Separate Marketing of Natural Gas
By Joint Venture Producers in Australia

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Optima Energy

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I. Introduction and Terms of Reference

1. My name is Paul Carpenter. I am a Partner of The Brattle Group, an economic and management consulting firm with offices at 44 Brattle Street, Cambridge, Massachusetts, USA, and in Washington D.C. and London, England. I hold a Doctorate in Applied Economics and a Master of Science in Management, both from the Massachusetts Institute of Technology, and a Bachelor of Arts in Economics from Stanford University. I specialise in the economics of the natural gas, oil and electric power industries.

2. I have been assisted in the preparation of this paper by Jurgen Weiss. Dr. Weiss is an Associate of The Brattle Group. He holds a Doctorate in Business Economics from Harvard University, a Master of Business Administration from Columbia University and a Bachelor of Arts in European Business Administration from the European Partnership of Business Schools. Dr. Weiss also specialises in the economics of network industries, such as natural gas and electric power.

3. In commissioning this paper, Optima Energy has asked me to describe and comment on the economic issues surrounding the separate marketing of natural gas by producers participating in exploration, development and production joint ventures. In particular, I have been asked to describe in some detail the commercial and contractual arrangements under which separate marketing is accomplished in North America. And I have been asked to assess the merits of requiring, as a matter of public policy, that producers in Australia separately market their ownership shares of natural gas not currently under contract or under contracts that have not yet received authorisation under the Trade Practices Act.

4. In preparing this paper, I have reviewed the August 1998 Public Consultation Document of the Upstream Issues Working Group established by the Australian and New Zealand Minerals and Energy Council (ANZMEC), various documents associated with the 1997 Review of the Cooper Basin (Ratification) Act, and many public sources of information on gas marketing and contracting practices, cited throughout this paper where relevant. I am quite familiar with the evolution of the gas industry in Australia by virtue of prior engagements there, including evidence that I gave before the Australian Competition Tribunal, on behalf of the ACCC, in the matter of the AGL/Cooper Basin contract authorisation.

5. This paper is organised as follows: I begin with a brief discussion of the economic principles that should guide our thinking about the relationship between the commercial arrangements to sell natural gas, the process of natural gas exploration, development and production, and market structures that support competition in gas production and sales. Then I turn in detail in section III to the

commercial and contractual arrangements that support separate marketing of gas in North American joint ventures. This informs the discussion in the fourth section on the relative costs and benefits of a change in policy requiring the separate marketing of natural gas by joint venture producers in Australia. I close the paper with brief responses to each of the questions posed by the Upstream Issues Working Group in its Consultation Document of August 1998.

II. Background and Principles

6. The exploration, development and production of natural resources, such as oil, coal, uranium, and precious metals, are risky endeavours. Natural gas is no exception, nor is it particularly unique in this regard. All such endeavours require extensive initial investments to be made prior to the start of production and sales, as well as the development of extensive delivery infrastructure. Much of this investment is immobile once sunk, and the returns on and of invested capital must occur over long periods of time. The same is true of industries, such as electric power generation, whose capital-using equipment depends on natural gas, coal or oil for fuel.

7. The initial development of such industries, and the management of the risks inherent in these businesses, has been accomplished around the world through a variety of mechanisms. In some cases governments directly underwrite the industry development through the creation of government-owned enterprises. In other cases, private industry is encouraged to arrange these activities through joint ventures or government-sanctioned monopolies. Sometimes such rights or licenses to produce are sold to parties with the understanding that there will be competition to secure the rights and/or to sell the commodities once produced. It is typical in all of these circumstances that long-term contracts between producers and consumers of the resources are employed to manage the inherent capital-recovery risk.

8. A second common feature of such natural resources is that once produced, they have commodity characteristics. In other words, but for accountable variations in quality and measurement, the resources produced from one supplier are fungible (interchangeable) with those from another supplier. The commodity feature of these resources enables them to be traded on open cash, forward and futures markets. The development of such trading is a natural consequence of efficient market behaviour, as parties that place the highest value on the use of the commodity at any point in time seek supplies from producers, marketers and traders, who themselves are seeking out counterparties to maximise their gains from trade (i.e., arbitrage).

9. But the desire to obtain the benefits of trading such commodities on open markets

creates conflicts with the desire of resource developers and producers to manage their business risks during the transition away from the government-managed monopoly structures. Such conflicts are particularly acute prior to the development of commodity markets characterised by many buyers and sellers (i.e., liquidity.) Experience shows that once liquid commodity markets are developed, producers can manage their risks efficiently by taking forward financial positions of various kinds in these markets. But liquid trading markets will not develop in the absence of liquid spot (cash) markets for the underlying commodity. Unfortunately, the development of such liquidity can be impeded by the joint-venture monopoly and long-term contracting practices that were the primary means of risk management at the time the resources were initially developed. This creates a significant chicken-or-egg dilemma for governments that are seeking to liberalise the commercial regimes associated with their formerly state-owned or licensed monopoly enterprises. The difficulty is primarily in the transition from one regime to the next.

10. It is apparent that the natural gas industry in Australia is currently at this crossroads. Australia's gas producing industry and delivery infrastructure were financed and developed through government-sanctioned joint venture monopoly arrangements. These arrangements received explicit exemption from Trade Practices Act enforcement. Risk was managed, in part, through the use of long-term, take-or-pay contracts between the producers and the large gas-consuming utilities and reticulators in each state. In some cases, such as in South Australia, the government itself was the purchaser and pipeline developer. These contracts typically covered very large portions of the total gas consumption requirements of the state. The arrangements were quite successful in the sense that significant gas reserves were discovered and developed, and significant delivery infrastructure was put in place, under conditions that were apparently profitable for the participants (including government.)

11. But since the issuance of the Hilmer Report and the initiation of the CoAG reform process, Australia and its individual states have also sought to liberalise the regimes governing the gas industry by pursuing policies to introduce greater competition into both the purchase and sale of gas. This includes policies designed to create conditions whereby spot and forward trading in the natural gas commodity would occur.[1]

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[1] Indeed, Victoria' proposed market structure for gas sales within its state is designed to create a spot market from whole cloth that would be administered by a privatised system operator. See also the 29 July 1998 ACCC Determination in the Application for Authorisation of the Northwest Shelf Project, which states: " Reforms to the gas industry instigated by CoAG are intended to provide gas users, particularly the larger industrial users, with the opportunity to contract directly with a number of suppliers. In addition to dealing with producers directly, it is envisaged that gas users would have the opportunity for dealing with aggregators trading in a secondary market." (at page 15).

12. Spot and forward trading markets in natural gas will develop when: 1) there is gas supply available for sale that is not committed to a buyer under an existing long-term contract; and/or 2) where an existing buyer has contracted for supplies in excess of its needs at a particular point in time and seeks to on-sell the excess (in a "secondary market" transaction.)

13. Currently in Australia, gas trading that occurs is primarily with supplies of the second type, and not the first, and there appears to be very little interstate competition between joint ventures. The existing producer joint ventures appear to only develop sufficient production deliverability to support existing long-term contracts. When new development takes place, it is usually undertaken only on the basis of new or extended long-term contracts. Such a strategy is consistent with the historical risk-management model under which the gas reserves were originally developed, but it may also result in slower than optimal resource exploitation due to its reliance on monopoly joint venture conduct.

14. There is an open question as to whether both types of available supplies (separately marketing production not under long-term contract, and secondary market activity) will be necessary to support a liquid and competitive gas trading market in Australia. In other regions characterised by liquid gas markets, such as North America and the UK, most available supplies are of the first type, and do not rely heavily on secondary market trading of excess gas previously sold to buyers under long-term contract. But the secondary market trading of excess gas may be a very important inducement to the development of liquid markets during the transition period to market liberalisation.[2]

15. In North America and in the UK (to a somewhat lesser extent)[3], available supplies supporting market liquidity derive from gas sales made by individual producers, who are frequently themselves interest owners in joint ventures or "unitised" gas development and production arrangements. Gas sales by individual producers may be made directly to end-use buyers, or they are made to one of many "aggregators" or marketing companies that, in turn, repackage the supplies and manage the purchasing and transportation transactions for consumers. Thus, in this situation, individual gas producers still benefit from the economies of scale and risk management associated with joint venture *exploration, development and production,* while they compete with other producers to make sales. In some cases this competition takes place in prices, in other cases it may take the form of

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2 In the initial development of gas spot markets in the US, considerable excess supplies were made available through the renegotiation and/or buy-out of expensive ("out-of-market") take-or-pay contracts held by pipelines with producers.

3 For a paper analyzing the legal and policy trends favouring the separate marketing of gas by joint venture producers in the UK and Europe, see: James D. Dinnage, (Arnold & Porter, London) *Joint Activities Among Gas Producers: The Competition Man Cometh.*

innovative supply services to particular customers (a role that aggregators and marketers would inevitably play as well.)

16. It has been suggested by some in Australia that the transaction costs associated with separate marketing of gas by joint venture producers would be prohibitive, particularly for small producers, or that it would be impossible to coordinate within the context of joint venture operations. Based on international experience, these claims are largely unfounded. In the next section I describe in some detail the institutional and contractual arrangements that have developed in the US to support separate marketing by joint venture producers. These standardised arrangements contain some necessary complexities, but they appear to be manageable. And while transaction costs will always be a concern for small producers, the emergence of gas aggregators and marketers in the context of a liquid trading market is in part a response by self-interested third-parties to create and capture the benefits of economies of scale in marketing.

17. Thus, the argument made by some that the joint marketing of gas is necessary to preserve the economies of scale of joint venture exploration, development and production, is an extremely weak one. An alternative, if unstated, characterisation of the argument is that joint marketing of gas is necessary to maintain the benefits to the joint ventures of restricted competition in the sales of gas. But such "benefits" to the joint ventures are costs to society, in the sense that gas development and production will be slower and prices higher than is optimal to maximise the value of the resources for society. Of course, the elimination of such costs is one of the principle reasons for pursuing gas market liberalisation in the first place.

III. Institutional and Contractual Arrangements for the Separate Marketing of Natural Gas from Jointly Operated Fields in the United States

18. It is apparent from the description of the issues in the ANZMEC/UIWG Public Consultation Paper of August 1998 that there is some question as to whether separate marketing is technically feasible in the context of joint venture operations in Australia. For example, it is suggested (at p.75) that the "difficulty of *physically separating* gas production for allocation between the individual participants of a joint venture...[means that] joint disposal is still favoured for gas." [emphasis in original] In this section of the paper, I describe the commercial mechanisms that have arisen in the United States to permit separate marketing even when *physical* separation is not feasible. Despite the apparent complexity of many of the allocation and accounting issues that arise in separate marketing,

contractual arrangements have been devised to handle the complexity, to the point that they have been incorporated into standard form agreements.

A. Fundamentals

19. As discussed above, due to the large investments and high degree of risk involved in the exploration, development, and operation of natural gas fields, such investments are often undertaken by joint ventures. This is true for all major areas of gas exploration around the world, and in particular in Australia as well as in the USA. In the USA, the operations of such joint ventures are typically governed by a Joint Operating Agreement (JOA).

20. In the USA a few standardised forms are frequently used as the basis for the majority of JOA's. These pro forma agreements are useful in assessing standard industry practice. Commonly used in the mid-Continent producing region (including Texas, Oklahoma and Kansas) is Form 610 prepared by the American Association of Petroleum Landmen (AAPL). In the Rocky Mountain region Form 2, issued by the Rocky Mountain Mineral Law Foundation (RMMLF), is frequently employed.

21. Both of these standard forms provide explicitly for the separate taking and marketing of gas by each of the parties to the joint venture, of the gas from the jointly developed and owned gas field.[4] This is different from the situation in Australia where joint selling of gas from joint ventures has evolved as the industry standard even though, in theory, the joint venture operating agreement also allows for the separate taking of gas.[5]

22. Separate sales under JOA's in the US can take one of two forms: Separate sales by individual joint venture partners to the same buyer, e.g. a pipeline operator, or a local gas distributor; or, separate sales to different buyers, referred to as "split stream" gas sales.

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4 AAPL Form 610 – 1989, Article VI, Section G states that "[E]ach party shall take in kind or separately dispose of its proportionate share of all oil and gas produced from the contract area", pp. 10-11; RMMLF Form 2 – 1994, Article 6.4 states that "Each Party shall take in kind or separately dispose of its proportionate share of production."

5 It appears that in spite of this apparent similarity in rules, the main difference lies in the fact that in Australia all parties have to agree to the desire of any one party to sell gas separately, and that this clause has acted as an efficient barrier to separate sales. [See, for example, Nick Dyki's Report on *The Review of the Cooper Basin (Ratification) Act*, September 1997, p.20: "although the Unit Agreement is a production joint venture, it has this effect [restricts competition] because it provides no *mechanism* for a Producer separately marketing its share of uncontracted reserves. The Unit Agreement does entitle each Producer to take its share of agreed production and separately dispose of it. This is not a *mechanism* for separate marketing rather it is a mechanism which effectively forces the Cooper Basin Producers to market their gas jointly." [emphasis added]

23. Because split stream sales are not uncommon, it is necessary to reconcile joint operations of the gas field with the takes of gas associated with separate marketing by some or all of the joint venture partners. The most critical issue to be accounted for in this context is the over- or underselling of gas relative to the share of the gas field owned by each of the JV partners. These are referred to as production "imbalances."

24. To address this issue, both standard form JOAs include, as an attachment, standard "gas balancing agreements" that spell out how imbalances that result from separate marketing of jointly owned and produced gas are to be accounted for. Such balancing agreements tend to supersede any default rules in the JOA and form the contractual basis for compensation of all members of the JV when imbalances occur between actual sales and the allocated shares of a well's (or field's) production.

B. Balancing Basics

25. Imbalances are most likely to arise under the following two circumstances:

a. One of the parties doesn't take its full share of production because it doesn't (yet) have contracts to sell its entire share.

Example: *Two parties, A and B, each own 50% of the production from a well operated by A. For the first six months after the beginning of production, B only has a sales contract for half of its share. A's contract allows for the sale of additional gas. Hence, A sells 75% of the well production, and B only 25% for the first six months.*

b. There is a difference between contracts and actual takes by purchasers in split-stream situations, i.e. in situations in which the output from a well or field is sold to more than one buyer.

Example: *A sells its share to buyer X, B to buyer Y. Although the contracts of A and B are each for the entire allocated share of production to each seller, buyer Y is unable to take gas delivery for the first six months. A's contract with X provides for X to take the entire production of the well. Again, A "overproduces" for the first six months, and B "underproduces", creating an imbalance between the two.*

26. If one party takes less than its allotted share, the other parties are typically entitled to take the difference between the actual take and the allotted share and sell it on their own account, creating "over-production" on their account, and "under-

production" by the other party. The right of other parties to a share of the underproducing parties' unused gas is typically specified to be either proportional to the ownership shares of each of the overproducing parties[6], or it is allocated to parties that have been underproducing in the past in proportion to their interest in the JV relative to other underproduced parties desiring to take extra. Only if extra gas is left after all historically underproduced parties have taken their desired shares is extra gas distributed to anybody else in proportion to their overall ownership shares.[7]

Example: *Assume sellers A, B, C, and D each own 25% of a well. Parties A and B had not taken any of their gas for the first three months of production, possibly because their buyers were then unable to take delivery. Since then, each party has taken its share of the production. Now assume that C's buyer is unable to take delivery of any gas for a one month period. The RMMLF form balancing agreement allocates the 25% of production unused by C among A, B, and D according to their ownership shares. Since those are equal (25% each), each of the three gets to take one third of C's unused gas. In total, A, B, and D will thus end up selling an extra 8.33% of gas for a total of 33.3% each. Under the AAPL agreement, parties A and B would have a first call on the underproduction. If they both desire, they can split the unused capacity between them. This would lead to final takes of 37.5% each by A and B, and 25% by D. Assume finally that B can only sell an extra 5% of production. In that case, D, being the only remaining producer entitled to increased production, could take the 7.5% of gas unused by B to boost its own sales. In this scenario, the final takes of the four parties would be 37.5% (A), 30% (B), 0% (C), and 32.5% (D).*

27. Though not part of the US standard forms, other mechanisms for allocating unused capacity are conceivable. For example, it may make good economic sense to allocate any unused gas to the remaining parties based on their cumulative underproduction to date rather than based on ownership shares. This would give parties with a greater need to make up past underproduction the rights to a larger portion of the unused gas production, which seems efficient.

28. Typically, it is required that parties make a good faith effort to take their full monthly share, and the operator can require parties to take (part of) their share for operational reasons.

29. Once an imbalance exists, the parties regain balance over some period of time. This balancing can occur either *in-kind* or *in-cash*. In-kind balancing gives the underproduced party the right to overproduce for some period to enable the accounts to be brought back into balance. In-cash balancing removes the

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6 RMMLF Form 6, Paragraph 2 (b)

7 AAPL From 610-E, Paragraph 3.3

imbalance through a transfer of money from the overproduced to the underproduced party. In the absence of a specified method it has been generally assumed that the default method is balancing in-kind.

C. Balancing in-kind

30. Balancing in-kind refers to the process whereby a party who has sold less than its share of the joint production over some time "makes up" the deficit by increasing its sales above its share until, in the aggregate, the total amount of gas taken to date is equal to that party's share of the joint production volume to date. Making up underproduction implies that other parties have to reduce their sales below their relative shares of joint production.

31. To start the process of making up underproduction, the underproduced party needs to inform the operator of the well (or field) of its intent to make up the imbalance.[8] The operator can then adjust each party's schedule to allow for the process to begin.

32. In order not to infringe on overproduced parties' rights to gas and obligations manifest in their own sales contracts, the way in which underproduction can be made up is limited in several important ways:

a. The amount of make-up gas the underproduced party can sell in addition to its own share is limited to a certain percentage of the other parties' shares of production. This percentage ranges from around 20% to about 65%. The Rocky Mountain Agreement calls for overproduction of up to 50%. The AAPL form leaves the percentage open to the parties to negotiate. If there are several underproduced parties, they make up for the imbalance in proportion to their ownership shares.

Example: *A, B and C each own 33.3% of the output from a well. A has underproduced over the past 6 months and has just announced that it would like to start making up gas to regain overall balance. According to the RMMLF Form 6 Balancing Agreement, A's maximum sales during the make-up period (i.e. until it reaches balance) are its share (33.3%) of output plus half of the share of each of the other parties (16.67% of production from B and from C each), for a total of 66.66% of the output of the well.*

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[8] RMMLF Form 6, Paragraph 2 b, "Such Underproduced Party, upon giving timely notice to Operator, shall be entitled, on a monthly basis beginning the month following the receipt of notice, to produce, take, sell and deliver, in addition to the full share of gas to which such party is otherwise entitled, a quantity of gas ("make-up gas") equal to fifty percent (50%) of the total share of gas attributable to all parties having cumulative overproduction".

b. Making up gas imbalances is restricted during those periods of the year when gas prices tend to be high, i.e. the winter months in the US, when heating requirements drive up the demand for gas. Making up gas might be prohibited altogether (RMMLF Form 6 excludes the months of December through March), or otherwise limited to some maximum amount (AAPL Form 610)[9]. These limitations are designed to reduce parties' incentives to deliberately reduce sales during off-peak months and to make-up the underproduction during peak months, thus profiting from increased sales at higher prices. The restrictions are also reasonable since, during the peak months, the demand for gas for the other parties is high and less flexible than during off-peak periods.

33. The process of making up gas becomes somewhat more complicated when there is more than one party with historic underproduction. Existing US gas balancing agreements allocate the available make-up gas (e.g. up to 50% of the overproduced parties' share of output in the RMMLF Form 6) in relation to the ownership percentages of each underproduced party in the JV. Any unclaimed make-up gas is typically allocated among the remaining interested parties in the same fashion.

34. To accommodate underproduced parties' efforts to make up the existing imbalance, overproduced parties have to reduce their sales. The volume reduction typically takes place in proportion to ownership share.

35. There are situations in which the operator can deviate from this rule if one or more of the overproduced party has, in the operator's view, already extracted 100% or more of its total share of production over the life of the well (or the length of the agreement). In such cases, the operator can require such parties to cease selling any output from the well and allocate the entire share to the underproduced parties as make-up gas until balance is regained.[10]

36. In addition to any rules that limit the amount of make-up gas available, existing gas balancing agreements sometimes place a limit on the amount of overproduction allowable for any overproduced party. For example, the AAPL Form 610-E limits the maximum take by an overproduced party to 300% of its share of the maximum monthly availability in any given month, unless more is needed to maintain leases or to continue production[11].

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9 The AAPL form has two alternative provisions, one of which limits the amount of make-up in the winter months to the amounts made up in the months preceding the winter, the other to a certain pre-agreed percentage of production.

10 RMMLF Form 6, Paragraph 2 (e)

11 AAPL Form 610-E, Paragraph 3.5

37. Other methods for allocating make-up gas and assigning sales reductions to overproduced parties are conceivable, although such provisions are not part of the standard gas balancing agreements in the US. For example, make-up gas could be allocated to underproduced parties in relation to each underproduced party's share in the total amount of cumulative underproduction, and overproduced parties could be required to reduce output in proportion to their share in the total overproduction to date rather than according to their ownership percentage in the well. Both provisions should allow a faster move towards a new balance.

38. The unit of account is potentially significant when balancing in-kind is employed. This is particularly important when gas from more than one well is involved. Traditionally, most balancing has taken place using Mcf of gas as the unit of account (a volumetric measure). However, especially if several wells and hence different qualities of gas are involved, the value of each Mcf of make-up gas may exceed the value of underproduced gas substantially. One alternative employed is to apply adjustment factors when gas of different quality is used as make-up gas. However, since an increasing number of sales contracts use MMBtu as the unit of account (a measure of energy content), and since measuring gas imbalances in MMBtu largely eliminates problems arising from different gas qualities, using MMBtu as the basis for gas balancing is becoming increasingly popular. Both US standard forms allow for this option, and the RMMLF Form 6 makes it the only option[12].

D. Balancing in-cash

39. There exist situations where in-kind balancing is not technically feasible. The two most common situations are:

a. When a well is nearing depletion and there is not enough gas remaining to allow the accounts to be balanced physically;

b. When under-production is the result of a split-stream well and, by the time balancing is to occur, there is no longer a split stream, i.e. the entire production of the well is sold to a single buyer.

It is under these circumstances that alternatives to in-kind balancing are needed. The alternative of choice is in-cash balancing.

40. In-cash balancing refers to the process whereby any existing imbalances in the sales of gas are resolved through payments from the overproduced parties to the

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12 The AAPL Form 610-E also gives the option to use Mcf as the basis for balancing.

underproduced parties. The primary question that needs to be addressed when balancing takes place in cash is one of valuation, i.e., how much the overproduced parties owe the underproduced parties.

41. The most common way to value the overproduction is to use the prices at which gas was actually sold by the then-overproducing party at the time overproduction took place[13].

Example: *A and B each own 50% of a well. Over a six-month period, B only sells half of its share. By the time B is ready to make-up the imbalance, the remaining reserves are insufficient for balancing in kind. Hence, balancing in cash is chosen. During the six month period, A sold the overproduction at a price of $2.00/MMBtu. The current market price for gas at the time of in-kind balancing is $2.50/MMBtu. B is entitled to be paid $2.00/MMBtu for the total quantity underproduced over the six-month period, and not the current market price.*

42. For in-cash balancing to work properly, all parties must provide the operator with information regarding volumes and prices of sales at regular intervals. Typically, the operator requires information by all of the parties on the amounts and prices received on a monthly basis.

43. Sometimes, overproduction is not sold through an existing sales contract, but rather "sold" in ways that do not involve an actual sales price. This is the case when overproduction is taken for own use or transferred to an affiliate. In such cases, the market or spot price for gas at the time of overproduction is sometimes used as the appropriate benchmark for in-cash balancing. The spot market price may be used as the default price for in-cash balancing in such cases (RMMLF Form 6), or it may serve as a "price of last resort" only if the overproducing party has made no sales during the month of overproduction which can be used to calculate an average sales price to value the overproduced gas (AAPL Form 610-E).

44. In-cash balancing at the sales price of the overproduced party may not be optimal. There are alternative methods of valuation, including a valuation at current spot prices, or a valuation using inventory valuation conventions such as FIFO (First-In-First-Out) or LIFO (Last-In-First-Out). None of these are likely to be ideal under all circumstances. The perceived fairness of any valuation technique will depend on whether market prices for gas increase or decrease between the time of underproduction and the time of in-cash balancing. The ideal standard would be to value underproduction at the price the underproduced party would have received had it sold its entire share of production (i.e., its opportunity costs). Unfortunately, that price is typically not easily observed.

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13 RMMLF Form 6, Paragraph 3 (b)

45. While there is no "perfect" valuation method, acceptable alternatives exist that are employed commonly in agreements. One of the two form gas balancing agreements, AAPL Form 610-E, offers two options for calculating cash-balances: 1) historic costs, as illustrated in the above example, where any make-up gas is subtracted from the balance in chronological order, similar to a FIFO valuation scheme, and 2) the "most recent sales" method, where overproduction is valued at the last sales made in a volume equal to the overproduction, similar to the LIFO method.

Example: *A and B each own 50% of a well producing 100,000 MMBtu per month. During April, B only sold half of its share. During May and June, it sold none of its share. A sold the overproduction along with its existing contracts at prices indexed to the average spot market price for each month. The average spot price was $1.50/MMBtu in April, $2.00/MMBtu in May, and $2.50/MMBtu in June. In July, spot market prices averaged $2.50/MMBtu, and both parties sold their full share of production. Cash-balancing is to take place in August. If the historic (FIFO) method is used, A will have to pay B 25,000 MMBtu times $1.50/MMBtu (= $37,500) for overproduction in April, 50,000 MMBtu times $2.00/MMBtu (=$100,000) for overproduction in May, and 50,000 MMBtu times $2.50/MMBtu (=$125,000) for overproduction in June, for a total of $262,500. To calculate the cash balance using the "most-recent sales" method, it is important to understand that cash-balancing typically takes place because there are not enough gas reserves left for in-kind balancing. In that case, it is assumed that overproduction by A doesn't begin until after it has reached 100% of its cumulative share of production. Hence, the overproduction is valued at the prices achieved for the latest sales. Since the total underproduction by B is 125,000 MMBtu, the value of this underproduction is equal to the sales price achieved by A for the last 125,000 MMBtu sold. A sold 50,000 MMBtu in July for $2.50/MMBtu, and 100,000 MMBtu in June for $2.50/MMBtu. Hence, A owes B 50,000 MMBtu times $2.50/MMBtu (=$125,000) and 75,000 MMBtu times $2.50/MMBtu (=$187,500) for a total of $312,500. This is $50,000 more than B would obtain under the historic price method, caused by the increase in gas prices over the months under consideration.*

46. Cash balancing becomes more complicated whenever there are several under- and overproducing parties. One workable scheme in such a case is to use as the reference price the overproduction-weighted average price received by the overproducers. Distribution to the underproduced parties takes place by having all overproducers pay their respective cash-balances into a general pool, and to distribute it to the underproducers at the average price achieved by the overproduced parties. In this case, overproducers pay for overproduction according to the respective sales prices they have achieved, but all underproduced

parties receive the same average price for their underproduction.

47. There is at least one reason why parties may use cash balancing in situations other than at the end of a well's productive life, or when in-kind balancing is otherwise infeasible. To avoid incurring losses due to foregone interest, cash balancing can take place periodically as well as at the end of the well's lifetime. From an economic perspective, it seems that periodic cash balancing would be preferable to end-of-life balancing. End-of-life balancing increases bankruptcy risks and reduces the value of the payments received due to the loss of interest in the time between underproduction and cash-balancing[14].

E. Miscellaneous Balancing Issues

48. In the context of gas over- and underproduction, there is also the need to address the relationship of such over- or under-production to the rights to any liquefiable hydrocarbons resulting from joint production of gas. The two standard US gas balancing agreements provide different sets of options to deal with this issue.

49. AAPL Form 610E provides the option to link the sale of liquefiable hydrocarbons to the process of cash balancing. If the gas contract stipulates the price of gas as a percentage of the receipts for the sale of liquefiable hydrocarbons, then any gas imbalances will be valued based on the combined receipts for gas and liquefiable hydrocarbons attributable to overproduction. Excluded from the option are liquefiable hydrocarbons recovered using field equipment operated for the joint account.

50. RMMLF Form 6 stipulates that the rights to liquefiable hydrocarbons are independent of any imbalances in gas. Hence, underproduction of gas does not reduce a party's rights to its share of liquefiable hydrocarbons[15]

51. Even the most carefully drafted gas balancing agreement will not solve all conflicts over gas imbalances. Typically, gas balancing agreements stipulate binding arbitration to resolve disputes.

52. Effective gas balancing requires a fair amount of information to be provided by all parties involved. A standard process for doing so is for each party (and the operator) to create monthly volume statements. The operator's volume statement summarizes each party's share, total production, and over-/undertakes by the different parties. The non-operators also provide the operator with a statement

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[14] RMMLF Form 6 only addresses settlements at the end of well's life. AAPL Form 610-E gives overproduced parties the option to settle in cash periodically (not more often than every two years). If that option is chosen, all cash balancing must be made proportionally to all underproduced parties.

[15] See RMMLF Form 6, Paragraph 16.

indicating the sales prices per month for the last calendar year, to be used for in-cash balancing. Underproduced parties have the right to audit the overproduced parties' statements

53. The sharing of information on sales prices among competitors alone is often looked upon in the US as anticompetitive. For this reason, sharing of price information and auditing of such information is only allowed to take place with significant time lag.

F. Transition From Joint to Separate Selling

54. To guarantee a party's ability to market and sell separately its share of production from the joint venture, US JOA's generally assume that any party can withdraw any sales made by the operator of its share without lengthy advance notice. As a consequence, the operator of the well cannot commit to any sales beyond its own share for long periods.[16]

55. To deal with the problems of small companies lacking sufficient scale to market and sell their own gas, many marketing affiliates of larger companies or gas contract aggregators also sell the gas of smaller producers who lack expertise and/or staff to market their gas efficiently by themselves.

56. In the US, the right to market and sell separately has led to a fair amount of beneficial product differentiation. Features of such product differentiation include reliability, length of commitment, and flexibility of the contracts. It is interesting to note that, in the US, there has never been an argument that joint selling should be the norm. Rather, parties have insisted on their rights to sell gas from joint production separately.

57. The fact that workable solutions for these issues have been found and are used frequently in the US shows that the difficulties resulting from over-and under-production in the context of separate sales can be overcome in a mutually agreeable contractual framework.

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[16] One year is assumed to be the maximum time for such commitments, and even then there remains a question of whether such commitments can be firm, given the ability of the other members to withdraw their share.

IV. Assessing the Costs and Benefits of a System that Requires the Separate Marketing of Gas by Producers

A. Alleged Costs of Separate Marketing

58. Opponents of separate marketing frequently list the following costs of separate marketing:

- Transaction costs
- Costs associated with lost economies of coordination with joint venture development and production functions
- Lost economies of scale in marketing and sales
- Costs imposed on small producers
- Costs associated with lack of physical storage
- Costs associated with increased uncertainty about prices and sales

59. In my opinion, transaction costs and lost economies of coordination and scale in marketing should be low as long as reasonable balancing mechanisms, such as those described above, are included in joint operating agreements. Also important for small producers would be the encouragement of an environment in which gas aggregators and marketers would likely enter the market. In my experience in Australia, it is apparent that there are many entities already in the market that could take on (and indeed have contemplated) such a role.

60. Does the lack of physical storage capacity in Australia create a costly barrier to separate marketing? Obviously, the existence of greater storage capabilities, all else equal, would be conducive to a greater degree of gas trading. But the lack of storage, by itself, should not be a barrier to separate marketing for several reasons.[17] First, the ability to alter one's rate of take from an existing production field under an adequate gas balancing agreement is sufficient to accomplish separate marketing. Gas balancing does not require physical storage to be feasible. Second, other parties in the market can perform the functional equivalent of storage, even if physical storage is not present. For example, power generators and other industrial gas users that have the ability to alter their operations and thus rate of fuel consumption, or that can switch fuels for short periods, can provide "virtual" storage if it is economic to do so. Finally, it may

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[17] There are many pipelines in the US that do not have significant physical storage on their systems, but which support active spot and forward trading markets in gas. A good example is Enron's Florida Gas Transmission system that runs from Texas along the Gulf Coast to central Florida.

seem that without substantial physical storage there would be no place to "put" gas if an individual producer were seriously out of balance with respect to his production share and sales contracts. But that is one of the functions of an efficient spot market, which allows gas to be sold and purchased on short notice when long-term contracts may not be in hand to handle the swing.[18] When the spot market functions in this way as the "market of last resort" for buyers and sellers, prices will adjust in the spot market to clear supplies. The absence of physical storage simply means that the spot price may be more volatile than would be the case with more storage. However, the absolute volatility of prices in the spot market will be a function of overall demand and supply conditions. Demand in Australia tends to be less "peaky" than natural gas demand in many parts of North America.

61. Finally, concern has been expressed regarding the cost of increased uncertainty about prices and sales that a separate marketing regime might encourage. Such concern is exaggerated. If separate marketing helps encourage more competitive prices and the development of a more liquid spot market, then some volatility and increased uncertainty in prices is offset by a much more significant benefit in the form of certainty that the price received for gas is consistent with market conditions. This will be accompanied by greater assurance that gas will be available when it is needed on short notice at market prices, and that there will be a market available to absorb any excess supplies. Furthermore, a more liquid forward market helps reduce the uncertainties associated with important long-term investment decisions by both buyers and sellers.

62. While it is difficult to quantify specifically the likely costs of each of the above concerns, in my view it safe to conclude that they are de minimus, even in the relatively early state of the Australian gas industry's transition to market liberalisation.

B. Likely Benefits of Separate Marketing

63. There are at least four benefits that would derive from separate marketing of gas by joint venture producers in Australia's current gas market context. It would:

- promote the development of **intrabasin competition**, in an area where it is virtually non-existent, and where currently there exists only limited competition between basins.

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18 Indeed, the proposed Victorian gas market arrangement institutionalises the role of its short-term market in the physical balancing of supplies, in the presence of limited storage opportunities. In the UK, British Gas Transco employs a within-day spot market mechanism, referred to as the "flexibility market" to balance its transmission system.

- **increase efficiency in the development and production of gas** by mitigating the monopoly incentives of the joint venture to withhold production, create artificial "scarcity," and/or to only develop reserves sufficient to cover specific long-term contractual requirements.

- assist materially in the **development of liquid spot and forward markets**, as discussed above, which in turn promotes more efficient consumption of natural gas and more efficient long-term investment decisions (particularly as it relates to power generation).

- increase efficiency and **service innovation in gas marketing and contracting** by fostering product/contract differentiation.

64. There is currently very limited competition in Australia between the different joint ventures operating in the various major supply basins. The pipeline infrastructure allows only limited linkages between the various states at the moment, and in some cases there is cross-ownership amongst the JV's that creates incentives to refrain from vigorous price and service competition. This is primarily true in the southeast states. In Western Australia considerable competition for sales between the joint ventures has occurred in recent years, but the Northwest Shelf JV still maintains a dominant position in the market as measured by its share of sales. [19]

65. Historically, the lack of competition among JV's was mitigated by the market power of a single or a few large buyers, some of which were state governments. But in the post-reform environment in Australia, the large buyers have been replaced by multiple purchasers in a contestable market. Similar reform has not occurred on the supply side and it creates an imbalance of market power in favour of the JV producers acting jointly.[20]

66. With limited intrabasin competition there is little incentive for the joint venture producers to develop and produce gas reserves as rapidly as would be socially desirable. The incentive to underdevelop is reinforced by the structure of the typical long-term contracts that may contain exclusive dealing, right-of-first-refusal, and price review clauses tied to market conditions. The establishment of a separate marketing requirement would provide an avenue for producers to circumvent these restrictions.

67. In this regard, if joint venture producers knew that it would remain in their (monopoly) interest to market jointly, a policy that simply encouraged but did not require separate marketing (particularly for new contracts) may be insufficient to

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19 ACCC, Northwest Shelf Project Determination, 29 July 1998

20 Dyki Report, p.21.

alter behaviour.

68. I have discussed above, to some extent, the benefits of separate marketing in promoting spot market liquidity. The principle benefit lies in its assurance to buyers that there is a mechanism for ensuring the availability of supply on short notice (at a market price), and to producers that there is a mechanism to assure that gas may be disposed of (at a market price). When such markets are well-developed, they become mechanisms of supply assurance that can be more effective than the assurance of supply via long-term contracts with a single party or joint venture. Even if long-term contracts continue to be a significant mechanism for gas sales (as they are in the US), these contractual arrangements benefit from the "price discovery" enabled by the spot market activity. Indeed, most US and Canadian long-term contract prices are now referenced in some fashion to spot prices. This substantially improves the efficiency with which gas is purchased. For example, gas-fired power generators that can observe a market price of gas on the spot market, and a spot market price of electric power in the National Electricity Market, can make highly efficient decisions in near real-time concerning whether to sell the gas as electricity or as gas. The size of such efficiency benefits is difficult to measure quantitatively, but given the importance of the gas and electricity sectors to the Australian economy such effects are unlikely to be small.

69. Finally, as alluded to above, separate marketing is conducive to innovation in gas contracting. Service attributes that are suitable to particular buyers, and that may not be compatible with large, long-duration take-or-pay contracts, would likely be developed. Examples are many, but some contracts might include "load-following" services for power generators, or seasonal or peaking services for reticulators that may face lower load factors than they became accustomed to in the days before their high load-factor industrial customers became contestable.

C. Other Policies Conducive to Obtaining the Benefits of Separate Marketing and Intra-basin Gas-on-Gas Competition

70. Despite its likely net benefits, separate gas marketing by joint venture producers is not the sole panacea for creating a more efficient and competitive gas market in Australia. Other policies will need to be pursued simultaneously to achieve the desired result. The UIWG Public Consultation Document identifies three of the most important:

- Access to upstream processing and pipeline facilities
- Acreage management and relinquishment policies
- Reforms to anticompetitive terms in existing long-term contracts

71. In addition to joint marketing, joint ventures in Australia typically control the operation of, and terms of access to, upstream processing and pipeline facilities. To make separate marketing feasible and profitable for individual producers, it may also be necessary to ensure that appropriate contractual arrangements are in place to permit access to those facilities on a non-discriminatory basis. Conceptually, this requirement is no different than the recognised need for third-party access to the high-pressure transmission pipelines at tariffed rates to allow customers to choose amongst competing gas suppliers. Such an access requirement may be particularly important at the Moomba processing facility, in part because of the strategic position of Moomba at the head of the transmission pipelines serving New South Wales and South Australia, and in part due to its size, available processing capacity and connection to the natural gas liquids market infrastructure.

72. Competition among independent suppliers of gas would also be promoted by specific policies to encourage third-party producers to obtain development rights to acreage that is relinquished by the joint venture producers, and to expand the amount of acreage that is subject to relinquishment. Unlike restrictions on upstream access, the lack of such a policy is not a barrier to separate marketing, per se, but its implementation would assist in increasing the liquidity of short and long-term supply markets. This, in turn, would support the development of trading markets and thus decrease the costs to individual producers of separate marketing.

73. Finally, as mentioned above, certain provisions in existing long-term contracts can have anticompetitive effects on developing gas trading markets. These include primarily exclusive dealing arrangements with particular large customers, and right-of-first refusal clauses that allow the incumbent supplier to match the terms of an alternative sale. The former is a blatant restriction on competitive sales, while the latter has a chilling effect on new entrants to the market.[21] Again, the lack of such reforms by themselves would not be a barrier to separate marketing, but contractual reform in this area would support the development of a competitive trading market, which *would* be conducive to separate marketing.

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[21] *Re: Review of a Determination of the Australian Competition and Consumer Commission revoking Authorisation No A90424 (AGL Cooper Basin Natural Gas Supply Arrangements),* Australian Competition Tribunal Decision No V1 of 1996, 14 October 1997, unreported.

V. Conclusion and Responses to Specific Questions in Upstream Issues Working Group Public Consultation Paper

1. Are there any other international approaches to the regulation of marketing arrangements that may be relevant to Australian markets and should be considered as part of the consultation process?

- In North America, marketing arrangements are not regulated *per se*, although there are obviously some constraints on the activity that arise from the application of competition (antitrust) law to joint activity, particularly if market conditions would permit such joint activity to fix prices successfully. I am not aware of any such cases in the modern era, however, because the presence of liquid spot markets for gas generally precludes any individual producer or producers acting jointly from possessing or exercising market power in North America.

- In the UK and Europe, the effects of joint marketing by some of the joint venture producers is beginning to come under competition law scrutiny.[22]

2. What factors have led to the joint marketing of gas by joint venture partners in Australia? (e.g. is it the result of the joint nature of production or does it reflect the lack of depth in the market?)

- As discussed above, the historical practice of joint marketing is the result of a variety of factors. These include, the lack of depth in the market (i.e. only a few large buyers and sellers in each state); the convenience and risk-protection provided by large, long-term contracts during the development phase of Australia's gas industry infrastructure; and the role and dominance of state governments in the initial gas sales contracts. There has been historical value in these arrangements, but they are ultimately incompatible with a privatised, competitive industry.

- Relatedly, the absence of contestable customers, until recently, has made incremental sales by individual producers difficult to achieve. Under those circumstances the transaction costs of separate marketing historically may have exceeded the individual benefits.

- Finally, there has been a lack of incentive to sell gas incrementally at a lower price even though it may be efficient to do so. This is due, in part, to the flow-on

[22] James D. Dinnage, (Arnold & Porter, London) *Joint Activities Among Gas Producers: The Competition Man Cometh.*

effects of price reductions to existing long-term contracts with price-review provisions.

3. **What have been the effects of joint marketing of gas by joint venture partners to date and what are they expected to be in the future? What would be the effects and costs of mandating separate marketing?**

   - As discussed, the lack of separate marketing arrangements and incentives contributes to the lack of liquidity in spot and secondary markets. Without a liquid spot market for gas, the response of demand to short term price changes is inefficient, and fails to reflect changes in the cost or availability of gas. This leads to inefficiency in the incentives to explore for, develop and produce new gas reserves, and it leads to inefficient gas consumption decisions (such as the decision of when to burn gas in a new or existing gas-fired power generation facility, given the market price of electric power.)

   - This is a chicken-egg problem to some extent. It suggests that any solution should combine arrangements to permit/encourage separate marketing, with policies to encourage the development of a gas spot and secondary trading market.

   - In the absence of the creation of a liquid spot market, a policy which mandates separate marketing may raise marketing costs. With a liquid spot market, marketing costs may actually fall, particularly as third party aggregators and brokers step in to repackage gas and services. The increased competition to provide the marketing function (not just among producers) should drive down marketing costs.

   - In any case, it is probably not a good idea to simply consider the costs of marketing in isolation. One must also consider whether the costs of production may fall with increased incentives to produce competitively.

4. **What effect would separate marketing have on gas prices in Australia? Would they necessarily be lower? Would joint venture partners sell at different prices?**

   - Increased competition between producers and third-party aggregators and brokers to market gas should result in lower prices to consumers. This has certainly been the experience in North America.[23]

   - Yes, it is quite likely that sellers would sell at different prices. Prices are likely to be a function of the specific contract terms involved. In addition to differences in prices, separate selling may also lead to innovation in contract structure, hence

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[23] Australian Competition Tribunal *Re: AGL Cooper Basin Natural Gas Supply Arrangements* (Tribunal *AGL*), Statement of P R Carpenter, par. 29.

some form of product differentiation. But the simultaneous creation of a liquid spot market would likely lead to a single price reference (albeit more volatile over time) for short-term transactions.

5. **How do Australian gas prices compare with those internationally? If prices are relatively low in Australia, does this indicate that existing marketing arrangements are competitive?**

- Comparisons of the *level* of gas prices across continents do not provide evidence of the competitiveness of marketing arrangements because the costs of gas production and transportation vary significantly between regions. Low relative gas prices do not necessarily mean that marketing arrangements are competitive. One would have to compare the costs of gas production in Australia relative to those elsewhere and evaluate the competitiveness of those gas markets as well. It is somewhat instructive, however, to consider evidence of the downward movement in prices in areas that have become open to competition between gas suppliers. An excellent example is the experience of the last several years in Western Australia where competition between joint production ventures to supply incremental demand has occurred, and prices have fallen significantly. As discussed above, however, the amount of interbasin competition in the southeastern states is relatively limited and dominated by only two joint ventures with overlapping membership.

6. **What market prerequisites have been in place in other gas markets prior to the emergence of separate marketing?**

- The principal market (as opposed to contractual) prerequisites for separate marketing, based on experience in other markets, include:

  - Third-party access arrangements on major pipelines and upstream facilities;
  - Existence of contestable buyers behind the reticulation systems; and
  - Short-term excess gas supplies not under long-term contract or surplus to buyer requirements, permitting the development of spot/secondary market sales.

7. **If joint production is taking place, is it feasible to have separate gas marketing? Is it practical for separate marketing to occur between large and small parties in a joint venture?**

- Yes, as described above, separate marketing is feasible as long as there exists some form of a balancing arrangement between the joint producers. If the production schedule is totally fixed and each party is forced to take or leave the allotted quantity, then there is no room for separate marketing. If, on the other hand, there exists a balancing agreement then the link between production and marketing is broken, and there is no reason why the two should not be able to profitably coexist. Indeed, they have coexisted in the North America for many years.

- As discussed above, there obviously may be economies of scale in marketing by large entities, but the existence of a spot market, and the likely entry into the market of larger third-party aggregators and brokers should eliminate any small firm diseconomies.

8. How, in practice, would separate marketing be mandated and enforced?

- It is possible that simply eliminating the TPA exemption for joint marketing, and by encouraging the formation of a spot/secondary market should be sufficient to create sufficient economic incentives for individual producers to market separately. To make separate marketing feasible/effective, it may be necessary to require the liberalisation of access to upstream facilities (such as the Moomba processing plant).

9. Would a requirement to market separately act as a significant barrier to entry into the Australian gas industry?

- No, just the opposite. To the extent that the lack of separate marketing is a barrier to the creation of spot, secondary and forward markets, then separate marketing may actually enhance entry by third parties (other producers, marketers, aggregators, etc.) that will compete with producers for incremental sales of gas.

10. What would be the consequences for smaller parties if they were forced to market separately?

- Again, one cannot answer this question without also specifying whether the requirement to market separately was accompanied by the creation of a spot/secondary market and upstream access. It is my expectation that such a market would develop in the southeastern states, supported by the Victorian gas market reforms, and that smaller parties would find a competitive outlet for their gas supplies. Larger third-party marketing companies and aggregators would likely enter the market to provide services to smaller producers.

- Without a supporting market structure in which to sell their gas, *forced* separate marketing could raise the costs faced by smaller parties. With a spot/secondary market and upstream access, any such risks are greatly reduced or eliminated. In the US and Canada, many small producers continue to thrive under a separate marketing regime.

11. **What impediments (both technical and market-related) exist to separate marketing of natural gas in Australia? How might they be overcome?**

- As discussed above, it has been argued that one market-related impediment to separate marketing in Australia is the lack of physical storage facilities to allow market swings to be buffered by things other than swings in lifting rates. But certain gas users, such as gas-fired power plants, could take on the characteristics of "virtual" gas storage in the market by varying their dispatch in response to changes in the spot price of gas and electric power. Additionally, a spot/secondary trading market in gas that allows prices/demand to fluctuate with market conditions may be necessary for separate marketing to occur feasibly in Australia.

12. **Will the evolution of the Australian gas market naturally result in conditions conducive to separate marketing? If so, in what ways?**

- Obviously, continued legal protections for joint selling will inhibit the natural evolution of separate marketing, and thus intra-basin competition among producers.

- It is less likely that a spot market (and thus separate marketing) will develop efficiently as long as the market is dominated by joint sales and contracts with competitive restrictions, such as exclusive dealing arrangements and rights of first refusal. Thus, even if legal protections are removed, without a conscious effort to develop spot/secondary market mechanisms there may be little incentive for producers to market separately. (Victorian market reforms may significantly assist in this regard.) Separate marketing evolved in North America primarily because of the spot market sales imperative created by excess gas supplies. A parallel exists in the case of Australia because some parties currently hold gas contracts in excess of their requirements. This excess gas currently under contract could become an important initial tranche of supply for secondary market trading.

- Without liberalisation in upstream access arrangements, it is also less likely that separate marketing will evolve naturally.

- Contestability of Australian gas buyer demands should help the evolution, as should the existence of a competitive electricity market.

13. **Should joint and separate marketing be further regulated? Are the provisions of the Trade Practices Act of 1974 sufficient? Is there a case for introducing an arrangement that specifically regulates the marketing of gas?**

- While legal interpretation is outside of my area of expertise, it is my impression that the current practices are only feasible through exemption from the Act. If that is so, then eliminating the exemption would be a first step.

14. **How important are long-term contracts in supporting gas industry developments? Are they still relevant given the current state of industry development in Australia?**

- Long-term contracts are, and will remain, important to the development and support of the gas industry. But there is no incompatibility between the continued existence of long-term contracts, spot markets, and competition between producers in a given field. The nature and terms of the existing long term contracts may need to (and would likely) evolve away from the current rigid pricing and quantity relationships, however.

15. **What, if any, effects do the provisions of long-term contracts have on competition? Do the benefits of long-term contracts still outweigh the detriment that some of their provisions have on competition?**

- The existing long-term contracts reduce the size of the potential market for new entrant producers. In the extreme case in which all future demand is under long-term, high take-or-pay contracts with exclusionary provisions, the market is essentially foreclosed. If existing demand is covered, then entry could only occur as a result of demand growth.

- For this reason, some of the specifics of long-term contracts matter, in particular the size of the take-or-pay requirement in relation to the contracted demand, the exclusivity rules, and the rights of first refusal. In particular the latter two are ways to foreclose markets for new entrants and hence such rules should be illegal. With respect to take-or-pay percentages, there needs to be a balance between securing a revenue stream for the producers (see above on the rationale for long term contracts) and the ability of consumers to procure some of their needs from alternative sources in reaction to changes in final demand and prices.

- Existing long-term contracts can be problematic from a market power point of view if they were negotiated at monopoly prices in a pre-competition era and now lock in buyers at above-market rates for a very substantial portion of demand.

16. What are the advantages and disadvantages of long-term contracts for the downstream gas sector?

- The main advantage of long-term contracts is the ability to allocate risks efficiently between buyers and sellers. But liquid spot and forward markets provide this benefit as well. In fact, long-term contracts perform the risk allocation mechanism better if there is a mechanism for prices to respond over time to changes in market conditions. In the absence of a spot market, the risks are both price and quantity risks, i.e. a buyer with a long term contract can insure against the risk of not getting enough supplies to meet demand, and against the risk of having to pay a high price. With a spot market, the quantity risk is sharply reduced.

- The disadvantages are that the buyer is locked into a relationship that may not be market-responsive. As such, the buyer may not be able to take advantage of lower prices in the short term, and that long term contracts may limit entry and hence the competition that would promote lower prices in the long run.

17. Should gas contracts be regulated beyond the existing provisions of the TPA? Is there a role for both the State Governments and the ACCC in regulating anti-competitive arrangements?

- This is a question that requires legal advice, primarily. Competition law enforcement may be sufficient "regulation" of contracts if the rest of the market and institutional arrangements are adequately structured.