Victorian Energy Networks Corporation

Our ref: 119178

26 March 2004

Mr Tony Hinton
Presiding Commissioner
Gas Access Regime Inquiry
Productivity Commission

By email to: gas@pc.gov.au

Dear Mr Hinton

Comments by VENCorp on the Commission's Draft Report

We thank the Commission for this opportunity to comment on your draft report released in December 2003.

The Commission's review of the national gas access regime is an important task and should inform the MCE process going forward.

Brief comments on the draft findings are provided in the attached paper. Also attached are copies of our consultation paper on pipeline investment released late last year, and a copy of the information paper released on this matter last week, as part of our review into the Victorian gas market pricing and balancing arrangements. These papers and other information relating to the work being undertaken by VENCorp in its review of the spot market and pipeline investment arrangements are available on our website: www.vencorp.com.au.

Should you require any further information on matters referred to in this submission or other areas, please contact Mr Craig Price, on 8664 6614.

Yours Sincerely

Terry Grimwade
Executive Manager, Energy Markets
Victorian Energy Networks Corporation

att.

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Submission to Productivity Commission on Draft Report

Performance of the gas access regime

The national gas access regime was only implemented in late 1997. Since that time, substantial investment has occurred in the pipeline industry. No doubt there are areas where the regime could and should be reviewed to improve its efficiency, and as such we support the initiatives proposed in this regard.

However, the Commission has not yet clearly demonstrated a case for replacement of the regime by another form of regulation, nor undertaken a proper justification of the need for or timing of its proposals to shift regulation into a form of monitoring. The case for replacement of the current regulation has not been made until this important step has been undertaken.

Information disclosure

If the ultimate aim is for regulation to be replaced by markets, then commensurate with this aim should be the acceptance of responsibility by all market participants to be required to inform the market place appropriately of all relevant information. This includes information on gas prices, gas supply, pipeline capacity, and indeed, any relevant factors which might influence the end price of gas. In other words, there should be a similar level of responsibility for disclosure of pertinent and relevant information in the energy industries as is commonly applied in the normal financial markets (and enforced by law). The Commission's views in regard to removal of regulation should recognise this need.

Regard for impacts on Electricity Markets and Investment in the Electricity Industry

The two energy industries of gas and electricity supply are strongly related today with many parallels, dependencies, and operational interfaces.

In Victoria, we are well aware of the relationships. We are pleased that the governments across Australia are now taking action on this critical relationship to redress the failings of the current approaches.

The Terms of Reference for this review stipulated that the Commission should take an encompassing view of both industries in its review of the gas access regime. It is disappointing, therefore, that the Commission did not recognise the deep relationships between the two energy industries in producing its draft findings.

To date, the Commission appears to have focussed solely on the gas transportation aspects of the gas industry with no clear regard of the implications of its findings for the national electricity market. At the same time, it has acknowledged the future expected growth of gas fired power generation (both peaking and intermediate) to meet the nation's future energy needs, so should be aware that there are operational and investment relationships between the industries.

There is no clear reason why in the future the treatment of the access regime in gas should be so distinctly different to electricity. Being a gas and electricity business, VENCorp fully understands the technical and legal differences of each energy sector and is well aware of the history which has led us to this point. However, technical differences aside, we do not see why there is any reason that the two sectors should continue to be regulated along such diverging paths across the Nation, especially when the businesses in each energy industry operate in both industries around the Nation and need a consistent approach. We urge the Commission to consider, far more thoroughly, the interrelated nature of energy supply in south eastern Australia, and listen more carefully to the industry and governments in this regard.

IPA submissions

In regard to the IPA criticisms at the Melbourne hearing of the Victorian gas market arrangements, we urge the Commissioners to concentrate on the principles of what is required from the access regime. As we noted in our previous submission to the Commission on 18 September 2003, trying to draw meaningful comparisons by resorting to labels of market carriage and contract carriage are unproductive exercises. The labels are misleading and in most cases misinterpreted. Both systems of capacity management aim to deliver market driven solutions. The Victorian arrangements do so by an open and transparent market in which prices are transparent and discoverable and participants are able to trade gas with or without contracts for capacity.

We believe that the ultimate aim is the existence of efficiently operating, open access, markets for gas. In these markets, gas should be able to be transacted easily and at low cost, prices should be transparent and easily discoverable, information pertinent to the market, network and supplies should be readily accessible, and there should be well defined property rights which provide participants with adequate means to manage the transaction risks and create the basis for underpinning of investment - in network assets, supplies (including supply flexibility), and demand initiatives (e.g. demand side management). It would be far better for the Commission to focus on those objectives and specify the desired principles of those objectives, as relevant to the questions of economic access and its regulation, to ensure the attainment of them.

We point out that market carriage does not exclude contracts or property rights. The concept of market carriage is an open spot market in which the existence of well defined rights prevent "free riding", and ensure that the rights are not competitively undermined by actions of users without rights. Market carriage is an approach which relies upon property rights to underpin contracting in conjunction with the open spot market for trading of gas. Market carriage requires that these property rights provide both:

- congestion hedges to provide one of the means by which participants are able to manage their congestion risk; and
- transmission rights to provide shippers with incentives to underpin investment by contracting with the asset owner(s) for those rights.

The current gas market arrangements in Victoria are a simplified form of the probable ultimate requirements for that market, particularly in light of recent infrastructure developments in terms of new supply sources, additional gas fired power generation and interconnecting pipelines. While VENCorp has always acknowledged some limitations of the current simplified arrangements, at the same time, the need for better development of rights within these arrangements for promoting investment has not been a significant issue to date.

The network is capable of transporting over 1200 TJ to customers in daily quantity terms, which has been entirely appropriate for all past and current requirements. On this basis, investment for major expansion in capacity is not required for some time to come. Indeed, current planning indicates the need for long term capacity expansion is post 2009. The performance of the current rights (AMDQ and AMDQ credits) in directing that capacity investment simply reflects the situation that this is a much longer term requirement.

Congestion does occur on the Victorian network. The bulk of this congestion relates to the management of within day constraints. To date, this has not been severe, but we expect this situation to increase over the next decade.

Constraints can be incurred at times within a day at levels well below the theoretical levels indicated by daily capacity. The network's actual capacity over any given day is primarily the consequence of the hourly flow rates and within day events, and more particularly the uncertainty involved as they unfold. It is for this reason that constraints can often occur at daily demands less than 900TJ, leading to additional costs to manage the within day congestion. This cost has been minimal and demonstrated to be efficient to date, but nevertheless is expected to grow in the future as the level and volatility of the system usage increases. This is why the current review by VENCorp of the pricing and balancing arrangements is closely considering this matter. Property rights which continue to focus on daily quantities will not be well suited to managing these issues in the future. These are complex issues, involving the development of more sophisticated rights and balancing arrangements, which are matters of market design.

In summary, most of the matters raised by IPA in debating aspects of the Victorian arrangements are matters of the specifics of market design. These are best determined by the participants involved in those markets, who are both well informed and the most suitable parties to make decisions in this regard. The current design of the Victorian gas market reflects an appropriate balance between the competing needs of various parties and the environment in which they operate and is supported by the majority of industry participants and customers. These matters are being reviewed by industry under the current Pricing and Balancing Review. To date, the IPA has not participated in this review.

Pricing and Balancing Review

VENCorp is currently undertaking a major review of the pricing and balancing arrangements of the Victorian gas market and will make recommendations on this to the Victorian Government in late June 2004. This review is broad in scope and covers both the design of the spot market arrangements and the requirements for future investment in pipelines, supplies and demand side management in Victoria. It involves gas market participants, gas end users, NEMMCo, and electricity users.

VENCorp's review covers the design of the spot market arrangements with respect to the specifics of pricing, balancing, trading, and incentives for future investment in pipeline, supply, and demand side infrastructure. This review is being conducted in an open and consultative manner, utilising experts from within industry and overseas (including examining arrangements in place overseas and considering their applicability to Victoria).

VENCorp's review is still in progress. Based on the consultant's review of alternative market designs, their findings suggest that the following directions may be appropriate:

- initially, the introduction of greater pricing transparency through the introduction of ex ante pricing, rebidding, and allocation of costs of deviations from schedule more directly to participants via updated prices;
- in the next access period, the introduction of transmission rights in the market and new tariffing designs for the network revenue recovery which are better integrated with the market; and
- potentially, the introduction of locational pricing in the form of hub-based pricing with transmission rights between the hubs which define and price capacity and are integrated with the market scheduling process.

These conclusions are, however, subject to review and consideration by the stakeholders over the next two months, following which VENCorp will be able to develop a firmer view of the recommended approach for the future.

During the course of VENCorp's review, several areas of potential weaknesses either in the Code itself or its application by Regulators have been examined. Should this eventually result in a need for Code changes, this will be taken up with the AEMC. These areas may include such matters as the detailed application of sections of the Code (such as ss2.16, 2.28 and chapter 8). These issues are more particularly discussed in the consultation papers.

Attached with this paper are copies of our consultation paper on pipeline investment released late last year, and a copy of the information paper released last week. These papers and other information, including the draft reports by the consultants on the design of the spot market arrangements, are available on our website: www.vencorp.com.au.

Should you require further information on any matter relating to our current review of the pricing and balancing arrangements, please contact VENCorp and we will be more than happy to assist.

Gas Market Pricing and Balancing Review

Stakeholder Consultation Paper

The Pipeline Investment Issue

24 December 2003

Preface

VENCorp is currently undertaking a significant review of the Victorian gas spot market pricing and balancing arrangements.

VENCorp produced a comprehensive Issues Paper in July 2003, which documented issues raised by stakeholders in respect of the current gas spot market arrangements and identified the key issues that the Review should seek to address. Among these issues, a number of stakeholders identified concerns with the current market arrangements in terms of providing adequate pricing signals and incentives for investment in gas supply and pipeline infrastructure.

The Review has now reached the stage where a number of alternative market design "packages", aimed at addressing the issues identified in the Issues Paper, have been defined for evaluation. ICF Consulting (ICF) is assisting VENCorp in this process, and has produced a report "Definition of Market Design Packages", 24 December 2003 (available from the Pricing and Balancing Review page of the VENCorp web-site http://www.vencorp.com.au/html/gas_market_balancing.htm##reports).

In parallel with ICF Consulting's ongoing evaluation and refinement of these packages, VENCorp is proposing to progress an additional work stream in January/February 2004 to develop and assess a range of alternative pipeline capacity rights models and mechanisms to facilitate pipeline investment.

The purpose of this Discussion Paper is to:

- Summarise the pipeline investment issue as documented in the Issues Paper and identified in consultation with a range of stakeholders during the course of the Pricing and Balancing Review;
- Discuss the possible concept of an Independent Planner, and explore its potential benefits and limitations as it would apply within the framework of the current Gas Access Code and the existing VENCorp and GasNet access arrangements;
- Discuss a range of alternative forms of financial and/or physical capacity rights and their value in terms of driving new investment on pipeline capacity in response to market needs; and
- Canvass the views of stakeholders on the proposal to review these matters in parallel with ICF's initial evaluation of the market design packages.

VENCorp would welcome stakeholder feedback on the various options for addressing the pipeline investment issue that have been canvassed in this Consultation Paper and the proposed way forward. To this end, VENCorp will be conducting a Workshop on the matter, to be held at the World Trade Centre on Thursday, 29 January 2004. Those wishing to attend should contact Peter Ferretto at peter.ferretto@vencorp.vic.gov.au.

VENCorp also invites written submissions in response to the matters discussed in this Paper, or providing alternative proposals. While late submissions will still be considered to the maximum extent practicable within the constraints of the timetable for the review, the closing date for lodgement of submissions is Friday, 6 February 2004 and should be sent in electronic form to the above email address. Alternatively written proposals may be sent or faxed to:

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1. Introduction

1.1 Pipeline Investment in the Context of the Pricing and Balancing Review

The Victorian Minister for Energy Industries and Resources has directed VENCorp to undertake a review of the Victorian gas spot market pricing and balancing arrangements.

In July 2003, after a period of extensive consultation with stakeholders, VENCorp produced a comprehensive Issues Paper, which documented issues raised by stakeholders in respect of the current gas spot market arrangements and identified the key issues that the Review should seek to address. Among these issues, a number of stakeholders identified concerns with the current market arrangements in terms of providing adequate pricing signals and incentives for investment in gas supply and pipeline infrastructure.

The Issues Paper noted that investment in pipeline infrastructure was subject to a number of influences external to the gas spot market arrangements, and that to address this issue fully may require a more holistic review of the overall process for pipeline planning and investment than is provided for in the Terms of Reference of the Pricing and Balancing Review, as set out by the Minister's direction. Nevertheless, through the Issues Paper, VENCorp confirmed that the Review would consider and seek improvements to the existing spot market pricing arrangements and pipeline capacity management mechanisms with a view to facilitating better pipeline investment signals.

The Review has now reached the stage where a number of alternative market design "packages", aimed at addressing the issues identified in the Issues Paper, are being defined for evaluation. ICF Consulting (ICF) is assisting VENCorp in this process. ICF has produced a report "Definition of Market Design Packages", 24 December 2003 (available from the Pricing and Balancing Review page of the VENCorp web-site: http://www.vencorp.com.au/html/gas_market_balancing.htm##reports).

In this report, ICF has defined five packages of market design elements for evaluation and refinement. These five packages cover a range of potential alternatives, from relatively minimal refinements to the existing market arrangements, to more substantive changes including a move to a nodal/hourly pricing arrangement.

For those packages which retain the current concept of a single daily price, with no locational pricing signals, ICF has acknowledged difficulties in providing a well defined market-based mechanism to drive investment to address pipeline constraints in the PTS. For those packages, ICF has indicated the intention to develop an approach to facilitate such pipeline investment via an "Independent Planner" concept. For packages that seek to introduce locational pricing in some form, ICF is also considering market driven approaches to pipeline investment, through implementation of financial transmission rights and/or physical capacity rights.

As noted in the Issues Paper, provision of a fully effective framework to facilitate investment in pipeline infrastructure may require more far-reaching consideration than the Victorian gas spot market arrangements alone. This is particularly so in the current environment that sees increasing interconnection and trading of gas between pipelines in South Eastern Australia. Therefore, in parallel with the package definition and evaluation process being undertaken by ICF, VENCorp considers it worthwhile to separately canvass and explore a range of alternatives to address both the capacity management issue and the facilitation of pipeline investment. This separate process may identify possible approaches and/or raise issues that are beyond the scope of the current Pricing and Balancing Review (and, furthermore, beyond VENCorp's statutory responsibilities and powers) to implement or address. Nevertheless, based on stakeholder consultation and input during the course of the Pricing and Balancing Review to date, VENCorp believes that there is general industry support for such further consideration of the pipeline investment issue. Therefore, VENCorp considers it prudent to undertake at least some investigative assessment of alternative mechanisms to facilitate investment in the PTS, in order to provide a detailed commentary on this issue in its final Pricing and Balancing Review report, which is to be submitted to the Minister by June 2004.

1.2 Objectives of this Discussion Paper

VENCorp is proposing to establish a separate work stream to further progress the matters discussed in this Paper through January/February 2004, in parallel with ICF's initial evaluation work. In this process, VENCorp intends to collaborate closely with the pipeline owner, GasNet (subject to the availability of GasNet personnel), and to consult with other stakeholders as appropriate.

In this context, the purpose of this Paper is to:

- Summarise the pipeline investment issue as documented in the Issues Paper and identified in consultation with a range of stakeholders during the course of the Pricing and Balancing Review;
- Discuss the Independent Planner approach, and explore its potential benefits and limitations as it would apply within the framework of the current Gas Access Code and the existing VENCorp and GasNet access arrangements;
- Discuss a range of alternative forms of financial and/or physical capacity rights and their value in terms of driving new investment on pipeline capacity in response to market needs;
- Canvass the views of stakeholders on the proposal to review these matters in parallel with ICF's initial evaluation of the market design packages.

2. The Pipeline Investment Issue

This section of the Paper summarises the existing framework for investment in augmentations of the PTS, and discusses the current limitations that have been identified by stakeholders during the course of the Pricing and Balancing Review consultative processes.

2.1 Existing Framework for Pipeline Investment

The Victorian gas principal transmission system (PTS) is owned by GasNet and operated by VENCorp in accordance with the MSO Rules. It is a covered pipeline under the National Access Code, and both VENCorp (as operator) and GasNet (as owner) are required to develop Access Arrangements and have them approved by the ACCC.

Incentives for investment in pipelines may be influenced by a number of factors, including both:

- Regulation of such investment under the National Access Code; and
- Pricing signals and property rights provided under the MSO Rules.

Under this structural framework, VENCorp, as the independent system and market operator, publishes market and system information, including an Annual Gas Planning Review. This information can supplement interested parties' own research and market intelligence to enable them to undertake planning and/or pursue investment opportunities related to the gas supply and transmission system. VENCorp owns no pipeline assets and has no decision-making role in terms of pipeline investment. Unlike the National Electricity Market, where Transmission Network Service providers have obligations or powers to direct the augmentation of the transmission system, either to maintain prescribed standards of transmission reliability, or to deliver system benefits, subject to a regulatory test, there is no party in the gas market that is assigned any obligation or responsibility for augmentation of the transmission pipeline.

GasNet, and potentially other parties, make their own decisions with regard to investment in PTS augmentations, under the provisions of the National Access Code and consistent with the terms and conditions of GasNet's Access Arrangement.

Thus, while the PTS is a fully regulated pipeline, expansions, augmentations and extensions rely on commercial decisions, which can be heavily influenced by the basis upon which costs are accepted by the ACCC for incorporation in the regulated asset base and the allowed WACC.

The spot market arrangements under the MSO Rules also seek to provide some incentives for pipeline investment. This is attempted through the AMDQ and AMDQ credits mechanisms, which are described in more detail in the following section of this paper. Under these arrangements, if a party negotiates with and pays GasNet to augment the pipeline, it can receive in return AMDQ or AMDQ credits commensurate with the additional capacity provided by that augmentation. These mechanisms provide protection against uplift, and some protection against curtailment, in the event of pipeline constraints, or "congestion", as determined on a daily basis.

2.2 Existing Capacity Management Mechanisms (AMDQ and AMDQ Credits)

The PTS currently has sufficient capacity to supply all Victorian gas consumers' daily gas needs without suffering congestion on the pipeline (i.e. exceeding the daily capacity of all or part of the pipeline system) for all but a few days in the year.

In the event that part of the pipeline system becomes congested, it may be necessary for VENCorp to re-schedule gas supplies and/or deliveries to ensure appropriate pressures are maintained throughout the principal transmission system.

The mechanisms used in the Victorian gas spot market to deliver pricing signals, and for prioritising access to the transmission pipeline system at times of congestion are Authorised MDQ (AMDQ) and AMDQ Credits[1].

2.2.1 Initial Allocation of AMDQ

The concept of AMDQ was developed in 1998, when Longford remained the single predominant source of gas on the PTS, and was implemented for commencement of the spot market in 1999. Thus, the total quantity of AMDQ allocated was based on the nominal 990TJ/day capacity of the Longford to Melbourne pipeline.

AMDQ was allocated to all daily metered, or "Tariff D", end-use customers. This allocation involved an extensive process whereby each individual Tariff D customer site was allocated AMDQ on the basis of pre-existing MDQ-based supply contracts they had held with Gascor or the Gas and Fuel Corporation, or implied contractual amounts based on their historical usage of gas.

The allocation of AMDQ was made directly to Tariff D end-use customers, rather than to wholesale spot market participants (the retailers), to pave the way for the introduction of full retail contestability. It was recognised that if retailers held the AMDQ rights rather than the customers, then this would be a potential barrier to customers moving from one retailer to another. The AMDQ allocation to Tariff D customers was made without any specified termination date and, initially, was on a site-specific basis and was not transferable (transferability of AMDQ was subsequently introduced in 2001- see section 2.2.3). Also, while the initial allocation of AMDQ was based on the Longford-Melbourne capacity of 990TJ, the rights conferred by AMDQ are not conditional upon holders of those rights making injections of gas (or having injections of gas made on their behalf) at Longford; i.e. it is not injection related or "path-related".

The total amount of AMDQ initially allocated to end-use Tariff D customers was 446TJ. After an allowance was made for diversity of that daily demand, an assessment was made that about 660TJ of AMDQ would be available for small volume, or "Tariff V", customers

[1] Operational scheduling does not normally take account of AMDQ at present; this would only become a consideration in the event that curtailment is required due to pipeline constraints.

The majority of Tariff V customers are not daily metered. Therefore, there is no allocation of AMDQ to individual Tariff V customers. Instead, there is a collective “block” allocation in respect of these customers and there is no “ownership” of this AMDQ by any individual party.

As well as providing for protection against congestion uplift, AMDQ at Tariff D sites provides a form of priority protection against curtailment, where such action is necessary to maintain system security in the event of pipeline constraints. In such circumstances and to the extent practicable, VENCorp is obliged by the MSO Rules, to curtail gas usage at sites where there is no assigned AMDQ, or the assigned AMDQ has been exceeded on the day, ahead of authorised gas users.

The AMDQ concept is thus aimed at providing a measure of both financial and physical “firmness” of supply for market participants. It is also seen as providing a potential mechanism to facilitate pipeline investment, as parties can negotiate with GasNet and in return for funding pipeline expansions can receive an allocation of AMDQ commensurate with the additional resultant system capacity.

Other than investment in the gas transmission system, parties seeking additional AMDQ at existing or new sites may be able to transfer it from other sites or obtain it from other users who are willing to relinquish their entitlement. Consistent with the market carriage approach, however, it is not essential for shippers to hold AMDQ in order to ship or use gas.

Tariff D customers are able to withdraw gas without AMDQ, but would be subject to uplift charges and potential curtailment in the event of pipeline constraints. New Tariff V customers, or increasing Tariff V gas usage, automatically fall under and are covered by the currently allocated block Tariff V AMDQ. As the Tariff V demand grows, there is an increased likelihood of Tariff V AMDQ exceedance. Nevertheless, since all shippers share uplift charges associated with Tariff V usage on the basis of their Tariff V customers’ total daily withdrawals, this would provide limited incentive to individual parties to invest in the gas transmission system to mitigate against the effects of Tariff V AMDQ exceedance.

2.2.2 AMDQ Credits

While the initial concept and allocation of AMDQ prior to market commencement was based on the predominant single source of gas supply from Longford, it was recognised at that time that other sources of gas supply were likely to be introduced in the future. It was also acknowledged that injections of gas at those other, non-Longford, sources would not contribute to congestion on the Longford to Melbourne pipeline, and may in fact ameliorate such constraints. It would be inappropriate if shippers injecting from non-Longford sources of gas were to be allocated a share of uplift costs arising through management of a Longford to Melbourne pipeline constraint in respect of withdrawals of gas supplied from those other gas sources.

The concept of AMDQ credits was introduced to accommodate the introduction of the SW Pipeline and the western Underground Storage facility (and other potential new sources of gas supply). Where a pipeline expansion is involved in enabling gas from the new source to be delivered to the market, then the owner of that pipeline can assign AMDQ credit certificates to shippers (on the basis of commercial arrangements negotiated between the shipper and the pipeline owner) up to the capacity of that pipeline.

Shippers who hold AMDQ credit certificates and inject gas at those sources are then entitled to claim AMDQ credits, which can be used to offset any cumulative AMDQ exceedance at their customers’ sites and, hence, reduce their potential exposure to congestion uplift. In this way AMDQ credits can be applied as a general uplift “hedge”, and are treated as applying at a notional reference “hub”, without any physical protection against curtailment should curtailment be required to manage pipeline constraints. Alternatively, AMDQ credits can be assigned to specific customer sites in which case they would offer the same protections as AMDQ, i.e. protection against uplift and physical curtailment at that site only.

In addition, the arrangements provide for unutilised AMDQ credits applied at the notional hub to be converted back to entitlements for ancillary payments. Since AMDQ credits are injection dependent, this added feature offers market participants the scope to utilise injections of gas as an uplift hedge via AMDQ credits and to have any surplus injections, not required to offset congestion uplift, eligible for ancillary payments (provided, of course, that the prices in the offers require that ancillary payments are warranted – if they are not more than the resultant market price, no ancillary payment is required).

Unlike the initially allocated AMDQ, AMDQ credits are conditional upon and limited to the quantity of gas injected on the day by the holder of the AMDQ credit. Thus, AMDQ credits that are assigned to specific customer sites are injection dependent and path related.

2.2.3 Transfer of AMDQ and AMDQ Credits

Transferability of AMDQ was introduced in 2001. AMDQ and AMDQ credits may now be held either at a customer site or at a notional reference hub, which is a common point of reference within the gas transmission system established for the purpose of valuing AMDQ and AMDQ credits. When held at the reference hub they provide the owner with a general system wide uplift hedge only, whereas when held at a customer site, they provide protection from both uplift and curtailment (subject to the Curtailment Rules) at that site and that site only. The transfer of AMDQ may be from site to site, site to hub, hub to hub and hub to site. The transfer of AMDQ credits may be from hub to hub and hub to site.

All transfers[2] of AMDQ and AMDQ credits are subject to transfer factors that take into account the impact on the gas transmission system that customer loads and usage patterns have at different locations. Depending on where a quantity of AMDQ or AMDQ credit is being transferred to and from, these transfer factors will either factor up or factor down the quantity of AMDQ or AMDQ Credits. For sites with smaller loads, these factors are predetermined and would typically result in a one for one transfer. However for larger loads, VENCorp considers transfer factors on a case-by-case basis.

The terms and conditions for trading or transfer of AMDQ between parties is a matter for bilateral negotiation between those parties, and transfers can take place for any specified period.

Since transfers of AMDQ were first permitted, in July 2001, about 27TJ of AMDQ has been transferred between customer sites to date.

2.2.4 Transition to Alternative Rights Models

As discussed in section 2.2.1, above, the initial allocation of AMDQ, prior to market commencement comprised of two components:

(i) an allocation to each specific daily metered, or Tariff D, customer site, with that right being allocated to the end-use customer in perpetuity and at no cost;

(ii) a “block” allocation was made to apply in respect of non-daily metered, or Tariff V, customers, there being no ownership of this right by any individual party.

AMDQ credits have been assigned by GasNet to various parties (all of whom are wholesale Market Participants) on the basis of bilateral arrangements between GasNet and those parties.

In the event that it should be decided to modify the entitlements or application of the existing AMDQ or AMDQ credits rights, or move to an alternative form of financial or physical pipeline rights model, then the appropriateness of these rights being held by end-use customers rather than direct wholesale market participants may need to be reviewed. For at least some of the alternatives presented in this

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2 *The process of transferring AMDQ and AMDQ credits between parties is defined according to a set of procedures available from the VENCorp website http://www.vencorp.com.au.*

Paper, it would be a desirable and, perhaps, a necessary requirement for those rights to be held by, and tradeable between, wholesale market participants rather than end-users purchasing through a retailer.

Implementation of a revised form of pipeline capacity right could, therefore, present some legal issues in terms of how the AMDQ rights currently allocated to and held by end-use Tariff D customers are translated into another form of right and/or transferred from those end-use customers to the retail businesses or other wholesale market participants. While there may be other options available, this may require a legislative approach, which aims to ensure that those end-use customers are left in no less advantageous position in the market than they are as a result of holding the existing AMDQ rights.

This issue would be less significant for the current allocation of AMDQ rights in respect of Tariff V customers, as these are not currently assigned to any particular party, although the method of re-allocation of the equivalent rights to that part of the pipeline capacity would need to be established.

With regard to AMDQ credits, provided the replacement rights are also assigned or allocated by GasNet, then presumably GasNet would have the task of converting the existing AMDQ credits into equivalent rights under the new arrangements. It would clearly be preferable if it were possible for this to be done by some prescribed formula-based approach rather than requiring separate negotiation with each affected party.

2.3 Limitations of Current Capacity Management/Investment Mechanisms

The regulatory requirements for a pipeline owner's capital base to be increased in respect of new facilities investment are set out in section 8.16 of the National Access Code. Under these provisions, the capital base may be increased to cover the actual cost of new facilities investment, provided this amount is not more than would be invested by a prudent service provider acting efficiently (acting in accordance with accepted good industry practice to achieve the lowest sustainable costs of delivering services), and provided one of the following conditions is satisfied:

(i) Anticipated incremental revenue exceeds the costs incurred (the economic feasibility test); or

(ii) The new facility has system-wide benefits that justify a higher tariff for all users (the system-wide benefits test); or

(iii) The new facility is necessary to maintain the safety, integrity or contracted capacity of services (the safety, integrity and contracted capacity test).

Section 8.21 of the National Access Code states that if the regulator agrees to reference tariffs being determined on the basis of *forecast* new facilities investment, this need not mean that the regulator is bound to accept that that new investment meets the requirements of section 8.16 when the service provider's access arrangement is next reviewed. The regulator may agree at the time at which the new facilities investment takes place that it meets section 8.16, in which case, that decision will be binding on the regulator in subsequent reviews. This, however, requires the service provider to seek such a decision in writing and be subject to a consultation process similar to that for a revision of an access arrangement.

In the case of the Victorian PTS, contractual rights to pipeline capacity in return for investment to increase that capacity are essentially limited to AMDQ or AMDQ credits. For reasons explained further below, neither AMDQ nor AMDQ credits in their current form are likely to provide adequate incentive for third parties to commit to investing in augmentations of the PTS.

Thus, without contracts for capacity underpinning investment in augmentations, GasNet's revenue is based primarily on volumetric tariffs. GasNet would need to rely on *forecasts* of increased gas flows in order to meet the tests under section 8.16 of the National Access Code. GasNet would bear the risk of reduced revenues during the access period should the projected increased flows not eventuate for any reason. Further, in the absence of a prior binding decision by the regulator that a planned new facilities investment meets the requirements of section 8.16 of the National Access Code (a decision that would need to be based on forecast increased flows rather than contractual commitments), GasNet may also face some risk that the regulator may not allow the full costs of that investment to be included in the capital base in subsequent access periods.

In terms of effectiveness as a mechanism for capacity management or facilitation of pipeline investment, stakeholders have identified the following limitations of AMDQ and AMDQ credits in their current form:

- By definition, AMDQ is a right based on daily quantities whereas almost all constraints that currently arise on the PTS are "within-day" in nature.
- The protection from uplift charges afforded by AMDQ or AMDQ credits is, or historically has been, negligible. This is because over 90% of all uplift charges in the market to date have been allocated as "surprise" uplift (being due to within day constraints, rather than pipeline congestion or AMDQ exceedance) which is smeared across all market participants on a pro-rata basis on total withdrawals on the day, irrespective of the level of AMDQ held.
- The physical protection or priority against forced curtailment in the event of pipeline constraints that is afforded by AMDQ or AMDQ Credits is, in practice, somewhat limited. This is because, in the context of the Victorian gas system, VENCorp as the system operator, has limited real choices in terms of customers whose gas usage is sufficiently large and can practically be curtailed at short notice to assist in managing system security threats. Thus, if the situation is serious enough for curtailment tables to be invoked then, even if unauthorised gas withdrawals (withdrawals not covered by AMDQ or AMDQ credits) are curtailed first, it is not always likely that this will, in practice, enable protection from curtailment to be afforded to all "authorised" customer withdrawals. This is particularly so in the case of gas fired generators.
- Further, even if large users do hold AMDQ, uplift costs may arise or, in the extreme, curtailment may be necessary, not because of the *daily* demand for gas on the system but the hourly profile of that usage. For example, the system may be capable of supplying a gas-fired power station with AMDQ of 20TJ, provided that 20TJ is spread over a 24-hour period, but not if that 20TJ is taken unexpectedly over the space of a few hours.
- For other Tariff D users, at the time curtailment may be called during a day, there may be difficulties in determining whether they have used their full AMDQ – not all Tariff D meter data is telemetered in real time.
- AMDQ/AMDQ Credits do not (in their current form) address the "free rider" issue – parties who do not hold AMDQ can still use the system paying essentially the same tariffs, and enjoying close to the same level of security of supply as some of those who do. In the absence of the pipeline being congested, all parties are able to make use of spare capacity on the pipeline available as a result of investment by others, without making additional pipeline tariff payments and without providing compensation or re-imbursement to the holder of the AMDQ rights.

3. The Independent Planner Option

One possible approach for addressing the pipeline investment issue is the introduction of an independent planner with responsibilities to ensure there is adequate investment in pipelines to maintain an acceptable level of reliability of supply to gas users. This approach is similar in concept to the role of independent planners in electricity transmission in those States where the transmission network has been privatized. However, if it were to be applied in the Victorian gas market, the practical application would need to vary somewhat from the electricity model due to the different access regime that applies to gas pipelines.

The rationale for an Independent Planner role is primarily to transfer and minimise the regulatory risk associated with investment in pipeline infrastructure, which is inherently "lumpy" in nature and, if economies of scale are to be realized, presents difficulties in matching market requirements and capacity precisely at all times. Where pipeline investments are undertaken by the pipeline owners on the basis of a regulated return, then the regulators have a natural reluctance to make prior decisions on that regulated return without the ability to revisit those decisions after the event. In part, this is because the pipeline owners, who are the proponents of such developments, have a clear self-interest in expanding their capital base and hence their returns. The advantage of an Independent Planner is based on that entity having no direct commercial interest in either under or over investing in the pipeline system, nor in the manner in which an efficient level of pipeline capacity is achieved – whether it be by increasing the capital base of the pipeline owner through building additional pipeline infrastructure, or through maximizing the utilization of existing infrastructure through procurement of other services. As a consequence, and particularly if the Independent Planner has an appropriate governance structure and reaches its planning decisions through an open, transparent and consultative process with all key stakeholders, the regulator may feel more inclined to provide a firm commitment to approval of a regulated investment at the time at which that investment takes place, rather than reserving the right to revisit that decision in subsequent access periods.

3.1 Advantages of a Victorian Independent Planner

Introduction of a Victorian Independent Planner ("VIP") into the State's gas transmission investment planning regime may have the following advantages in facilitating investment in expansion or augmentation of the PTS:

a) *Achieving competitive services in transmission capability*

The VIP would focus on achieving the most efficient and prudent investment strategy for the overall benefit of the Victorian community. It would do so by considering the needs of the market and basing its decisions on economic tests based on market considerations. In so doing, it would seek competition between alternatives for provision of services to increase the transmission capability of the shared transmission network (the PTS), such as competitive offers for expansion of the pipeline capacity, but also by seeking alternatives in supply and demand that could provide similar benefits.

The capacity of the pipeline to transport gas over a day is a function of the pipeline itself (maximum diameter, compression etc.), and of the patterns of usage at off takes and profile of injection by suppliers. Supplies that are essentially flat injections with low rates of change can impose significant limitations on the capacity of the pipeline when consumption is not similarly restricted so that the pattern of off take consumption matches supply. Loading factors are paramount to full service provision and maximisation of the use of the transmission assets. Services which are aimed at improving the profile matching of injections versus off takes offer significant opportunities to maximise the capacity of the existing transmission assets without further expenditure in transmission asset facilities, thereby providing an effective alternative for optimising the efficiency of investment whilst maximising the transmission capability.

b) *Optimizing the benefits of investment to the overall market and Victorian community*

Under the current approach, the path taken to achieve benefits for the Victorian community relies on private investors recognizing and acting on the commercial opportunities available to invest in new pipeline capacity to satisfy the needs of the market. However, they are required to do this in an environment with potentially material regulatory and market risk. There is currently no entity with an obligation to plan pipeline developments on the basis of system or market benefits.

A VIP would facilitate investment by focusing on the net overall benefits of potential investments to service delivery (i.e. improved transmission capability) and managing the stakeholder consultation and regulatory approvals processes for such investments. A VIP could also facilitate competition in provision of services for augmentation of the shared transmission network in order to increase the level of service provision to users.

c) *Facilitating a coordinated approach to energy nationally*

The ACCC and COAG's Energy Markets Review have endorsed this approach for the national electricity regime. It may have significant advantages for application in gas as each of the isolated pipelines across the nation link up and try to form a national gas grid.

The current position sees the emergent national gas grid at the early stages of development that characterized the electricity transmission grid in the early 1980's. However, today the markets being served by this infrastructure are much more developed. The markets are already co-joined, and the eastern seaboard is serviced by a few major dual-energy retailers who each have significant portfolios of supply sources across each of the States and with a market base in most of them. These retailers are advocating market arrangements that give them the opportunity to manage their portfolios efficiently so as to maximize their competitiveness in serving their markets. In terms of gas, this implies that a broader focus is required, that is, one which looks across the whole eastern seaboard, rather than treating each segment of the grid individually on a pipeline to pipeline basis.

VIP would provide the first step on this road, and introduce arrangements that for the first time would better align electricity and gas transmission services under the current national competition framework, to the benefit of the Victorian community.

3.2 Key Features

A VIP need not necessarily completely replace the current arrangements whereby the pipeline owner (GasNet) seeks to identify commercial opportunities, proposes and seeks regulatory approval for expansion of its rate base for augmentations to the PTS. It is conceivable that a VIP could be implemented as a fall back option (a "planner of last resort"), should the pipeline owner choose not to pursue certain investments where the VIP believes there are potential system or overall market benefits in doing so.

Another option is canvassed in ICF Consulting's Report on the Definition of Design Packages (24 December 2003), whereby VENCorp fulfils the role of the Independent Planner by undertaking planning studies at the request of participants, seeks participants to subscribe to the proposed expansion based on the likely cost and benefits, and only proceeds with the project if it is fully subscribed.

The following is a summary of another possible VIP model, where it assumes full responsibility for planning of PTS expansion/augmentation:

- VIP would plan and direct the augmentation of the PTS, which would be treated as a shared gas transmission network. Importantly, the aim would be to achieve this under and in accordance with the requirements of the Code[3]. In order to address existing, emerging or forecast future transmission constraints, VIP would also seek to procure alternative services which do not involve investment in the transmission network where these alternatives were considered to be more efficient.
- VIP itself would not own any transmission assets and it would operate on a not for profit basis. Stringent measures would be needed in terms of its structure and governance to ensure that its independence from vested commercial objectives is maintained. As such, it would have no commercial incentive to over-invest in the pipeline and over build the asset base. Rather, VIP would seek to augment the transmission network only where this is assessed to be for the net benefit of the overall community. VIP would be required to directly consider effects on related markets in electricity and gas that are impacted upon by service provision by the covered pipeline.
- VIP would enter into long-term service contracts (i.e. "Network Agreements") with an asset owner or other service providers for the provision of an efficient level of transmission capability, with these

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3 National Third Party Access Code for Natural Gas Pipelines

agreements usually providing for strong performance incentives for delivery and ongoing performance of a service[4].

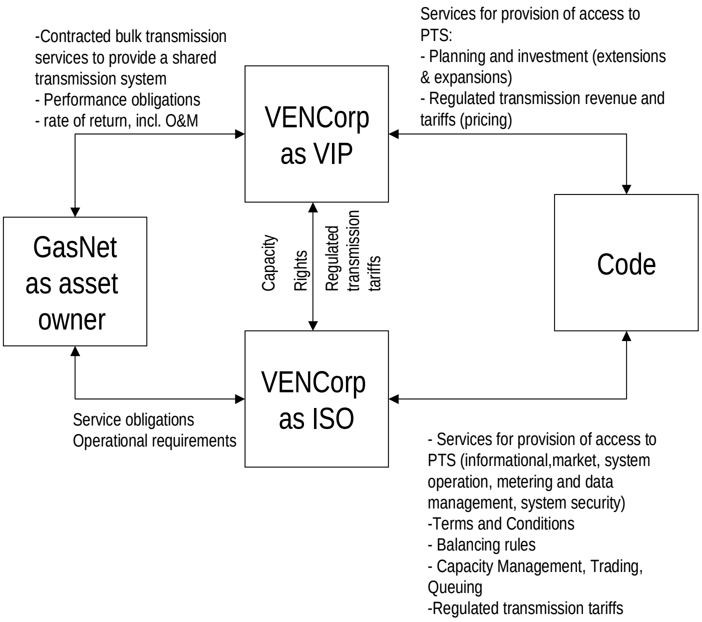
- VIP would operate under a set of planning criteria based on satisfying a "market benefits" test. This market benefits test would be approved by the relevant economic regulator and require an objective assessment of overall costs and benefits to substantiate an investment, rather than relying on a reliability requirement, and would not be limited to procuring services based on investment in transmission infrastructure of the PTS alone.
- VIP would examine all appropriate solutions to a transmission constraint and may, if feasible and practical, conduct an open competitive tender process, which is open to all appropriate solutions, including initiatives in supply and consumption, without commercial bias as to which of the available solutions is selected.
- The proposed market benefits test approach would utilise market driven costs and benefits to assess whether the optimal solution involves procuring service which rely on augmentation of the PTS, or may be better addressed by procurement of services arising from initiatives relating to supplies or consumption. Examples of this are services that provide more responsive and dynamic supplies and/or consumption patterns, preparedness to alter flow rates, ability to respond on short notice (e.g. non-firm gas supplies, interruptibility, fast response injections). In this context, a VIP's approach would be consistent with the proposals contained in Package 3 of the Pricing and Balancing Review that involves integrating arrangements for such services within the spot market.
- Where the independent assessment suggests that the optimal solution *is* augmentation of the transmission network, application of the market benefits test would determine whether or not network development returns a net economic benefit in the context of the broader market and community, not just in the context of whether it is an efficient and prudent commercial investment for the asset owner. As such, the market benefits approach would be compliant with the principles of the Code itself but more appropriate within a competitive market context where the "market" is broader than the covered pipeline alone.
- In cases where the investment has these broader advantages in service provision, application could be made under all three criteria of section 8.16 of the Code (economic feasibility, system wide benefit, and contracted capacity).
- GasNet's obligations would be to own and manage its share of the transmission assets that comprise the covered pipeline. GasNet, as owner of the current assets that comprise the PTS, is the main asset owner, and would hold the main Network Agreement with VIP for bulk transmission services. Transmission augmentations would be classified as either contestable or non-contestable. GasNet would undertake all non-contestable augmentations (subject to a "fair and reasonable costs" obligation), which are investments in transmission network assets that are not technically or commercially feasible for other providers to undertake. Contestable augmentations would be investments that are open to competitive alternatives.
- The following model for gas in Victoria as illustrated in Figures 1 & 2 below may provide a suitable means of integrating a VIP with the Code:
    - Service provision for access to the covered pipeline would fall between VIP as planner and VENCorp as ISO.
    - GasNet would provide services to VENCorp under contract, the main Network Agreement. This contract would be required to include the O&M costs for GasNet required by it to

[4] VENCorp's existing Service Envelope Agreement with GasNet would need to be revised and converted into a Network Agreement of this type.

provide the transmission capability services. GasNet would own and operate the assets comprising the bulk of the shared transmission network known as the PTS.

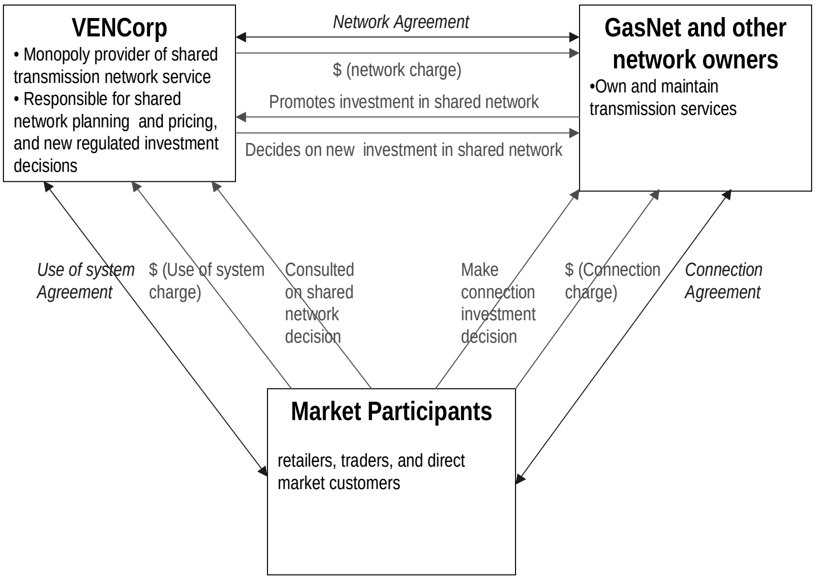
- Other contestable transmission services would likewise provide services to VENCorp under Network Agreements.
- In terms of the Code framework, VENCorp and VIP would be the service providers for users of the PTS. Other parties would provide transmission services under contract, which would not be directly regulated by the Code.
- Figures 1 & 2 below illustrate these arrangements on the basis that VENCorp would fulfil the role of VIP as well as its existing role of independent system operator[5].

Figure 1: VIP – Institutional & Regulatory Framework



[5] While an entirely separate, independent body could be established as the VIP, it is also conceivable that use could be made of VENCorp's existing Government ownership and independent governance structure, such that VENCorp takes on the dual role of independent system operator and VIP for the PTS. Thus, while this is not necessary for implementation of a VIP approach, Figures 1 and 2 illustrate the potential framework for a VIP on the basis that this function is undertaken by VENCorp.

Figure 2: PTS Access – Contractual & Financial Arrangements



- Several aspects of the current regulatory regime require further examination:
  - The Code currently is based on incentive regulation, which provides incentives for regulated entities to outperform the benchmark approved by the regulator by either growing the market or performing more efficiently. A key factor influencing the current structure and application of the Code is that where the regulated entity is able to outperform the benchmark, it is permitted to retain the higher earnings. However, VIP would be an independent, not-for-profit organisation which would be obliged to return all cost savings and efficiency gains that it achieves during the regulatory period.
  - A VIP could work under an approved CPI-X revenue cap for the 5 year regulatory period, with a capital structure and regulated revenues which allow it to establish provisions for managing the costs and risks associated with facing a CPI-X revenue cap, to remain consistent with the principles embodied in the current Code. This increase in risk would increase the costs of VIP over an entity that is not exposed to such a discipline, however this should be offset by some corresponding reduction in cost in regard to GasNet's contract services under a Network Agreement, as it would no longer be exposed to this aspect of regulatory risk. However, if VIP operates as a not-for-profit entity the value and application of a CPI-X approach is questionable.
  - In addition, VIP would face significant non-financial incentives under the MSO Rules, State legislation and governance which would ensure that it conducts its planning activities in a transparent manner, accountable to market participants.
  - At the end of the regulatory period, the economic regulator could still review the investments comprising the services procured by VIP for transmission services and, if needed, re-optimise its revenue base. In this event, VIP would face the risk of any re-optimisation at this point, whereby it may face the risk of having the regulator exclude any investments which it feels are inefficient or surplus to the asset base required for provision of bulk transmission services managed by VIP. Whether or not this additional risk on the independent not-for-profit VIP is supportable or useful in the long run will greatly depend on how well the market benefits test performs. It would be expected that if the market benefits

test is recognised by the regulator as having performed appropriately over the period that such risk is minimised to factors relating more to the efficiency of the business rather than its investment decisions.

3.3 Limitations:

Rights are still required

Introducing an independent planner does not necessarily create an environment that obviates the need for better-defined rights to pipeline capacity. If a VIP is implemented in a way that complements the existing arrangements, whereby the pipeline owner is still afforded the opportunity to pursue commercially based investment, then AMDQ/AMHQ or some form of financial transmission right (either FTR's or shipping rights) would still be required. Even if this were not the case and the VIP assumed sole responsibility for investment decisions, then to the extent that there were still some form of locational pricing (either directly through the spot price or through some form of uplift charges), similar rights would still be required to allow those price differentials or "adders" to be allocated and managed.

Pre-approval

The concept of an independent planner probably works best with:

- A mechanism involving a clearly defined "market test" to be applied for all new investments;
- The market test being applied to all investment proposals through an Independent Planner with an appropriate governance structure, following an open, transparent and consultative process, thus enabling a binding "up front" decision by the regulator on investment decisions;
- The threat of subsequent re-optimisation being minimised – provided the investments have been delivered in accordance with the information provided to the regulator as the basis for its initial approval of the investment, and revenue requirements do not exceed the cap established at the time of the approval (with savings returned) – allowing the independent planner to minimise its costs of operation and risk and thereby maximise savings to the community.

It is questionable whether these features are entirely compatible with the current Code; however, the Productivity Commission is understood to be examining similar issues in response to concerns raised by asset owners during its current review of the gas access regime.

Interconnection Planning

It is unclear how a VIP would satisfactorily address the issue of investment in the expansion of interconnections with other pipelines and/or other States, or even the augmentation of the PTS to facilitate increased inter-pipeline or inter-State flows of gas through existing interconnected pipelines. Unless the resultant increased flows of gas on the PTS, and the incremental pipeline revenue that results, enable the "economic feasibility test" under section 8.16 of the Code to be met, how and on what basis would an Independent Planner determine whether to proceed with such an investment, and how and to whom would it allocate the costs of that investment, particularly if the usage of the additional capacity provided by the investment were to change over time? In this regard, the concept of an independent planner would be limited in being "State-based"[6]. Further development of rights that support an asset owner contracting directly for them with prospective investors may, therefore, be a more suitable approach for interconnection expansions while the access regimes in gas remain isolated to individual pipelines.

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[6] The concept of an independent planner as proposed by the Parer Panel in reviewing transmission planning in the national electricity market as part of its report on the national energy markets for COAG (December 2002) was to be applied nationally across all the interconnected transmission systems, allowing the planner to assess interconnections between systems in different jurisdictions on a consistent basis with a full set of market and network information.

4. Alternative Transmission Rights Proposals

Even with the introduction of more accurate price signals in the balancing market, VENCorp is not yet convinced that either modification to the existing AMDQ related rights arrangements, or the introduction of an Independent Planner for the PTS in Victoria, is capable of addressing the perceived issues relating to new investment in the PTS. While these initiatives may go some way towards improving the situation, particularly in relation to investments that may be required in the future to meet system wide increases in gas demand, they may not be adequate to facilitate further investment in the PTS for supply to a new major gas load nor would they overcome the issues raised by stakeholders with regard to investment to facilitate opportunities for increased interstate trade in gas.

This Paper therefore canvasses a number of possible approaches for the introduction of transmission property rights; which are as follows:

> *Financial Transmission Rights* – conceptually at least, these would be similar to the various forms of Financial Transmission Rights for which we have seen more than 5 years of practical application in some overseas electricity markets with locational spot pricing.
>
> *Shipping Rights* – the form of Shipping Rights being canvassed in this Paper would also be purely financial, except that those trading in the balancing market without the requisite amount of Rights would face financial penalties in addition to the normal exposure to inter-locational price differences in the balancing market.
>
> *Physical Capacity Rights* – in broad terms, the form of Physical Capacity Rights being considered here involve the priority scheduling of gas injections/withdrawals which are associated with firm capacity rights, and with other gas flows being scheduled on an interruptible basis.
>
> *Biddable Capacity Rights* – the form of Rights envisaged here display some of the features and characteristics of both the physical and financial forms of rights described above.

It should be emphasised that the proposals being canvassed in this Paper are still very preliminary in nature. In all cases, there would be a very considerable body of theoretical development and detailed design work needed before one could be convinced that any of them could provide a workable solution to the pipeline investment issue.

Table 1, overleaf, compares the suggested functionality and expected implications of the 4 capacity rights models as currently described in this Paper. It should be noted that these are initial views only, which could be subject to change as and when further work is undertaken in respect of each model.

Tables 2 to 6 provide a brief overview of each of the capacity rights models. In each of the tables, a key aspect of each of the 4 proposals is discussed so that the reader can compare each against the others. A more expanded discussion of each is provided in the Appendices.

A consistent theme that emerges from this discussion is that experience in the practical application of transmission rights-based models in electricity markets is not directly transferable into gas markets generally and into the Victorian gas market in particular. The relatively low level of storage in the form of linepack in the PTS as compared with most other gas transmission systems creates a number of unique operational challenges that would need to be reflected in the detailed design and application of any gas transmission rights-based model in Victoria.

In addition, there are a considerable range of unresolved issues that would need to be addressed and resolved if we were to attempt to implement any one of these capacity rights models in Victoria, and a considerable lead time would be needed to develop the theory and market test its application before committing to proceed with its introduction.

It should be noted that the same operational issues that cause the complexity and uncertainty about the application of any of these models in Victoria would still be present if Victoria were to introduce an access regime based on contract carriage. Arguably, any simplified form of contract carriage would merely mask these operational difficulties and smear the costs of managing them, just as an inadequately designed capacity rights model introduced in conjunction with market carriage would.

The discussion presented in relation to the Revenue Adequacy issue in Appendix 1 provides considerable insight into the theoretical challenges involved in developing FTRs. However, the same issues would impact on each of the other capacity rights models. Therefore, at this stage, all of the capacity rights models being canvassed in this Paper should be regarded as conceptual and unproven for application in the Victorian gas market.

Table 1: Comparative Summary of the Suggested Capacity Rights Models

	Financial Transmission Rights	Shipping Rights	Physical Capacity Rights	Biddable Capacity Rights
For which ICF Packages could the Rights be applicable?	Packages 4 & 5 only	All packages	All Packages	Packages 4 & 5 only
Would the Rights be scheduled?	No	No	Yes	Yes
Would they hedge price differences in the BOD schedule?	Yes - probably	Yes - probably	Yes – if scheduled	Yes – if scheduled
Would they hedge price differences for deviations in on-the-day revised schedules?	No	No	No	No
Could the Rights holder physically withhold them from the market?	N/A	N/A	Probably not	No
Could the Rights holder be liable for difference payments if the locational price difference is negative?	Yes	Unresolved	No	No
Would the Rights be capable of incentivising adequate new investment in the PTS?	No	Possibly – if penalty charges are "right"	Possibly – if penalty charges are "right"	Probably – if prices are not unduly capped
Would the Rights be tradeable?	Yes	Yes	Yes	Yes
What would be likely Impact on GasNet tariffs?	Minor	Substantial	Substantial	Substantial
Ideally, who should issue and administer the Rights?	VENCorp	GasNet	GasNet	GasNet
Would it be feasible for VENCorp to issue and administer the Rights on an interim basis?	N/A	Probably	Unclear	Probably

Table 2: Alternative Capacity Rights Models: Key Features

Form of Rights	Key Features
Financial Transmission Rights	FTRs provide a financial hedge against inter-locational price risk in markets with locational pricing. The degree of firmness of the hedge depends on the detailed design of the hedge instrument. FTRs are generally unidirectional, two-way instruments. The holder receives a hedge payment when the price at the nominated offtake point exceeds the price at the nominated injection point, and the hedge applies to a nominated energy quantity in each trading interval. However, the holder usually has a liability to pay a difference payment to the seller when the price difference is negative. The quantum of FTRs issued to the market is limited to a combination that would be physically feasible for the network to support on a firm basis assuming all network facilities are in service. A feasible set of FTRs is one for which the seller of the rights is assured that there will be revenue adequacy to meet the difference payments payable under any physically feasible market outcome. As GasNet wholly owns the PTS, the FTRs could be issued either by VENCorp or GasNet. FTRs would be expected to be fully tradeable, and they have no direct impact on scheduling or price determination in the balancing market.
"Shipping" Rights	Shipping Rights are also purely financial in that they have no direct impact on the scheduling and price determination in the balancing market. They are also extremely flexible and arguably could be introduced in conjunction with a wide variety of balancing market designs, ranging fro m the current daily ex post single price market through to a full hourly nodal market with ex ante pricing. The have 2 key financial components: (i) The first relates to hedging or protection against congestion costs (provided the congestion is not the result of deviations by the rights holder from the BOD schedule). In a locational spot market, they would have very similar functionality to a "conventional" FTR. Where there was only a single market price, the Rights would have a similar application to the current AMDQ mechanism to protect the rights holder from some uplift costs. (ii) The second involves a comprehensive regime of penalties (paid by shippers without the requisite Shipping Rights) and rebates (payable to Rights holders who do not fully utilise their rights and the freed up capacity in the network is then used by shippers without the requisite Rights). The prime purpose of the penalties and the rebates is not to punish those without Rights but to create the correct price incentives for all participants to underpin new investment in the PTS by purchasing new Rights at the appropriate time.
Physical Capacity Rights	Physical Capacity Rights would directly impact on scheduling and pricing because the Rights, when linked to specified gas injections and offtakes, would be given priority over other dispatch bids and offers. Physical capacity rights would probably be defined in terms of firm access and interruptible access. They provide holders of firm rights with first priority in scheduling, but where this capacity is not scheduled, it would automatically become available for scheduling of others flows in accordance with bids, allowing overall system balancing to be managed via spot market processes. Individual shippers would still not be required to be in balance - spot market utilised to manage individual imbalances to ensure that the overall system is in balance in the most economic manner (based on a transparent process using bids for gas from participants). When used in conjunction with locational pricing, the Rights would offer the same sort of protection against inter-locational price differences that would be available for a "conventional" FTR. In order to provide sufficient incentive to drive efficient new investment in the PTS, either the holder of the Rights should be entitled to withhold them from the market (i.e. prevent their use by others) or alternatively, a system of penalties and rebates as suggested in the Shipping rights proposal would probably be needed. These arrangements would also probably need to attempt to track and allocate linepack by participant across the paths and at the points defined in the issue of physical capacity rights.
Biddable Capacity rights	Biddable capacity rights would be bid into the scheduling process for dispatch in essentially the same way as controllable injections and offtakes, and compete for inclusion in the least cost dispatch to clear the market. The rights would probably be unidirectional, one-way rights. The rights would probably be link-based (i.e. defined in terms of a right to transmit gas via a specific link or pipeline between 2 nominated points in the network). The total set of rights issued to the market would be limited to the combined capacity of the PTS assuming all facilities in service. The Rights holder would be entitled to receive difference payments for the full price difference between the 2 nominated points in the network. The price differences would be much more volatile because locational spot prices would now include a network component that would include the real time market value of the network capacity at the margin. This could be very high when the available network capacity is close to being fully utilised.

Table 3: Alternative Capacity Rights Models: How do they address the Stakeholder Issues?

Form of Rights	How does it address the issues?
Financial Transmission Rights	For packages involving locational pricing, FTRs are an effective mechanism for managing inter-locational price risk. The market price for FTRs at any time should reflect the market's overall expectations concerning future locational price differences in the market. As such, those prices are an efficient and highly transparent indicator of the future market costs of congestion in the network. Therefore forward FTR prices can be used by pipeline investors to assess the market value of new pipeline investment proposals and where necessary justify their proposed network tariffs to the economic regulator. The FTR prices could be used by GasNet (or an Independent Planner) to assess the extent of the 'system wide benefit' of any proposed pipeline augmentation, and therefore facilitate regulatory approval of the resultant network charges. Such a transparent indicator of market benefit may therefore facilitate new pipeline investment where it is needed within the general framework of the existing PTS access regime.
"Shipping" Rights	The Shipping Rights model can assist in the appropriate allocate of short-run congestion costs whether the balancing market includes locational pricing or not. In the case where there is locational pricing, in exchange for paying a fixed price for the Shipping Right, the holder of the Right would receive difference payments from the market operator which would in effect hedge its exposure to congestion costs. The Shipping Rights model would be capable of driving new investment in the PTS provided that either: • The holder of the Right was entitled to withhold the use of the Right from the market (under current competition and access laws and regulations, this option would seem to be non-viable); or • A series of penalties and rebate arrangements were to be introduced along the lines discussed in Appendix 2. The series of penalties and rebates would need to be designed very carefully to ensure that they provide appropriate price signals for new investment without causing unintended but nevertheless adverse market consequences.
Physical Capacity Rights	The design of the Physical Capacity Rights model being contemplated here would include provisions to deal with the dual issues of short-run congestion costs and long term investment signalling. Where used in conjunction with locational price signalling, the Right would contain financial features that reasonably closely parallel to treatment of both the short run and long run Similar to the Shipping rights proposal, in the case where there is locational pricing, in exchange for paying a fixed price for the Physical Capacity Right, the holder of the Right would receive difference payments from the market operator which would in effect hedge its exposure to congestion costs. Similarly, in order to address the long-term pipeline investment issue, on the basis that Rights holders would not be permitted to withhold capacity from the market, then presumably some form of penalties and rebates would be necessary.
Biddable Capacity rights	Similar to both the Shipping Rights model and the Physical Capacity Rights model, a Biddable Capacity Rights model would include sufficient mechanisms to address participants' needs to manage inter-locational price and quantity risk: • Firstly it would have an FTR element to enable participants to manage the costs and risk of short-run congestion costs and • Secondly, because biddable capacity rights prevent free-riders from gaining access to the transmission network without paying the full market value of the available network capacity at the margin, the market value of the Rights over an extended period should approach or possibly even exceed the long run marginal cost of the creation of new rights which would represent additional prudent investment in the network. Investors in new pipe would presumably pre-sell some if not all of the rights that would be created by the proposed new investment before committing to proceed with the investment. The market risk associated with the value of the new network capacity would transfer from the investor to the holder of the rights. However, this would be essentially the same as the market risk attached to a long-term gas supply contract from a producer. As a market would set the price of the Rights from time to time, the need for regulatory involvement would be reduced, although probably not eliminated.

Table 4: Alternative Capacity Rights Models: Limitations

Form of Rights	Limitations
Financial Transmission Rights	While the market price for FTRs may be a good indicator of the potential need for and overall value to the market of new pipeline investment, the creation of and trading in FTRs are not an effective mechanism for incentivising new pipeline investment because investment in new pipe to relieve a constraint will cause the market price of the relevant FTRs to collapse. When applied to a gas market, on their own, they also may not be sufficient to address all of the quantity and price risks associated with trading across a network with locational prices, particularly for shorter trading intervals. They may need to be supplemented with additional instruments and market rules relating to linepack trading and price hedging arrangements to address the inter-temporal issues involved in gas market operation, the role linepack plays in underpinning the capacity of the network, and the regional nature and constantly changing value of linepack from one trading interval to another. In addition, the need for revenue adequacy and the stringent limit it might impose on the number of Rights that may be issued could also limit the effectiveness of FTRs as a means of managing short-term inter-locational price uncertainty.
"Shipping" Rights	The key limitations of this model are: • The potential restrictions imposed (on the number of rights that may be issued) by the need for revenue adequacy (see earlier reference above); and • The difficulties that would inevitably be encountered in attempting to develop a robust set of price signals in the form of regulated penalties and rebates that would incentivise participants to fund economically efficient investment in augmentations of the PTS. In theory, the package of penalties (payable by shippers without the requisite Rights) and rebates (payable to Rights holders who did not use all of their Rights in the form of a redistribution of penalty payments received) should reflect the true short-term opportunity value of network capacity at the margin in each trading interval. However, it would be almost impossible to develop regulated charges that would provide such a signal, and some loss of efficiency would be inevitable.
Physical Capacity Rights	In theory, the holders of "Physical Dispatch Rights" have some control over the physical dispatch of their Rights and therefore can influence dispatch outcomes. In reality however, Rights holders would probably not be permitted to completely withhold any of the physical network capacity for which they hold Rights from the market. One would expect regulators to impose "use it or lose it" access rules that would in seriously diminish the benefits of introducing a physical form of Right. If this were to occur, it would then be necessary to introduce the same sort of penalties and rebates as discussed above in relation to Shipping Rights in order to restore the necessary incentives within the arrangements to drive new investment in the PTS. In these circumstances, any potential benefits of Physical Capacity Rights compared with Shipping Rights would probably be lost, but the added complexity in the scheduling process would remain.
Biddable Capacity rights	The concept of biddable capacity rights is relatively new and untested in either gas or electricity markets. A very limited form (i.e. market network services) has been used in the Australian National Electricity Market but with limited success because it has had to compete with 'free' regulated transmission. To fully hedge price differences between locations when a holder's rights have been dispatched, it may be necessary to impose additional obligations on the rights holder in the form of minimum linepack ownership requirements. This would recognise that energy traders can affect the short-term capacity of the network to the extent that their trading can change the level of linepack in various parts of the network at any point in time.

Table 5: Alternative Capacity Rights Models: Requirements/Prerequisites

Form of Rights	Requirements/Prerequisites
Financial Transmission Rights	FTRs would serve no useful purpose in the market in the absence of at least some locational pricing. Therefore, they would only be applicable in conjunction with Packages 4 & 5. The revenue adequacy requirement would impose a strict limit on the number of FTRs that could be issued for any particular part of the PTS. The issuer would need access to the settlement surpluses. However, depending upon the degree of firmness of the hedges, this funding may need to be supplemented with additional underwriting by GasNet (the cost of which would be recouped via network tariffs) and/or an additional uplift payment in the balancing market arrangements. The issuer of the rights would need to constantly track who holds the primary rights at any point in time for the purposes of settlements. As rights holders may have an obligation to pay the issuer when price differences are negative, there would be creditworthiness restrictions applied to potential traders in the primary instruments. This however would not prevent secondary trading by the rights holders of derivative products with other parties.
"Shipping" Rights	Shipping Rights could be introduced in an interim form wherein VENCorp issues the Rights and VENCorp also administers the arrangements on an ongoing basis. Alternatively, they could be introduced and administered by GasNet. The requirements in each case would be somewhat different: *VENCorp administered arrangements* – Presumably VENCorp would need to issue Rights for the existing pipeline capacity taking into account current GasNet PTS tariffs. The way to do this fairly and equitably would need to be determined. Also, VENCorp and GasNet would need to agree on what new Rights may be issued in the event the PTS is augmented. VENCorp would also need to establish the systems and procedures to track ownership of the Rights including short-term transfers. *GasNet administered arrangements* – Presumably GasNet would modify the current structure of their PTS tariffs for them to be more compatible with a Rights based regime, and presumably the purchasers of the Rights would be seeking contractual guarantees from GasNet re the ongoing capacity of its network. VENCorp and GasNet would still need to agree on what new Rights may be issued in the event the PTS is augmented. Presumably, VENCorp would still administer the balancing market and provide the settlement surplus to GasNet to make the required difference payments to Rights holders. However, in a market without locational pricing, presumably VENCorp and GasNet would need to cooperate to ensure that uplift costs were allocated amongst participants as intended.
Physical Capacity Rights	As Physical Capacity rights would involve similar functionality to other forms of Rights being canvassed in this Paper, the same prerequisites would generally apply in terms of: • Liaison and agreement required between GasNet and VENCorp in order to define the amount of Rights that may be issued and to properly administer the financial transactions associated with settlements; • Probable revision of the PTS access regime in general, and GasNet's PTS tariffs in particular, to allow it to switch to capacity based charges; and • Revenue adequacy. In addition, the introduction of Physical Capacity Rights would introduce added complexity into the scheduling process that would not be needed for other forms of Rights.
Biddable Capacity rights	The introduction of biddable capacity rights in conjunction with intra-day locational pricing would be a paradigm shift in the design of the market and would probably necessitate the development of a new MOS as well as a new system for day-to-day administration and market settlement of the rights arrangements. In addition, the other prerequisites listed above in relation to Shipping rights and Physical Capacity Rights would largely apply in this case as well. In particular, in the Victorian context, a transparent process involving both GasNet and VENCorp would need to be established to manage the processes of rights creation, trading, bidding and settlement that are totally compatible with VENCorp's needs for both scheduling and operation of the balancing market.

Table 6: Alternative Capacity rights Models: Unresolved Issues

Form of Rights	Unresolved Issues
Financial Transmission Rights	Defining FTRs that would be effective risk management instruments for addressing both the price and quantity risks involved in trading across a gas market with locational pricing has, to our knowledge, not been attempted elsewhere as yet, and there are many complex unresolved technical issues associated with the detailed design of the instruments and how they would address inter-temporal and linepack related matters associated with the physical operation of a gas network. Other unresolved issues include how firm the rights should be and how they would be underwritten to give them the intended level of firmness, how to transition from the existing AMDQ rights based regime to an FTR based regime, how if at all an FTR based regime would impact on the existing PTS access arrangements and related network tariffs, who would be responsible for issuing them and settling the difference payments, how and how frequently the primary instruments might be traded, and how the forward prices for FTRs could usefully be applied as an indicator of the total system benefit to be gained by further network investment.
“Shipping” Rights	Virtually all of the same issues that need to be resolved in relation to the introduction of FTRS would equally apply to the introduction of Shipping Rights. Some of the key questions that arise include the following: - What would be the precise form and allocation of shipping rights. How would the issuer determine the available capacity on each pipeline sector as a basis for issuing rights- when the capacity is dependent upon on scheduled gas injections and withdrawals at various locations, and on the PTS, there will be loop and bi-directional flows to be taken into account. There would also be a need to extensively redesign of the current transmission access regime and associated contractual environment across the industry. This would probably involve a major re-work of the transmission access regime for the PTS and consequential approval by the energy regulator, and impacts on much of the current contractual environment that is often based on long-term commitments. How to develop an appropriate set of penalties and rebates is probably the most critical unresolved issue associated with this Rights model because this will determine whether or not a practical “Shipping Rights” model that would also be an efficient and effective driver of new PTS investment is even feasible.
Physical Capacity Rights	In addition to the other unresolved issues that are common across each of the capacity rights models, the Physical Capacity Rights model introduces further issues in terms of precisely how the Physical Capacity Rights would be scheduled in VENCorp’s scheduling process. If Rights holders are to be given some sort of priority in the scheduling process, the scheduling rules that would in effect determine what this priority would be would need to be resolved in some detail in order to fully assess the feasibility and relative merits of this approach compared with the other models. As they are physical by definition, they would presumably be linked to specific injection offers and offtake bids, which do not necessarily need to be matched, as this is the role of the balancing market. The precise form and allocation of physical capacity rights. How are rights defined? What are the paths along which capacity is defined, how are these defined, is their long-term definition suitable for addressing shorter term market outcomes? How does issuer determine the available capacity on each pipeline sector as a basis for issuing rights- will be dependent on scheduled gas injections and withdrawals at various locations, and on PTS there will be loop and bi-directional flows. Where rights are implicitly path based, it is highly problematic to manage capacity on a network. This model would probably also require linepack allocation and tracking to manage within day aspects –how to do this would need to be resolved.
Biddable Capacity rights	Access rules would also need to address market power issues as well as market revenue distributions associated with rights that are only partially dispatched and the use of ‘unsold’ rights (i.e. those still being held by pipeline investors who are not active traders in the market). Therefore, there would be a range of complex competition and pricing related issues to be resolved, and defining the feasibility test, assuming it can be done, would also be a complex exercise. In addition, the dispatch algorithm in the Market Clearing Engine would be much more complex than for a market with so-called full locational pricing (i.e. Package 5 without biddable capacity rights), and the unresolved inter-temporal issues associated with locational and intra-day pricing models would be even more challenging. As with other rights-based models, the overall arrangements would need to address and resolve inter-temporal issues such as linepack management, and the transitioning of existing AMDQ property rights regime into the new arrangements.

5. Proposed Way Forward

Given that all of the capacity rights models canvassed are quite speculative in nature, VENCorp is concerned that resolving which rights-based approach should be preferred for incorporation into the market design packages where appropriate has the potential to cause considerable delays in the review process and could jeopardise a timely conclusion to the Review. In addition, given the complexity of the issues to be resolved and the pioneering nature of the work, in VENCorp's view, it would be quite unrealistic to expect that this could be completed within the current budget and timeframe for the Pricing and Balancing Review.

In these circumstances, VENCorp proposes that the Review should proceed on the following basis:

> *Initial Package Definition & Evaluation:* - ICF Consulting have included their recommended capacity rights approach in each of the market design packages where appropriate, and this is discussed in some detail in their 24 December 2003 report. VENCorp believes that the iterative approach to the evaluation and refinement of the packages should proceed as planned, and the current target date for the public release of their draft report (i.e. 24 February 2004) remain unchanged.
>
> *Canvassing of Stakeholder Views and Concerns* – VENCorp is proposing to canvass stakeholder views and concerns about the alternative models described in this Paper, and this is discussed in more detail in Section 6 below.
>
> *Further Work* – Subject to stakeholder feedback and VENCorp discussions with Government officials, VENCorp proposes to launch a further work program in January 2004 in corroboration with GasNet that will aim to:
>
> (a) More fully describe each of the models and its proposed functionality;
>
> (b) Identify its impact if implemented in terms of:
>
> (i) The extent to which it would drive new infrastructure investment in terms of the most efficient type and location of investment,
>
> (ii) Required changes to the balancing market functionality in each of the applicable packages,
>
> (iii) Required changes to the current access regimes of VENCorp and GasNet,
>
> (iv) Its effect on market participants and market behaviour; and
>
> (c) More fully define their weaknesses.

VENCorp would then aim to publish the findings of this work in parallel with the timing of ICF Consulting's draft final report in February 2004 for a further round of consultation before ICG Consulting's evaluation of the packages is finalised.

This approach would enable the current ICF Consulting work to proceed as planned whilst the various approaches to capacity rights are looked at in more detail by VENCorp and GasNet taking into account the objectives of the Pricing and Balancing Review as well as the various constraints of the National Gas Code and the national regulatory framework for access to covered pipelines in Australia, and the rights of GasNet as owners of the PTS.

6. Stakeholder Feedback

VENCorp would welcome stakeholder feedback on the various options for addressing the pipeline investment issue that have been canvassed in this Consultation Paper and the proposed way forward. To this end, VENCorp will be conducting a Workshop on the matter, to be held at the World Trade Centre on Thursday, 29 January 2004. Those wishing to attend should contact Peter Ferretto at peter.ferretto@vencorp.vic.gov.au.

In addition, to assist individual parties or stakeholder groups in informing themselves of the issues or in formulating a response to this paper, VENCorp will also consider and seek to accommodate requests for individual meetings or workshops – subject to resource availability.

Such requests and written submissions from stakeholders should be sent to Peter Ferretto at VENCorp. While late submissions will still be considered to the maximum extent practicable within the constraints of the timetable for the review, the closing date for lodgement of submissions is Friday, 6 February 2004 and should be sent in electronic form to the above email address. Alternatively written proposals may be sent or faxed to:

Mr Peter Ferretto

VENCorp

PO Box 413

World Trade Centre

MELBOURNE VIC 8005

Facsimile no. (03) 8664 6511

Appendix 1: Financial Transmission Rights

It is useful to begin by describing what a Financial Transmission Right is. Suppose a gas supplier can supply at a marginal cost of c and sells a quantity Q_1 of gas at its local spot price of P_1. Its effective spot market profit is $Q_1 (P_1 – c)$.

Now suppose that this supplier has a contract for differences to supply a quantity of gas Q_C at a price of P_C at another time or location where the price is P_2. In settling this contract, the supplier will earn an amount equal to $Q_C(P_C – P_2)$. Thus when P_2 is less than the contract price, the supplier earns revenue, but otherwise it pays. Its net profit is:

$$\begin{aligned}\text{NET PROFIT} &= Q_1 (P_1 - c) + Q_C(P_C - P_2)\\ &= (Q_CP_C - c\,Q_1) + (P_1 Q_1 - P_2 Q_C)\end{aligned}$$

The first of the two bracketed terms describes the net profit the supplier would make if the contract for difference were defined at the same node and time as its spot market sales. The second term describes the cost associated with the shipping of that gas to the time/point of contract settlement. This shipping cost is uncertain, as we do not know the price difference ahead of time, and transmission constraints create the danger that the supplier is constrained–down, causing Q_1 to be less than Q_C. Thus there is both price and quantity risk when trading in a market with locational pricing.

A Financial Transmission Right would alleviate the risk of the supplier by returning it the price difference between the supply point and the contract point. If the supplier held an FTR for a quantity Q_C from point 1 to point 2 then it would return an amount equal to $Q_C(P_2 – P_1)$ in each trading interval.[7] The net profit of the right holder becomes:

$$\begin{aligned}\text{NET PROFIT} &= Q_1 (P_1 - c) + Q_C(P_C - P_2) + Q_C(P_2 - P_1)\\ &= Q_1 (P_1 - c) + Q_C(P_C - P_1)\\ &= (Q_CP_C - c\,Q_1) + P_1 (Q_1 - Q_C)\end{aligned}$$

The first of the two bracketed terms again describes the net profit the supplier would make if the contract for difference were defined at the same node and time as its spot market sales. The FTR has largely eliminated the risks associated with shipping, the second term now only representing the risk associated with being scheduled to provide an amount that differs from Q_C. If the supplier produces exactly Q_C then the second term is zero. Further, if the supplier is constrained down, we would expect P_1 to drop below the supply cost of c so Q_1 would drop to zero (since the price is less than its supply cost) and the net earnings becomes: $(Q_CP_C – P_1 Q_C)$. But since P_1 is less than c, the supplier is now earning more than the $(Q_CP_C - c\, Q_c)$ it would have earned had there been no constraints and it had supplied exactly the contract quantity.

In essence therefore, the difference payments associated with a Financial Transmission Right provide an efficient and effective method of hedging inter-locational price differences in a market with volatile and highly uncertain inter-locational price differences.

Key Features:

Establishing a market in FTRs within the context of the Victorian gas market would require most of the features one would normally associate with other established FTR regimes.

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[7] An option could be defined whereby the right only returns an amount if that amount is either positive or negative but not both. However, here we assume it is an obligation, whereby the FTR could return a positive or negative amount. Most electricity markets with node-to-node FTRs employ obligations, though some of them also offer a small range of options.

Subject to achieving revenue adequacy (see below), one would expect the FTRs to display the same basic features as their electricity market counterparts; namely each FTR would be for a defined quantity of gas for each market trading interval for the duration of the right, and it would also include a nominated injection point or node and a nominated off-take point or node. The financial right associated with the instrument would be defined in terms of the right to receive (and a corresponding right to pay) difference payments in the event of price differences in the market between the nominated nodes in accord with the formula $Q_C(P_2 – P_1)$ as described earlier. The FTRs would also be firm under virtually all market conditions.

FTRs could be issued either by VENCorp in its role of independent market and system operator or by GasNet in its role of pipeline owner. The most appropriate body for issuing the FTRs and administering the arrangements would depend on:

- How the revenue adequacy issue is resolved and the source of any residual funding that may be necessary in this regard; and therefore
- How the network related operational and availability risks associated the PTS are allocated between GasNet and network users.

However, regardless of which organisation was responsible, it would need access to the settlement surpluses generated in the balancing market as the prime source of funds for making the difference payments to holders of the rights.

Limitations:

While FTRs are a highly effective mechanism for hedging inter-locational price risk in volatile markets, it is now generally accepted that, on their own or in conjunction with spot electricity markets with so-called “full locational pricing”, they do not provide sufficient incentive to participants or pipeline investors to fund new investment in the network. Electricity markets with FTRs still have as an integral part of the market framework, other levers such as an obligation to supply or a centralised planning function to ensure the needed investment takes place.

The same fundamental limitation in the value of FTRs would apply if they were to be introduced in the Victorian gas market in conjunction with locational pricing in the balancing market. The reason for this is that, while inter-locational price differences may be quite high when a pipeline constraint occurs, as soon as any new pipeline investment relieves the constraint, the locational price differences collapse. This then allows those who have not funded the investment to relieve the constraint, free access to the pipeline. That having been said, forward FTR prices however are a very useful indicator of the market value of pipeline capacity augmentations, in which case they can be used to help justify new investments to the economic regulator and therefore facilitate needed investment to satisfy the requirements of the market.

Unresolved Issues:

Although there is a growing body of experience with the practical application of FTR models in overseas electricity markets with locational pricing, that experience is not directly or readily transferable into an equivalent FTR regime in a gas market. The reasons for this are illustrated in some detail in the discussion regarding revenue adequacy below.

Resolving the revenue adequacy issue would also require resolution of other related issues including definition of appropriate risk allocation arrangements associated with the FTRs, dealing with the temporal inter-dependencies that affect pipeline capacity and other operational constraints on the network, and the linkages between the FTR arrangements and GasNet’s pipeline tariffs.

In addition, as with any of the other potential rights based models canvassed in this Paper, a suitable transition strategy for implementation would be needed that took due account of existing AMDQ and

AMDQ credit allocations, as well as the current GasNet and VENCorp access regimes relating to the PTS and how they might need to be modified.

Revenue Adequacy

While FTRs appear to be a valuable and simple device, there is another aspect of them that is relatively complicated to address in electricity markets, and which is unproven in gas markets. This concerns revenue adequacy.

A set of FTRs can be considered revenue adequate if the settlement surplus collected in the spot market is adequate to fund the FTRs. Consider a simple two-node example. The gas flow between node 1 and node 2 is at its capacity of 2 TJ/hr with the price at node 1 being $3/GJ and that at node 2 being $5/GJ. The settlement surplus is the difference between what the consumers pay and what the suppliers must be paid. This surplus is ($5-$3)× 2000 GJ/hr or $4000 per hour. If the FTRs that have been issued do not exceed 2 TJ/hour between these nodes, the settlement surplus will be able to fund the FTR payments, and the revenue adequacy requirement will have been satisfied. If more FTRs are issued (without issuing FTRs in the reverse direction that cancel them) then there would not be enough revenue to fund the FTRs.

In electricity, revenue adequacy has been applied not just between individual nodes, but across entire networks. In effect, all FTRs are scheduled simultaneously through a tool like a market clearing engine, which will only allow a set of FTRs to be sold that corresponds to a physically feasible flow.

There has been substantial work on revenue adequacy in regard to electricity FTRs, with the original work pre-dating the first implementation of FTRs by over 10 years. By contrast there has been very little work done on how the theory of FTRs work in the context of gas. While we would expect the general concepts to carry over, no one has ever developed a description of a fully consistent and revenue adequate model for FTRs.

Some issues that complicate FTRs in the context of the Victorian Gas Market are:

- If gas is injected in one period but not consumed in that period, than we cannot define a revenue adequate FTR for that single period unless we explicitly account for the net change in value of linepack within that period. If an hour starts with no linepack, 10 GJ is injected, and no gas is consumed, then we will not have revenue adequacy in that hour unless we treat the 10 GJ of stored gas as being a demand for gas in the current period and a sale of gas in the next period.
- A similar issue exists if we define an FTR over an entire day, as we still need to account for the change in linepack over the day. Suppose we define a "daily FTR" as being a profile of injections or withdrawals across the day. If we account for linepack then we might expect to be able to form a revenue adequate daily solution. However, this has yet to be proven, since the injections and off-takes in each hour will have different prices, and it has not been proven that revenue adequacy holds for any feasible injection and off-take where the injections and off-takes occur in quite different time periods.
- Valuing linepack is required for a fully general FTR regime, but this is not a trivial task. There is not one value of linepack across the whole market; rather, linepack can have different values in each pipeline if the system is sufficiently constrained. Further, depending on precisely what formulation is used to generate gas prices, it is not necessarily true that the price of linepack in a given pipeline equals the price of gas at either of the nodes connected to that pipeline. If a large section of the gas system were unconstrained over many hours then we would expect gas prices and linepack prices in that region to be the same. However, just as nodal gas prices can exhibit complex patterns in the event of pressure constraints, so can the value of linepack given pressure or linepack constraints. During testing of an early version of the MCE (which used a different formulation from that employed to day) it was demonstrated that an impact of end of day linepack

constraints could be to make the marginal cost of linepack quite different from the prevailing marginal cost of gas.

- While most FTR examples are presented in terms of there being a quantity of gas that is constrained by some physical limit, the reality is more complicated. Gas flows tend to be constrained by limits on pressure changes across a pipeline, while linepack tends to be constrained by the maximum and minimum pressure limits of a pipeline. Thus the problem has more dimensions than the equivalent electricity problem. Further, electricity power flow equations tend to involve a combination of quadratic terms and sines and cosines, which are relatively well behaved, while gas flow equations are significantly more complex equations. The current MCE formulation includes 4^{th} order polynomials and terms raised to fractional powers. Deriving the revenue adequacy rules is quite involved for electricity, and will be significantly more involved for gas.
- The existing pricing regime schedules gas over a 24-hour period so that the revenue earned over 24 hours recovers the costs incurred over 24 hours. However, the price in any given hour may be less than the daily marginal cost of a GJ of gas. It is not immediately obvious how contract for differences between market participants would work under this regime given that the energy revenue recovery is only guaranteed over the day, but the locational and time dependent prices we are trying to hedge are only sub-components of that final settlement position. Given this, it is not clear how we would define an FTR for the current nodal pricing model. Any alternative spot market pricing regime has to be defined before we can analyse the FTR properties of that regime.

It follows that defining a workable FTR regime requires that we:

- Define a workable locational spot market with prices relative to which market participants could form meaningful bilateral contracts,
- Analyse the gas flow equations for that spot market model, including forming the partial derivatives of the gas flow equations and deriving the dual pricing optimisation problem, to determine a set of revenue adequacy rules.
- Determine the conditions, if any, under which revenue adequacy would hold.
- If revenue adequacy holds, or if not but if an additional source of funding can be found, design a set of hedging instruments.
- Verify that the set of hedging instruments so defined provide an adequate hedge for market participants, and are not so complicated that the market participants will not want to use them.

This discussion serves to illustrate the high level of complexity and the pioneering nature of any attempt to develop a practical workable model for the application of Financial Transmission Rights in the Victorian Gas Market. It is also quite possible that after having spent considerable time and effort in an attempt to resolve the complex, inter-related issues discussed above, it could become apparent that FTRs in gas are unworkable, or alternatively, would need to involve practical simplifications and approximations that collectively diminish the efficiency and effectiveness of the instrument as a mechanism for managing inter-locational price differences in a gas market.

Appendix 2: Shipping Rights

Shipping Rights as envisaged in this Paper are a financial form of transmission right that would overcome the main weakness of conventional FTRs; i.e. they would include additional pricing signals that, if appropriately designed, should in theory provide sufficient incentive to drive new pipeline investment.

Their main advantage compared with the other Rights models is that, subject to overcoming the concerns relating to the detailed design of the associated financial arrangements, they are potentially the most flexible of all of the models canvassed in this Paper. For example, they could potentially be applied in conjunction with almost any type of balancing market design with marginal pricing and reasonable allocation of costs on a causer pays basis. For example, they could equally be introduced in conjunction with the current market design with a single daily ex post price or in conjunction with a full hourly nodal market with ex ante pricing.

Combining Shipping Rights with other pricing approaches, such as ex ante pricing or locational/within day pricing, would result in an overall market design and access regime which far better allocates the total costs of transportation on the network in general, and in particular better allocates the cost of "surprise" events to those whose actions triggered the event whilst facilitating a more robust mechanism for supporting network investment. Shipping Rights are particularly compatible with the introduction of forward markets, and the combination would address the pricing and investment issues directly in a much more encompassing manner (i.e. total gas transportation costs) than a purely spot market based approach can.

Shipping Rights provide a right to use the gas transmission network essentially at cost, without exposure to costs caused by other users. They do not create the Right to have gas scheduled, however, as this function is performed in the spot market, and they would not directly impact on the scheduling or pricing of gas in the spot market; that, is, the Rights would not be recognized or taken into account by VENCorp in the scheduling or price determination processes in the balancing market, but presumably, they would impact on participant behaviour and therefore have an indirect effect on market outcomes. In addition, for efficient allocation of costs on a 'causer pays' basis, the Shipping Rights should not protect Rights holders from the recovery of the cost of "surprise" events where the holder's deviations from previously stated intentions are a contributing factor to those costs being incurred. This would need to be considered in the detailed design of the Shipping Rights.

In summary, those who held Shipping Rights and were scheduled, (and had a commodity price hedge via a gas purchase contract, forward market contract or bilateral contract) would have access to the system with real-time financial certainty about transmission costs, and would face no spot transmission charge, and would not need to settle with VENCorp. Any real-time deviations from forward market schedules however would need to be settled at the real-time gas prices.

Features:

Managing short run congestion costs

The core component of the suggested Shipping Rights model is a financial transmission right. In a market with locational marginal pricing such as would be the case with Packages 4 (Intra-day Hub Based) & 5 (Full Hourly Nodal), the FTR would be virtually identical in concept and application to the FTR model that has already been described previously in this Paper. However, if applied in a market without locational pricing, the rights would effectively displace the current AMDQ arrangements to determine the allocation of uplift costs, and, where feasible, to determine priorities for physical curtailment of gas demand where this was needed to protect the security of the gas system.

This core FTR component of the Right would provide an effective hedge for the holder against the volatility of the short-run costs of network congestion. For Packages 4 & 5, the holder of the Rights would be entitled to a difference payment (as well as being obliged to make a difference payment when the inter-locational price difference was negative) in exactly the same way as is envisaged for the FTR option.

On the other hand, for Packages 1 to 3, the holder of the Rights would be exempted from contributing towards the recovery of uplift costs that are a direct result of the congestion in the PTS between the 2 nominated points in the network to which the Right applies.

Shipping Rights would be associated with consumption but a corresponding supply point would also need to be associated with that Right. A forward market, either in the primary instruments or in secondary derivative products, would be highly advantageous to allow re-trading of Shipping Rights to facilitate a viable capacity release management program.

Incentivising long-term investment in the network

As has been discussed previously, FTRs that merely hedge the short run costs of congestion in the network are insufficient to drive new pipeline investment because they fail to prevent free riders gaining in effect free access to network capability that would have been underwritten by others. To overcome this, the Shipping Rights model includes an additional financial feature.

Market participants who require gas transmission across the PTS between locations for which they do not hold the requisite Shipping Rights would face additional penalty charges over and above their liability to pay short run congestion costs. Ideally, the penalty charges should be designed to provide network users with price signals that would drive economically efficient new investment in the PTS.

The holders of Shipping Rights who did not utilise them would be recompensed by those without pre-purchased Rights who effectively used the Rights of others by being allocated a fair and equitable share of the penalty payments received. The penalty payments and their subsequent redistribution would be equivalent to a pipeline tariff for short-term use of the network capacity, paid by the user of the network capacity and received by the beneficial owner of that capacity (i.e. as the holder of the requisite Shipping rights).

In summary, the Shipping Rights model offers:

- the possibility of far better allocation of costs to cause;
- the potential for market participants who have adequately covered their shipping requirements to achieve better certainty up front about their *total* gas transportation costs, both long run and short run; and
- a potentially effective means to incentivising new investment in the PTS as and when required by the market.

Limitations/Unresolved Issues:

Determining the Amount of Rights that can be Issued:

A critical issue to be resolved in a practical application of this model is determining the amount of Shipping Rights that can be issued for any given configuration of the PTS taking into account potentially feasible patterns of gas injections and offtakes that may occur from time to time.

Factors that would need to be taken into account in making this decision include the following:

(i) The degree of firmness in the detailed design of the Shipping Rights instrument and in particular the market-related circumstances under which the Shipping Rights would not offer protection against inter-locational price differences;

(ii) Any preconditions that may need to be satisfied in order for the holder of the Rights to be entitled to receive the benefits that the Rights may offer; and

(iii) The need for revenue adequacy to be able to make difference payments in accord with the terms of the Rights – this is discussed further below.

It is conceivable for example that there may be different forms of Shipping Rights. At one extreme, they may be firm under virtually all market conditions, while at the other extreme, they may only apply when the operating conditions in the PTS are such that the overall transfer capability of the relevant section of the PTS falls within pre-defined limits. Under this approach, there could be Shipping Rights that have varying degrees of firmness.

Secondly, as discussed earlier, the holder of the Rights may only be protected against inter-locational price differences or uplift costs where the Rights apply to gas injections and offtakes scheduled at the beginning of the gas day. Any deviations on the day that contribute towards a requirement for VENCorp to schedule high cost gas injections from the LNG plant or underground storage for example should not be exempted from paying their fair share of these uplift costs.

Thirdly, the capability of the PTS to transport gas across the system is dependent in part on system pressures throughout the network, and this is directly related to the amount of linepack in each section of the PTS. In these circumstances, it may be necessary to link the benefits offered by the Shipping Rights to linepack conditions and/or individual linepack holdings. In the case of the latter, this would necessitate the introduction of some form of linepack trading, and tracking gas flows and ownership of linepack through the network

Getting the Penalty Charges Right

Efficient pricing principles would suggest the penalty charges should be set at the true short run opportunity value of the transmission capacity that was utilised by the participants without the required level of rights. However, this would vary considerably from time to time and would be influenced by factors such as the overall loading on the network and the amount of spare capacity available at the time, the available flexibility in the production and consumption patterns to respond and adapt to impending pipeline congestion, and in the ultimate, the value foregone by consumers at the margin if their gas supply is involuntarily curtailed.

Presumably, the penalty charges would be set by or at the very least approved by the economic regulator. As it would be quite impractical for the level of the penalties to be set by regulation taking into account the highly dynamic and volatile nature of the above factors, at best, those charges may include some variation but they would most likely have a relatively simple, predictable structure and level, and it would be quite unrealistic to expect that they would deliver highly efficient price signals to participants. A critical issue therefore that would determine how effective this model would be for driving new investment would be the detailed design of the penalty charging and rebate arrangements, and this would need to be considered in parallel with the structure of GasNet's network charges.

Where additional Rights were created to underpin new investment in the PTS, presumably the network charges would be predominantly in the form of long-term capacity charges with only a relatively small volumetric component. In this situation, the structure of the rebates would be relatively straightforward. However, for the pre-existing network, if the network charges remained as essentially volumetric or variable charges, the structure of what would be deemed to be an equitable rebating scheme would be relatively more complex.

As the financial driver for new investment is in effect the expected difference in transportation cost faced by participants either with or without the requisite Rights, all of the transmission related charges (spot market price differentials, uplift cost allocations, penalties and rebates, and GasNet transmission tariffs) would impact on a participant's decision when considering the funding of new investment in exchange for new Shipping Rights.

In spite of the above difficulties and complexities, it may still be possible to develop adequate penalty and rebating arrangements that provide reasonably blunt but nevertheless quite effective drivers that would result in relatively efficient investment in new network facilities. Assuming this is the case, a remaining concern would be the regulatory risk associated with these arrangements. In effect, every time the regulator decided to change the penalty and rebating arrangements, this would have consequential effects on the market valuation of the Shipping Rights.

Revenue Adequacy

When applied in conjunction with markets with locational marginal pricing, the detailed design of the conventional FTR component of the Shipping Rights model faces all the same issues and challenges as would apply to FTRs and which were discussed in some detail in Appendix 1. This would impact on the overall combination of Shipping Rights that could be issued in conjunction with any marginal investment in the PTS, and it may also impact on the firmness of the Rights in terms of the extent of the protection they provide the holder against exposure to locational price differences in the market.

Compatibility with the current Access Regime

In its ultimate form, the Shipping Rights model would probably require a major overhaul of the existing arrangements for access to the PTS by both VENCorp and GasNet. A reasonably effective interim solution may be possible whereby the Shipping Rights arrangements are coordinated by VENCorp and the financial impacts are restricted to VENCorp and pipeline users only, with GasNet largely insulated from the arrangements. Ultimately however, because of the importance of applicable transmission tariffs in the overall arrangements, it would probably make sense for issuing of the Rights and their long-term administration to be the responsibility of GasNet in its capacity as PTS owner.

The Rights that could be issued would be determined by agreement between the asset owner and the independent system operator, and relate to system capacity. The Rights may be allocated by the asset owner, or an independent agency might allocate Shipping Rights, where the allocation would be designed to achieve a feasible set of rights given physical characteristics of the network and operational constraints.

Revenue from sale of the Rights should accrue to the asset owner to fund its investment in the pipeline. The asset owner's recovery of funding from users of the network assets would therefore switch from what is currently a primarily volume based tariffing approach to a capacity based tariffing, with a large proportion of its revenue fixed by being recovered under contracts based on fixed capacity, with part variable based on volume. This variable part is desirable to ensure that the tariffing principles are still based on the concept of reference tariffs rather than allowed rates of return, consistent with the current regulation of the industry whereby the network owner is able to earn higher returns if actual revenue exceeds forecasts.

Shipping Rights and the Independent Planner

In theory at least, the Shipping Rights model on its own may be an adequate driver of new investment in the PTS without the need for supplementary arrangements within the access regime. However, given the perceived difficulties in developing a well designed set of arrangements governing penalty payments and corresponding rebates, there could be some merit in considering the introduction of an Independent Planner of Last Resort in conjunction with this Rights model.

If this were to be done however, it would raise a whole plethora of new issues about the precise form of the IP's planning powers, how its investment decisions would be funded, who should have access to the new Shipping Rights created by the investment, the value effects of the IP's decisions on the market valuation of the pre-existing Shipping Rights in the market and so on.

Appendix 3: Physical Capacity Rights

- Physical capacity rights is a concept whereby a physical rights system, based on the transportation capacity of the pipeline, is introduced. These rights would be taken into account in the spot market dispatch process so that injection/withdrawal offers for which physical capacity rights are held are afforded priority both in terms of physical dispatch and spot market outcomes.
- Physical capacity rights will attempt to provide a means of better encompassing the complete transmission access regime by more completely integrating the spot market used for balancing and operation of the gas system with rights which underpin long term contracting in the assets of that system.
- Physical capacity rights would probably require a path definition. These arrangements may also need to track and allocate linepack to participants in each transaction period as gas is transported across the system.
- Physical capacity rights as canvassed in this paper are based on an approach whereby the asset owner is responsible for making network investment decisions. It's decisions are to be underpinned by contracts with investors, and the physical capacity rights are intended to provide the means of underwriting these contracts in the spot market dispatch and settlements processes.

Market carriage does not preclude rights to access, and was always intended to offer the means of combining such rights with a spot market (it is not common carriage). It's current form is a very simplified version of what market carriage may become, and this was the critical reason why a more sophisticated and effective rights system was not introduced initially. Under more developed market carriage arrangements, rights that offer firm and possibly physical access can and should be considered.

The Physical Capacity Rights model is based on an extension of the current market to incorporate a rights based system that will underpin longer term contracting by GasNet for access to the PTS. The proposal being canvassed in this section would allow GasNet to alter its current tariff design into one based primarily on contracts. The proposal is intended to develop into a rights approach that supports a new transmission access regime that is more completely integrated with the spot market that is utilised for daily balancing and operation of the system. The concepts presented in this section have been developed by combining the desirable features of more conventional contract-based forms of transportation regimes with a system operated by an independent system operator under a transparent centralised spot market which is suitable for operation in Victoria.

Key features:

The critical aspects involved in this conceptualisation of a potential future market carriage are:

a) *Balancing the system overall, using the spot market to manage and settle deviations and tolerances*

   Balancing the system would be conducted via a spot market which would attempt to determine the optimal way of balancing the system overall and the way the system is operated for total gas flows. Importantly, the concept does not require individual shippers to be in balance, rather utilises the spot market to ensure that the overall system is in balance in the most economic manner (based on a transparent process using bids for gas from participants). The spot market would accordingly provide the means for managing and pricing out tolerances and deviations from nominations in a highly transparent and orderly fashion. Such a conceptualization may require the allocation of and tracking of linepack by participant across the paths and at the points defined in the issue of physical capacity rights, and this proposal therefore incorporates some initial thinking on how this may be introduced.

b) *Right to use the pipeline*

The rights approach being contemplated under physical capacity rights would see the dispatch process explicitly incorporate physical capacity rights within its dispatch algorithm in order to prioritise usage of the system in accordance with the rights, thereby attempting to define and price out physical access.

Physical capacity rights would probably be defined in terms of firm access and interruptible access.

Importantly, the clear intention in market carriage is that there not be exclusive and preventive access to the system locked away by the firm capacity right allocation. The arrangements would be designed to provide holders of firm rights with a first priority in scheduling (providing physical access priority), but where this capacity is not used or needed by the holders in any given transaction period, it should automatically become available for others to use (at a charge), allowing overall system balancing to be managed via the interruptible gas within the processes of the spot market. Unused firm capacity in any transaction period will therefore be automatically released for use in balancing the system under the spot market much as interruptible capacity would be, based on participant bids and market outcomes. Secondary markets may eventuate for trading of firm capacity. A registration process would be required to inform the system operator of such trades, so that capacity that is traded by agreement between parties would still be treated as a firm right in the hands of the party to whom it is traded.

Additional features:

Physical capacity rights would seek to provide a firm right to use the gas transmission network (at a cost). It could also be extended to provide the means for participants to manage their exposure to costs caused by those without rights. Its primary focus would be intended to provide for physical priority based on the rights to be introduced in the dispatch process in the spot market.

The introduction of firm physical capacity rights should be more likely to underpin contracts that the asset owner could write to users and potential investors. These rights would therefore allow the asset owner to recover a larger proportion of its regulated revenue based on fixed contract arrangements.

In this form of the proposal, physical capacity rights could be allocated to users by GasNet, as asset owner, (presumably based on contracting). The rights which could be allocated would be determined by agreement between GasNet and the VENCorp, as independent system operator, and relate strongly to system capacity along pre-defined paths. This definition of the rights that could be offered would need to recognise the requirements to achieve a feasible set of rights given physical characteristics of the network and operational constraints. This will require good liaison between VENCorp and GasNet as to what rights could be issued for any given investment. Depending on what sorts of physical conditions are attached to the rights (e.g. force majeure relief, rights in the event of pipelines or compressors being out of service etc.), there is most likely the need for introduction of a strong performance guarantee between the GasNet and VENCorp to underpin the firmness of the rights.

The physical capacity rights being envisaged here would be associated with consumption at an offtake point and injection at a corresponding supply point along a set of pre-defined paths. The injection and offtake points would also be predefined. For example, under a hub-based pricing system, the following may apply:

- Long term definition of hubs and simplified hub-hub paths for purpose of capacity rights definitions (and implicitly, tariff policies where these rights are used to underpin long term contracting by the asset owner for regulated revenue), which included separate definitions for forward flows and reverse flows, and delivery rights from each hub to specific points. Hubs should represent natural centres of trading reflective of interconnections with other pipelines where pricing becomes more important. Examples of Hubs are Longford, Culcairn, Iona, and Dandenong City Gate.

- Capacity rights would be defined between Hubs (e.g., Longford to DCG) and be allocated to specific withdrawal nodes. Capacity rights would also include a component for intra-day variation in linepack and be associated with Hubs.
- One option could be for participants to provide bids for their capacity along each path, including multiple price steps
- Flow capacity and linepack capacity could be traded separately within a secondary market.

A liquid secondary market may eventually develop which allows for effective re-trading of rights to facilitate a viable capacity release management program. VENCorp would not need to develop a market for performing the trades (this could be conducted by OTC bilateral dealing), however, VENCorp would need to have processes in place to register the mechanisms (for capacity management based on rights transfers, for dispatch, and settlement implications) associated with desired trades.

Physical capacity rights would probably offer significant advantages when developed in conjunction with a forward market under which market participants could schedule their transactions ahead of time and settle upon forward contracts. Suppliers and consumers could define bilateral contracts by matching injections with off-takes in this market. Those who hold rights and are scheduled, (and have a commodity price hedge via gas purchase contract, forward market contract, futures contract or bilateral contract) would have their access to the gas system defined in with real-time financial certainty about total transmission costs, would face no spot transmission charge, and be protected from the costs of managing congestion within a day.

Those who do not hold physical capacity rights could be charged a transmission penalty rate, based on the long run cost of capacity expansion, for use of the PTS on a day. The revenue from this charge should be returned in the form of a rebate to those who hold physical capacity rights, as a rental payment by others for their effective use of others contracted firm capacity. The penalties for network usage by participants who do not hold the requisite rights would need to be set high enough so as to incentivise them to sponsor new investment in the appropriate times, but remain a fair and equitable penalty charge based on long run marginal cost. The primary question here, if such a scheme was considered an appropriate addition, is whether it should reside with VENCorp and be transacted out within the spot market, or whether it would make more sense for it to reside with GasNet as part of their tariff policy, by providing rebateable tariffs.

Unresolved Issues

Physical capacity rights would face the same revenue adequacy issues as would apply to FTRs, which are discussed in some detail in Appendix 1.

Possibly the most problematic matter in this approach is that it implicitly involves a long term pre-determination of the path definition of likely flows and location of potential constraints and natural pricing centres (hubs):

- it is very difficult to pre-define long term paths for physical capacity rights that will have ongoing relevance to short term considerations (such as dispatch) in a dynamic market. The PTS will shortly have five sources of supply, and the major users of the PTS are all major energy retailers with portfolio interests across the eastern seaboard. The PTS is in the middle this interconnected network, and the future use of the PTS will depend on market choices and outcomes by major retailers over time. In the future, this may see major shifts in flows from east-west or north-south on a seasonal or monthly basis, depending on the contracting, and even day to day or within day to manage NEM requirements or an unanticipated outage at a refinery;
- this means that market outcomes determine flows and constraints, and therefore influence the ongoing value of rights issued with an implicit path definition;

- The approach to modelling capacity constraints would need to address flow constraints (MDQ, MHQ capacities), intra-day linepack constraints, and time required for gas to flow from point to point.; and
- probably require linepack allocation and tracking to manage within day aspects.

Appendix 4: Biddable Capacity Rights

Biddable Capacity Rights are a form of transmission right that would be bid into the balancing market scheduling process along side controllable injections and offtakes, and only when the use of those transmission rights would contribute towards clearing the market at least cost would they actually be dispatched.

Biddable Capacity Rights are neither a purely physical or financial form of transmission right. On the one hand, the holder of the rights does not need to own or operate physical pipeline capacity or control the way it is scheduled in the market

On the other hand:

- the amount of rights issued and which are eligible for inclusion in the bidding and scheduling process must be backed by physical network design capability;
- as the rights are bid into the balancing market and may or may not be scheduled depending upon their offer price(s), the holder of the rights can by his bidding behaviour directly impact the scheduling of gas injections and flows in the network and the balancing market locational spot prices throughout the network;
- the eligibility of some rights to be dispatched could be linked to the physical status of specified network facilities and/or actual characteristics of the network such as linepack levels; and
- if the Biddable Rights are not link-based, eligibility to receive inter-locational price difference payments in market settlements in each trading interval would be conditional upon both the entry and exit rights being dispatched by VENCorp in the operational schedule.

In some respects, Biddable Capacity Rights are akin to the concept of Market Network Services as applies in the Australian National Electricity Market. However, they need not necessarily be link-based (i.e. they may merely be defined on a 'point to point' or 'hub to hub' basis), and they would apply much more broadly across the main gas transmission network wherever locational price differences may be found in the balancing market.

Features:

Biddable Capacity rights would display many of the features of other forms of capacity rights that would be robust enough to drive new investment in pipelines as and when required by the market. For example:

(a) They would protect the holder from exposure to inter-locational price differences in the balancing market – however, in this case, the protection would only apply when the rights are accepted and included in VENCorp's scheduling process;

(b) New rights can be created by additional investment in network capacity;

(c) The primary rights would be tradeable on both a short and long term basis – it would only be necessary for VENCorp to be able to track who is the legitimate holder of the primary rights at any point in time, and if physical conditions are attached to their eligibility for dispatch, the tracking would need to be close to real time;

(d) It would probably be feasible for a market in secondary derivative products to develop to provide much more flexibility in rights trading and provide greater transparency and price discovery; and

(e) Provided the Market Rules do not unduly constrain permissible offer prices (i.e. in effect, the minimum price that the holder of the rights may demand in the balancing market for short-term use of the rights by others), over time, the market would value the rights at their true opportunity value which should be sufficient to sustain new pipeline investment as and when required by the market.

However, the essential difference between this form of rights and the Shipping Rights proposal is that the market is allowed to set the price for the short-term transfer of rights in the real time balancing market rather than this being done in accord with some set of regulated tariffs that may or may not be sufficient to drive new investment and, in any event, would not reflect the true opportunity value of the of the rights in the competitive marketplace at any point in time.

The rights would be issued by the pipeline owner, but the process for determining what rights may be issued in relation to any particular network investment would be clearly defined in the Access Rules and would involve VENCorp as the Independent System Operator.

While the rights do not necessarily need to be link-based, when applied in a gas market, there are a number of potential advantages associated with a link-based approach:

- It would more closely approximate the workings of a contract carriage model that is most familiar to and accepted by pipeline investors, gas producers and other gas market participants;
- It would in fact be less constrained in terms of the range of feasible solutions to the dispatch algorithm in the balancing market in which case it should deliver more competitive and more efficient market outcomes and a lower delivered cost of gas over time; and
- It would generally be easier to define the amount of rights associated with any particular investment and to attach any specific physical preconditions in relation to the status of the network or operational parameters (e.g. linepack levels in a specific part of the network) that need to be satisfied in order for the rights to be scheduled.

To minimise the presence of, and potential misuse of, market power by pipeline investors and/or purchasers of the rights, the Access Regime may need to impose constraints on:

- the amount of rights that any single market participant may hold at any time[8];
- the ability of a rights holder to prevent the rights being scheduled; and
- the price at which a pipeline owner would be permitted to offer any unsold rights into the balancing market[9].

Conceptually, the rights would be deemed to be the right to offer a defined level of network capacity from one node or hub to another node or hub into the balancing market for scheduling and dispatch. The holder of the rights would be entitled to set the minimum price that he would be prepared to accept for the rights to be dispatched. If dispatched, this would suggest that the locational price difference between the sending and receiving nodes or hubs should not be less than the offer price submitted by the rights holder into the scheduling process.

If the rights are dispatched, the rights holder would be entitled to receive from the market operator, a payment as follows:

$$P_{n,t} = CR_{n,oi,t} \text{ X } [P_{o,t} \text{ X } P_{i,t}]$$

[8] The condition imposed may simply be that a rights holder must offer any rights he holds into the balancing market for dispatch – however, he would be free to set whatever price he chooses within the overall price caps that may apply to all offers.

[9] This would in fact be a minimum price so as to not undercut the value of pre-purchased rights – it would need to be specified in the Access Rules as it would probably constitute a price-fixing arrangement that, without authorisation, would probably be in contravention of the Trade Practices Act.

where:

$P_{n,t}$ = The payment received by Participant n in Trading Interval t;

$CR_{n,oi,t}$ = The Capacity Rights held by Participant n from Node i to Node o for Trading Interval t;

$P_{o,t}$ = The price for Node o in the balancing market for Trading Interval t; and

$P_{i,t}$ = The price for Node i in the balancing market for Trading Interval t.

At least in theory, Biddable Capacity Rights could be implemented in conjunction with any form of balancing market that employs locational pricing based on a constrained schedule. This could be an ex post market at one extreme or it could be a series of ex ante markets where each successive market clearing only sets the price for deviations from the previous schedule. Clearly, the accountabilities and incentives for market participants vary considerably between these extremes as has been demonstrated by ICF Consulting in their 24 December 2003 report. The same incentive and accountability issues discussed by ICF Consulting in relation to gas injections and offtakes would equally apply to the scheduling and use of Biddable Capacity Rights in each case.

How does it address the issues:

This form of rights matches the other 3 forms of capacity rights canvassed in this paper in that they provide to the rights holder the equivalent of a difference payment for the inter-locational price difference between the injection node and the offtake node as specified for each individual Biddable Capacity Right.

The key differences with these rights when compared with the other options are as follows:

- As stated previously, these are not purely financial rights in that the right to receive difference payments is contingent upon the rights being scheduled and dispatched;
- The rights do not need to be linked directly to specific gas injections or withdrawals in the scheduling process as would presumably apply in the case of Physical Capacity Rights – however, they may need to be linked to a rights holder's ownership of linepack in specified sections of the network;
- Whereas FTRs can result in payment obligations by the rights holder to the market operator in the event of negative price differences, this could probably be avoided for Biddable Capacity rights; and
- As stated previously also, the Biddable Capacity Rights model allows the market to determine the true opportunity value of the available rights in the market in any trading Interval whereas the Shipping Rights model relies heavily on price regulation, which could not possibly emulate a competitive market outcome in this respect.

In summary, an access regime centred around Biddable Capacity Rights would not only provide participants with the means to manage most if not all of their inter-locational price and quantity risks, but it would also provide clear price signals and the strongest possible market-based incentive for new investment in pipeline capacity when required. Arguably, the Biddable Capacity rights approach could potentially deliver investment price signals that would be more competitive, more efficient and more transparent than any of the other 3 rights-based alternatives canvassed in this Paper.

Issues to be resolved:

To our knowledge, while the general concept of biddable capacity rights can be readily defined, there is no practical operating experience with this form of rights model being applied elsewhere in conjunction with market carriage, and there are many issues of detail that would need to be addressed both in the detailed design of the balancing market and in the detailed design of the Access Regime.

The difficulties associated with the creation of a Financial Transmission Rights regime in respect of revenue adequacy have already been discussed in Appendix 1. Similar issues would need to be addressed and resolved in the creation of a suitable Biddable Capacity Rights regime. It is for this reason for example that it may be necessary to attach some physical preconditions that need to be satisfied before specific Biddable Capacity Rights are eligible to be dispatched.

However, as the basic design of the Biddable Capacity Rights can be closely aligned to the physical operational capability of the network, it should be quite feasible to define a series of preconditions that would adequately address this requirement. The advantage in this case is that it is quite feasible to impose dispatch conditions on each set of rights so that the required consistency and compatibility between scheduling, pricing and dispatch can be preserved under virtually all conditions.

Also, as is the case with the other Rights models, the introduction of Biddable Capacity Rights would probably require substantial changes to the existing PTS access regime and impact significantly on GasNet's current transmission tariff structure. It would also raise a number of market power related concerns because of the potential for a participant to acquire a dominant share of the available rights either in a defined part of the network or overall, and then use those rights to manipulate locational prices in the balancing market.

Gas Market Pricing and Balancing Review

Pipeline Investment Working Group Paper

19 March 2004

Executive Summary

Following the release of VENCorp's Stakeholder Consultation Paper on "The Pipeline Investment Issue" (24 December 2003), a Pipeline Investment Working Group (with representation from VENCorp and GasNet) has further examined the issues raised by stakeholders on the adequacy of the current market and regulatory framework in facilitating investment in pipeline expansions.

This paper has been developed and agreed by the Pipeline Investment Working Group and compiled with the assistance of Creative Energy Consulting. It expands on the December 2003 Consultation Paper in defining the pipeline investment issue and in considering possible solutions. In light of ICF Consulting's Draft Evaluation of Market Design Packages Report (2 March 2004), particular attention is paid to possible solutions that would complement ICF's market design packages 2 and 4.

The Working Group is to provide recommendations to VENCorp in early April as input to VENCorp's Gas Market Pricing and Balancing Review report to the Minister. While these recommendations have yet to be finalised, this paper identifies the key findings to date:

- Investment in pipeline expansion should be commercially driven wherever possible, and to this end the Working Group has focussed on proposals that would complement but not replace commercial/contract-driven investment;
- Changes to the regulatory framework and/or the application of the Gas Access Code are suggested to better facilitate investment in pipeline expansions which provide diffuse benefits to a range of users;
- To complement this, an expansion to VENCorp's current "Annual Planning Review" role would be beneficial in assisting GasNet and other industry participants to identify and independently assess the potential benefits of such expansions and, where appropriate, develop proposals to the regulator for approval;
- To provide shippers with the required incentives to invest in pipeline capacity, the existing AMDQ and AMDQ credit mechanisms need to be refined in the short term and ultimately replaced with "transmission rights" that provide a high degree of financial, physical and competitive certainty;
- Financial congestion rights alone would not provide adequate incentive for investment, but effective transmission rights should incorporate or be stapled to congestion rights;
- Transmission rights may take a number of different forms and substantial further work and industry consultation would be required to develop and define the preferred form;
- A potential staged implementation plan, to complement ICF's draft findings with regard to market design packages 2 and 4, could be as follows:
  - Modification of existing AMDQ and AMDQ credits to a consistent point-to-point AMDQ congestion right, incorporating an hourly profile (by 2006);
  - Further assessment/definition of preferred form of transmission rights (by 2006)
  - Conversion of AMDQ to transmission rights held by shippers, with differential pipeline tariffs for holder/non-holders of rights (by 2008)
  - Further work should also be undertaken to develop a planned transition path to convert transmission rights to biddable capacity rights to accommodate a future decision to move to hub-based pricing, as in package 4.

Feedback Sought

The Pipeline Investment Working Group would welcome feedback on issues raised and the preliminary findings set out in this paper.

To this end, an open workshop is to be held at VENCorp's offices at the World Trade Centre, Melbourne on Monday 22 March 2004.

Written submissions are also invited. Such submissions should be sent electronically to the following e-mail address:

peter.ferretto@vencorp.vic.gov.au

While VENCorp will endeavour to take account of any late submissions to the maximum extent practical within the constraints of the overall timetable for completion of the Gas Market Pricing and Balancing Review, the required date for receipt of submissions is **Friday 26 March 2004.**
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1 Introduction

VENCorp published a stakeholder consultation paper on 24th December 2003[1], which described stakeholder concerns about incentives for new pipeline investment within the current market framework and discussed some possible solutions.

In that Consultation Paper, VENCorp proposed a program of further work to more fully describe each of the models and its proposed functionality, more fully define their weaknesses and identify its impact if implemented in terms of:

- The extent to which it would drive new infrastructure investment in terms of the most efficient type and location of investment,
- Required changes to the balancing market functionality in each of the applicable packages,
- Required changes to the current access regimes of VENCorp and GasNet,
- Its effect on market participants and market behaviour

To undertake this work, a "Pipeline Investment Working Group" has been established with representatives drawn from VENCorp and GasNet. Since the release of the Consultation Paper in December 2003:

- some stakeholder feedback has been provided and considered;
- ICF Consulting's work on the evaluation of market design packages has progressed to the point of a detailed draft report being released for comment ("Stage 2 Evaluation of Market Design Packages Detailed Report (Draft)", 2 march 2004); and
- there has been considerable discussion by the Working Group on how to take the pipeline investment issue forward in light of these recent developments.

The Working Group has therefore agreed to the preparation and release of this paper which:

- more fully defines the possible solutions described in the Consultation Paper;
- considers more broadly whether alternative or other related potential solutions exist;
- identifies the key elements and characteristics of each solution;
- considers the practicalities of designing, implementing and administering the new arrangements;
- looks at how these solutions depend upon the possible implementation of the market development packages proposed and evaluated by ICF; and
- describes possible "implementation scenarios" for how and when possible solutions may be implemented.

Following discussions of these issues with stakeholders, the PIWG is aiming to provide draft recommendations to VENCorp in early April.

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[1] Gas Market Pricing and Balancing Review, Stakeholder Consultation Paper: The Pipeline Investment Issue, VENCorp 24th December 2003

2 The Pipeline Investment Issue

2.1 The Investment Problem

The pipeline investment issue was described and discussed in the Consultation Paper. The concern set out in that paper is that the current framework for pipeline investment will not necessarily deliver efficient pipeline investment: ie it will not ensure that investment in pipeline infrastructure delivers the market's transportation needs. In summary, the reasons for this concern were that:

- Investment by GasNet is voluntary; it has no obligations to invest.
- GasNet will invest only if it is confident of an adequate return on that investment.
- This return must come from a combination of tariff revenue and contract revenue.
- Tariff revenue is determined by the GasNet access arrangements which, in turn are governed by the Code and approved by the regulator. This regulatory framework may not provide GasNet with a sufficient level or certainty of tariff revenue.
- Contract revenue is determined by contracts between GasNet and shippers under which shippers agree to make payments in return for GasNet providing contractual rights. The current market framework confines these rights to "AMDQ" and "AMDQ credits" which are considered to have limited value.

The tariff/code and the contract/rights issues are treated separately in this paper, which considers addressing tariff issues through the introduction of a Victorian Independent Planner and addressing contract issues through the introduction of modified transmission rights. It should be kept in mind that it is the aggregate of these two revenue streams that will determine GasNet's propensity to invest. Interdependencies between these two areas are discussed further in section 6.

2.2 Tariff Issues

In this paper, "tariff revenue" means the additional revenue that GasNet will collect through applying TUoS charges to shipper injections and withdrawals as a direct result of the new investment. This tariff revenue may come from:

- the additional shipper volumes allowed due to the increase in pipeline capacity, on which pre-existing TUoS tariffs are charged; and
- any increases in tariff levels allowed by the regulator to recover the investment cost.

The regulatory framework may constrain the level or certainty of tariff revenue for new investment by:

- restricting the new tariff revenue to the level of existing approved tariffs[2] (the "economic feasibility test"), unless there are system wide benefits that justify tariff increases for all shippers (the "system wide benefits" test);
- creating uncertainty as to whether the regulator will include the full cost of the new assets in the regulatory asset base (RAB) in future regulatory periods; and
- leaving GasNet exposed to volume risk within each regulatory period, since tariffs are set at the start of each regulatory period, based on projected volumes over that period.

The Consultation Paper proposed addressing these issues by introducing the concept of a "Victorian Independent Planner" (VIP). The Paper noted that there was a range of possible models for the VIP, but described one particular model under which the VIP would:

- have responsibility for planning and commissioning pipeline investment;
- be able to raise tariff revenue on the basis of a new "market benefit" test, which would complement or replace the existing tests;
- oblige the regulator to include in the RAB any new assets which the VIP could show passing the market benefit test; and
- deter the regulator from subsequently removing assets from the RAB.

The Consultation Paper also noted two other possible VIP models: the one proposed by ICF in some of its market design packages; and a "planner of last resort" which would only undertake the functions listed above where GasNet has chosen not to undertake a potential investment showing "market benefit".

There are two aspects to these VIP models, which can be considered separately:

- changing the Code framework to introduce a market benefits test and remove risk of new assets falling outside the RAB; and
- giving an independent body some roles in planning and developing investments.

These two aspects are considered in sections 3 and 4, respectively. As the Consultation Paper highlighted, there are "synergies" between these two aspects, in the sense that the suggested Code changes may be more acceptable if they are applied by an independent body that does not have a direct financial interest in augmenting the RAB.

[2] The Code also allows a surcharge to be applied on incremental flows. This paper categorises surcharges as "contract revenue", which is discussed in the next section.

2.3 Contract Issues

Where the level or certainty of tariff revenue alone is insufficient to fund new investment, there is a need for a "foundation shipper" (or shippers) to support the investment through a contractual arrangement with GasNet. Under this arrangement, the shipper would agree to make payments to GasNet over and above those required under the existing tariffs. These payments – referred to in this paper as "contract revenue" – may variously take the form of:

- a surcharge to the existing tariff;
- a "take-or-pay" obligation on usage of the new capacity; or
- an upfront capital contribution or "equity contribution".

However, a shipper will only enter into such a contract if, in return, GasNet is able to meet the shipper's needs in relation to its use of the new capacity and the benefits flowing from that use. Typically, a foundation shipper will have three needs:

- *physical certainty*: confidence that the shipper will, under all circumstances, be entitled to inject gas "at one end" of the new capacity and withdraw it at the other end;
- *financial certainty*: confidence that there will not be significant charges – over and above those agreed in the contract – associated with using the capacity; and
- *competitive certainty*: confidence that a "competing shipper" is not able to make use of the "contracted" capacity to undercut or otherwise damage the business of the foundation shipper that is supported by the new capacity.

In the current market, GasNet only has two mechanisms for meeting these shipper needs:

- by making the capacity available to the market (and therefore available on equal terms to all shippers); and
- by allocating AMDQ or AMDQ Credits to the foundation shipper

AMDQ and AMDQ Credits are described in detail in the Consultation Paper. In summary, these rights confer two types of "property right" on the holder:

- a financial right to avoid having to contribute to the cost of congestion uplift ("a congestion right"); and
- a physical right to having a lower likelihood of being curtailed ("curtailment rights")

These existing mechanisms do not enable GasNet to address entirely the foundation shipper needs listed above; specifically:

- They do not guarantee a right to inject gas. Whilst the foundation shipper can seek to achieve this by nominating or bidding at zero price in the market, this does not guarantee the injection being scheduled fully in the event that other shippers also nominate or bid zero and the total gas offered into the market through such nominations or zero priced bids exceeds the overall market requirements[3].
- They do not guarantee a right to withdraw gas. This is because there are only a few large gas customers on the PTS who are capable of quickly reducing gas usage by significant quantities to assist in managing pipeline constraints; small customers are either uncontrollable or too small, individually, to have any practical effect. Consequently, the controllable large end-users may still be curtailed while other "unauthorised" end-users continue to take gas[4].
- They do not provide financial certainty: whilst congestion costs are avoided, most "uplift" costs in the market are currently categorised as "surprise uplift" which is allocated to all shippers, including those holding congestion rights. Furthermore, congestion rights associated with AMDQ Credits are only operative if the shipper is able to inject gas at the specified injection point.
- "Competing shippers" may be able to undercut the foundation shipper, since they are only obliged to pay the existing TUoS tariff (by definition, below the contract price), plus congestion uplift which is generally immaterial, due to both the uplift allocation process and the amount of spare capacity existing on most pipelines.
- The foundation shipper is not compensated for usage of its contracted capacity by other shippers even if this leads to its customers being taken by competing shippers.

Financial certainty can potentially be improved by modifying the uplift allocation process defined in the market rules, such that holders of congestion rights do not contribute to the costs of congestion, and only contribute to the costs of "surprises" to the extent that their behaviour causes them. Some proposals in this regard, developed by ICF Consulting, are discussed in section 7.1.

To address the other shipper needs, the Consultation Paper proposed the introduction of alternative "transmission rights" which could be assigned to foundation shippers and potentially:

- improve physical certainty by favouring rights holders in the scheduling process; and
- improve competitive certainty by levying additional charges on non-rights holders and using this charge revenue to compensate rights holders.

Building on the Consultation Paper, Section 5 considers the necessary characteristics of these new transmission rights and the implications for the market design and regulatory framework of administering and enforcing these new rights.

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[3] This has never actually happened since the market started in 1999
[4] this has happened only once since market start

3 Changing the Regulatory Framework

3.1 Market Benefits Test

The Code currently prohibits a pipeliner from increasing existing tariffs[5] in order to pay for new investment, unless the pipeliner can demonstrate that there are "system wide benefits" arising from the new investment that justify increased charges to all shippers. Although the Code is not specific in defining what "system wide" means, regulatory practice to date has interpreted it to mean that *all* shippers in the market see *some* benefit. The Code also does not specify how the tariffs should be raised to recover the investment Cost: GasNet practice has been to "postage stamp" the cost, by raising all tariffs by an equal amount.

The Consultation Paper discussed the "regulatory test" or "market benefit" test used in electricity and whether a similar test could be applied under the gas Code. A simple example shows how this test might work. Suppose that $3/GJ gas is available at one end of the pipeline, serving load at the other end. Suppose also that there is $10/GJ gas at the load end, and this must occasionally be scheduled as a result of pipeline congestion constraining full use of the $3/GJ gas.

Suppose also that the pipeline can be expanded to remove this congestion, at an average cost (in terms of additional gas flowing) of $4/GJ. There is then a clear "market benefit" as the $10/GJ gas supply is replaced by $4/GJ pipeline capacity. However, the recipients of this market benefit may not be clear, since this will depend upon the rules for allocating congestion costs, existing supply contracts and so on.

Suppose finally that the existing pipeline tariff was $2/GJ. Thus, under the Code, the investor would not be able to recover the full $4/GJ investment cost from tariff revenue unless system-wide benefits could be shown. This is unlikely to be the case: for example, those *not* benefiting might include:

- shippers on other pipelines for whom the market rules means the congestion costs are not allocated;
- the supplier of the $10/GJ gas, or shippers who are contracted to take (or pay) the $10/GJ gas

In practice, this difficulty in demonstrating such system-wide benefits has meant that the test has only been applied to "global" benefits such as enhanced competition or system security.

There might be merit, then, in reviewing the SWB test to allow for the common situation where benefits of an investment are "diffuse" (ie accrue to a number of different shippers which cannot be definitively identified) but not "global" (ie they do not accrue to *all* shippers). Thus a "market benefits test" may allow tariffs to be increased where:

[5] It is entitled to levy a "surcharge" on "incremental shippers". This surcharge is regarded as "contract revenue" in this paper and is included within the discussion in section 5.

- an investment provides a net market benefit;
- the cost of the investment will not be recovered at existing tariffs;
- it is not possible to be definitive about exactly which shippers receive benefits; and
- tariffs can be modified such that they, firstly, recover the investment cost and, secondly, mean that the increased tariff payments made overall by shippers for each tariff service are no more than the overall increased benefits derived from that service as a result of the new investment.

This then raises the question of whether it is appropriate to raise tariffs for shippers holding congestion rights, who may see little benefit in relation to the investment relieving congestion. One can consider two possible situations:

- where the congestion has arisen because of general growth (eg Tariff V users), it is likely that all shippers are using gas somewhat in excess of their congestion rights, and thus all see some benefit from the new investment: in this case, a rise in tariffs applying to all shippers may be appropriate.
- where the congestion has arisen (or is expected to arise) as a result of one or a few shippers having a “step increase” in their usage, the benefits are concentrated on those few shippers and a general rise in tariffs may be inappropriate(since beneficiaries are clearly identified)

Thus a market benefits test would allow investment costs arising from general growth to be recovered through tariff increases, whilst leaving investments arising from “new” shipper requirements to be funded through contract revenue.

3.2 Tariff Changes

The investment problem discussed above might be ameliorated, by more closely aligning tariffs with future investment costs: thus, if the pre-existing tariff in the example had been $4/GJ or more, there would be no impediment to investment, since the revenue from levying $4/GJ on incremental volumes would be sufficient to fund the investment[6]. There are a number of reasons why tariffs may be misaligned with future investment costs:

- the new capacity is more expensive than existing capacity;
- investment lumpiness means more new capacity is added than is required in the short-term;
- the investment may facilitate only additional peak flows (say), whereas tariffs may be structured on average flows; and
- existing tariffs are based on depreciated asset values, whereas the investment is in new assets.

[6] Assuming that volume risks are also addressed, as discussed in the next section.

The first two issues are intrinsic to the physical nature of the investment and cannot be addressed by Code changes. The third issue can, in principle, be addressed within the existing Code, although there may be practical difficulties in implementing the appropriate charging structure.

Addressing the fourth issue may require a Code change, since the existing Code requires tariffs to be based on allocating the depreciated cost of assets to shippers who are deemed to use those assets. This essentially means that tariffs cannot reflect existing levels of spare capacity on different pipelines, or the likelihood that growth will lead to new investment requirements. Whilst aligning tariffs to future investment costs is likely to encounter practical difficulties, arguably the Code should at least allow pipeliners flexibility to seek to do this. However, such a change might be seen as unfair on existing shippers who had already contributed – through tariffs – to the depreciation on existing pipelines and should not then have to pay again for the new assets.

3.3 Addressing Asset Base Risk

Even where GasNet can demonstrate that a new investment passes the existing Code tests, there is no guarantee that the regulator will allow the new assets to be included in the RAB. And even if they are included in the current regulatory period (for example, because their need was forecast prior to the commencement of the current period, and the anticipated cost was rolled in), there is no guarantee that the regulator will not subsequently disallow all or part of the asset value from the RAB by declaring them fully or partially redundant

There are two sources of this RAB risk. The first arises from the absence of detail in the Code over how the tests should be applied, leaving substantial discretion to the regulator. This risk could be mitigated either by more detail in the Code, or by the regulator setting out its test application principles and process: for example through a “Statement Of Regulatory Intent”[7].

The second source of risk is volume uncertainty. Both GasNet and the regulator, in applying the tests, must rely on forecasts of pipeline usage, potentially covering the life of the asset. If updated forecasts show that demand will not reach the levels initially forecast, the regulator has the ability to rule that all or part of the capacity that has been added is not needed and can be declared redundant.

This volume-related risk could be mitigated by the regulator being required to decide on the validity of the GasNet forecasts before the investment decision is made, and not be allowed to subsequently “re-test” the investment on different forecasts. Such an “ex ante approval” approach would rely on the regulator having access to reliable, and independent, advice on usage forecasts.

3.4 Other Volume Risks

Some volume risks arise independently from RAB risk. In particular, if GasNet, in good faith, relies on a forecast usage which subsequently does not eventuate, then the tariff revenue will not be

[7] The regulator’s “Draft Statement” is considered inadequate in addressing this risk.

sufficient to recover its costs. Furthermore, it may not be possible to raise the tariffs sufficiently to preserve the RAB. The level of actual volumes compared with forecasts is a risk that is inherent in the current incentive based regulatory regime and can be partly ameliorated by the use of "economic depreciation"[8] or by levying tariffs on volume measures which are of lower uncertainty. The alternative is to lay off this risk to shippers, such as through contractual take-or-pay conditions. Contracting issues are discussed in section 5.

3.5 Summary

In summary, impediments to pipeline investment associated with regulatory constraints on the level or certainty of incremental tariff revenue could potentially be addressed by:

- introducing a “market benefits test” to replace or complement the existing system wide benefits test;
- providing more flexibility in tariffing methodologies, so that tariffs can be better aligned with future investment costs;
- providing a clearer definition of the Code investment tests and/or the regulator’s interpretation of these; and
- providing where possible ex ante regulatory approval for investments that pass the test.

[8] The use of "economic depreciation" does not remove this risk but only postpones the risk to later years in the pipeline life in the hope that the postponed depreciation can be recouped at that time.

4 Introducing an Independent Planner

4.1 Introduction

The Consultation Paper described the concept of a Victorian Independent Planner (VIP), noting that there was a range of different models under which this could be introduced. The Paper identified some potential benefits and a number of limitations with the VIP concept. Whilst some stakeholders indicated support for introducing a VIP-type body, some have expressed concern about the degree of intervention in the market that the described model would imply.

It should be stressed that the model in the Consultation Paper was a "straw man" to introduce the VIP concept and to prompt discussion and response from stakeholders. Taking into account feedback from stakeholders, VENCorp – with GasNet – has considered further what role – if any – a VIP should have in the market.

4.2 Possible VIP Roles

There is a range of different roles that a VIP might undertake in order to improve investment efficiency, including:

- regulatory facilitator
- market facilitator
- investor of last resort
- central planner

These roles are described below.

Regulatory Facilitator

In this role, the VIP may assist GasNet and/or other industry participants in determining whether the regulator, pursuant to the Gas Code, is likely to include the proposed new assets in the RAB and to approve any tariff increases needed to earn an adequate return on the new asset.

In this role, the VIP might:

- provide independent usage forecasts, which GasNet could then use to apply the relevant investment test to the proposed investment;
- undertake the investment test itself, based on a detailed process description provided by the regulator, pursuant to the Code; or
- develop a detailed investment test process, based on applying the principles set out in the Code, and then apply this detailed test to the proposed investment and, where necessary, inform GasNet of the beneficiaries of the new investment.

The exact nature of this role will depend upon what Code or regulatory changes – if any – are made to address the issues discussed in section 3: for example, whether the regulator establishes a detailed test description.

The objective of this VIP role is that it would allow the regulator to provide ex-ante approval (as discussed in section 3.3), or at least to provide some assurance that the new assets would be included in the RAB for future regulatory periods. In giving such approval or assurance, the regulator would be able to rely on the VIP independence from GasNet, its lack of direct fiduciary interest in the regulatory outcome, and its specialist knowledge and expertise in usage forecasting and pipeline planning. On the other hand, if the regulator was unable to give this approval or assurance, the VIP role may have limited value.

Market Facilitator

In this role, which was introduced by ICF in some of its market design packages, the VIP helps to identify efficient investments and assist the market in coordinating a response to such potential investments. This is done through:

- developing forecasts of additional capacity requirements (as VENCorp does now);
- working with GasNet to identify and cost options for providing such additional capacity;
- promoting and marketing this new capacity; and
- approaching GasNet to undertake this investment, once sufficient capacity has been “signed up” by shippers.

The marketing would involve identifying what additional transmission rights could be provided through the new capacity (as discussed in section 5.3) and finding shippers who had need for such rights. This process would only be needed where the level or certainty of new tariff revenue alone was insufficient to fund the investment.

There are at present no regulatory constraints on GasNet undertaking such a role itself, so this proposal would only improve investment efficiency if the VIP could undertake the role more effectively than GasNet.

Investor of Last Resort

In this role, VIP itself undertakes those efficient investments that GasNet has declined to undertake for the reasons previously discussed. In practice, VIP would do this by tendering for the construction, ownership and management of the new assets, or by having powers to direct GasNet to make the investment. In either case, VIP would be obliged to reimburse the investor for the reasonable cost of the investment.

In this role, and under the Code, VIP would be in the same position as GasNet and would therefore be exposed to the same investment impediments. Indeed, if the VIP was a non-profit organisation with low or no capital base, it would be even less able to bear commercial risks than GasNet.

Thus, if VIP was to be able to successfully undertake this role it would either need exemption from the Code constraints on GasNet, or it would need to have a separate mechanism, not subject to these Code constraints, for recovering any revenue shortfalls.

Central Planner

This is the role described in the Consultation Paper. It is an extension of the investor of last resort role, whereby the VIP would have responsibility for *all* investments, not just those that GasNet or other private investors declined to pursue. This role is similar to that played by VENCorp in the electricity market. If it were to follow the electricity model, VIP would have responsibility for all regulated expansions of the PTS, would bill customers for TUoS directly and would enter into network agreements with GasNet and others for the provision of the pipeline assets to provide the service.

This model goes beyond addressing the pipeline investment issue, since it empowers VIP to “intervene” in all investment decisions, not just where there has been a market failure. The rationale for this might be that it is not practical for the pipeline system to be partly VIP-built and partly GasNet-built.

4.3 Evaluation of VIP Roles

The benefits of the regulatory facilitator role depend both on the introduction of any Code changes along the lines of the discussion in section 3 and, perhaps more importantly, the extent to which the likelihood of those Code changes being approved depends upon the independence of the body that would be undertaking the testing role.

VENCorp would be well suited to the regulatory facilitator role as:

- It is already well established as an independent body with the relevant energy system and market expertise;
- It’s governance structure and experience in industry consultation mean that it would be able to successfully incorporate stakeholder views in the assessment process; and
- Such a role would represent a minor expansion of its current role in providing planning information to the market through production of its Annual Planning Report.

The market facilitator role could be established under the existing regulatory framework, and would also be suitable to be undertaken by VENCorp as an extension of its existing market information and forecasting role. Potential advantages in VENCorp (rather than the investor) performing this role are that:

- VENCorp has more operational information on injection and withdrawal patterns ;
- VENCorp already has a forecasting capability as part of its planning review obligations;
- VENCorp has more information on the congestion costs and so can better assess the trade off between congestion and infrastructure costs; and

- Shippers may be more willing to share commercially sensitive information – such as projected gas flows - with an independent body such as VENCorp.

On the other hand, GasNet (or other investor) may be in a better position to undertake the marketing role than a VIP as:

- they have a direct commercial interest in making the project successful;
- they have experience in promoting and negotiating contractual arrangements with shippers; and
- they are able to make commitments about how or when the project will proceed.

Thus, while VENCorp has a role to play in providing information to support the marketing process, the actual market facilitator role would best be undertaken by the investor themselves.

The "investor of last resort" role relies on VIP being treated differently by the regulator, in regard to RAB risk, than other investors. Such differential treatment might reflect VIP's perceived planning independence, in which case the regulatory facilitator role might be a viable and sensible alternative. The investor of last resort role will also lead to a duplication of tariff requirements, whereby GasNet and VIP must each define and levy TUoS tariffs to recover their investment costs. It may also lead to a duplication of transmission rights arrangements or else a reconciliation process to determine whose assets are supporting which rights.

This duplication would be resolved in the central planner role, under which all assets – and therefore all tariffs and rights – would come under VIP. However, this would represent a major structural change to the existing industry and regulatory framework and goes well beyond what is directly necessary to address the pipeline investment issue.

4.4 Summary

In summary, VENCorp and GasNet consider that the most appropriate role for a Victorian Independent Planner would be as a "regulatory facilitator". VENCorp would be well placed to fulfil this role under which, either of its own volition (through its existing annual planning review process), or at the request of industry participants:

- it could identify pipeline expansion options with the potential to provide overall benefits;
- undertake an independent assessment of those benefits;
- consult with stakeholders; and
- where appropriate, assist in the development of proposals to the regulator for approval.

This role would be limited to potential expansions of the PTS where there are diffuse benefits, or other commercial/regulatory impediments to GasNet or other third parties being prepared to undertake the necessary investment. Its introduction would be conditional on the Code - and the regulator's application of this – allowing the VIP role to be effective in reducing these impediments.

The other possible VIP roles canvassed involve the VIP either intervening in the market when there is no evidence of market failure, or mitigating GasNet's regulatory risk simply by taking on the risk itself. Such roles appear inappropriate for an independent, non-profit body to undertake and will not be considered further.

5 Introducing Transmission Rights

5.1 Purpose of Transmission Rights

The purpose of transmission rights is to improve the level of physical and competitive certainty for foundation shippers contracting with GasNet to fund new investment. In concept:

- GasNet would be empowered to issue transmission rights based on the amount of new capacity its provides through pipeline investment;
- GasNet would contract with foundation shippers to assign them the new transmission rights in return for a financial contribution to the investment; and
- Revised market scheduling and/or tariffing arrangements would confer on rights holders improved physical and competitive certainty that shippers seek.

Section 2 noted how financial certainty is conferred through congestion rights, under a process analogous to the transmission rights concept described above[9]. It would be convenient, then, for shippers and GasNet, if congestion rights are "stapled" to transmission rights, such that all of the shippers' needs are met within a single "product". This approach will be adopted, unless practical considerations prevent it.

5.2 Defining Transmission Rights

Introduction

Section 2.3 identified the two characteristics of transmission rights which could address shipper needs:

- rights to have priority or preference in the scheduling process: referred to in this paper as "physical rights"; and
- rights to receive compensation from competing shippers (who do not hold rights): referred to in this paper as "financial rights".

This paper uses the following terminology for capacity usage:

- "authorised usage" means usage by a rights holder up to its entitlement;
- "unauthorised usage" means usage by a non-rights holder, or by a rights holder above its entitlement;
- "overrun" is the amount by which a rights holder's usage exceeds its entitlement; and

[9] Except that congestion rights are conferred through the uplift allocation process, rather than through the scheduling or tariffing process.

- "underrun" is the amount by which a rights holder usage is below its entitlement.

The Consultation Paper described four possible types of transmission rights. These are listed in the table below, which shows whether they include physical and/or financial rights and also the "overrun pricing" – the rate at which non-rights holders compensate rights holders.

Form of Rights	Physical?	Financial?	Overrun Pricing
FTRs[10]	N	Y	Congestion price
Shipping Rights	N	Y	Overrun Tariff + Congestion Price
Physical Dispatch Rights	Y	Y	Overrun Tariff
Biddable Dispatch Rights	Y	Y	Market-based Price

This section considers more generally all possible forms of transmission right which might be introduced and the processes for defining, issuing and administering these rights.

Physical Rights

Physical rights, which give scheduling preference to rights holders, might take the following forms:

- *exclusive scheduling rights*: only rights holders are entitled to be scheduled; non-rights holders are prohibited from flowing gas;
- *absolute scheduling priority*: rights holders' flow requirements are scheduled first, with non-rights holders scheduled to the extent that any pipeline capacity remains; and/or
- *relative scheduling priority*: a rights holder is scheduled in preference to non-rights holders, unless the former's offer (bid) price is more than a specified dollar amount above (below) the latter's offer (bid) price: for example, a $3 offer from a non-rights holder may be scheduled in preference to a $23 offer from a rights holder.

Different scheduling rights may apply to injections and withdrawals. For example, existing "curtailment rights" only apply to withdrawals.

Exclusive scheduling rights are considered to be counter to access principles, under which all shippers should have the right to access spare capacity. Furthermore, since there is in general no way for the schedule to be enforced, unauthorised usage may occur, even if it is prohibited from the schedule. Therefore exclusive scheduling rights will not be considered further.

The implications of applying scheduling priorities are considered in section 5.3.

[10] FTR stands for "Financial Transmission Right". However, in the terminology used in this paper, an FTR is purely a congestion right. It does not incorporate the other "penalty" aspects of financial transmission rights described below.

Financial Rights

Two separate aspects of financial rights need to be defined

- "overrun penalties": the amount charged for unauthorised usage;
- "underrun rewards": the amount credited to rights holders where they are not fully utilising their rights, and that spare capacity is used by non-rights holders.

In combination, these penalties and rewards provide for rights holders to be compensated when a competing, unauthorised shipper uses "their" capacity. Penalties and rewards will be defined such that they balance in aggregate.

In their simplest form, overrun penalties take the form:

Overrun Penalty = Overrun tariff * max {0, (usage – holding amount)}

A key consideration, therefore, is the appropriate level for the overrun tariff.

For maximum competitive certainty, it would seem appropriate to set the overrun tariff as high as possible. This would prevent a competing, unauthorised shipper from having the commercial ability to undercut the prices charged by the foundation shipper, irrespective of the relative levels of the contract payments, TUoS tariffs and congestion costs. It would ensure that, in negotiating with GasNet to fund new investment, the foundation shipper's only concern would be the value of the new capacity to *its* business, not the potential use of the capacity by competitors. In effect, the foundation shipper obtains exclusive commercial – if not physical – rights to the new capacity.

However, a high tariff would raise concerns from other shippers that they may be unfairly penalised for inadvertent unauthorised usage[11], arising as a result of unpredictability in scheduled and actual gas flows, or because of the way that capacity usage is inferred from these flows. This uncertainty is considered further in section 5.3. A high overrun tariff might create market inefficiency by causing shippers to be conservative: for example by reducing the quantity of their offered amounts, or by pricing a risk premium into their offer prices.

The overrun tariff, therefore, must strike a balance between these competing concerns. A reasonable principle to adopt would be to set the overrun tariff such that the unauthorised shipper cannot use the contracted capacity on preferential terms to the authorised shippers, taking into account relevant factors such as contract charges, tariff levels, congestion allocation and any physical rights included within the transmission right. This principle would suggest that overrun tariffs may vary, depending upon the nature and cost of the relevant capacity. However, the principle may be difficult to apply in practice, as the authorised and unauthorised shippers may be using the capacity quite differently: for example, the authorised shipper may have a firm, high load factor, usage whereas the unauthorised shipper may use the capacity only intermittently.

[11] It is possible that this concern may be mitigated by allowing shippers a certain "overrun tolerance" for which they are not charged, or charged at a lower rate.

Underrun rewards will be calculated based on a process for allocating overrun penalty revenue between rights holders. The following principles should be used in defining this allocation process:

- underrun rewards should be paid only where unauthorised shippers are making use of that contracted capacity (to the extent that this can be determined);
- where there are multiple owners of contracted capacity, the level of reward to each holder should be in proportion to underrun, since this represents the amount of contracted capacity which is not used by the rights holder and so is available for unauthorised usage; and
- overrun penalties in relation to unauthorised usage of uncontracted capacity should be paid to GasNet and not allocated to rights holders (GasNet is effectively the holder of the rights for this uncontracted capacity).

The practical application of these principles will be complex, and is discussed in section 5.3.

Forms of Capacity

Transmission Rights must also define the capacity over which rights are conferred. Capacity may be defined in 3 ways:

- by flowgate;
- point-to-point; or
- by entry and exit.

A flowgate is a physical point on the network; ie a point on a specified pipeline. It is internal to the network, so there may be no metering and there would certainly be no existing allocation arrangement to determine title to the gas that is flowing at that point. A flowgate right may be defined in either direction along the pipeline.

Point-to-point capacity is determined by an injection point and a withdrawal point, which must either represent physical connection points to the pipeline system or be a notional or physical “hub” at which gas is traded. Depending upon the market design, there may be several hubs, in which case hub-to-hub capacity could be included. As gas cannot be physically tracked from point to point across the pipeline system, there needs to be some process for “matching” metered/allocated injection and withdrawal quantities. Direction is typically specified: ie A-to-B capacity is different from B-to-A capacity

Entry capacity refers to just to a physical injection point and exit capacity to a physical withdrawal point. The direction is specified by whether the capacity is entry or exit.

Capacity must also specify a usage time: for example hourly, daily etc. So, a transmission right might specify the maximum daily quantity of gas that can be flowed using that capacity. It might also specify an hourly profile for this daily usage.

5.3 Administering Transmission rights

Issuance Process

The issuance process defines how shippers obtain transmission rights. It is anticipated that allocation of rights to shippers would be by:

- agreed allocation algorithm for existing pipeline capacity; and
- negotiation and agreement with GasNet for new or unallocated pipeline capacity.

GasNet would be entitled to any contract revenue from issuing new rights.

To ensure an appropriate incentive on GasNet to invest in new pipeline assets, rights should only be issued up to the physical capacity of the system. In other words, the pipeline should be able to receive, transport and deliver gas in accordance with the issued rights. It should, if necessary, be able to accommodate all of the rights simultaneously or, alternatively, any subset of those rights which was physically meaningful (for example, which implied balanced injections and withdrawals): ie authorised shippers should be able to flow any amount of gas up to their authorised limit without being constrained by congestion. This check on the number of rights issued will be referred to as the “feasibility test”.

This test could perhaps be undertaken using a similar approach to that currently used under the VENCorp/GasNet Service Envelope Agreement for determination of system capacity. Under this approach, the physical capacity of the gas transmission system and increases in physical capacity resulting from system augmentations are determined by VENCorp in conjunction with GasNet by using the ‘common model’ and a standard set of operating conditions and assumptions. The ‘common model’ is a calibrated computer model of the gas transmission system maintained by VENCorp.

Calculating Usage

To determine penalties and bonuses, each shipper’s use of capacity must be calculated and compared to its rights holdings. The calculation process will depend on the form of rights issued.

Entry and exit rights can easily be calculated based on allocated injection and withdrawal quantities. Thus, a shipper injecting 100TJ at injection point X over the defined usage period is using 100TJ of the corresponding entry capacity.

Calculating point-to-point usage is not so straightforward. Consider the example of injections and withdrawals by a single shipper shown in Figure 1.

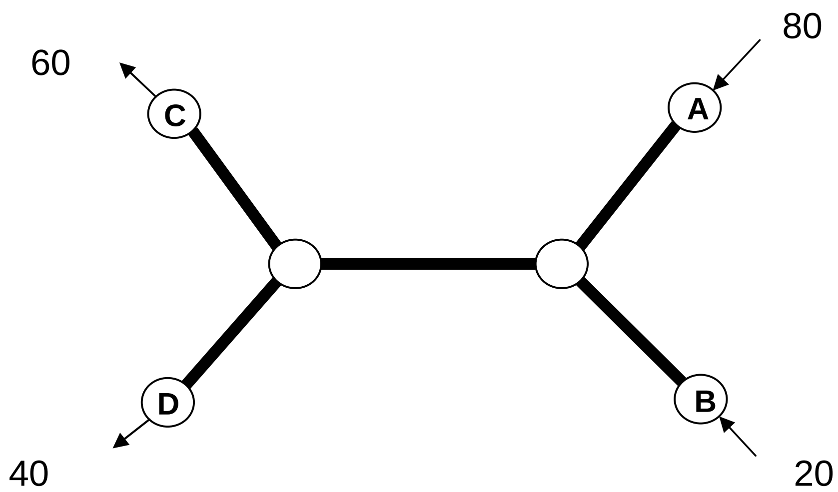

Figure 1: Point-to-point Mapping Example

Two – among many - possible usages of point-to-point capacity consistent with this flow are shown below

	to C	to D	Total
From A	60	20	80
From B	0	20	20
Total	60	40	100

Table 1A: A possible usage mapping

	to C	to D	Total
From A	48	32	80
From B	12	8	20
Total	60	40	100

Table 1B: Another possible usage mapping

Two approaches may be taken to resolving this ambiguity:

- each shipper may determine their own usage quantities, consistent with metered injection and withdrawal amounts, and notify these to VENCorp/GasNet; or

- the mapping may be done centrally by VENCorp or GasNet according to some defined and agreed algorithm.

If a shipper were to determine its usage, it would typically choose the usage combination which minimised its overrun penalties and/or maximised its underrun rewards. If a central body were notified of all shippers' rights holdings, it could similarly determine usage for all shippers, based on minimising overrun penalties for each shipper.

In general, aggregate injections for a shipper will differ from aggregate withdrawals and the matching process will need to accommodate such imbalance. This might be done through:

- deeming that the imbalance arises at a specified market "hub" and that the relevant shipper has accordingly made use of "point-to-hub" or "hub-to-point" capacity; or
- deeming that the imbalance has been provided by another shipper with opposite imbalance: ie have a separate process for "matching" imbalances between shippers.

In the first approach, the rights issuance process would need to include point-to-hub and hub-to-point capacity, to allow shipper imbalances to be authorised.

The *imbalance* matching process in the second approach would best be done centrally[12]. However, this would not prevent the *balanced* point-to-point matching still being done by shippers individually.

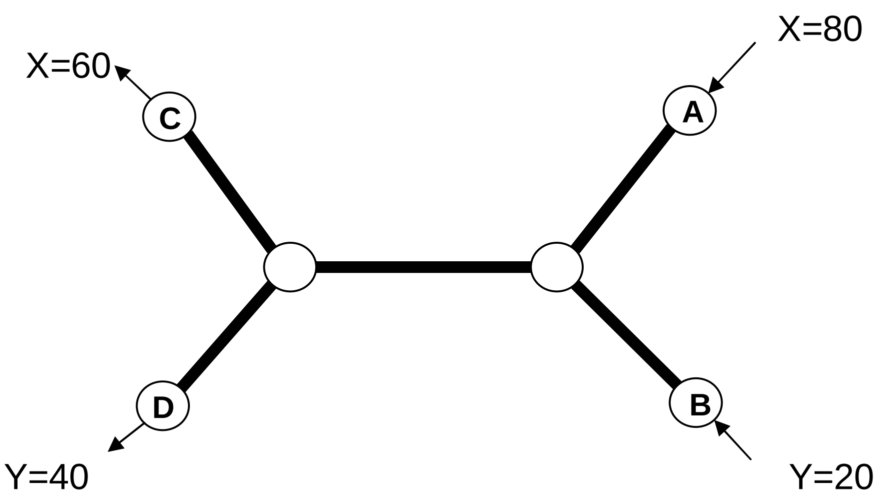

Figure 2: Point-to-point Mapping with Imbalance

[12] It could potentially be done bilaterally between shippers, but this may be a time-consuming process for them

Consider the previous point-to-point example, adapted to allow for two different shippers, X & Y, injecting and withdrawing at different points and, individually, being out of balance, as shown in Figure 2. A possible mapping using point-to-hub and hub-to-point rights is shown in Table 2A.

Shipper X Usage				
	to C	**to D**	**to Hub**	**Total**
From A	60		20	80
From B				
From Hub				
Total	60		20	80
Shipper Y Usage				
	to C	**to D**	**to Hub**	**Total**
From A				
From B		20		20
From Hub		20		20
Total		40		40

Table 2A: A possible usage mapping using hub rights

A possible inter-shipper mapping is shown below. In this case, Shipper Y is deemed to have acquired its imbalance gas from Shipper X at point A. Thus, shipper Y uses A-to-D capacity to transport this imbalance gas to D, whilst shipper X uses no capacity for this imbalance gas.

Shipper X Usage			
	to C	**to D**	**Total**
From A	60		60
From B			
Total	60		60
Shipper Y Usage			
	to C	**to D**	**Total**
From A		20	20
From B		20	20
Total		40	40

Table 2B: A possible usage mapping using inter-shipper mapping

Flowgate usage can be calculated by “tracing” the path through the pipeline that would be implied by a shipper’s injections and withdrawals and calculating the flow at each flowgate point. For example, a gas flow from A to B may have to pass through flowgates F1, F2 and F3. Such tracing is only fully defined on a radial network, so assumptions would be required about how flow split between two alternative paths in a non-radial network.

Where injections and withdrawals are out of balance, a physical location would be required for the hub. Depending upon the market design, this may already be defined, or may need to be assumed.

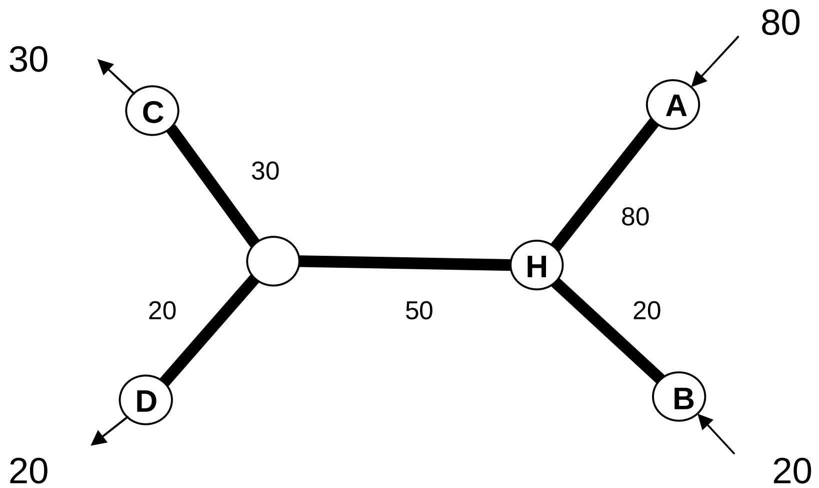

Figure 3: Flowgate Tracing with Hub

Figure 3 shows an example of flowgate tracing, where each pipeline segment is considered to be a different flowgate. The injections and withdrawals are out of balance, and the hub is deemed to be physically located at (internal) point "H". The flowgate usage is shown by the number next to each pipeline segment. This tracing takes no account of linepack, which could in practice significantly complicate the process.

Allocating Overrun Revenue

Section 5.2 set out some principles for allocating overrun penalty revenue between rights holders. This section considers the practical application of these principles.

The first principle is that underrun rewards should be paid to rights holders only where unauthorised shippers are making use of their contracted capacity. In applying this principle, we need to distinguish between physical capacity and "notional capacity": the form of capacity defined in transmission rights.

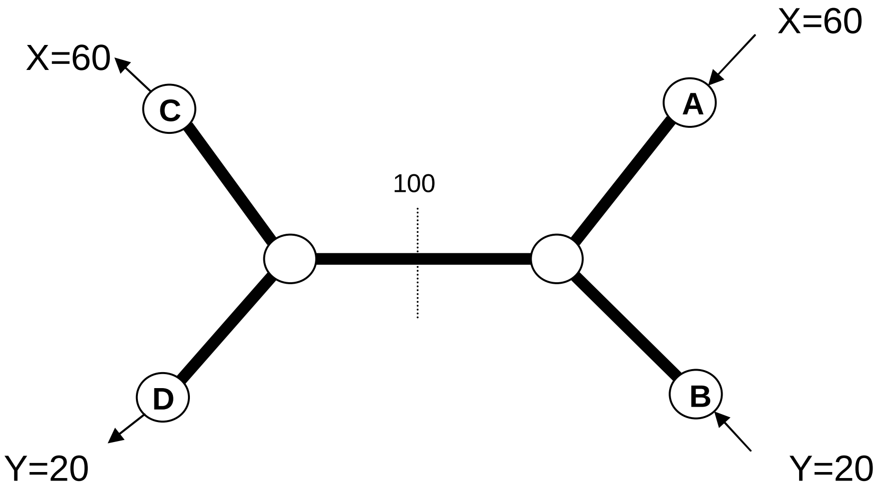

Figure 4: Overrun Penalty Allocation

Figure 4 shows the same pipeline system as in previous examples. In this case, the only constraint on scheduling is the 100TJ capability of the "central" link. This link is assumed to have been funded by shipper X, who has been assigned 100TJ of A-to-C rights by GasNet. Shipper Y has no rights.

The schedule of injections and withdrawals is shown. In this case, X is clearly underrunning, on A-to-C capacity and Y is clearly overrunning, but on B-to-D capacity. If the overrun revenue allocation process is to compensate shipper X for the use of its *physical* capacity (but *not* for the use of its notional point-to-point capacity) by shipper Y, it must include a process for mapping between the physical and notional capacity.

The second principle states that the allocation should be in proportion to underrun. Underrun, the difference between rights holding and usage, is straightforward to calculate once usage is determined.

The third principle is that overrun penalties for unauthorised usage of uncontracted capacity should be paid to GasNet. This further complicates the application of the first principle. For example, suppose that in the example shown in Figure 4, GasNet had only assigned 95TJ of A-to-C rights to shipper X (and still no rights to shipper Y). Then the allocation process must decide how much of the shipper Y overrun penalty should be allocated to shipper X (on the basis of its point-to-point underrun) and how much to GasNet (on the basis of its uncontracted physical capacity).

One approach that would partially reconcile the first and third principles is to require that GasNet explicitly allocates any spare capacity to itself, in the form of transmission rights and subject to the feasibility test. Thus, in the previous example, GasNet could have allocated the 5TJ of spare physical capacity to either A-to-C capacity or B-to-D capacity.

This would then distinguish between "firm" spare capacity (ie that allocated to GasNet transmission rights) and "non-firm" spare capacity (any residual capacity). The former would be entitled to underrun rewards (paid to GasNet) as for shipper-contracted capacity, whereas the latter might only be entitled to receive a regulated "interruptible" tariff (also paid to GasNet). There would remain the problem of distinguishing whether firm or non-firm capacity was being used by unauthorised shippers.

This discussion indicates that the application of the allocation principles could be practically complex. Since part of the difficulty is reconciling between notional and physical capacity, the process may be simplified somewhat if these capacity forms are the same or similar: ie if transmission rights were based on flowgate capacity.

Trading Transmission rights

Shippers should be free to trade transmission rights. For example, a shipper who acquired 100TJ of A-to-B rights may wish to on-sell 20TJ of these to a third party. Shippers could undertake such trades bilaterally, or organise some form of secondary market.

However, the need to find a buyer with exactly the right capacity need may unduly restrict liquidity, particularly considering that, from a feasibility point of view, physical capacity may be put to a range of uses.

To illustrate this, suppose that in the example shown in Figure 4, Shipper X wished to trade with shipper Y. A direct trade is not possible, as Shipper X holds only A-to-C rights, whereas Shipper Y requires only B-to-D rights. However, GasNet could accommodate – within the feasibility criterion – a request from Shipper X to convert 20TJ of its A-to-C rights into B-to-D rights. The converted B-to-D rights could then be sold to shipper Y.

Such "transmutation" of rights is already allowed for AMDQ, which may be swapped for AMDQ at a different delivery point, subject to the application of a scaling factor determined by VENCorp. However, such transmutation may be difficult in general, and require complex scheduling studies to be undertaken.

Scheduling and Trading

The uncertainties of the scheduling process potentially expose shippers to overrun penalties, even where they hold transmission rights. To some extent, this risk can be mitigated through a shipper's market offers and bids. For example, suppose shipper X has 80TJ of entry rights at injection point A but 100TJ of gas to be scheduled. The shipper could offer the final 20TJ of "unauthorised gas" at a premium price, to ensure that, if it is scheduled, the market price is high enough to cover the overrun penalty as well as the cost of gas supply.

If there is sufficient pipeline capacity to schedule 100TJ at point A, it is likely that this capacity has been contracted to another shipper. This example is shown in Table 3 below.

Shipper	Holding	Offered	Scheduled	Traded	Overrun
X	80	100	50	-30	0
Y	20	50	50	+30	0

Table 3: A possible usage mapping using inter-shipper mapping

In this case, it may make sense for Shipper X to trade with Shipper Y. Such trading can ensure that neither incurs the overrun and that the seller of rights receives some value from its unused capacity. However, this trade cannot be undertaken until the schedule is known. In the example, it turns out that shipper Y would have a 30TJ overrun. Therefore, it decides to purchase 30TJ of rights from shipper X, who has a 50TJ underrun.

Some markets allow “ex post” secondary trading of capacity, so that revenue may be obtained from selling unused rights, and overrun charges avoided by purchasing unused rights from other shippers. Whilst this is beneficial, the shipper is still left with some uncertainty as to whether they will be able to make the trades they desire in the ex-post market, and the cost of doing this.

A possible alternative is for a secondary capacity market to be incorporated within the scheduling process, such that the trading of gas and the trading of capacity are undertaken concurrently. Such a market could allow Shipper X and Shipper Y to place conditional bids and offers for transmission rights such that overrun penalties were avoided whenever it was cheaper to purchase additional rights through the secondary market.

Such a concept is embodied in the “biddable capacity rights” that are described in the Consultation Paper. In this model, holders of transmission rights are required to offer these into the scheduling process at some price. The scheduling process then simultaneously clears both the spot gas and secondary rights markets, such that all shippers scheduled or flowing above their rights holding are automatically deemed to have purchased the necessary additional rights from the rights secondary market, and are charged accordingly, in lieu of a tariffed overrun penalty. Similarly, shippers using less than their rights holding may receive payment for any unused rights deemed to have been sold in the secondary market, in lieu of an allocated underrun reward.

This concept is attractive in that it:

- removes the need to set an overrun tariff (although there may still need to be a regulated or administered cap on the secondary market prices); and
- removes the need to specify a separate process for allocating overrun penalty revenue.

However, the clearing process for biddable capacity rights is likely to be complex, particularly if the market offers and transmission rights are structured differently, creating a requirement to “map” between two different forms within the scheduling process.

Administering Physical Rights

Possible forms of physical rights were listed in section 5.2. In particular, physical rights could provide absolute or relative scheduling priority to injections and/or withdrawals.

The practicality of applying these rights within the scheduling process depends upon:

- the form of capacity
- the form of scheduling priority
- the design of the market and scheduling processes

If the transmission rights and the scheduling process have the same structure, for example entry/exit, then applying scheduling priority is straightforward. So, for example, if shipper X with 80TJ of entry rights at injection point A offers 100TJ of gas at that point, the scheduler would give the first 80TJ of "authorised gas" priority, and the 20TJ of "unauthorised gas" lower priority.

Where the structures are different the scheduling process becomes more involved. Suppose, for example, the transmission rights are now point-to-point but the scheduling process remains entry/exit. Tables 4A and 4B show how a shipper's overrun depends upon its withdrawals, even when its injection is known. Therefore, the scheduler cannot apply scheduling priorities to the shipper's injection, without also knowing the shipper's scheduled withdrawals.

Capacity	Holding	Usage	Overrun
A-to-B	30	50	20
A-to-C	50	50	0
Total	80	100	20

Table 4A: shipper withdraws 50TJ at B and 50TJ at C

Capacity	Holding	Usage	Overrun
A-to-B	30	70	40
A-to-C	50	30	0
Total	80	100	40

Table 4B: shipper withdraws 70TJ at B and 30TJ at C

Therefore, the scheduling process now requires an iterative process by which scheduling priorities are adjusted in the light of the capacity usage implied by a schedule result, and the scheduling process is then recalculated in the light of these revised priorities.

Physical rights also have implications for market pricing. Market prices are currently based on the price of the "marginal supplier" – the most expensive scheduled offer or cheapest scheduled bid – in the market schedule, on the basis that this represents the marginal cost of gas supply.

However, if the market schedule is a mixture of authorised and unauthorised gas, the marginal cost of gas may be less easy to identify.

For example, suppose physical rights holders have absolute scheduling priority and that authorised gas is fully scheduled, together with some unauthorised gas. Suppose that the most expensive authorised gas offer price is $100/GJ and the most expensive unauthorised gas offer price is $10/GJ. What should the market price be? Not $100/GJ, because this gas is fully scheduled; but not $10/GJ either, since this is below the cost of gas already scheduled.

5.4 Summary

To summarise, it is considered that:

- transmission rights can conceptually improve physical and competitive certainty for shippers, enhancing the value that pipeline investments can provide and increasing the likelihood that shippers would agree to contract to fund them;
- physical certainty, however, can still only be provided through the scheduling process and only to the extent that other shippers comply with the schedule;
- whilst it should be possible in principle to set the overrun tariff at a high enough level to prevent any "free riding" by uncontracted shippers, such a tariff might create significant shipper risks and regulatory concerns;
- transmission rights could take a number of forms, such as point-to-point, entry-exit or flowgate rights. The closer these forms correspond with physical pipeline capacity, the more effective they are likely to be in promoting investment;
- processes for administering rights may be quite complex, particularly if there is a need for these to be incorporated within the scheduling process, in order to enforce physical rights or to facilitate secondary trading; and
- complexity will also depend upon the form of the market model; in general, administration complexity will be reduced if the form of rights can be aligned with the market model.

6 Combining Solutions

6.1 Introduction

The preceding sections consider a range of potential solutions to the pipeline investment issue. Sections 3 & 4 consider ways to increase the level or certainty of incremental tariff revenue, whereas Section 5 looks at ways to improve the value of rights issued to shippers and, therefore, the level of contractual payments they are prepared to make to acquire such rights.

These solutions are complementary, in that it is the aggregate incremental revenue – tariff plus contract – which will determine GasNet's propensity to invest. This section looks at the interdependencies between the "tariff" and "contract" solutions.

6.2 GasNet Revenues

The first issue to consider is how GasNet's revenues and tariff levels would be affected once transmission rights are introduced. GasNet's revenue streams would then be:

- contract revenue
- tariff revenue
- overrun revenue

GasNet's aggregate revenue would continue to be regulated according to the Code, based on the value of its RAB, its regulated return on this asset base and so on.

Contract revenue would be determined by the provisions of the contracts under which transmission rights are allocated to shippers.

Tariff revenue would be based on the prevailing access arrangements. It is assumed that these tariffs would be structured similar to the current arrangements: ie charged on a mix of peak and average usage.

Overrun penalty revenue would be "recirculated" to the shippers holding rights for the capacity used by unauthorised shippers. Therefore, this revenue would only be retained by GasNet to the extent that unauthorised shippers made use of capacity against which no rights had been issued. Given GasNet's reluctance to invest in new firm capacity on a speculative basis (ie with no foundation shipper), such capacity would typically be "non-firm" capacity which was available from time to time, but could not be relied upon sufficiently to allow rights issuance based on the feasibility criterion.

It is likely that GasNet would not charge TUoS in relation to usage covered by contracted transmission rights, since this would be perceived as "double dipping" by the shipper, and would just add volume risk for GasNet. TUoS charges might remain on capacity covered by “allocated” transmission rights, just as they currently apply to capacity covered by allocated AMDQ. On the other hand, new tariffed “capacity” charges might instead apply to those holding allocated transmission rights.

6.3 Allocating Rights from Tariff-funded Capacity

Where investment is funded through tariff revenue only, there will be some incremental capacity that is not issued to shippers. A question arises as to how this capacity should be treated.

Firstly, it could be issued to shippers, perhaps through an auction process, with any auction revenue used by GasNet to offset tariff charges. However, if it is possible to issue transmission rights in this way, this could probably already have been done to raise at least some contract revenue.

Secondly, it could be “held” by GasNet, with any overrun penalty revenue allocated to GasNet as a result, with this revenue similarly being used to offset tariff charges.

Thirdly, it could be used to issue new transmission rights at a later date. This may occur when some shippers realise that they are frequently incurring overrun penalties and wish to acquire transmission rights to avoid this. Perhaps incremental volumes of rights could be auctioned annually, reflecting gradual growth in shipper requirements.

Finally, GasNet might use the capacity to back a standing offer for short-term transmission rights in the secondary market, although it would need to ensure that this does not reduce shipper propensity to sign up to longer term contracts. If GasNet were to operate in the secondary market, ring-fencing would be required to prevent conflicts with GasNet’s operational roles.

6.4 Summary

In summary, it is considered that:

- both the “tariff-route” and the “contract-route” are likely to play a role in funding future pipeline investments; indeed many investments will be “jointly-funded” by tariff and contract revenue;
- introduction of transmission rights may cause significant changes in how GasNet structures and calculates its reference tariffs; and
- whilst much new pipeline capacity will be contracted by foundation shippers, there will be a need to develop marketing mechanisms to cover tariff-funded capacity.

7 Implementation

7.1 Market Rules

Introduction

The current market situation is described in detail in the Consultation Paper. In summary:

- congestion rights exist in the form of AMDQ and AMDQ Credits;
- AMDQ is an exit right, although the allocation process assumes that it is matched with injection at Longford. AMDQ Credits are point-to-point rights from non-Longford injection points to either withdrawal points or a notional "hub";
- AMDQ is allocated variously between customers and shippers. AMDQ Credits are contracted to shippers by GasNet;
- Congestion uplift is calculated from total uplift, based on the amounts by which shippers or customers are overrunning. If there is no overrunning, there is deemed to be no congestion uplift[13];
- Congestion uplift is allocated equally across all overruns. There is no differential allocation of congestion costs on different capacity types; and
- There is only one, notional market "hub", so settlement is based on injections and withdrawals at the GasNet commercial boundary. There is no information, deemed or actual, about gas ownership between these points.

ICF Consulting have developed and evaluated 5 possible "packages" for future market development. Their evaluation suggests that Package 2 should be implemented in the short-term, with Package 4 possibly to be implemented at a later date. These packages – in as far as they relate to the Pipeline Issue – are described in the following sections.

Package 2

This package makes the following changes to congestion rights and allocation:

- the AMDQ and AMDQ Credits are reformed into a single-form point-to-point AMDQ right. Essentially, this means that existing AMDQ becomes point-to-point with the same withdrawal point and Longford as the injection point
- all existing AMDQ is reallocated to shippers;
- An hourly profile is introduced to each AMDQ and AMDQ Credit, and overrun is calculated based on a combination of hourly and daily overruns;

[13] Whilst there may be actual congestion, the costs in this situation would be allocated to surprise uplift

- Congestion costs will be calculated based on the uplift costs arising from a perfect-foresight day-ahead operational schedule. This should have the effect of improving the split between congestion and surprise uplift and therefore improving the financial certainty provided by congestion rights[14];
- Congestion costs will still be allocated equally across all overruns; if there are no overruns, then any congestion costs are allocated to authorised withdrawals; and
- Therefore, whilst the changes formalise and simplify the AMDQ arrangements, the congestion rights do not necessarily become significantly more valuable[15].

On preliminary considerations – and assuming no consequential changes are required to the GasNet access arrangements – it is anticipated that, if agreed, Package 2 could be implemented by 2006.

Package 4

This package introduces a multi-hub market, with intra-day pricing. Thus, shipper gas can be traded at each hub and, if necessary, tracked between hubs. This package also proposes biddable capacity rights in the form of hub-to-hub rights. These rights would be issued by GasNet and would replace whatever rights are in place at the time of its introduction.

As noted in section 5.3, biddable capacity rights are essentially transmission rights which are traded between shippers within the scheduling process. This would allow the market schedule and prices to reflect the clearing prices of these secondary trades, rather than relying on regulated overrun tariffs or penalties. As such, biddable capacity rights would appear to resolve the pipeline investment issue, or at least address it better than other rights models, especially for congestion occurring between hubs; given the physical spread of the hubs across the pipeline system, this would appear to cover the majority of likely investment requirements.

As such, any implementation of biddable capacity rights would need to address the practical issues of scheduling and administration discussed in section 5.3. However, given the multi-hub market, it seems more likely to be feasible to have broadly consistent structures for physical capacity, notional capacity and market schedules, which should mitigate these complexities.

7.2 GasNet Arrangements

GasNet currently levies TUoS tariffs under an access arrangement that runs until the end of 2007. The TUoS charges are based on actual injections and withdrawals, and calculated based on injection point usage and point-to-point usage, the latter employing a mapping method to convert

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[14] In fact, other changes introduced in Package 2 will also improve financial certainty, by better allocating surprise uplift to those whose actions cause it.

[15] In their Evaluation Report, ICF have also considered introducing overrun penalties, effectively converting the AMDQ rights into financial transmission rights. This is similar to what is considered in this paper. For clarity, it will be assumed that “Package 2” refers to modified AMDQ rights being only congestion rights.

from injection/withdrawal quantities to point-to-point usage. Injection point charges are peak demand based, whereas the point-to-point charges are throughput based.

GasNet also contracts with shippers to provide AMDQ Credits. Typically, these contracts also place take-or-pay requirements on TUoS charges. AMDQ issuance and pricing is not covered by the access arrangements.

GasNet is of the view that, were transmission rights to be introduced, a new access arrangement would be required in order to cover the new overrun tariffs, were these new tariffs to exceed existing tariffs. This is because shippers have the right to stay with the existing Reference Service. Furthermore, to introduce these concepts into the regulatory approval process, the transmission rights would need to be defined two years prior to the commencement of the new access arrangements. Practically, this means that Transmission Rights cannot be introduced before 2008, and would need to be fully defined no later than 2006 to achieve this. There is an attendant risk that the regulator may not accept the new overrun tariff.

If new investment were required prior to the introduction of transmission rights, GasNet could potentially contract with the foundation shipper to provide modified AMDQ rights in the interim and to convert these to transmission rights once implemented. However, the shipper would need confidence that the transmission rights would indeed be introduced and of the form and value these would have.

7.3 Code Changes

Code changes may be needed to implement the solution options discussed in sections 3 and 4. At this stage, it is not clear that Code changes are needed to implement transmission rights, although this issue has not been analysed in detail.

The Productivity Commission is currently reviewing the Gas Code. This may lead to some significant changes to the Code, which may therefore also create an opportunity to introduce some of the changes suggested in this paper. Timescales associated with the PC review and the Code change process make it unlikely that Code changes could be introduced earlier than 2006.

7.4 Rights Allocation

A question arises as to whether congestion rights held by shippers under existing AMDQ and AMDQ Credits, or resulting from an allocation of modified AMDQ rights under package 2, should be “converted” into transmission rights if and when these are introduced and, if so, how this conversion should be done. As noted previously, although there is no necessary linkage between congestion rights and transmission rights, it is convenient to have them “stapled” within the same product. However, to the extent that transmission rights are more valuable than congestion rights, there may be a perception that this conversion unfairly gives a windfall gain to rights holders, at the expense of non-rights holders.

If the transmission rights are point-to-point, like the modified AMDQ rights, then the mechanics of the conversion process may be straightforward. If they are of a different form – eg flowgate rights – the process will be more complex and contentious.

7.5 Transmission Rights Systems

The implications of implementing transmission rights depends upon what form they take and what arrangements need to be put in place for secondary trading of these.

At their simplest, transmission rights would be purely financial, and would be traded (if at all) outside of the scheduling process. In this case, no changes to the market rules or scheduling would be required, and systems would be required simply to:

- determine amounts that can be issued;
- determine capacity usage, based on information from the market; and
- calculate overrun charges and allocation of overrun penalty revenue.

These systems could potentially be developed either by VENCorp or by GasNet. In the latter case, there would need to be at least an independent check on the issuance amounts.

Implementation would be significantly more complicated if the transmission rights are physical. In this case:

- rights holdings must be communicated to the scheduler;
- the scheduler must convert market quantities (eg injections and withdrawals, for package 2) to capacity usage quantities within the scheduling process; and
- depending upon the form of physical rights, overrun tariffs may be reflected in the market pricing.

Finally, a further complication is added if secondary rights trading is to occur within the scheduler. This would require:

- rights holdings and bids and offers to be communicated to the scheduler;
- trading amounts to depend upon schedule quantities compared to rights holdings (and possibly vice versa if the rights are also physical);
- the scheduler to convert market quantities to capacity usage quantities within the scheduling/trading process;
- overrun tariffs to be factored in, since overrunning is an alternative to buying additional rights; and (possibly)
- trading prices and/or overrun tariffs to be reflected in price outcomes.

These complexities suggest that it would be problematic to implement physical rights and/or trading within the scheduling process where the form of rights is inconsistent with the form of the market: for example where the market was entry/exit (as in package 2) but the rights were point-to-point.

Package 4 includes biddable capacity rights. However, it may be valuable to consider whether these biddable capacity rights – or perhaps alternative forms of transmission rights - could be introduced under a simplified form of package 4; for example, where multiple hubs are defined, but where there is no intraday pricing or, alternatively, no biddable capacity rights.

Table 5 below shows the possible implications of introducing different forms of transmission rights under the alternative market design packages. The views on implementation complexity and issues arising are preliminary, based on the considerations described in this paper, and substantial further work would be required to confirm them.

Form of Capacity	**Physical? (1)**	**Market Package**	**Implementation complexity(2)**	**Issues Arising**
Entry/exit	N	2	Very low	Poor investment driver. Shipper risks managed through market offers.
Point-to-point	N	2	Low	Shipper risks from inadvertent scheduled overruns: cannot easily be managed through offers
Point-to-point	Y	2	Medium to high	Possible conceptual and design feasibility risks. Reduced shipper risks
Hub-to-hub	N	4 (3)	Medium	Not clear what shipper risks arise and whether they can be managed through hub linepack bidding?
Hub-to-hub	Y	4	medium to high	Equivalent to biddable dispatch rights, but only drives inter-hub investment

Notes:

(1) This covers both physical aspects to the rights and incorporation of secondary trading within the scheduler

(2) Of the central systems required to administer the rights

(3) Package 4 but without biddable dispatch rights

Table 5: Implications of introducing Transmission Rights

7.6 Implementation Scenarios

Whilst it is not possible at this stage to answer all of the implementation questions raised in this section, it may be possible to assess how our implementation plans may be affected by the answers to these questions.

The key questions are:

- at what point is the pipeline investment problem likely to substantially impact on market efficiency and development, such that package 4 might be justified?
- can effective transmission rights be introduced under package 2, or under a modified package 2 to facilitate physical rights or rights trading, or would this require implementation of package 4 or, at least, a simplified version of it?

Depending upon the answers, it might be appropriate to aim to implement transmission rights from the start of the next VENCorp/GasNet access period (1 January 2008), either under package 2 or a package 4. This would mean that transmission rights, and the package needed to implement them, would need to be defined by 2006, to allow for the necessary access arrangements and market systems to be put in place for 2008. If investment were required before then, GasNet may be able to negotiate contracts to provide AMDQ rights from 2006 (say), to be then converted to transmission rights in 2008.

If rights were introduced under package 2, then they may need to be converted – eg into biddable capacity rights – to operate under package 4 if this were introduced. A process and principles for this conversion would probably need to be specified by 2006 to give rights buyers' confidence that the value of their rights would be protected.

7.7 Summary

In summary:

- introducing transmission rights - in a form which is likely to be effective in addressing the pipeline investment issue without creating unreasonable risks for shippers – will require complex administration processes and systems, under either the Package 2 or Package 4 market designs;
- it will not be possible to introduce transmission rights before the new GasNet access arrangement commencing 2008, which allows around 2 years for the design of transmission rights to be determined and implementation issues to be fully understood;
- if, as expected, the market will be operating under Package 2 (or similar) at this date, there will be a need to prove the conceptual feasibility of transmission rights under this package;
- in any case, it would be prudent to further explore the design and implementation issues associated with introducing biddable capacity rights under Package 4, so that these can be introduced quickly should it be decided to move to Package 4 at a later date; and
- principles must be established under which conversion of existing rights will take place, so that long-term investors have confidence that the value of their rights will be preserved under this process.

8 Conclusions

Based on the discussion and analysis described in this paper, the Pipeline Investment Working Group believes that the solution to the pipeline investment problem lies with some regulatory changes, combined with the introduction of new transmission rights.

Suggested regulatory changes are:

1. To introduce and describe a "market benefits test" to replace or complement the existing system-wide benefits test. The new test would allow tariffs to be increased where the market benefits from the investment exceeded its cost and where the beneficiaries of the investment could not be clearly identified.
2. To apply a market benefits test where investment needs arise from general market growth, rather than from distinct new requirements of one or more shippers.
3. For VENCorp to assess potential expansions under the market benefits test as an expansion of its role in providing planning information through its annual planning review process, and, where appropriate, VENCorp would then assist in development of submissions to the regulator for approval.
4. Where a regulator approves a proposed expansion that has satisfied the market benefits test, for the cost of that expansion to be rolled into GasNet's regulatory asset base.

Conclusions in regard to the introduction of transmission rights are as follows:

5. Notwithstanding the regulatory changes described above, there is still likely to be a need for foundation shippers to contract with GasNet to fund, or partially fund, their future capacity requirements;
6. In agreeing to fund new capacity, foundation shippers will expect in return a high level of *financial*, *physical*, and *competitive certainty* in the use of this new capacity, as defined below.
7. "*financial certainty*" means a fixed and known transportation charge and, in particular, a right to avoid paying the costs of any congestion management on the new capacity. This certainty is provided, to some extent, under the existing AMDQ and AMDQ Credits arrangements and is expected to be enhanced under the proposed market design packages. Such "congestion rights" should also be a component of any new transmission rights that are introduced.
8. "*physical certainty*" means confidence that a foundation shipper will be able to flow its gas on the new capacity and not be displaced by other, uncontracted shippers. This could be provided, to some extent, by introducing "*physical rights*" which would give the contracted shipper priority in the scheduling process. However, this would not prevent the shipper being displaced due to other shippers deviating from the schedule.

9. "*competitive certainty*" means confidence that a competing shipper, or "free rider" will not be able to access the contracted capacity on preferential terms. This can be provided by introducing "*financial rights*" which apply an "overrun penalty" to any uncontracted shipper using contracted capacity and using this overrun penalty revenue to compensate the contracted shipper.
10. New systems will be needed to administer and enforce the transmission rights, whether physical and/or financial. These systems may be quite complex, particularly where the rights need to be administered or applied within the scheduling process.
11. Regulatory treatment of the proposed overrun penalty tariffs means that transmission rights could not be introduced until the commencement of the next GasNet access arrangement in 2008[16]. They would then need to be defined by 2006 in order to be introduced into the regulatory review process.
12. Transmission rights could be introduced under either the Package 2 or Package 4 market designs, albeit in different forms and with potentially different levels of complexity and effectiveness. Further work is required to explore these interdependencies.
13. Processes will need to be defined to convert pre-existing rights into the new forms of rights in a way which preserves value for the holder of the rights.
14. At this stage, a possible implementation scenario is for financial, point-to-point rights to be introduced in 2008 under Package 2, with a future introduction of biddable capacity rights under Package 4. However, the feasibility of this needs to be confirmed, and other alternatives explored.

[16] While it would be theoretically possible to implement changes to the VENCorp and GasNet access arrangements before this date, the practicalities of the process for achieving authorization of revised access arrangements and GasNet's negotiation of new contracts mean that there would be little, if any, benefit in seeking to do so.