Amended Proposed Revised Access Arrangement Information
2 JUNE 2005

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

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1. INTRODUCTION

This document sets out the Access Arrangement Information for the Dampier to Bunbury Natural Gas Pipeline ("DBNGP") pursuant to the requirements of the Gas Pipelines Access (Western Australia) Act 1998, which incorporates the National Third Party Access Code for Natural Gas Pipeline Systems ("Code").

2. ACCESS AND PRICING PRINCIPLES

2.1 Reference Service and Reference Tariff

Section 3.3 of the Code requires the Operator's Access Arrangement to offer a Reference Tariff for at least one service likely to be sought by a significant part of the market.

The Reference Tariff for the Tf Service offered by the Operator in its Access Arrangement is such a Reference Tariff.

2.2 Non-Reference Services

In addition to the Reference Service, Operator will, subject to operational availability (as determined by Operator as a reasonable and prudent pipeline operator), make available to a prospective shipper the following Service or Services:

(a) Part Haul Service;

(b) Back Haul Service;

(c) Spot Capacity Service;

(d) Park and Loan Service;

(e) Seasonal Service;

(f) Peaking Service;

(g) metering information service;

(h) pressure and temperature control service;

(i) odorisation service; and

(j) co-mingling service.

The Operator is prepared to negotiate to provide a prospective shipper with any other Service that is not a Tf Service.

Each of the services listed above in this section 2.2 is known as a Non-Reference Service. The Non-Reference Services offered by the Operator are intended to cater to the individual needs of prospective shippers. They are described in more detail below.

(a) Part Haul

Part Haul is a Gas transportation Service in the DBNGP where the Delivery and Receipt Points are upstream of Compressor Station 9 on the DBNGP, but does not include Back Haul.

(b) Back Haul

Back Haul is a Gas transportation Service in the DBNGP, where the Receipt Point is downstream of the Delivery Point.

(c) Spot Capacity Service

Spot Capacity Service means a Service for Spot Capacity by way of one or more Spot Transactions.

(d) Park and Loan Service

Shippers or prospective shippers serving end users with gas demands that are difficult to predict from day to day, or when faced with an outage from their gas supplier, may find the maintenance of their imbalances within the tolerance specified in the Access Arrangement difficult. To assist these shippers and prospective shippers, Operator will offer a Park and Loan Service, permitting limited gas storage in the DBNGP, and/or taking of additional Gas from the DBNGP when required. Operator's ability to offer a Park and Loan Service is restricted by the operating characteristics of the DBNGP.

(e) Seasonal Service

Capacity in the DBNGP varies inversely with ambient temperature. A higher pipeline capacity is available during winter months when ambient temperatures are low. A lower capacity is available during summer months, with the lowest capacity usually available in January. Seasonal Service will only be made available subject to operational availability (as determined by Operator as a reasonable and prudent pipeline operator) and Operator meeting its obligations under Gas transportation contracts entered into prior to the commencement of the Access Arrangement Period.

(f) Peaking Service

This service will enable an increase in the MHQ at a Delivery Point for a specified period.

(g) Metering information service

This service will entail the provision of metering and operational data directly to a shipper in addition to the data the Operator agrees to provide under an Access Contract for the Reference Service.

(h) Pressure and temperature control service

This service will entail the provision of a service by the Operator to vary the temperature and/or pressure at which the Operator shall deliver Gas at an Delivery Point.

(i) Odorisation service

This service will entail the provision of a service by the Operator to odorise the Gas being delivered at an Delivery Point.

(j) Co-mingling service

This service entails the agreement by the Operator with a Shipper to blend Out–of–Specification Gas with the main Gas stream such that the aggregate of the main Gas stream is within specification.

In addition to the above Non-Reference Services, the Operator will provide services to shippers with Gas transportation contracts entered into before the commencement of the Access Arrangement Period.

3. TARIFF DETERMINATION METHODOLOGY

3.1 Tariff Structure

The Tf Service offered by the Operator is a Full Haul Service. It is a Gas transportation service on the DBNGP to a Delivery Point which is downstream of Compressor Station 9, regardless of the location of the Receipt Point, but does not include Back Haul.

The Reference Tariff for the Tf Service is a two-part tariff as follows:

(a) Capacity Reservation Tariff

The Capacity Reservation Tariff is a number of dollars per GJ of Contracted Capacity for Tf Service.

Each Tf Service Shipper is to pay the Operator a Capacity Charge, which is to be calculated for each Gas Day by multiplying the aggregate of the Shipper's Delivery Point MDQs by the Capacity Reservation Tariff.

(b) Commodity Tariff

The Commodity Tariff is a number of dollars per GJ of Gas actually Delivered to any Delivery Point downstream of Compressor Station 9 on the DBNGP.

Each Tf Service Shipper is to pay the Operator a Commodity Charge, which is to be calculated for each Gas Day by multiplying the aggregate of the quantity of gas delivered to the Tf Service Shipper at a Delivery Point or Delivery Points by the Commodity Tariff.

3.2 Cost allocation

The portion of Total Revenue attributable to provision of the Tf Service is recovered through the Reference Tariff.

The portion of the Total Revenue attributable to provision of the Tf Service is the Total Revenue less the costs of providing Part Haul Services which have been assessed as the costs of the additional fuel gas required to provide those Services.

The Reference Tariff has been determined under an assumption that all Shippers using Full Haul services are users of the Reference Service.

The Capacity Reservation Tariff recovers from each Tf Service Shipper a proportion of the return and depreciation on, and a proportion of the non capital costs incurred in operating and maintaining, the DBNGP. The Capacity Reservation Tariff essentially recovers the fixed costs of the DBNGP. The levels of these costs are determined by the total requirement for capacity to provide the Tf Service, and they are to be recovered on the basis of Tf Service Shippers' contracted capacity requirements.

The Commodity Tariff recovers from each Tf Service Shipper a proportion of the cost of the fuel gas used on the DBNGP. Fuel gas costs are the only variable costs associated with operation of the DBNGP. They are recovered from Tf Service Shippers on the basis of the quantity of Gas delivered to those shippers.

3.3 Incentive structures: price path

The Reference Tariff Policy set out in the Access Arrangement provides for Reference Tariff adjustment in accordance with a predetermined price path. The Reference Tariff will be adjusted annually during the Access Arrangement Period by 100 per cent of the increase in the CPI.

Price path regulation provides Operator with an incentive to minimise the costs of delivering the Reference Service. With the Reference Tariff constrained to increasing at 100 per cent of the increase in CPI, reductions in the cost of delivering the Reference Service increase profits, and these increases in profits are retained at least until the end of the Access Arrangement Period.

If Operator is able to increase demand for the Reference Service above the forecast quantities used in tariff determination, its revenue from sales will exceed the forecast revenue. To the extent that the increase in demand can be accommodated without a proportionate increase in cost, the Operator will generate higher than expected profits. These higher profits are retained at least until the end of the Access Arrangement Period.

3.4 Incentive structures: efficiency carryover

Additional incentives for efficiency improvement are provided by the inclusion of an efficiency carryover mechanism in the Reference Tariff Policy of the Access Arrangement. That mechanism provides, in accordance with section 8.44 of the Code, 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. This sharing is effected through inclusion of any efficiency gains in the current Access Arrangement Period in the Total Revenue from which the Reference Tariff for the following Access Arrangement Period is to be determined. If efficiency gains are made in the current Access Arrangement Period, the Operator is rewarded with a higher Reference Tariff in the following Access Arrangement Period. If efficiency "losses" are realized, the efficiency carryover mechanism works, symmetrically, to penalize the Operator with a lower Reference Tariff in the following Access Arrangement Period.

4. INFORMATION REGARDING CAPITAL COSTS

4.1 Initial Asset Values

The initial Capital Base has been established at a value of $1,550.00 million as at 31 December 1999 in accordance with the Final Decision of the Independent Gas Pipelines Access Regulator.

The allocation of the initial Capital Base to asset classes as at 31 December 1999 is in accordance with the allocation made for determination of the Reference Tariff applicable during the initial Access Arrangement Period. Asset values by class of assets as at 31 December 1999, and at 31 December 2004, are indicated in Table 1.

TABLE 1: ASSET VALUE BY ASSET CLASS

Asset	Percentage of total asset value	Asset value at 31 December 1999 ($m)	Asset value at 31 December 2004 ($m)
Pipeline	81.49	1,263.15	1,491.14
Compression	13.65	211.60	249.80
Metering	1.12	17.35	20.49
Other			
Depreciable	3.07	47.66	56.26
Non depreciable (land and linepack)	0.66	10.24	12.09
Total	100.00	1,550.00	1,829.77

4.2 Actual New Facilities Investment

The actual New Facilities Investment during the initial Access Arrangement Period is shown in Table 2.

TABLE 2: ACTUAL NEW FACILITIES INVESTMENT ($M REAL 31 DEC-04)

Year ending 31 December	2000	2001	2002	2003	2004
Pipeline	1.55	0.03	0.07	0.00	0.62
Compression	20.78	1.44	0.09	-0.12	0.18
Metering	0.64	0.58	0.38	-0.03	1.67
Other	5.69	1.48	0.79	0.94	0.90
Total	28.65	3.54	1.32	0.79	3.38

4.3 Roll-forward of the Capital Base

The Operator has rolled forward the Capital Base to 31 December 2004 as follows:

(a) commencing with the initial Capital Base of $1,550.00 million on 31 December 1999;

(b) actual new facilities investment during the initial Access Arrangement Period has been added;

(c) depreciation, determined (as described in section 4.6) for the assets comprising the initial Capital Base and the actual New Facilities Investment during initial Access Arrangement Period, has been subtracted; and

(d) the Capital Base in each year of the initial Access Arrangement Period has been escalated at the actual rate of inflation.

The roll forward of the capital base to 31 December 2004 is shown in Table 3.

TABLE 3: ROLL FORWARD OF THE CAPITAL BASE ($M REAL 31 DEC-04)

Year ending 31 December	2000	2001	2002	2003	2004
Capital base at beginning of year	1,829.77	1,814.44	1,773.75	1,730.47	1,686.25
New facilities investment	28.65	3.54	1.32	0.79	3.38
Depreciation	43.98	44.23	44.60	45.01	45.27
Capital Base at end of year	1,814.44	1,773.75	1,730.47	1,686.25	1,644.36

4.4 New Facilities Investment

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.

A description of the forecast New Facilities Investment, and justification for that investment, is provided in Annexures 2 & 3.

The value of New Facilities Investment for the Access Arrangement Period is as shown in Table 4.

TABLE 4: FORECAST NEW FACILITIES INVESTMENT ($M REAL 31 DEC-04)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Pipeline	0.50	0.00	251.51	271.70	81.62	143.26
Compression	0.00	65.66	115.00	40.00	0.00	0.00
Metering	0.00	0.00	0.00	0.00	0.00	0.00
Other	12.81	13.25	6.74	8.10	8.81	7.93
Non-depreciable	0.00	0.00	0.00	0.00	0.00	0.00
Total	13.31	78.90	373.25	319.80	90.44	151.19

4.5 Rate of Return

The Rate of Return for the Access Arrangement Period has been established as a pre-tax real weighted average of the returns applicable to debt and equity.

The return on debt has been determined as the sum of a risk free rate of return, an estimate of the corporate debt margin, and an estimate of the costs of raising debt.

The return on equity has been determined using the capital asset pricing model.

The Rate of Return parameters and values are shown in Table 5.

The pre-tax real weighted average cost of capital of 7.24%, shown in the last row of Table 5, has been used in calculation of Total Revenue.

Table 5: Rate of Return parameters and values

Parameter	Calculation	Value
Nominal risk free rate of return	$R_{f,\ nominal}$	5.39%
Real risk free rate of return	$R_{f,\ real}$	2.77%
Market risk premium	$R_m - R_f$	6.00%
Asset beta	β_a	0.60
Debt beta	β_d	0.20
Debt margin	Δ	1.36
Ratio of debt to total assets	D/V	60.00%
Corporate tax rate	T	30.00%
Valuation of imputation credits	Γ	50.00%
Calculated values		
Ratio of equity to total assets	$E/V = 1 - D/V$	40.00%
Equity beta	$\beta_e = \beta_a + (\beta_a - \beta_d) \times D/E$	1.20
Cost of equity	$K_e = R_{f,\ nominal} + \beta_e \times (R_m - R_f)$	12.59%
Cost of debt	$K_d = R_{f,\ nominal} + \delta$	6.75%
Expected inflation	$\pi_e = (1 + R_{f,\ nominal})/(1 + R_{f,\ real}) - 1$	2.55%
WACC		
Post-tax nominal		6.99%
Post-tax real		4.32%
Pre-tax nominal		9.98%
Pre-tax real		7.24%

4.6 Depreciation

A separate depreciation schedule has been determined for each of the four groups of physical assets that form the DBNGP. These four groups are:

(a) pipeline assets;

(b) compressor station assets;

(c) metering assets; and

(d) other assets.

For the assets in each of the four groups, depreciation during the Access Arrangement Period has been determined by applying the straight line method.

Assumptions for asset lives for new assets, and remaining lives as at 31 December 2004 for assets in the initial Capital Base as at 31 December 1999, are shown in

Table 6. (To facilitate presentation, Table 6 shows the weighted average life for metering assets. Depreciation of metering assets has, however, been calculated for each individual meter station using the remaining life for that meter station.)

TABLE 6: ASSUMED ASSET LIVES

Asset	Asset Life (years)	Average Remaining Asset Life at 31 December 2004 (years)
Pipeline assets	70	49.50
Compression assets	30	
CS1		14.75
CS2		8.75
CS3		12.40
CS4		8.75
CS5		14.75
CS6		16.49
CS7		8.75
CS8		14.75
CS9		20.75
CS10		23.25
Metering assets	50	38.50
Other depreciable assets	30	11.85

Table 7 shows the depreciation schedule for each class of assets comprising the Capital Base.

TABLE 7: DEPRECIATION SCHEDULE ($M REAL 31 DEC-04)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Pipeline assets	27.39	27.40	27.40	30.99	34.88	36.04
Compression assets	13.61	13.61	15.80	19.63	20.97	20.97
Metering assets	0.61	0.61	0.61	0.61	0.61	0.61
Other depreciable assets	3.65	4.08	4.52	4.74	5.01	5.31
Total	45.27	45.70	48.33	55.98	61.47	62.93

Table 8 shows the roll forward of the Capital Base over the Access Arrangement Period on the basis of the forecast New Facilities Investment shown in Table 4 and Depreciation shown in Table 7.

TABLE 8: ROLL FORWARD OF THE CAPITAL BASE THROUGH THE ACCESS ARRANGEMENT PERIOD ($M REAL 31 DEC-04)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Capital Base at beginning of year	1,644.36	1,612.40	1,645.61	1,970.53	2,234.34	2,263.31
New facilities investment	13.31	78.90	373.25	319.80	90.44	151.19
Depreciation	45.27	45.70	48.33	55.98	61.47	62.93
Capital Base at end of year	1,612.40	1,645.61	1,970.53	2,234.34	2,263.31	2,351.57

The accumulated depreciation for the DBNGP, from 1 January 2000 to 31 December 2010 is shown in Table 9.

TABLE 9: ACCUMULATED DEPRECIATION ($M REAL 31 DEC-04)

Year ending 31 December	2000	2001	2002	2003	2004	2005
Accumulated depreciation	43.98	88.21	132.81	177.82	223.09	268.36

Year ending 31 December	2006	2007	2007	2007	2010	
Accumulated depreciation	314.06	362.39	418.37	479.84	542.77	

5. INFORMATION REGARDING NON CAPITAL COSTS

5.1 Fixed versus variable costs

The costs associated with the operation and maintenance of a gas transmission pipeline system are predominantly fixed. For a given pipeline configuration, capital costs, pipeline operating and maintenance costs and, to a lesser extent, compressor maintenance costs, do not vary materially with the volume of gas delivered to shippers. The only truly variable costs are the costs of fuel gas.

When the capacity of the DBNGP is expanded (implementing a new pipeline configuration), the level of these fixed costs will rise.

5.2 Forecast Non Capital Costs

Forecast Non Capital Costs for the Access Arrangement Period are shown in Table 10.

TABLE 10: NON CAPITAL COSTS ($M REAL 31 DEC-04)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Wages and Salaries	5.24	5.34	5.44	5.55	5.66	5.77
Materials and Services	34.90	32.56	44.27	41.76	39.25	39.82
Corporate Overheads	0.00	0.00	0.00	0.00	0.00	0.00
Fuel gas	19.27	19.22	23.44	27.60	29.30	31.13
Total	59.40	57.12	73.15	74.92	74.21	76.72

5.3 Total costs at corporate level

The DBNGP business is a stand-alone entity. The Non Capital Costs in Table 10 are, therefore, the total service provider costs at corporate level.

The business of the DBNGP is the provision of gas transportation services. There is, therefore, no allocation of costs between regulated and unregulated segments.

5.4 Gas used in operations

The cost of fuel gas is derived from estimates of the quantity of gas used in operations. The quantity of gas used in operations in each year of the Access Arrangement Period is an estimate of the quantity of gas used as compressor fuel during the year assuming steady state flow, plus an allowance of 5% for:

(a) additional compressor fuel used in accommodating variable flow rates;

(b) Gas used as fuel in gas engine alternators and heaters;

(c) Gas which is vented during maintenance activities; and

(d) Gas which is lost from the DBNGP.

6. TOTAL REVENUE

The Total Revenue has been calculated by the Cost of Service methodology as described in section 8.4 of the Code, wherein the Total Revenue is equal to the cost of providing all Services (which may be the forecast of such costs), and with this cost to be calculated on the basis of:

(a) a return on the value of the capital assets that form the Covered Pipeline or are otherwise used to provide Services (Capital Base);

(b) depreciation of the Capital Base (Depreciation); and

(c) the operating, maintenance and other non capital costs incurred in providing all Services (Non Capital Costs).

The methodology has been applied in accordance with section 8.5A(c) of the Code under which a real Rate of Return is applied to the nominal Capital Base, and Depreciation and the Non Capital Costs are expressed as nominal (or escalated) values.

The Total Revenue for the Access Arrangement Period is shown in Table 11.

TABLE 11: TOTAL REVENUE ($M REAL 31 DEC-04)

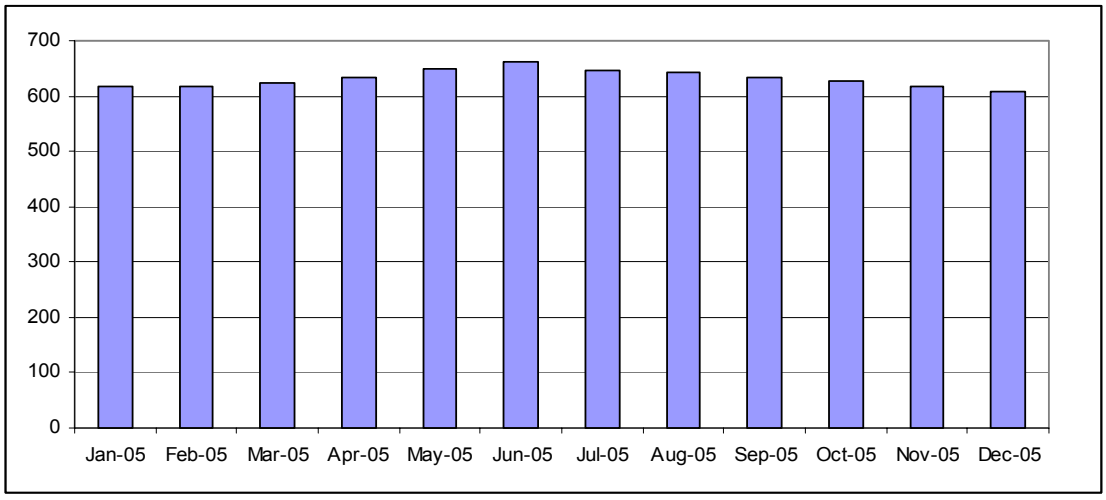
	2005	2006	2007	2008	2009	2010
Return on Assets	119.08	116.77	119.17	142.70	161.81	163.91
Depreciation	45.27	45.70	48.33	55.98	61.47	62.93
Non Capital Costs	59.40	57.12	73.15	74.92	74.21	76.72
Total	223.75	219.59	240.66	273.60	297.48	303.56

7. INFORMATION REGARDING CAPACITY AND THROUGHPUT

7.1 Maximum delivery capability

The forecast maximum capacity of the DBNGP during 2005 is shown in Figure 1.

FIGURE 1: DBNGP FORECAST MAXIMUM CAPACITY 2005 (TJ/D)



A large number of assumptions must be made in determining the maximum capacity of a gas transmission pipeline. Assumptions made in determining the maximum capacity of the DBNGP related to:

(a) receipt point pressures;

(b) quantities received at receipt points;

(c) heating value of the gas transported;

(d) composition of the gas transported;

(e) gas temperature;

(f) ambient temperature;

(g) compressor unit availability;

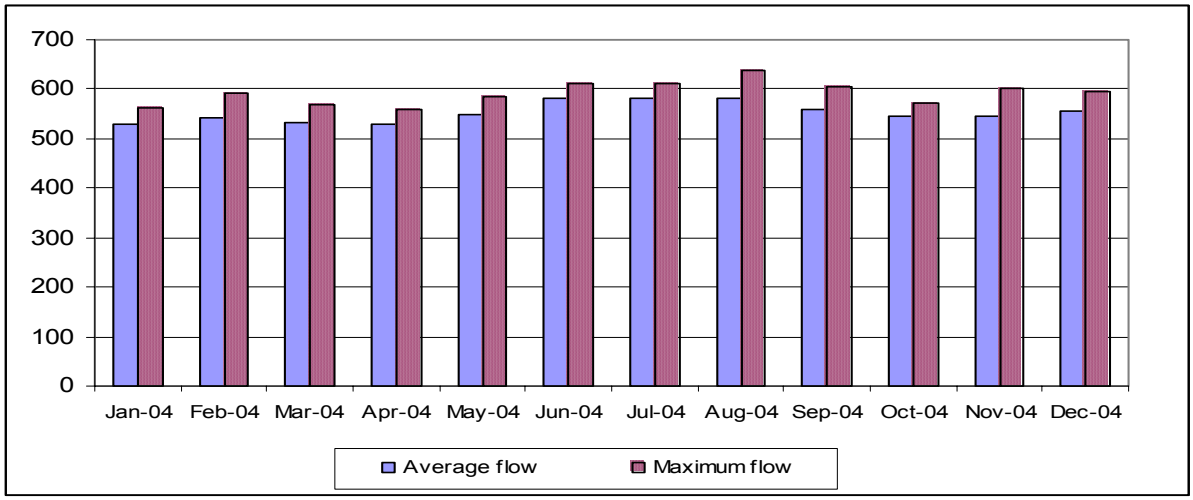
(h) delivery point pressures; and

(i) shipper load profiles.

7.2 Average daily and peak demand

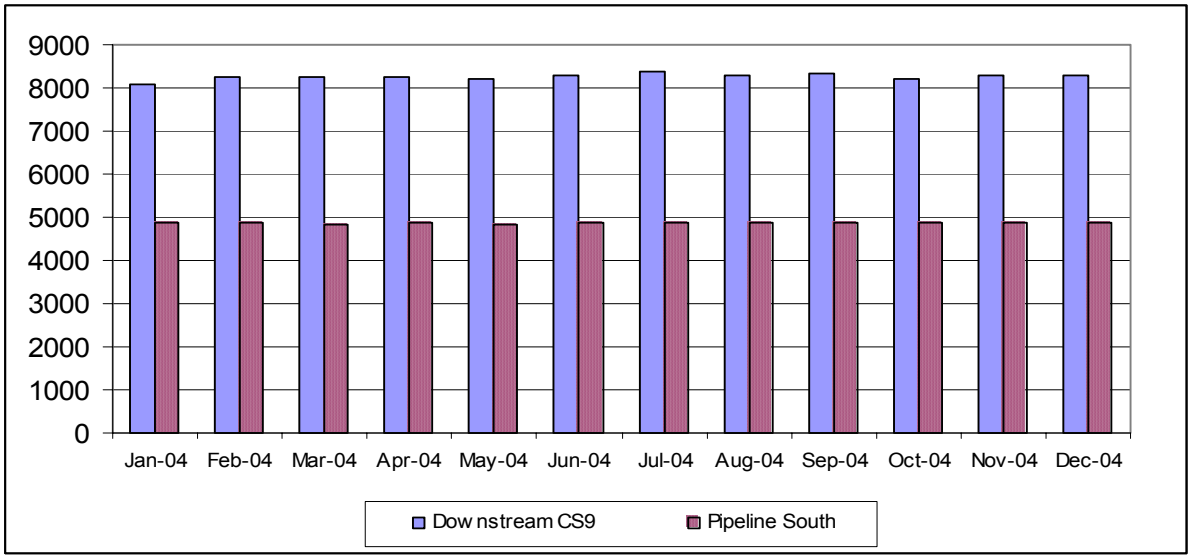
Daily flows through CS 9 during 2004, averaged over each month of the year, are shown in Figure 2. Figure 2 also shows the maximum flow (largest daily flow) through CS9 in each month of 2004.

FIGURE 2: AVERAGE AND MAXIMUM FLOWS THROUGH CS9 DURING 2004 (TJ/D)



Monthly average pressures immediately downstream of CS9, and at the inlet to southern section of the pipeline (at Kwinana Junction), during 2004, are shown in Figure 3.

FIGURE 3: AVERAGE PRESSURES DURING 2004 (KPAG)



7.3 Contracted capacities and throughput: actual and forecast

Tables 12 and 13 show the contracted Full Haul capacity between 2000 and 2004, and of the total volumes of Gas – throughput – delivered using that contracted capacity. The corresponding forecasts for the period from 2005 to 2010 are shown in Tables 14 and 15.

TABLE 12: CONTRACTED CAPACITY (TJ/DAY)

Year ending 31 December	2000	2001	2002	2003	2004
Full Haul	548.3	551.1	547.6	538.9	557.9

TABLE 13: THROUGHPUT (TJ/DAY)

Year ending 31 December	2000	2001	2002	2003	2004
Full Haul	499.1	533.6	543.4	546.7	553.0

TABLE 14: FORECAST CONTRACTED CAPACITY (TJ/DAY)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Full Haul	594.2	614.2	690.0	744.9	762.1	799.7

TABLE 15: FORECAST THROUGHPUT (TJ/DAY)

Year ending 31 December	2005	2006	2007	2008	2009	2010
Full Haul	572.9	591.6	659.4	713.4	729.9	764.5

7.4 Delivery Points and Numbers of Customers

Table 14 shows the Full Haul Delivery Points on the DBNGP, and the number of Shippers taking delivery of Gas at each of those Delivery Points.

Table 14: Full Haul Delivery Points on the DBNGP and numbers of Shippers taking delivery of Gas at each Delivery Point

Delivery Point	Number of Shippers
Muchea	1
Pinjar	3
Della Road	3
Ellenbrook	1
Harrow Street	3
Caversham	3
Welshpool	3
Forrestdale	3
Russell Road	3
Wesfarmers LPG	1
Australian Gold Reagents	1
Alcoa Kwinana	3
Kwinana Power Station	3
Cockburn Power Station	3
Barter Road/HiSmelt	2
Mission Energy Cogeneration	3
Kwinana Beach Road	1
Rockingham	1
WMC	0
Pinjarra	1
Alcoa Pinjarra	1
Pinjarra Cogeneration	2
Oakley Road	1
Harvey	1
Worsley	1
South West Cogeneration	3
Kemerton	1
Clifton Road	2

8. KEY PERFORMANCE INDICATORS

8.1 Code Requirements

Attachment A to the Code requires Operator to provide information regarding key performance indicators ("KPIs"). More specifically, the Code seeks information on:

(a) industry KPIs used by the Operator to justify "reasonably incurred costs"; and

(b) the Operator's KPIs for each pricing zone, service or category of asset.

Provision of industry KPIs is difficult. There are few, if any, useful comparators for gas transmission pipelines in Australia. The principal national industry body representing pipeline owners and operators, the Australian Pipeline Industry Association, does not publish key performance measures for operation of the pipelines owned by its members.

8.2 KPIs for the DBNGP

In the absence of accepted industry performance measures, Operator has adopted the following KPIs for the DBNGP:

(a) compressor reliability;

(b) compressor availability;

(c) asset utilisation; and

(d) fuel ratio.

8.3 Compressor reliability

This KPI measures, as a percentage figure, the reliability of Compressors on the DBNGP by the following formula:

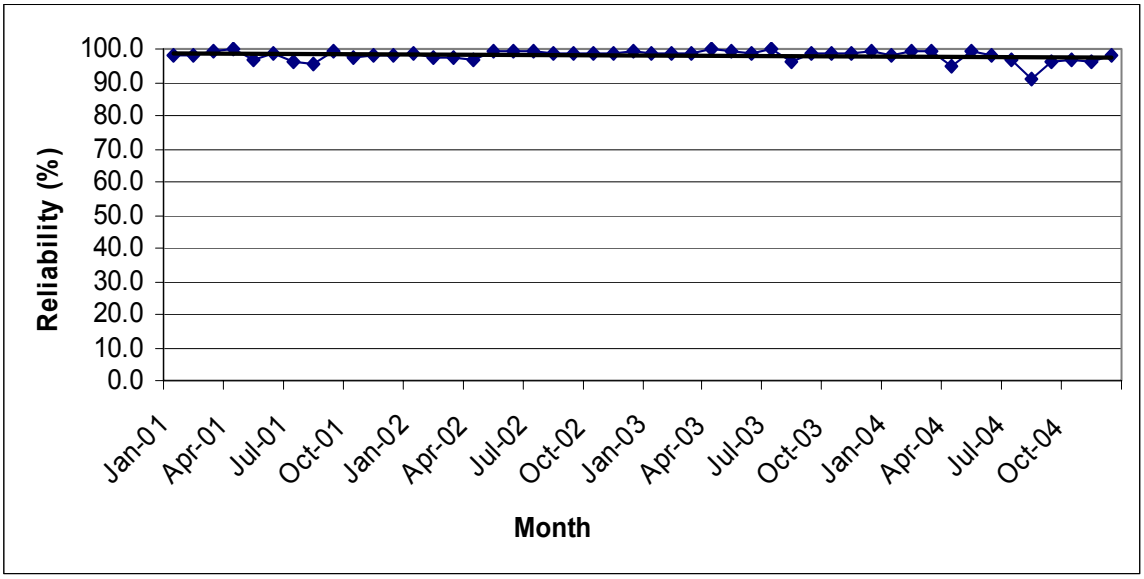
Compressor Reliability % = 100 x (Total Hrs - Forced Outage Hrs)/Total Hrs

where:

"Forced Outage Hrs" means the number of hours in a period when the compressor is not available for service, and the cause of unavailability has not been planned (for example, a shutdown due to failure of a critical pressure transmitter); and

"Total Hrs" means the number of hours that elapse between the start and finish times for the period.

Figure 4: Average compressor reliability



8.4 Compressor availability

This KPI measures, as a percentage figure, the availability of each Compressor on the DBNGP by the following formula:

Compressor Availability % = 100 x (Total Hrs - Forced Outage Hrs - Planned Outage Hrs)/Total Hrs

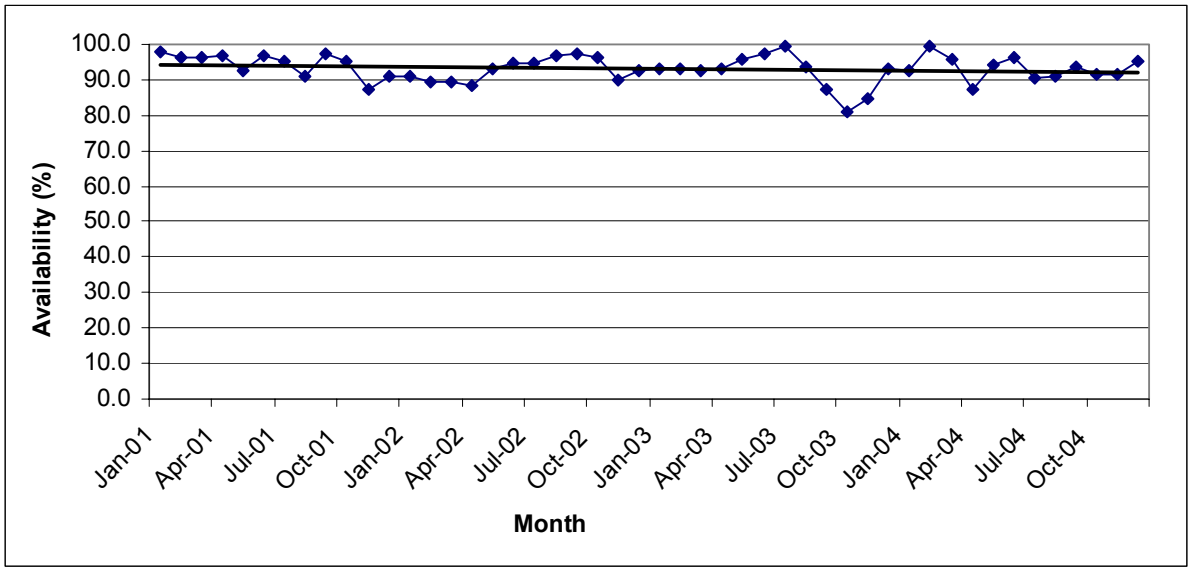
where:

"Forced Outage Hrs" means the number of hours in a period when the compressor is not available for service and the cause of unavailability is not due to preplanned reasons (for example, a shutdown due to failure of a critical pressure transmitter);

"Total Hrs" means the number of hours that elapse between the start and finish times for the period; and

"Planned Outage Hrs" means the number of hours in a period when the compressor is not available for service and the cause of unavailability is preplanned (for example, a planned oil change, or a planned modification to the compressor fuel gas skid which prevents operation).

Figure 5: Average compressor availability



8.5 Asset utilisation

This KPI measures, as a percentage figure, the utilisation of the DBNGP. It is calculated using the following formula:

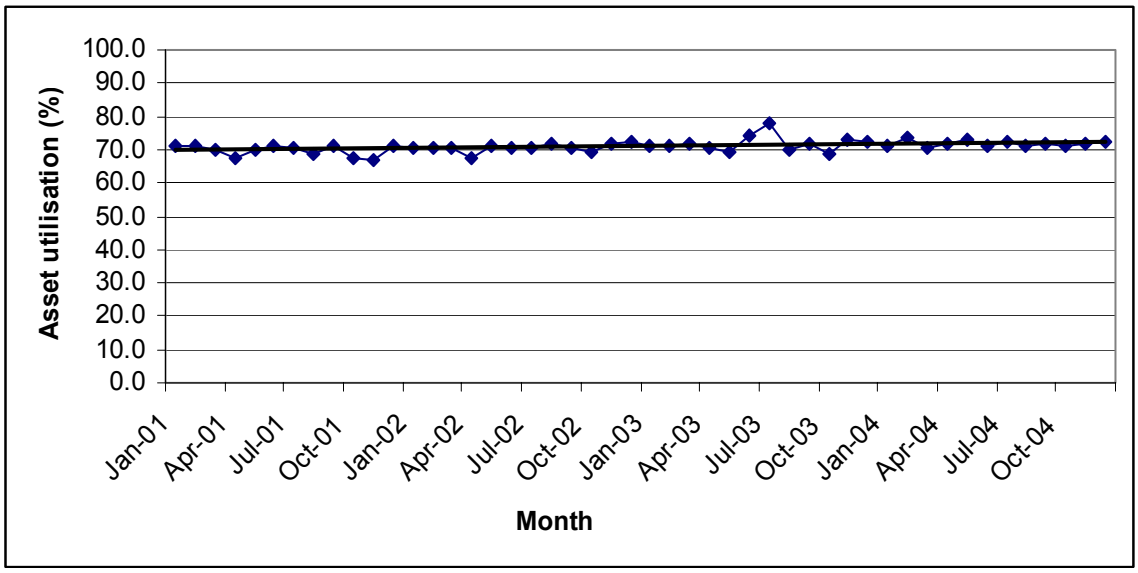
Asset Utilisation % = 100 x Actual Full Haul Throughput/Monthly Design Maximum Throughput

where:

"Actual Full Haul Throughput" means the summation of Gas deliveries from the DBNGP downstream of CS9 over a period; and

"Monthly Design Maximum Throughput" means the DBNGP maximum full haul throughput predicted by DBNGP operator modelling for the month(s) in which the period is contained.

Figure 6: Asset utilisation



8.6 Fuel ratio

This KPI is the ratio at which fuel gas is used on the DBNGP. It is calculated using the following formula:

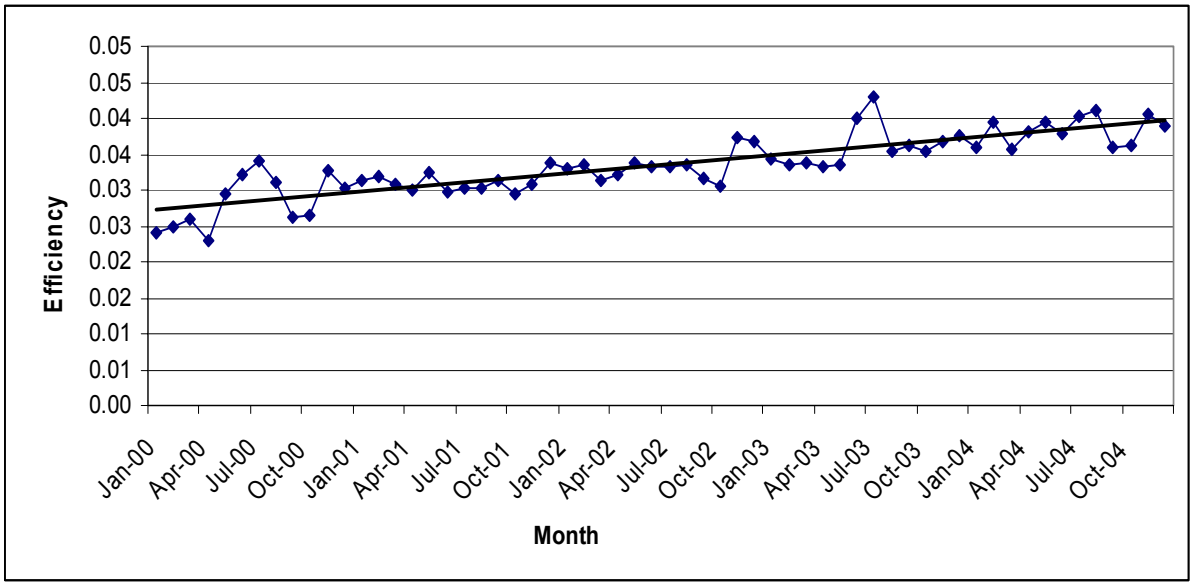
Fuel Ratio % = 100 x Actual Fuel Consumption/Actual Full Haul Throughput

where:

"Actual Fuel Consumption" means the total of all compressor fuel gas consumed over a period; and

"Actual Full Haul Throughput" means summation of Gas deliveries from the DBNGP downstream of CS9 over the period.

Figure 7: Fuel ratio



Annexure 1
DBNGP SYSTEM DESCRIPTION
AS AT JANUARY 2005

Amended Proposed Revised Access Arrangement Information
22 March 2005

Annexure 1: Description of the Gas Transmission System

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

PUBLIC VERSION

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1. REFERENCE TO ANY STATUTORY LAW EXTENDS TO AND INCLUDES ANY AMENDMENT OF

The DBNGP is described in Section 2 in terms of the boundaries of the transmission pipeline system between Dampier and Bunbury. These boundaries are defined by the system's receipt points, delivery points and notional gate points.

At receipt points ownership of gas transfers from shippers to the Operator. Facilities upstream of the receipt points are owned by shippers or by parties other than the Operator .

At delivery points ownership of gas transfers from Operator to shippers. Facilities downstream of the delivery points are owned by shippers or by parties other than the Operator .

Section 3 describes the major component parts of the DBNGP.

Section 4 provides the route map for the DBNGP.

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2. DESCRIPTION OF THE GAS TRANSMISSION SYSTEM: RECEIPT POINTS, DELIVERY POINTS AND NOTIONAL GATE POINTS

The schematic on the following page describes the DBNGP in terms of its receipt and delivery points.

"Receipt point" means a flange or joint or other point specified in an access contract as the point at which the shipper delivers gas to the Operator under the contract. Table 1 defines each of the receipt points in the DBNGP.

"Delivery point" means a flange or joint, notional gate point or other point specified in an access contract as a point at which the Operator delivers gas to the shipper under the contract. Table 2 defines each of the delivery points.

"Notional gate point" means the point for a distribution sub-network at which all grants of capacity in respect of that sub-network are to be made. Each notional gate point is defined in Table 3 which also shows the associated delivery points.

The following designations are used in the schematic and tables:

▭		Gas source
■	Ix-xx	Receipt point x-xx
■	Oy-yy	Delivery point y-yy
■	BP-zz	Branching point zz Branching points have no regulatory significance but service to identify points of branch from the main pipeline
▭		Inline metering facility KJ-A Kwinana Junction Meter Station M2A KJ-B Kwinana Junction Meter Station M2b
●	CSn	Compressor Station n
	PS	Power Station

Number of receipt points	= 4
Number of branching points	= 29
Number of delivery points	= 39
Number of notional gate points	= 12

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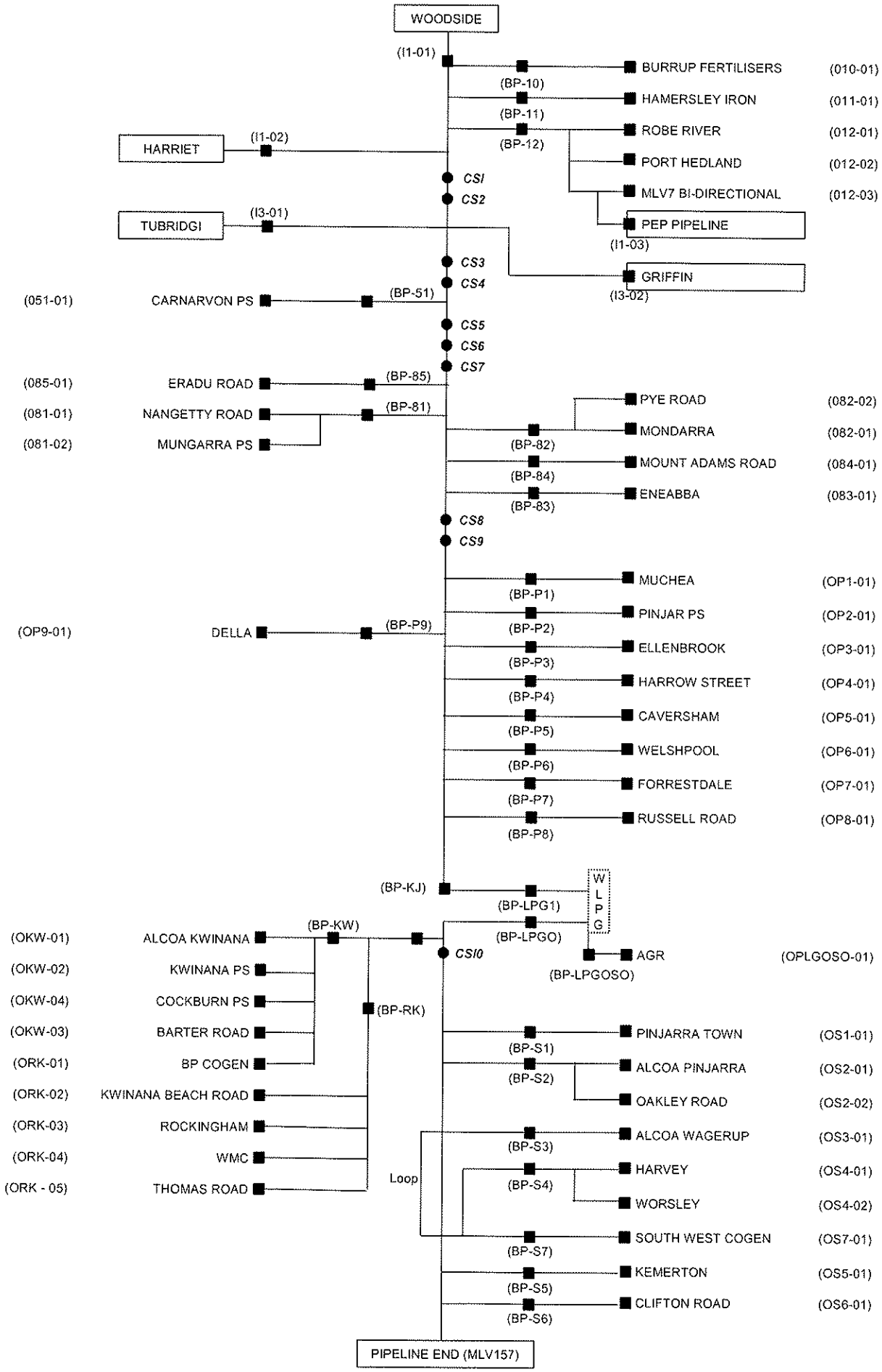

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TABLE 1 - GAS TRANSMISSION SYSTEM: RECEIPT POINTS

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline Kilometres)	DESCRIPTION
DOMGAS Dampier Plant	I1-01	0.000	Receipt point is at the upstream flange of the flange joint upstream of the monolithic insulation joint on the main gas pipeline just inside the fence of the Dampier facilities compound.
Harriet	I1-02	136.924	Receipt point is at the second insulation gasket upstream of valve ZV1 between the Harriet meter station and the mainline interconnecting pipe. This gasket is located inside the Harriet meter compound.
PEP Pipeline	I1-03	21.968	Receipt point is at the PEP side flange of isolation valve HV5020 located on the meter run 3/4 within MLV7 compound
Tubridgi	I3-01	272.694	Receipt point is at the second insulation gasket upstream of valve ZV1 between the Tubridgi meter station and the mainline interconnecting pipe. This gasket is located inside the Tubridgi meter compound.
Griffin	I3-02	272.729	Receipt point is at the second insulation gasket upstream of valve ZV2 between the Griffin meter station and the mainline interconnecting pipe. This gasket is located inside the Griffin meter compound.

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TABLE 2 - GAS TRANSMISSION SYSTEM: BRANCHING POINTS AND DELIVERY POINTS

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline Kilometres)	DESCRIPTION
Branching Point Burrup Fertilisers	BP-10	3.574	This is a branching point located at the insulation gasket downstream of the hot-tap valve within the Burrup Fertilisers metering compound
Burrup Fertilisers	O10-01	3.574	Delivery point is at the insulation gasket downstream of the venturi nozzle RO019 located within the Burrup Fertilisers metering compound
Branching Point MLV6	BP-11	8.845	This is a branching point located at the first tee downstream of HV100A and HV100B valves located inside the MLV6 compound.
Hamersley Iron	O11-01	9.440	Delivery point is on the upstream side of the insulation joint located 0.5km downstream of the odorant facilities.
Branching Point MLV7	BP-12	21.933	This is a branching point located at the first reducer downstream of HV100A and HV100B valves located inside the MLV7 compound.
Robe River	O12-01	22.083	Delivery point is at the reducer on the downstream side of the odorant injection facility at the delivery of Cajaput Well meter station.
Port Hedland	O12-02	21.968	Delivery point is at the spectacle-blind upstream joint located downstream of the meter station.
MLV7 Bi-directional meter	O12-03	21.968	Delivery point is at the PEP side flange of isolation valve HV5020 located on the meter run 3/4 within MLV7 compound
Branching Point MLV55	BP-51	578.858	This is a branching point located at the first flanged joint downstream of HV100A and HV100B located at the MLV55 compound.
Carnarvon Power Station	O51-01	748.583	Delivery point is at the insulation joint downstream of the pig receiver located at the Carnarvon Power Station.
Branching Point MLV90	BP-85	967.096	This is a branching point located at the pipeline junction between valve HV205C and HV206 inside the MLV90 compound.
Eradu Road	O85-01	967.116km	Delivery point is at the first isolation joint located downstream of Eradu Road meter station located inside the MLV90 compound.
Branching Point MLV91	BP-81	996.544	This is a branching point located at the first reducer downstream of HV100A and HV100B located at the MLV91 compound.
Nangetty Road	O81-01	996.851	Delivery point is at the first insulation flange located downstream of the injection line of the odorant facility. This insulating flange is located inside the Nangetty Road compound.
Mungarra Power Station	O81-02	999.126	Delivery point is on the upstream side of the isolation valves on each gas turbine generating unit located downstream of pressure relief valves.
Branching Point Pye Road	BP-82	1043.730	This is a branching point located on the downstream flange of valve HV001 located inside the Pye Road meter station compound.
Mondarra	O82-01	1043.740	Delivery point is at the insulating gasket downstream of Mondarra meter station. This gasket is located inside the Mondarra compound.
Pye Road	O82-02	1043.765	Delivery point is at the insulating flange upstream of the odorant injection point, located inside the Boral compound at the Pye Road meter station.
Branching Point MLV93	BP-84	1054.211	This is a branching point located at the first insulating joint on the supply line to the meter station. The insulating joint is located in the MLV93 compound.
Mount Adams Road	O84-01	1054.216	Delivery point is at the first insulation joint located downstream of Mount Adams Road meter station located inside the MLV 93 compound.

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TABLE 2 - GAS TRANSMISSION SYSTEM: BRANCHING POINTS AND DELIVERY POINTS *(Cont)*

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline Kilometres)	DESCRIPTION
Branching Point CS8	BP-83	1113.551	This is a branching point located on the downstream side of HV105B. The branching point is located in the MLV95 and Eneabba meter station compound.
Eneabba	O83-01	1113.621	Delivery point is at the insulation joint downstream of the launcher isolating valve.
Branching Point Muchea	BP-P1	1307.000	This is a branching point located at the downstream flange of HV1 located in the Muchea meter station compound.
Muchea	OP1-01	1307.036	Delivery point is at the reducer located downstream of the odorant injection facility.
Branching Point MLV116	BP-P2	1311.157	This is a branching point located on the downstream side of the HV 100A valve located inside the MLV116 compound.
Branching Point MLV117	BP-P9	1323.931	This is a branching point comprising the downstream flanges of valves HV100A and HV100B located inside the MLV117 compound.
Della Road Meter Station (MLV117)	OP9-01	1323.996	Delivery point is at the insulating joint upstream of the distribution system valve pit located outside the MLV117 compound.
Pinjar Power Station	OP2-01	1326.157	Delivery point is on the upstream side of isolation valves on each gas turbine generating unit located downstream of pressure relief valves.
Branching Point MLV118	BP-P3	1336.740	This is a branching point located at the first insulation joint on the supply line to the Ellenbrook meter station. This insulation joint is located inside the MLV118 compound.
Ellenbrook	OP3-01	1336.750	Delivery point is at the first insulation joint located downstream of valve HV010.
Branching Point Harrow Street	BP-P4	1343.510	This is a branching point located at the first tee upstream of HV100A on the 350mm receipt header to the Harrow Street meter station.
Harrow Street	OP4-01	1343.610	Delivery point is on the upstream side of the second delivery valve located downstream of odorant injection facility.
Branching Point MLV119	BP-P5	1347.339	This is a branching point located at the first reducer downstream of valves HV100A and HV100B located inside the MLV119 compound.
Caversham	OP5-01	1347.434	Delivery point is at the insulation joint located downstream of the odorant injection facility.
Branching Point MLV120	BP-P6	1359.664	This is a branching point located at the first reducer downstream of valves HV100A and HV100B inside the MLV120 compound.
Welshpool	OP6-01	1359.714	Delivery point is on the upstream side of the second delivery valve located downstream of the odorant injection facility.
Branching PointMLV122	BP-P7	1379.695	This is a branching point located at the first reducer downstream of valves HV100A and HV100B inside the MLV122 compound.
Forrestdale	OP7-01	1379.750	Delivery point is on the upstream side of the second delivery valve located downstream of the odorant injection facility.
Branching Point MLV129	BP-P8	1398.638	This is a branching point located on the downstream side of valve HV700 located on the receipt side of the Russell Road pre-regulation set. The point is adjacent to the Kwinana Junction scrubber bypass.
Thomas Road	ORK-05	1407.620	Delivery point is on the upstream side of the TiWest valve located inside the TiWest cogeneration facility.

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TABLE 2 - GAS TRANSMISSION SYSTEM: BRANCHING POINTS AND DELIVERY POINTS *(Cont)*

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline Kilometres)	DESCRIPTION
Russell Road	OP8-01	1408.183	Delivery point is on the upstream side of the second delivery valve located downstream of the odorant injection facility.
Branching Point Receipt to WLPG	BP-LPGI	1401.997	This branching point is at the first insulating flange located downstream of the pressure reducing valve PV035.
WLPG	OPLPGI-01	1402.025	Delivery point is at the second insulating flange located downstream of the pressure reducing valve PV035.
Branching Point Kwinana Junction	BP-KJ	1399.000	This is a branching point located at the centreline of the valve HV401A, located in the Kwinana Junction compound.
Branching Point Delivery from WLPG	BP-LPGO	1402.066	This branching point is at the first insulating flange upstream of valve V14 located on the return line from the WLPG plant.
Branching Point Second Delivery from WLPG	BP-LPGOSO	1401.997	This branching point is at the insulating gasket upstream of the AGR metering facility located at the second return line from the WLPG plant.
AGR	OPLPGOSO-01	1402.297	Delivery point is at the spectacle blind located on the downstream side of the restriction nozzle/blind located downstream of the AGR meter skid.
Branching Point KLV1	BP-RK	1405.327	This is a branching point located at the downstream side of valve VB11 located upstream of the TiWest Cogen meter station offtake.
BP Cogen	ORK-01	1407.716	Delivery point is at the upstream flange of the second isolation valve (HV017) located downstream of the meter skid.
Kwinana Beach Road	ORK-02	1409.647	Delivery point comprises the upstream flange of the second valve located downstream of the pig receiver of the BP Kwinana lateral and the first insulation gasket downstream of the first valve located downstream of the pig receiver of the BP Kwinana lateral.
Rockingham	ORK-03	1410.857	Delivery point comprises the: i) upstream flange of the meter station delivery valve located downstream of the odorant injection facilities. ii) upstream flange of the second valve located downstream of the CSBP pipe.
WMC	ORK-04	1410.837	Delivery point comprises the upstream side of the second isolating valve located on the WMC boundary for the high pressure line and the insulation joint located upstream of the second isolation valve for the low pressure line.
Branching Point Kwinana West	BP-KW	1405.217	This is a branching point located at 500 to 300 reducer located upstream of valves KLV3 and KLV4.
Alcoa Kwinana	OKW-01	1410.557	Delivery point comprises the delivery flanges on the downstream side of the meter station delivery valves HV601A and HV601B.
Kwinana Power Station	OKW-02	1409.651	Delivery point is at the insulating gasket on the downstream side of the meter station delivery valve HV501A.
Cockburn Power Station	OKW-04	1409.651	Delivery point is at the insulation gasket on the downstream side of the sonic nozzle (F0439).
Barter Road	OKW-03	1409.751	Delivery point comprises the upstream flange of the second meter station delivery valve downstream of the insulation joint and the upstream flange of the valve located downstream of the insulation joint.
Branching Point South 1	BP-S1	1449.456	This is a branching point located at the first insulating flange downstream of valve HV001 located upstream of the MLV143 compound.

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TABLE 2 - GAS TRANSMISSION SYSTEM: BRANCHING POINTS AND DELIVERY POINTS *(Cont)*

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline Kilometres)	DESCRIPTION
Pinjarra Town	OS1-01	1449.476	Delivery point is on the upstream side of the second delivery valve located downstream of the odorant injection facility.
Branching Point South 2	BP-S2	1458.106	This is a branching point located at the anchor flange located downstream of valve PLV1 located inside the MLV143 compound.
Alcoa Pinjarra	OS2-01	1463.426	Delivery point comprises the delivery flanges on the downstream side of the meter station delivery valves HV601A and HV601B
Oakley Road	OS2-02	1462.592	Delivery point is at the insulation gasket located downstream of valve HV105.
Branching Point South 3	BP-S3	1489.329	This is a branching point located at the first tee upstream of MLV150 located inside the Wagerup West compound.
Alcoa Wagerup	OS3-01	1498.857	Delivery point comprises the delivery flanges on the downstream side of the meter station delivery valves HV601A and HV601B.
Branching Point South 4	BP-S4	1513.630	This is a branching point located at the first tee upstream of the insulation joint adjacent to MLV154 located inside the MLV154 compound.
Harvey	OS4-01	1522.096	Delivery point is at the upstream flange of the isolation valve located downstream of the odorant injection facility.
Worsley	OS4-02	1546.620	Delivery point is at the flange downstream of the insulation joint located downstream of the meter station delivery valve.
Branching Point South 7	BP-S7	1513.635	This is a branching point located on the tee at the junction of the SW loop and the Worsley Cogeneration lateral, below ground in the MLV154/155 compound.
South West Cogeneration	OS7-01	1546.000	Delivery point is at the first insulating flange located downstream of the meter skids.
Branching Point South 5	BP-S5	1525.104	This is a branching point located on the downstream side of the offtake valve HV1 located inside the Kemerton meter station.
Kemerton	OS5-01	1525.124	Delivery point is at the upstream flange of the valve located downstream of the insulation joint.
Branching Point South 6	BP-S6	1530.439	This is a branching point located at the first reducer downstream of MLV156 and situated in the Clifton Road compound.
Clifton Road	OS6-01	1530.457	Delivery point is at the first insulating joint located downstream of the odorant injection facility.

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TABLE 3 - GAS TRANSMISSION SYSTEM: NOTIONAL GATE POINTS

NOTIONAL GATE POINT	ASSOCIATED DELIVERY POINT/S	TRANMISSION DELIVERY POINT/S DESIGNATION
NGP - Nangetty Rd	Nangetty Road	O81-01
NGP - Eneabba	Eneabba	O83-01
NGP - Muchea	Muchea	OP1-01
NGP - Ellenbrook	Ellenbrook	OP3-01
NGP - North Metro	Harrow Street Caversham	OP4-01 OP5-01
NGP - South Metro	Welshpool Forrestdale Russell Road	OP6-01 OP7-01 OP8-01
NGP - Barter Road	Barter Road	OKW-03
NGP - Rockingham	Rockingham	ORK-03
NGP - Pinjarra	Pinjarra Town Oakley Road	OS1-01 OS2-02
NGP - Harvey	Harvey	OS4-01
NGP - Kemerton	Kemerton	OS5-01
NGP - Clifton Road	Clifton Road	OS6-01

NGP - "name" Notional gate point - "name"

3. DESCRIPTION OF THE DBNGP: COMPONENT PARTS

The principal component parts of the DBNGP are:

(a) the main line between Dampier and Bunbury;

(b) gas turbine driven centrifugal compressor units and associated facilities including aftercoolers;

(c) main line valves;

(d) laterals;

(e) delivery stations;

(f) Kwinana Junction metering station;

(g) supervisory control and data acquisition (SCADA) system and the associated microwave communications facility; and

(h) odorising facilities.

3.1 General Description

The DBNGP comprises 1,845.3km of high pressure gas transmission pipeline, including laterals, and associated compression plant, and valves, linking gas suppliers in the north west of Western Australia with markets principally in the South West.

The DBNGP is not a single continuous entity, and consists of the following major parts.

The Dampier to Kwinana section is 1,398.6km of 660mm (26 inch) diameter pipe, and is rated and operates at 8.48MPa. It delivers gas to all part haul delivery points, and to all full haul delivery points between Compressor Station 9 (CS9) and Kwinana Junction. Five laterals with a total length of 195.6km ranging in diameter from 350mm (14 inches) to 150mm (6 inches) are connected to this pipeline section. The main line loops to Wesfarmers LPG Plant at Kwinana Junction. This loop is 6.4km of 660mm (26 inch) diameter pipe. Under an arrangement with Wesfarmers LPG Pty Ltd, gas leaves the system at a point immediately upstream of the company's LPG extraction plant at Kwinana and is returned to the system immediately downstream of the plant.

Kwinana Junction, 1,399km downstream of Dampier, is a major junction in the DBNGP. Two inline metering facilities are located at Kwinana Junction. One measures the quantity of gas delivered into the Kwinana West and Rockingham laterals, and the other measures the quantity of gas delivered into the Pipeline South. Facilities for gas quality measurement upstream and downstream of the LPG plant are also located at Kwinana Junction.

The main line branches immediately downstream of Wesfarmers LPG Plant into three independent sections:

(a) Kwinana West Lateral

This section is rated at 6.89MPa and operates at approximately 4.5MPa. It consists of three different pipes with a total length of 6.3km, ranging in diameter from 500mm (20 inches) to 200mm (8 inches). The Kwinana West Lateral delivers gas to delivery points at Alcoa Kwinana, Kwinana Power Station, and to the delivery point at Barter Road.

(b) Rockingham Lateral

A 180m long, 600mm (18 inches) pipeline provides a link between the suction of CS10 and Rockingham lateral. The Rockingham lateral and the link are rated at 6.89MPa and operates at approximately 4.5MPa. It consists of three different pipes with a total length of 8.9m, ranging in diameter from 300mm (12 inches) to 150mm

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(6 inches). The Rockingham Lateral delivers gas to delivery points at the BP/Mission Energy Cogeneration Plant, Mason Road, Western Mining Corporation, and the Rockingham delivery point supplying the distribution system serving Rockingham and Mandurah.

(c) Pipeline South

Compressor Station Number 10 (CS10) is located at the beginning of Pipeline South. Pipeline South MAOP is equal to 6.89MPa. It consists of three different pipes with a total length of 125.1km, ranging in diameter from 500mm (20 inches) down to 200mm (8 inches). It terminates at MLV157 located at Clifton Road, north of Bunbury. Four laterals with a total length of 79.7km ranging in diameter from 450mm (14 inches) to 250mm (10 inches) are connected to this pipeline section. The pipeline section between MLV150 and MLV154 is looped. The 18" loop length is equal to 24.3km. The Pipeline South delivers gas to delivery points at Alcoa Pinjarra, Alcoa Wagerup and Worsley Alumina, South West Cogen, and to delivery points supplying the distribution systems at Pinjarra Town, Oakley Road, Harvey, Kemerton and south of Clifton Road.

The main line between Dampier and Bunbury is externally coated with a fusion bonded epoxy powder coating. Between Dampier and Wagerup West, the pipe is internally coated with a two-part epoxy paint. The pipeline section between Wagerup West (MLV150) and the end of the pipeline (MLV157), and all laterals, are not internally coated. Further corrosion protection is provided by an impressed current cathodic protection system. The physical characteristics of the main line are set out in Table 4.

Laterals for supply of gas from the Dampier to Bunbury main line are listed in Table 5. The major laterals are shown on the Pipeline Route Maps of Section 6.

The locations of the main line valves which control gas flow through the Dampier to Bunbury main line are shown on the Pipeline Route Maps of Section 6. Areas through which the main line passes are classified (in accordance with Australian Standard 2885) as broad rural R1 and suburban T1. In areas classified as R1, main line valves are spaced approximately 30km apart. They are approximately 10km apart in areas classified as T1. The majority of the mainline valves can be remotely actuated from the control centre.

"MAOP" denotes maximum allowable operating pressure.

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TABLE 4 - MAIN LINE: PHYSICAL CHARACTERISTICS

SECTION:	DAMPIER TO KWINANA JUNCTION	
Length	1,311.2km	87.4km
Nominal size	660mm	660mm
Wall thickness	8.74mm	12.7mm
Steel type	API 5LX 65 DSAW	API 5LX 65 DSAW
MAOP	8,480kPa (gauge)	8,480kPa (gauge)

SECTION:	KWINANA JUNCTION - WLPG PLANT - KWINANA JUNCTION
Length	6.4km
Nominal size	660mm
Wall thickness	14.27mm
Steel type	API 5LX 65 DSAW
MAOP	8,480kPa (gauge)

SECTION:	KWINANA JUNCTION TO MAIN LINE VALVE 141
Length	10.8km
Nominal size	500mm
Wall thickness	7.94mm
Steel type	API 5LX 65 DSAW
MAOP	6,890kPa (gauge)

SECTION:	MAIN LINE VALVE 141 TO MAIN LINE VALVE 150
Length	73.5km
Nominal size	500mm
Wall thickness	5.56mm
Steel type	API 5LX 65 DSAW
MAOP	6,890kPa (gauge)

SECTION:	MAIN LINE VALVE 150 TO MAIN LINE VALVE 154
Length	23.9km
Nominal size	250mm
Wall thickness	4.80mm
Steel type	API 5LX 52 ERW
MAOP	6,890kPa (gauge)

SECTION:	MAIN LINE VALVE 154 TO MAIN LINE VALVE 157
Length	16.9km
Nominal size	200mm
Wall thickness	4.80mm
Steel type	API 5LX 52 ERW
MAOP	6,890kPa (gauge)

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TABLE 5 – GAS TRANSMISSION SYSTEM LATERALS

SECTION: MAIN LINE VALVE 150 TO MAIN LINE VALVE 154 (LOOPLINE)	
Length	24.3km
Nominal size	450mm
Wall thickness	6.35mm
Steel type	API 5LX 60 ERW
MAOP	8,280kPa (gauge)

SECTION: CS10 TO ROCKINGHAM LATERAL PIPELINE (ROCKINGHAM LATERAL LINK)	
Length	0.18km
Nominal size	600mm
Wall thickness	12.65mm
Steel type	API 5LX 70 ERW
MAOP	6,890kPa (gauge)

HAMERSLEY IRON	
Length	0.5km
Nominal size	200mm
Wall thickness	6.4mm
Steel type	API 5LX 52 ERW
MAOP	8,480kPa (gauge)

CARNARVON		
Length	163.7km	7.4km
Nominal size	150mm	150mm
Wall thickness	4.8mm	6.4mm
Steel type	API 5LX 42 ERW	API Grade B ERW
MAOP	8,480kPa (gauge)	1,900kPa (gauge)

MUNGARRA	
Length	2.5km
Nominal size	150mm
Wall thickness	6.4mm
Steel type	API 5L Grade B ERW
MAOP	8,480kPa (gauge)

PINJAR	
Length	14.2km
Nominal size	350mm
Wall thickness	7.1mm
Steel type	API 5LX 52 ERW
MAOP	8,480kPa (gauge)

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TABLE 5 - GAS TRANSMISSION SYSTEM LATERALS (CONTINUED)

RUSSELL ROAD	
Length	7.3km
Nominal size	300mm
Wall thickness	9.5mm
Steel type	API 5LX 46 ERW
MAOP	6,890kPa (gauge)

KWINANA WEST			
Length	2.0km	2.8km	1.5km
Nominal size	500mm	350mm	200mm
Wall thickness	7.9mm	9.5mm	8.7mm
Steel type	API 5LX 65DSAW	API 5LX 52 ERW	API Grade B ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)	6,890kPa (gauge)

ROCKINGHAM		
Length	3.2km	2.6km
Nominal size	300mm	150mm
Wall thickness	9.5mm	6.4mm
Steel type	API 5LX 46 ERW	API 5L Grade B ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)

KNC/BP (Part of Rockingham Lateral Located Downstream of Mason Road Delivery Station)	
Length	1.6km
Nominal size	250mm
Wall thickness	9.3mm
Steel type	API 5LX 42 ERW
MAOP	6,890kPa (gauge)

COGEN (Part of Rockingham Lateral Located Downstream of Cogen Delivery Station)	
Length	0.9km
Nominal size	200mm
Wall thickness	8.2mm
Steel type	API 5LX 42 ERW
MAOP	6,890kPa (gauge)

TIWEST COGENERATION LATERAL (Part of Rockingham Lateral)	
Length	0.58km
Nominal size	150mm
Wall thickness	7.1mm
Steel type	API 5LX 42 ERW
MAOP	6,890kPa (gauge)

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TABLE 5 - GAS TRANSMISSION SYSTEM LATERALS *(Continued)*

ALCOA PINJARRA		
Length	2.5km	2.9km
Nominal size	300mm	300mm
Wall thickness	7.1mm	9.5mm
Steel type	API 5L Grade B ERW	API 5LX 52 ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)

ALCOA WAGERUP		
Length	8.0km	1.5km
Nominal size	350mm	350mm
Wall thickness	7.1mm	9.5mm
Steel type	API 5L Grade B ERW	API 5LX 42 ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)

WORSLEY	
Length	32.9km
Nominal size	250mm
Wall thickness	4.8mm
Steel type	API 5LX 52 ERW
MAOP	6,890kPa (gauge)

SOUTH WEST COGENERATION LATERAL	
Length	32.9km
Nominal size	250mm
Wall thickness	6.35mm
Steel type	API 5LX 60 ERW
MAOP	8,280kPa (gauge)

3.2 Compressor Stations

Nine compressor station sites are spaced at intervals of about 140km along the main line. Gas turbine driven centrifugal compressors at eight of these stations are used to maintain pipeline pressure to meet natural gas demand in the Perth metropolitan area and at the receipt to Wesfarmers LPG Plant.

A ninth compressor station has been built at a site which was established and partially developed when the Dampier to Bunbury Pipeline was constructed. Compressor Station Number 10 comprising two units has been built at the beginning of Pipeline South. A summary of compression plant is presented in Table 6.

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TABLE 6 – COMPRESSOR STATIONS

COMPRESSOR STATION	DISTRANCE FROM DAMPIER (KM)	GAS TURBINE DRIVER	
1	137.2	Solar Mars 12600hp	(9MW)
2	272.1	Unit 1: General Electric Model LM500	(4MW)
		Unit 2: Solar Mars 15000hp	(10MW)
3	409.3	Unit 1: Solar Mars 15000hp	(10MW)
		Unit 2: General Electric Model LM500	(4MW)
4	546.9	Unit 1: General Electric Model LM500	(4MW)
		Unit 2: Solar Mars 15000hp	(10MW)
5	684.8	Unit 1: Solar Mars 12600hp	(9MW)
		Unit 2: Solar Mars 12600hp	(9MW)
6	824.9	Unit 1: General Electric Model LM500	(4MW)
		Unit 2: Nuovo Pignone PGT10	(10MW)
7	966.6	Unit 1: General Electric Model LM500	(4MW)
		Unit 2: Solar Mars 15000hp	(10MW)
8	1114.1	Unit 1: Solar Mars 12600hp	(9MW)
		Unit 2: Solar Mars 15000hp	(10MW)
9	1256.8	Nuovo Pignone PGT10	(10MW)
10	1402.3	Unit 1: Solar Centaur 4000hp	(3.0MW)
		Unit 2: Solar Centaur 4000hp	(3.0MW)

3.3 Aftercoolers

Aftercoolers are installed immediately downstream of the Domgas Dampier Plant receipt point, and immediately downstream of CS1 to CS9 compressor stations. The aftercoolers have been designed to control the downstream gas temperature below 45°C.

3.4 Delivery and Receipt Stations

Operator owns and operates delivery stations on the Dampier to Bunbury Natural Gas Pipeline.

"Delivery station" means *either a gate station or the metering equipment site associated with a transmission delivery point, and includes all facilities installed at the site to perform overpressure protection, reverse flow protection, excessive flow protection, gas metering and measurement, and telemetry, and all standby, emergency and safety facilities, and all ancillary equipment and services.*

Receipt stations are located upstream of the receipt points to the DBNGP and are owned and operated by parties other than Operator. "Receipt station" means the metering equipment site associated with an receipt point and includes any facilities installed at the site to perform overpressure protection, reverse flow protection, excessive flow protection, Gas quality monitoring, Gas metering and measurement, any telemetry, and all standby, emergency and safety facilities and all ancillary equipment and services.

3.5 SCADA System

The SCADA system is a micro-computer facility located at the control centre. The master station is a network of nineteen stations interconnected by a local area network, and consists of four operator stations, two logging stations, seven communication stations, three remote stations and three remote operator stations. Over one hundred Field Remote Terminal Units

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(RTUs) are polled by the communication stations for data and respond to commands from the master station.

The communication link to stations north of Perth is a microwave system. There are microwave antennas and repeater stations at main line valve stations and at compressor stations. SCADA communications south of Perth make use of a UHF radio system.

3.6 Odorising

Gas in the main pipeline between Dampier and the Wesfarmers LPG plant at Kwinana is not odorised. Upstream of Kwinana Junction, gas is odorised at delivery stations with the exception of those stations serving the Port Hedland Pipeline and the Geraldton area. Gas into the Geraldton area is odorised at the Nangetty Road delivery station. Downstream from Kwinana Junction, gas is odorised in accordance with the Gas Standards Act sufficient for commercial/industrial use. The level of odorant is increased at delivery stations delivering gas into the distribution system and at Clifton Road delivery station.

4. DBNGP MAPS

For security reasons, copies of these documents are available to bona fide prospective users and can be obtained by contacting DBNGP's Manager, Commercial on 9223 4300.

Annexure 2

DESCRIPTION OF NATURE AND JUSTIFICATION FOR STAY IN BUSINESS RELATED FORECAST NEW FACILITIES INVESTMENT

REVISED ACCESS ARRANGEMENT INFORMATION
2 JUNE 2005

ANNEXURE 2: DESCRIPTION OF AND JUSTIFICATION FOR FORECAST NEW FACILITIES INVESTMENT

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

DBNGP (WA) TRANSMISSION PTY LTD
ACN 061 609 190
LEVEL 7/ 239 ADELAIDE TERRACE, PERTH WA 6000
CONTACT: ANTHONY CRIBB
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1. JUSTIFICATION OF STAY-IN-BUSINESS CAPEX 2005-2010

1.1 Operator divides its forecast New Facilities Investment into:

(a) expansion CAPEX; and

(b) stay-in-business CAPEX.

1.2 Expansion CAPEX is the capital expenditure expected to be incurred in expanding the gas transportation capacity of the DBNGP. Expansion CAPEX is usually:

(a) large – it is for pipeline looping and additional compression; and

(b) infrequent – it is required only when shippers require additional capacity.

1.3 Expansion CAPEX during the Access Arrangement Period is estimated to be $1,074.3 million ($ nominal), and comprises $836.1 million for pipeline looping, and $238.2 million for compression. This is an exceptionally large program. It is to be undertaken over a fairly short time – the Access Arrangement Period – because major shippers have requested additional capacity, and the prior owners of the DBNGP were unable to finance expansion of the pipeline to provide that capacity.

1.4 Stay-in-business CAPEX comprises, by and large, a relatively large number of recurring capital projects of relatively small value.

1.5 These two broad classes of CAPEX are shown in Table 1.

Table 1: Forecast New Facilities Investment 2005-2010 ($m nominal)

CAPEX	2005	2006	2007	2008	2009	2010
Expansion						
Pipeline looping	0.513	0.000	272.339	302.109	93.199	167.971
Compression	0.000	69.234	124.524	44.477	0.000	0.000
Stay-in-business	13.157	13.967	7.300	9.006	10.062	9.293
Total	13.670	83.201	404.163	355.592	103.261	177.264

1.6 The individual capital projects which comprise stay-in-business CAPEX are listed in Tables 2a and 2b.

Table 2a: Stay-in-business CAPEX ($m nominal)

Capital project	2005	2006	2007	2008	2009	2010
Pipeline, main line valves and facilities						
CCVTs and GEA upgrades	0.210	0.216	0.221	0.227	0.233	0.000
DBNGP emergency simulation	0.000	0.000	0.000	0.000	0.233	0.000
Design changes to control systems	0.526	1.618	0.000	0.000	0.000	0.000
Easement encroachment management	0.526	0.539	0.553	0.567	0.582	0.596
Gas supply chain – design changes	0.368	0.377	0.000	0.000	0.000	0.000
Hazardous area audits implementation	0.210	0.216	0.221	0.227	0.233	0.239
Induced voltage and CP system upgrades	0.263	0.539	0.830	0.567	0.000	0.000
MLV and repeater site earthing upgrades	0.736	0.755	0.000	0.000	0.000	0.000
MLV fuel gas cabinets replacement	0.263	0.270	0.000	0.000	0.000	0.000
Odorant storage facilities upgrades	0.000	0.216	0.221	0.000	0.000	0.000
Phasing out of bypass odorisers	0.158	0.162	0.000	0.000	0.000	0.000
Pipeline efficiency monitoring	0.000	0.270	0.000	0.000	0.000	0.000
Pipeline integrity - lateral pigging facilities	0.631	0.647	0.664	0.681	0.698	0.716
Sulphur deposition management	0.210	0.216	0.221	0.227	0.233	0.000
Compressor stations and related facilities						
Compressor station airstrip upgrading	0.526	0.000	0.000	0.000	0.000	0.000
Compressor station facilities improvement	1.578	0.000	0.000	0.000	0.000	0.000
Compressor station on-line monitoring	0.210	0.216	0.221	0.227	0.233	0.239
Compressor station water treatment upgrade	0.421	0.431	0.442	0.227	0.233	0.477
CS9 stormwater drainage upgrade	0.210	0.000	0.000	0.000	0.000	0.000
Fire and gas systems	0.000	0.431	0.442	0.000	0.000	0.000
LM500 stations drainage upgrade	0.368	0.377	0.000	0.000	0.000	0.000
Solar Mars 90 compressed air supply upgrade	0.000	0.809	0.830	0.000	0.000	0.000
Solar Mars 90 control system upgrade	0.316	0.324	0.000	0.000	0.000	0.000
Solar Mars 90 HMI upgrade	0.000	0.539	0.553	0.000	0.000	0.000
Solar Mars 90 surge control upgrade	0.158	0.162	0.000	0.000	0.000	0.000

Table 2b: Stay-in-business CAPEX (continued) ($m nominal)

Capital project	2005	2006	2007	2008	2009	2010
SCADA and communications						
Microwave system replacement/upgrade	0.263	0.000	0.000	4.469	5.816	4.939
South West communications transfer	0.789	0.809	0.000	0.000	0.000	0.000
SCADA master station upgrade	0.000	0.216	0.000	0.000	0.000	0.000
SCADA emergency backup	0.263	0.270	0.000	0.000	0.000	0.000
Metering						
Additional gas chromatographs	0.158	0.162	0.166	0.000	0.000	0.000
Design changes and compliances	0.526	0.539	0.000	0.000	0.000	0.000
Meter station cabinets and marshalling boxes	0.263	0.270	0.000	0.000	0.000	0.000
Meter station equipment shelters	0.000	0.108	0.000	0.000	0.000	0.000
Flow computer upgrades	0.210	0.216	0.000	0.000	0.000	0.000
Computer equipment and systems						
Customer reporting system upgrades	0.053	0.054	0.055	0.057	0.058	0.060
IT Infrastructure	1.483	0.971	0.664	0.681	0.698	0.716
Plant and equipment						
Engineering tools and equipment	0.210	0.216	0.221	0.227	0.233	0.239
Field tools and equipment	0.053	0.054	0.055	0.057	0.058	0.060
Motor vehicles	0.263	0.270	0.277	0.284	0.291	0.298
Buildings and grounds						
Corporate head office modifications	0.105	0.108	0.111	0.113	0.116	0.119
Jandakot Depot improvement	0.105	0.108	0.111	0.113	0.116	0.119
Security upgrades	0.526	0.270	0.221	0.057	0.000	0.477
Total (Tables 2a and 2b)	13.157	13.967	7.300	9.006	10.062	9.293

1.7 Forecast expenditures for each of the other capital projects listed in Tables 2a and 2b are considered and substantiated as New Facilities Investment (against the tests in section 8.16 of the Code) in the paragraphs which follow. In each case, the expenditure is for the construction, development or acquisition of assets during the Access Arrangement Period to enable the provision of Services using the DBNGP.

1.8 Expenditure for the expansion related new facilities is explained and justified in Annexure 3 to the Access Arrangement Information.

1.9 As a general submission applicable to all of the capital projects listed above, the assets to be created:

(a) are required to maintain levels of service being afforded on the DBNGP;

(b) contribute to lower costs of providing services, particularly where they facilitate improved equipment availability without an increase in manpower; and

(c) are required to maintain the safety and integrity of Services provided using the pipeline.

2. DESCRIPTION AND JUSTIFICATION OF FORECAST STAY IN BUSINESS RELATED NEW FACILITIES INVESTMENT

CCVTs and GEAs

2.1 Closed Circuit Vapour Turbines ("CCVTs") and Gas Engine Alternators ("GEAs") are the primary means of electric power generation at DBNGP compressor stations and remote main line valve ("MLV") sites. Much of the equipment in question was installed before, or during, the Stage 1 expansion of pipeline capacity in 1991. It is technologically obsolete, and has deteriorating reliability. Furthermore, replacement components are now difficult to obtain.

2.2 There are 24 CCVTs and 34 GEAs installed on the DBNGP, and a programme of progressive replacement is to be initiated during the Access Arrangement Period.

2.3 Without power generation at compressor stations and MLV sites, Operator will have difficulty in maintaining the integrity and contracted capacity of services on the pipeline.

2.4 Accordingly, the investment in supply chain design changes is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

DBNGP emergency simulation

2.5 The DBNGP is a critical link in the energy supply chain in south western Australia. The importance of that link will increase as pipeline capacity is expanded for electric power generation and industrial use during the Access Arrangement Period. With expanded capacity, greater volumes of gas being transported, and increased numbers of users, pipeline operation will become more complex. The frequency of transient conditions and extreme events is likely to increase, requiring that pipeline operators respond quickly and precisely to the unusual circumstances. Furthermore, pipeline operation to maintain gas deliveries will become more complex in times of emergencies elsewhere in the energy supply chain.

2.6 In these circumstances, the proper training of pipeline operators is essential to maintaining the safety and integrity of the DBNGP, and to ensuring the reliability of the energy supply chain of which it is a part. As part of its continuing to provide this training, Operator is intending to invest in a pipeline training simulator which will allow operators to practice responses to a wide range of pipeline incidents and system emergencies.

2.7 Accordingly, the investment in the simulator is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Design changes to control systems

2.8 Unexpected supply interruptions have occurred at delivery points at Alcoa of Australia's Wagerup refinery, and at other delivery points on other pipelines that were owned by the prior owners of the DBNGP (and supplied partly through the DBNGP). These interruptions were the result of unplanned pressure control valve closures.

2.9 Operator is proposing to apply the learning from these supply interruptions by reviewing the configuration and settings of pressure control valves at other delivery points. Where necessary, Operator will reconfigure control systems to minimise the risk of unplanned supply interruption.

2.10 This work is required primarily for maintenance of the integrity and contracted capacity of services on the DBNGP. However, the avoidance of unplanned supply interruption may also have implications for the maintenance of the integrity of downstream facilities, and for the safety of personnel operating those facilities.

2.11 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Easement encroachment management

2.12 As other human activity encroaches on the DBNGP, additional measures will be required to protect the pipeline and to ensure compliance with AS2885 and the Safety Case.

2.13 AS2885 provides methodologies for pipeline risk assessment. These methodologies have been applied, encroachment risks identified and mitigation measures recommended.

2.14 During the Access Arrangement Period, the following protective measures will be carried out on sections of the DBNGP at risk from further encroachment of other human activity:

(a) slabbing;

(b) additional markers and signage;

(c) further fencing of facilities; and

(d) increasing the depth of cover over the pipe.

2.15 These measures are necessary to ensure the safety of the general public, and to maintain the integrity of services provided using the pipeline.

2.16 Accordingly, the investment in protective measures is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Gas supply chain – design changes

2.17 The DBNGP has now been in service for more than 20 years. The pipeline was designed during the early 1980s, and major construction was completed in 1984. Since then, its capacity has been progressively expanded with the addition of compressors and, more recently, with looping. The initial compression-based enhancements were in 1985 and 1991. In these circumstances, pipeline facilities and systems (of which the pressure control systems referred to above are a specific example) may no longer be adequate to the current gas transportation task.

2.18 Operator has therefore undertaken a review of the entire gas supply chain, from receipt points to delivery points, to identify potential causes of supply interruption, and a large number of recommendations have been made for design changes and other measures to mitigate the risks. Some of these recommendations involve only procedural changes (for example, allowing any field officer to operate any valve). Some involve minor modifications to equipment, such as placing identifying codes on critical isolation valves, while others (for example, creation of a single SCADA screen to provide an overview of the Kwinana area) require more substantial modifications.

2.19 Operator expects that implementation of these recommendations will result in the improved reliability of services provided using the DBNGP. That is, their implementation is required primarily for maintenance of the integrity and contracted capacity of services on the pipeline.

2.20 Accordingly, the investment in supply chain design changes is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Hazardous area audits implementation

2.21 The age of the principal facilities and systems comprising the DBNGP has been noted above. Operator is concerned that either:

(a) older equipment is no longer compliant with current safety standards; and

(b) older equipment has deteriorated to the point where it is still operational but represents a safety risk (for example, electrical switchgear which may now arc during use in areas where gas may be present).

2.22 Operator is therefore proposing to continue, during the Access Arrangement Period:

(a) safety auditing of potentially hazardous areas;

(b) identification of actions to mitigate the risks identified; and

(c) modification or replacement of equipment which is found to be unsafe.

2.23 This work is to be undertaken to ensure the continued safety of, primarily, maintenance personnel and contractors working on the DBNGP.

2.24 Accordingly, the investment in hazardous area audit implementation is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Induced voltage and CP upgrades

2.25 Where electric power lines are located close to a gas transmission pipeline, a significant potential difference may exist between the power lines and the pipeline. The possibility of this potential difference existing, and the hazard it creates is recognised in pipeline design, and protection is provided through, for example, appropriate earthing.

2.26 The original design for the DBNGP anticipated protection against potential differences as high as 1,500 volts AC. However, current standards require a much lower voltage tolerance.

2.27 Furthermore, as other human activity encroaches on the DBNGP corridor, and an increasing number of power lines cross the pipeline, the likelihood of high induced potential differences rises, exacerbating the problem of non-compliance with current standards.

2.28 In these circumstances, Operator proposes reviewing power line crossings and, where necessary, enhancing existing pipeline earthing facilities, or adding new facilities, to achieve compliance with current standards.

2.29 The main line between Dampier and Bunbury is externally protected against corrosion by a fusion bonded epoxy powder coating, and further corrosion protection is provided by an impressed current cathodic protection system.

2.30 After some 20 years in service, the DBNGP remains reasonably well protected by its external coating. However, annual monitoring has revealed evidence of some coating failure at points along the pipeline. The incidence of corrosion resulting from coating failure can be reduced by providing additional cathodic protection.

2.31 Investment in induced voltage protection, and in additional cathodic protection, is now required if Operator is to maintain the safety and integrity of the pipeline, and is to continue to provide Services, over the long term.

2.32 Accordingly, the investment in induced voltage protection, and in additional cathodic protection, is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

MLV and repeater site earthing upgrades

2.33 Earthing systems are installed for the protection of equipment and personnel at all sites supplied with electric power.

2.34 Their metallic components are subject to corrosion, and the maximum physical life of earthing systems is about 15 years.

2.35 Earthing systems at 24 sites between Dampier Facilities and MLV91 have lives approaching 15 years, and systems at 10 of those sites are expected to require replacement during the Access Arrangement Period.

2.36 A risk assessment undertaken for the Safety Case required under the pipeline licence revealed that the earthing systems at some sites had deteriorated to the point where they posed an unacceptable risk to personnel.

2.37 Investment in new earthing systems is now required if Operator is to maintain the safety and integrity of the pipeline, and continue to provide Services in accordance with its current contractual obligations.

2.38 Accordingly, the investment in earthing systems is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

MLV fuel gas cabinets replacement

2.39 Steel cabinets providing weather protection for the valves and gauges that form part of the fuel gas supply systems at main line valve sites, and cable marshalling boxes at those sites, have been in place since the 1980s and are now extremely corroded. They require replacement.

2.40 Investment in new cabinets is now required if Operator is to maintain the safety and integrity of the pipeline, and continue to provide Services in accordance with its current contractual obligations.

2.41 Accordingly, the investment in earthing systems is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Odorant storage facilities upgrades

2.42 Operator delivers odorised gas to shippers at a number of delivery points on the DBNGP (principally in the Perth metropolitan area). As the volume of gas delivered increases over the Access Arrangement Period, requirements for odorant storage at those delivery points are expected to exceed the design capacities of existing storage facilities.

2.43 Operator therefore expects to upgrade odorant storage facilities, by installing larger tanks and pumps, during the Access Arrangement Period.

2.44 Investment in new odorant storage facilities is now required if Operator is continue to provide Services in accordance with its current contractual obligations.

2.45 Accordingly, the investment in odorant storage facilities is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Phasing out of bypass odorisers

2.46 At six sites along the DBNGP, gas flowing through bypass pipework can be odorised from underground odorant storage vessels. These vessels impose a significant risk

to the environment. Were a vessel to be damaged, odorant may leak out into groundwater supplies. Were the use underground odorant storage to be proposed today, it would not be approved by the Environmental Protection Authority.

2.47 Operator therefore proposes to replace the underground bypass odorisers with above-ground odorant injection facilities during the Access Arrangement Period.

2.48 Investment in the new odorant injection facilities is now required if Operator is to maintain the safety and integrity of the pipeline, and continue to provide Services in accordance with its current contractual obligations.

2.49 Accordingly, the investment in odorant injection facilities is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Pipeline efficiency monitoring

2.50 Minor modifications made to pipeline facilities – in particular, to compressor units – in the course of major maintenance, as a result of equipment replacement, or to deliver operating efficiencies tend to have the effect of reducing, over time, the design capacity of the pipeline.

2.51 The DBNGP now has a history of some 20 years of these minor modifications which may have reduced the capacity available to shippers.

2.52 Operator is therefore proposing to install, during the Access Arrangement Period, instrumentation, computer equipment and software for monitoring the efficiency of compressor operations with a view to restoring the capacity of the DBNGP to its design capacity.

2.53 This investment in efficiency monitoring equipment will ensure that Operator is able to continue to provide Services in accordance with its current contractual obligations.

2.54 Accordingly, the investment in efficiency monitoring equipment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Pipeline integrity - lateral pigging facilities

2.55 The pipeline licences that apply to the DBNGP (PL40, PL41 and PL47) require that, every five years, the licensee confirm that the pipeline is rateable to the maximum allowable operating pressures ("MAOP") stipulated in those licences.

2.56 To be able to provide the required confirmations of MAOP, Operator must regularly inspect the interior of the pipeline by pigging. However, the following laterals do not have facilities for the launching and receival of pigs:

(a) Alcoa Kwinana;

(b) Alcoa Pinjarra;

(c) Alcoa Wagerup;

(d) lateral from MLV155 to MLV157; and

(e) the Kwinana West lateral (excluding the Rockingham lateral).

2.57 Pipeline licensing serves, among other things, to ensure that facilities are maintained to a standard consistent with providing for the safety of shippers and the general public, and a pipeline operator who fails to comply with the requirements of its pipeline licence risks having its operation closed down.

2.58 Investment in lateral pigging facilities is now required if Operator is to maintain the safety of the pipeline, and continue to provide services in accordance with its current contractual obligations.

2.59 Accordingly, the investment in lateral pigging facilities is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Sulphur deposition management

2.60 The deposition, on the internal components of pipeline equipment, of elemental sulphur from sulphur compounds in the gas stream has been a problem for the DBNGP for many years. Elemental sulphur generally forms at pressure regulation points such as pressure controllers and fuel control valves on gas turbines. It also affects metering equipment. To date, the problem has been managed through increasing the frequency of maintenance carried out on equipment likely to be affected by sulphur deposition.

2.61 In recent years, minor changes in gas composition have exacerbated the sulphur deposition problem. With the broadening of the gas quality specification, higher levels of sulphur are likely to be introduced into the gas stream.

2.62 Operator now proposes to replace sulphur damaged equipment – principally filters and turbine meters – at affected sites on the DBNGP.

2.63 Without these replacements, there will be an increased risk of unplanned interruptions to gas supplies to particular shippers, impacting Operator's ability to maintain integrity and contracted capacity of services. Also, there is a greater risk that incorrect meter readings will occur, making compliance with the metering and invoicing provisions of contracts difficult to achieve.

2.64 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Compressor station airstrip upgrading

2.65 Airstrips at CS1 and CS5 were upgraded during the period from 2000 to 2004, providing safer landing strips for larger aircraft. This work was undertaken to allow maintenance crews to be flown in on a regular basis, and to allow manning in times of peak capacity utilisation. It was necessary to minimise supply interruption in circumstances where the pipeline capacity is fully contracted. Furthermore, allowed manning in emergency situations, and allowed flying doctor access to the sites.

2.66 Further upgrade work is now planned for the airstrips at CS2, CS3, CS4, and CS6.

2.67 The work involved will include the following:

(a) lengthening of the strips; and

(b) the purchasing and installation of lights for night landing.

2.68 In addition to its facilitating minimisation of supply interruption in circumstances where the pipeline capacity is fully contracted, this work is required to meet the requirements of the aviation safety regulator.

2.69 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Compressor station facilities improvement

2.70 Pipeline field staff are based at certain compressor station sites along the DBNGP. However, given the distance between compressor stations and the need to ensure security of supply on the pipeline, there is a need to improve the conditions and working environment of employees to meet the Operator's safety standards.

2.71 Compressor station facilities, many of which were built in 1984, have deteriorated. Building maintenance is increasing, given the increase in operational assets at these sites.

2.72 In addition, working space at some sites is at a premium.

2.73 It has therefore been identified that the following upgrade work needs to be undertaken during the Access Arrangement Period:

(a) upgrade of some of the accommodation units at some of the sites

(b) improving the intrinsic safety at all sites;

(c) upgrading the control rooms at CS2, CS4 and CS7.

2.74 The enhancements will provide more working space for operational requirements, and improved accommodation. Improvements in accommodation will provide better living conditions for the field operational staff, focusing on cooking, and ablution areas. Intrinsic safety audits are a requirement under AS 2885; and initial audits conducted have indicated upgrading is required in order to bring the sites up to compliance.

2.75 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Compressor station on-line monitoring

2.76 Operator expects the capacity of the DBNGP to be fully contracted, or close to fully contracted for firm type capacities, during the Access Arrangement Period. In these circumstances, unplanned equipment failures will impact directly on Operator's ability to continue to provide services in accordance with its contractual obligations.

2.77 Operator is therefore proposing to install vibration monitoring equipment on compressor units, and to provide on-line visibility of signals from that equipment.

2.78 Vibration is a key indicator of the current operating condition of a compressor unit. A unit that is vibrating excessively can be expected to fail in the near future.

2.79 On-line vibration monitoring should allow the early dispatch of maintenance crews to compressor units behaving abnormally, resulting in fewer failures and greater reliability of gas transportation service. In effect, investment in the monitoring equipment is necessary to maintain the integrity and contracted capacity of services.

2.80 Accordingly, the investment to be made in vibration monitoring equipment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Compressor station water treatment upgrade

2.81 Reverse osmosis water purification units installed at CS1, 2, 3, 4, 5, 6, 7 and 8 between 1984 and 1991 will reach the ends of the design lives during the Access Arrangement Period. In some cases the units have already deteriorated and are close to the point where water supplies may not meet health and safety standards. The existing water purification units are, therefore, to be replaced with new water treatment units.

2.82 In addition, to ensure the quality of water quality which meets health and safety standards, Operator will install new pipework, valves and pumps.

2.83 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

CS9 stormwater drainage upgrade

2.84 Stormwater drainage at CS9 has been found to be inadequate. The drainage system is unable to cope with heavy rainfall, and the runoff has the potential to cause significant erosion which has the potential to undermine pipework and structures installed at the station.

2.85 Were undermining to occur, gas flow through CS9 may have to be restricted so that facilities can be made safe and the problem rectified.

2.86 Investment in the upgrading of the CS9 stormwater drainage system is now required if Operator is to maintain the safety and integrity of the pipeline, and continue to provide Services in accordance with its current contractual obligations.

2.87 This upgrade will require diversion of bulk water to areas of the site that are not prone to erosion.

2.88 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Fire and gas systems

2.89 Operator's fire and gas systems, which provide gas detection and protection against fire at compressor stations, were reviewed in 2004 by the Western Australian Safety and Technical Regulator in accordance with current safety requirements.

2.90 As a result of that review, the Safety and Technical Regulator identified a need to upgrade fire suppression equipment at compressor stations which had been extended or modified as part of the Stage 3A capacity expansion project.

2.91 This was the case, notwithstanding the fact that the Stage 3A compression plant was built in accordance with design standards applying at the time.

2.92 In addition, older compressor stations on the DBNGP (those at which LM500 gas turbine compressor units were installed) were originally equipped with halon gas fire protection systems. In the event of fire, the compressor building would be flooded with halon gas and the fire extinguished. In the absence of fire, accidental halon release would displace air in the compressor building, making entry into the building unsafe. The risk of accidental halon release, and employee asphyxiation, was judged higher than the risk associated with a fire in a compressor building, and the halon protection systems were decommissioned before the DBNGP was sold by the State of Western Australia in 1998.

2.93 Compression plant installed as part of an expansion of pipeline capacity in 1991 was equipped with fire and gas detection systems, and with fire suppression capability using carbon dioxide. Compression plant subsequently installed, for the Stage 2 and 3A expansions of pipeline capacity was equipped with fire and gas detection, but not with fire suppression. These systems are managed by programmable logic controller ("PLCs"), which are due for replacement in the next 5 years.

2.94 Sites to be upgraded include CS2, CS4 and CS7.

2.95 The investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

LM500 stations drainage upgrade

2.96 At LM 500 compressor stations, drainage is via leach drains. As a result, any oil spilled onto the floors of station buildings during engine changes and compressor overhauls passes into the ground via this drainage system.

2.97 There is therefore a potential to contaminate the ground with oil.

2.98 This risk does not meet the environmental requirements of the pipeline licence, and drainage facilities at LM500 stations must be upgraded to eliminate it.

2.99 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Solar Mars 90 compressed air supply upgrade

2.100 Dryers in the compressed air supply systems that deliver clean, dry air to Solar Mars 90 gas turbines for sealing and cooling are difficult to maintain in a condition of high reliability. Without reliable air supplies to the gas turbines, the turbine/compressors themselves are unreliable, and the reliability of the gas transportation service provided using the DBNGP is reduced.

2.101 Operator is therefore proposing to redesign and rebuild the dryers and pressure reduction facilities of the compressed air supply systems to improve the reliability of the Solar Mars 90 units. This work is necessary to maintaining the integrity and contracted capacity of services.

2.102 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Solar Mars 90 control system upgrade

2.103 Solar Mars 90 series gas turbine compressor units were installed on the DBNGP in the early 1990s. Their control systems use proprietary computing and communications hardware and software.

2.104 This proprietary hardware and software is not compatible with the generic computing and communications platforms in use today, and is becoming increasingly difficult to maintain as components for the hardware are no longer available and the software is no longer supported.

2.105 Operator is therefore proposing to upgrade computing and communications hardware and software on its four Solar Mars 90 units so that it is both compatible

with current industry standards, and the units are more accessible for the purpose of remote operation.

2.106 Investment in the in the upgrade of the Solar Mars 90 control systems is necessary to maintaining the reliability of gas transportation services provided using the DBNGP. It is necessary to maintaining the integrity and contracted capacity of services.

2.107 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Solar Mars 90 HMI upgrade

2.108 Like the unit control systems, the human-machine interfaces ("HMI") in the control rooms at compressor stations equipped with Solar Mars 90 units use proprietary hardware and software, and they are also becoming increasingly difficult to maintain as components for the hardware are no longer available and the software is no longer supported.

2.109 Operator is therefore proposing to upgrade HMI hardware and software for its four Solar Mars 90 so that it is compatible with current industry standards.

2.110 Investment in the upgrade of the Solar Mars 90 HMI is necessary to maintaining the reliability of gas transportation service provided using the DBNGP. It is necessary to maintaining the integrity and contracted capacity of services.

2.111 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Solar Mars 90 surge control upgrade

2.112 Surge control equipment on the Solar Mars 90 units is, like the unit control systems and HMI, obsolete and now difficult to maintain. Parts are difficult to obtain from the specialist manufacturer (Petrotech), and the control system uses proprietary hardware and software.

2.113 Operator is therefore proposing to upgrade surge control on its four Solar Mars 90 units to the standard of its most recently installed Solar Mars compressor units, and to replace proprietary hardware and software with generic programmable logic controllers (similar to those used on the newer units).

2.114 Investment in the in the upgrade of Solar Mars 90 surge control is necessary to maintaining the reliability of gas transportation service provided using the DBNGP. It is necessary to maintaining the integrity and contracted capacity of services.

2.115 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Microwave system replacement/upgrade

2.116 Replacement of the DBNGP's microwave communications system was effectively deferred from the period of the Original Access Arrangement. Work forming part of the major feasibility study required to identify a replacement communications system was undertaken in 2000 and 2001, but the project was not progressed to completion.

2.117 In its Draft Decision dated 21 June 2001, the Regulator accepted the forecast of capital expenditure for the upgrade of the microwave system proposed in the Original Access Arrangement. In respect of this expenditure, the Regulator required:

(a) results of a feasibility study that the then owner of the DBNGP indicated it would carry out in 2000, before the Regulator would allow actual expenditure on the system upgrade to be added to the capital base; and

(b) consideration of alternatives in the study: in the absence of a study demonstrating that a microwave system was the most cost effective communication system, the Regulator suggested that a satellite system could have a lower initial cost, and lower maintenance costs.

2.118 The existing analogue microwave system was built on the basis of criteria set in 1980, and has now been in service for some 20 years. The technology is based around voice circuits with limited high bandwidth data transmission capability, and no digital data transmission capability. This obsolete technology:

(a) has limited capability to transmit data required by both Operator and shippers under the third party access regime of the Code, and this has necessitated innovative but complex and expensive solutions to particular communications problems; and

(b) is becoming increasingly more difficult and expensive to maintain as replacement components cease to be available from suppliers and equipment manufacturers.

2.119 Operator notes that the investigations that were undertaken in 2000 and 2001 showed that the satellite option is technically flawed in that it would not provide all the necessary services for voice communication, and would not meet reliability and availability requirements for pipeline control. In addition the operating costs of satellite services to compressor stations, main line valve sites and meter stations were likely to be significantly higher than for a microwave radio bearer. Satellite was, however, a short term solution to communication with compressor stations

given the high incremental costs of providing increased bandwidth on the existing microwave system.

2.120 These investigations now need to be revived, and the work of replacing the microwave system progressed to completion.

2.121 The existing microwave system is the principal communications system along the DBNGP between Dampier and Perth. It was originally built to provide the communications needed for the remote operation of pipeline facilities. That original purpose remains, but has now been supplemented by a need to communicate the information required for operation of the open access regime of the Code. As the system becomes increasingly obsolete, the risk of Operator being unable maintain the safety, integrity and contracted capacity of services increases. Investment in microwave system replacement is therefore important, particularly as the volume of communications traffic will increase as the DBNGP is expanded during the Access Arrangement Period.

2.122 The investment to be made in a replacement for the existing microwave system is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

South West communications transfer

2.123 Operator currently relies on Western Power Corporation for provision of communications infrastructure south of Perth. Communications with pipeline facilities takes place over Western Power's digital microwave network. These communications are critical to the operation of the open access regime of the Code. Nearly all of the major delivery points on the DBNGP are located south of Perth.

2.124 Operator is extremely uncertain as to how long Western Power will remain in its current organisational form, and will have the capacity within its digital microwave system to meet Operator's communication needs. Operator anticipates that restructuring and refocusing of the electricity utility will result in the ultimate owner of the digital microwave system asking Operator to transfer its communications to a commercial communications carrier such as Telstra (via its TPIP network), or to a provider of equivalent services using satellite.

2.125 Operator has therefore provided for investigation of alternatives to the Western Power digital microwave network for its South West communications needs, and for transfer of its communications to a new carrier, during the Access Arrangement Period.

2.126 If Operator is unable to continue using the Western Power network, the investment required to transfer its communications to another carrier will be essential to maintaining the safety and integrity of the gas transportation service provided using the DBNGP.

2.127 The investment to be made in a South West communications transfer is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

SCADA master station upgrade

2.128 Master station protocols and data storage are to be upgraded during the Access Arrangement Period to maintain the high level of reliability of the DBNGP SCADA system.

2.129 This work is required primarily for maintenance of the integrity and contracted capacity of services on the pipeline.

2.130 Accordingly, the investment required is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

SCADA emergency backup

2.131 The DBNGP is remotely operated from a control centre located in GHD House in Adelaide Terrace, and a very limited backup facility has been established at the Jandakot maintenance depot.

2.132 The backup facility is being progressively developed so that complete SCADA functionality is available at Jandakot in the event of Operator being unable to operate the pipeline from GHD House.

2.133 During the Access Arrangement Period, Operator proposes to expand the data storage capability at Jandakot to provide full backup of historical operating data captured by the SCADA system.

2.134 Further development of the SCADA backup facility is required primarily for maintenance of the integrity and contracted capacity of services on the pipeline.

2.135 Accordingly, the investment required is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Additional gas chromatographs

2.136 The broadening of gas quality specification for the DBNGP (as a result of the removal of the minimum LPG requirement) will require modifications to existing chromatographs which measure gas composition at MLV 30, CS and Kwinana Junction.

2.137 In addition, three new chromatographs will be required to provide complete gas quality monitoring throughout the DBNGP system and to ensure compliance with the broadened specification.

2.138 Without the additional gas chromatography capability, Operator will have difficulty in maintaining the integrity and contracted capacity of services on the pipeline.

2.139 Accordingly, the investment in supply chain design changes is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Design changes and compliances (meter stations)

2.140 This project is an aspect of the planned work described earlier under the heading "Hazardous area audits implementation". The earlier project was concerned with the identification of hazards associated with pipeline facilities. The focus of this project is hazards arising at meter stations.

2.141 Operator is proposing to continue, during the Access Arrangement Period, with:

(a) safety auditing of potentially hazardous areas at meter stations on the DBNGP;

(b) identification of actions to mitigate the risks identified; and

(c) modification or replacement of equipment which is found to be unsafe.

2.142 This work is to be undertaken to ensure the continued safety of, primarily, maintenance personnel and contractors working on the DBNGP.

2.143 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Meter station cabinets and cable marshalling boxes

2.144 Steel cabinets providing weather protection for the valves, gauges, and related equipment at meter stations, and steel boxes for the marshalling of cables, have, in many cases, been in place since the 1980s and are now extremely corroded. They require replacement.

2.145 Investment in new cabinets and marshalling boxes is now required if Operator is to maintain the safety and integrity of the pipeline, and continue to provide Services in accordance with its current contractual obligations.

2.146 Accordingly, the investment is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Meter station equipment shelters

2.147 At larger meter stations (for example, Alcoa Wagerup), a steel roof supported by steel pillars covers above ground pipework containing the primary gas measurement equipment. This roofing serves to protect valves, gauges and related equipment from direct exposure to the elements, and provides protection from the sun and rain for crews carrying out accuracy verification tests and maintaining the metering.

2.148 Some of these shelters have now been in place for nearly 20 years. They are badly corroded (particularly in the Kwinana area and the South West), and are potentially hazardous for crews working beneath them.

2.149 Operator is therefore proposing to commence replacement of the shelters during the Access Arrangement Period. The primary reason for the investment to be made is the maintenance of safe working conditions for employees and contractors. There is also a small added benefit from the weatherproofing of equipment to a lesser standard than would otherwise be the case.

2.150 Accordingly, the investment in meter station equipment shelters is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur

Flow computer upgrades

2.151 Meter station flow computer software, which is critical to accurate gas measurement, is scheduled to be upgraded during the Access Arrangement Period.

2.152 New versions of the software also facilitate the automation of, and improved methods for, the Accuracy Verification Tests Operator is obliged to carry out in accordance with the terms and conditions of its standard shipper contracts.

2.153 Operator's investment in flow computer software upgrades is necessary to maintaining the integrity and contracted capacity of services.

2.154 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Customer Reporting System upgrade

2.155 New shipper contracts that were negotiated by the current owners in 2004 require Operator to maintain its Customer Reporting System ("CRS") and enhance its functionality. CRS must now have the functionality to:

(a) issue notices to shippers;

(b) provide details of the available spot capacity on at regular intervals throughput the day;

(c) notify shippers of any related party transactions for spot capacity;

(d) provide information on hourly and daily quantities delivered to shippers; and

(e) make available details relating to the interconnection of the DBNGP with the distribution system.

2.156 The shipper contracts also anticipate that, in the future, CRS becomes the means of facilitating capacity trading, and of recording and reporting transfers of capacity on the DBNGP. (Currently there is no central facilitation of capacity trading; bilateral trading arrangements are a matter for the shippers directly involved).

2.157 CRS will also require modification as:

(a) new shippers contract for transportation service using the DBNGP, and as new delivery points are added to the pipeline; and

(b) additional data (in particular data pertaining to nominations, overruns, imbalances and peaking behaviour) are to be provided to the gas market manager in accordance with the market rules governing full retail contestability in the Western Australian gas market.

2.158 Further investment in CRS will be required if Operator is to continue to provide services in accordance with its contractual obligations. Accordingly, that investment

is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

IT infrastructure

2.159 The prior owner of the DBNGP maintained its own corporate systems for accounting and finance (PeopleSoft), human resources management (Chris), and maintenance management (Maximo). These systems, and the hardware platform that supports them, are now operated by Epic Energy Corporate Shared Services Pty Ltd ("EECSS"), which currently provides information technology and information processing services to Operator under a Transitional Services Agreement with Operator (and DBNGP (WA) Nominees Pty Ltd).

2.160 On termination of the Transitional Services Agreement, information technology and information processing services for Operator and DBNGP (WA) Nominees Pty Ltd (the "DBNGP companies") are expected to be provided by Alinta Network Services Pty Limited ("ANS") under an Operating Services Agreement.

2.161 Operator expects that ANS will provide the equivalent of the corporate systems and the supporting platform currently provided by EECSS. This will require some further investment in computing and communications hardware, and a much larger investment in:

(a) modification of the ANS corporate systems (accounting and finance, human resources, asset and maintenance management) to provide information processing for DBNGP companies;

(b) transfer of DBNGP data to the modified ANS corporate systems; and

(c) development of reporting and other utilities for the DBNGP companies within the ANS corporate systems environment.

2.162 In addition, Operator will need to develop a stand-alone computing environment for its management of DBNGP operations. Key drivers for the creation of this stand-alone environment are the ring fencing obligations imposed on Operator by the Code, and by the undertaking given by Alinta Limited and others to the Australian Competition and Consumer Commission under section 87B of the Trade Practices Act 1974.

2.163 Operator anticipates having to set up a small hardware platform and network which will provide the DBNGP companies with a secure environment:

(a) for the management of all DBNGP legal, regulatory, commercial and technical data and documentation;

(b) with capability to access data and reports for the DBNGP companies in ANS corporate systems;

(c) supporting the use of standard Microsoft Office products; and

(d) supporting the CRS.

2.164 Operator also intends to create an independent web site for DBNGP operations.

2.165 Planned investment in this IT infrastructure, in addition to the initial investment, investment in software upgrades (in 2006 and 2009), and hardware replacement investment. Operator has adopted the standard industry practice of and replacement cycle of three years desktop and notebook computers, and other items of computing equipment subject to rapid obsolescence.

2.166 Operator's investment in IT infrastructure is essential to its providing the gas transportation service of the DBNGP. It is necessary to maintaining the integrity and contracted capacity of services.

2.167 Accordingly, the investment to be made in IT infrastructure is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Engineering Tools and Equipment

2.168 This item of forecast expenditure is part of the Operator's continuous improvement activity.

2.169 It involves expenditure for the purposes of:

(a) updating worn, broken and outdated tools; and

(b) purchasing new tools.

2.170 As the reliable performance of the pipeline becomes more and more critical, new ideas and teams are developed to look more closely at the performance of all areas of operation. To enable this, new software, enhanced software to upgraded versions, improved/new internal inspection tooling equipment is required to improve

the efficient and reliable operation of the pipeline which is aimed at maintaining the Services on the pipeline.

2.171 In addition to field maintenance tools and equipment, inspection and testing tools used by the Engineering and Technical Specialists will be required to be maintained during this period. This includes the following:

(a) pipeline integrity and testing tools and equipment;

(b) internal inspection and boroscoping tools and equipment;

(c) thermography test equipment; and

(d) special software and drives.

2.172 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Field Tools and Equipment

2.173 As is the case with the immediately preceding forecast investment, this item of forecast expenditure is part of the Operator's continuous improvement activity.

2.174 Again, it involves expenditure for the purposes of:

(a) updating worn, broken and outdated tools; and

(b) purchasing new tools.

2.175 The following items have been earmarked for acquisition or manufacture:

(a) gas detectors - required for gas monitoring to ensure safe working environments.

(b) electrical meters - required to test calibration of operational equipment.

(c) the manufacturing of new tools specific to plant required to improve efficiency of conducting activities.

2.176 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Motor Vehicles

2.177 Operator owns and operates a fleet of vehicles used for maintenance activities on the DBNGP.

2.178 These vehicles are continuously in service transporting maintenance crews to remote locations along the pipeline. To ensure their reliability, and the safety of the crews which use them, Operator has a policy of replacing all motor vehicles at regular intervals.

2.179 In accordance with its replacement policy, Operator is proposing to replace six vehicles in each year of the Access Arrangement Period.

2.180 Without the vehicle replacements, Operator will have difficulty in maintaining the integrity and contracted capacity of services on the pipeline.

2.181 Accordingly, the investment in supply chain design changes is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Corporate head office modifications

2.182 With the sale of the DBNGP to its new owners in 2004, the following capital projects have been identified as being required during the Access Arrangement Period:

(a) establishment of a stand-alone office for Operator which is ring fenced from the operations of any other system operator (such as Alinta Network Services), and from any of its shareholders; and

(b) additional office space to cater for the increased corporate support that will need to be provided given the significant expansion program being proposed. This will involve the establishment of new work stations and the upgrade of existing work stations.

2.183 The separate office is required for Operator in order to comply with the Operator's obligations contained in the Undertakings given to the ACCC at the time of acquisition in accordance with the provisions of the Trade Practices Act 1974.

Jandakot Depot improvement

2.184 As part of the recent acquisition of the DBNGP by the current owners, a decision has been made to relocate certain staff based at the previous owner's corporate head office to the Jandakot depot. This is primarily because increased operational requirements requires an increase in field operational staff which requires support from Operator's field operational base at the Jandakot depot.

2.185 The project will include the following capital works:

(a) an increase in office space, supply storage space and amenities; and

(b) an upgrade to the standing facilities to enhance the ability to support the field operations.

2.186 As the organisation grows and changes, there will be a requirement to continue to revise the plans for Jandakot depot.

2.187 Accordingly, the investment to be made is New Facilities Investment which is expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Security upgrades

2.188 Operator's facilities are either in remote locations or, in the case of facilities in the South West (in particular, meter stations), are away from built-up areas and generally "out-of-sight". Operator has now experienced "break-ins" at a number of meter station sites, which have resulted in either or both of damage to facilities and removal of computers and electronic equipment.

2.189 This is a major concern, not only because equipment has been damaged or stolen. Individuals removing or damaging equipment:

(a) place themselves in considerable personal danger; and

(b) may cause disruptions to gas supplies.

2.190 Furthermore, although all facilities are fenced and locked, the break-ins indicate that determined individuals can access what were regarded as reasonably secure facilities when they were built during the 1980s. This is an important issue both for Operator, and the wider community, with recent recognition that infrastructure facilities are potential targets for terrorist activity.

2.191 Operator has therefore included in the stay-in-business component of its new facilities investment for the period 2005 to 2010 amounts for the upgrading of security at its facilities. The total amount to be spent ($1.6 million) represents expenditure of approximately $50,000 on security at each of some 30 sites downstream of CS9.

2.192 The investment is investment that would be undertaken by a prudent pipeline operator. It is necessary to maintain the safety, integrity and Contracted Capacity of the Services, and is therefore expected to satisfy the test in section 8.16(a)(ii)(C) of the Code when it is forecast to occur.

Annexure 3

DESCRIPTION OF NATURE AND JUSTIFICATION FOR EXPANSION RELATED FORECAST NEW FACILITIES INVESTMENT

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

FURTHER AMENDED PROPOSED REVISED ACCESS ARRANGEMENT INFORMATION

ANNEXURE 3

PUBLIC VERSION

JUNE 2005

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DBNGP ACCESS ARRANGEMENT

PUBLIC VERSION

FURTHER AMENDED PROPOSED REVISED ACCESS ARRANGEMENT INFORMATION

ANNEXURE 3

1. INTRODUCTION

1.1 The forecast New Facilities Investment included in the proposed revised access arrangement to which this annexure is attached involves an exceptionally large capacity expansion program. It is proposed to be undertaken over a fairly short time – the proposed Access Arrangement Period – because major shippers have either requested additional capacity or it is forecast that they will request it. The shippers and prior owners of the DBNGP were unable to agree on terms and conditions which would have enabled the prior owners to finance the expansion of the pipeline to provide that capacity before now.

1.2 Operator and DBNGP (WA) Nominees Pty Ltd ("Nominees") are now proposing to expand the capacity of the pipeline pursuant to requests for additional capacity made by shippers under existing contractual arrangements. These existing contractual arrangements include, in particular, the series of renegotiated contracts that were entered into prior to the current owners acquiring the pipeline in October 2004.

1.3 In a letter to Regulator dated 9 March 2005, Operator indicated that the assumptions that underpinned the forecast capital expenditure for the period 2005 – 2010 originally included in the proposed Access Arrangement revisions were currently being reviewed by the Operator's and Nominees' Boards of Directors and Unitholders of the Trust that owns the DBNGP.

1.4 The Board decision has now been made.

1.5 Accordingly, this annexure to the Access Arrangement Information outlines:

(i) what New Facilities are proposed during the proposed Access Arrangement Period;

(ii) the forecast capital expenditure for the New Facilities Investment; and

(iii) how these forecast new facilities and the associated expenditure satisfy the test in section 8.16 of the Code as New Facilities Investment.

1.6 However, it should be noted that the Regulator has required an amendment to the proposed gas quality specification on the DBNGP as part of the Draft Decision (Amendment #15). This amendment, if implemented, would require a reassessment of the capital expenditure and non capital cost forecasts. Operator has however, provided a further submission in response to the Draft Decision outlining why amendment 15 is unreasonable and does not reflect a proper application of the Code.

1.7 Accordingly, this document is structured as follows:

(i) Section 2 outlines Operator's commitments to expand the capacity of the DBNGP;

(ii) Section 3 outlines the initial stage of expansion of the pipeline (ie stage 4);

(iii) Section 4 contains the analysis of the risks for this initial stage of expansion that was undertaken by Operator.

(iv) Section 5 explains the balance of the forecast expansion-related expenditure for the proposed Access Arrangement Period (ie after stage 4);

(v) Section 6 contains a justification of the Operator's contracting strategy with service providers engaged for the purposes of the expansion program;

(vi) Section 7 outlines the costs associated with the proposed expansion program;

(vii) Section 89 then substantiates the proposed expansion program as New Facilities Investment in accordance with the criteria in section 8.16(a)(ii) of the Code.

2. OPERATOR'S EXPANSION OBLIGATIONS

2.1 Much has been made, in the lead up to and following the completion of the sale of the DBNGP in October 2004, of the commitment to expand the DBNGP and the impact that this will have on the State's energy system. Extracts of various statements from the Minister for Energy at the time of the sale are contained in Annexure 2.

2.2 It is important therefore, to understand the expansion obligations that stemmed from this sale, as they form an important part in substantiating the investment as New Facilities Investment under the Code (which is expanded upon in a later section of this Submission).

2.3 The expansion of the capacity of the DBNGP is required to meet:

(i) contracted capacity committed to shippers under the existing shipper contracts that were renegotiated immediately prior to the sale of the pipeline in October 2004;

(ii) obligations to the State; and

(iii) obligations to the ACCC under the ACCC undertakings.

2.4 Accordingly, the objectives of the forecast expansion of the DBNGP are as follows:

(i) Complete each phase of the expansion program on time in order for all shipper commitments to be met.

(ii) Deliver each expansion program with minimal disruption to current gas supply levels for existing customers.

(iii) Ensure that, given the very tight timetable for delivery of capacity to shippers, work is completed in the most cost effective manner, on time and on budget (which requires the adoption of a contracting strategy that enables this to occur).

(iv) Satisfy the requirements of the facility agreements with Operator's financiers.

(v) Ensure that work is completed in full compliance with all occupational health and safety requirements, with minimal safety incidents occurring.

(vi) Ensure that work is completed within a co-operative and stable industrial relations environment so as to minimise delays in the work schedule.

(vii) Conduct the expansion program in a sustainable manner through strict adherence to environmental management and cultural management plans.

(viii) Manage all stakeholders in relation to project expectations.

Standard Shipper Contract Expansion Obligations

2.5 The Standard Shipper Contracts renegotiated with existing shippers in October 2004 (a form of which Operator will make available to any prospective shipper which seeks a T1 Service) contain a number of relevant provisions.

2.6 Clause 16 obliges Operator to expand the pipeline for an existing shipper requiring additional T1 capacity subject to:

(i) the shipper providing 30 months notice;

(ii) the shipper and the operator agreeing an amendment to the existing Shipper Contract which includes a capacity commencement date which can be no earlier than 24 months from the date of the agreement (unless otherwise agreed by the parties);

(iii) the shipper satisfying all of the usual tests for a shipper (creditworthiness, no disputes, etc); and

(iv) Operator being able to secure finance for the expansion on reasonable commercial terms and conditions for a verified amount.

2.7 There is no cap on the capacity which DBNGP is obliged to provide under the Standard Shipper Contract, however, the obligation on Operator to provide additional T1 capacity ceases on 1 January 2016.

2.8 As part of the sale of the pipeline in October 2004, several shippers exercised their rights to require Operator to fund an expansion of the capacity of the DBNGP under clause 16.

Expansion Obligations to the State

2.9 Operator owes obligations to the State under the terms of a Financial Assistance Agreement ("FAA") entered into in October 2004. The expansion obligations are set

out in Schedule 1 to the FAA. They require Operator to undertake the expansion obligations in accordance with the timeframes set out in Schedule 1.

2.10 Clause 2 of Schedule 1 states "The DBNGP Operator will offer all Shippers and Prospective Shippers access to Gas Transmission Capacity on a non-discriminatory basis on the terms and conditions of, and at the price, specified in the Standard Shipper Contract."

2.11 Clause 5 of Schedule 1 obliges the DBNGP Operator to use reasonable endeavours to enter into a Standard Shipper Contract with a Shipper or Prospective Shipper who has submitted a request for access within a reasonable time of receiving the request.

2.12 Clause 10 of Schedule 1 obliges Operator to, within 5 years of the completion of the sale of the pipeline in October 2004, expand by no less than 100TJ/day and to invest up to $400 million, subject to contracts being entered into with shippers for the additional capacity.

2.13 Clause 11 of Schedule 1 sets out the Operator's "Future Expansion Commitments" which oblige Operator to expand the pipeline in accordance with clause 16 of the Standard Shipper Contract for a Shipper or Prospective Shipper.

2.14 It should be noted that clause 12 requires the owners of the DBNGP to use reasonable endeavours to fund future expansions.

2.15 These obligations cease on 1 January 2016.

ACCC Undertakings Expansion Obligations

2.16 In relation to the ACCC Undertakings given by Operator, clause 5.6 requires Operator to offer to all Prospective Shippers who require a T1 Service, a Standard Shipper Contract.

2.17 Clause 5.7 obliges the DBNGP group to expand the capacity by not less than 100TJ/day and to invest up to $400 million within 5 years of the acquisition subject to contracts being entered into for that capacity.

2.18 In summary, the only substantive qualification on the Operator's obligation to expand for Prospective Shippers is unless the owners of the DBNGP cannot fund the expansion on "reasonable commercial terms and conditions".

2.19 The following aspects of the above expansion obligations substantiate the system wide benefits of expansions that are to be undertaken pursuant to these obligations:

(i) All users are entitled to participate in the expansions.

(ii) Because the expansions will be to satisfy full haul users, they will enhance the availability of capacity on the entire pipeline, for both full haul and part haul users.

(iii) The mechanism by which shippers can require an expansion to be undertaken under the Standard Shipper Contract means that shippers will not be affected by unnecessary delays in accessing additional capacity.

(iv) The ability of users and prospective users to access capacity on a certain and timely basis will benefit downstream markets, thereby creating the environment in those markets in which competition can be promoted.

3. EXPANSION PROGRAM RECONSIDERED

3.1 Operator's objectives for the expansion of the capacity of the DBNGP are:

(i) Complete each phase of the expansion project on time in order for all shipper commitments to be met.

(ii) Deliver the additional capacity with minimal disruption to current gas supply levels for existing customers.

(iii) Ensure work is completed in the most cost effective manner and on budget.

(iv) Work is completed in full compliance with all occupational health and safety requirements, with minimal safety incidents occurring.

(v) Complete the projects within a co-operative and stable industrial relations environment.

(vi) The project is conducted in a sustainable manner through strict adherence to the environmental management and cultural management plans.

3.2 The expansion of the capacity of the DBNGP to meet the contracted and forecast demand for gas transportation service during the proposed Access Arrangement Period is expected to be achieved through the following sequence of activities:

(i) The expansion known as the Stage 4 expansion project, which itself is broken down into various substages over the period December 2004 to January 2007. The substages are described as follows:

(ii) installation of additional 10 MW gas turbine driven compressors at CS3 and CS9 – Stage 4A;

(iii) installation of an additional Solar Taurus 70 gas turbine driven compressors at CS10 – Stage 4B;

(iv) installation of 23 km of 26 inch looping south of Kwinana Junction – Stage 4C;

(v) installation of 194km of 26 inch looping of parts of the mainline between Dampier and Kwinana Junction, immediately downstream of all compressor stations except CS 10 – Stage 4D;

(vi) installation of additional 10 MW gas turbine driven compressors at CS6 and CS2 – Stage 4E;

(vii) installation of an additional 10 MW gas turbine driven compressor at CS4 – Stage 4F;

(viii) installation of an additional 10 MW gas turbine driven compressor at CS7 – Stage 4G;

(ix) installation of an additional 10 MW gas turbine driven compressor at CS1 – Stage 4H.

(x) following the completion of Stage 4 (which is due to occur in January 2007) further expansion stages are to be undertaken which will involve pipeline looping from 2008 to 2010.

2005 – 2007 Expansion program - Stage 4 Expansion

3.3 The pipeline must initially be expanded in order to meet existing contractual obligations owed to shippers. This work is covered by the expansion stage called Stage 4. Stage 4 is broken into several substages – Stages 4A to 4H in order to deliver additional capacity in time for specific shipper requirements.

3.4 Stages 4A-C and 4E-H "fully compress" the pipeline given its existing configuration and pipeline licence constraints (particularly in so far as the maximum allowable operating pressure of the pipeline is concerned).

3.5 The work required to be undertaken for Stage 4A involves the installation of 2 new compressor units – one at each of Compressor Station 3 and Compressor Station 9.

3.6 In regards to the supply of compressors for Stages 4A, 4B and 4E-H, pursuant to the long term alliance agreement in place between the prior owners of the DBNGP and Solar Turbines but now replicated with Alinta Network Services and Pipeline Trustee, Solar Turbines will supply the turbines for all the compressors at existing sites. This decision has been made primarily due to the extremely tight timeframes which must be met in order to comply with obligations to shippers to provide additional capacity.

3.7 A more detailed explanation of the work involved in stages 4A, 4B and 4E-H is contained in Attachment 1.

3.8 The expansion option chosen for Stage 4D will have a significant effect on the costs of providing gas transportation service during the proposed Access Arrangement Period, and in the future.

3.9 Operator examined a range of pipeline expansion options for Stage 4D which include:

(i) looping with pipe of 26 inches diameter, and other diameters;

(ii) mid-line compression; and

(iii) any of the options outlined in the 2 sub-paragraphs above but reconfiguring the DBNGP to allow for an increase in the maximum allowable operating pressure ("MAOP") of the DBNGP in accordance with proposed changes to Australian Standard 2885.1.

3.10 Operator has now determined that the Stage 4D expansion program is to include 194 km of looping of the mainline pipe with pipe of 26 inch diameter. The project is to be commissioned on 1 January 2007. A more detailed description of the work required for Stage 4D is outlined in a subsequent section of this document.

3.11 Following the completion of the Stage 4 expansion program, there exist a range of options as to how the pipeline can be expanded. However, the availability of these options are predetermined largely by the option adopted for Stage 4D.

4. STAGE 4D EXAMINED

Explanation of New Facilities required to be constructed

4.1 This substage involves the looping of nine of the northern mainline sections of the DBNGP – the construction of nine pipeline loops downstream of the existing compressor stations 1-9 for an estimated total length of 194 km of 26 inch (660mm) NB pipe.

4.2 Key components of the scope of work for this project are as set out below.

4.3 The following pre-construction work will need to be undertaken:

(i) FEED, including approved construction drawings and alignment sheets;

(ii) Final route topographic survey and route optimisation due to environmental, cultural heritage and land owner issues;

(iii) Identification of sections of the pipeline route that will require special construction methods and/or procedures including sections that are restricted in terms of available working space;

(iv) Environmental assessments, approvals and surveys;

(v) Cultural heritage survey;

(vi) Geotechnical survey – for the mainline trench and river crossing works (primarily to identify areas of rock that will be encountered);

(vii) Approvals by statutory authorities;

(viii) Agreements with land owners and traditional landowners (through indigenous land use agreements);

(ix) Procurement of all other materials and equipment;

(x) Placement of orders and commitment to critical subcontractors (eg camp, catering, etc);

(xi) Establishment of a project site industrial agreement;

(xii) Development of a construction execution plan and schedule and any other required management plans and procedures, including OHS, Quality Assurance;

(xiii) Development of quality welding and coating procedures;

(xiv) Mobilisation of construction equipment and materials;

(xv) Establishment of site facilities including camps, project site offices and maintenance and storage facilities and communication systems;

(xvi) Locate and set up sources for supply of water for the project;

(xvii) Identify access roads and restrictions relative to the same that will have to be addressed and or work that will have to be undertaken prior to the commencement of the delivery of pipe to the right of way; and

(xviii) Liaison and notification involving relevant land owners and or local authorities.

4.4 A total of 194km of looping of the mainline of the DBNGP is required for the 26 inch pipeline. It is to be undertaken downstream of each compressor station as follows:

(i) Downstream of CS1 – 12km

(ii) Downstream of CS2 – 32km

(iii) Downstream of CS3 – 25km

(iv) Downstream of CS4 – 25km

(v) Downstream of CS5 – 22km

(vi) Downstream of CS6 – 11km

(vii) Downstream of CS7 – 5km

(viii) Downstream of CS8 – 47km

(ix) Downstream of CS9 – 15km

4.5 The following table outlines the details of the two looping substages to be undertaken as part of Stage 4.

	Northern Loop 194km 26" Stage 4D	**Southern Loop 23km 26" Stage 4C**
Pipe Diameter	26" 660.0mm	26" 660.0mm
Total Meters	194,000m	23,000m
Light wall length	191,000m	22,500m
Light wall thickness	8.84mm	8.84mm
Heavy wall length	3,000m	500m
Wall heavy thickness	10.61mm	10.61mm

4.6 The pipe diameter and coating options are based on the following assumptions:

(i) The pipe coatings reviewed are the coatings that are currently used on most recent Australian and international pipeline projects.

(ii) Internal coating is required to improve the pipeline friction factor.

(iii) The quantity of heavy wall pipe was estimated by the project team from initial takeoffs from the current pipeline in the same locations.

4.7 The pipe is to be acquired, coated and supplied to site. This will require the following steps to be undertaken:

(i) Supply of bare steel pipe by a steel mill;

(ii) Transporting of bare pipe for coating;

(iii) Coating of the pipe;

(iv) Transporting or stockpiling of coated line pipe from ports to stockpiles; and

(v) Transporting of the coated line pipe to the Right of Way to be unloaded and strung by the construction contractor.

4.8 Due to the high diameter to thickness ratio of the pipe it will be susceptible to damage during ship loading, transit, and unloading processes, therefore it is imperative that the type of ships engaged to transport the pipe to and from the coating plants are self geared full open hatch box hold between deck vessels.

4.9 A simultaneous survey of required specialised equipment for pipe handling has been conducted.

4.10 The project also involves the installation of the following systems:

(i) SCADA;

(ii) Cathodic Protection; and

(iii) Electrical and Instrumentation Systems;

4.11 The following associated facilities for each pipeline loop will also need to be constructed:

(i) New scraper stations;

(ii) New valving;

(iii) Tie-ins to the existing compressor station facilities;

(iv) Installation of new mainline valve stations on the pipeline loops, parallel to and at locations corresponding with existing mainline valve stations; and

(v) Installation of permanent end of loop line valves, scraper station and crossover piping to the existing pipework.

4.12 Hot-taps will also need to be undertaken on the existing pipeline in order to tie-in cross-over pipeline to the new loop pipeline. (The associated supply interruptions are to be minimised by negotiating with shippers to reduce their throughput nominations to the absolute minimum at the times hot tapping is required.) Tie-ins at the compressor station end will be via a compressor station shut down not requiring hot-taps.

4.13 Because of the distance of the looping involved, 4 rivers will be crossed by the pipework. This will require horizontal directional drilling to be undertaken to ensure that the pipe is laid in accordance with appropriate safety and environmental standards.

4.14 Hydrostatic testing, air drying and pre commissioning of the installed pipeline loops and associated mainline valves and facilities will also need to be undertaken.

4.15 The commissioning work that will need to be undertaken involves the introduction of gas into the pipeline and associated facilities.

Approach to looping

4.16 Given that the cost of line pipe will be a significant component of the total costs for this option, Operator provides the following explanation of the approach that has been adopted in analysing the pipework required.

4.17 As a preliminary comment, Operator, through its service provider Alinta Network Services ("ANS"), undertook a pre-tender phase which was aimed at eliminating high risk options or those which are not available due to other commitments. This was aimed at reducing the tender evaluation time so that the pipe order could be placed, and so that the pipework can be constructed and commissioned, in time to meet the obligations Operator owes to shippers to provide the developable capacity.

4.18 The following approach has been adopted by Operator and its primary service provider, ANS, in order to best determine the appropriate suppliers to engage for the various aspects of the project:

(i) 10 API accredited international Pipe Mills from around the world were approached to determine available capacity and receive current pricing and schedule information to a 5% level of accuracy.

(ii) Two shipping companies were approached to determine shipping availability and capacity to freight pipe.

(iii) Seven coating plants were approached to determine coating strategy, plant capacity, availability, and current costing for internal and external coating of the line pipe.

(iv) Port Authorities at Dampier, Geraldton and Fremantle were approached for all costs associated with bringing ships into the west coast ports.

(v) A schedule of rates for inspection costs associated with linepipe manufacture, coating, load out and receipt activities and operations was ascertained.

(vi) Operator and ANS compared data from recent projects they have been involved in backed up by some budget estimates to determine the costs of set up and operation of linepipe stock piles.

(vii) Three specialised line pipe haulage freight companies were approached for the cost of transporting linepipe from ports to the stockpiles, and stockpiles to the ROW. As an alternative, the national rail carrier was asked to provide a costing estimate for transporting linepipe from the east coast of Australia to Perth.

(viii) Coastal shipping companies were approached for the cost of transporting line pipe to Fremantle.

(ix) A review was undertaken as to the cost of product insurances for all aspects of project.

(x) An audit was conducted of available dedicated material handling equipment for 26" coated linepipe.

4.19 The following resulted from the above approach:

(i) Electric Resistance Weld ("ERW") pipe is produced from hot rolled coil which has cost and availability benefits over plate steel which is used for Submerged Arc Weld ("SAW") pipe. The cost benefit is significant.

(ii) A second benefit of ERW linepipe is that it can be supplied in longer lengths which subsequently reduces the quantity of welding and non destructive testing ("NDT") on this project. Joint coating and line coating costs are also reduced with the longer pipe lengths which in turn generates further cost savings.

(iii) In relation to pipe coating, three coating options were considered in this process. They include single layer FBE, dual layer FBE and Trilaminate. The internal lining in all three cases is 50 micron epoxy. It is understood that certain external coatings will be preferred to others due to their resistance to handling and installation damage. The establishment of a dedicated on shore coating plant will require a 6 month lead time for establishment, and will rely heavily on no delays in the development application process.

(iv) In relation to shipping, due to the high diameter to thickness ratio of the pipe it will be susceptible to damage during ship loading, transit, and unloading processes. Therefore it is imperative that the type of ships engaged to transport the pipe to and from the coating plants are self geared full open hatch box hold twin deck vessels.

(v) The two largest and most experienced coated linepipe haulage contractors have provided details of haulage costs and equipment availability. There is an identified need for the full time mobilisation of extendable semi-trailers to provide support for on shore logistics.

4.20 The approach to the installation of the loops and associated facilities has been based on undertaking the construction and installation phase of the Stage 4 project by implementing conventional and proven industry construction methods and procedures

and the utilisation of conventional construction and specialised pipeline construction equipment.

4.21 The pipeline loops are to be installed, for the most part, within the existing DBNGP land access corridor. The WA Government has established an additional 70 meter services corridor parallel to the DBNGP corridor which can be used for re-routing of the pipeline or to provide a temporary working easement.

4.22 The use of subcontractors is to be minimised, given the experience of the main alliance contractors and the capabilities of ANS to undertake much work "in house". However, the following additional work is required:

(i) Non destructive testing of welds;

(ii) Supply, installation and operation of camps; and

(iii) Installation of HDD river crossings; and

(iv) Construction of looping.

4.23 In order to best ensure the provision of the additional capacity on time, the construction of pipeline looping is to be undertaken by two separate and independent construction spreads and crews. Each spread will be made up of similar construction crews in terms of equipment and personnel and will have the capability and resources to execute all aspects of the project, including the following:

(i) Construction survey;

(ii) Clear and grade the right of way;

(iii) Upgrading and maintaining access roads;

(iv) Unloading and stringing of loop line;

(v) Bending of pipe;

(vi) Welding of pipe, including NDT and inspection;

(vii) Coating of field joints;

(viii) Excavation of loop line trench;

(ix) Lowering in and tieing in of welded or coated mainline sections;

(x) Bedding and padding of the trench and pipe in sections of rock;

(xi) Efficient required buoyancy control;

(xii) Backfilling of pipe trench;

(xiii) Installation and tie ins of open cut roads and water crossings;

(xiv) Cleaning and reinstating the pipeline right of way;

(xv) Hydrostatic testing and air drying; and

(xvi) Pre-commissioning.

4.24 In carrying out the installation of the above facilities, the following has been assumed:

(i) All work (both on and off site) will be undertaken by separate and independent crews to those installing the pipeline loops; and

(ii) The installation of the facilities associated with the looping would be undertaken during the same period by the same contractor that is installing the 8 additional new compressor units at the existing compressor stations (ie for Stages 4A-C and 4E-H).

(iii) The majorityof the assemblies to be installed at all locations will be pre-fabricated off site and transported to each site for assembly and installation.

(iv) The on site works at existing compressor stations and at the end of each loop, for the most part, will be undertaken and installed prior to the construction of the pipeline loop including the pre-testing where practical.

(v) Following the hydrostatic testing and drying of the pipeline, the pre-tested facilities and pipeline will be tied in to the loop line by means of a “golden weld”.

(vi) Main line valve stations are to be prefabricated off site and are to be installed following hydrostatic testing but before air drying of the pipeline loop.

(vii) Existing site accommodation and facilities located at each compressor station are to be utilised, including additional temporary facilities that will need to be established for the installation of additional compressor units.

Maximum Allowable Operating Pressure uprating – MAOP

4.25 Proposed changes to Australian Standard 2885.1 should, if they are implemented in Western Australia, allow the DBNGP to be operated at a pressure higher than the current MAOP of 8.48 MPa. With relatively minor modifications to existing compression and metering facilities, Operator expects to be able to increase the MAOP to 9.3 MPA, and this should provide an additional 40 TJ/d of capacity which could be used to provide a firm service at a lower tariff than would otherwise be the case for shippers.

4.26 It would also mean a significant reduction in the configuration and therefore, forecast capital expenditure relating to Stage 4D if the changes were implemented and approved as part of the pipeline licences for the DBNGP. It is important to note that given the delays in approving the changes to the standard and the need to proceed with Stage 4 expansion, this option can now only be seriously considered as part of subsequent expansion stages. But even then, it should be noted that an increase in the MAOP would not be instantaneous.

4.27 Investigation of the configuration required as a result of an increase in MAOP for the pipeline downstream of Kwinana Junction is still to be carried out, and a recommendation on the capacity increment and modifications to existing facilities is expected to take around 12 months.

4.28 It should be noted however, that the WA safety and technical Regulator has publicly objected to the proposed modifications to AS 2885.1.

4.29 Department of Industry and Resources certification of the up-rated DBNGP would need to be obtained relatively quickly (probably by the beginning of July) to allow sufficient time for the manufacture, delivery to site, and installation of either mid-line compression units, or pipe for looping.

4.30 Operator understands that the timetable for consideration of proposed changes to AS2885 by the relevant committee established by Australian Standards (known as ME38) means that any changes will not be implemented until at least August 2005.

4.31 Even if this timeline is achieved, amendments to the pipeline licences for the DBNGP would be required to reflect the changes in AS2885. This is a further process that ordinarily would take additional time. Given the public position of the WA safety and technical Regulator on this issue to date, there is a real possibility that the changes to the licence will take some significant time.

5. ANALYSIS OF OPTIONS

5.1 A detailed risk analysis of the proposed expansion program for stage 4 and for other options for that stage was undertaken by Operator in deciding on the appropriate expansion program.

5.2 A detailed risk assessment has been completed for all work to be undertaken prior to approval to proceed being obtained, including technical risks, commercial risks, regulatory risks, construction risks and operational risks. This risk assessment outlines both risks and measures which are to be undertaken to manage the risks to a level acceptable to Operator.

5.3 The risk assessment was carried out in accordance with the relevant Australian Standard for risk assessment. This involves an assessment of project risks before and after treatment, against the criteria outlined in the matrices outlined below.

5.4

Risk Map
Before Treatment

Likelihood			Consequence				
			Insignificant 1 Up To $1,000	Minor 2 Up To $10,000	Moderate 3 Up To $100,000	Major 4 Up To $1,000,000	Catastrophic 5 Over $1,000,000
	A Almost Certain	95%					
	B Likely	80%					
	C Moderate	50%					
	D Unlikely	20%					
	E Rare	5%					

5.5 The following risks were identified for the looping option:

(i) Environmental risks associated with the construction of a "duplicated" pipeline. Such risks include putting at risk endangered flora and fauna, impacts on wetlands, cultural heritage and native title issues.

(ii) Industrial relations issues causing delays to the commissioning of the additional capacity.

(iii) Availability of skilled labour given the current skills shortage.

(iv) The proposed construction methodology for river crossings.

(v) The risks to security of existing supply as a result of greater number of hot-taps to connect new looping with existing pipework.

(vi) Risks associated with hydro testing.

(vii) Potential non compliance with environmental management plan required by Regulator.

(viii) Changes in route selection from that on which the initial budget was based.

(ix) Weather impacts (both heat and flooding) given that looping construction projects take longer and cover more diverse geographical areas than compression construction.

(x) Resultant risk of liquidated damages under existing contracts as a result of delays.

(xi) Inability to secure sufficient resources due to competing pipeline projects being constructed at the same time.

(xii) Landowner access issues.

(xiii) Pipeline licence variation approval delays.

(xiv) Late delivery of pipework to site.

5.6 In relation to the looping option, the effect of a delay in commencing the expansion program works could have resulted in adjusting the risk profile of the program and increasing the Operator's risk by way of:

(i) Reducing the opportunity to obtain competitive market prices for the construction work and transfer of risk to the Contractor if sufficient time is not available; and

(ii) Delaying the completion of the program works may incur penalties under the gas supply contracts.

5.7 The above risk analysis, combined with financial analysis, identified a number of risks that are common to both main options identified in section 3 – ie looping and midline compression.

5.8 However, the:

(i) operational risks associated with the midline compression option, including additional non capital costs and ongoing system reliability issues; and

(ii) the additional capital costs and financial implications for Operator associated with a looping option assuming a larger diameter pipe,

are major reasons why Operator has decided to proceed with the 26" looping option.

6. POST STAGE 4 EXPANSION PROGRAM

6.1 The only means by which the pipeline can be expanded to provide additional capacity following commissioning of Stage 4 is via looping of the pipeline.

6.2 Based on the approved option for Stage 4, the following configuration has been estimated for the further expansion, based on the Operator's most recent demand forecasts.

Looping downstream of:	2008	2009	2010
Dampier	0 km	0 km	0 km
CS1	33 km	10 km	17 km
CS2	28 km	8 km	14 km
CS3	28 km	7 km	15 km
CS4	29 km	8 km	15 km
CS5	29 km	8 km	15 km
CS6	32 km	8 km	16 km
CS7	34 km	9 km	19 km
CS8	29 km	6 km	14 km
CS9	26 km	7 km	13 km
CS10	7 km	2 km	7 km
Total Loop	**275 km**	**73 km**	**145 km**

6.3 Operator has assumed the same methodology for the design, procurement and construction of the additional looping for the years 2008 to 2010 in developing the configuration and costing estimates for these years as was adopted for the looping component required for the Stage 4 expansion project. It should be noted that the proposed looping program involves 26" looping and is configured to meet forecast contracted capacity for the period.

6.4 However, if contracts can not be entered into or shippers do not exercise their additional capacity rights under existing contracts, the additional capacity in these years will not be funded by Operator. This is consistent with the proposed expansions policy and the Standard Shipper Contracts entered into last year with shippers.

7. CONTRACTING STRATEGY

7.1 Operator has a commercial interest in keeping the cost of expanding the capacity of the DBNGP to a level that is consistent with achieving the lowest sustainable cost of providing gas transportation services.

7.2 In particular, Operator has contractual obligations to those shippers which have exercised their rights under clause 16 of the Standard Shipper Contract ("SSC") to minimise costs.

7.3 These have been the principal reasons for why Operator has explored alternative expansion options and, in the case of the Stage 4 expansion program, why the particular option for Stage 4D has been adopted by Operator.

7.4 Once the lowest sustainable cost expansion path available to provide the services to users in accordance with their requirements has been identified, Operator will aim to provide the expanded capacity at – or below – the forecast cost and on time.

7.5 An appropriate contracting strategy is essential to achieving this outcome.

7.6 As a prudent service provider, acting efficiently, Operator does not maintain its own cadre of engineering and technical staff capable of undertaking all of the design, development, acquisition and construction of facilities required to expand the capacity of the DBNGP. For the technical services required for pipeline expansion, Operator draws on the technical expertise of ANS, via the Operating Services Agreement and on its alliances with other suppliers of equipment and engineering services. This has become standard industry practice within the pipeline industry.

7.7 A range of methods is available for securing the services of suppliers of equipment, and of engineering and technical services. At one end of the spectrum, that equipment or those services may be secured through fixed price contracts with suppliers. Somewhere along this spectrum is the method of engaging a supplier under a schedule of rates contract so that the contractor is better able to exclude contingencies from its pricing. At the other end of the spectrum, equipment, or engineering and technical services, may be secured through an alliance contract.

7.8 In alliance contracting, the party requiring equipment, or engineering and technical services, forms an alliance with the contractor, enabling both parties to work co-operatively to deliver required facilities of the desired quality at the best possible price. Alliance contracting delivers these outcomes through its facilitation of knowledge flow between the parties, and the provision of incentives for the sharing of knowledge.

7.9 The fundamental principles behind the alliance contract method include the following:

(i) The incorporation of a philosophy of "no disputes" and "no blame" so that when issues do arise, the parties are encouraged to work together to determine the best result for the project.

(ii) A primary emphasis on business outcomes for all the parties.

(iii) Clear understanding of individual and collective responsibilities.

(iv) An equitable balance of risk and reward for all parties.

(v) Encouragement of openness and cooperation between the parties. This open book approach is important in setting the target price for an alliance contract.

(vi) Encouragement to develop and apply innovative approaches and achieve continuous improvement.

(vii) Access to and contribution of the expertise and skills of all parties.

(viii) A commercial basis which offers the opportunity to achieve rewards commensurate with exceptional overall performance.

7.10 Under the alliance contract method, little or no risk is separately allocated to particular participants in an alliance. Instead, parties jointly accept the project risks up to a point, and work together to achieve the best outcome for a project. However, suppliers under alliance contracts are generally entitled to full recovery of the costs incurred during the alliance. Therefore their risk is effectively capped at their profit and overheads recoverable by them under the alliance.

7.11 There is no rigid contractual structure for an alliance project. The actual structure adopted will be influenced by the nature of the project, and the culture, corporate objectives and drivers of each of the alliance participants.

7.12 Some argue that the non-allocation of risk in an alliance contract favours the supplier, as they are the party who would usually bear the majority of risks under conventional forms of contracts, such as latent conditions, completion and defects. However, this position ignores the fact that risks usually borne solely by an owner under conventional forms of contracts are also shared between the participants under an alliance contract, such as legislative risk, cultural heritage and environmental risks.

7.13 Where these risks are encountered under a lump sum contract, they would usually result in a variation being directed by the owner, and the supplier being entitled to an adjustment of the lump sum price and time for completion.

7.14 In contrast, alliance contracts are more flexible. Where such issues are encountered under an alliance contract, the parties work together to overcome them.

7.15 Commercial arrangements under alliance contracts are often structured so that they require minimal adjustment during the course of the works. The risk/reward regime will usually only be altered in very limited situations. Similarly, there will usually be only limited grounds on which participants will be entitled to extensions of time or increased costs.

7.16 The issue of whether the contract price is too high or too low, always an issue with lump sum contracts (price is inevitably less than actual cost), remains an issue with alliance contracts. However, if an alliance contract has some form of target cost incentive, experience suggests that the ultimate price for the delivery of the service will be less than the co-operative estimate of that price (typically greater than actual cost), or the estimate of price arrived at by the buyer or the service supplier.

7.17 Alliance contracts provide beneficial cost and service related outcomes relative to lump sum contracts (even when those contracts are the results of tender process) for the following reasons:

(i) the supplier is able to mobilise quickly;

(ii) the buyer of services (ie Operator) can exert a high level of control over any contract work carried out by the supplier (i.e. the alliance partner);

(iii) the buyer can more readily change the delivery approach to accommodate project changes;

(iv) alliance partners usually have a good understanding of projects and risks;

(v) there is the greatest likelihood of meeting tight deadlines;

(vi) under lump sum or schedule of rates agreements, there is a steep learning curve for the supplier which will be factored into the pricing, resulting in an increased price for service provision;

(vii) lump sum and schedule of rates agreements take time to formalise, and this may not be appropriate in circumstances where a New Facility must be designed, and constructed or acquired, in a short period; and

(viii) specification of the full scope of work for inclusion in a lump sum or schedule of rates contract takes time, and the buyer of the services bears the risk of later scope change.

7.18 The alliance contracts Operator and its service provider have entered into will be essential, not only to ensuring the expansion of capacity at lowest (actual) cost. They will also be essential to ensuring completion of the various stages of capacity expansion in accordance with commitments, in respect of the timing of the availability of capacity during the proposed Access Arrangement Period, which have been given to shippers.

7.19 The benefits of adopting an alliance contract strategy for at least the initial stages of the expansion program were reinforced during Operator's risk assessment of the Stage 4 project where it became apparent that the risk of delays to project completion was one of the biggest risks facing Operator's ability to meet its obligations to shippers under pre-existing access contracts.

7.20 The prime reason for this is that there is at least one other pipeline construction project being undertaken at the same time as the Stage 4 project, therefore resulting in the two projects competing for the same resources such as construction personnel, equipment, camp and site support facilities etc. Therefore an important risk mitigation strategy is to lock in the required resources at an early stage to ensure availability in accordance with the contractual requirements.

7.21 The timely supply of pipe and securing of all required approvals is also considered major aspects of the expansion project that must be effectively addressed in order to ensure that there will be no delays.

7.22 In light of the above, Operator considers that the utilisation of the aforementioned alliance partners is prudent, particularly given they have been involved in the most recent major gas pipeline and facility construction projects carried out in Australia.

7.23 The alliance arrangements will still require a significant part of the cost items to be the subject of a tender process. Operator envisages most of the total cost of the project will relate to projects which have been the subject of competitive tender. This is consistent with the requirement of the Operating Service Agreement between the Operator and its prime service provider ANS, which require contracts to be the subject of a competitive tender process.

7.24 Requests for tender may only be issued to those parties satisfying Clause 5.8(c) of the Operating Services Agreement, namely contractors that:

- Are properly and fully qualified and authorised to carry out the task;

- Are reputable in the industry; and
- Are sufficiently creditworthy to meet the obligations and liabilities incurred by them in connection with the work to be performed.

7.25 Evaluation of tenders will involve an assessment of each tender against the following criteria:

- Commercial terms and provisions;
- Technical conformance; and
- Value, including, but not limited to, the following:

  Financial elements (direct);

  Life cycle costs analysis;

  Product liability coverage;

  Total supply chain management;

  Quality processes and systems (TQM and accreditation);

  Customer focus and responsiveness;

  Reliability of performance; and

  Financial capability of company.

8. PROPOSED FORECAST CAPITAL COSTS

8.1 This section of the submission outlines the costs associated with the proposed expansion related New Facilities Investment during the Access Arrangement Period.

8.2 It should be noted that Operator is required to justify to shippers under the Standard Shipper Contracts, the costs by reference to certain cost categories that are stipulated in the Standard Shipper Contracts. These are outlined in Annexure 3 to this Submission.

8.3 The following table contains the forecast costs for the expansion program in aggregate by year and broken down by relevant asset category and cost categories (as per the standard shipper contract).

DBNGP Forecast Capital Expenditure 2005-2010 $'000	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
Expansion Capex	**Stage 4**	**Stage 4**	**Stage 4**	**Stage 5**	**Stage 6**	**Stage 7**
Number of Compressors Mainline North		2	5			
Number of Compressors Mainline South		1		2		
km of Looping - Mainline North	0	0	194	268	71	138
km of Looping - Mainline South			23	7	2	7
Costs in 2005$						
Compression - Mainline North	-	46,000	115,000	-	-	-
Scrubber and Aftercooler/Restaging	500	-	6,850	-	9,500	-
Compression - Mainline South	-	19,657	-	40,000	-	-
Looping - Mainline North	-	-	221,936	264,784	70,148	136,344
Looping - Mainline South	-	-	22,724	6,916	1,976	6,916
	500	65,657	366,510	311,700	81,624	143,260
CAPEX Breakdown - Compression						
Total	***500***	***65,657***	***121,850***	***40,000***	***9,500***	***-***
Detail Design		5,039	9,352	3,070	729	
FEED		261	484	159	38	
Material		29,690	55,100	18,088	4,296	
Construction	500	14,166	26,289	8,630	2,050	
Transport		2,366	4,392	1,442	342	
Pre-commissioning		-	-	-	-	
Commissioning		1,916	3,556	1,167	277	
Consultant Fee		927	1,720	565	134	
Duty		-	-	-	-	
Interest Cost		-	-	-	-	
Overhead		2,678	4,969	1,631	387	
Project Management		7,989	14,826	4,867	1,156	
Insurance		62	115	38	9	
Documentation		565	1,048	344	82	
CAPEX Breakdown - Looping						
Total	***-***	***-***	***244,660***	***271,700***	***72,124***	***143,260***
Detail Design		-	1,703	1,891	502	997
FEED		-	1,534	1,704	452	899
Material		-	92,973	103,248	27,408	54,440
Coating	-	-	14,233	15,806	4,196	8,334
Construction		-	105,584	117,253	31,125	61,824
Transport		-	13,791	15,315	4,065	8,075
Pre-commissioning		-	-	-	-	-
Commissioning		-	370	411	109	217
Consultant Fee		-	2,648	2,941	781	1,551
Duty		-	3,657	4,061	1,078	2,141
Interest Cost		-	-	-	-	-
Overhead		-	2,064	2,293	609	1,209
Project Management		-	2,987	3,317	881	1,749
Insurance		-	2,901	3,222	855	1,699
Documentation		-	215	239	63	126

8.4 While the cost categories, as stated in the Standard Shipper Contract, are relatively self explanatory, the following information provides a further explanation of the nature of costs, items of plant and equipment and activities covered by each category:

8.5 Detailed design – in addition to the explanation, it includes design work for procurement, geotechnical surveys for looping, risk assessments, minor service contracts and other design work including:

(i) alignment sheets

(ii) final route topographic survey and route optimisation due to environmental, cultural heritage and land owner issues;

(iii) Identification of sections of the pipeline route that will require special construction methods and/or procedures including sections that are restricted in terms of available working space;

8.6 FEED – this includes costs relating to the commissioning of a FEED study, and internal costs associated with engaging the FEED consultant.

8.7 Material procurement – all costs associated with the purchase of materials and equipment, including compressor units and ancillaries, pipework and valves, control systems and instrumentation, and power supplies and cabling. It also includes:

(i) the tendering of the material purchase requisition packages, evaluation and award to the successful tenderer.

(ii) Environmental assessments, approvals and surveys;

(iii) Cultural heritage survey;

(iv) Approvals by statutory authorities;

(v) Agreements with land owners and traditional landowners (through indigenous land use agreements);

(vi) Placement of orders and commitment to critical subcontractors (eg camp, catering, etc);

(vii) Establishment of a project site industrial agreement;

(viii) Development of a construction execution plan and schedule and any other required management plans and procedures, including OHS, Quality Assurance;

(ix) Development of quality welding and coating procedures;

8.8 Coating – this cost relates to the coating of the looping pipe.

8.9 Construction - all off-site and on-site fabrication and installation costs of the additional compressor station facilities, including set up and site costs, and construction costs, costs. This covers the following:

(i) Mobilisation of construction equipment and materials;

(ii) Establishment of site facilities including camps, project site offices and maintenance and storage facilities and communication systems;

(iii) Locate and set up sources for supply of water for the project;

(iv) Identify access roads and restrictions relative to the same that will have to be addressed and or work that will have to be undertaken prior to the commencement of the delivery of pipe to the right of way; and

(v) Liaison and notification involving relevant land owners and or local authorities.

8.10 Transport – this includes the costs associated with transporting materials to site.

8.11 Pre-commissioning – Operator has not allocated any costs to this category as they are minor and hard to differentiate between commissioning costs. Instead, they have been included as part of the commissioning costs.

8.12 Commissioning and handover – these cover the costs associated in ensuring that the contracted capacity is able to be supplied at a level of reliability in accordance with the requirements of the shipper contract. They reflect about 2% of the total costs.

8.13 Consultants fees – these cover 3rd party inspection fees for such individuals as the banks' advisers, the safety and technical regulator, legal advisers and other consultants.

8.14 Duty – duty is payable on the import of the line pipe. This covers this cost, which is approximately 5% of the cost of pipe.

8.15 Interest costs during construction – this covers the interest costs of the expansion facility that the Operator has taken out with its financiers to fund the expansion. The estimate is based on the assumed cost of debt adopted for the purposes of the WACC calculation which is applied to the assumed gearing ratio used in that

calculation. However, these costs are likely to differ once the expansion facility interest payments have been calculated precisely.

8.16 Departmental overheads – this category includes the following costs:

(i) Design review costs

(ii) Regulatory compliance

(iii) Project support costs

(iv) The incremental costs of the Opeator's GIS system, the labour costs of the Operator's and its service providers corporate staff providing support. This includes heritage and land management support, engineering support etc.

8.17 Project Management – this includes on site and off site project management costs such as overall project management, risk assessment work, project safety management, construction support, topographical survey work and noise and vibration assessment work.

8.18 Insurance – this includes costs associated with obtaining project insurance for the expansion program. This includes brokers' fees, insurance premiums, stamp duty and other government charges. The types of policies envisaged are contract works (material damage), contract works (delay in start up), third party legal liability, Marine cargo, and project professional indemnity insurance. Liquidated Damages insurance is allowed for in operator's forecast non capital costs.

8.19 Project documentation – this is estimated to be less than 1% of the total costs of the program and includes costs relating to project close out work, such as the preparation and actioning of any punch list items.

Additional detail regarding compression capital expenditure

8.20 Preliminary station layouts have identified that it is possible to install the additional compression facilities for Stage 4 within the confines of the existing station graded and levelled sites. Thus, in many respects, the equipment to be provided and the work to be undertaken for Stage 4 is similar to, and comparable with, that executed during the Stage 3A Capacity Expansion Project. Consequently, the Stage 3A basis of design, and supporting design, procurement and construction data has been used as a benchmark for determining the 'baseline' Stage 4 cost. The baseline scope of work for each compressor station is discussed in detail in Annexure 1.

8.21 Where necessary, adjustments to the Stage 3A cost have been made to reflect cost increases resulting from inflation, variations in scope, and as a result of catering for the upgrade of seven compressor stations in lieu of the three stations upgraded during Stage 3A. Key assumptions for the compression facilities, in particular where the facilities have been optimised over those provided during Stage 3A, are given elsewhere in this submission.

8.22 As a consequence, the cost estimate is based on the installation of a Solar Mars 100 turbine with C652 compressor within a Solar provided 'on skid' style enclosure at the sites north of Perth and a Taurus T70 unit at CS10.

9. COMPLIANCE WITH SECTION 8.16

9.1 As noted in section 4 of this submission, Operator has, in accordance with section 8.20 of the Code, determined the Reference Tariff of the Proposed Revised Access Arrangement on the basis of new facilities investment forecast to occur within the proposed Access Arrangement Period. Section 8.20 requires that, in these circumstances, the New Facilities Investment be reasonably expected to pass the requirements of section 8.16(a) when the New Facilities Investment is forecast to occur.

9.2 Section 8.16(a) of the Code provides, subject to sections 8.16(b) and 8.20 to 8.22, for addition of New Facilities Investment into the capital base of a covered pipeline only if two conditions are satisfied. These two conditions are set out in sections 8.16(a)(i) and 8.16(a)(ii).

1st Condition – section 8.16(a)(i)

9.3 Section 8.16(a)(i) requires that the amount of the New Facilities Investment added to the capital base not exceed the amount that would be invested by a prudent service provider acting efficiently, in accordance with accepted good industry practice and to achieve the lowest sustainable cost of providing services.

2nd Condition – section 8.16(a)(ii)

9.4 New Facilities Investment as limited by the 1st Condition, can be added to the capital base only if it is expected to satisfy one of the three "tests" set out in section 8.16(a)(ii). The three tests for New Facilities Investment in section 8.16(a)(ii) are:

(i) the anticipated incremental revenue generated by the new facility exceeds the New Facilities Investment; or

(ii) the new facility has system wide benefits that, in the Regulator's opinion, justify the approval of a higher Reference Tariff for all shippers; or

(iii) the new facility is necessary to maintain the safety, integrity or contracted capacity of cervices.

9.5 Operator submits that that component of New Facilities Investment forecast to occur during the proposed Access Arrangement Period which is expansion CAPEX satisfies the test of section 8.16(a)(ii)(B) of the Code. That is, there are sound reasons for the Regulator forming the opinion that the new facilities to be created have system wide benefits which justify the approval of a higher Reference Tariff for all shippers.

9.6 Operator notes that the Reference Tariff of the Further Amended Proposed Revised Access Arrangement for 2005, incorporating the costings for New facilities Investment to expand the pipeline contained in the proposed access arrangement is:

	$/GJ
Capacity reservation tariff	0.9407
Commodity tariff	0.1036
Tariff for shipper with load factor of 100%	1.0443

9.7 Operator has estimated the Reference Tariff for 2005 without investment in new facilities to expand the capacity of the DBNGP to be:

	$/GJ
Capacity reservation tariff	0.9442
Commodity tariff	0.0870
Tariff for shipper with load factor of 100%	1.0312

9.8 Operator argues, in the following paragraphs of this submission, that there are sound reasons for the Regulator forming the opinion that the new facilities created to expand pipeline capacity have system wide benefits which justify approval of a Reference Tariff that is 0.9% higher than would be the case without expansion.

Expansion will benefit the WA economy

9.9 The system-wide benefits which justify the higher Reference Tariff are the benefits to the Western Australian economy from industry in the south west having greater access to the State's gas reserves, particularly for power generation and for minerals processing.

9.10 That these benefits are available is evidenced by:

(i) existing shippers entering into new contracts for gas transportation service, based on a Standard Shipper Contract, in accordance with terms and conditions of which each shipper has a right to additional capacity, but must pay a tariff reflecting the costs of expansion irrespective of whether or not the right to additional capacity is exercised;

(ii) the Government of Western Australia providing financial assistance to Operator, via the Financial Assistance Agreement, provided Operator enters into certain arrangements (noted below) which have the effect of obliging Operator to expand the capacity of the DBNGP; and

(iii) the Australian Competition and Consumer Commission ("ACCC") accepting an undertaking under section 87B of the Trade Practices Act 1974, given by the current owners of the DBNGP, which requires that

Operator enters into certain arrangements (noted below) which have the effect of obliging Operator to expand the capacity of the DBNGP.

9.11 These benefits were also expressed in various statements made by the Government and relevant Ministers at or about the time of the sale of the DBNGP in October 2004. Copies of these statements are outlined in Annexure 2.

9.12 As outlined in section 2 of this Submission, clause 16 of the Standard Shipper Contract, the pro-forma for the contracts negotiated with existing shippers in the process of the current owners acquiring the DBNGP, requires that Operator expand the capacity of the pipeline for a shipper requiring additional T1 capacity subject to:

(i) the shipper giving 30 months notice;

(ii) the shipper and Operator agreeing an amendment to the existing shipper contract which includes a capacity commencement date which can be no earlier than 24 months from the date of the agreement (unless otherwise agreed by the parties);

(iii) the shipper satisfying all of the usual commercial tests (creditworthiness, no disputes, etc); and

(iv) Operator being able to secure the finance for expansion on reasonable commercial terms and conditions.

9.13 Under the terms and conditions there is no limitation on the amount of capacity which Operator is obliged to provide in response to requests for capacity from shippers on contracts based on the Standard Shipper Contract. However, as outlined earlier in this submission, the obligation to provide capacity ceases on 1 January 2016.

9.14 As also outlined in section 2 of this submission, Schedule 1 to the Financial Assistance Agreement sets out the commitment the State sought from the current owners of the DBNGP in respect of the expansion of pipeline capacity.

9.15 Acquisition of the DBNGP by a consortium including Alcoa of Australia and Alinta was initially of concern to the ACCC. The consortium's acquisition of the pipeline could, in the ACCC's opinion, have inhibited competition in the downstream retail gas market, in alumina production, and in electricity generation. These concerns were alleviated by the consortium offering a court-enforceable undertaking under section 87B of the Trade Practices Act 1974. This undertaking explicitly recognised the current need to expand pipeline capacity:

(i) Operator is to offer to all prospective shippers who require a T1 service, a Standard Shipper Contract that contains capacity expansion rights that are

not materially less favourable than the capacity expansion rights contained in any other shipper contract for a T1 service (clause 5.6(a));

(ii) Operator is to expand the capacity of the DBNGP between Dampier and CS10, no later that five years following completion of the acquisition, by not less than 100 TJ/d, in aggregate to meet the known capacity requirements of contracted shippers or prospective shippers who enter into Standard Shipper Contracts (clauses 5.7(a) and (b)); and

(iii) Operator is to invest up to $400 million in connection with the expansion of capacity under clause 5.7(a) provided that shippers that require the expanded capacity have entered into Standard Shipper Contracts (clause 5.7(c)).

9.16 In effect, shippers using the DBNGP, the Government of Western Australia, and the ACCC, have collectively agreed, through the agreements that they have entered into, that the pipeline must be expanded by Operator to meet the current and future needs of the Western Australian economy.

9.17 The principal users of the additional capacity to be made available by expansion of the DBNGP will include electricity generators Western Power and Alinta, minerals processors, Alcoa of Australia and Worsley Alumina, and agricultural chemicals manufacturer, CSBP. All of these organisations have now contracted, under their existing contracts, for capacity which is to become available during the proposed Access Arrangement Period (see table in section 2 of this submission).

9.18 Alcoa of Australia, Alinta, CSBP, Western Power and Worsley Alumina are all large organisations whose operations are significant for the State's economy. Over the longer term, pipeline capacity expansion should allow the further development of their operations, and of other businesses in minerals processing and manufacturing.

9.19 Furthermore, the provision of additional pipeline capacity will facilitate competition between electricity generators, and between coal and gas as substitute fuels in power generation. It should have a wide impact through its facilitating competition in the electricity sector which should, in turn, benefit industrial, commercial and domestic consumers of electricity in the south west of the State through its constraining effect on electricity price increases.

9.20 The Standard Shipper Contract, the Financial Assistance Agreement with the State, and the ACCC undertaking (clause 5.7(d)) all require that Operator expand the capacity of the DBNGP when called upon to do so by shippers or prospective shippers. As outlined in section 2 of this submission, the only limitations on Operator's obligation to expand are:

(i) Operator's inability to secure the finance for expansion on reasonable commercial terms and conditions; and

(ii) the obligation effectively ceases on 1 January2016.

9.21 If Operator is unable to secure the finance for expansion on reasonable commercial terms and conditions shippers may fund expansion themselves. Shipper funding of expansion would, however, result in some shippers (those requiring additional capacity) paying more for capacity than others. This is of concern to existing shippers, particularly those requiring gas for power generation projects, and for minerals processing, where a higher price for gas transportation can translate into a significant competitive disadvantage. It is one of the reasons why existing shippers have signed up to Standard Shipper Contracts under which they pay the same price for capacity irrespective of whether they use the additional capacity provided by pipeline expansion.

9.22 In summary, expansion of the DBNGP is now necessary for continuing economic development in the south west of Western Australia, and for the success of initiatives to create a more competitive electricity market in the South West. The benefits from development, and from the constraining effect of gas on electricity price increases, justify, in Operator's view, Regulator forming the opinion that the new facilities created by expansion of the pipeline have system wide benefits which justify approval of the higher Reference Tariff that would result from addition of the New Facilities Investment in the capital base of the DBNGP.

9.23 If Operator must rely on the anticipated incremental revenue test of section 8.16(a)(ii)(A) of the Code, Operator may be unable to justify investment in the new facilities required to expand the DBNGP.

Section 8.16(a)(ii)(A)

9.24 Section 8.16(a)(ii)(A) requires that, before the capital base of a covered pipeline is increased by New Facilities Investment, the anticipated incremental revenue generated by those new facilities must exceed the New Facilities Investment.

9.25 Anticipated incremental revenue is, according to the definition in section 10.8 of the Code, the difference between two present values, each of which is calculated using the rate of return as the discount rate. The two present values are:

(i) the present value of the reasonably anticipated future revenue from the sale of services at the prevailing tariffs which would not have been generated without the incremental capacity; and

(ii) the present value of the best reasonable forecast of the increase in non-capital costs directly attributable to the sale of those services.

9.26 "Prevailing tariff" is also defined in section 10.8. It means, for a reference service, the applicable Reference Tariff.

9.27 Section 8.20 of the Code allows the Reference Tariff which is to apply in the Access Arrangement Period following the current period to be determined on the basis of New Facilities Investment that is forecast to occur during that next period, provided the investment is reasonably expected to satisfy the conditions of section 8.16(a) when it is forecast to occur.

9.28 Operator has argued in previous submissions to the Regulator (see, for example, Submission#26, *Further Justification of Forecast Expansion of the DBNGP*) that the Code does not provide clear guidance on the prevailing tariff to be used for calculating the anticipated incremental revenue for the purposes of 8.16(a)(ii)(A) in the context of a service provider's reliance on section 8.20. However, Operator maintains that the appropriate interpretation is that the prevailing tariff is the Reference Tariff that would have applied on the assumption that the relevant New Facilities Investment had **not** been made.

9.29 Operator has made an assessment of whether the New Facilities Investment forecast for the period 2005 to 2010, and taken into account in determining the Reference Tariff of the Revised Access Arrangement passes the test of section 8.16(a)(ii)(A) using this interpretation of prevailing tariff.

9.30 When the prevailing tariff for the test is the tariff determined on the assumption that expansion would not take place, the New Facilities Investment of the Revised Access Arrangement satisfies the test of section 8.16(a)(ii)(A).

9.31 Operator has applied the test of section 8.16(a)(ii)(A) in the following way:

(i) non capital costs for the period 2005 to 2010 have been estimated on the basis of the New Facilities Investment that is forecast to occur during that period being made;

(ii) non capital costs for the period 2005 to 2010 have been estimated on the basis of the New facilities Investment that is forecast to occur during that period not being made;

(iii) the present value of the difference between these two estimates of non capital costs for 2010 (the final year of the next access arrangement period, and the year in which all of the expanded capacity is available to shippers) is calculated for the remaining life of the pipeline using the pre-

tax real rate of return used in reference tariff determination as the discount rate; this present value is the present value of the best reasonable forecast of the increase in non capital costs directly attributable to the sale the increment in services made possible by expansion;

(iv) revenue for the period 2005 to 2010 has been estimated on the basis of the New Facilities Investment that is forecast to occur during that period being made, the tariff used in the estimation being the reference tariff proposed by Operator assuming the forecast New Facilities Investment is made;

(v) revenue for the period 2005 to 2010 has been estimated on the basis of the New facilities Investment that is forecast to occur during that period not being made, the tariff used in the estimation being the tariff calculated by Operator assuming that the forecast New Facilities Investment is not made;

(vi) the present value of the difference between these two estimates of revenue for 2010 (the final year of the next access arrangement period, and the year in which all of the expanded capacity is available to shippers) is calculated for the remaining life of the pipeline using the pre-tax real rate of return used in reference tariff determination as the discount rate; the present value of this revenue is the present value of the reasonably anticipated future revenue from the sale of services at the prevailing tariffs which would not have been generated without the incremental capacity attributable made possible by expansion;

(vii) the difference between the present value of the revenue (as calculated in steps (iv), (v) and (vi) above), and the present value of the increase in non capital costs (as calculated in steps (i), (ii) and (iii) above), is the anticipated incremental revenue generated by expansion of the pipeline;

(viii) the present value of the New Facilities Investment forecast to be made during the period 2005 to 2010 has been calculated using the pre-tax real rate of return used in reference tariff determination as the discount rate;

(ix) the anticipated incremental revenue exceeds the present value of the New Facilities Investment forecast to be made during the period 2005 to 2010;

(x) hence the proposed expansion of the DBNGP during the period 2005 to 2010 satisfies the test of section 8.16(a)(ii)(A).

9.32 In the Draft Decision, the Regulator concluded that the forecast average cost of gas transmission would remain effectively unchanged by the New Facilities Investment in

expansion of pipeline capacity if forecast increases in throughput are realised (Draft Decision, paragraph 176).

9.33 Operator notes that the Regulator's analysis extended over a period of 11 years (2005 to 2015). Capacity was expanded as forecast by Operator during the first half of this period, and the effects of the fully expanded capacity were seen only in the second half of the period.

9.34 In determining the average incremental revenue, Operator has, in contrast, considered only the long-term steady-state implications of the capacity expansion. When a longer term view is taken, which Operator maintains is entirely consistent with the requirements of section 8.16(a)(ii)(A), a much clearer conclusion emerges: the expansion is not "breakeven" as the Regulator indicates; the forecast New Facilities Investment clearly satisfies the test of section 8.16(a)(ii)(A).

9.35 Although the investment satisfies the test, Operator reiterates the view in its Submission#26: given the ambiguity inherent in section 8.16 of the Code, the difficulties of applying the test of section 8.16(a)(ii)(A) in the present circumstances of the DBNGP, and the need to proceed immediately with capacity expansion to meet the needs of the Western Australian economy, the test of section 8.16(a)(ii)(A) should not be relied upon. Regulator should form the opinion that the new facilities created by expansion of the pipeline have system wide benefits which justify approval of the higher Reference Tariff that would result from addition of the New Facilities Investment into the capital base of the DBNGP.

Location of forecast demand for developable capacity

9.36 The forecast New Facilities Investment will also provide system wide benefits in so far as it will offer additional capacity to full haul, part haul and back haul users and prospective users.

9.37 Based on the demand forecasting undertaken by Operator, and Shippers' requests to date, most of forecast demand that supports the expansion of the pipeline is located downstream of CS9.

9.38 Given that this forecast demand is located at the downstream end of the pipeline and the new facilities that need to be built to provide the required capacity are to be constructed at various locations along the entire length of the pipeline, the forecast investment will provide additional part haul and back haul capacity. It will therefore benefit all users and prospective users of the pipeline.

System reliability benefits of proposed expansion

9.39 A further reason as to why the proposed expansion program meets the test in section 8.16(a)(ii)(B) is that significant looping expenditure will provide a more reliable service.

9.40 This is because capacity created by looping is less susceptible to supply interruption than capacity created solely by compression.

9.41 It is noted that in the Draft Decision, Regulator reached a view that the addition of additional compression provided greater system reliability.

9.42 In circumstances where the additional compression is simply being added to provide additional capacity, this view is not correct. When designing an expansion program for additional capacity, Operator will design on the basis of an assumed level of availability and reliability of compressor units and the need to meet the contracted capacity of the pipeline. This level is determined based on the historical operation of the units. Accordingly, there is no greater system reliability as a result of the addition of the new compressors, if the existing compressors are all still required to provide the additional and existing capacity.

9.43 However, in the case of this expansion, there are certain compressors which are being installed to replace existing compressors. These “replaced” compressors are not being replaced but rather are being maintained on site to be able to be utilised in the event of one of the compressors becoming unavailable.

9.44 It is therefore submitted that the “replaced” compressors:

(i) Are not being made redundant; and

(ii) Will increase the reliability of the system.

Annexure 1:
EXPLANATION OF STAGE 4 COMPRESSION

This annexure outlines in detail the extent of the modifications to be undertaken at each of the compressor station sites as part of Stage 4 (Stages 4A-C and 4E-H) It should be noted the compressor station modifications contain a number of activities that are common to all sites – these modifications are identified initially. The annexure then identifies the additional items of work that are required to be performed to cater for site specific differences. (An early section of the submission outlines the scope of work for looping.)

Common Station Modifications

Mechanical

- Supply and install Solar Turbines 10 MW MARS 100 turbine / C652 (at CS10, Solar Taurus 70) compressor unit complete with on skid enclosure;
- Supply and install remote lube oil cooler for new turbine /compressor unit;
- Supply and install fuel gas filter rack for new turbine / compressor unit;
- Supply and install below ground waste water transfer tank;
- Supply and install new double skinned above ground lube oil storage / waste water collection tank complete with vacuum transfer pump for new turbine / compressor unit;
- Supply and install air inlet filter / ducting for new turbine / compressor unit; and
- Supply and install exhaust silencer / ducting for new turbine / compressor unit.

Piping

Compressor Process Piping

- Supply and install suction and discharge piping for new compressor unit;
- Supply and install new check valve in the station header between tie-in for new compressor suction and the station after cooler; and
- Supply and install recycle piping for new compressor.

Waste Water Piping

- Supply and install waste water drain piping between new compressor enclosure and new transfer / collection tanks.

Lube Oil Piping

- Supply and install lube oil piping from turbine / compressor unit to lube oil coolers.

Fuel Gas Piping

- Supply and install fuel gas piping (including filter and PRV's) to new turbine.

Instrument Gas Piping

- Supply and install instrument gas pressure reduction skid for the new turbine / compressor installation; and
- Supply and install instrument gas piping to instrument gas consumer points associated with the new turbine / compressor unit installation.

Civil and Concrete

- Clear ground, prepare finished ground levels and excavate / backfill for new turbine / compressor installation;
- Install concrete footings for new turbine / compressor and enclosure, turbine inlet filter/ducting, turbine exhaust silencer, enclosure ventilation inlet filter / ducting and enclosure ventilation exhaust;
- Install concrete ground slab apron around new turbine / compressor enclosure;
- Install concrete raft footing for new turbine / compressor lube oil cooler;
- Install concrete raft footing for the fuel gas skid associated with the new turbine;
- Install concrete raft footing for the instrument gas skid associated with the new turbine / compressor installation;
- Install concrete footings for pipe supports, valve platform and pipe crossovers for process gas piping associated with the new compressor installation;
- Excavate and backfill trenches for piping, cable ducts and pits, and electrical, instrument and control cabling; and
- Install concrete footings for off site fabricated 'local' unit switchgear and control room

Structural

- Supply and install new offsite fabricated 'local' unit switchgear and control room;
- Supply and install structural steel to support turbine inlet filter and enclosure ventilation inlet filter associated with the new turbine / compressor installation; and
- Supply and install structural steel to support the lube oil cooler associated with the new turbine / compressor installation.

Electrical

New Unit MCC

Supply and install new Unit MCC c/w with the following drives:

- New compressor unit starter motor feeder and Solar supplied VFD;
- New compressor enclosure DOL ventilation fans;
- New compressor unit lube oil cooler fans;
- New compressor unit lube oil pump;
- New compressor lube oil sump decant pump;
- Miscellaneous ventilation/air conditioner feeders; and
- New compressor enclosure lighting and small power panel feeder.

Cabling, Ducts and Ladders

- Supply and install power, control and instrumentation cabling to:
- New compressor unit and ancillary drives;
- Supply and install A/G cable ladder system within switchgear / control room; and
- Supply and install U/G cable duct system to the new compressor enclosure.

24V DC Power Supply

- Install Solar supplied 24V DC UPS system in switchgear/control room;
- Supply and install new compressor unit 24V DC distribution board; and
- Modify existing station 24V DC system to accommodate new equipment

110V DC Power Supply

- Modify existing 110V DC power supply system to provide a feeder to the new compressor emergency lube oil pump

Lighting and Small Power

- Supply and install new turbine / compressor installation lighting and small power distribution panel
- Supply and install lighting and small power to:
- New turbine / compressor enclosure and surrounds.

Earthing and Cathodic Protection

- Modify existing cathodic protection TRU to provide new circuits
- Supply and install cathodic protection cables and test points
- Supply and install new earthing and lightning protection to:
- New turbine / compressor enclosure and surrounds

Instrumentation and Control Systems

- Supply and install pressure, differential pressure, temperature and level transmitters, indicators and switches to the new compressor unit off skid piping and ancillary equipment;
- Supply and install new ultrasonic flow meter in pipeline at entrance to compressor station;
- Supply and install additional hardware and modify existing unit control systems to suit installation of additional turbine / compressor unit; and
- Supply and install additional ACF/ load shed PLC hardware and cabinet, to be integrated with existing ACF / load shed PLC.

SCADA and Telecommunications

- Modify and upgrade existing SCADA system to suit installation of additional compressor unit and associated station equipment; and
- Provide additional Public Address (PA) and telephone for new facilities.

Fire and Gas Systems

- Supply and install new Fire and Gas system for new turbine / compressor unit; and
- Supply and install new Fire and Gas system for unit switchgear / control room.

Compressor Station CS1

Piping

Vent Piping

- Modify station venting system to a common station venting system which includes:
- Supply and installation of a station vent header including vent stack and silencer;
- Supply and install piping to connect the existing Unit 1 and Unit 2 turbine / compressor installation to the new station vent header;

- Replace existing vent isolation valves with plug valves; and
- Supply and install vent piping from new compressor unit suction/discharge installation to the new station vent header.

Civil and Concrete

- Realign and Chipseal surface the road running along the east side of new compressor/turbine installation plus provide a Chipseal surface road to the compressor enclosure turbine removal access door;
- Install Gravel surface road along the west side of new compressor / turbine installation; and
- Install concrete footings for new station vent stack and silencer.

Electrical

MDB – A

- Modify existing MDB-A to suit new compressor unit 400A MCC feeder

Instrumentation and Control Systems

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

Compressor Stations CS2, CS4 and CS7

Mechanical

- Remove existing 230kW Waukesha powered GEA and replace with upgraded 400kW GEA; and
- Install additional 400kW GEA at CS7 only.

Piping

Vent Piping

- Supply and install vent piping from new compressor unit suction and discharge piping to existing vent piping running from the Unit 1 compressor installation.

Fuel Gas Piping

- Supply and install increased capacity fuel gas piping and Regulators to suit upgraded 400kW GEA(s).

Civil and Concrete

- Demolish concrete footings for existing 230kW Waukesha powered GEA / remote radiator and install new concrete footings for a packaged 400kW GEA;
- Install concrete footings for an additional 400kW GEA to CS7 only;
- Install a Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door;
- Install Gravel surface roads along the north and west sides of new turbine / compressor installation; and
- Re-align airstrip to obtain adequate clearance from new turbine / compressor installation.

Electrical

Power Generation

- Supply and install 400kW GEAs and associated remote control panels; and
- Supply and install load banks and associated cabling.

MDB – A

- Modify existing MDB-A to suit 400kW GEA power and controls;
- Modify existing MDB-A to suit GEA load bank starters; and
- Modify existing MDB-A to suit new 400A Unit MCC feeder.

Earthing and Cathodic Protection

- Supply and install new earthing and lightning protection to new 400kW GEA enclosure.

Instrumentation and Control Systems

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems;
  - New station valve control system; and
  - New station PLC and HMI.

Fire and Gas Systems

- Modify existing Fire and Gas systems to suit the following:
  - Deletion of 230kW Waukesha powered GEA; and
  - Installation of new 400kW GEA c/w unitised Fire and Gas system;

Demolition and Isolation

- Carry out electrical demolition work to suit:
  - Removal of 230kW GEA and associated control panels; and
  - Removal of entire existing station control panel.

Compressor Station CS3

- Supply and install turbocharger units to GEA 1 and GEA 2 (upgrade to 500kW).

Piping

Vent Piping

- Modify station venting system to a common station venting system which includes:
  - Supply and installation of a station vent header including vent stack and silencer;
  - Supply and install piping to connect the existing Unit 1 and Unit 2 turbine / compressor installation to the new station vent header;
  - Replace existing vent isolation valves with plug valves; and
  - Supply and install vent piping from new compressor unit suction/discharge installation to the new station vent header.

Civil and Concrete

- Realign and Chipseal surface the road running along the east side of new compressor/turbine installation plus provide a Chipseal surface road to the compressor enclosure turbine removal access door;
- Install Gravel surface road along the west side of new compressor/turbine installation; and
- Install concrete footings for new station vent stack and silencer.

Electrical

MDB – A

- Modify existing MDB-A to suit 500kW GEA power and controls; and
- Modify existing MDB-A to suit new compressor unit 400A MCC feeder

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and
  - New station PLC and HMI, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

Compressor Station CS6

Piping

Vent Piping

- Supply and install vent piping from new compressor unit suction/discharge piping to existing vent piping running from the Unit 1 installation.

Civil and Concrete

- Install Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door; and
- Install Gravel surface roads along the north and west sides of new turbine / compressor installation.

Electrical

MDBs

- Modify existing MDB to suit new 400A Unit MCC feeder.

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and

- New station PLC and HMI with full Modbus connectivity, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

Compressor Station CS9

Piping

Compressor Process Piping

- Supply and install new underground station header;
- Tie-in existing Unit 1 compressor discharge piping into the new underground station header; and
- Install isolation spectacle blinds on the Unit 1 compressor unit suction and discharge lines.

Vent Piping

- Supply and install vent piping from new compressor unit suction/discharge piping to the station vent header.

Civil and Concrete

- Install Chipseal surface road along the east side of new compressor/turbine installation and to the compressor enclosure turbine removal access door; and
- Install Gravel surface roads along the south and west sides of new compressor/turbine installation.

Electrical

MDBs

- Modify existing GEA1 and 2 MDBs to suit new 400A Unit MCC feeders; and
- Modify existing GEA1 and GEA 2 MDBs to make earth leakage protection operational

Instrumentation and Control

- Supply and install new station control panel incorporating the following:
  - New SESD and MESD systems; and

- New station PLC and HMI with full Modbus connectivity, to be integrated with existing station PLC.

Demolition and Isolation

- Carry out electrical demolition work to suit.

Annexure 2:
STATEMENTS ON SYSTEM WIDE BENEFITS OF THE PROPOSED EXPANSION PROGRAM

Transcript

Station:	ABC 720 PERTH	**Date:**	31/08/2004
Program:	12:00 NEWS	**Time:**	12:03 PM
Compere:	NEWSREADER	**Summary ID:**	P00015070083
Item:	ENERGY MINISTER ERIC RIPPER SAYS SUCCESSFUL SALE OF DAMPIER TO BUNBURY GAS PIPELINE WILL LEAD TO LOWER ENERGY COSTS FOR CONSUMERS. INTV: ERIC RIPPER, ENERGY MINISTER		

Demographics:	Male 16+	Female 16+	All people	Abs	GBs
	18000	9000	28000	8000	15000

NEWSREADER: The Energy Minister Eric Ripper says the successful sale of the Dampier to Bunbury gas pipeline will lead to lower energy costs for consumers. A consortium comprising DUET, Alinta and Alcoa has bid $1.86 billion for the pipeline. Alinta Chief Executive Bob Browning says the deal should be finalised within eight weeks and work will begin immediately to expand the line to help meet the States' growing energy demands. Mr Ripper says the sale is good news for the State.

ERIC RIPPER: Well, the sale and expansion of the pipeline is very important to promote competition in our electricity market and competition in our electricity market will

create downward pressure on prices, so this is a very important issue for both the security of our electricity supply and for competition in our electricity market with consequent benefits on ultimate prices.

* * **END** * *

9.45 Statement of then Energy Minister, Mr E Ripper

Statement Released: 25-Oct-2004
Portfolio: Deputy Premier, Energy

Gas contract secures long-term energy supplies

25/10/04

Deputy Premier and Energy Minister Eric Ripper has given approval for Western Power to enter into a billion-dollar contract to protect the State's energy security for the next 25 years.

Mr Ripper said the gas transport contract allowed Western Power to secure the gas supplies it needed to generate more electricity for the growing State economy.

He said the agreement would clear the way for the imminent sale of the Dampier-to-Bunbury natural gas pipeline - which had been in receivership since April 2004 - to be concluded.

"Sale of the pipeline will mean the long-awaited expansion can occur, delivering more gas to meet the needs of a growing State," the Deputy Premier said.

"It will mean that, for the first time since the privatisation of the pipeline in 1998, we can say that the State's long-term energy needs have been secured.

"Importantly, Western Power has negotiated a gas transport contract that is in its best commercial interests.

"I could not have accepted an arrangement that disadvantaged Western Power as it faces an increasingly competitive market environment."

Mr Ripper said the Government was close to concluding its financial assistance agreement with the pipeline's prospective new owners.

"The transaction will attract stamp duty, which must be paid in full," he said.

"However, the Government has secured guaranteed, timely expansion of the pipeline through the provision of financial assistance.

"Expansion of the pipeline is in the best interests of the State. An affordable and reliable electricity supply and the development of gas powered projects in the South-West depend on it."

9.46 Statement from Energy Minister

Statement Released: 27-Oct-2004
Portfolio: Deputy Premier, Energy

Pipeline sale a boost for State economy

27/10/04

Energy Minister Eric Ripper has hailed the sale of the Dampier-to-Bunbury natural gas pipeline as a major shot in the arm for the Western Australian economy.

Mr Ripper said the sale to a credible, financially stable owner meant the long awaited expansion could go ahead, providing gas for electricity generation and for major industrial projects.

"It gives local businesses and new investors confidence that the South-West of WA will have the gas supplies needed to power economic growth well into the future," he said.

"Without the sale of the pipeline and its timely expansion, WA could have faced years of economic uncertainty with unreliable electricity and stalled industrial projects."

The gas pipeline has been sold to a consortium of Diversified Utility and Energy Trusts (DUET), Alcoa and Alinta.

"It is the most important strategic issue that has faced the Gallop Government since its election to office," the Minister said.

"We have always said a successful commercial outcome was the best solution to the impasse with the previous owner about independently regulated tariffs and the owners refusal to undertake expansion.

"The pipeline saga is an important illustration of the pitfalls of privatisation, particularly of strategic assets."

Mr Ripper said the Government had committed $88million to the timely expansion of the pipeline.

"The consortium will pay stamp duty in full. However, the Government has secured guaranteed, timely expansion of the pipeline through the provision of financial assistance to an equivalent amount," he said.

"The assistance will be in the form of a 99-year loan, which may convert to a non-repayable grant at the request of the consortium if the expansion commitments are

satisfied.

"This is an important investment in long-term energy security for WA."

The Minister said the successful sale meant the Government had maintained the integrity of the Regulatory system by resisting calls to compromise State law and Federal agreements by interfering in the Regulator's tariff decisions.

"Setting tariffs by political fiat in order to prop up the previous pipeline owner financially, would have signalled to investors that the WA Government has no respect for the law or proper processes," he said.

The sale of the pipeline follows the finalisation of a billion dollar gas transport contract between Western Power and the new owners earlier this week.

The 1,300km pipeline was privatised by the Court Government in 1998 for $2.4billion. The pipeline was placed in receivership in April this year.

Annexure 3:

Provisions of Standard Shipper Contract relating to capital expansion cost categories.

Cost categories for expansions undertaken by adding compression:

(i) detailed design, including the preparation of all the discipline construction drawings, material purchase requisitions, material tender packages, specifications, detailed project schedule, detailed costings and the construction specification for the Compressor Expansion;

(ii) front end engineering design;

(iii) material procurement, including the tendering of the material purchase requisition packages, evaluation and award to the successful tenderer for material;

(iv) construction, including all off-site and on-site fabrication and installation of the additional compressor station facilities;

(v) transport;

(vi) pre-commissioning;

(vii) commissioning and handover;

(viii) consultants fees;

(ix) duty;

(x) interest costs during construction and after commissioning;

(xi) departmental overheads;

(xii) project management, including all aspects of managing the Compressor Expansion from the decision to conduct Compressor Expansion to completion of Compressor Expansion, and including the project management costs of contractors;

(xiii) insurance; and

(xiv) project documentation compilation and handover, including compilation and handover to Operator in hardcopy and electronic form of all relevant documentation associated with the Compressor Expansion.

Cost categories for expansions undertaken by adding looping:

(xv) detailed design, including the preparation of all the discipline construction drawings, material purchase requisitions, material tender packages, specifications, detailed project schedule, detailed costings and the construction specification for the Looping Expansion;

(xvi) front end engineering design;

(xvii) material procurement, including the tendering of the material purchase requisition packages, evaluation and award to the successful tenderer for material;

(xviii) coating (internal and external);

(xix) construction, including all off-site and on-site fabrication and installation of the pipeline duplication;

(xx) transport;

(xxi) pre-commissioning;

(xxii) commissioning and handover, including the actual gas-up of the pipeline duplication to the nominated transmission pressure and leak testing prior to the pipeline actually flowing gas to shippers;

(xxiii) consultants fees;

(xxiv) duty;

(xxv) interest costs during construction and after commissioning;

(xxvi) departmental overheads;

(xxvii) project management, including all aspects of managing the Looping Expansion from decision to conduct Looping Expansion to completion of Looping Expansion and including the project management costs of contractors;

(xxviii) insurance; and

(xxix) project document compilation and handover, including compilation and handover to Operator in hardcopy and electronic form of all the relevant documentation associated with the Looping Expansion.