receive the money from UIOLI volumes sold, less a handling fee that the MO retains. The handling fee would be set equal to the spread of the market maker, discussed above. The MO would use this revenue to partially cover its costs.

In terms of cash flows, the MO would receive the money for the gas sold in the UIOLI auction. The MO would then pass on the money for the gas sold to the relevant primary buyers, less the handling fee. The contract for the gas sale would be between the primary buyer and the buyer in the UIOLI process – the primary buyer would be deemed to have entered into the contract by virtue of not nominating the gas for production before the UIOLI deadline of 15:30 on D-1.

At 18:30 D-1 the MO would notify the relevant producers of the volumes of gas sold under the UIOLI auction, and the primary buyers whose gas had been sold. The gas producers would increase their planned production accordingly and notify the primary gas buyers of the final production levels by 19:00 D-1. The MO would also notify the parties that have bought gas in the UIOLI process that they were successful, and who their counterparties are – that is, which primary buyers they are actually buying gas from and how much by 18:30 D-1.[6] UIOLI gas would be delivered in a flat or constant hourly profile.

We understand that in Colombia, it is possible for shippers to re-nominate both gas supply and transport capacity four times during the gas day, and that the re-nominations become effective 6 hours after the re-nomination is made. Therefore the MO would organise four within-day UIOLI auctions for gas that has become available as a result of downward nominations for primary gas contracts (note that upward nominations would not be possible, since any gas not nominated would already have been sold in the UIOLI gas auction). The gas would be sold in the form of a standard within-day gas contract, and the process would be similar to that described above for the day-ahead UIOLI process.

6.2 GAS TRANSPORT CAPACITY UIOLI PROCESS

In the short-term capacity UIOLI process, transport capacity that has been bought by a party (hereafter the 'primary shipper') but is then unnominated will be made available in the UIOLI process. We discuss the issue of whether capacity that has not been sold by the pipeline should also fall into the UIOLI process below.

At 16:30 the pipelines would inform the MO of unnominated primary transport capacity. They would specify the primary shipper, the route, and the average daily capacity.

Between 17:00 and 18:00 the MO would auction the UIOLI capacity products. Capacity products would be differentiated by route (pipeline segments) – that is capacity products with a different route would be auctioned as a separate product. The MO would also differentiate UIOLI capacity held by power stations (see discussion below). The MO would aggregate any products that had the same route, but again differentiating capacity held by power stations. Participants would bid for each product, or a fraction of each product in a sealed bid auction. Participants would bid for the capacity, and there would be no reserve price. The winning bidders would accept the commitment to pay for the associated variable fee (i.e. commodity charge).

By 18:30 D-1 the MO would confirm the results of the UIOLI capacity auction. Buyers of UIOLI capacity would then have until 18:50 to submit a nomination schedule for their UIOLI capacity. Note that while our proposal is consistent with the existing nomination schedule, it is possible that introduction of the UIOLI capacity auction may require a change in the existing scheduling process. This should be determined by CNO-Gas.

As described for the gas UIOLI process, the MO would organise four within-day UIOLI auctions for transport capacity that has become available as a result of downward nominations for primary transport contracts (note that upward nominations would not be possible, since any transport capacity not nominated would already have been sold in the day-ahead UIOLI auction).

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6 Since there is a single price for each UIOLI product at each location nothing differentiates the UIOLI product sold by each primary buyer. Accordingly the MO can match buyers and sellers using any process. For example the MO could rank primary buyers and UIOLI buyers by volumes of UIOLI gas bought and sold, and match counterparties in the order of the list.

Ideally, we would prefer it if the system of payments for the transport capacity auction would differ somewhat than the system for the UIOLI process for gas, described above, in that primary capacity holders would not receive any money directly for UIOLI capacity sold on their behalf by the MO. In essence ownership of the unnominated capacity would revert back to the pipeline. There are two reasons for preferring this difference with the gas UIOLI process. First, the buyer of the capacity in the UIOLI process would be responsible for paying the variable fee, and it would be most efficient if this was paid directly to the pipeline, rather than passing through the primary shipper. Second, the exercise of market power in gas transport is more of a concern than the exercise of market power by primary buyers in the gas market. While the upstream market is concentrated, there are many buyers, and so the risk of a primary buyer withholding gas supplies seems small. In contrast, each pipeline route in effect defines a market, and the risk of withholding transport capacity on a given route is a higher risk. Accordingly, we prefer to give stronger incentives for primary shippers to sell unused capacity before the start of the UIOLI process. Depriving primary shippers of the revenues from UIOLI capacity sales provides such an incentive.

Under this scheme, the contract for gas transport would be between the pipeline and the buyer of the UIOLI transport capacity. Any proceeds from the auction would be paid to the pipeline providing the capacity directly.

As described, the scheme would result in the pipeline's getting paid twice for the same capacity – since they would continue to receive the fixed capacity fee from the primary shipper for the capacity that went into the UIOLI process, as well as the capacity fees raised from selling the capacity in the UIOLI auction. To prevent this, we propose that the pipeline would use the UIOLI capacity fees to reduce primary shippers' fees on the pipeline – in other words, the pipeline would re-cycle the UIOLI revenues back to all of its customers – not only the customer that lost the capacity in the UIOLI process – in the form of lower capacity fees. This would again give strong incentives for primary shippers to sell their unnominated capacity ahead of the UIOLI process, since they get to keep any revenue received but also benefit from the re-cycled UIOLI capacity revenues from shippers that did not sell their capacity in time.

However, we understand that in practical terms the refund mechanism we describe above is not possible within the current price control period. Without the refund mechanism the system we describe above would simply allow the pipeline to sell the capacity twice, which is not desirable.

Given these constraints our preferred UIOLI scheme is as described above, except that the MO would keep the capacity fees raised in the auction as a contribution to its costs. This would avoid a windfall for the pipelines, while maintaining strong incentives for primary capacity holders to sell unnominated capacity before the nomination deadline passes. Since all parties pay for the MO, then all parties benefit from the reduction in the share of the MO's costs they must pay because of the contribution of the UIOLI capacity revenues. Again, the transport contract would be between the pipeline and the buyer of the UIOLI capacity.

Under both systems, the pipeline would keep the variable fees. However, these would not be the variable fees specified in the original transportation contract. Rather, the CREG would calculate a common variable UIOLI fee for capacity sold in the UIOLI auction for each route, which is designed to cover the average variable costs of transporting gas on that route.

The advantages of a common variable fee are two-fold – it would prevent pipelines retaining UIOLI capacity revenues that are in excess of their variable costs. Second, it would reduce the number of UIOLI capacity products to be auctioned, which could increase liquidity in the UIOLI auctions and simplify them.

We recognise that setting a uniform and relatively low variable cost may disadvantage pipelines that have a higher variable charge. This is because, for capacity sold in the UIOILI process, they will only collect the fixed charge from the primary capacity holder, but will not collect the original variable charge required to fully cover the pipelines capital costs. However, mitigating this we expect the amount of capacity to be sold via the UIOLI process to be relatively small, since there are good incentives for the pipelines to sell their unwanted capacity in the secondary market before the capacity enters the UIOLI process. Second, we understand that the CREG is in the process of reducing the proportion of costs recovered via variable fees, and this should mitigate the cost-recovery effect over time.

6.3 FIRM AND INTERRUPTIBLE UIOLI CAPACITY

Most UIOLI capacity sold would be firm. That is, primary shippers would not be able to 'claim back' UIOLI capacity by increasing their nominations during the gas day. In many markets, UIOLI capacity is not firm, and the primary shipper is able to displace UIOLI nominations during the gas day (see for example Appendix II, which describes US UIOLI process and the way in which firm capacity can 'bump' or interrupt UIOLI capacity).

The reason for making UIOLI capacity interruptible in other jurisdictions is either that UIOLI capacity is given away for nothing, and so holders cannot complain if they are interrupted, and/or that there is a chance that the primary shipper might somehow 'discover' more gas it wants to ship, and may not be able to do so if it has lost the capacity to the UIOLI process. However, in the case of the Colombian gas market users will be paying for UIOLI capacity, or at least may do so if demand exceeds supply in the auction. Because of the UIOLI process for gas, it will not be possible for primary shippers to nominate more gas from producers on the day. On the contrary, the assumption is that buyers of UIOLI transport capacity will simultaneously buy gas, and so will have gas to ship.

However, power stations that we have spoken to have expressed concerns that, if they were to lose unnominated capacity, this would compromise their ability to respond to changing circumstances in the electricity market during the day, and could even compromise their ability to earn reliability payments.

We recognise that this is an issue for power stations in Colombia. Two factors exacerbate the situation for power stations with respect to short-term UIOLI rules. First, all users are required to submit an hourly program for use of transport capacity. In contrast, in most markets in the US and the EU, users submit a daily program only. So in most other markets the power station would not have to account for possible hourly variations, and could simply nominate the required average transport capacity over the day, while varying off-take within the day. Second, the point-to-point nature of the transport contracts makes it more difficult to adjust gas positions within the day than in an entry-exit capacity system. In the latter, the UIOLI rules in effect apply only to entry points. The power stations would usually be the only potential user of its exit capacity, and so it would never lose this capacity even in a UIOLI process. If the power station needed more gas, it could simply buy it at the virtual trading point, and need not worry about buying transport capacity (other than the exit capacity it already holds). In contrast in the Colombian system, if the power station found it needed to buy more gas during the day, as well as buying the gas commodity it would also need to buy transportation capacity. In all likelihood, the additional gas would come from the power stations primary supplier, and so the power station needs to reserve transport capacity to the primary supply point.

At the same time, there are circumstances where power stations do not run, transport capacity goes unused, but the power station is unwilling to re-sell the capacity for the reasons given above. This is inefficient. Therefore, we propose that transport capacity associated with power stations would be part of the UIOLI process, but that the capacity would be deemed interruptible. This means that at any of the renomination cycles during the gas day, the power stations could in effect take back the capacity sold to nominate gas, displacing the nominations of the interruptible shippers. However, in the US in the last nomination cycle on the gas day the primary capacity holder cannot displace interruptible shippers. Under our proposal, the power stations could displace interruptible shippers at every nomination cycle.

6.4 CAPACITY TO BE MADE AVAILABLE IN THE UIOLI PROCESS

During the course of our discussions with shippers and pipelines the question arose as to whether capacity that is unsold by the pipeline should also fall into the UIOLI process.

In other jurisdictions, only capacity that has been sold by the pipeline but not nominated would fall into the UIOLI process. The logic is that if a party was trying to hoard its unused primary transport capacity, then other third parties would first overcome this behaviour by buying the remaining primary capacity from the pipeline. Only when all the primary capacity has been sold would a party have the possibility to choke supply by withholding transport capacity.

However, in the case of Colombia there is a complication, since we understand that transport capacity has to be bought under longer-term contracts. For example, a situation could arise where a party withholds its unused primary capacity, but third parties are reluctant to overcome this hoarding by committing to an e.g. 10-year capacity contract. So the long-term primary capacity could go unsold, while there is a shortage of transport capacity in the short-term. This would not be an efficient situation.

The pipelines have argued that if they were forced to offer unsold primary transport capacity in the UIOLI process, then in a situation where there was known to be an excess of capacity, shippers could avoid committing to long-term contracts and simply buy up capacity on a daily basis via the UIOLI process. If the price of UIOLI capacity was less than the long-term regulated rate, this behaviour would reduce the pipeline's revenue.

Setting a reserve price for UIOLI capacity equal to the price of long-term capacity would also not fully address the problem. Shippers could buy full-price capacity only at the times they need it, and avoid buying capacity when they do not. On average, they would pay less than the price of capacity under a long-term contract. TSOs in the EU recognise this issue, and will typically charge higher capacity rates for short-term e.g. daily or monthly capacity than for annual capacity.

One solution would be for the pipelines to offer a range of transport products, including shorter term capacity. Absent that solution, we recommend that the UIOLI process is restricted only to pipeline capacity that has been sold but is not nominated. The CREG and the pipelines should work toward developing a range of shorter-term capacity products.

7 THE LONG-TERM USE-IT-OR-LOSE-IT PROCESS

In section 6.3.2 of our task 5 report, we briefly sketched a longer-term UIOLI process. Numerous industry participants have suggested that the upstream auctions for gas contracts will be negatively affected by the fact that most transport capacity is held under long-term contracts with the TSOs. Thus potential purchasers of contracts from particular fields may be deterred from bidding by uncertainty over the availability of transport capacity. This may not only reduce competition in general, for example by discouraging industrial consumers who currently purchase their gas from local distributors from participating in the auctions, but may also limit the number of bidders for each field if potential purchasers believe that necessary transport capacity will not subsequently be made available, or only offered at very high prices. Potentially, the auctions for contracts in some fields might be dominated by a few bidders who hold large amounts of transport capacity from that delivery point.

The UIOLI rule will therefore require holders of long-term transport capacity contracts who do not succeed in purchasing longer-term gas contracts in the upstream auctions to offer their excess capacity to successful gas contract purchasers. Specifically, following each annual upstream auction the MO will compare the contracted amounts of gas for each purchaser from each field (including any gas contracted in previous auctions, or otherwise) with their contracted transport capacity for the following calendar year from that field (i.e. delivery point). Any positive difference between the amount of contracted capacity and the amount of contracted gas will then be offered via the MO to holders of gas contracts from that delivery point who lack transport capacity.

The capacity will be offered in one-year contracts at the same commodity charge specified in each original transport contract. The capacity charge in each offered one-year transport contract will be determined in an ascending clock auction to be organized by the MO. The reservation price for each auctioned contract will be set at the capacity charge specified in the relevant original contract. Successful purchasers will subsequently sign secondary contracts directly with the original contract holders at the auction-determined capacity prices. Capacity will be offered in divisible units and by pipeline segment.

APPENDIX I – CURRENT NOMINATION TIMINGS

We understand that, according to section 4.5.1 of the RUT[7], the current nomination timetable for transport capacity is as follows:

(all times refer to the day before gas flow, or D-1)

16.25: Limit for the control center (CPC) to receive transport nominations from shippers.

18.20: Limit for the CPC to inform shippers of the feasible gas transport program and the authorized energy quantities.

18.50: Limit for the shippers to send confirmed energy quantities to their CPC.

19.50: Limit for the CPC's to coordinate their respective transport programs.

20.20: Limit for the CPC to send definitive transport program to its shippers.

The shipper may make, and the CPC must accept, up to 4 renominations during the gas day, provided they are made with at least 6 hours from the time when the modification in gas flows is required. The CPC can reject renominations if there are demonstrable technical or capacity limitations in the national transport system. The 4 renominations must be made in a syncronized way across the national system at the times that will be decided by the National Operations Council (CNO-Gas).

The transport nomination cycle will begin 1 hour and 20 minutes after the conclusion of the electricity despatch, but no later than 16.25 of D-1.

For nominations by shippers for gas to be supplied by producers or producer/commercialisation companies for the coming gas day, we understand that the timing is as follows (again all times refer to D-1):

15.30: Limit for the producers or producer/commercialization companies to receive gas nominations from shippers.

16.15: Limit for the producers or producer/commercialization companies to authorize the amount of gas to be supplied.

18.50: Limit for the shippers to confirm to the producer or producer/commercialization company the amount of gas to be supplied.

19.50: Limit for the producers or producer/commercialization companies to send to the shippers the definitive gas supply program.

[7] Resolución CREG 154 de 2008.

The gas nomination cycle will begin immediately after the conclusion of the electricity despatch, but no later than 15.30 of D-1.

APPENDIX II – THE UIOLI PROCESS IN THE US

Most interstate pipelines in the U.S. generally follow a basic nomination and scheduling procedures outlined by the North American Energy Standards Board ("NAESB")[8]. As per NAESB standards, the gas day[9] is divided into four separate scheduling or nomination cycles two of which occur a day prior to gas flow while the last two occur during the day of gas flow.

The key points of the system are that:

1. Market parties make nominations for both firm and interruptible capacity during each nomination cycle;
2. Firm capacity pays a tariff which consists of both a fixed "reservation charge" and a variable or "commodity charge". Interruptible users only pay the variable commodity charge;
3. If nominations for capacity exceed supply, the pipeline will curtail nominations. The pipeline will curtail the nominations of the interruptible capacity holders first, before curtailing firm capacity holders;[10]
4. There is also an order of priority among interruptible capacity holders. Interruptible users can negotiate to pay less than the maximum commodity charge approved by the regulator.[11] The pipelines prioritize interruptible users according to the price they pay, with higher-paying interruptible users being given a higher priority;
5. Subsequent scheduling rounds can result in the interruptible users' nominations being replaced or 'bumped' by subsequent firm nominations or subsequent interruptible capacity nominations that are willing to pay more;
6. Accordingly, while it is not usually described as such, the interruptible capacity is in effect allocated by a four round auction, in which the highest paying users are ultimately awarded the interruptible capacity;
7. There are provisions in some pipeline tariffs that allow the IT shippers paying the discounted rate to "request [the] pipeline at the time of its nomination to automatically increase its rate as necessary to reserve the highest priority in the category [of

8 The North American Energy Standards Board (NAESB) serves as an industry forum for the development and promotion of standards which will lead to a seamless marketplace for wholesale and retail natural gas and electricity, as recognized by its customers, business community, participants, and regulatory entities. However, the exact protocols may vary by different pipelines. For example, El Paso Natural Gas has three additional late day nomination cycles as compared to the NASEB standards.

9 "Standard time for the NAESB grid-wide Gas Day is based on the period from 9:00 a.m. through 9:00 a.m. (central clock time) the next day.

10 There is in fact an intermediate level of priority known as secondary capacity. Primary capacity contracts specify receipt/delivery points. But a capacity holder can nominate to flow gas from/to receipt/delivery points other than those designated as primary, and this is known as secondary capacity, which has a lower priority.

11 The pipeline recovers the cost of operating the compressors through a fuel charge which is separate from the variable commodity charge. Hence, in some cases, the marginal cost of shipping for the pipeline might be less than the maximum commodity charge set by the regulator. In such cases, a shipper can pay a negotiated rate which is lower than maximum tariff rate without the pipeline losing money on a marginal cost basis by transporting the gas.

interruptible capacity]"[12] up to the maximum commodity charge allowed by the regulator for interruptible capacity. This is similar to the function on E-bay, which allows bidders to automatically increase their bids.

We describe the process for each nomination cycle in more detail below, using simple hypothetical nominations for illustration.

- **Timely Nomination Cycle**: This is the first cycle of the gas day. The nominations for this cycle are made by 11:30 AM Central Clock Time ("CCT") for gas flow starting at 9 AM (CCT) the following day. At 11:30 AM (CCT) the nomination period closes and nominations made by all shippers up to that point, including both firm and interruptible shippers, are aggregated and compared to available capacity. For example, suppose a hypothetical pipeline with only one receipt and one delivery point with 100,000 Dth/d of capacity. Before the nominations, all of the 100,000 Dth/d of capacity is available to be scheduled. Suppose that by 11:30 AM (CCT) deadline only two nominations are received, a firm shipper (FIRM A) for 70,000 Dth/d and an interruptible shipper (IT A) for 50,000 Dth/d. Since firm nominations get priority over interruptible nominations, the nominations from IT A are cut to 30,000 Dth/d while FIRM A's 70,000 Dth/d is scheduled.
- **The Evening Nomination Cycle**: The nominations for this cycle are made by 6:00 PM (CCT) for gas flow starting in 9 AM (CCT) the following day. In this cycle, scheduled quantities from the timely nominations are carried over and adjusted based upon scheduling priorities. Assume that there are two additional nominations made during the evening cycle, a firm shipper (FIRM B) nominated 20,000 Dth/d and an interruptible shipper (IT B) nominated 30,000 Dth/d. Further, the commodity rate that IT A pays is greater than the rate that IT B pays. Since the nominations (150,000 Dth/d) are greater than the available capacity (100,000 Dth/d), reductions are made based on priority and 'bumping' of the lesser priority nominations occur. Since, IT A pays a higher variable rate than IT B, IT B nominations are the first to get cut. However, since IT A is a lower priority nomination than FIRM B, IT A's nomination that was scheduled in the prior nomination cycle gets bumped to accommodate FIRM B's nominations. As a result the scheduled quantities are: FIRM A (70,000 Dth/d), FIRM B (20,000 Dth/d), and IT A (10,000 Dth/d). IT A's scheduled volumes dropped from 30,000 Dth/d scheduled in the previous cycle to just 10,000 Dth/d.

[12] Dominion South Pipeline Company, Tariff Record No. 40.14 Version 0.10, pg. 51

- **Intraday 1 (ID1) Nomination Cycle**: The nominations in this cycle are due by 10:00 AM (CCT) on the day of gas flow for flow occurring at 5:00 PM (CCT). This cycle is the first opportunity to modify previously scheduled quantities after the gas flow has started for the gas day. In this cycle, the IT nominations can still get bumped to serve primary and secondary firm nominations. However, since gas has already started flowing on the previously scheduled nominations, the amount that a nomination can be bumped is limited. For example, IT A had 10,000 Dth/d that was scheduled during the evening cycle. If IT A's scheduled volumes were bumped during the ID1 Nomination cycle due to a new firm nomination (FIRM C), then bumping would only affect the volumes that will flow after 5:00 PM (CCT) or just 6,666 Dth. IT A would still get 3,333 Dth out of the 10,000 Dth of scheduled volumes for the day.[13]
- **Intraday 2 (ID2) Nomination Cycle**: This is normally the last cycle of the gas day, although some pipelines such as El Paso have later day cycles beyond this. The nominations for this cycle occur by 5:00 PM (CCT) for flow starting at 9:00 PM (CCT). This is the only cycle where bumping is not allowed. Thus, IT nominations made in prior cycles cannot be bumped by firm nominations in ID2. However, all nominations made in ID2 still get scheduled based upon priority. For example, if there is 100 Dth/d of available capacity on the pipeline after the previous cycles and both a firm shipper and an IT shipper nominated 100 Dth/d in ID2, then only the firm shipper would have 100 Dth/d scheduled to flow after 5:00 PM (CCT). The IT nomination would not be scheduled. However, if there was an existing IT nomination that got scheduled during ID1, then this would get priority over even firm nominations occurring during ID2.

[13] The portion of the scheduled quantity that would have theoretically flowed up to the effective time of the intraday nominations being confirmed, based upon a cumulative uniform hourly quantity is known as the "Elapsed Prorated Scheduled Quantity" ("EPSQ") and the process by which bumping is limited to 2/3 of the previously scheduled volumes is known as the EPSQ process. After allowing for the EPSQ, reductions occur according to the scheduling priorities until nominated volumes equal available capacity.