**WESTERN POWER CORPORATION**

**Submission to the Western Australian Economic Regulation Authority regarding DBNGP (WA) Transmission Pty Ltd's proposed revisions to the DBNGP Access Arrangement**

# Second Submission on Proposed Revised Access Arrangement

## (Public Version)

**21 April 2005**

**This is the public version of the submission lodged confidentially by Western Power on 13 April 2005**

**CONTENTS**

# Part 1. Preamble

## 1.1 Introduction

1. This submission is being made by Western Power (**"WPC"**), a statutory corporation established under the *Electricity Corporation Act 1994*, addressing the PRAA and the access arrangement information dated 25 January 2005.

2. This second submission (**"Second WPC Submission"**) is supplementary to the submission made by WPC (**"First WPC Submission"**) to the Regulator on 14 March 2005.

3. WPC makes this submission in accordance with the notice published by the Regulator on 14 March 2005 which states that the Regulator will exercise its discretion, under section 2.34 of the Code, to consider late submissions (see paragraph 12).

### 1.1.1 Summary of key submissions

4. This submission further demonstrates that the Reference Tariff Policy and Services Policy in the PRAA are not compliant with the Code.

5. WPC's primary concerns are that:

   (a) the Reference Tariff Policy proposed by the Operator is in many aspects inconsistent with the Code, resulting in substantial over recovery for the Operator;

   (b) the Reference Tariff is considerably higher than the regulatory tariff path intended and expected by all parties who entered into contracts based on the SSC in 2004 (see clause 20.5 and Schedule 9 of the SSC) which were agreed only 4-5 months earlier, without any justification provided for this dramatic increase in costs;

   (c) the Services Policy is inconsistent with the Code and should include the T1 service and Part Haul service as Reference Services; and

   (d) the characteristics of the Tf Reference Service proposed by the Operator make it unlikely to be sought by shippers and as a result creates potential for gaming opportunities leading to windfall gains for the Operator.

### 1.1.2 Expert reports

6. As noted in the First WPC Submission, WPC has commissioned John Whaley of Venture Associates (**"VA"**) and Henry Ergas and Mike Thomas of Charles River Associates (**"CRA"**) to advise and prepare reports on the PRAA and access arrangement information (respectively the **"VA Report"** and the **"CRA Report"**).

7. These expert reports are contained in Appendix 2 and Appendix 3 of this submission.

8. WPC adopts and repeats those reports in full as part of this submission.

## 1.2 Inadequacy of Information

### 1.2.1 Inadequacy of information

9. The PRAA and access arrangement information (and even the Operator's Submission 4, which is not part of the PRAA or access arrangement information) contain inadequate detail and information.

10. The deficiencies in information hinder WPC's ability to effectively understand the derivation of the elements in the PRAA, form an opinion as to the PRAA's compliance with the Code, and hence to make submissions to the Regulator.

11. WPC reserves its right to make further submissions to the Regulator when Code-compliant revised access arrangement information (**"RAAI"**) become available.

### 1.2.2 Revised Access Arrangement Information

12. On 14 March 2005, the Regulator issued a notice stating that the Operator would be submitting RAAI by 22 March 2005, and the Regulator would exercise its discretion under section 2.34 of the Code to consider submissions made before the Regulator's Draft Decision in order to provide interested parties with an opportunity to comment on the RAAI.

13. On 23 March 2005, the Regulator issued another notice advising that the Operator would not be submitting the RAAI until a date in April 2005.

14. The 23 March 2005 notice also advised that the Regulator anticipates inviting submissions on the RAAI at the same time as it invites submissions on the Draft Decision.

15. WPC acknowledges that there are a number of ways in which the Regulator can ensure that interested stakeholders are accorded procedural fairness. Otherwise, WPC reserves its rights but does not comment further on these matters at this time.

# Part 2. Reference Tariff Issues

## 2.1 Summary of key submissions

16. WPC is concerned that a number of inputs into the calculation of Total Revenue for the purposes of determining the Reference Tariff in the PRAA have increased substantially:

    (a) from the equivalent inputs used in the current Access Arrangement and more recently the SSC (the latter being the basis for DAA's acquisition model for the DBNGP); and

    (b) without detailed explanation or justification for such increases.

17. Inputs of particular concern are noted below.

18. A number of these concerns are based on estimations and assumptions used by VA and CRA in lieu of the information being available from the Operator (as Code-complaint access arrangement information or otherwise). Some of these concerns may ultimately prove to be non-substantial after the Code-complaint RAAI becomes available.

19. Finally, it is worth noting that while increases to particular inputs may not seem material when considered in isolation, their combined effect could be as high as or even greater than $9 million per annum[1].

## 2.2 Capital base

20. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests that the Regulator carefully scrutinise all elements used in determining the capital base in the PRAA, including but not limited to the matters identified below, to ensure the PRAA complies with the Code and where it is inconsistent with the current Access Arrangement, the Operator has explained and justified those inconsistencies.

### 2.2.1 Capital base

21. The CRA Report notes that CRA has not been able to replicate the Operator's calculation of the roll-forward of the capital base over the period 2000-2004 (as set out in Table 2 of the access arrangement information).[2]

22. The VA Report notes that the CPI escalation used in 2000 for the capital base includes the once-off increase due to the introduction of GST.[3] WPC submits that this is inappropriate given that the introduction of GST did not result in an increase in the costs borne by the Operator (as GST paid may be reclaimed), and OffGAR's previous adjustment to the price path to eliminate the GST effect on CPI in 2000.

23. In separate correspondence, VA has advised WPC that the drafting of sections 7.3 and 7.4 of the PRAA is confused. WPC sets out in Appendix 5, suggested amendments to these clauses to clarify the difference between:

    (a) setting the capital base at 1 July 2005;

[1] Part 4.1 CRA Report
[2] Part 4.2.1 CRA Report
[3] Part 4.1.1 VA Report

(b) calculating the capital base for each year during the Access Arrangement period; and

(c) calculating the capital base as at the start of the next Access Arrangement period,

which WPC requests the Regulator consider as part of its review of the PRAA.

### 2.2.2 Actual new facilities investment

24. The VA Report notes that the Operator's calculation of actual new facilities investment for 2000 appears to be contrary to the Regulator's previous decisions by including expenditure for turbine and compressor upgrades that have already been incorporated into the initial capital base.[4]

25. WPC submits that if this is the case the new facilities investment does not comply with section 8 of the Code.

### 2.2.3 Redundant capital

26. The CRA Report notes that the PRAA does not include any provision for redundant capital, contrary to the requirements of section 8.9 of the Code.[5]

27. WPC's understanding[6] is that the proposed capacity expansions involve (among other things) the addition of 7 new compressors. At present, only 2 of the Compressor Station sites have a single compressor with the other compressor bay being vacant. Thus the other 5 compressors must be being installed as an upgrade to the smaller units at sites which already have two compressors. Presumably the replaced smaller compressors will be redundant and either scrapped or sold.

28. WPC submits that the Regulator should confirm whether redundant capital exists, and if so, ensure that it is appropriately dealt with in the capital base calculation in the PRAA.

### 2.2.4 Asset life

29. The CRA Report notes that the reduction in average remaining asset life from 1 January 2000 to 31 December 2004 is not the expected 5 year reduction.[7] The Operator has not provided any explanation for this.

### 2.2.5 Depreciation method

30. WPC submits (and requests the Regulator to consider as part of its review of the PRAA) that:

(a) section 7.7(b) of the PRAA should specify that depreciation has been determined using the straight line method on a current cost accounting basis (i.e. straight line depreciation applied to the real capital cost in 31 December 1999 dollars escalated), to clarify that it is not straight line depreciation based on nominal cost; and

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4 Part 4.1.2 VA Report
5 Part 4.2.2 CRA Report
6 [redacted]
7 Part 4.2.3 CRA Report

(b) as depreciation is determined by the policy adopted for asset lives, the asset lives in Table 5 of the access arrangement information should be disclosed in section 7.7 of the PRAA.[8]

## 2.3 Forecast new facilities investment

31. WPC requests that the Regulator carefully examine the basis of any submission by the Operator that forecast new facilities investment will satisfy section 8.16(b) of the Code in the context of the higher Reference Tariff for all users which would apparently result from the proposed expansion programme.

32. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests that the Regulator carefully scrutinise all elements of forecast new facilities investment contained in the PRAA, including but not limited to the matters identified below, to ensure the PRAA complies with the Code.

### 2.3.1 Capital and capacity

33. The VA Report notes that the capital expenditure forecasts in the PRAA differ markedly from the capital expansion model used in Schedule 9 of the SSC which was also used by DAA in its acquisition of the DBNGP. [redacted]

34. There may be legitimate reasons for this change, but until information is provided on the matter WPC is unable to comment.

### 2.3.2 Mainline South expansion

35. WPC submits that the capital expansion for compression and looping for Mainline South, south of CS10, is of benefit to only shippers located downstream of CS10 and consequently should not be recovered from all shippers on the DBNGP.[10] To do otherwise would be inconsistent with:

(a) section 8.1(a) of the Code, because from the perspective of users located upstream of CS10, the Reference Tariff will be recovering more than the cost of providing the Reference Service to Perth and Kwinana;

(b) section 8.1(b) of the Code, because in a competitive market a user would pay only for assets required to provide the services that it used (i.e. the service provider would not be able to extract cross-subsidies from users located in the Perth metropolitan area or in the Kwinana strip to the benefit of users located downstream of CS10);

(c) section 8.1(d) of the Code, because it masks locational signals for users in the capacity-constrained lower sections of the pipeline; and

(d) section 8.1(e) of the Code, because a central element of efficiency is that a user pays only for the assets used to provide the service it acquires.

36. WPC notes that the Operator's use of zones is selective and appears to be geared toward maximising revenue rather than achieving Code compliance including ensuring that the risk and rewards are distributed in a balanced manner. For instance, zones are used to preclude the aggregation of contracted capacity in

[8] VA advised WPC in separate correspondence.

[redacted]

[10] Part 4.2.2 VA Report

calculating overrun (which increases the likely amount of overrun penalties which would be paid by Tf shippers). WPC notes that one of the main users of Mainline South (and hence one of the main beneficiaries of the proposed cross-subsidy) is Alcoa Limited, one of the owner-shippers of the DBNGP.

### 2.3.3 Compressor unit costs

37. The VA Report notes that there is a discrepancy in forecast new facilities investment in compressors between the PRAA and Schedule 9 of the SSC.[11]

### 2.3.4 Unit looping costs

38. WPC requests the Regulator identify the present unit cost of 30 inch looping and review this against pipeline costs assumed under the SSC. The VA Report notes that there is currently no information on the unit cost of looping in the Operator's PRAA.[12]

### 2.3.5 No policy on rolling in of actual expenditure

39. WPC requests the Regulator procure the Operator to provide a PRAA that states the policy (within section 7 – Reference Tariff Policy) to be adopted with regard to the incorporation of actual expenditure into future Access Arrangements.[13] WPC also requests that the Regulator confirm whether such a policy is appropriate and consistent with the Code.

### 2.3.6 Relationship with ANS

40. The VA Report indicates that the project management fee paid by the Operator to ANS (which is described in the Duet PDS as 3% of the cost of capital works) may not be an allowable cost incurred under section 8.16(a) of the Code.[14]

41. WPC requests the Regulator consider:

    (a) whether any project management fees payable to ANS are included in forecast new facilities investment; and

    (b) whether these fees are consistent with section 8.16(a) of the Code and section 8 of the Code generally.

## 2.4 Rate of return

42. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests that the Regulator carefully scrutinise all elements of the rate of return calculations contained in the PRAA, including but not limited to the matters identified below, to ensure the PRAA complies with the Code.

### 2.4.1 Risk free rate

43. The CRA Report notes that the Operator appears to have selected a 20 day trading period for calculating the risk free rate which maximises the estimated WACC.[15]

[11] Part 4.2.2 VA Report
[12] Part 4.2.2 VA Report
[13] Part 4.2.2 VA Report
[14] Part 4.2.2 VA Report
[15] Part 4.3.1 CRA Report

### 2.4.2 Debt margin

44. The CRA Report notes that the Operator's proposed debt margin, reflecting a hypothesised credit rating of BBB, which increases Total Revenue, has insufficient basis. A credit rating of BBB+ appears more generally in line with regulatory precedent, and reduces the debt margin by 9 basis points.[16]

### 2.4.3 Debt raising costs

45. The CRA Report notes that the regulatory precedent for debt raising costs supports values between 10.5 and 12.5 basis points, which is less than the Operator's proposed 25 basis points. The use of 25 basis points rather than 12.5 basis points increases Total Revenue.[17]

## 2.5 Non-capital costs

46. WPC notes that there appear to be significant increases proposed for non-capital costs from the figures contained in the current Access Arrangement and Schedule 9 of the SSC which do not appear justified based on the information available.

47. In particular, WPC requests that payments to ANS are separately disclosed from reimbursed expenditure, which should be disclosed in accordance with the expenditure type notwithstanding amounts are reimbursed to ANS.

48. As WPC has insufficient information, WPC requests that the Regulator carefully scrutinise all elements of the non-capital costs contained in the PRAA, including but not limited to the matters identified below, to ensure the PRAA complies with the Code.

### 2.5.1 Fuel costs

49. The CRA Report notes that over the 6 year forecast, the cost of gas comprises between 32 and 42 per cent of annual non-capital costs, and more than doubles in nominal terms (from approximately $20m to $41m annually).[18]

50. The VA Report notes that this is an unexplained increase in projected fuel gas usage from the forecasts contained in both Schedule 9 to the SSC and the current Access Arrangement.[19] The VA Report notes that this increase does not seem explicable in terms of increases in compressor usage. This unexplained increase implies that the PRAA contains an inflated figure that does not comply with section 8.37 of the Code.

51. [redacted]

### 2.5.2 Equity raising costs

52. The CRA Report notes that the Operator adopted the equivalent annuity value provided by the ACCC in the GasNet decision. However, in light of subsequent ACCC decisions, the actual value could be higher or lower than this value and it would seem more appropriate to use actual data where it is available.[21]

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[16] Part 4.3.2 CRA Report
[17] Part 4.3.3 CRA Report
[18] Part 4.4.1 CRA Report
[19] Part 4.3.3 VA Report
[redacted]
[21] Part 4.4.2 CRA Report

53. [redacted]

### 2.5.3 Arrangements with ANS as Operator

[redacted][22] [redacted]

55. VA considers that ANS should be treated as the service provider under the Code, consistent with the representations made in the Duet PDS.[23] WPC therefore submits that ANS should be treated as though it was the service provider and full disclosure of fees payable to ANS must be included in the PRAA.

56. WPC requests the Regulator scrutinise the arrangements between the Operator and ANS to ensure:

(a) that fees payable to ANS are consistent with achieving the lowest sustainable cost of delivering the Reference Service in accordance with section 8.37 of the Code[24]; and

(b) that payments under the Incentive Fee arrangement disclosed in the Duet PDS result in a reduction of the cost of service for users[25].

### 2.5.4 Asymmetric risk

57. The CRA Report notes that the Operator does not appear to have met the standard required by the ACCC for a self-insurance premium to be included in regulatory cash flows, therefore the inclusion of asymmetric risk costs may be unreasonable.[26]

### 2.5.5 Liquidated damages insurance

58. [redacted] CRA suggests that in these circumstances it would be reasonable that costs of liquidated damages insurance are considered as part of the costs of new facilities investment rather than a non-capital cost of the Reference Service.[27]

## 2.6 Incentive mechanism

59. The CRA Report identifies a number of issues in relation to the incentive mechanism in clause 7.12 of the PRAA, including:

(a) that the formula allows for efficiency gains in non-capital costs, while the description of the mechanism seems to relate to revenue gains attributable to increased sales;

(b) that the proposed retention period of non-capital costs savings is 10 years, and not 5 years as is more common; and

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[22] WPC refers the Regulator to its discussion of the relationship between ANS and the Operator in the First WPC Submission (see paragraphs 75, 76 and 368 in the First WPC Submission).
[23] Part 4.3.2 VA Report
[24] Part 4.3.2 VA Report
[25] Part 4.3.2 VA Report
[26] Part 4.4.3 CRA Report
[27] Part 4.4.4 CRA Report

(c) that CRA has been unable to replicate the real labour cost escalation element figures, and is therefore unable to assess whether the element is appropriate.[28]

60. The Operator has provided little detail or explanation of why this incentive is required.

61. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests the Regulator to carefully scrutinise all aspects of the incentive mechanism, including but not limited to the matters identified above, to ensure the PRAA complies with the Code.

## 2.7 Fixed principles

62. WPC refers to paragraphs 89 to 107 in the First WPC Submission (discussed in part 4.6 of the CRA Report).

## 2.8 Key performance indicators

63. WPC refers to paragraph 88 in the First WPC Submission.

64. The CRA Report notes that the GasNet 2003 Access Arrangement Information included five benchmarks:

(a) operating costs per GJ of gas delivered;

(b) operating costs as a percentage of capital investment;

(c) operating and maintenance costs per metre of pipeline;

(d) general and administrative costs per GJ of gas delivered; and

(e) operating and maintenance cost as a percentage of capital investment.[29]

65. The Operator has only included 2 benchmarks in its comparison against other domestic pipelines (in Submission #4), and given the risk of asymmetric information, WPC submits that the Regulator should develop and/or insist upon a wider range of benchmarks.[30]

## 2.9 Volume forecasts

66. Volume forecasts are a critical aspect of determining the tariff. The CRA Report notes that there is insufficient information with which to assess the accuracy and implications of the volume forecasts[31], which could result in a significant difference in the tariff.

67. Of particular concern is the fact that the volume forecasts only relate to full haul services, even though Total Revenue is allocated to both full haul and part haul services.

68. In addition, as the Operator has proposed that non-reference services and other services be non-rebateable, forecasts of these services are also required to prevent over-recovery by the Operator.

[28] Part 4.5 CRA Report
[29] GasNet Australia 2003 Access Arrangement Information, p.34-35.
[30] Part 4.7 CRA Report
[31] Part 4.8 CRA Report

69. WPC submits that, to ensure the tariff derivation is consistent with the SSC and the capacity available for firm service:

(a) the Reference Service be amended from Tf to T1, consistent with the capacity definition, the service being sought through expansions during the Access Arrangement period and the SSC; and

(b) capacity available above T1 and Tx be forecast (and revenue and costs attributed to the Reference Tariff) or be rebateable.[32]

70. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests that the Regulator carefully scrutinise all elements of the treatment of volume forecasts in the PRAA, including but not limited to the matters identified above, to ensure the PRAA complies with the Code.

## 2.10 Cost allocation

71. The CRA Report notes that CRA has been unable to derive the methodology used by the Operator to allocate costs.[33] Cost allocation is important because it could significantly impact on the tariff and the calculation of rebateable revenue. CRA notes that there is insufficient information to enable it to determine the reasonableness or otherwise of the PRAA.

72. In separate correspondence, VA has advised WPC that the PRAA should clarify how costs are to be allocated between users within a service. For example, is the rule to be that the Reference Tariff is calculated assuming each shipper pays the same tariff (the so-called “a GJ is a GJ” rule)?

73. As WPC has insufficient information to definitively assess these matters on its own behalf, WPC requests that the Regulator carefully scrutinise all elements of the cost allocation methodology used by the Operator in the PRAA to ensure the PRAA complies with the Code.

## 2.11 Code compliance

74. As a result of one or more of the abovementioned inputs for the calculation of Total Revenue increasing without justification, the ensuing Reference Tariff and Reference Tariff Policy may not comply with:

(a) section 8.1(a) of the Code, because the Operator would have an opportunity to earn a stream of revenue that recovers *more* than the efficient costs of delivering the Reference Service over the expected life of assets;

(b) section 8.1(b) of the Code, because the Reference Tariff and Reference Tariff Policy proposed under the PRAA would not replicate the outcome of a competitive market (which, in contrast, WPC submits is the outcome achieved under the SSC);

(c) section 8.1(d) of the Code, because distorted or over-recovering tariffs deriving from incorrect volume forecasts, cost allocations, etc., are likely to send inappropriate locational and other investment signals to users;

[32] Part 4.4 VA Report
[33] Part 4.9 CRA Report

(d) section 8.1(e) of the Code, because the Operator is introducing inefficiencies in the level and structure of the Reference Tariff resulting in opportunities for over-recovery by the Operator; and

(e) section 8.1(f) of the Code, because the PRAA and access arrangement information do not provide an incentive to the Operator to reduce costs and develop the market for Reference and other services.

75. In addition, WPC considers for the reasons noted above that the provisions in the PRAA relating to the Reference Tariff:

(a) go beyond the Operator's legitimate business interests and investment in the DBNGP (section 2.24(a) of the Code);

(b) would not result in the economically efficient operation of the DBNGP (section 2.24(d) of the Code); and

(c) are not in the public interest (section 2.24(e) of the Code) or in the interests of shippers or prospective shippers (section 2.24(f) of the Code).

# Part 3. Services Policy Issues

## 3.1 Service as distinct from terms and condition of a service

### 3.1.1 Introduction

76. WPC has made a number of submissions concerning the distinction, for the purposes of the Code, between a "Service" and the "terms and conditions" (**"Terms"**) of that Service. The matter is most completely dealt with in WPC's Written Outline of Submissions dated 1 September 2004 filed pursuant to Order 16 made 16 April 2004 in Gas Review Board Proceedings No. 3 of 2004 (**"GRB submissions"**).

77. WPC repeats and affirms its submissions on this subject in both the GRB submissions and elsewhere. The following submissions are in the alternative to and without resiling from that previously-stated position.

78. To summarise the issue:

    (a) OffGAR determined in its decisions on the current Access Arrangement that a Service can be considered independently of its Terms, and can be expressed at a very high level of generality; and

    (b) WPC considers that it is neither meaningful nor consistent with the Code to consider a Service independently of its Terms, and accordingly that the Service must be considered together with Terms specified in full detail, in order to achieve Code compliance and a workable Access Arrangement.

79. In this submission, WPC explores an alternative approach that offers a potential middle ground between these two extremes.

### 3.1.2 The "terms sheet" approach

80. WPC invites the Regulator to consider what level of information would likely be required in a commercial context to describe or evaluate a Service. For example, the level of information that would be required by a commercial decision-maker such as the CEO of a prospective shipper, in determining whether or not to enter into a contract for a Reference Service. It is unthinkable that the decision-maker would make the decision based on a minimalist description of the Service such as that proposed by OffGAR in its 2003 decision. WPC submits that this supports its criticism of OffGAR's approach, but that it also points the way to the middle ground.

81. Any commercial decision maker, even if prepared to forego a detailed briefing on the Terms of the proposed Service, would require a high-level summary of all major commercial aspects of the Service before it considered that it had enough information to assess the Service. This would take the form of a "terms sheet" or similar.

82. WPC suggests that the Regulator consider this in forming its view as to what level of detail is required in describing the Reference Service or any other Service in the Services Policy. To illustrate what is proposed, Appendix 4 sets out an indicative terms sheet for the SSC T1 Service.[34]

[34] The precise details which should be included in a terms sheet is an important issue. The sample in Appendix 4 is not intended to be a definitive description of the key commercial aspects of the T1 SSC, but rather is indicative of the level of detail required.

83. The following paragraphs illustrate the potential usefulness of this line of submission, by applying the analysis to a condensed summary of the key deficiencies of OffGAR's minimalist approach identified by WPC in the GRB submissions.

### 3.1.3 The three levels

84. The three levels of descriptive detail being considered are:

(a) **Level 1 – minimalist:** this is the approach adopted by OffGAR in the Further Final Decision of 2003, in which the Reference Service is described in a few lines, devoid of almost all key commercial detail.[35]

(b) **Level 2 – terms sheet:** this is the proposed middle ground approach, outlined above, which would provide sufficient detail to describe the essential commercial aspects of the Service, while stopping short of setting out all of the Terms. Level 2 actually encompasses a range of possible levels of descriptive detail.

(c) **Level 3 – full Terms:** this approach requires a Service to be defined having regard to the full commercial effect of all of the Terms.

85. These three levels of descriptive detail are discussed below.

### 3.1.4 Detailed terms are very important in gas transport contracts

86. WPC observes that gas transportation agreements are unusual compared with many other major commercial contracts, in that a great deal of the value in a contract lies buried in the minutiae of the detailed terms and conditions.

87. For example, apparently minor changes in a clause dealing with nominations, curtailment or even maintenance scheduling can have a substantial impact on value and cost under the contract. This is because the technical and operational aspects of the pipeline can flow through to become major commercial consequences.

88. [redacted]

89. A more general illustration which applies to all shippers lies in the outlet point temperature specifications. Suppose that for example a contract specified a permitted maximum outlet point temperature of 70 ºC, or a permitted minimum of –20 ºC, compared with the more usual temperature range. This change of one highly technical detail could cause the shipper to incur very considerable capital and operating costs to heat or cool the gas respectively. Alternatively, a prospective new shipper may choose a different fuel or relocate to a different pipeline, in order to avoid those costs. Although this particular example is unlikely to occur in fact, it serves to illustrate that very significant commercial consequences can flow from changes in what may seem like very mundane technical details.

[35] Clause 6.2 of the current Access Arrangement.

### 3.1.5 Main deficiencies addressed in GRB submissions

90. The GRB submissions identify the following major deficiencies in OffGAR's 2003 Further Final Decision.

*a. Definition of Service is meaningless without Terms*

91. As a starting point, WPC considers that it is meaningless for any practical purpose to discuss a Service without having a reasonably comprehensive understanding of the Terms of that Service. See for example at paragraph 134 of the GRB submissions:

> *"Without knowing the terms and conditions and price of such services their utility is unknown … ."*

92. While this deficiency can only be fully alleviated by the use of a Level 3 description of the Service, i.e. including the full Terms as part of the Services Policy (rather than as a separate concept under section 3.6 of the Code), WPC submits that a Services Policy which included a Level 2 description would go a considerable way to remedying the deficiency identified.

93. The availability of a "terms sheet" would enable a shipper or prospective shipper to form a clear view of what the Service is, from a commercial and operational perspective.

*b. Cannot assess whether Service likely to be sought by significant part of the market*

94. This deficiency is described in paragraph 38 of the GRB submissions:

> *"…unless and until the material Terms of the Service are defined, including all of the usual aspects of that Service … it is impossible to say whether that is a service which would be sought by a significant part of the market…"*

95. WPC reiterates that with only a Level 1 description in the Services Policy it is impossible for the Regulator to form a meaningful view on whether a Service meets the requirements of clauses 3.2 to 3.4 of the Code.

96. However, WPC submits that for the purposes of section 3.2 to 3.4 of the Code, a Services Policy containing a Level 2 description might arguably be sufficient to enable the Regulator to form a view on this point.

*c. Cannot assess tariff*

97. See for example GRB submissions paragraph 37:

> *"It is impossible to identify what any service is unless its material Terms and Conditions are identified – those Terms and Conditions define the service. It follows that providing a Reference Tariff without specifying the particular Terms and Conditions of the Service is a futile exercise, as neither Shippers nor the Arbitrator engaged to determine the particular terms of any Shippers' contract could apply that Tariff in a meaningful way …."*

98. As with the previous deficiency, while it would be an imperfect assessment of the actual value contained in any given Service, WPC submits that a Services Policy which included a Level 2 description would go a considerable way to remedying the deficiency identified. An interested commercial observer, such as a prospective shipper, would be able to form a reasonably clear view of what was being obtained, and hence how well the tariff related to the value of the service.

99. In addition, and as described in WPC's First Submission, because the terms (e.g. curtailment priority, peaking and overrun rights and others) of a service impact on the pipeline's capacity to deliver that service, WPC submits that without at least a Level 2 description in the Services Policy, the Regulator cannot form an adequate view of the appropriate denominator (ie. volume forecasts) for use in the tariff calculations. The Level 1 description currently in the Access Arrangement gives no guidance in this regard.

*d. No point having a Reference Service with undesirable terms and conditions*

100. See for example the GRB submissions at paragraph 29:

> *"The Code will not work as intended if a Reference Service can be selected by the Regulator for the purposes of s.3.2 but the Tariff under s.3.5 and/or the terms and conditions under s.3.6 are such that the service will not be sought by a significant part of the market."*

101. WPC submits that to fully alleviate this deficiency, it would be necessary to have a Level 3 description, i.e. the full Terms being specified as part of the Services Policy. However, the risk of a mismatch between a Reference Service and what will be actually be sought by a significant part of the market will be substantially reduced, if the Reference Service is specified at a terms sheet (ie. Level 2) level of detail, and those Terms are likely to be sought by a significant part of the market, particularly if the detailed implementation of those Terms was then subject to rigorous scrutiny under section 3.6 of the Code.

*e. Inconsistent with section 8.1*

102. See for example the submissions set out at paragraphs 125 and 142 of the GRB submission.

103. Once again, although a Level 3 description would be far more preferable, WPC submits that there is a much greater likelihood of the Access Arrangement complying with the Code including section 8.1 if the Services Policy includes at least a Level 2 description of the reference service.

*f. Promote expensive and inefficient arbitration*

104. See for example paragraphs 124 and 122 of the GRB submissions.

105. It is a reality of commercial life that the process of moving from a terms sheet description to a fully documented contract can be controversial and protracted. Accordingly, only a Level 3 description can effectively eliminate the risk of expensive and inefficient arbitration arising from the Service being inadequately described in the Services Policy.

106. However, WPC submits that there is a vast difference between the likely cost and complexity of an arbitration seeking to determine the detailed Terms of a Service when starting from a Level 2 description, compared with the much worse position confronting a shipper when starting from a Level 1 description.

107. If the Arbitrator were faced with determining the Terms of a Service which comprised only a Level 1 description, he or she would need access to huge quantities of commercial information before being able to fix appropriate terms and tariffs. For a full-haul capacity service similar to a Reference Service the level of inquiry would seem similar to that required of the Regulator in a full Access Arrangement reset. This would have a concomitant impact on the size and expense of any arbitration,

and would thus be a very substantial disincentive to any prospective shipper commencing the arbitration.

108. As has been demonstrated elsewhere in this submission and in particular in the CRA Report, the greater the uncertainty surrounding the terms and conditions of a Service, and the greater a prospective shipper's reliance on expensive and protracted negotiation or arbitration to ascertain acceptable detailed terms and conditions for that Service, the more bargaining power the Service Provider has, and the greater the likelihood of the Service Provider being able to extract monopoly rents and for inefficient outcomes to result. In many circumstances it will simply not be commercially viable for a prospective shipper to undertake a comprehensive access dispute arbitration in order to remedy the paucity of description of a Level 1 Services Policy. The effect of this will be to place practical control of the Terms of such a Service solely in the hands of the Service Provider, which is inconsistent with the Code's objectives.

*Summary*

109. In summary, and without resiling from WPC's submissions before the GRB and the Regulator, the above analysis demonstrates that from at least one perspective many of the key deficiencies in OffGAR's 2003 decision which have been identified by WPC in the GRB submissions could be remedied if OffGAR had included in the Services Policy a Level 2 description of the Reference Service, rather than a Level 1 description.

110. If the Regulator does not accept WPC's previous submissions regarding the adoption of a Level 3 approach, then WPC urges the Regulator to take this analysis into account in considering the PRAA.

### 3.1.6 Interrelationship between sections 3.2–3.4 and section 3.6

111. The importance of this issue lies in the different roles of sections 3.2 to 3.4, which deal with the Services Policy, and section 3.6 which deals with the terms and conditions of a Reference Service. Another important benefit of adopting a Services Policy that includes a Level 2 description is that it will result in a very different level of inquiry under section 3.6.

112. Adopting OffGAR's Level 1 approach means that the entire commercial essence of the contract (i.e. all those aspects which are summarised in a terms sheet) is subject only to the "reasonableness" scrutiny in section 3.6, rather than the "sought by a significant part of the market" and other tests in section 3.2 to 3.4.

113. It means that the Regulator's job under section 3.6 is a very challenging one, because it must determine whether each of those commercial aspects both individually and collectively, is reasonable. Likewise, an arbitrator having to establish Terms for a non-reference Service has a much harder task.

114. In contrast, if the Regulator adopts the Level 2 Services Policy approach outlined above, the task of establishing and approving terms and conditions will become easier, because the Services Policy will now provide a comprehensive framework within which the reasonableness of the Terms can be assessed.

115. In considering and contrasting the two tasks of:

(a) developing (for the Arbitrator in an access dispute) or assessing (for the Regulator, under section 3.6) the Terms which are necessary to make an effective Reference Service when the starting point is a Level 1 Services Policy; and

(b) developing or assessing the Terms which are necessary to do so when the starting point is a Level 2 Services Policy,

a parallel can be drawn with the issues facing the Supreme Court in the case of *Anaconda Nickel Ltd v Tarmoola Australia Pty Ltd* [2000] WASCA 27.[36] In that case, the Supreme Court was prepared to give effect to a very brief letter agreement comprising just 5 terms, despite the fact that this left the Court with the task of implying a wide range of other terms and conditions. This can be contrasted with the position had there not been a basic "terms sheet" of core provisions. In that situation there is little doubt that the Court would not have found the agreement to be enforceable, because the task of implying the rest of the agreement would have been impossible.

116. This case illustrates the proposition that the commercial essence of a service can be reduced to a relatively brief set of propositions, such as is set out in Appendix 4, despite the absence of a more fully-documented set of terms and conditions.

117. Ipp J in the *Anaconda* case described what is analogous to the difference between the terms sheet (Level 2) and a full contract (Level 3) in the following terms:

> *"[The absence of a full contract raises] many other difficulties of a practical nature. All of them, in my view, relate only to issues of construction or implication. Some are indeed not without complexity and good commercial reasons exist for the parties to come to a more detailed agreement in regard thereto. It does not follow, however, that these ambiguities constitute incompleteness or uncertainty."*

118. WPC submits that section 3.6 of the Code provides a suitable framework for regulating the process of documenting a more detailed set of Terms to provide commercial certainty and completeness for a Reference Service, but that the commercial essence of a Service should be reflected in the Services Policy and regulated under sections 3.2 to 3.4 of the Code. As in the *Anaconda* case, if there is a reasonable Level 2 description of the Service the parties will have enough commercial bones on which to base an agreement. However, capturing the commercial essence of a Service requires considerably more than the minimalist description adopted by OffGAR in the current Access Arrangement.

## 3.2 Reference service is a reference point

119. As demonstrated in the CRA Report[37], the Reference Service is, by design, a reference point for negotiation and/or arbitration. It is required to be a service that is likely to be sought by a significant part of the market.[38] In addition, each service that is likely to be sought by a significant part of the market should be a Reference Service. These provisions are at the heart of the regulatory objectives, to replicate outcomes in a competitive market whilst minimising transaction costs. The extent to which this is achieved is determined by the relevance of the Reference Service(s) to the market.

120. This means that negotiations between users and the Operator on access to the DBNGP will necessarily use the standard set by the most relevant Reference Service as a basis for developing negotiated variations. It is therefore a logical imperative that the Reference Service comply with section 3.2 of the Code and be likely to be sought by a significant part of the market.

[36] This case is not direct authority for the interpretation of the Code, but provides a useful comparison.
[37] Part 2. 2 CRA Report
[38] Section 3.2 of the Code

121. WPC reiterates its submissions in the First WPC Submission that the Tf service is not likely to be sought by a significant part of the market and should not be approved as a Reference Service[39] given that (among other things):

(a) Tf service is, in effect, a fully interruptible service;

(b) Tf service could never be bundled with non-reference services to synthesize a service sought by a significant pert of the market;

(c) the Firm Service (which the Tf service is based on) was recently rejected by the market; and

(d) the Tf service has been designed so as to be unattractive to the market.

122. The VA Report notes that the Tf service [redacted] is unlikely to be sought by any users or prospective users.[40] As such the Tf service is of limited relevance as a reference point for negotiations.

123. WPC is therefore justifiably concerned that, as a result of the above, [redacted] allowing shippers who require services substantially different that those provided under the Reference Service to be exploited.

124. WPC also reiterates its submissions in the First WPC Submission that the T1 service in the SSC should be a Reference Service because the overwhelming evidence can lead only to the conclusion that the T1 service is likely to be sought by a significant part of the market[41]. As such the T1 service is likely to be highly relevant as a reference point for negotiations.

## 3.3 Why T1 service is a more suitable Reference Service

### 3.3.1 Market power mitigation

125. The CRA Report notes that one of the purposes of an Access Arrangement is to mitigate potential misuse of the market power of the Operator.[42] The Operator can circumvent this purpose by defining a Reference Service that is unattractive to shippers, forcing users to negotiate with the Operator for any service attributes that it requires in addition to the attributes of the Reference Service. In most cases shippers will be negotiating from a weak bargaining position, giving the Operator an opportunity to extract monopoly rents from shippers.

126. For the reasons noted below, the T1 service is much more likely to achieve the objective of mitigating the market power of the Operator than the Tf service.

### 3.3.2 Tf service is inferior to the T1 service

127. The Tf service is a markedly inferior service to the T1 service, and contains less of the attributes that make T1 service the undisputed service of choice for the Major Shippers. The VA Report illustrates the key differences between the Tf and T1 service (see Part 3 of the VA Report).

[39] Part 3.3 of the First WPC Submission
[40] Parts 3.1.3 and 3.4 VA Report
[41] Part 3.4 of the First WPC Submission
[42] Part 1.2.4 CRA Report

128. Specifically, the Tf service is an interruptible rather than a firm service. Every other Covered pipeline in Australia has a firm service Reference Service (except DBNGP under the PRAA). WPC submits that the T1 service should be the firm Reference Service.

129. The Tf service contains sufficient differences in crucial non-price terms to make it difficult for a shipper to synthesise a T1 service by negotiating additional non-reference services to the basic Tf service. In practical terms, because the Tf service is interruptible and far inferior, the task would involve so much bolstering of the Tf service that it would amount to the negotiation of a completely new non-reference service. Thus, any such attempt to synthesise a T1 service from the Tf service would require re-opening issues that have been extensively negotiated and agreed to in the SSC.

130. By proposing a Reference Service which omits key attributes, it forces the shippers that value the omitted attributes to negotiate with the Operator from a weaker bargaining position, giving the Operator an opportunity to earn unregulated revenues (see section 3.3.3 below).

131. A further question which must be addressed is the effect of having the T1 SSC and Tf Reference Service terms and conditions in the marketplace at the same time.

132. The FAA and ACCC Undertakings require the Operator to offer a T1 service to all users and prospective users under terms and conditions specified in the SSC. This may be viewed as having a similar effect to specifying the T1 service and the SSC as a “reference service”.

133. The Operator has, however, chosen to ignore entirely the T1 service (it is not even a non-reference service in the PRAA) and has instead introduced a completely different service with incompatible terms and conditions. [redacted] It also raises questions about the standing of the Tf service (and possibly the entire PRAA) as a reference point for future negotiations between the Operator and shippers for non-reference or other services.

134. The Operator should be asked:

(a) why the “generic” elements of the Tf terms and conditions (i.e. the great bulk of contractual terms which will remain unchanged, or require only minor changes, whatever the actual haulage service involved – in effect the “general conditions”)[43] should not be the same as the generic SSC terms and conditions;

(b) how it can operate a pipeline with two generic sets of terms and conditions; and

(c) why the substantial differences between the SSC and the Tf terms and conditions (both of which are available to prospective shippers – one under the ACCC Undertakings and the FAA, and one under the Code) do not undermine the regulatory intent of a Reference Service?

43 [redacted]

135. WPC submits that the PRAA should also be amended to state clearly the Operator's obligations under the ACCC Undertakings and the FAA in respect of the T1 service and the SSC.

136. On a related point, a long minimum contract term for a fully-interruptible service seems inappropriate[44]. WPC submits that a minimum term of no more than 1 month would be more suitable for a Tf service.

### 3.3.3 Implications for negotiating unregulated services

137. Given that the Tf service is unlikely to be sought by a significant part of the market, the possibility of windfall gains for the Operator is opened through the Operator's provision of unregulated, non-rebateable non-reference and other services.

138. The CRA Report clearly identifies the potential risk of the Operator using a combination or non-rebateable non-reference services and other services together with a Reference Service that does not align with the T1 service already contracted for by shippers, to leverage the difference in value between the T1 service and the inferior Tf service[45].

139. WPC requests that the Regulator carefully scrutinise the possible ramifications of gas transportation services being sold on an unregulated and non-rebateable basis to ensure the PRAA complies with the Code.

### 3.3.4 Non-price terms and penalty provisions could result in greater revenues

140. The CRA Report notes that non-price terms and associated penalty provisions are an important regulatory concern because they alter the risk and value of the Reference Service and can result in:

(a) greater direct revenues to the Operator to the extent penalties are incurred without corresponding offsetting costs also being incurred;

(b) greater indirect revenues to the Operator to the extent that shippers negotiate variations to the proposed Tf service to reduce penalties or curtailment risks; and

(c) other forms of economic efficiency loss arising because shippers take steps to alter their gas usages (to avoid incurring penalties or costly renegotiations).[46]

141. CRA also notes that a Tf Reference Service would tilt negotiations in favour of the Operator, and giving the Operator an opportunity to earn unregulated direct and indirect revenues in excess of its required revenue.[47]

142. Other terms and conditions have similar significance. For example, the Regulator should take into account that the credits for curtailments under the PRAA[48] are much more narrow in scope than the curtailment refund provisions in the SSC[49].

143. WPC requests that the Regulator carefully scrutinise those terms and conditions in the PRAA which affect the risk and value of the Reference Service, including but not limited to the matters identified above, to ensure the PRAA complies with the Code.

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[44] See section 6.2(b) PRAA
[45] Part 1.2.2 CRA Report
[46] Part 3.1 CRA Report
[47] Part 3.1 CRA Report
[48] Clause 14.3(b) PRAA Annexure A: Access Contract Terms & Conditions
[49] Clause 17.4 of the SSC

## 3.4 Code compliance

144. WPC is concerned that a Tf Reference Service would, for the reasons set out above, be:

(a) (when considered in the context of the Tf service terms and conditions) unreasonable, in breach of section 3.6 of the Code;

(b) inconsistent with section 8.1 of the Code, by:

(i) providing the Operator with opportunities to extract monopoly rents from users in additional to recovering efficient costs of providing the Reference Service;

(ii) being anticompetitive, and failing to replicate the outcome of a competitive market;

(iii) distorting investment decisions in pipeline transportation systems or upstream and downstream industries; and

(iv) resulting in inefficiency;

(c) inconsistent with section 2.24(d) of the Code because it is inefficient to propose a service that is unlikely to be sought by a significant part of the market, requiring shippers to negotiate from a disadvantaged position for service attributes not included under the Tf service; and

(d) against public interest under section 2.24(e) of the Code and inconsistent with the interests of users or prospective users under section 2.24(f) of the Code for the same reasons.

## 3.5 Part haul service

145. [redacted]

146. [redacted]

147. [redacted] WPC is concerned that any provision of a part haul contract which rendered part haul, in effect, fully interruptible would be:

(a) unreasonable, in breach of section 3.6 of the Code;

(b) inconsistent with section 8.1 of the Code, by:

(i) failing to replicate the outcome of a competitive market under section 8.1(b) (particularly given that it appears to be intended to render use of the Mondarra interconnect unattractive or commercially unviable, and thus limit shippers' choice between the DBNGP and the Parmelia Pipeline);

(ii) providing the Operator with opportunities to extract monopoly rents in excess of revenue to recover efficient costs under section 8.1(a); and

(iii) providing an incentive for the Operator to increase costs, by interrupting part haul and forcing shippers to purchase higher-priced spot;

(c) not required by sections 2.24(a) or (c) of the Code;

(d) inconsistent with section 2.24(d) of the Code because it is not efficient to artificially induce customers to buy a full haul service rather than a part haul service merely because the part haul service is completely unattractive;

(e) inconsistent with section 2.24(e) of the Code because the public interest is best served by having viable pipe-on-pipe competition south of Mondarra;

(f) for the above reasons inconsistent with sections 2.24(f) of the Code; and

(g) completely at odds with contracting practice on the DBNGP from 1995 up to and including the current Access Arrangement, in which shippers have always had access to firm part haul capacity.

148. WPC also submits that part haul contracts should provide shippers with (among other things):

(a) rights to relocate by nomination (called “aggregation”) subject only to genuine operational constraints (but not artificial constraints imposed for commercial leverage);

(b) rights to relocate capacity within zones on a similar basis; and

(c) imbalance, peaking and overrun provisions equivalent to those under the SSC.

149. WPC submits that this further information strongly supports its call for part haul to be included as a Reference Service.

# Part 4. Clarification

## 4.1 Clarification of paragraphs in the First WPC Submission

150. A query has been raised relating to the fact that the language used in paragraph 24 of the First WPC Submission differs from the language used in paragraph 21 of that submission.

151. To avoid any doubt, WPC confirms that paragraphs 21 and 24 are to be read in the same way. Namely, that WPC adopts and repeats the material referred to in those paragraphs as if it were set out in full in the First WPC Submission, save for when that material is inconsistent with the First WPC Submission.

152. Paragraphs 21 and 24 of the First WPC Submission, as clarified in paragraph 151, equally apply to this submission except when the material referred to in paragraph 151 is inconsistent with this submission.

153. The generality of paragraphs 150 to 152 is not affected by any specific references in either the First WPC Submission or this submission to all or part of any of the material referred to in paragraph 151.

# Appendix 1: Glossary

**Access Manual** means the *DBNGP Access Manual* dated 10 March 1998 having effect under the *Dampier to Bunbury Pipeline Act 1997*;

**ACCC Undertakings** means the undertakings given under section 87B of the *Trade Practices Act 1974* by DAA on 25 October 2005;

**ANS** means Alinta Network Services Pty Ltd, contracted by the Operator to operate, manage and construct the DBNGP;

**Code** means the *National Third Party Access Code for Natural Gas Pipeline Systems* having effect under the GPAA;

**CRA** means Charles River Associates who are advising WPC in relation to the PRAA;

**CRA Report** has the meaning given in paragraph 6 of this submission;

**DAA** means the Duet Alinta Alcoa Consortium;

**DBNGP** means the Dampier to Bunbury Natural Gas Pipeline;

**Duet PDS** means the Duet Product Disclosure Statement released on 17 November 2004;

**FAA** means the Financial Assistance Agreement dated 27 October 2004;

**Firm Service** means the Firm Service referred to in the current Access Arrangement;

**First WPC Submission** has the meaning given in paragraph 2 of this submission;

**GPAA** means the *Gas Pipelines Access (Western Australia) Act 1998*;

**GRB** means the Gas Review Board;

**GRB submission** has the meaning given in paragraph 76 of this submission;

**Major Shippers** means Alinta Sales Pty Ltd, Alcoa of Australia Ltd, CSBP Ltd, North West Shelf Gas Pty Ltd, South West CoGeneration, WPC and Worsley Alumina Pty Ltd, collectively representing 95% of the total throughput capacity of the DBNGP;

**OffGAR** means the Office of Gas Access Regulation;

**Operator** means DBNGP (WA) Transmission Pty Ltd;

**PRAA** means the proposed revised access arrangement, access arrangement terms and conditions and access arrangement information for the DBNGP lodged with the Regulator on by the Operator on 21 January 2005;

**RAAI** has the meaning given in paragraph 12 of this submission;

**Regulator** means the Economic Regulation Authority;

**Second WPC Submission** has the meaning given in paragraph 2 of this submission;

**SSC** means the Standard Shipper Contract forming the basis of terms and conditions upon which shipper contracts [redacted] were negotiated with individual shippers in October 2004 and which the Operator intends to use as the basis for future shipper contracts;

**Submission #4** means the Operator's submission #4 dated 27 January 2005;

**Terms** has the meaning given in paragraph 76 of this submission;

**VA** means Venture Associates who are advising WPC in relation to the PRAA and other commercial and strategic matters;

**VA Report** has the meaning given in paragraph 6 of this submission;

**WPC** means Western Power Corporation; and

**WPC's 2004 Contract** means the contract between WPC and Operator for gas transportation provided for under the Deed of Amendment and Restatement (WPC's 2004 Contract) (Full-Haul) dated 27 October 2004.

# Appendix 2: Charles River Associates' Report

SUBMISSION

# Report to Western Power on the Proposed DBNGP Access Arrangement

**Submitted to**

**Western Power Corporation**

**Prepared by:**

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**12 April 2005**

# TABLE OF CONTENTS

# 1. INTRODUCTION AND BACKGROUND

Charles River Associates ("CRA") has been asked by Western Power Corporation ("WPC") to review the proposed revised Access Arrangement ("PRAA") and related Access Arrangement information ("PRAA Information") concerning the Dampier to Bunbury Natural Gas Pipeline ("DBNGP"). The PRAA has been proposed by the DBNGP (WA) Transmission Pty Ltd ("Operator").

WPC has requested that CRA comment on whether the Operator's PRAA complies with the Gas Code requirements and with normal regulatory practice.

## 1.1. History

On 27 October 2004, WPC entered into a suite of contracts with the DBNGP's owners [redacted]

- [redacted]
- [redacted]
- [redacted]

Around the same time, other shippers also entered into similar contracts based on a T1 service.

In January 2005, the Operator submitted the PRAA for consideration by the Economic Regulation Authority ("ERA"). The PRAA is based substantially on the Firm Service which is currently the reference service in the current Access Arrangement ("AA"). To CRA's knowledge no agreements have been reached under contracts in relation to this Firm Service.

The differences between the proposed Tf reference service (which is based on, but differs from, the essentially unused Firm Service described above) and the T1 service[2] are important enough in their economic and potential financial impacts to justify a close examination by the ERA of the PRAA and of the proposed boundary between regulated and unregulated revenue streams.

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[redacted]

2 Throughout this document, the expression "T1 service" is used as a convenient shorthand for "T1 service on terms and conditions broadly equivalent to the 2004 contracted T1 services."

## 1.2. SUMMARY OF ECONOMIC ISSUES WITH THE PRAA

The PRAA has been developed in an environment in which a number of substantial long-term commercial contracts have already been struck. The existing contracts, which enable the DBNGP to be 95 percent to 96 percent utilised already, are intended to secure gains from trade for the contracting parties. It is important that the regulatory arrangements not disturb or undermine those gains unless clear offsetting benefits are at stake.

### 1.2.1. Types of Services Provided

Generally, the Operator will provide three types of services under the PRAA:

- Reference services;
- Non-reference services; and
- Other services (i.e., those services not specified as reference services or non-reference services under the services policy in the PRAA).

Of these three types of services, only references services are proposed to be regulated. As a result a number of concerns arise.

### 1.2.2. Shipper Concerns

From an economic perspective, a shipper's concerns with respect to the provision of these services has three dimensions:

- How costs are to be allocated among reference, non-reference and other services;
- How a service that is desired by the shipper could be synthesised from available services or whether the desired service would need to be negotiated with the pipeline Operator; and
- How costs that may be over-recovered by the pipeline are to be treated (i.e., the extent to which excess recovery is rebateable and, if so, how the rebates are allocated amongst the shippers).

The Operator has proposed that non-reference services and other services be non-rebateable. As a result, the Operator would have an opportunity to enhance its revenues by offering non-reference services and other services in addition to the reference service. Whereas the intent may be that services such as metering information services and improved temperature and pressure monitoring can be provided on an unregulated basis, the provision of transport services other than the proposed Tf reference service exclusively on an unregulated and non-rebateable basis raises a number of potential market power concerns.

Put differently, the combination of non-rebateable, non-reference services and other services together with a reference service that does not align with services already contracted for by the shippers potentially creates opportunities for the Operator to leverage the difference between the value accorded by shippers to the T1 service, which they have revealed as their preferred service, and the value of the inferior Tf service.

### 1.2.3. Materiality of Over-Recovery

The materiality of the potential over-recovery by the Operator depends on:

- The financial exposure of shippers to the differences (perceived and actual) between the proposed Tf reference service and the T1 service that is being provided currently by the Operator; and

- The leverage that the Operator would gain in future commercial negotiations due to the curtailment, notification, penalty assessment and other gas and service quality provisions under the proposed Tf reference service as compared to the corresponding features of the T1 service that is currently provided by the Operator.

Importantly, the Operator would have every reason to expect to earn at least its Total Revenue requirement regardless of the choice of reference service (i.e., the proposed Tf or the currently provided T1 service). The sufficiency of revenues to the Operator under either reference service definition does not appear to be an issue.

Instead, the issue comprises:

- The extent to which the proposed Tf reference service would give the Operator access to unregulated revenues above and beyond the Total Revenue requirement; and

- The extent to which additional revenues are likely to relate to penalties paid or from the Operators' ability to negotiate variations around a reference service that is inferior to the T1 service currently provided.

If the reference service is inappropriate, a proposal to, in effect, regulate only a proportion of the services supplied by the pipeline is potentially problematic. The three types of services, reference, non-reference and other, supplied on a pipeline have joint costs such that regulating a subset of the services offered creates opportunities for gaming of the regulatory regime to the extent that the pipeline can exploit the financial exposure of the shippers who require services substantially different from those provided in the reference service.

### 1.2.4. Role of the Access Arrangement

A well-specified Access Arrangement can mitigate the potential misuse of market power of an otherwise monopoly supplier of gas pipeline transport services, and achieve other important objectives such as facilitating investment in future pipelines and promoting efficient usage of existing pipeline assets. The ability of a particular AA to achieve these purposes depends in part on how the reference service(s) is(are) defined and what services shippers require. Given that the T1 service has been commercially agreed by shippers and the Operator, it appears to serve these purposes well.

Making revenues from non-reference and other services rebateable would reduce the financial incentive of the Operator to apply negotiating leverage to over-recover relative to its required revenues, but these incentives stem in the first instance from the reference service that is put in place. Whereas rebating excess revenues can mitigate market power, the way in which rebates are determined and allocated can still result in significant distortions if the combination of charges and rebates for each shipper do not create the intended overall price signal.

It matters more, therefore, that the reference service be properly specified. Based on materials provided to us, including prior WPC submissions and the current shipper contract setting out the T1 service, and based on analysis we have performed of potential cost impacts on WPC and potential revenue impacts on the Operator, we consider the economic merits of the proposed Tf reference service have not been established, particularly in relation to the currently provided T1 service.

Furthermore, we consider that the proposed Tf reference service is likely to result in over-recovery by the Operator relative to the required revenues that underpin the reference tariff of the proposed Tf reference service.

### 1.2.5. Other Deficiencies in the PRAA

In addition to the above, the PRAA and PRAA Information are deficient in other respects to the extent that it is not possible to either conform or reproduce important assumptions and parameters.

## 1.3. ORGANISATION OF REPORT

This report is organised as follows:

- Section 2 develops the economic context for the issues considered;
- Section 1 applies the economic framework to specific issues of the PRAA; and
- Section 4 covers other issues with the PRAA and PRAA Information.

Additional background information on the modelling approach used to develop the quantitative estimates is provided in the appendix.

# 2. ECONOMIC FRAMEWORK FOR ASSESSING THE APPROPRIATE REFERENCE TARIFF

## 2.1. OVERVIEW

Section 3.3 of the Gas Code provides that an access arrangement must include at least one service likely to be sought by a significant part of the market and include any other service for which the regulator considers a reference tariff is required under the Gas Code. Section 3.6 of the Gas Code requires that the terms and conditions of supply be reasonable.[3]

The specification of a reference service directly affects the extent to which shippers will seek to negotiate significantly different services, and potentially the extent of cost over- or under-recovery by a pipeline. Obviously, if shippers do not consider the reference service to have the characteristics they value, they may seek negotiate a different service. Otherwise, they could face much greater costs as a result of either contractual penalties they incur or through changes in their behaviour (such as through investments to alter their gas consumption quantity or pattern).

In this section we describe economic principles that are relevant to evaluating the choice of reference service, and the potential efficiency implications of an inappropriate reference service being chosen. In particular, we set out a bargaining framework to highlight how the choice of reference tariff translates into commercial outcomes for both shipper and pipeline.

All terms and conditions of the reference service need to be assessed. However, in this report, we focus particularly on the consideration of the appropriate penalty provisions in a reference service. If these penalty provisions are inconsistent with the value of the potential economic harm they are designed to stop/restrict, the provisions can result in over-recovery or distort efficient decision-making by shippers and the pipeline.

## 2.2. COMMERCIAL NEGOTIATIONS AND THE REFERENCE SERVICE

A reference service is a vital part of the PRAA. A reference service need not be (and it may not be possible for it to be) optimally suited to *every* shipper, but the choice of reference service has important financial implications for each shipper and can result in inefficient outcomes. For example, the quantity and timing of gas usage and the costs incurred as a result have important implications for downstream markets, including electricity supply in Western Australia.

3 The Gas Code's general objectives are also relevant (section 2.24 of the Gas Code).

The reference service is a point of reference around which negotiated variations can be developed. An inappropriate reference service can influence these negotiations to a degree that results in economic detriment. The present situation is unusual in that a candidate reference service, the T1 service, already exists that reflects agreed commercial outcomes negotiated between shippers and the Operator.

### 2.2.1. Economic Analysis of Commercial Negotiation

Economists view bargaining as an exchange situation whereby two (or more) parties engage in mutually beneficial trade but have conflicting interests over the terms of that trade. More generally, a bargaining situation is one in which two or more players have a common interest in cooperating, but have differing interests over exactly how to cooperate.

Nobel Prize winner John Nash developed a basic solution for cooperative games, usually referred to as the Nash Bargaining Solution ("NBS"), which has been applied extensively in different branches of economic theory.[4] Nash started from a set of four basic axioms[5] or properties and showed that precisely one bargaining solution satisfied his axioms: the solution that selects the outcome that maximises the product of the players' gains in utility over their disagreement outcome.

Consider a situation where two parties negotiate over the split of some fixed surplus. Suppose negotiation takes the following form. Party A makes an offer (a division of the surplus) that can be accepted or rejected by Party B. If B accepts the offer, then the negotiation ends and the parties split the surplus according to A's proposal. If Party B rejects the offer, then it has the opportunity to make an offer of its own (again a division of the surplus) that can be accepted or rejected by Party A. The parties continue to alternate between offers until one of the parties accepts a proposed agreement.

The parties' incentive to agree lies in the fact that they are impatient and hence the possible value derived from securing a better deal is traded-off for a quicker agreement. Party A then makes an offer that is in the best interest of Party B to accept immediately rather than wait for one more round of negotiations and incur the depreciation of the gains from trade.[6]

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4 John Sutton (1986), 'Non-cooperative bargaining theory: An introduction', *Review of Economic Studies*, 53 (5) October: 709-724 provides a useful survey with examples of practical applications.

5 These axioms can be described as follows: (1) scale-free solution, (2) symmetry (if our bargaining situations are alike then an agreement should split things equally as well, (3) no money left on the table (all gains from negotiation are exhausted if there is trade), and (4) alternatives not chosen do not matter.

6 In addition, each party likely faces a risk that the expected joint opportunity may be lost. For example, at each stage of the bargaining process, a third party might snatch the opportunity. In other words, each party fears that, by prolonging the negotiations, the opportunity to reach an agreement at all might be lost. This will lead to a similar conclusion – that the agreement is reached instantaneously.

What happens to the equilibrium outcome in this alternating offer bargaining game when the time between offers becomes very small or when the risk of exogenous breakdown of negotiations become very large? The answer is that the equilibrium converges to the NBS with payoffs reflecting the incentives to settle (either because of impatience or the risk of exogenous breakdown of negotiations).[7]

In this context, Binmore, Rubinstein and Wolinsky showed that outside options play significant roles in bargaining games which take place over time and in which the driving force to reach an agreement is players' impatience (because the surplus is reduced as a result of delay). For example, the threats of the players walking out of the negotiations should be modelled as outside options open to them.

In equilibrium, such threats would only be implemented if they are credible: either party must find it profitable to actually withdraw from the negotiations with the incumbent party if the offer made yields less than its outside option. In this case, the party making the offer should actually propose an agreement where the other party would receive its outside option in order to avoid the breakdown of negotiations.

The result described above implies, quite intuitively, that in such bargaining processes, having a better outside option will result in a larger share of the surplus other things being equal. That is, a player can increase his or her bargaining power by increasing, in a credible fashion, the value of his or her outside option.

### 2.2.2. "Outside Options" for the Pipeline and Shippers

The reference service influences the outside option of both pipeline and shipper. The more reflective of shipper preferences the reference service is, the more constraining of the potential misuse of market power by the pipeline the reference service is able to be.

Defining a reference service that is insufficiently reflective of what shippers require weakens the shippers' outside option, strengthening the hand of the pipeline in a negotiation. If the financial exposure of shippers to such negotiations is relatively modest, then it matters somewhat less how far the reference service departs from the "ideal" reference service. If, on the other hand, the financial exposure of one or more shippers to variations from the ideal reference service is more significant, then this is a factor that should be considered when evaluating alternative candidate reference services because it affects the ability of the access arrangement to promote economically efficient outcomes.

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7 See Binmore K, Rubinstein A and Wolinsky A (1986), 'The Nash Bargaining Solution in Economic Modelling', *Rand Journal of Economics*, 17-2: 176-188.

Consider a simplified example: Assume that two reference services will equally result in the efficient operation and cost recovery of the pipeline. Assume further that there are five shippers, numbered [1] through [5], who seek access to that pipeline. Assume further that shippers [1], [2], [4] and [5] would either prefer or be content with reference service "A" while shippers [2], [3], [4] and [5] would prefer or otherwise be content with reference service "B". Clearly shippers [1] and [3] have differing views of the preferred reference service. The logical next stage of analysis would be to focus on shippers [1] and [3] as the two shippers whose preferences for the reference service are most likely to be determinative of which reference serviced is economically efficient.

In economic terms, the choice from amongst candidate reference services that are believed to be generally supported by shippers should also be guided by a consideration of how shipper financial exposure varies with respect to different reference services (assuming the pipeline is provided with no less than full cost recovery under all of the options being assessed). Economic detriment can then arise even if only a single shipper has particularly significant exposure to the negotiating risk arising from a reference service that does not account for that shipper's needs. If an alternative reference service would also have been acceptable to other shippers and would have dealt effectively with the exposed shipper's concerns, then the alternative reference service is likely to be economically preferred reference service (again, on the assumption that the pricing meets the cost recovery requirement for the facility owner).

A bargaining framework and a consideration of the value of outside options is crucial when considering the implications of reference service selection; so too is analysis of shipper financial exposure and analysis of potential extra revenues to a pipeline from shippers. This extra revenue may partly be obtained from shippers who choose to incur greater penalties rather than abide strictly by the terms of the reference service in order to mitigate higher costs that would otherwise have been incurred.

Based on information available, the T1 service meets these broader objectives of being a reference service that would have broad support and which would mitigate significant exposure to economic detriment arising from either the need to renegotiate variations to the reference service, incur substantial penalties or undertake economically inefficient cost avoidance investments.

### 2.2.3. Regulated versus Unregulated Services

The provision of both regulated and unregulated services from the same facility has analogies in other sectors, notably airports. The discussion below refers to "single till" versus "dual till" approaches. The "till" concept refers to the way in which revenue is regulated. In a single till approach, all services provided are regulated. In a dual till approach, some services are not regulated because it is believed they are sufficiently constrained by alternatives (i.e., competitive pressure).

Price monitoring of airports in Australia is conducted on what is referred to as a dual-till basis.[8] That is, while airport facilities are jointly utilised in the provision of aeronautical services and non-aeronautical services,[9] airports are considered to have market power in the provision of aeronautical services. Accordingly aeronautical services are subject to price monitoring by the ACCC to prevent misuse of market power. Prices for non-aeronautical services, on the other hand, are not regulated, on the basis that they are supplied in a competitive market, which provides its own constraint on price.[10] Therefore, these services would only need to be subject to price monitoring to the limited extent necessary for reviewing underlying cost allocations.

The alternative to a dual-till is a single-till approach. In relation to airports, a single-till approach would result in the regulation of all services provided by the airport, including both aeronautical and non-aeronautical. A single-till approach therefore generally requires less involved monitoring of cost allocation and pricing methods, as returns are constrained for the airport as a whole and it is not necessary to go through each individual component of business in the airport.[11]

Were non-reference services to be sold in a competitive market, the effective dual-till approach implied in the PRAA would possibly have merit. However, for most of the non-reference and other services, there is no suggestion, either by the Operator itself or according to economic principles, that shippers negotiating with the Operator for access to non-reference services would have competitive alternatives for those services. As a result, a single-till appears to be more appropriate for the DBNGP as it would limit the Operator's ability to exploit its position as a potential monopoly provider of these services. [12]

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8 For a detailed comparison of single till and dual till pricing, see: NECG (2002), *'"Dual Till" at Sydney Airport'*, Report for ACCC, May 2000.

9 An example of a non-aeronautical service is an airport retail shop. For a precise definition of these services see: ACCC (2005), *'Airport price monitoring and financial reporting 2003-04'*, 21 February 2005.

10 As noted below, even if the markets in which non-aeronautical services are provided are non-competitive, reliance on a dual-till framework may still be appropriate if determination of the efficient level of provision of these services (and monitoring of performance against that level) is difficult for regulators, so that it is preferable to accept some allocative inefficiency from over-pricing of these services than the loss in both allocative and technical efficiency arising from under-provision.

11 Although cost allocation between regulated services may still be an issue.

12 Whether a service is supplied competitively is an important consideration in deciding whether dual or single till is justified – but it is not the only one. The other is the extent of the information asymmetry and hence the extent to which a particularly strong or direct incentive needs to be provided to induce efficient provision of a particular service. A regulator without sufficient access to information may not be able to set parameters of the regulatory regime sufficiently to induce the full range of efficiency maximising services. An efficiency incentive in the form of an opportunity to pursue unregulated sources of revenue may help to address the effects of such asymmetry in some instances. Where such asymmetries exist and support the implementation of a dual till approach they should be explicitly analysed. We are not aware of any such factors that are relevant to the context here at issue.

## 2.3. PENALTY PROVISIONS IN THE REFERENCE SERVICE

Analysis of specific terms and conditions in the reference service need to be assessed against the purpose they service, such as (in general terms) risk management, dispute resolution and information exchange. One set of provisions of particular note is the penalty provisions that are part of the reference service. Penalties can be set higher than necessary to achieve outcomes that support the efficient operation of the pipeline, potentially resulting in over-recovery. They will therefore also have an impact on commercial negotiations between the shippers and pipeline, for the reasons set out above.

The relevant economic and regulatory consideration is whether penalties achieve the objective of efficient deterrence or whether they are set so high as to provide supplemental revenue to the pipeline, either directly or by altering the balance of negotiating power between the parties to the pipeline's benefit (thus allowing the pipeline to obtain additional revenue for providing a service that does not involve those penalties).

In any significant contract, certain events may occur that harm one party or the other [redacted]. These events can often be prevented via the effort(s) of one, or both, of the parties.

Efficient precaution is achieved when the penalties for breach of a particular contract term neither under- nor over-deter efforts to prevent a harmful event occurring. If penalties are set too high, then there will be too much precaution. If penalties are set too low, insufficient precaution will be taken. Assuming risk-neutrality and that damage is observable, efficient precaution will occur when:

$$C_P = P_E.D_E,$$

Where $C_P$ is the cost of precaution, $P_E$ is the probability of the event occurring and $D_E$ is the damage caused by that event. $P_E.D_E$ is simply the expected harm. If the effort is greater (less) than the expected harm, *ex ante* the expected cost of avoidance would be greater (less) than the expected harm and it would be efficient not to attempt to avoid the harm.

A contract can include clauses that provide for one party to make compensating payments, penalties or liquidated damages to the other if an event occurs. If any of these payments or forms of compensation have value that is materially different from the value of the actual harm caused, too little or too much precaution may be taken.[13] The theory of efficient deterrence has relevance to the way a reference service is defined, particularly the terms and conditions providing for penalties and potential curtailment of supply.

13 Liquidated damages may still be efficient if they avoid costly negotiations over the quantum of loss.

If $P_C$ is the probability that the contract will require damages and $D_C$ the damages to be paid under the contract, it can be seen that if liquidated damages under the contract are likely to be paid in circumstances where no actual harm is caused, then over-deterrence can also occur.

That is,

$$P_C.D_C > P_E.D_E$$

Therefore, while it is potentially efficient for contract damages to be greater than the actual damage that is caused, it will only be so if the $P_C < P_E$.

In a competitive market, inefficiently high penalty clauses would be unsustainable. If excessive penalties were to be imposed, the anticipated excess penalty recovery (that is, recovery above that which is required to compensate for the underlying damage) would be recognised and those who tried to charge excess penalties would face the need to reduce the price of their services to compete with others who charged "appropriate" penalties.

Shippers have alternative responses to a reference service that does not meet their needs. For example, a shipper can choose to incur penalties charged by the Operator, or take steps such as seeking to purchase additional capacity, seeking alternative sources of supply or otherwise taking steps to decrease or modulate requirements to fit the contractual limitations.

Penalty provisions should also be considered in light of contractual rights and related procedures by which services can be curtailed. The more "process" is required or possible before curtailment occurs, the more flexible the arrangements may be seen to be. Thus, the market power mitigating aspects of penalties are reduced by arbitrary or overly strict curtailment provisions because the risk of curtailment is likely to impose greater costs on shippers and may force shippers to seek to renegotiate contractual arrangements so as to reduce exposure to curtailment risks. The required variations to the reference service would provide an opportunity for the Operator to secure additional revenue.

Determining the appropriate level of penalties can be difficult but important particularly if penalties have the potential to contribute significantly to the revenue received by the shipper. Rather than call for a detailed estimation of such detriment, however, it is possible to use available information to rank candidate reference services. For example, we would expect that an agreement, reached as part of the commercialisation of the pipeline, would tend to have economically efficient penalty/tariff/term combinations. By this logic, the combination of prices, terms and conditions found in the commercially negotiated and agreed shipper contract stands as a reasonable benchmark against which to compare the `terms and conditions found in the reference service.

The cost curve for pipeline usage generally displays decreasing costs up to the point where congestion occurs. Unit costs decrease, and then begin to rise as usage increases and congestion imposes costs on other shippers or the pipeline. If penalties are too high, then shippers could choose to optimise their usage in the segment of the cost curve where unit costs are still declining, reducing the efficiency with which the pipeline is used. By implication, the penalties prevent the most efficient use of the pipeline, underdevelopment of gas resources and the incurrence of inefficient costs by the shippers who act to avoid penalties in the short-term through behavioural adjustments and in the longer-term through investment decisions.

## 2.4. SUMMARY

Section 3.3 of the Gas Code provides that the reference service must be likely to be sought by a significant part of the market. Requiring the reference service to be specified in a way such that it would be chosen by a significant portion of the market reduces, all else equal, the opportunities for the pipeline to offer a service that may result in inefficient utilisation of the pipeline, higher prices for end-users and ultimately distort investment decisions in the long-run. The next section specifically considers the proposed Tf reference service, drawing upon the economic principles discussed in this section.

# 3. ECONOMIC ISSUES WITH RESPECT TO THE PROPOSED TF SERVICE AS A REFERENCE SERVICE

Sub-clause 7.10(a) of the PRAA provides that the Reference Tariff is to recover the portion of Total Revenue attributable to the provision of the proposed Tf service. Shippers with Full Haul Access Contracts entered into prior to the commencement of the new access arrangement period are treated as though they are provided with the proposed Tf service (clause 7.9).

It is important, therefore, to consider how the PRAA relates to the ability to recover the appropriate level of revenues and how the PRAA reference service compares to the services contractually agreed prior to the commencement of the access arrangement period.

The PRAA is flawed for a number of reasons:

- The proposed Tf reference service is inferior to the currently provided T1 service;
- The Tf service has adverse implications for commercial negotiations between shippers and the pipeline; and
- Choosing the Tf service has implications for the efficiency of the behaviour of the shippers and the Operator.

These points are discussed below.

## 3.1. THE TF SERVICE IS INFERIOR TO THE T1 SERVICE

The following table summarises important differences in penalties and related non-price terms between the Tf and T1 services.

**Table 1: Comparison of Tf and T1 Services**

| Charge | Proposed Tf Service[14] | T1 Service |
|---|---|---|
| Cost per GJ of Capacity | $1.09 GJ/day was used for modelling purposes. | $1.09 GJ/day was used for modelling purposes. |
| Reliability and Curtailment Rights | 99%<br><br>However, this is a nominal | 98% |

14 PRAA Annexure A, p. 27

| Charge | Proposed Tf Service[14] | T1 Service |
|---|---|---|
| Rights | permissible limit and is practically irrelevant when one considers the range of reasons that curtailments may be excluded from the 1% limit. The T1 service also has exclusions[15] but the Tf service allows the Operator to curtail without liability beyond the permissible limit:<br>▪ Where the Operator considers it necessary as a reasonable and prudent pipeline Operator, including for planned maintenance; or<br>▪ In order to comply with any contract that is either pre-existing, or can be curtailed only after the Tf service.<br>The effect of the first point is that the only curtailments and interruptions that count towards the Permissible Limit will be unreasonable or imprudent ones (which is extreme considering that unreasonable and imprudent behaviour is typically not the type of behaviour that is sanctioned in contracts). The effect of the second point is that the Tf service will be curtailed *after* the Tx service (see also Curtailment Plan Priority below). | |
| Curtailment Plan Priority | The Tf service would rank at the bottom of the Other Reserved Services (which includes Tx) all of which rank below the T1 service.<br>Although the Tf service is described as a firm service, it is | Subject to certain extreme circumstances, the T1 service ranks highest[16] |

15 Shipper Contract, Clause 17.3

16 Shipper Contract, Schedule 8. Note that in extreme circumstances there is a priority reservation for the distribution system, and Alcoa has certain priority rights under its existing contract.

| Charge | Proposed Tf Service[14] | T1 Service |
|---|---|---|
| | 5th of 7 in the priority queue and therefore would be curtailed before the T1 service. | |
| Out of Specification Gas | Only the Operator has a right to refuse out of specification gas.[17] | Both the Operator and the shipper have the right to refuse out of specification gas. If the shipper refuses out of specification gas, it is entitled to a refund of the capacity charge for the part of the gas it cannot use. If the shipper receives out of specification without agreement, the Operator is liable for any direct damages.[18] |
| Out-of - Specification Gas Charge | 350% of relevant 100% load factor Reference Tariff. | No penalty. |
| Refusal of gas | The Operator may refuse to accept or deliver gas for specified reasons[19] to an unspecified extent and without notification. | The Operator may refuse to accept or deliver gas for specified reasons but must use its best endeavours to notify the shipper and may only do so to the extent that the acceptance or delivery is affected by the specified reasons.[20] |
| Renominations | There is no renomination mechanism after 14:00 hours on the prior day.[21] | There are three renomination windows throughout a gas day (7:00, 12:00 and 20:00) for renominations up to 1 hour ahead.[22] |
| Overrun Charge | The greater of: | The greater of: |

17 PRAA Annexure A: clause 2.5.

18 Shipper Contract for T1, clause 7.6 and 7.9.

19 PRAA Annexure A: clause 3.15 and 3.16.

20 Shipper Contract for T1, clause 5.3, 5.4, 5.7 and 5.8.

21 PRAA Annexure A: clause 4.3.

22 Shipper Contract for T1, clause 8.11.

| Charge | Proposed Tf Service[14] | T1 Service |
|---|---|---|
| | • 115% of the Base Tariff; and<br>• 110% of the highest price paid for Spot Capacity on that Day<br><br>allowing only aggregating within a zone. | • 115% of the Base Tariff; and<br>• the highest bona fide price bid for Spot Capacity which was accepted for that Gas Day<br><br>allowing aggregating across zones. |
| Unavailable Overrun Charge | Equal to:<br>• $15/GJ for the overrun at each delivery point,<br>• reflecting aggregation only within a zone. The charge is equivalent to 1000-1500% of the Base Tariff. | The greater of:<br>• 250% of the Base T1 Tariff; and<br>• the highest price bid for Spot Capacity which was accepted for that Gas Day, other than when the highest price bid was not a bona fide bid, in which case the highest bona fide bid,<br><br>allowing aggregating across zones. |
| Nominations Surcharge | 350% of relevant 100% load factor Reference Tariff for exceeding the balancing threshold. | No penalty. |
| Imbalance Charge | 350% of relevant 100% load factor Reference Tariff on the basis of daily imbalances, thus not allowing for the offsetting of differences over time. | 200% of the Base T1 Tariff from time to time on the basis of rolling accumulated imbalance. |
| Peaking Surcharge | 350% of the relevant 100% load factor Reference Tariff for exceeding a 120% of MHQ[23] at all times. | 200% of the Base T1 Tariff from time to time for exceeding a 120% of MHQ during Summer and 125% of MHQ during Winter.<br><br>There are also a number of procedural provisions limiting the extent to which the Operator can seek an imbalance charge. Separate out peaking limit of 140 percent of MHQ |

23 MHQ is 1/24 of MDQ.

The role of non-price terms and associated penalty provisions is an important regulatory concern because these terms and provisions alter the risk and value of the reference service and can result in:

- Greater direct revenues to the Operator to the extent penalties are incurred without corresponding offsetting costs also being incurred;
- Greater indirect revenues to the Operator to the extent that shippers negotiate variations to the proposed Tf service to reduce penalties or curtailment risks; and
- Other forms of economic efficiency loss arising because shippers take steps to alter their gas usages (so as to avoid incurring penalties or costly renegotiations) such that the Operator is able to offer more unregulated services to others.

The proposed Tf service is inferior to the T1 service, and if adopted as the reference service, it would tilt negotiations of an Access Contract in favour of the Operator, giving the Operator an opportunity to earn unregulated direct and indirect revenues in excess of its required revenue.

## 3.2. TF NOT SOUGHT BY A SIGNIFICANT PART OF THE MARKET

The Code requires that the reference service be one that is sought by a significant part of the market. Tf is not sought by a significant part of the market as shown by the fact that majority of current usage of the DBNGP is by shippers operating under a materially different service (the T1 Service) for the majority of capacity on the pipeline.[24] Had shippers desired the Tf service they would have been in a position to specify it in their commercial negotiations with the pipeline. If shippers such as WPC had felt they had insufficient bargaining power at the time they negotiated the existing T1 service, then they would now have the chance to endorse the proposed Tf reference service or some other service, but in fact they continue to support the contracted T1 service.

Even if one considered that the Tf service were an appropriate reference service, which we do not, the crucial question would be whether the Tf service is a better or worse choice for reference service as compared to the T1 service (or any other service).

To address this question, the Code allows the regulator to require modifications to a proposed Access Arrangement or to determine that additional reference services are needed for the Access Arrangement to fulfil its function.

24 *PRAA Information, 21 January 2005, p. 13*

If two alternative alleged candidate reference services are deemed to have adequate support from shippers; and each would enable the pipeline to earn at least its required revenue, then the reference service that more comprehensively represents the full capability of the pipeline is likely to be the superior reference service candidate, at least under circumstances where some or all shippers would face substantial costs associated with managing the *differences* between the two reference service candidates.

Applying the bargaining framework previously noted, the question is whether the T1 or Tf service more comprehensively allows for the range of services and revenues that the pipeline offers to be obtained on mutually accepted terms (through negotiation or through regulated access) and at reasonable transaction costs. In this case, the T1 service is a more representative, and therefore more appropriate reference service.

## 3.3. Penalties in the Tf Service are Particularly Onerous to Shippers such as WPC

We have analysed penalty risks to WPC using a model described in Appendix A. The analysis focussed on peaking and nomination error-related penalties. Of these, we focus for conservatism, on peaking-related penalties in the discussion below.

The relationship between contracted capacity and peaking penalty costs is summarised in Table 2.

**Table 2 : Comparison of Peaking Penalties to WPC Under the Proposed Tf Service and the Current T1 Service (in millions of dollars per annum, ignoring curtailment risk)[25]**

| Contracted Capacity (TJ/day) (Summer) | Tf Peaking Penalties | T1 Peaking Penalties | Difference (Tf-T1) |
|---|---|---|---|
| 90 | $17.20 | $8.08 | $9.13 |
| 95 | $15.58 | $7.40 | $8.19 |
| 100 | $13.95 | $6.70 | $7.25 |
| 105 | $12.33 | $6.02 | $6.31 |
| 110 | $10.82 | $5.37 | $5.45 |
| Note: T1 contracted capacity covers summer and shoulder periods; winter contracted capacity is assumed to be 27 TJ/day less than summer. The Tf service does not allow seasonal capacity contract differences. | | | |

25 Based on a tariff of $1.09/GJ for both the T1 and proposed Tf services. See Appendix A for additional information on the modelling approach.

Of course, the above table and commentary also ignores the previously noted fact that curtailment risks are much higher for the Tf service.[26] Contracting for additional capacity under the terms of the Tf service would still result in a Tf service that is inferior to the T1 service.

Penalty exposure under the proposed Tf service is more than double the equivalent penalty exposure under the T1 service. [redacted] based solely on peaking penalties and ignoring curtailment risks or other factors, WPC could be exposed to increased penatly cost risk of $5 million or more each year.

## 3.4. Other Penalty Payments Only Increase Shipper Exposure

The above analysis focussed on peaking penalties to highlight the point of how the selection of the reference service changes both exposure to risk and what shippers must do to manage those risks. The analysis is conservative in that it focusses on peaking penalties, which are the most easily modelled. To underscore this point, we considered the possibility that nomination error penalties could be applied under the proposed Tf reference service.[27]

The incurrence of nomination error penalties depend on whether a variance notice is in effect. Assumptions regarding the frequency of such notices must be made, with the most conservative treatment being the assumption that such notices are never in effect.[28]

To provide some indication of the bounded impacts of these notices, we analysed different scenarios involving different probabilities that such notices were in effect, ranging from 0 percent to 30 percent of the time. The approach adopted is discussed in Appendix A. The results are summarised in Table 3.

26 See Section 3.1

27 Note that other penalties, such as overrun and imbalance penalties which require a more elaborate and comprehensive gas system model, as opposed to an electricity system model, have not been calculated.

28 See Appendix A for a description of the modelling approach and penalty arrangements.

**Table 3: Estimated Annual Peaking and Nomination Error Penalty Payments to the Operator by WPC Under the Proposed Tf Service as Compared to the T1 Service.**

| Percent of time a Variance Notice are in Effect | Supply- or Demand-Side Shock Affecting Preferred Gas Usage by (X%) Scenario (in millions of dollars per year) | | |
|---|---|---|---|
| | Low (5-10%) | Medium (10-15%) | High (20-30%) |
| 0% | $5.69 | $5.69 | $5.69 |
| 10% | $6.25 | $7.08 | $8.48 |
| 30% | $7.36 | $9.87 | $14.35 |

Estimated using simple dispatch model of relevant parts of the WPC electricity generation system.
Based on $1.09/GJ for all gas under both the proposed Tf and the T1 services.
Contracted Tf capacity is assumed to be 108.5 TJ/day and contracted T1 capacity is 108.5 TJ/day in summer and 81.5 TJ/day in winter.

We estimate additional revenue to the Operator of between $5.7 to $14.35 million per annum were WPC to incur penalties in lieu of running its distillate power stations. We have not estimated any additional costs to the Operator from offering the T1 versus Tf services, but we have no information to suggest that the Operator would actually incur materially greater costs as a result.

## 3.5. Implications for Commercial Negotiations Around a Tf Reference Service

Clearly, the specification of the reference service plays a crucial role in shaping the value of the outside option (discussed in Section 2.2.2) for both the pipeline and the shipper(s). As previously noted, the specification of a reference service should be seen as part of a broader negotiating framework, with associated implications for revenues and returns that the pipeline can earn.

Given the significant differences between the proposed Tf reference service and the T1 service currently provided to shippers, and given that revenues from non-reference services would flow to the pipeline on a non-rebateable and unregulated basis, the pipeline's ability to hold firm and seek to capture a larger share of value from any such negotiations would be enhanced.

Rebateability would reduce the Operator's bargaining position as it can reduce the value to the Operator of holding out for a better deal, as the additional value that would otherwise flow to the Operator would be rebated. Rebateability raises other questions and complications, however, such as how would the rebates be allocated to shippers when the additional revenues may be attributable to the costs incurred by only a subset of shippers. Rebateability may also so reduce the benefits of a negotiated outcome in that the pipeline has no commercial interest in doing so. Rebateability can be important, but it is clearly not an antidote to the selection of an inappropriate reference service.

OffGAR's previous decision suggested that it was not necessary for the T1 service to be offered as a reference service, even though it was likely to be sought by a significant part of the market.[29] We understand that this decision was influenced by OffGAR's view that the pipeline would offer supporting non-reference services (such as a seasonal service) that OffGAR regarded as forming a bundle alleged to be equivalent to the T1 service.[30] It is clear, however, based on both qualitative and quantitative analysis of the PRAA provisions, that such synthesis of the desired services by combining the reference service with other negotiated services would require further negotiations between the shippers and the Operator, and would enhance the Operators' ability to secure revenues above those that have been considered as part of the PRAA.

As a result, we conclude that a reference service based on the T1 service would support a more robust long-term result involving less financial risk to shippers while still enabling the Operator to recover its cost.

29 OffGAR (2003), *op. cit.*, para. 78.

30 *Ibid.*

# 4. OTHER DEFICIENCIES WITH THE PRAA AND AAI

## 4.1. OVERVIEW

There are a number of issues arising from the PRAA, which may be immaterial (or of uncertain impact) in isolation, but which together, considering most are either neutral or in favour of the Operator, could be financially significant. In general, the impacts increase the Operator's revenues and should be considered carefully. Table 4 summarises the issues we have identified.

A further general comment is that we have not been able to replicate or support a number of parameters, and while some of the parameter uncertainty may turn out not to be material, it is not possible to confirm many parameters' veracity or the magnitude of possible deviations without the relevant supporting material.

**Table 4: Summary of Other Deficiencies with PRAA and AAI**

| Issue | Comment | Possible Cost (millions per year) |
|---|---|---|
| Redundant Capital | Further information is required to determine its magnitude and to consider whether it potentially should be removed. In particular, if compressors are being replaced as part of new capital expenditure, removing redundant capital from the regulatory asset base could have a significant impact on the cost of access. | $[unknown] |
| Calculation of Risk-free Rate | While ERA may determine the appropriate the risk-free rate at the time of its decision, the Operator has chosen a favourable date on which to base the current estimate. Using a more appropriate estimate (20 days prior to the start of the regulatory period) would reduce Total Revenue by approximately $2 million. | $2.0 |
| Calculation of Debt Margin | The Operator's proposed debt margin, reflecting a hypothesised credit rating of BBB, has insufficient basis. A credit rating of BBB+ appears more generally in line with regulatory precedent, and adds 9 basis points to the debt | $1.0 |

| Issue | Comment | Possible Cost (millions per year) |
|---|---|---|
| | margin. The use of the BBB rating in the PRAA increases Total Revenue by approximately $1 million per year. | |
| Calculation of Debt Raising Costs | Regulatory precedent for debt raising costs appears to support values between 10.5 and 12.5 basis points, which is below the Operator's proposed 25 points. The use of 25 basis points rather than 12.5 basis points increases Total Revenue by approximately $1 million per year. | $1.0 |
| Fuel Cost | Fuel cost is a significant item for which more detail is required. Over the 6 year forecast, the cost of gas comprises between 32 and 42 per cent of annual non-capital costs, and more than doubles in nominal terms (from approximately $20m to $41m annually). | $[unknown] |
| Incentive mechanism for non-capital expenses | The incentive mechanism allows for the retention of efficiency savings in non-capital costs for 10 years, which is greater than the retention period that has been commonly used (5 years).<br><br>Also, the Operator has included a 2 percent real increase in labour costs in the incentive mechanism ($R_t$). Labour costs contribute approximately 14% of the non-capital costs in 2005. | $[unknown] |
| Equity Raising Cost | The Operator adopted the value provided by the ACCC in the GasNet decision. However the actual value could be higher or lower than this value and it would seem more appropriate to use the actual data where available. Equity raising costs are approximately $1.5 million in 2005. | $1.5 |

| Issue | Comment | Possible Cost (millions per year) |
|---|---|---|
| Asymmetric Risk Costs | It does not appear that the Operator has met the standard required by the ACCC for a self-insurance premium to be included in regulatory cash flow, therefore the inclusion of asymmetric risk costs may be unreasonable. Asymmetric risk costs are $0.2 million per annum. | $0.2 |
| Liquidated Damages Insurance | If insurance for liquidated damages is part of the costs of expansion being incurred by the Operator, it would seem reasonable that it be considered as part of the costs of new facilities investment, rather than a cost of the reference service, and therefore its inclusion may be unreasonable. Liquidated damages insurance is estimated to be between $0.7 and $3.6 million. | $0.7 to $3.6 |
| Fixed Principles | Paragraph 7.13(a)(iii) locks in greater revenue for the Operator than the regulation would otherwise allow. ERA should give particular consideration to the inappropriateness of this fixed principle, as the Operator has, at the same time, proposed some pipeline services not be included within the scope of price regulation. | $[unknown] |
| Volume Forecasts | Volume forecasts are a critical aspect of determining the access price and much more information should be provided to determine whether the forecasts provided by the Operator are reasonable. Small differences in the volume forecasts could result in significant differences in the access price. | $[unknown] |
| Cost Allocation Methods | In addition to the general problems discussed in detail in this report, more information is | $[unknown] |

| Issue | Comment | Possible Cost (millions per year) |
|---|---|---|
| | required to determine the methodology used to allocate costs. This could result in a significant reduction in the access price, and/or in significant changes to the rebated revenue provisions. | |
| Further Benchmarking Information | More information on benchmarking the Operator's performance is required. Benchmarking is an important tool for the regulator to confirm whether costs and other aspects of the PRAA are reasonable. Benchmarking requirements, including KPIs, should be developed based on the questions and comparisons that the ERA requires to do its job effectively. | N/A |
| Sum of impacts of issues for which a possible numerical estimate can be developed | | $8.4 to $14.3 |

Each of these areas is discussed further below.

## 4.2. Capital Base, Redundant Capital and Depreciation

Under the cost of service approach as adopted by the Operator, the capital base is the key determinant of what must be recovered by investors after all other costs are covered, such as operating, maintenance and financing costs.

In the following sections, the following issues relating to the capital base are discussed:

- Inability to replicate the roll forward of the capital base over the period 2000-2004;
- Treatment of redundant capital; and
- Unexplained changes to the remaining effective asset lives.

### 4.2.1. Capital Base

While potentially not a major factor in terms of value implications, we have not been able to exactly replicate the Operator's calculation of the roll forward of the capital base over the period 2000-2004 (as set out in Table 2 of the PRAA Information).

### 4.2.2. Redundant Capital

Section 8.9 of the Gas Code additionally refers to reductions in the capital base as a result of taking into account redundant capital identified prior to the start of the relevant AA period. The Operator's submissions do not note redundant capital, either between 2000 and 2004, or in the new AA period. In particular, we understand from WPC that expansion plans for the pipeline involve the installation of seven compressors and that the installation would involve the removal and decommissioning of some of the current compressors. Redundant capital may exist as a result, and the common regulatory approach would indicate that it should be removed from the capital base.[31]

### 4.2.3. Changes to the Average Remaining Asset Life

Clause 7.7 of the PRAA and Tables 5 and 6 of the PRAA Information outlines the depreciation schedule and assumed asset lives. The reduction in the average remaining asset life from 1 January 2000 to 31 December 2004 for each asset class is shown in Table 5.

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31 E.g. ACCC (2002), *'Final Decision – Access Arrangement proposed by NT Gas Pty Ltd for the Amadeus Basin to Darwin Pipeline'*, p. 45.

**Table 5: Changes to Average Remaining Asset Life Between 2000 and 2004**

| Asset | Average remaining asset life as at 1 January 2000 | Average remaining asset life as at 31 December 2004 | Reduction in average remaining asset life |
|---|---|---|---|
| Pipeline assets | 54.5 | 49.5 | 5 year reduction |
| Compression assets | 19.34 | 14.6 | 4.74 year reduction |
| Metering assets | 39.98 | 33.5 | 6.48 year reduction |
| Other depreciable assets | 16.85 | 11.85 | 5 year reduction |

All things being equal, we would expect a 5 year reduction due to the passage of 5 years of the first AA period. To our knowledge, the Operator provides no explanation why the reduction in the average remaining asset life for compression and metering assets is not five years.

## 4.3. Rate of Return

Clause 7.6 of the revised AA provides that the weighted average cost of capital (WACC) is to be calculated on a real pre-tax basis. Table 4 of the PRAA Information lists the key parameters.[32] Elements that merit particular review include: the risk free rate, debt margin and debt raising costs.

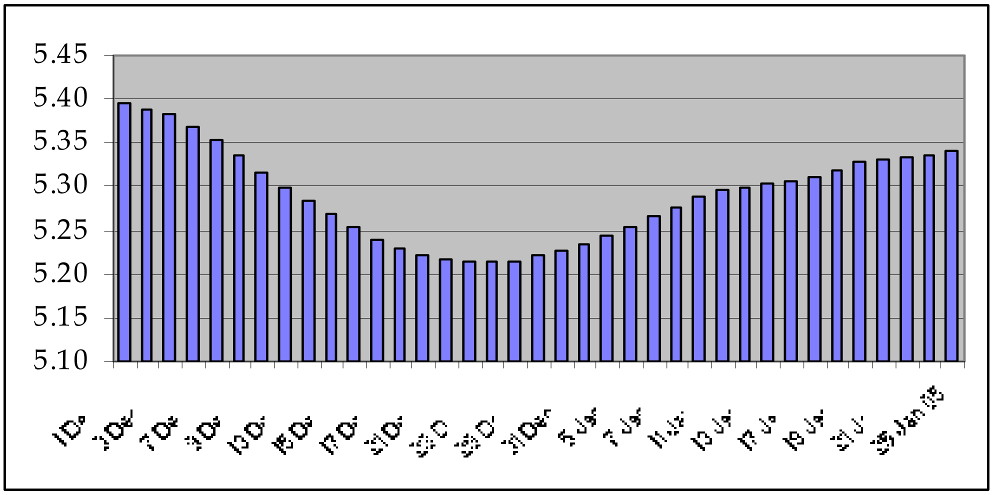
### 4.3.1. Calculation of the Risk Free Rate

The PRAA calculates the nominal risk free rate by averaging the yields on 10-year Commonwealth bonds over 20 trading days.

The period over which the risk free rate has been calculated appears to maximise the estimated WACC. Despite the PRAA information being dated 27 January 2005, the Operator applied a 20 trading day period ending as of 1 December 2004. As can be seen in Figure 1, a 20-day average beginning on any other subsequent day would result in a lower nominal risk free rate.

32 The PRAA also includes some of these parameters as Fixed Principles (sub-clause 7.6(d)).

**Figure 1: 20-day Moving Average Interest Rate on 10-Year Commonwealth Bonds (1 Dec 04 to 25 Jan 05)**




For example, recalculating the nominal risk-free rate using an average over 20 trading days to 31 December 2004 (the start of the regulatory period), decreases the nominal risk-free rate to 5.23 percent, and using an average over 20 trading days to just prior to the filing of the PRAA, to 5.34 percent.

A similar pattern can be observed in the 20-day moving average of the Commonwealth Indexed Bond maturing in August 2015, used in the calculation of the real risk-free rate.[33]

### 4.3.2. Debt Margin

The debt margin is the amount above the risk free rate that the regulated firm must pay in order to be able to access debt funding. The Operator has proposed a debt margin of 111 basis points for the 20-day period ending 1 December 2004 based on an assumed credit rating of BBB.

The Operator cites the Australian Competition Tribunal's (ACT's) decision for the Moomba to Sydney Pipeline for its selection of a BBB credit rating.

33 The real risk free rate used for the proposed AA is based on a hybrid of the August 2015 and August 2010 Indexed Bonds. For ease of exposition, only the August 2015 Commonwealth Indexed Bond is examined here.

The ACT decision, however, does not stipulate adoption of a BBB rating. The ACT decision merely rejects the ACCC's approach in that particular review. The ACT criticised the crude averaging exercise undertaken by the ACCC in deriving a credit rating from those of the comparators GasNet (BBB), Envestra (BBB), Alinta (BBB) and AGL (A). The ACT then removed the only A-rated company that had been presented in that instance, leading to its conclusions that a BBB credit rating was appropriate – in short the ACT's conclusion was based *solely* on its interpretation of the evidence brought before it. We note that, in its recent draft decision on Alinta's distribution network, ERA provided evidence from Standard & Poors for a rating of BBB+ for distribution and transmission networks.

Based on a 20-day averaging period ending 31 December 2004 the respective margins for BBB+ and BBB ratings as estimated by CBA Spectrum are 101 and 110 basis points respectively.[34] The impact on the debt margin between ratings of BBB+ and BBB for the period used by the Operator is a reduction of 9 basis points.

### 4.3.3. Debt Raising Costs

Companies incur costs associated with the raising and securing of debts. The Operator has allowed 25 basis points for debt raising costs. The Operator cites the ACT's GasNet decision as precedent for this value.

Debt raising costs include advisory fees, agency fees, arrangement fees, credit rating costs, syndication expenses and swap margins.[35] In general, the majority of these costs are not directly related to the interest rate itself, but rather are fixed amounts payable up front on the establishment of debt (or, for example in the case of credit rating costs, ongoing costs which are not directly related to the level of debt undertaken).

The Operator proposed that a 25 basis points allowance is at the upper end of regulatory precedent. We have seen no documentation or calculations that justify this number. In addition, the Operator use of the GasNet decision as a precedent is inappropriate as it reflected a private settlement between GasNet and the ACCC and therefore would likely have had regard to circumstances specific to that matter. In fact, the ACT expressed no public view on this issue. Prior to this agreement, regulatory precedent had evolved towards a value between 10.5 and 12.5 basis points.[36] We note that the ERA's draft decision on Alinta provided an allowance of 12.5 basis points.

34 Estimated using 10 year BBB+, BBB and Government bond figures as recorded by CBA Spectrum for the 20 trading days to 31 December 2004.

35 ACCC (2004), *'Statement of principles for the regulation of electricity transmission revenues – background paper'*, p. 118.

36 The ICRC, IPART and the ERA have all separately applied debt issuance costs of 12.5 basis points.

## 4.4. NON-CAPITAL COSTS

Clause 7.8 of the PRAA provides that the Reference Tariff should be set to enable the recovery of all forecast non-capital costs "to the extent permitted under section 8.37 of the Gas Code". Section 8.37 of the Gas Code permits the recovery of forecast non-capital costs subject to those costs being prudent.[37]

### 4.4.1. Fuel Costs

Gas is required to operate the compressors along the pipeline. Over the 6 year forecast, the cost of gas comprises between 32 and 42 percent of annual non-capital costs, and more than doubles in nominal terms (from approximately $20 million to $41 million annually). As fuel cost represents a significant cost item, additional public information on the price and volume forecasts of fuel should be required from the Operator in order for interested parties to determine whether these costs have been appropriately estimated. It should be clarified whether these estimates include fuel gas that is paid for directly by shippers.

### 4.4.2. Equity Raising Costs

Equity raising costs are payments to financial institutions to raise equity. These costs are expressed as 0.224 percent of regulated equity per year. Equity-raising costs can be legitimate costs if a business needs to issue equity to provide the regulated reference service, but this need has not been established with respect to the Operator's ability to provide the proposed regulated reference service. Rather, we understand from WPC that equity and debt has been previously committed prior to the AA period.

In proposing an annual allowance equivalent to 0.224 percent of regulated equity per year, the Operator adopted the equivalent annuity value provided by the ACCC in its GasNet decision. However, the ACCC's approach to equity raising costs has been clarified since that decision. In its Transend decision and draft decision on Transgrid it declined to provide an allowance on the basis that the organisation would not be required to issue equity over the regulatory period.[38,39] The ACCC has noted that the approach adopted remains subject to the findings of a review on this issue.

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37 The exact wording is that costs are allowed "except for any such costs that would not be incurred by a prudent Service Provider, acting efficiently, in accordance with accepted and good industry practice, and to achieve the lowest sustainable cost of delivering the Reference Service".

38 ACCC (2003), *'Decision: Tasmanian transmission network revenue cap 2004-2008/09'*, p. 72.

39 ACCC (2004), *'Draft Decision: NSW and ACT transmission network revenue caps – TransGrid 2004/05-2008/09'*, p. 84.

### 4.4.3. Asymmetric Risk

Asymmetric risks include the costs of events such as extortion and bomb threats, insurer credit risk, employment practices risk, key person risk and uplift liability risk (of $0.2 million). The Operator notes that its proposed allowance for asymmetric risk is consistent with the ACCC's GasNet decision. However, it does not appear that the Operator has met the standard required by the ACCC for such a self-insurance premium to be included in regulatory cash flows. These standards include the provision of Board resolutions, documentation from qualified insurance consultants and confirmation that the business will not seek extra funds should things go "wrong" in areas for which it claims now to be self insured. The ACCC's position on self-insurance was first set out in the decision on SPI PowerNet.[40] In this decision, the ACCC stated:[41]

> *"As a general matter, the Commission is required to apply an incentive based form of regulation under the code. After careful examination of the merits of self-insurance on efficiency grounds, the Commission has determined that the following matters must be established prior to considering a self-insurance application:*
>
> - *confirmation of the board resolution to self-insure;*
> - *a report from an appropriately qualified insurance consultant that verifies the calculation of risks and corresponding insurance premiums;*
> - *relevant self-insurance details that unequivocally set out the categories of risk the company has resolved to assume self-insurance for. This would need to clearly establish what the insured events and exclusions are so as to avoid any future debate as to whether or not an event was a self insured one and form the basis for actuarial assessment noted above;*
> - *a regulated entity's resolution to self-insure would also be expected to explicitly acknowledge the assumed risks of self-insuring (i.e. in the event of future expenditure required as a result of an insurance event such costs would not be recoverable under the regulatory framework as the relevant premiums would have already been compensated for within the operating and maintenance element of the allowed MAR and funded by users, e.g. if a 1 in a 100 year event occurs in year 1 then the business will need to have the financial ability to restore assets out of own resources).*

40 This wording has been repeated in subsequent draft and final decisions in the electricity sector, and similarly expressed in the ACCC's *'Draft Greenfields Guideline for Natural Gas Transmission Pipelines'*.

41 ACCC (2002), *'Decision: Victorian Transmission Network Revenue Caps 2003-2008'*, pp. 78-79.

> *Board resolution and corporate governance requirements are fundamental issues. Risk management strategy of an entity and approaches to events that could affect the overall risk profile of the entity are matters for Board consideration. This is important because it may require parent entity/shareholder support to self-insure and/or affect debt covenant requirements of lenders."*

In some instances a Board resolution would not be appropriate, such as in situations where the business is essentially forced to self-insure. It would still be appropriate to obtain a report from a third party confirming the accuracy of the proposed self-insurance premium.

### 4.4.4. Liquidated Damages Insurance

Liquidated damages insurance is required as part of existing transportation contracts against liquidated damages. We understand from WPC that the insurance for liquidated damages is part of the costs of expansion being incurred by the Operator. If our understanding is correct, then it would seem reasonable that the cost of such insurance be considered as part of the costs of new facilities investment, rather than a non-capital cost of the reference service. The costs vary between $0.7 million and $3.6 million.

## 4.5. Efficiency Mechanisms

The Operator has introduced an efficiency carryover mechanism that allows it to retain the benefits of efficiency savings in non-capital costs for 10 years irrespective of when those savings occur during the regulatory period.

A carryover mechanism allows the service provider to retain any gains/savings for a set period, in part to provide a clearer incentive for the provider to pursue efficiency improvements throughout the regulatory period. Without the mechanism, the provider will obtain less return from improvements made towards the end of the regulatory period than from earlier improvements, potentially distorting investment decisions. In principle, carryover mechanisms are also intended to benefit *users* of the pipeline by making sure that the owner of the pipeline has a clear and consistent incentive to operate the pipeline efficiently.

The carryover mechanism described in the PRAA and in the corresponding PRAA Information notes that the mechanism provides for:

> *[A] sharing of any returns to the Operator from the sale of Full Haul services in an Access Arrangement Period that exceeded the level of returns that were expected during that Access Arrangement Period for the sale of such services.*

However, the actual formula given in the PRAA[42] allows only for the sharing of efficiency gains in relation to non-capital costs, not for revenue gains attributable to increased sales. Therefore, the PRAA formula does not appear to allow for the carryover of gains in revenue.

It is not clear whether or not sharing in the gains in revenue was intended by the Operator. Importantly, the GasNet precedent for such a carryover mechanism also applies only to non-capital savings. If the carryover mechanism did apply to volume changes, even greater pressure would be placed on ensuring forecast volumes are accurate (lest the Operator obtain even further revenue gains from any favourable (to it) forecast errors).

Further, the Operator has proposed retention of non-capital costs savings over 10 years, a period that exceeds the five-year period that has more commonly been observed.[43] The Operator has provided little detail or explanation of why this higher incentive is required. Without this detail, it is difficult to assess whether the incentive mechanism is reasonable under the Gas Code.

### 4.5.1. Real Labour Cost Escalation in the Incentive Mechanism

The Operator has included a 2 percent real increase in labour costs in the incentive mechanism ($R_t$). The Operator argues that 3 percent per annum is a reasonable estimation of the likely real labour cost increase it will face in the AA Period. However, it submits that this amount should be offset by a 1 percent per annum efficiency improvement, which it considers a "reasonable target over the Access Arrangement Period".[44]

The Operator proposes the following values for the real labour increase:

| T | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|
| $R_t$ | 1.0046 | 1.0044 | 1.0039 | 1.0041 | 1.0041 |

We have been unable to replicate the values given for Rt in the PRAA applying this approach, due to insufficient information provided by the Operator, and therefore cannot comment on whether it is appropriate.

42 PRAA, Clause 7.12 (c).

43 The GasNet AA allows for only a 5-year retention.

44 DBNGP (2005), Submission #4, *op.cit.*, para. 4.14.

## 4.6. FIXED PRINCIPLES

The PRAA lists the following fixed principles[45] for the fixed period until 31 December 2031.

- Paragraph 7.13(a)(i) of the PRAA provides that the method of determination of the Capital Base at the commencement of each year of the AA Period, as set-out in clause 7.3 of the PRAA, will be a fixed principle.

- Paragraph 7.13(a)(ii) of the PRAA provides that the rate of return calculation in clauses 7.5 and 7.6, and the elements used in that determination set out in clause 7.6(d) are fixed principles. The use of a pre-tax WACC, use of the CAPM methodology, and the calculation of the return on debt (using the sum of a risk free rate of return, an estimate of corporate debt margin and an estimate of the costs of raising debt), and the following WACC Parameters are all specified.

| Parameter | Value |
|---|---|
| Market risk premium | 6.0% |
| Asset beta | 0.60 |
| Debt beta | 0.20 |
| Gearing ratio (D/V) | 60.0% |
| Value of imputation credits | 50.0% |

- Paragraph 7.13(a)(iii) provides that the calculation of the revenue earned by the Operator until 31 December 2015 which is in excess (in NPV terms) of the sum of:

  - The revenue that would have been earned if any services were full haul services sold at the reference tariff; and

  - The revenue actually earned from the sale of services other than full haul services,

  must not:

45 Section 8.47 of the Gas Code provides that the reference tariff policy may include fixed principles, which are to be fixed for a specified period and cannot be changed without the agreement of the Service Provider. A fixed principle may include any 'structural element', but not a 'market variable element' (section 8.48). The regulator must have regard to the interests of the Service Provider and of the Users and Prospective Users when assessing fixed principles (section 8.48).

- Be taken into account directly or indirectly for the setting of a Reference Tariff or applying any Reference Tariff Policy that applies after 31 December 2010; or
- Otherwise be taken into account by the Regulator in performing any of its functions under the Code.

These fixed principles are discussed below.

### 4.6.1. Paragraph 7.13(a)(i) – Calculation of Capital Base

Paragraph 7.13(a)(i) of the PRAA (referring to section 7.3) does not include a reduction for redundant capital. As discussed above, insufficient information is provided by the Operator to assess the potential magnitude of redundant capital. In any event, it does not appear there is any economic basis for adopting a Fixed Principle that essentially replicates a 'mechanistic procedure'.[46]

### 4.6.2. Paragraph 7.13(a)(ii) – Rate of Return

Paragraph 7.13(a)(ii) of the PRAA (referring to section 7.6) includes what are more accurately considered market variables. In particular, the asset and debt betas can vary with changes in the estimated systematic risk exposure of investors.

The CAPM is a widely used basis for asset pricing. However the Code allows for other methods to be used (such as the Arbitrage Pricing Theory), and there are many criticisms of the CAPM model.[47] For this reason, SAIPAR declined to accept the use of CAPM as a fixed principle.[48]

It is unnecessary and unreasonable to establish the use of CAPM as a fixed principle because, logically, CAPM will either be seen as a commonly applied methodology and suitable for application, if potential criticisms are not deemed sufficiently material to support the use of a different approach; or those criticisms of the CAPM will be seen as material, in which case excluding consideration of the merits of those criticisms in a regulatory setting would be inappropriate.

46 OffGAR (2001), '*Draft Decision Proposed Access Arrangement - Dampier To Bunbury Natural Gas Pipeline*', Part B, p. 120; IPART (1999), '*Final Decision Access Arrangement – Albury Gas Company Limited*', p. 86; SAIPAR (2001), '*Final Decision Access Arrangement – Envestra Limited's South Australian Natural Gas Distribution System*', pp. 178-182.

47 For a textbook discussion of these issues, see for example, Bishop, S., R. Faff, B. Oliver and G. Twite (2004), '*Corporate Finance (5th edition)*', chpt 7.

48 *Ibid.*, p. 200.

### 4.6.3. Paragraph 7.13(a)(iii) – Calculation of Revenue

Paragraph 7.13(a)(iii) deals with the treatment of revenues that are relevant to current investment decisions. In effect, it appears intended to enable the Operator to obtain, until 2016, greater revenue than those to which it would be normally be entitled under the regulatory regime. Shippers have been prepared to enter such contracts to provide sufficient returns for the Operator to undertake further investment.

[redacted]

Changes in the PRAA have eliminated certain kinds of rebateable revenue, increasing the likelihood that the Operator would over-recover as a result of future negotiations with shippers.

In any event, to be clear, this fixed principle should only apply to revenue from contracts signed prior to 2005. Any full haul services sold after 1 January 2005 should be included at the level of revenue actually obtained, which may be potentially higher than the Tf price.

## 4.7. FURTHER BENCHMARKING INFORMATION IS NEEDED

Comparing (benchmarking) pipelines is complicated by their different operating circumstances, and therefore a variety of Key Performance Indicators ("KPIs") are often used to assist in making comparisons and tracking performance.[49]

The Operator provides (in Submission #4) a comparison of the pipeline against five other domestic pipelines[50] across only two benchmarks:[51]

- Non-capital costs (exclusive of fuel costs) per km per GJ; and
- Non-capital costs (exclusive of fuel costs) per km per compressor station.

49 ACCC (2003), *'East Australian Pipeline Limited Access Arrangement for the Moomba to Sydney Pipeline System – Final Decision'*, p.311.

50 The Moomba-Sydney, GasNet system, Goldfields, Moomba-Adelaide and Amadeus-Darwin pipelines.

51 DBNGP (WA) (2005), *'Submission #4 – Reference Tariff Policy and Reference Tariff (Public Version)'*, pp.25-26.

The PRAA Information contains substantially less detail on the specifics of the non-capital costs (contrast, for example, Table 3-6 in the GasNet 2003 AA Information[52] and Table 8 in the PRAA Information). The GasNet 2003 AA Information, on the other hand, compared domestic pipelines across five benchmarks:

- Operating costs per GJ of gas delivered;
- Operating costs as a percentage of capital investment;
- Operating and maintenance costs per metre of pipeline;
- General and administrative costs per GJ of gas delivered; and
- Operating and maintenance cost as a percentage of capital investment.[53]

The set of benchmarks and KPIs should also take account of the reference service definition. For example, in the case of a Tf versus T1 service, an important difference is the level of penalties and the extent of flexibility in the nomination process. A set of KPIs should be developed in relation to penalty (or effective-price) revenue collected, the circumstances surrounding penalty-related situations, compressor station performance, other congestion-management related costs incurred and/or actions required.

These are just examples – given the risks associated with asymmetric information, and given that benchmarking is generally preferable across a range of indicia, the ERA should develop and/or insist on a wide range of benchmarks.

## 4.8. Volume Forecasts (2005 to 2010)

The forecast volumes from 2005 to 2010 are set out in Table 6 and Table 7, which replicate Tables 10 and 11 from the PRAA.[54]

52 *GasNet Australia Access Arrangement Information*, ACCC revised Access Arrangement Information further revised following Australian Competition Tribunal decision, Order of 23 December 2003 – commencement 1 January 2004, p.9. See also the ACCC's defence of volume based benchmarking in ACCC (2003), *'East Australian Pipeline Limited Access Arrangement for the Moomba to Sydney Pipeline System – Final Approval'*, pp.40-41.

53 GasNet Australia Access Arrangement Information, *op. cit.*, p.34-35.

54 DBNGP (WA) (2005), *'2005 Proposed Access Arrangement for the DBGNP – Information'*, p. 13.

**Table 6: Forecast Contracted Capacity (TJ/day) (Table 10: PRAA)**

| Year Ending 31 Dec | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Full Haul | 575.85 | 615.59 | 714.98 | 771.10 | 788.52 | 826.35 |

**Table 7: Forecast Throughput (TJ/day) (Table 11: PRAA)**

| Year Ending 31 Dec | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| Full Haul | 554.83 | 591.85 | 681.93 | 736.94 | 753.68 | 788.39 |

Insufficient information exists in the PRAA with which to assess the accuracy and implications of these forecasts. Additional independent analysis of the forecasts should be undertaken, particularly of the contracted capacity. In addition, any findings of the independent expert report should reflect consultation with users about their expected consumption and the main drivers of that consumption to assist the assessment of the nature of the service required.

Particular concerns include that the forecast only relates to Full Haul[55] services, even though Total Revenue is allocated between it and Part Haul[56] services, and therefore forecasts of Part Haul services are also required. Forecasts of other non-reference services are also required, given the Operator has not proposed to include them as rebateable services.

Excluding non-reference services from rebateable services means that some non-contestable pipeline revenues may fall outside the regulatory net, allowing potential over-recovery. As previously noted, a reference service that does not correspond to the service required by shippers may cause shippers to incur additional cost, cost that will be treated as unregulated income to the pipeline owner. Such a situation would be unsatisfactory to a shipper, and would result in over-recovery.

55 Full Haul is defined in the PRAA as Gas transportation in the DBNGP where the Deliver Point is downstream of CS9 regardless of the location of the Receipt Point, but does not include Back Haul.

56 Part Haul is defined in the PRAA as a Gas transportation service in the DBNGP where the Deliver Point is upstream of CS9 on the DBNGP regardless of the location of the Receipt Point, but does not include Back Haul.

We note that the pipeline's load factor is projected to be around 95 percent by 2010, down very slightly from approximately 96 percent in 2005. The slight load factor decrease not withstanding, the projected load factor level and trend show that the pipeline is not expecting a major "step" change in congestion or manageability over the period, relative to present conditions. We note also that the Operator has provided no information to suggest that it is facing materially increased congestion, load-management or operational risk-related costs or that it is particularly concerned about any other factors that would impair its ability to continue offering the T1 service currently offered to shippers.

## 4.9. Cost Allocation

Paragraph 6.2 of the Operator's Submission #4, states that the costs of delivering the Reference Service during the AA Period have been determined by subtracting the costs of providing Part Haul services from the Total Revenue.[57] We are unable to derive the relevant elements in the PRAA, to determine the reasonableness or otherwise of the Operator's proposal. The explanation in Submission #4 indicates that costs have been allocated between Part and Full Haul services but provides no information on how this allocation has been implemented. Consequently, it is unclear whether the attributable costs of Full and Part Haul services have been identified and whether the common costs have been properly allocated.

Accordingly, additional information is required to indicate whether the cost allocation method is based on zones, distance or some other methodology, and to detail the forecasts that have been used. Without additional information, it is not possible to determine whether the methodology used to allocate common costs between Full Haul and Part Haul services is reasonable.

## 4.10. Summary

A number of deficiencies exist in the information provided in the PRAA and corresponding PRAA Information. It is important that these information gaps be reviewed as they have potentially significant (individually and cumulatively) impact on the revenues deemed appropriate.

57 DBNGP, Submission #4, *op.cit.*

# APPENDIX A: MODEL BACKGROUND

## A.1 OVERVIEW

CRA analysed WPC's cost to generate electricity using gas and other fuels. The analysis was undertaken to enable a general quantification of the implications for shippers such as WPC and, more importantly, to assess the potential revenue implications for the Operator, of the difference between the T1 and Tf services.

The modelling work undertaken by CRA is similar in nature to that which was performed by WPC in previous (2003) submissions to OffGAR. The main difference is that of focus and emphasis. We analyse links between the choice of reference service and the ability of the Operator to extract revenues from penalty provisions and monopoly rent from future negotiations of variations to the Tf service that shippers, such as WPC, would likely require.

Efficiently incurred penalties – that is, penalties that are incurred by the shipper to avoid greater costs – should also be efficiently *imposed* penalties. That is, the penalties imposed should reflect costs to the pipeline. A penalty that is charged to a shipper without an equivalent cost imposed on the pipeline is a source of supplemental income to the pipeline. As shown below, penalty revenue can be a significant source of revenue to the Operator under the proposed Tf reference service.

## A.2 BACKGROUND ON THE MODEL DESIGN

In this section we describe CRA's model of that part of WPC's electricity generation requirements that affect WPC's preferences for gas shipped through the DBNGP. CRA's model was originally developed to analyse the impact of uncertain wind generation outcomes on WPC's dispatch of distillate-fired stations and has been modified to enable analysis of WPC's gas procurement and deliverability preferences.

### A.2.1 Impact on Oil/Distillate-Fired Peaking Capacity

[redacted]

[redacted]

[redacted]

### A.2.2 The Model

Wind cannot be predicted with great accuracy over any short interval, though there is some utility in predictions over longer time frames. Wind's uncertainty translates into more or less wind generation than expected, implying that more or less generation must be "made up" from other sources. [redacted]

A model able to provide useful insights into the interactions between varying wind outcomes and distillate unit dispatch requirements can be easily modified to examine the impact on distillate dispatch of having flexible access to gas capacity. That is, at any given time, load can be higher or lower than expected, supporting more or less preferred gas usage relative to the expected gas requirement for a particular "type" of day. As a result, WPC, having contracted for, or nominated, a particular level of gas supply, would be in a position to choose whether or not to incur penalties to vary the amount of gas it takes.

The model essentially works through this decision from a starting assumption of the amount of gas required for a particular day, a contracted level of capacity and an actual "outturn". The difference between the actual outturn and the contracted level of capacity drive the gas usage requirements. The model then uses the gas it deems necessary to meet WPC's generation requirements at least cost, incurring whatever peaking penalties result.[58]

58 [redacted]

The basis for this approach is found in the fact that the dispatch costs of WPC's distillate-fired peaking capacity generally exceed the peaking penalties such that the decision to incur penalties would almost always result in lower costs to WPC.

### A.2.3 Aggregation of Actual Demand Data: Day Types

The demand input for the CRA model, which is used to estimate various costs associated with the T1 and Tf contracts, is a complete record of half hourly demand data from WA for all of 2003. All of the modelling results reflect what would have happened had the Tf contract been introduced in 2003. The model was constructed in this way simply because only 2003 demand data and system information was available to be processed in the time available for this exercise.[59]

The demand data is then transformed into six representative day types, according to the time of the year and the day of the week. These categories are: hot working; hot non-working; mild working; mild non-working; cold working; and cold non-working. These day types are then grouped into seasons, with hot and mild days being categorised into the "summer" season and cold days being categorised into the "winter" season. Such seasonal categories are relevant to the analysis of the T1 service because the T1 service allows two different seasonal contracted quantities, summer [redacted] and winter [redacted].

Although transforming a year of data into a set of six day types decreases the precision of the model results, it does not compromise the directional accuracy or significance of the results given the nature of the question being considered. For reasons discussed in some detail below, categorising and averaging the annual demand data into six day types has the effect of reducing variability of electricity generation requirements, resulting in more predictable gas requirements. Much of the costs associated with the proposed Tf service would arise as WPC deals with unexpected outcomes, creating pressure for much more or less gas being required than the model would typically show, and hence there is considerable conservatism in the modelled results.

### A.2.4 Generation Facilities

In addition to the demand data, the model also contains plant data for every plant in the SWIS, including heat rate, marginal costs, capacity, fuel type, and the number of units.

59 WPC's modelling supplement (referred to at the beginning of this appendix) covers the years 2003 to 2006. In this modelling supplement, the results for each year after 2003 show a significant increase in Firm Service penalties. Therefore, it is reasonable to assume that the estimates discussed in this section provide a minimum estimate, and that any results found in the CRA model would increase significantly were they extended to later years.

Using the plant input data the model creates a stack ("merit order"), which is based on the variable cost of each plant. Each plant is derated by an amount necessary to allow for annual average levels of planned and unplanned outages. In other words, the available capacity of each plant is decreased by 10%-15%.[60]

This approach produces reasonable annual generation results for each plant, though it means that at any given instant the available capacity could be more or less than would otherwise be expected given that entire units are taken out of service for maintenance during defined periods and can become unavailable for periods of time due to failure.

We then use the generation bid stack to determine which plants must run to meet load during each day type. The model then calculates the total load that would be met by WPC's gas plants that would obtain their gas from the DBNGP. These plants include Mungarra, Kwinana, Pinjar, and Cockburn. Some plants, such as Cockburn are used in more-or-less baseload mode, meaning they are required to run essentially continuously to meet daily generation requirements. Other plants are run in mid-merit and others are used less frequently to meet peak loads. Loads vary for many reasons, including time of day, type of day and season. Using heat rate data for each of the units in these plants to convert from MWh of demand to TJ of gas consumed, the model then calculates the amount of gas used, by plant, for each half hour.

Peaking penalties are driven by two factors:

- The actual load shape which will generally require some peaking capacity to be utilised; and
- The impact of shocks, suprises and random effects outside of WPC's control, such as temperature spikes, unusual economic activity, or outages at other generation stations.

As a result of each of these factors, gas requirements vary, and WPC's preferred gas quantity can exceed its generally contracted levels.

60 This is a common approach. Two points should be noted: the approach implies that in the modelled results 100% of installed capacity is never available (which tends to *increase* the need for peaking plant to run), but it also means that 85-90% of each type of plant is always available, which reduces the need for peaking plant to run given that in "real life" plants can fail or be taken out of service for extended periods for maintenance We have no reason to believe that this simplification introduces any material bias to the results, either up or down.

The model reflects these effects using load shapes for each day type and then introducing random variation in demand within each day type to capture the impact of such variation on WPC's gas procurement preferences. Put differently, events occur that cause preferred gas use "on the day" to be different from "expected" gas use. Gas usage variation gives rise to exposure to various penalties, such as the peaking and overrun penalties. The degree of variation in demand introduced is based on the range of variation that WPC experiences, on average.

### A.2.5 Building the day types into a year

Each of the 365 days was allocated into one of the six types according to season, the state holiday schedule in WA, and the average annual frequency of each day type. The results are presented in Table 8.

**Table 8: Parameters for Day Type Categories**

| | Months included | Number of days in the year |
|---|---|---|
| Hot working day | December, January, February, March | 90 |
| Hot non-working day | | 37 |
| Mild working day | April, May, October, November | 85 |
| Mild non-working day | | 34 |
| Cold working day | June, July, August, September | 85 |
| Cold non-working day | | 34 |

### A.2.6 Modelling Gas Usage

Electricity systems are dispatched continuously to ensure that supply matches demand at all times. Failure to achieve a precise matching of supply and demand can cause system instability, blackouts and equipment failure. Gas networks operate to different tolerances as a result of linepack—the ability to store gas within the pipeline by varying the pipeline pressure—and because injections typically occur quite some time ahead of extractions. In a gas network, unlike instantaneous processes in an electricity network, events happen with some delay and with some tolerance for temporary imbalances.

As a result, the modelling of a gas contract is somewhat different from the modelling of an electricity network. If an electricity generator needs slightly more or slightly less gas in any given hour it is usually not a big problem. Over the course of the day and over longer periods of time, gas injections and extractions must balance. Thus, in modelling the gas supply, one category of penalties penalties have to do with imbalances over longer periods of time. For example a daily balancing or overrun limit would tend to be at risk of being violated only during the last few hours of the day even though the hours of unexpected higher gas use may have occurred much earlier. The decision to either incur a penalty, or to manage gas requirements, depends on what plant is expected to be available (and what is then actually available) during the relevant timeframes.[61]

Peak demand for gas on an hourly rather than a daily basis is the most amenable to modelling as it can be defined over time quite simply, by analysing the maximum demand for gas generation during each day. Other penalties require tracking of daily or other time-oriented gas balances. Seasonal and annual limits are somewhat more difficult to model because there are many decisions that could be taken over longer periods of time and these decisions can have significant impacts on gas needs. The model used does not optimise gas usage over longer time frames. The incremental benefit of using an optimisation model in this situation, however, is fairly limited given that the main points can all be clearly highlighted using a simpler framework, particularly one in which the majority of simplifications introduce conservatism that add robustness to the results obtained.

### A.2.7 Conservatism

It is worth noting that, having focussed on peaking penalties as a source of potential revenue to the Operator, we have not included an analysis of overrun and imbalance penalties. In part this is because peaking penalties are the most financially significant of the penalty provisions. There is also a need for a somewhat different modelling approach when evaluating overrun and imbalance penalties. Several different levels of nomination error, which are penalized only under the Tf contract, are modelled at the end of this appendix as well.

Other sources of conservatism include:

- Using six day type groupings means that the average gas use between a summer (hot) day, winter (cold) day and a spring or autumn (mild) day, was preserved. However, within each day type, the estimated average half hourly gas consumption within each group will be less ‘peaky’ than a more granular model. Being less peaky, the model will tend to *underestimate* the ‘peakiness’ of the most extreme days of each day type, the days that can attract the highest penalties;

61 Once again this discussion focuses on economic issues only, and ignores curtailment risk (i.e. the risk of being curtailed for breach of peaking etc limits) and the fact that for non-economic reasons [redacted] a shipper, [redacted] may not wish to deliberately breach its contract even if that is the lowest-cost option.

- Because each plant was derated using the method outlined above, there are no days where one of the large baseload units is unavailable. In such a situation, the mid merit gas plants (sourcing gas from the pipeline) would be used to meet the extra demand. Such baseload outages increase the amount of gas used during the course of a day, and therefore would likely cause significant peaking and overrun charges as well[62];

- Under the proposed Tf service, penalties are calculated for each specific outlet point on the pipeline, whereas the model calculates all penalties on an aggregate, total pipeline basis. Aggregating penalties has the effect of reducing total penalty costs, as described below. When peaking penalties, for example, are calculated by outlet point rather than over the entire WPC gas requirement, the peaking penalties can be greater because some plants (specifically Pinjar) are crucial peaking plants because of their locations in the gas and electricity networks. Pinjar's operation can swing substantially. When Pinjar is grouped with all the other plants, however, the total WPC gas use provides a wider peaking margin for Pinjar, and therefore reduces the magnitude of its peaking penalties captured in this model; and

- The T1 contract allows for two contracted capacities—one for the Summer and one for the Winter. Historically, we understand the difference has been of the order of 27 TJ/day. In contrast, the proposed Tf service is based on a single, year-round contracted capacity figure. Except for the T1 service in the winter period, a contracted capacity of 108.5 TJ/day has been used in the model.

### A.2.8 Calibration

To confirm the accuracy of the modelled results, we compared the annual quantity of gas subject to peaking penalties in the CRA model to that of the WPC model, which was presented in WPC's September 2003 submission to OffGar (as noted at the beginning of this appendix). The comparisons are presented in Table 9.

62 WPC's 24 September 2003 Modelling Supplement illustrates some potential impacts of the more extreme days.

**Table 9: Comparison of the CRA and WPC Models in Terms of Estimated Gas Quantities that Trigger Peaking Penalties**

| | [redacted] | [redacted] | [redacted] | [redacted] |
|---|---|---|---|---|
| [redacted] | [redacted] | [redacted] | [redacted] | [redacted] |
| [redacted] | | | | |

The amount of gas subject to peaking penalties in the CRA model is very close to that used in the WPC model. If anything the CRA modelled figure is low, in line with the conservative nature of the model set-up and modelling approach.

## A.3 PENALTIES

Several parameters determine the magnitude of penalties under the Tf service.

- Contracted capacity: WPC reserves capacity to have a certain quantity of gas delivered each day to each outlet point. This quantity must be the same for every day of the year.

- Nomination: In the afternoon before each gas day, WPC predicts the level of gas it will put in at each inlet point, and take out at each outlet point. This estimate can vary from day to day depending on several factors, including the weather forecast and planned plant outages.

- Variance Notice: Under the Tf service, unlike the T1 service, the pipeline has the ability in certain circumstances to issue a variance notice. This notice determines whether or not there will be a nomination penalty. There is nothing in the contract that specifies how often the pipeline is allowed to issue these notices or how long they are allowed to keep them in effect

- Unavailability Notice: The pipeline has the ability in certain circumstances to issue an unavailability notice. This notice significantly affects the size of the overrun penalty.

63 [redacted]

### A.3.1 Peaking Penalties

Because electricity consumption varies throughout each day and season, gas consumption varies as well. Peak consumption of gas can be greater than contracted capacity, triggering the peaking penalties.

Under the proposed Tf service, peaking penalties are 350% of T1 tariff per GJ ($1.09), and apply when the gas used in an hour is more than 120% of the average hourly total contracted capacity within each zone. Average hourly total contracted capacity is defined as total contracted capacity divided by 24.

Peaking penalties are amongst the most significant financial penalties facing shippers such as WPC.

### A.3.2 Nomination Penalties

Due to events beyond WPC's control, such as weather forecast error, other causes of demand variations and unexpected plant outages, WPC frequently uses an amount of gas significantly different from that which it nominated the day before.

Under the proposed Tf service, nomination penalties are 350% of the relevant reference tariff per GJ ($1.09), but nomination penalties only apply when a Variance Notice has been in effect for at least 21 days.[64]

The penalties are incurred when WPC uses an amount of gas that varies by more than 10% from the nominated amount for each inlet point and each outlet point. Penalties are payable for both positive and negative nomination errors.

Nomination penalties apply per outlet point, rather than on aggregate gas use basis. This significantly increases the magnitude of the penalties. For example, if Kwinana (at one outlet point) tripped, and the load was picked up by Pinjar (at a different outlet point), WPC would send the gas nominated for Kwinana to Pinjar. In this situation, even though WPC's total gas usage matched their total nomination, WPC would be liable to pay a penalty for the resulting under nomination at Kwinana and over nomination at Pinjar.

Generally, because it is difficult to forecast how frequently nomination error penalties might be incurred, they have been treated illustratively in the analysis performed.

64 The nomination penalty is $3.82 per GJ.

### A.3.3 Imbalance Penalties

Imbalance penalties are associated with the difference between the amount of gas WPC puts into the pipeline at its inlet points and the amount of gas WPC takes out of the pipeline at its outlet points. This can happen as a result of several factors, including unplanned plant outages and weather forecast error.

Trading between shippers in order to alleviate individual imbalances is allowed under the proposed Tf service. For example, if shipper A has a +9 TJ imbalance and shipper B has a –7 TJ imbalance, they are able to trade so that they only pay imbalance penalties of +1 TJ each.

Imbalance penalties are 350% of T1 tariff per GJ ($1.09), and are calculated on a daily (rather than rolling or accumulated) basis.

Penalties are incurred when WPC's imbalance is 8% greater or less than its daily contracted capacity.

Imbalance penalties cannot be modelled easily without a model that incorporates all shipper requirements. We have not modelled imbalance penalties.

### A.3.4 Overrun Penalties

Overrun penalties are incurred when WPC uses more gas in a given day than it has available based on its contracted capacity.

Overrun is calculated on a daily (rather than rolling or accumulated) basis. It is also calculated across three separate zones (across all delivery points for T1 service). The size of the overrun penalty depends on whether or not there is an unavailability notice in effect. If there is an unavailability notice in effect, penalties can be $15/GJ. If there is no unavailability notice in effect, the overrun penalties can be 110% of the spot price.

Overrun penalties have not been modelled. Provided that an unavailability notice would *not* be in effect most of the time, the omission is not significant, and is a conservative.

### A.3.5 Relative Magnitude of the Penalties

Under the T1 service in the 2004 Standard Shipper Contract, there are fewer penalties, the penalties in most cases do not apply automatically, there are a number of procedural requirements limiting the extent to which the Operator can seek penalties and their cost is lower. As a result, the revenues to the Operator under the T1 service are relatively clear.

Under the proposed Tf reference service there would be a nomination error penalty that applies if a variance notice has been issued. Under the T1 service, nomination error penalties do not exist. The same applies for out-of-specification gas charges, which do not exist under the T1 service but are part of the proposed Tf reference service.

Under the T1 service, the peaking limit is 120% in the summer and 125% in the winter, as opposed to the Tf peaking limit, which is 120% year round. Not only is there a larger winter margin under the T1 service (and an additional outer peaking limit of 140%), but the penalties are only 200% of the T1 tariff per GJ, rather than the significantly larger 350% of the T1 tariff per GJ penalty under the proposed Tfreference service. Also, there are a number of other procedural requirements limiting the extent to which the Operator can charge penalties for peaking under the T1 service.

An imbalance penalty does exist under the T1 service. Like the proposed Tf service, penalties begin when the imbalance is either more or less than 8% of the accumulated daily contracted capacity (although the T1 contract also provides for an outer imbalance limit of 20%). However, unlike under the proposed Tf service, T1 penalties are calculated on a much more forgiving, rolling, day-to-day basis. In addition to the more forgiving method of calculating imbalance penalties, the penalties themselves are 200% of the T1 tariff per GJ, rather than the significantly larger 350% of the T1 tariff per GJ under the proposed Tf service. Also there are a number of other procedural requirements limiting the extent to which the Operator can charge penalties for imbalances under the T1 service.

Under the T1 service, overrun calculations are summed over all the inlet and outlet points, and are therefore calculated on an accumulated, aggregate basis, based on WPC;s nominations for the day. This is a reasonably forgiving method of calculating overrun as it allows WPC to average overrun among plants.

Under the Tf service, on the other hand, overrun is calculated on a per-zone level based on the shippers contracted capacity. This limits the opportunity for WPC to average its overrun among plants, and is therefore a more rigorous way to calculate overrun.

The penalty incurred as a result of using overrun can take one of two forms under The penalty incurred as a result of using overrun can take one of two forms under both the proposed Tf and the currently provided T1 service. The cost of the basic overrun penalty is 115% of the T1 tariff per GJ, and is exactly the same under both the T1 and the Tf services. However, under an ‘unavailability notice’, the cost of the penalty under the T1 contract goes to 250% of the T1 tariff per GJ, while under an ‘unavailability notice’, the Tf penalty increases more than ten fold to $15/GJ.

## A.4 Summary of Results

Our analysis focussed on peaking and nomination error-related penalties as these were amenable to the modelling approach adopted and the time available.[65] Though discussed above, overrun and imbalance penalties were not calculated. A tariff of $1.09/GJ is used in the penalty calculations for both the proposed Tf reference service and the T1 service.

In order to calculate the annual cost of the penalties, several assumptions must be made, including the frequency with which a variance notice is in effect. The most conservative assumption is, of course, to assume such notices are never in effect, in such case peaking penalties would be the only penalties incurred in the modelled world.

To provide some indication of the bounded impacts of these notices, we analysed different scenarios involving a range of probabilities that such notices were in effect, ranging from 0 percent to 30 percent of the time. It is possible not all penalties would be charged at all times, but differences between the penalty levels for the two services is a measure of both financial risk to a shipper such as WPC.

To provide some indication of the bounded impacts of these notices, we analysed different scenarios involving a range of probabilities that such notices were in effect, ranging from 0 percent to 30 percent of the year. A detailed account of the results is presented in Table 10. A summarized version of the results is presented in Table 11.

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65 Complex modelling of the gas delivery system as opposed to the relevant parts of the WPC electricity generation system would create additional layers of complexity, but would only reinforce, not alter, the principal conclusions.

**Table 10 : Illustrative Results Across Day Types and Penalty Scenarios (part 1)**

| SMALL ERRORS | Tf Service Penalties (Type and $/Year) | | T1 Service Penalties (Type and $/Year) | |
|---|---|---|---|---|
| **Variance Notice in effect 0% of year** | Nomination Error: variance notice | - | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$11,252,139** | | $5,561,531 |
| **Variance Notice in effect 10% of year** | Nomination Error: variance notice | $557,421 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$11,809,560** | | $5,561,531 |
| **Variance Notice in effect 30% of year** | Nomination Error: variance notice | $1,672,262 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$12,924,401** | | $5,561,531 |

The above outcomes reflect the following nomination error bands for the six day types:

| | Small Under | Large Under | Small Over | Large Over |
|---|---|---|---|---|
| All day types | -5% | -10% | 5% | 10% |

Part 2

| MEDIUM ERRORS | Tf Service Penalties (Type and $/Year) | | T1 Service Penalties (Type and $/Year) | |
|---|---|---|---|---|
| **Variance Notice in effect 0% of year** | Nomination Error: variance notice | - | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$11,252,139** | | $5,561,531 |
| **Variance Notice in effect 10% of year** | Nomination Error: variance notice | $1,393,552 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$12,645,691** | | $5,561,531 |
| **Variance Notice in effect 30% of year** | Nomination Error: variance notice | $4,180,655 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$15,432,794** | | $5,561,531 |

The above outcomes reflect the following nomination error bands for the 6 day types:

| | Small Under | Large Under | Small Over | Large Over |
|---|---|---|---|---|
| All day types | -10% | -15% | 10% | 15% |

Part 3

| LARGER ERRORS | Tf Service Penalties (Type and $/Year) | | T1 Service Penalties (Type and $/Year) | |
|---|---|---|---|---|
| **Variance Notice in effect 0% of year** | Nomination Error: variance notice | - | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$11,252,139** | | $5,561,531 |
| **Variance Notice in effect 10% of year** | Nomination Error: variance notice | $2,787,103 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$14,039,242** | | $5,561,531 |
| **Variance Notice in effect 30% of year** | Nomination Error: variance notice | $8,361,310 | - | - |
| | Nomination Error: no variance notice | - | - | - |
| | Peaking | $11,252,139 | Peaking | $5,561,531 |
| **TOTAL** | | **$19,913,449** | | $5,561,531 |

The above outcomes reflect the following nomination error bands for the six day types:

| | Small Under | Large Under | Small Over | Large Over |
|---|---|---|---|---|
| All day types | -20% | -30% | 20% | 30% |

The results in Table 10 are then summarised in Table 11, which is also reproduced in the main body of the report.

**Table 11: Estimated Annual Peaking and Nomination Error Penalty Payments to the Operator by WPC Under the Proposed Tf Service as Compared to the T1 Service.**

| Percent of time Unavailability and Variance Notices are in Effect | Supply- or Demand-Side Shock Affecting Preferred Gas Usage by (X%) Scenario (in millions of dollars per year) | | |
|---|---|---|---|
| | Low (5-10%) | Medium (10-15%) | High (20-30%) |
| 0% | $5.69 | $5.69 | $5.69 |
| 10% | $6.25 | $7.08 | $8.48 |
| 30% | $7.36 | $9.87 | $14.35 |

Estimated using simple dispatch model of relevant parts of the WPC electricity generation system.
Based on $1.09/GJ for all gas under both the proposed Tf and the T1 services.
Contracted Tf capacity is assumed to be 108.5 TJ/day and contracted T1 capacity is 108.5 TJ/day in summer and 81.5 TJ/day in winter.

We estimate additional revenue to the Operator of potentially $9 million (range $5.69 to $14.35 million) per annum were WPC to incur penalties in lieu of other strategies such as running its oil or distillate power stations or, as a last resort, shedding load.

To manage these penalty-related costs or avoid them, a shipper, such as WPC, facing the proposed Tf reference service would need either to negotiate with the Operator to secure additional flexibility, or it would choose to incur substantial penalties – an economically efficient strategy so long as it can manage the risk of gas supply curtailment by the Operator (an option that is available more flexibly to the Operator under the terms of the proposed Tf service).[66]

66 Proposed Access Arrangement: Annexure A – Access Contract Terms and Conditions, 21 January 2005 – Clause 14.1

# Appendix 3: Venture Associates' Report

**V**enture **A**ssociates

Commercial and Strategic Advisers

# Review of 2005 Proposed Revised Access Arrangement for DBNGP and Schedule 9 of the Standard Shipper Contract

21 April 2005

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## Contents

# 1. BACKGROUND

On 21 January 2005, DBNGP (WA) Transmission Pty Limited ("**the Operator**") lodged with the Economic Regulation Authority ("**Regulator**") Proposed Revisions to the Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline (**"DBNGP"**) ("**PRAA**"). Subsequently, the Regulator issued an Issues paper and called for public submissions on the PRAA.

This report has been prepared for Western Power Corporation ("**Western Power**") to analyse the PRAA and identify matters which should form part of their submissions.

## 1.1 Contractual Arrangements – October 2004

In October 2004 Western Power concluded negotiations with the Duet Alcoa Alinta Consortium ("**DAA**") and finalised new contractual arrangements for gas transportation through the DBNGP for a term of 15 years (with options to extend). These contractual arrangements were based upon a standard form shipper contract ("**SSC**") and were summarised in section 10.2.7 of the Duet Product Disclosure Statement ("**Duet PDS**") dated 19 November 2004. Both the SSC and Duet PDS are public documents.

As set out in the Duet PDS, the seven significant shippers all entered into new contracts for the provision of T1 service (being a service for full-haul capacity in the DBNGP with 98% reliability). Common terms included:

- A 15 year term (with two 5 year options);
- A CPI linked tariff to 2016 and the Reference Tariff for a full haul T1-Equivalent Reference Service from 2016 onwards;
- A mechanism to access additional T1 capacity through expansion (given the DBNGP is fully contracted for T1 Service); and
- Certain relinquishment rights

[redacted]

In addition, [redacted] a new Tx service was also contracted for Western Power, with a 90% reliability [redacted]

## 1.2 Regulatory Expectations

Throughout negotiations Western Power was led to believe that the PRAA would be based upon a T1 Reference Service. This was based upon a number of factors:

- Western Power's opposition to the Firm Service in the 2003 Access Arrangement and subsequent actions by Western Power before the Gas Review Board;
- The establishment of the SSC and non discriminatory terms for T1 service which was contracted for by all significant users;
- The mechanism for new capacity to be granted as T1 Service pursuant to Clause 16 in the [redacted] SSC;
- [redacted]
- [redacted]

## 1.3 Approach taken by the Operator

[redacted] when the PRAA was lodged in late January, Western Power became aware that instead of a T1 Reference Service, the Operator was proposing a new Tf service as the Reference Service. The contractual terms of the Tf service were similar to the Firm Service in the prior access period with similar attendant concerns for Western Power.

# 2. NATURE AND SCOPE OF REPORT

Venture Associates Pty Limited ("**Venture Associates**") has been requested by Western Power to review the PRAA and related Access Arrangement Information with respect to the following benchmarks:

- in comparison to the form of Access Arrangement and expected Tariff Path projected in Schedule 9 to the SSC;
- the current Access Arrangement as approved on 30 December 2003 ("**2003 AA**");
- in respect of compliance with the Natural Gas Pipelines Access Code (**"the Code"**); and
- Generally accepted good gas transmission pipeline operating and commercial practice.

## 2.1 Nature and Purpose of the Report

Venture Associates is a specialist commercial adviser in the energy sector and has acted as a strategic and commercial adviser to Western Power over the last 18 months in connection with various negotiations for transportation services on the DBNGP. In particular, Venture Associates provided advice throughout the negotiations with the new owners of the DBNGP and with regard to the new transportation contractual arrangements and specifically Clause 20.5 and Schedule 9 of the SSC.

This analysis has been performed on a commercial rather than legal basis. Legal arguments about the compliance of the PRAA documentation with the Code are beyond the scope of this report.

In addition, this report should be read in conjunction with the contemporaneous report by Charles River & Associates International (**"CRAI"**) commenting upon the consistency of the PRAA with good regulatory practice and in particular other approved access arrangements under the Code.

## 2.2 Sources of Information

The following public information was utilised in the preparation of the report:

- The PRAA and related Access Arrangement Information;
- Submission 4 ( Public Version) by the Operator;
- The 2003 AA and related supporting documents, submissions and regulatory decisions;
- The SSC including in particular Schedule 9 and excel model prepared by Venture Associates replicating Schedule 9 calculations; and
- The DUET PDS.

## 2.3 Limitations and Reliance on Information

The analysis and conclusions in this report are preliminary only. In working through the disclosed detail in respect of the PRAA Reference Tariff, it is clear that there is insufficient information regarding the cost of service calculations to form a definitive view as to the reasonableness of all tariff inputs and calculations. This has been acknowledged by the Regulator in its determination of 14 March 2005 that the PRAA Access Arrangement Information was not compliant with the requirements of the Code.

Accordingly, within this report, it has been necessary to make inferences and deductions based upon the insufficient information available and therefore such inferences and deductions may be inaccurate. Where these inferences and deductions have been made and possible conclusions drawn, the relevant text has been highlighted.

Venture Associates has taken the view that it is better to identify possible deficiencies at this stage, while acknowledging that it may be necessary to revise such observations at a later date when more information is available.

It is recommended that the Western Power submission to the Regulator draw attention to these observations and the basis upon which they have been made.

# 3. REFERENCE SERVICE : TF VS T1

## 3.1 Key Differences in Service Quality

### 3.1.1 Curtailment or Interruptibility

The key contractual term for all gas transportation services is interruptibility or curtailment priority. The curtailment plan for all shippers is set out in Schedule 8 of the SSC. Tf is an interruptible rather than a firm service.

**TABLE 1: SUMMARY OF RELIABILITY OF SERVICE AND CURTAILMENT PRIORITY**

| | T1 | Tx | Tf |
|---|---|---|---|
| Position in System Curtailment Plan SSC | 3 & 4[1] | [redacted] | Bottom of 5 |
| Permissible Curtailment Limit ("PCL") | 2% by time | 10% by volume | 1% by volume *[but see below – most curtailments do not count towards this 1% limit]* |
| Curtailments not counting towards PCL | SSC - Operator Force Majeure, Major Works, Shipper default; AND<br>Refusals to receive/deliver gas; AND<br>Curtailments under Multi-Shipper Agreement ("MSA") | [redacted]<br>[redacted]<br>[redacted] | Operator Force Majeure; AND<br>Shipper default; AND<br>Relocations; AND<br>Prior Contractual Rights (i.e. T1 and Tx contracts); AND<br>*[much more significant than all of the above]*<br>Circumstances Operator reasonably considers necessary |
| Curtailment Sequence | Third | [redacted] | First |

In summary, the Tf service is significantly inferior to both the T1 and Tx services given that:

(a) most curtailments do not count towards the PCL, making the service much less reliable than the 1% PCL suggests (indeed the 1% "PCL" is largely irrelevant – only imprudent curtailments will be counted towards this limit); and

(b) it is to be fully curtailed before any curtailment of T1 or Tx services (as both are prior contractual rights[2]).

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[1] This ranking reflects extreme circumstances the T1 service normally ranks first except where there is a priority reservation for the distribution system, and Alcoa has certain priority rights under its exempt contract.

In addition, the terms dealing with curtailment do not allow for a rebate of the reservation charge where curtailment or interruption is "permissible" unlike refunds of reservation charges under the SSC in the same circumstances (clause 17.4 of the SSC)

As Tf is to be curtailed before T1 or Tx (clause 14.1(b)(ii) of Annexure A to the PRAA), it will rank ahead in priority only against [redacted] Spot Capacity, which are both also interruptible services. Given "*Tx is a firm service with a 10% (by volume) permissible curtailment limit (Duet PDS 10.2.7 iii)"* and the fact that Tf ranks below contracted Tx because it is a "prior contract", Tf must be regarded as a less than 90% by volume reliable service and the stated contractual permissible limit of 1% gives a misleading impression of reliability.

### 3.1.2 Other Service Characteristics

Notwithstanding its low reliability, the Tf service has significant other deficiencies in comparison to the SSC (and therefore the terms of the T1 and Tx services). From Western Power's perspective, additional cost would be incurred through penalties or purchasing of additional services for:

- Peaking (120% limit in Tf service compared to 120% (Summer)/125% (Winter) and an outer limit of 140% for T1 in the SSC, while under the Tf service penalties may be incurred without notice);
- Imbalances (Penalties may apply in excess of 8% of MDQ for Tf service in contrast to 20% of MDQ for T1 in SSC); and
- Overrun (Charge for Tf linked to 110% of Spot Price compared to 100% for T1 under SSC)

Furthermore, the tariff structure proposed requires a 90% take or pay through a 90%/10% split of reservation and commodity charges compared to an 80%/20% split in the SSC (ie higher take or pay for a much less reliable service).

### 3.1.3 What is underlying purpose of Tf Service

Western Power had not heard of a Tf service until the PRAA was submitted to the Regulator. [redacted]

The Tf service, like the Firm Service upon which it is apparently based, appears to be an artificial construction for regulatory purposes only. [redacted] A number of distorted outcomes are potentially possible which may increase the "Firm Service Reference Tariff" to apply to all SSC based contracts from 2016:

[2] Note that prior contract is not a defined term and is therefore taken to mean contracts executed before the Tf contract (i.e. all existing contracts)

- There may never be a T1 Reference Service, in which case a Firm Service Reference Tariff could be constructed for a firmer service (say 1.5% Permissible Curtailment limit) and at a higher tariff than Tf;
- Being driven by commercial considerations (take or pay inherent in Tf service, its interruptibility and narrow service parameters) to contracting for Spot Capacity or other Non Reference Services which would provide unregulated revenue to the Operator;
- Cost allocation between reference services could distort towards a higher T1 Reference Service; and
- The precedents set by OffGAR in that the users of a T1 service should pay a premium to the Firm Service, may be used to further justify a higher T1 Reference Tariff compared to the Tf baseline.

[redacted]

### 3.1.4 Commercial Merits of Tf as an Interruptible Service

As an interruptible service, the requirement of reservation charge commitments without any meaningful contractual restraint on interruption makes the service uncommercial. At the very least amendments need to be made to Clause 14 of the Tf Terms and Conditions to provide some certainty. Commercially a T1 service at the same tariff would be a superior service. Alternatively, all shippers have the ability to bid into the spot market for an interruptible service. This is clearly the preference for the Operator, since Tf capacity would reduce available spot capacity and revenue from sale of spot revenue appears to be unregulated and unrebateable.

The importance of spot revenue is highlighted in the Duet PDS which states DBNGP Distribution and Transmission Revenue forecasts for year to 30 June 2005 are based upon *"an average of 26TJ/d of Spot Gas …sold into the Spot Gas Market at an average price of $2.09/GJ*", which implies some $20m per annum of spot market revenue is expected. This revenue is unregulated, providing excess economic profit over cost of service which is fully recovered by the Operator through the Tf Reference Tariff. The Operator has forecast no sales of the Tf service, whereas spare interruptible capacity is clearly expected to be sold, but into the Spot Market outside of the total regulated revenue threshold. This is clearly contrary to the interest of users and the objectives of the Code.

### 3.1.5 Should there be a firm Reference Service

Venture Associates strongly believes that there should be a firm reference service available for users. It would be inappropriate not to provide a firm reference service when:

- All existing contracted capacity on the DBNGP is on a firm[3] rather than interruptible basis and

- DBNGP's own projected expansions over next 5 years are for firm capacity (on a T1 service basis).

In addition it is natural for users to contract on a firm basis, given the sunk capital usually committed to the plant using the gas and through take or pay arrangements for gas supply. This is supported by a review of reference services on other pipelines where, without exception, each has a firm reference service (and only a firm reference service if only one reference service).

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**It is clear that the Tf service is commercially unattractive and inferior to the T1 service under the SSC. Venture Associates does not anticipate any Tf service being required by any existing or prospective user – interruptible capacity is more likely to be sought on a spot basis. For all of these reasons Western Power should submit to the Regulator that the T1 service under the SSC should also be a Reference Service.**

## 3.2 Capacity of Pipeline to Deliver Reference Service

### 3.2.1 Capacity Definitions

The capacity of a pipeline is defined by the ability of the pipeline system to transport the required quantity of gas from inlet of the pipeline to the outlets at the required pressure.

Pipeline capacity is not a fixed value. It varies with gas receipt pressure, ambient conditions, load profiles and hourly quantities at outlets and the availability of compression plant, and also with the terms and conditions of the haulage services.

The DBNGP operates with 10 compressor stations to deliver gas principally from the North West Shelf. The use of compressors to enhance the capacity of the pipeline introduces operational unreliability that does not exist in free-flow pipelines. This is because compressors are subject to both planned and unplanned maintenance, which will cause temporary reductions in capacity whilst the relevant compressor is being repaired. As a result, depending upon the operational status of all compressor stations, the capacity of the pipeline to deliver gas to the Perth area can vary.

In addition, because of the effects of temperature on the gas, capacity is generally lower in summer than winter.

[3] Duet PDS refers to Tx service as firm.

Maximum capacity requires all compressors to be operating. “Firm Capacity” can be set at any level at or below maximum capacity. The Firm Capacity level is set by the Pipeline Operator taking into account the terms and conditions of its various haulage services and reflects a balance between the level of operating risk that the Pipeline Operator is willing to accept and the Shippers’ tolerance for capacity interruption. For example, a fully interruptible service loads the Shipper with all of the compressor operational risk.

## 3.3 Current DBNGP Capacity

Historically the DBNGP has dealt with the issue of Firm Capacity by defining transportation services by reliability. Hence the T1 service has a deemed 98% reliability (2% PCL). T1 capacity is defined by the tranche methodology which determines the amount of capacity which can be delivered by the pipeline despite the occurrence the worst combination of two concurrent single-unit compressor outages (which is expected to happen no more than 2% of the time).

Based upon our knowledge of the DBNGP, we set out below an estimate of pipeline capacity in respect of each service.

**TABLE 2: ESTIMATED CURRENT AVERAGE FIRM CAPACITY FOR DBNGP**

| Service | Incremental Capacity | Cumulative Capacity |
|---|---|---|
| T1 | 519 TJ/d | 519TJ/d |
| [redacted] | [redacted] | [redacted] |
| Tf | 29 TJ/d | 605TJ/d[5] |

The above table reflects the different contractual rights to curtail without penalty and the relative priority with which the services are contractually curtailed. It shows that because Tf is more interruptible than T1 and Tx, the pipeline has spare Tf capacity available for sale even when, as now, it is fully contracted in T1 and Tx.

### 3.3.1 Capacity assumed in deriving the Tf Reference Tariff

The PRAA does not specify the assumed levels of capacity used in the derivation of the Tf Reference Tariff. *In this regard, further information should be provided by the Operator.*

[redacted] it would appear that the Operator has used T1 plus Tx capacity for the purposes of forecasting contracted reserved capacity and throughput and has not included any sales of capacity in the tranche of Tf (around 30TJ/d).

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4 [redacted]

5 Average Firm Capacity according the DBNGP is 605TJ/d, Maximum between 619TJ/d Summer and 666TJ/d Winter – available Tf capacity of 29TJ has therefore been derived from 605TJ total. Given the complexity of defining capacity on the DBNGP, it may be necessary for the Regulator to take expert advice on this matter.

Reference Tariff calculation in the PRAA uses average contracted capacity of 576TJ/d in 2005, which appears to be consistent with the above. Capacity above the contracted "T1 plus Tx capacity" is we assert to be sold as Spot Capacity (allocated through the Spot Market or under Tw or Ty Contracts). The PRAA is silent on the revenue generated from these transactions. Spot Capacity service revenue appears to be retained by the Operator rather than rebated in some way, the Operator hence has no incentive to constrain the available Spot Capacity through the sale of additional firm capacity, as a Tf or another similar service. At \$20m per annum[6] this is clearly a significant issue for users

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**In summary, in our view:**

- **There is uncontracted capacity which could be sold as Tf Service; but**
- **Tf Tariff calculations have ignored Tf capacity in excess of the "T1 plus Tx" capacity;**
- **Spare Tf capacity is presumed not to be contracted, but instead used by the spot market to generate unregulated revenue for the Operator.**

## 3.4 Tariff Implications of Difference between Services

It is Venture Associates view that Tf [redacted] mixes a T1 service type tariff with a higher take or pay, an inferior transportation service and inferior terms and conditions. We note the following in support of this argument:

- There do not appear to be any sales of Tf service forecast during the Access Arrangement Period;
- Western Power and Alinta are the only shippers to have contracted for other services as well as T1, namely Tx, Ty and Tw services which meet the specific business needs of Western Power and Alinta[7].
- All significant shippers have recently recontracted for a T1 service and have accepted that new capacity by expansion will also be contracted as a T1 service in the future (through the use of clause 16 of the SSC)[7];
- Other services are offered and sold by the Operator (Ty, Tw and Spot) which utilise capacity which could otherwise be sold as Tf; and

[6] See 3.1.4

[7] Based upon section 10.2.7 of the Duet PDS

- As an "Other Reserved Service" (for the purposes of the curtailment plan in the SSC and hence, we assume, in all other shippers' contracts) with an effective reliability of less than 90% and no peaking or relocation rights, Tf is commercially unattractive to Shippers compared to T1, Tx, Ty, Tw and Spot.

Venture Associates believes there is significant risk that the [redacted] Tf Service (as an inappropriate reference service and incorrectly priced) will impact the tariff paid by Western Power under clause 20.5 of the SSC from 2016 onwards.

The PRAA tariff appears to be based upon a tariff applicable to the T1 plus Tx capacity but providing a less firm Tf service. There is therefore a mismatch in that the Total Revenue Requirement includes the cost of providing all capacity in the DBNGP[8] but this is spread over Contracted Capacity only, not a realistic forecast of pipeline usage across all services. The mismatch appears even more starkly when one considers clause 7. of the PRAA which assumes that all capacity is contracted as Tf capacity, but does not use Tf-based throughput forecasts.

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**It appears that the Tf Reference Tariff has been calculated based upon available "T1 plus Tx" capacity rather than Tf capacity. As a result the calculated reference tariff is a T1/Tx Reference Tariff, not a Tf Reference Tariff.**

**This should be addressed by Western Power requesting the Regulator to amend the PRAA by either:**

- **amending the Reference Service from Tf to T1 (and consequent change of terms and conditions) and treating revenue from sales of spot capacity as rebateable revenue; or**

- **amending the projected pipeline contracted capacity and throughput to include forecast sales of firm and interruptible capacity in excess of the T1 plus Tx capacity (i.e. forecast sales of the Tf capacity under Tf or Spot contacts).**

**Venture Associates believes the first option is the most appropriate since Tf is not [redacted] appropriate Reference Service in accordance with the Code.**

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[8] It may be that fuel gas costs for throughput in excess of T1 plus Tx contracted capacity is excluded from non-capital costs. The current detail in the AA is insufficient to confirm this. However fuel gas costs are of the order of 10 cents per GJ compared to the minimum spot price in excess of $1.20 per GJ (115% of Base T1 Tariff).

# 4. COMPARISON OF KEY COMPONENTS OF TARIFF CALCULATION

[redacted]

Schedule 9 incorporates:

- The assumptions about market variables which DAA were using; and
- The methodology used to determine a T1 Reference Tariff.

As stated above, Schedule 9 is currently just over 4 months old [redacted]. In many parts Schedule 9 is totally consistent with the 2003 AA, which itself was formulated with the benefit of actual performance for at least the first 2 to 21/2 years of the 5 year Access Arrangement.

As set out below in detail the PRAA is significantly different from Schedule 9. In addition, in most cases where we comment, cost items in the PRAA are significantly greater than would have been expected, based upon the experience of Venture Associates.

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[redacted]

## 4.1 Brought Forward Capital Base at 1 January 2005

The Brought Forward capital base at 1 January 2005 in the PRAA is $1,643m, 5.5% higher than the Brought Forward Capital Base at the same date in Schedule 9 of $1,558m (both in Nominal $). The reasons for this increase are twofold, different inflation factors and different new facilities investment capitalisation over the prior years.

### 4.1.1 Inflation 2000 to 2005

The table below compares the annual inflation used in Schedule 9 to that proposed by the Operator in the 2005 PRAA.

**TABLE 3: COMPARISON OF ACTUAL CPI 2000 TO 2004**

| | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| PRAA | 5.80% | 3.12% | 3.03% | 2.37% | 2.55% |
| Schedule 9 SSC (Oct 2004) | 2.50% | 2.50% | 2.50% | 2.50% | 2.50% |

The escalation used in 2000 includes the once off increase in CPI due to the introduction of the GST. In common with normal commercial practice the element of this increase attributable to the introduction of GST should be removed by adjustment. The introduction of GST did not result in the costs borne by the service provider increasing, since GST paid may be reclaimed. Furthermore to include the GST effect would provide the Service Provider with a windfall uplift in capital base, contrary to the approach taken by the ACCC in enforcing contractual CPI escalation.

Not to adjust for the GST effect on CPI, as the Operator advocates, is inconsistent with the Regulator's previous decisions on this pipeline[9] and several regulatory decisions in other jurisdictions[10].

### 4.1.2 New Facilities Investment 2000 to 2004

The total new facilities investment in the period 2000 to 2004 proposed to be added to the capital base in the PRAA is $34m (Nominal $) compared to $11m in Schedule 9, as set out in the table below.

**TABLE 4: COMPARISON OF ACTUAL NEW FACILITIES INVESTMENT 2000 TO 2004**

| *$m Nominal* | 2000 | 2001 | 2002 | 2003 | 2004 |
|---|---|---|---|---|---|
| PRAA | 25.68 | 3.27 | 1.26 | 0.77 | 3.38 |
| Schedule 9 SSC (Oct 2004) | 4.37 | 3.27 | 1.26 | 0.77 | 1.48 |

The difference in 2004 may be defensible now that actual capital expenditure is known. However, the difference of $21m in capital expenditure in 2000 appears to be contrary to the Regulator's previous decisions. If this expenditure includes capital for Turbine and Compressor upgrades, this expenditure is being double counted having already been incorporated in the Initial Capital base by the Regulator (see paragraph 300 of OffGAR's Final Decision and paragraph 43 of the Further Final Decision).

[9] Final Decision dated 23 May 2003, p.122, paragraph 411

[10] See Final Decision on the GasNet Australia Principal Transmission System Access Arrangement Revisions, dated 13 November 2002 at page 193 paragraph 6.5.7, Final Decision on Envestra Limited's South Australian Natural Gas Distribution System Access Arrangement, dated 21 December 2001 at page 188 paragraph 10.7.6, Final Decision on the ActewAGL Natural Gas System in ACT, Queanbeyan and Yarrowlumla, dated April 2004 at page 106

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**In conclusion the Brought Forward Capital Base at 1 January 2005 should be adjusted downwards to reflect exclusion of GST effect from CPI and capitalisation of turbine and compressor upgrades in the Initial Capital Base.**

## 4.2 Future New Facilities Investment

The future new facilities investment forecast has changed markedly from the expansion program represented to Western Power by DAA during negotiations on the SSC and subsequently incorporated into Schedule 9, as set out below.

**TABLE 5: COMPARISON OF FORECAST NEW FACILITIES INVESTMENT 2005 TO 2010**

| *$m Nominal* | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | TOTAL |
|---|---|---|---|---|---|---|---|
| PRAA | 203 | 407 | 7 | 236 | 111 | 9 | 973 |
| Schedule 9 SSC (Oct 2004) | 65 | 316 | 295 | 59 | 80 | 47 | 863 |
| Capacity Added (TJ/d) | | | 116 | 89 | 18 | 35 | 258 |

The PRAA contains minimal information about the expansion program, the looping or compression assumed, the capacity added and unit costs incurred. Whilst it is recognised that bringing forward of required expansion is consistent with the PRAA capital expenditure forecast, it is impossible to form a view and comment on the efficiency of the expansion program and the appropriateness of the projected costs of expansion. *In this regard, further information should be provided by the Operator.*

### 4.2.1 Capital and Capacity

Schedule 9 was based upon the following capacity and capital expenditure assumptions:

**TABLE 6: NEW FACILITIES INVESTMENT SCHEDULE 9 - 2005 TO 2010**

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 |
|---|---|---|---|---|---|---|
| T1 Pipeline Capacity | | | | | | |
| Opening Pipeline Capacity | 514 | 514 | 514 | 630 | 719 | 737 |
| Additional Capacity | | | 116 | 89 | 18 | 35 |
| Closing Pipeline Capacity | 514 | 514 | 630 | 719 | 737 | 772 |
| | | | | | | |
| New Compressor Units | | | 7 | 0 | 0 | 0 |
| km of Looping | | | 247 | 299 | 57 | 101 |
| | | | | | | |
| Cost of Compressors ($m 2004) | | | 154 | 0 | 0 | 0 |
| Cost of Looping ($m 2004) | | | 186 | 234 | 43 | 76 |
| Total ($m 2004) | | | 340 | 234 | 43 | 76 |

Compressors were assumed in Schedule 9 to cost $22m in $2004 each and looping $752,000 in $2004 per km. This looping cost is equal to the assumed base cost in the tariff adjustment factor (Clause 20.8 of SSC) whereas the assumed cost for compressors for tariff adjustment under clause 20.8 is $18m ($2004).

The forecast new facilities investment in the PRAA is as follows:

**TABLE 7: NEW FACILITIES INVESTMENT IN THE PRAA 2005 – 2010**

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | Total |
|---|---|---|---|---|---|---|---|
| Contracted Capacity (TJ/day) | 576 | 616 | 715 | 771 | 789 | 826 | |
| Increase | | 40 | 99 | 56 | 17 | 38 | 250.5 |
| Capital Expenditure ($m Nominal) | | | | | | | |
| Pipeline | 88.9 | 275.2 | - | 226.8 | 101.3 | | 692.2 |
| Compression | 100.5 | 117.8 | | | | | 218.3 |
| Other | 13.2 | 14.0 | 7.3 | 9.0 | 10.1 | 9.3 | 62.8 |
| New Facilities Investment ($m Nominal) | 202.6 | 407.0 | 7.3 | 235.9 | 111.3 | 9.3 | 973.3 |
| Escalation Index | 1.026 | 1.052 | 1.078 | 1.106 | 1.134 | 1.163 | |
| Capital Expenditure ($m 2004) | | | | | | | |
| Pipeline | 86.7 | 261.7 | - | 205.1 | 89.3 | - | 642.8 |
| Compression | 98.0 | 112.0 | - | - | - | - | 210.0 |
| Other | 12.8 | 13.3 | 6.8 | 8.1 | 8.9 | 8.0 | 57.9 |
| New Facilities Investment ($m 2004) | 197.5 | 387.0 | 6.8 | 213.3 | 98.2 | 8.0 | 910.7 |

The forecast new facilities investment of $973m nominal through to 2010 is equivalent to $910m in 2004 (assuming annual CPI of 2.55%). It is impossible to confirm whether the PRAA is consistent with Schedule 9 of the SSC given the lack of detailed data on the expansions proposed in the PRAA. Further information is required from the Operator to confirm consistency of the PRAA with Schedule 9, assuming construction has been undertaken, on an accelerated basis, since DAA clearly believed in October, after significant due diligence, that $752,000 per km for looping and $18m per compressor (both in $2004) was a reasonable estimate of expected costs.

[redacted] It would be appropriate to ask DAA not only why the Capex forecasts have been so markedly revised in the last 4 months, but also, if there is any variance between Schedule 9 and the PRAA in terms of assumed compressor costs and assumed looping costs, why this change should be permitted from the position represented [redacted] by the Operator just a few months ago.

### 4.2.2 Specific Issues for Forecast New Facilities Investment

- [redacted] On this basis all expansions through to Quarter 4 2007 should be subject to contractual commitments at this time and no other expansions are practically feasible. It is unclear whether this is consistent with the new facilities investment schedule and forecast of reservation. _Further information should be provided by the Operator_;

- The DAA Acquisition model assumed capital expenditure of $39m ($2004) on compression and looping for a mainline south expansion, south of CS10. We assume the capital expenditure forecasts in DAA include similar amounts for the same project. This expansion does not add to the capacity of the pipeline to provide firm full haul service. It is an expansion for the benefit of Zone 10 shippers only. Accordingly, this capital should be rolled into the capital base on a zonal basis so that this expenditure is not funded by shippers who will not use the expanded capacity. **This is a further reason for zonal tariffs. Western Power should request the Regulator to separate out the Mainline South expansion expenditure and such expenditure should be recovered from Zone 10 shippers only (through surcharge or other mechanism).**

- The expansion plans are understood to incorporate seven new 10MW compressor units. The Schedule 9 costs assumed were $22m per compressor unit; total $154m, compared to the original estimate of $18m (in $2004). Independent review of the FEED study for the next expansion of the DBNGP confirmed these costs as reasonable. Furthermore, we understood that arrangements had been finalised with Solar Turbines for supply of these units within this budgeted amount. The forecast new facilities investment in compressors is $210m in $2004 including compression for mainline south expansion. **Western Power should request the Regulator to review the significant increase in compressor costs and reject any unreasonable or unsubstantiated increase over $22m.**

- At this stage there is no information about how many km of mainline looping is assumed and the unit cost used to project new facilities investment in looping. The assumed average cost of $752,000 per km for 30in looping was recognised by Western Power as unreasonably low when reviewed in October 2004. Estimates at that time were at $855,000 per km and since that date steel prices have continued to escalate. **Western Power should request the Regulator to identify the unit cost for 30in looping assumed and review against contracted pipeline purchases.**

- The PRAA is silent on how actual expenditure ex post is incorporated into future Access Arrangements. In effect, through Clause 20.8 of SSC, all existing T1 shippers are required to fund any overspending against budget costs up until 2016, subject to such overspending "being verified" by acceptance "by the Regulator as the amount by which the Capital Base of the DBNGP is increased" (Clause 20.8 (e) (i)). **Western Power should submit to the Regulator that the PRAA state the policy to be adopted and Regulator should confirm such policy as appropriate.**

- There is a concern generally that the sub-contracting of operatorship to Alinta Network Services (**"ANS"**) will lead to the DBNGP incurring another layer of costs (including administration of the contract with ANS and any margin earned by ANS) and this is particularly significant for capital works which will be managed by ANS. The Duet PDS states ANS will be paid a project management fee of 3% of the cost of capital works, without any indication of the value provided for such a fee, given costs and disbursements of ANS are also reimbursed. It is our assertion that these additional costs would not fall within the definition of allowable cost incurred under the section 8.16(a) of the Code. In particular, it is unclear to us how the subcontracting arrangement with ANS can be regarded as the "Service Provider acting efficiently, in accordance with good industry practice, and to achieve the lowest sustainable cost of delivering services". **Western Power should request the Regulator to identify any project management fees payable to ANS included in forecast new facilities investment and critically assess whether these are consistent with section 8.16(a) of the Code.**

### 4.2.3 Requirement of section 8.16 of the Code

We note that the Operator has made a confidential submission to the Regulator supporting their view that proposed New Facilities Investment during the PRAA period meets the requirements of section 8.16(a) and (b) of the Code.

Given the lack of disclosure of components of the forecast New Facilities Investment it is impossible to provide any detailed comments on the compliance of forecasts in the PRAA. However, we note the following:

- Throughout 2002 to 2004, the former owner, Epic Energy, had declined to expand capacity of the DBNGP on the basis that it was uneconomic,
- Replacement of 5 compressor units with larger units would appear to be a relatively expensive addition of incremental capacity; and
- Schedule 9 and DAA's capital expenditure tables demonstrate that the cost of service increases faster than capacity, indicating that the expansion program does not satisfy 8.16(b)(i) of the Code.

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**Without further information, Western Power can only request that the Regulator carefully examine the basis of any claim by the Operator that New Facilities Investment satisfies 8.16 (b) of the Code in the context of the higher Reference Tariff for all Users which appears to occur as a result of the proposed expansion programme.**

## 4.3 Non Capital Costs

Non Capital costs fall into two categories, broadly overheads, including wages and salaries and operations and maintenance which are in the short to medium term fixed, and fuel gas costs which are variable with throughput.

### 4.3.1 Non Capital Costs excluding Fuel Gas

The table below compares the Schedule 9 forecast of non-capital costs (excluding fuel gas) with the PRAA for the six years to 2010.

**TABLE 8: NON CAPITAL EXPENDITURE FORECASTS 2005 TO 2010 EXCLUDING FUEL GAS**

| *$m Nominal* | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | TOTAL |
|---|---|---|---|---|---|---|---|
| PRAA | | | | | | | |
| Wages & Salaries | 8.6 | 7.9 | 12.4 | 12.2 | 12.0 | 11.6 | 64.7 |
| Materials and Services | 34.8 | 34.8 | 44.0 | 42.7 | 41.5 | 43.8 | 241.6 |
| Corporate Overheads | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | 43.4 | 42.8 | 56.4 | 54.9 | 53.5 | 55.4 | 306.3 |
| Schedule 9 SSC (Oct 2004) | | | | | | | |
| Wages & Salaries | 4.8 | 4.9 | 5.0 | 5.1 | 5.3 | 5.4 | 30.5 |
| Operations & Maintenance | 6.1 | 6.3 | 6.5 | 6.6 | 6.8 | 7.0 | 39.3 |
| Overhead Services | 11.6 | 11.9 | 12.2 | 12.5 | 12.8 | 13.1 | 74.1 |
| Insurance | 4.3 | 4.4 | 4.5 | 4.6 | 4.7 | 4.8 | 27.3 |
| Opex from capex Program | - | - | 3.9 | 6.1 | 6.6 | 7.4 | 24.0 |
| OSA Fee | 2.1 | 2.2 | 2.3 | 2.5 | 2.5 | 2.6 | 14.2 |
| | 28.9 | 29.7 | 34.4 | 37.4 | 38.7 | 40.3 | 209.4 |
| Draft AAI August 2003 | | | | | | | |
| Wages & Salaries | 11.2 | 11.5 | 11.8 | 12.1 | 12.4 | | |
| Materials & Services | 14.2 | 14.5 | 14.9 | 15.3 | 15.7 | | |
| Property taxes | 0.6 | 0.6 | 0.6 | 0.7 | 0.7 | | |
| Marketing | 0.5 | 0.5 | 0.5 | 0.6 | 0.6 | | |
| Corporate Overheads | 4.4 | 4.5 | 4.6 | 4.8 | 4.9 | | |
| | 30.9 | 31.7 | 32.5 | 33.4 | 34.2 | | |

It is difficult to comment further on whether the PRAA represents an appropriate increase in costs. The category of materials and services appears to be forecast at a significantly higher level. This may be due to a revised maintenance program. However, the level of disclosure is clearly inadequate to allow a view to be formed. *In this regard, further information should be provided by the Operator*.

The appropriate level of non-capital costs is further obscured as a result of the new subcontracting arrangements with ANS, which we presume has led to the lumping of most of the expenditure in the Materials and Services category. Notwithstanding, the almost 50% increase in total cost over the 6 year period for the forecast over the DAA acquisition forecast appears to be unreasonable, particularly in the context of the current access arrangement where forecast non capital costs excluding fuel gas were $29.6 million in 2004.

In our experience, operating costs for pipelines tend to be predicable until step changes occur through extension of the geographical scope or commencement of compression. Looping does not generally impact upon operating costs. Whilst the Operator is embarking upon a significant expansion program, it is difficult to see how the scope of pipeline operations has changed to justify the substantial cost increases submitted by the Operator, and in particular, it is hard to see what has changed since DAA's acquisition forecasts in late 2004 as reflected in Schedule 9.

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**In conclusion the significant increases proposed in non-capital costs (excluding fuel gas) over both the last Access Arrangement and Schedule 9 do not appear justified on the basis of the information available.**

### 4.3.2 Arrangements with ANS as Operator

One significant change from 2004 to 2005 will be the appointment of ANS as operator under subcontract from the pipeline owner. These arrangements are disclosed in the Duet PDS (clause 10.2.5).

Firstly, we believe that ANS should be regarded as if it was the Service Provider under the Code. It is clear that this is how ANS is described in the Duet PDS and this is consistent with the proposed transfer of staff of Epic Energy to ANS. We regard this as important to ensure that the two tier arrangements put in place by the Operator do not reduce the information available to users or increase the cost of service recovered from users through the Reference Tariff.

We are concerned that the subcontracting arrangements will not access significant economies of scale or scope (the DBNGP Operation is of significant size in itself). We note that under the transitional services agreement no margin was payable (Duet PDS section 10.2.6). In such circumstances any margin earned by ANS above costs (Management Fee of $2m per annum) represents inefficient costs (within the meaning of "efficient" under section 8.37 of the Code) and should not be passed onto users through the Reference Tariff.

Further, the Duet PDS discloses there is an Incentive Fee arrangement which pays to ANS 50% of the reduction in Reimbursable Costs from the previous years benchmark. It is unclear how this Incentive Fee has been treated in the forecast non-capital costs. However, it would appear equitable that users share in the benefits of any incentive fee outcome and that benchmarks are consistent, with the PRAA following relevant elements of the arrangement with ANS.

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**ANS should be treated as though it is the Service Provider with full disclosure of cost by category and fees payable to ANS. Fees payable to ANS must be reviewed to ensure that they are consistent with achieving the lowest sustainable cost of delivering the Reference Service in accordance with section 8.37 of the Code. Allowed non-capital costs should also be reduced to meet the Code requirements and incentive fee payments should result in a reduction in cost of service for users.**

### 4.3.3 Fuel Gas

The fuel gas cost is a function of volume of fuel gas used multiplied by the cost of gas (per GJ). The volume of fuel gas used is determined by the level of throughput on a daily basis above the free flow capacity. The fuel gas volume is therefore not directly related to total throughput, but varies with incremental throughput over say 300TJ/d. In addition, the power efficiency curve of compressors in operation is a factor.

The table below sets out the comparison between the Schedule 9 projections of fuel gas usage and the PRAA for the period to 2010.

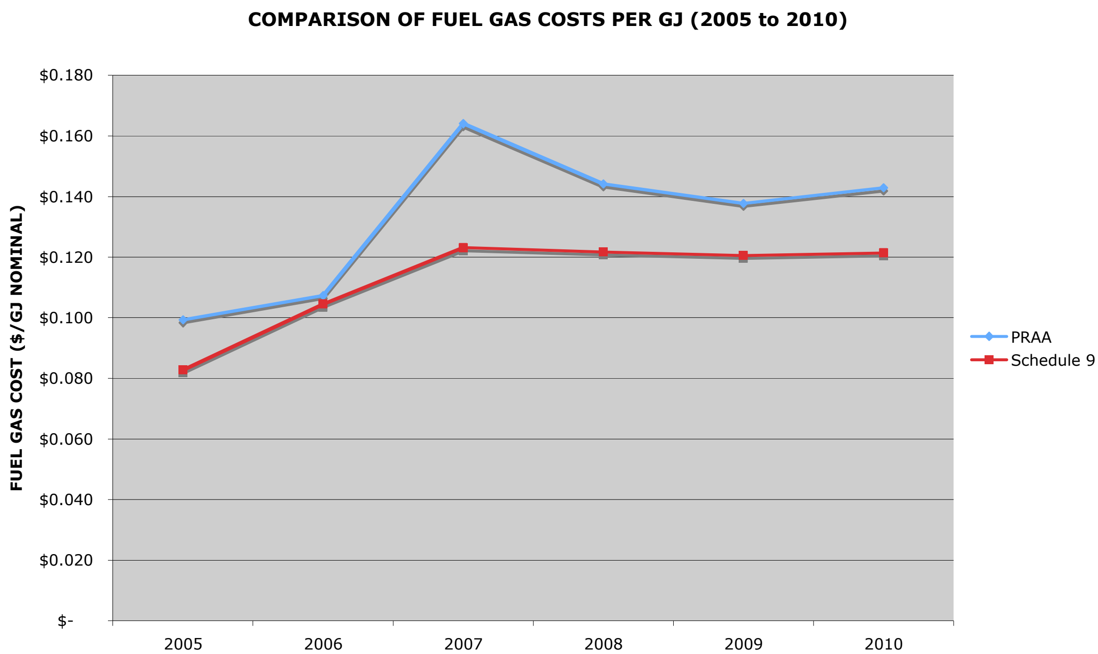
**TABLE 9: COMPARISON OF NON CAPITAL EXPENDITURE FORECASTS 2005 TO 2010**

| *$m Nominal* | **2005** | **2006** | **2007** | **2008** | **2009** | **2010** | **TOTAL** |
|---|---|---|---|---|---|---|---|
| PRAA | | | | | | | |
| Fuel Gas ($m Nominal) | 20.1 | 23.2 | 40.8 | 38.8 | 37.9 | 41.1 | 201.9 |
| Throughput (Full Haul) PJ | 203 | 216 | 249 | 269 | 275 | 288 | |
| $/GJ | $0.10 | $0.11 | $0.16 | $0.14 | $0.14 | $0.14 | |
| Schedule 9 SSC (Oct 2004) | | | | | | | |
| Fuel Gas ($m Nominal) | 17.3 | 23.5 | 29.7 | 32.8 | 33.5 | 34.8 | 171.6 |
| Throughput (Full Haul) PJ | 209 | 225 | 241 | 269 | 278 | 287 | |
| $/GJ | $0.08 | $0.10 | $0.12 | $0.12 | $0.12 | $0.12 | |

In assessing the reasonableness of the current DBNGP projections, consideration must be given to the following facts:

1. The expansion program has been accelerated, meaning the 7 compressors in the expansion program are in operation earlier, supporting a higher throughput but potentially accounting for higher fuel gas usage per TJ (insufficient data available to be conclusive on this issue

2. As part of the acquisition new fuel gas supply arrangements with Alinta Sales have been put in place (Duet PDS 10.2.7 (xii)), which should provide significant costs savings on a per GJ basis over the inflated arrangements previously in place with Alinta at the time of the privatisation.




The capital expansion program involves installation of compressors initially (to achieve two unit installations at each Compressor Station) followed by looping. The Schedule 9 capital expenditure program does not require any additional compression until over 75% of looping has been completed, which is beyond the Access Arrangement period. The quantum of fuel usage is limited to the maximum usage of installed compressors which we would not expect to change after 2007 (by which time all 7 new units are installed and operational). Therefore, we would expect capacity looping increases after 2007 to increase capacity but not increase fuel gas usage. Fuel gas cost per TJ should reduce as a result with compensating increases for gas cost escalation. The Schedule 9 curve above is consistent with this. However, we cannot reconcile the fuel gas increase in the PRAA with this, since neither the compressors being installed nor the fuel gas supply contract should have changed since October 2004 and Schedule 9.

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**The above graph supports the following conclusions:**

- **Projected fuel gas usage has increased in the PRAA compared with Schedule 9 of the SSC;**
- **There is no explanation in terms of the capital expenditure program to justify this; and**
- **the Operator should be required to reconcile the change in fuel gas usage.**

**In addition, Western Power should request the Regulator to be vigilant in ensuring that fuel gas charges are not being used as a means of shifting value from the DBNGP business to Alinta's gas retail business, at the expense of other shippers.**

## 4.4 Reservation and Throughput Forecasts

The forecasts of reservation and throughput are linked directly to the capacity expansion program. As stated above (see 2.2) there is insufficient data on the timing and amount of capacity additions to compare available capacity against forecasts.

The table below compares the Schedule 9 volume forecasts for full haul (including the Wesfarmers LPG volumes) against the PRAA for the six years to 2010.

**TABLE 10: COMPARISON OF VOLUME FORECASTS 2005 TO 2010**

| | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | TOTAL |
|---|---|---|---|---|---|---|---|
| 2005 Draft Access Arrangement | | | | | | | |
| Reservation (Full Haul) PJ annum | 210 | 225 | 261 | 281 | 288 | 302 | 1,567 |
| Average Reservation (Full Haul) TJ day | 576 | 616 | 715 | 771 | 789 | 826 | |
| Throughput (Full Haul) PJ annum | 203 | 216 | 249 | 269 | 275 | 288 | 1,499 |
| Average Throughput (Full Haul) TJ day | 555 | 592 | 682 | 737 | 754 | 788 | |
| Load Factor (%) | 96% | 96% | 95% | 96% | 96% | 95% | |
| Schedule 9 SSC (Oct 2004) | | | | | | | |
| Reservation (Full Haul) TJ | 216 | 225 | 248 | 278 | 286 | 295 | 1,549 |
| Average Throughput (Full Haul) TJ day | 593 | 617 | 680 | 761 | 784 | 810 | |
| Throughput (Full Haul) TJ annum | 209 | 225 | 241 | 269 | 278 | 287 | 1,509 |
| Average Throughput (Full Haul) TJ day | 572 | 616 | 661 | 738 | 761 | 785 | |
| Load Factor % | 97% | 100% | 97% | 97% | 97% | 97% | |

In view of the accelerated new facilities expenditure discussed in 3.2 above, the PRAA forecasts appear to be lower than would be anticipated. This indicates that the PRAA may have ignored the Wesfarmers LPG volumes in error and inconsistently with the current Access Arrangement. Furthermore, any argument (should one have been made in materials not publicly available) about prudent discounts in respect of these volumes is not tenable given the recontracting that took place as part of the DAA acquisition.[11]

The most important point about the volume forecasts is to ensure that capacity definition and hence reservation and throughput forecasts are consistent with the services offered and capacity available to provide services. As stated above, if Tf services were attractive to the market then some usage of the additional capacity between the T1 plus Tx cut-off and the Tf cut-off would be reasonable (perhaps instead of spot capacity sales) and the volume forecasts in the PRAA are understated. However, Tf is not attractive to the market for the reasons stated in Section 2 above.

[11] See 5.9.3.9 of Regulator's Draft decision

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**Venture Associates believes that the following amendments should be made to ensure the tariff derivation is consistent with both the SSC and the capacity available for <u>firm</u> service:**

- **Reference Service should be amended from Tf to T1, consistent with the capacity definition, the service being sought through expansion over the access arrangement period and the SSC [redacted];**

- **Capacity to be disclosed in the PRAA equivalent to the "T1 plus Tx cut-off" only (current capacity estimated at 576TJ/d); and**

- **Use of capacity available above the "T1 plus Tx cut-off" should either be forecast and revenue and costs attributed as part of the Reference Tariff setting process or alternatively, if accurate forecasting is considered difficult, included as rebateable revenue shared with all firm shippers on a pro-rata basis.**

# 5. CONCLUDING OBSERVATIONS AND RECOMMENDATIONS

The PRAA submitted by the Operator appears to be deficient in a number of respects.

The key issue for Western Power is the proposal of a Tf service as the only reference service. This gives rise to a number of prospective concerns, the main being how the Tf service might be used to "game" the tariff to apply under clause 20.5 of the SSCfrom 1 January 2016. In addition there are a number of concerns about the magnitude of some of the inputs to the cost of service calculations.

However, any analysis is uncertain because of the limited (and therefore non Code-compliant) amount of information disclosed by the Operator in connection with the forecast costs and volumes. There may be issues which are revealed to be non-issues when further information is disclosed. Alternatively, there may be new issues which arise out of the new information. This report will need to be updated once a Code-compliant access arrangement information is available.

**RECOMMENDATION 1: It is clear that the Tf service is commercially unattractive and inferior to a T1 service under the SSC. Venture Associates does not anticipate any Tf service being required by any existing or prospective user – interruptible capacity is more likely to be sought on a spot basis. For all of these reasons the Tf service is inappropriate as a sole Reference Service and Western Power should request the Regulator to decide that the T1 service should also be a Reference Service.**

**RECOMMENDATION 2: It appears that the Tf Reference Tariff has been calculated based upon available "T1 plus Tx" capacity rather than Tf capacity. As a result the calculated reference tariff is a T1/Tx Reference Tariff, not a Tf Reference Tariff.**

**The Regulator should be asked to amend the PRAA to either:**

- **Amend the Reference Service from Tf to T1 (and consequent change of terms and conditions) and treating revenue from sales of spot capacity as rebateable revenue; or**

- **Amend the projected pipeline contracted capacity and throughput to include forecast sales of firm and interruptible capacity in excess of the T1 plus Tx capacity (i.e. forecast sales of the Tf capacity under Tf or Spot contacts).**

**Venture Associates believes the first option is the most appropriate since Tf is not [redacted] appropriate Reference Service in accordance with the Code.**

[redacted]

**<u>RECOMMENDATION 4:</u> The Brought Forward Capital Base at 1 January 2005 should be adjusted downwards to refect exclusion of GST effect from CPI and capitalisation of turbine and compressor upgrades in the Initial Capital.**

**<u>RECOMMENDATION 5:</u> The Operator should be asked to reconcile the New Facilities Investment with Schedule 9 and the New Facilities Investment forecast should be adjusted as necessary to reflect:**

- **Separation of any Mainline South expansion expenditure (such expenditure to be recovered from Zone 10 shippers only through surcharge or other mechanism);**
- **Unreasonable or unsubstantiated increase in compressor expenditure over $22m per compressor unit;**
- **Per km unit looping expenditure consistent with contracted pipeline purchases;**
- **The policy to be adopted in respect of surcharges collected from contracted shippers pursuant to Clause 20.8 of the SSC; and**
- **The quantum of project management fees payable to ANS included in forecast new facilities investment and whether these are allowable under section 8.16(a) of the Code.**

**<u>RECOMMENDATION 6:</u> The significant increases proposed in non-capital costs (excluding fuel gas) over both the 2003 AA and Schedule 9 of the SSC do not appear justified on the basis of the information available. The Operator should be asked to justify the proposed increase and reconciling it to both the 2003 AA and Schedule 9.**

**<u>RECOMMENDATION 7:</u> ANS should be treated as though it is the Service Provider with full disclosure of cost by category and fees payable to ANS. Fees payable to ANS must be reviewed to ensure that they are consistent with achieving the lowest sustainable cost of delivering the Reference Service in accordance with section 8.37 of the Code. Allowed non-capital costs should be reduced to meet the Code requirements and incentive fee payments should result in a reduction in cost of service for users.**

**<u>RECOMMENDATION 8:</u> Fuel gas usage provided for in the PRAA has increased from between Schedule 9 of the SSC and the PRAA without any explanation or justification in terms of the capital expenditure program. The Operator should be required to reconcile the change in fuel gas usage with installed compressor capacity.**

**In addition, the Regulator should be asked to be vigilant that fuel gas charges are not being used as a means of shifting value from the DBNGP business to Alinta's gas retail business, at the expense of other shippers**

**<u>RECOMMENDATION 9:</u> Venture Associates believes that the following amendments should be made to ensure the tariff derivation is consistent with both the SSC and the capacity available for firm rather than interruptible service:**

- **Capacity to be disclosed in the PRAA equivalent to the "T1 plus Tx cut-off" only (current capacity estimated at 575TJ/d);**
- **Reference Service should be amended from Tf to T1, consistent with the capacity definition, the service being sought through expansion over the access arrangement period and the SSC; and**
- **Use of capacity available above the "T1 plus Tx cut-off" should either be forecast and revenue and costs attributed as part of the Reference Tariff setting process or alternatively, if accurate forecasting is considered difficult, included as rebateable revenue shared with all firm shippers on a pro-rata basis.**

**Venture Associates**

**April 2005**

# Appendix 4: Sample T1 service terms sheet

| | |
|---|---|
| **1. Parties** | TBA |
| **2. Conditions precedent** | TBA |
| **3. Minimum Term** | Refer to Access Arrangement |
| **4. Service type** | Full-haul firm (98%) with the following key commercial terms. |
| **5. Nominations Priority** | T1 ranks highest in nominations priority except in certain extreme circumstances (in which distribution system and some Alcoa exempt capacity have priority). |
| **6. Curtailment Priority** | Operator may curtail Services in certain circumstances and after providing notice to shippers. T1 Service will be curtailed last except in extreme circumstances. T1 curtailments are to be apportioned curtailments across all T1 shippers.<br><br>Permissible curtailment limit of 2% of time. |
| **7. Receiving and Delivering Gas** | Shipper may deliver gas, and obligation on Operator to receive, transport and redeliver that gas.<br><br>Parties may refuse to receive or deliver gas in certain circumstances provided notice requirements are complied with. |
| **8. System Use Gas** | Operator to supply SUG until Shipper elects to provide its own share, which may be done 31 December 2015. |
| **9. Gas Specifications** | Operating specification as per Table [a]. Operator must odorise.<br><br>Parties may reject out-of-specification gas.<br><br>Operator has protection against Change in Law on gas specification unless a shipper has an inconsistent prior specification.<br><br>Shipper may request move to broader specification as per Table [b] subject to operational and commercial protection for Operator.<br><br>Minimum and maximum temperatures and pressures as per Table [c]. |
| **10. Aggregation (short term relocation)** | Capacity can be temporarily relocated using the nominations procedure (known as “aggregation”), subject only to reasonable operational limitations. |

| | |
|---|---|
| **11. Imbalances** | Shipper's Accumulated Imbalance Limit is 8% of the sum of Shipper's Capacity under Contracted Capacity and Spot Transactions, and its Outer Imbalance Limit is 20% of the same.<br><br>Shipper must use best endeavours to comply with a notice from Operator to get back within the Accumulated Imbalance Limit. Operator can only issue a notice an if Shipper's imbalance will have a material adverse affect on the DBNGP, or will (or is likely to) adversely impact another shipper's capacity entitlements. Operator has a last-resort power to refuse to receive or deliver gas.<br><br>Shipper must pay an Excess Imbalance Charge (200% of Base T1) if it does not use best endeavours to comply with a notice (deemed to be so if still out of limits at the end of the next Gas Day after getting the notice). |
| **12. Peaking** | Shipper has Hourly Peaking Limits of 125% in Winter and 120% in Summer, of aggregate MHQ calculated across all outlet points in the peaking zone, and an Outer Peaking Limit of 140% of the same.<br><br>Shipper must use best endeavours to comply with a notice from Operator to get back within the Hourly Peaking Limit. Operator can only issue a notice if Shipper's peaking will have a material adverse affect on the DBNGP, or will (or is likely to) adversely impact another shipper's capacity entitlements. Operator has a last-resort power to refuse to receive or deliver gas.<br><br>Shipper must pay an Hourly Peaking Charge (200% of Base T1) if it does not use best endeavours to comply with a notice (deemed to be so if still out of limits at the end of the next Gas Hour after getting the notice). |
| **13. Overrun** | Overrun gas is calculated as the difference between gas received by Shipper across all outlet points and the aggregate of Shipper's contracted capacity across all capacity services (including spot).<br><br>Overrun is charged at the greater of 115% of the Base T1 Tariff and the highest bid spot price.<br><br>Overrun may be unavailable on notice to Shipper. If Shipper fails to comply with unavailability notice, then Shipper may be charged Unavailable Overrun Charge (the greater of 250% of Base T1 or the highest bid spot price). |
| **14. Relocation** | Shipper may permanently relocate Contracted Capacity from Existing Inlet and Outlet Points to New Inlet and Outlet Points, subject to operational feasibility and the operator maintaining the same revenue stream. |

| | |
|---|---|
| **15. Additional T1 Capacity and Capacity Expansion Options** | There is a right for Shipper to obtain additional T1 capacity through pipeline expansion. Shipper may request for additional capacity on 30 months, which must satisfy various conditions including a minimum 10 TJ/d and a minimum 15 year contract.<br><br>Terms and conditions of the expansion funding must be reasonable and Shipper may contribute to the Capital Cost of Expansion.<br><br>After expansion, the Base T1 Tariff is adjusted for all shippers to take into account the differences between actual and budgeted compression and looping costs. |
| **16. Maintenance** | Operator must conduct maintenance in accordance with an annual schedule developed in consultation with shippers. |
| **17. Tariffs** | Shipper must pay an 80% Capacity Reservation Charge (calculated by multiplying the sum of the Contracted Capacity by the Capacity Reservation Tariff) and a 20% Commodity Charge (calculated by multiplying the T1 Commodity Tariff by the amount of Gas Delivered to the Shipper up to its Contracted Capacity).<br><br>The Base Tariff is escalated by 100% CPI until 2012, then CPI minus 2.5% until 2016, and thereafter a regulated Reference Tariff will be adopted.<br><br>The Capacity Reservation Charge is payable each month in advance and the Commodity Charge is payable each month in arrears. |
| **18. Trading or Transferring Contracted Capacity** | Shipper has certain Capacity Trading rights. |

# Appendix 5: Suggested changes to PRAA clauses 7.3 & 7.4

**"7.3 Calculation of Capital Base**

(a) The Initial Capital Base at 1 January 2000 was $1,550.00 million.

(b) For each year of an Access Arrangement Period after 2000, the Capital Base for the DBNGP at the ~~beginning~~ end of the year is:

(i) the Capital Base at the beginning of the ~~immediately preceding~~ year; plus

(ii) an adjustment to the Capital Base ~~at the beginning of that immediately preceding year~~ for the effect of inflation during the year; plus

(iii) New Facilities Investment during the ~~preceding~~ year; less

(iv) depreciation for the ~~preceding~~ year (determined on a straight line basis using the current cost accounting method over the estimated economic life for each asset class) applied to~~.~~:

A. for those assets which formed part of the DBNGP at 1 January 2000 – the Initial Capital Base as at 1 January 2000; and

B. for those assets which were added to the DBNGP after 1 January 2000 – the New Facilities Investment (in accordance with section 8.16 of the Code) from the date the facility is brought into service;

(c) At the end of an Access Arrangement Period (**"previous Access Arrangement Period"**), the opening Capital Base at the beginning of the next Access Arrangement Period is calculated on the basis of opening Capital Base plus an adjustment for the actual effect of inflation plus actual New Facilities Investment during the previous Access Arrangement Period, less Depreciation and any Redundant Capital during the previous Access Arrangement Period, subject to the provisions of the Code. ~~New Facilities Investment after 1 January 2005 is New Facilities Investment that is forecast to occur during the Access Arrangement Period.~~

**~~7.4 Forecast New Facilities Investment~~**

~~(a) New Facilities Investment forecast to occur during the Access Arrangement Period is reasonably expected to pass the requirements of section 8.16 of the Code when that New Facilities Investment is forecast to occur.~~

~~(b) For the purposes of calculating the Capital Base at the commencement of the next Access Arrangement Period in accordance with section 8.9 of the Code, the New Facilities Investment will consist only of actual New Facilities Investment that has occurred during this Access Arrangement Period.~~

"