DAMPIER TO BUNBURY NATURAL GAS PIPELINE

REVISED PROPOSED ACCESS ARRANGEMENT INFORMATION UNDER THE NATIONAL ACCESS CODE

SUBMISSION VERSION
8 August 2003

PUBLIC VERSION

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1. INTRODUCTION

1.1 This revised proposed Access Arrangement Information was submitted by Epic Energy in support of its revised proposed Access Arrangement lodged with the Regulator on 8 August 2003.

1.2 Except where expressly provided, terms used in this Access Arrangement Information have the same meaning as in the Access Arrangement.

1.3 A reference to a “section” is to a section of this Access Arrangement Information.

2. INFORMATION REGARDING ACCESS AND PRICING PRINCIPLES

2.1 Reference Tariffs

(a) **Firm Service**

Section 3.3 of the Code requires Epic Energy's Access Arrangement to offer a reference tariff for at least one service sought by a significant part of the market.

The Reference Tariff for Firm Service offered by Epic Energy in its Access Arrangement is such a reference tariff.

Firm Service was developed after consultation with a number of existing shippers and producers. It is drawn from the firm service which was offered under the GTRs and the Transitional Regime.

The form and level of the Reference Tariff for Firm Service was determined in the process through which Epic Energy acquired the DBNGP.

Epic Energy acquired the DBNGP through a multistage competitive bidding process structured and executed by the Government of Western Australia ("State") to achieve a number of public policy outcomes. Those outcomes included the State securing a high purchase price for the DBNGP whilst delivering lower transmission tariffs to shippers. The process through which Epic Energy acquired the DBNGP is dealt with in greater detail in section 3.1 of this Access Arrangement Information.

Epic Energy's successful bid for the DBNGP of $2,407 million was considered by the State superior to any other bid and was consistent with the State's proposed price path for transmission tariffs. In its bid, Epic Energy committed to:

(i) a "tariff" from 1 January 2000 of $1.00/GJ for gas transportation to Kwinana Junction:

(ii) a "tariff" from 1 January 2000 of $1.08/GJ for gas transportation to delivery points downstream of Kwinana Junction; and

(iii) a price path that would see tariffs rise by no more than 67% of increases in CPI.

The "tariffs" were widely referred to by the State during the sale process of the DBNGP. The "tariffs" were not, however, a complete specification of the tariffs for Firm Service. Epic Energy has therefore developed its proposed Reference Tariff and Access Arrangement recognising the commitments it made to the State at the time it purchased the DBNGP. At the same time it has looked to refine and improve the structure where appropriate.

The final structure of the Reference Tariff is discussed in section 2.2. The manner in which the Reference Tariff has been determined is discussed in section 2.3. The Tariff Schedule to the Access Arrangement sets out the initial Reference Tariff to apply from the later of 1 January 2000 and the date the Regulator approves Epic Energy's Access Arrangement.

Paragraph 7 of the Access Arrangement sets out the way in which the initial Reference Tariff is varied in the second and subsequent years. The initial Reference Tariff is to be varied in accordance with a predetermined price path. The price path – the form of regulation – and its incentive properties are described in section 2.6.

(b) **Non Reference Services**

In addition to the Reference Service, Epic Energy will, subject to operational availability and commercial feasibility (as determined by Epic Energy in its absolute discretion), make available to a prospective shipper the following Service or Services:

(i) Secondary Market Service;
(ii) Park & Loan Service;
(iii) Seasonal Service;
(iv) peaking service.

Epic Energy is also prepared to negotiate, subject to operational availability (as determined by Epic Energy in its absolute discretion) the following service or services.

(i) metering information service;
(ii) pressure and temperature control service;
(iii) odorisation service;
(iv) commingling service.

Each of the above services named in this section 2.1(b) is known as a Non-Reference Service. Some of these Services which Epic Energy believes may be interest to shippers are Secondary Market Service, Seasonal Service and Park and Loan Service. The Non-Reference Services offered by Epic Energy are intended to cater to prospective shippers on an individual basis. Some of them are described in more detail below.

(i) **Secondary Market Service**

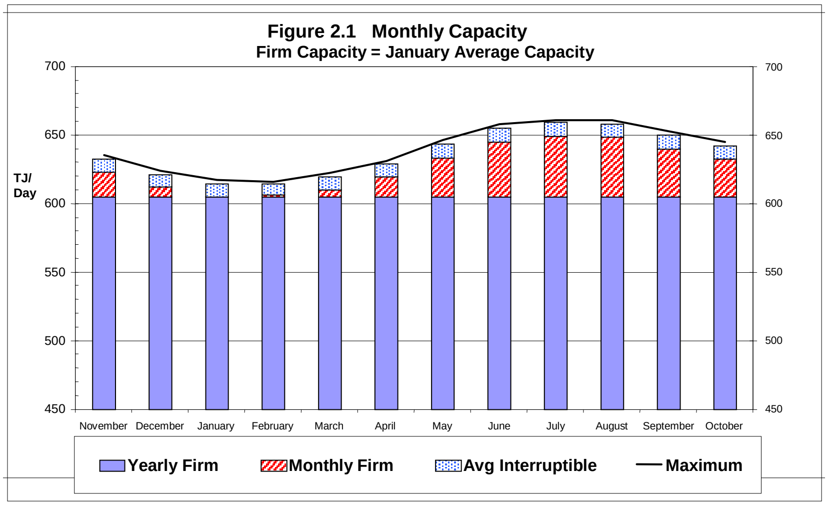
Epic Energy supports a secondary, or “spot”, market for gas using unutilised capacity on the DBNGP. Shippers with unutilised Firm Service capacity will be able to “post” all or any part of that unutilised capacity for a day in the Secondary Market, and sell it to Approved Third Parties on a firm basis.

Epic Energy will also offer spare capacity it may have available in the DBNGP for sale on a Day, in the Secondary Market. This Secondary Market Service will be made available on a Day by Day basis only. Shippers will not be able to contract with Epic Energy for Epic Energy’s Secondary Market Service capacity for extended periods.

Capacity which Epic Energy may offer as Secondary Market Service will be offered in competition with Shippers offering unutilised capacity in the Secondary Market. As a result there is substantial uncertainty regarding the future revenue that Epic Energy can expect from that service. Secondary Market Service is therefore a rebateable service.

(ii) **Seasonal Service**

Capacity in the DBNGP varies inversely with ambient temperature (see figure 2.1). 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. The pipeline capacity determined assuming January conditions ("Yearly Firm" in Figure 2.1) is the capacity made available to users of Firm Service. During the remaining eleven months of the year, capacity will usually be higher than the Firm Service capacity, and the difference ("Monthly Firm" in Figure 2.1) can be made available to shippers with seasonal variation in their gas transportation requirements. This will be after taking into account Epic Energy's obligations under pre Access Arrangement contracts.



Shipper requirements for seasonal capacity, which can only be made available on a seasonal basis, are uncertain, and the revenue which might be obtained is also uncertain. Seasonal Service is therefore a rebateable service.

(iii) **Park and Loan**

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, Epic Energy 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. Epic Energy's ability to offer a Park and Loan Service is restricted by the operating characteristics of the DBNGP.

Park and Loan Service is likely to be required only by those few shippers supplying gas to end users with unpredictable patterns of demand or to cover spasmodic occurrences caused by ad hoc incidents, making revenue obtained from the service uncertain. Accordingly, Park and Loan Service is offered as a rebateable service.

(v) Peaking service

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

(vi) Metering Information service

This service will entail the provision of metering and operational data directly to a third party in addition to the data Epic Energy agrees to provide under an Access Contract for any other Reference Service.

(vii) Pressure and Temperature Control Service

This service will entail the provision by Epic Energy of a service to vary the temperature and/or pressure at which Epic Energy shall deliver gas at a Delivery Point.

(viii) Odorisation Service

This service will entail the provision of a service by Epic Energy to odorise the gas being delivered at a Delivery Point.

(ix) Co-mingling service

This service entails the agreement by Epic Energy 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.

(c) In addition to the Non Reference Services, Epic Energy will provide services to shippers with gas transportation contracts entered into before commencement of the Access Arrangement.

2.2 Reference Tariff Structure

(a) **Objectives**

(i) Epic Energy's Reference Tariff has been designed in accordance with Section 8.1 of the Code to achieve the following objectives:

(ii) providing a revenue stream that recovers the efficient costs of delivering the Reference Service over the expected lives of the DBNGP assets used to provide that service;

(iii) replicating the outcome of a competitive market;

(iv) ensuring safe and reliable pipeline operation;

(v) not distorting investment decisions in pipeline transportation systems or in upstream and downstream industries;

(vi) efficiency in level and structure; and

(vii) providing incentives for cost reduction and the development of the market for the Reference Service and other services.

(b) **Reference Tariff Efficiency**

Epic Energy has sought to achieve efficiency in the structure of its Reference Tariff by:

(i) dividing the DBNGP into 12 Zones for pricing purposes in so far as the Reference Tariff relates to the Pipeline Capacity Charge; and

(ii) adopting a multi-part tariff.

Efficiency is achieved through setting the Reference Tariff at a level which recovers no more than the efficiently incurred costs of the resources used to provide the Reference Service. The costs of providing Reference Service using the DBNGP are set out in subsequent sections of this Access Arrangement Information.

Epic Energy has set levels for planned capital investment and for non-capital costs to be recovered by the Reference Tariff to ensure the continued safe and reliable operation of the DBNGP. Continued reliability of the DBNGP is essential to securing the benefits of market development. Epic Energy's costs have been set to ensure that high reliability and market growth can be achieved without compromising the safety record and reliability of the DBNGP.

(c) **Pricing zones**

To achieve cost reflective tariffs, Epic Energy has divided the DBNGP into 12 pricing zones in so far as the Reference Tariff relates to the Pipeline Capacity Charge. The Zones are listed in Table 2.1. Zone 1 commences at the Dampier receipt point which is located on the Burrup Peninsula immediately downstream of Woodside Petroleum's gas processing and liquefaction facilities.

Table 2.1 - Pricing Zones

Zone	Downstream Zone Boundary	Zone Length	Delivery Points In Zone
1a 1b	30 km downstream of Dampier receipt Point 1 km downstream of CS2 downstream isolating valve (MLV 30)	30 km 244 km	Hamersley Iron Robe River Port Hedland
2 3	1 km downstream of CS3 downstream isolating valve (MLV 42) 1 km downstream of CS4 downstream isolating valve (MLV 54)	137 km 138 km	
4	1 km downstream of CS5 downstream isolating valve (MLV 66)	138 km	
4a	Zone extends from branch of DBNGP mainline at MLV 55 to Carnarvon Power Station	170 km	Carnarvon Power Station
5	1 km downstream of	140 km	

Zone	Downstream Zone Boundary	Zone Length	Delivery Points In Zone
	CS6 downstream isolating valve (MLV 78)		
6	1 km downstream of CS7 downstream isolating valve (MLV 90)	142 km	Eradu Road
7	1 km downstream of CS8 downstream isolating valve (MLV 102)	147 km	Geraldton (Nangetty Road) Mungarra Pye Road Mondarra Mount Adams Road Eneabba
8	1 km downstream of CS9 downstream isolating valve (MLV 114)	143 km	
9	Upstream flange of Kwinana Junction valve V4 and upstream flange of valve HV401A	141 km	Muchea Pinjar Della Road Ellenbrook Harrow Street Caversham Welshpool Forrestdale Russell Road
10	Downstream flange of joint immediately downstream of MLV 157	131 km	Wesfarmers LPG Australian Gold Reagents Kwinana West lateral: Alcoa Kwinana Kwinana Power Station Barter Road/HiSmelt Rockingham lateral: Mission Energy Cogeneration Kwinana Beach Road Thomas Road WMC Rockingham Pinjarra
10 (cont'd)			Main line South: Alcoa Pinjarra Oakley Road Alcoa Wagerup Harvey Worsley South West Cogeneration Kemerton Clifton Road

Zones 1a and 1b are part of a gas production/gathering zone. All users of the Reference Service supply gas into the DBNGP at receipt points located within Zones 1a and 1b.

Zone 1a extends from the Domgas receipt point to a point on the DBNGP 30 km downstream of Dampier. Contractual arrangements entered into before commencement of the Code define the downstream boundary of Zone 1a. Gas is delivered from the pipeline, into the Pilbara region of Western Australia, from delivery points in Zone 1a.

Zone 1b extends from the downstream boundary of Zone 1a to the downstream boundary of Zone 1a to 1 km downstream of the downstream isolating valve (MLV 30) at Compressor Station 2.

Zones downstream of Zone 1b (other than Zone 4a) are of roughly equal length, with each Zone being approximately 140 km. Each of Zones 2 to 8 terminate 1 km downstream of a compressor station. Zone 9 terminates at Kwinana Junction, and Zone 10 terminates at the end of the DBNGP (downstream of MLV 157) immediately downstream of the Clifton Road meter station in the Bunbury area.

Zone 4a extends from the branching point on the DBNGP mainline at MLV 55 into the town of Carnarvon, some 170 kilometres to the west.

Commercially significant delivery points are located in Zone 7 (Geraldton and the Mid-West), Zone 9 (Perth and the surrounding urban area), and Zone 10 (the Kwinana industrial area and south to Bunbury).

(d) **Multi-part tariff structure**

The Reference Tariff comprises a multi-part tariff as follows:

(i) **Regulator's Funding Charge**

The Regulator's Funding Charge is the sum of the Regulator's Ongoing Charge and the Regulator's Access Arrangement Charge, as calculated in accordance with clause 16.4 of the Access Contract Terms and Conditions.

(ii) **Pipeline Capacity Charge**

The Pipeline Capacity Charge payable by a shipper is the product of the Pipeline Capacity Charge rate and the shipper's MDQ. The Pipeline Capacity Charge is payable for each Zone between a shipper's receipt point and delivery point (including the Zones in which the receipt point and the delivery point are located).

(iii) **Compression Capacity Charge**

The Compression Capacity Charge is payable by a shipper for each compressor station located between that shipper's receipt point and delivery point. The Compression Capacity Charge is the product of the Compression Capacity Charge rate and the shipper's MDQ.

(iv) **Compressor Fuel Charge**

The Compressor Fuel Charge is payable by a shipper in respect of each compressor station located between the shipper's receipt point and delivery point. The Compressor Fuel Charge is the product of the Compressor Fuel Charge rate and the quantity of gas actually delivered to the shipper at the delivery point on a Day.

(v) **Delivery Point Charge**

The Delivery Point Charge is an annual fixed charge which recovers the cost of the delivery point facilities used by the shipper. Where gas is delivered to more than one shipper at a delivery point, the Delivery Point Charge is shared between shippers on the basis of the total quantity of gas delivered at the delivery point.

The costs recovered by each component of the Reference Tariff, and the cost allocations which have been made in determining the charge rates are discussed in sections 2.3 and 2.4. Determination of the Reference Tariff is set out in section 2.5.

(e) **Gas Quality**

(i) Epic Energy's Reference Tariff is based on the gas quality specifications for the DBNGP in existence at the date of submission of the Access Arrangement with the Regulator

<table>
<tr><th colspan="2">Component</th><th>Category A Gas</th><th>Category B Gas</th></tr>
<tr><td colspan="2">Maximum carbon dioxide (mol %)</td><td>3.6</td><td>4.0</td></tr>
<tr><td colspan="2">Maximum inert gases (mol %)</td><td>5.5</td><td>6.0</td></tr>
<tr><td colspan="2">Minimum higher heating value (MJ/m^3)</td><td>37.3</td><td>37.3</td></tr>
<tr><td colspan="2">Maximum higher heating value (MJ/m^3)</td><td>42.3</td><td>42.3</td></tr>
<tr><td colspan="2">Minimum Wobbe Index</td><td>47.3</td><td>47.3</td></tr>
<tr><td colspan="2">Maximum Wobbe Index</td><td>51.0</td><td>51.0</td></tr>
<tr><td rowspan="2">Maximum total sulphur (mg/m^3)</td><td>Unodorised gas</td><td>10</td><td>10</td></tr>
<tr><td>Odorised gas</td><td>n/a</td><td>20</td></tr>
<tr><td colspan="2">Maximum Hydrogen Sulphide (mg/m^3)</td><td>2</td><td>2</td></tr>
<tr><td colspan="2">Maximum Oxygen (mol %)</td><td>0.2</td><td>0.2</td></tr>
<tr><td colspan="2">Maximum Water (mg/m^3)</td><td>48</td><td>48</td></tr>
<tr><td colspan="2">Hydrocarbon dewpoint over the pressure range 2.5 to 8.72 MPa absolute</td><td>Below 0 ºC</td><td>Below 0 ºC</td></tr>
<tr><td colspan="2">Maximum radioactive components (Bq/m^3)</td><td>600</td><td>600</td></tr>
<tr><td colspan="2">Minimum extractable LPGs (t/TJ)</td><td>1.45</td><td>n/a</td></tr>
</table>

If Epic Energy is contractually able to do so, and with the approval of the Coordinator of Energy, Epic Energy may broaden the gas specifications applicable to the DBNGP under the Access Arrangement. If it does so, Epic Energy may wish to amend the tariff structure for the Reference Tariff to accommodate different qualities of gas. In that instance, Epic Energy acknowledges that it would need to put such revised Reference Tariff to the Regulator for approval.

2.3 Forecast Total Cost of Providing Reference Services – Cost of Service ('COS') Method

Under the COS Method, Epic Energy's forecast total costs of providing the Reference Service and other services to shippers with gas transportation contracts entered into before the commencement of the Access Arrangement are shown in Table 2.2.

Table 2.2 - Access Arrangement Information

Forecast Total Costs of Providing Services **under the COS Method**

Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m	2005 $m	2006 $m	2007 $m	2008 $m	2009 $m
RETURN ON CAPITAL BASE										
Physical asset account										
Pipeline	218.12	218.06	217.97	217.85	217.74	217.60	218.92	220.88	220.67	233.36
Compression	37.93	37.93	37.24	36.83	36.33	35.46	34.47	50.85	49.32	45.77
Metering	2.99	2.99	2.98	2.98	2.98	2.97	2.96	2.95	2.94	2.90
Other assets	8.81	8.81	9.36	9.88	10.46	10.94	10.98	11.25	11.52	12.07
DEPRECIATION										
Physical asset account										
Pipeline	1.01	1.12	1.23	1.36	1.50	1.66	1.83	2.02	2.23	2.48
Compression	7.57	8.37	9.26	10.24	11.32	12.50	14.76	16.29	17.98	19.85
Metering	0.08	0.08	0.09	0.10	0.11	0.12	0.14	0.15	0.17	0.18
Other assets	0.22	0.25	0.28	0.31	0.35	0.39	0.43	0.47	0.53	0.58
NON-CAPITAL COSTS										
Pipeline Maintenance	21.94	22.81	22.97	22.23	22.18	27.80	28.26	28.77	29.49	30.56
Compression Maintenance	3.54	3.55	5.41	5.79	5.10	3.14	3.51	6.08	8.23	3.95
Compressor Fuel	12.45	13.07	13.30	13.92	14.22	16.53	18.41	32.47	26.81	30.33
TOTAL	314.66	316.89	320.20	321.58	321.88	328.15	351.31	370.92	368.45	351.31

2.4 Forecast Total Cost of Providing Reference Services – Net Present Value ('NPV') Method

Under the NPV Method, Epic Energy's forecast total costs of providing the Reference Service and other services to shippers with gas transportation contracts entered into before the commencement of the Access Arrangement are shown in Table 2.3.

Table 2.3 - Access Arrangement Information

Forecast total costs of providing services

Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m	2005 $m	2006 $m	2007 $m	2008 $m	2009 $m
RETURN ON CAPITAL BASE	192.83	197.00	201.83	206.85	211.90	231.02	243.65	250.84	255.86	274.57
Pipeline, CS1 and CS2 and other assets	22.50	22.61	22.84	23.45	23.70	25.49	39.25	40.39	41.59	43.31
Compressor stations (excluding CS1 and CS2)	2.41	2.43	2.47	2.50	2.53	2.73	2.78	2.82	2.86	2.91
Metering										
ECONOMIC DEPRECIATION										
Pipeline, CS1 and CS2, and other assets	-34.15	-38.67	-41.36	-43.06	-43.33	-52.80	-41.31	-42.17	-41.27	-45.69
Compressor stations (excluding CS1 and CS2)	-0.11	-0.15	-2.00	-0.48	0.27	2.13	-10.27	-10.90	-15.53	-8.79
Metering	-0.24	-0.25	-0.25	-0.26	-0.25	-0.39	-0.39	-0.39	-0.39	-0.40
NON-CAPITAL COSTS										
Pipeline Maintenance	21.94	23.33	24.02	23.77	24.24	27.80	28.26	28.77	29.49	30.56
Compressor Station Maintenace	3.54	3.63	5.66	6.19	5.57	3.14	3.51	6.08	8.23	3.95
Compressor Fuel	12.45	13.36	13.90	14.88	15.54	16.53	18.41	32.47	26.81	30.33
TOTAL	221.17	223.29	227.10	233.84	240.17	255.65	283.89	307.91	307.64	330.74

2.5 Cost Allocation

In developing its Reference Tariff, the forecast total cost of providing Services in the year ending 31 December 2000 has been allocated to the Reference Service and to services to shippers with gas transportation contracts entered into before the commencement of the Access Arrangement.

Epic Energy has allocated costs to shippers with gas transportation agreements entered into before the commencement of the Access Arrangement as if those shippers had been users of the Reference Service.

The allocation of the components of the forecast total cost of providing services in the year ending 31 December 2001 to the various charges which comprise the Reference Tariff is shown in Table 2.4.

Table 2.4 - Allocation of Forecast Total Cost Components to Charge Rates

Charge rate
Pipeline capacity charge rate *Recovers* Pipeline asset return by zone Pipeline asset depreciation by zone Pipeline maintenance costs by zone Compressor station asset return by for compressor stations 1 and 2 Compressor station asset depreciation for compressor stations 1 and 2 Compressor station maintenance costs for compressor stations 1 and 2 Other assets return Other assets depreciation Other non-capital costs *Recovery basis* Passthrough MDQ in each zone Delivery point MDQ
Compression capacity charge rate *Recovers* Compressor station asset return by compressor station Compressor station asset depreciation by compressor station Compressor station maintenance costs by compressor station *Recovery basis* Passthrough MDQ for each compressor station
Compressor fuel charge rate *Recovers* Compressor fuel costs by compressor station *Recovery basis* Passthrough volume for each compressor station
Delivery point charge *Recovers* Metering assets return by delivery point Metering assets depreciation by delivery point *Recovery basis* Fixed charge

Regulators Funding Charge

Recovers

The costs imposed by the Regulator on Epic Energy pursuant to the Gas Pipelines Access (WA) (Funding) Regulations 1999

Recovery basis

Delivery Point MDQ

Asset-related costs (asset return and depreciation) have been allocated to each of the component charges of the Reference Tariff on the basis of asset value.

Pipeline Maintenance costs and other Non Capital Costs have been allocated to zones on the basis of zone length either as a proportion of the length.

Compressor station maintenance costs, and compressor station fuel costs have, as appropriate, been allocated to each of the component charges of the Reference Tariff.

The costs recovered through the Pipeline Capacity Charge are fixed costs. They do not vary with pipeline throughput. The level of these costs is determined by the total requirement for pipeline capacity and they have been recovered on the basis of shippers' contracted capacity requirements in each zone.

Similarly, the costs recovered through the Compression Capacity Charge are essentially fixed costs, the level of which is determined by requirements for pipeline capacity. Accordingly, they have been recovered on the basis of shipper's contracted capacity requirements through each compressor station (apart from the costs related to CS1 and CS2 which are recovered through the Pipeline Capacity Charge.

Compressor fuel costs are the only variable costs associated with operation of the DBNGP. They are recovered from shippers on the basis of the quantity of gas passing through each compressor station.

The Delivery Point Charge recovers the capital costs – metering asset return and metering asset depreciation - of facilities at each delivery point. It is a fixed charge. The costs of maintaining delivery point facilities are small relative to the capital costs, and are captured as pipeline maintenance costs and recovered through the Pipeline Capacity Charge.

The Regulator's Funding Charge recovers the costs imposed on Epic Energy and recovered from Shippers pursuant to the Gas Pipelines Access (WA) (Funding) Regulations 1999 or any regulations which may supersede them.

2.6 Reference Tariff Determination – COS Method

As noted in section 2.1, in its bid for the DBNGP, Epic Energy gave a commitment to lowering gas transmission tariffs to \$1.00/GJ to Kwinana Junction, and \$1.08/GJ for gas transportation to delivery points downstream of Kwinana Junction.

These were the tariffs the Government of Western Australia sought as outcomes of the pipeline sale process.

A tariff determined from the forecast Total Revenue as outlined in sections 2.3 and 2.4 is consistent with these tariff expectations.

2.7 Incentive Structure

The reference tariff principles of Section 8 of the Code permit the setting of a Reference Tariff for the first year of an Access Arrangement, and the adjustment of that tariff in subsequent years. The method of future tariff adjustment is referred to as the form of regulation. The form of regulation may be:

(a) tariff adjustment in accordance with a predetermined price path; or

(b) tariff adjustment on the basis of actual outcomes (such as sales volumes and actual costs) in subsequent years; or

(c) tariff adjustment in accordance with a variation or combination of these two approaches.

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 is to be adjusted annually by 67 per cent of the increase in the CPI. This form of regulation, places a somewhat tighter constraint on future tariffs than a CPI – X price path with X determined from forecast efficiently incurred capital and non-capital costs. The Reference Tariff adjustment approach set out in the Access Arrangement is the form of regulation to which Epic Energy committed at the time of the DBNGP sale.

Price path regulation has important incentive properties. It provides Epic Energy with an incentive to minimise the costs of delivering the Reference Service. With the Reference Tariff constrained to increasing at no more than 67 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 Epic Energy 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, Epic Energy will generate higher than expected profits. These higher profits are retained at least until the end of the Access Arrangement Period.

A second structure of incentives for Epic Energy to reduce the costs of delivering the Reference Service is provided through the offering of a number of Non-Reference Services as rebateable services.

In offering these rebateable services (described in section 2.1), Epic Energy is seeking to expand utilisation of the DBNGP asset. To the extent that it is able to secure a market for rebateable services, Epic Energy will retain a portion of the revenue generated. A further portion of that revenue will be returned to shippers using the Firm Service, effectively lowering their costs of gas transportation. A third part of any revenues generated from rebateable services will be used to reduce Reference Tariffs for the next Access Arrangement Period (as described in section 3.6).

It should be noted that Threshold Revenue for the purposes of the rebate mechanism in Paragraph 9.2 of the Access Arrangement, has been calculated on the basis that shippers with transportation contracts entered into prior to the approval of Epic Energy's Access Arrangement will come across to the Access Arrangement charging regime.

3. INFORMATION REGARDING CAPITAL COSTS

3.1 Asset Values – Cost of Service ('COS') Method

Epic Energy's approach to establishing a value for the DBNGP supporting the proposed Reference Tariff of the Access Arrangement is set out in this section. A full appreciation of the consideration Epic Energy has given to the Code's requirements concerning pipeline valuation requires an understanding of policies being pursued by the Government of Western Australia, during 1997 and 1998, in the process of its selling the DBNGP. The Government's policy position, as articulated in recent statements by the Minister for Energy, is set out before addressing specific Code requirements, Epic Energy's consideration of them, and the resulting asset valuation.[1]

(a) Government Policy

The first steps toward sale of the DBNGP were announced by the Minister for Energy in August 1996. A steering committee was to be set up to examine a range of issues, including whether the sale would be a full or partial privatisation. The steering committee which, for the substantive part of the process, comprised the chief executive officers of the Treasury, the Office of Energy and the Department of Resources Development, was to report to the Minister for Energy. Later, legislation authorising the sale and dealing with procedural matters was introduced into Parliament. The form of the sale process was also determined.

The sale of the Pipeline was, as the Minister for Energy has observed, a "large and complex transaction".[2] A number of significant policy issues had to be dealt with including guaranteed third party access, future competition in pipeline transportation and in downstream markets, expansion of pipeline capacity to meet the needs of industry in the State, lower gas transportation tariffs, and protection for consumers. These policy issues were matters for the Government, and for the Minister, who had overall control of the sale process.[3]

Bids for the DBNGP were to comprise a bid price, proposed tariffs and a tariff path for the purpose of enabling the Gas Pipeline Sale Steering Committee ("GPSSC") to ascertain whether bidders could deliver reductions in tariffs sought by the Government in a way that was consistent with receiving an acceptable return on investment in the DBNGP and maintaining future financial viability. Bids were also to indicate plans for Pipeline expansion. As the Minister for Energy later explained:

> "*The Government did not want to sell a pipeline that never expanded; . . .*" [4]
>
> "*Attachments to the bid were included to be scrutinised so that the bidders could be questioned by the steering committee to ensure the bid stacked up; that is, the bid price was consistent with reasonable future tariff changes and the expanding capacity of the pipeline*."[5]

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1 Debate on a motion for the appointment of a Select Committee, 14 June 2000.

2 Hansard, 14 June 2000, page 7655.

3 Hansard, 14 June 2000, pages 7655, 7661 and 7662. The Minister advised Parliament: "*The sale process was overseen by me, as minister, and reporting to me was a gas pipeline sale steering committee which consisted of the chief executive officers of Treasury, the Office of Energy and the Department of Resources Development*" (Hansard, 14 June 2000, page 7662).

4 Hansard, 14 June 2000, page 7656.

5 Hansard, 14 June 2000, page 7656.

Gas transportation tariffs were a critical matter. There was uncertainty about future tariffs due to the foreshadowed introduction of the third party access regime of Code, which had not at the time of sale been brought to the Parliament of Western Australia for consideration.

The Government knew that any uncertainty about tariffs could severely impact on the price that bidders would be prepared to pay for the DBNGP. In addition there was also the risk to the Government that the purchaser might ultimately obtain a higher tariff than the Government had spent some time prior to the sale saying it was expecting.

The tariff was therefore one of the policy issues that the Minister had to resolve as part of the sales process. As the Minister said in the 14 June 2000 debate:

> "*We sold* [the DBNGP] *subject to a range of policy issues designed to guarantee the business continued and to deliver a 20 per cent cut in tariff which was put in place by me by regulation. A host of matters were contained in a schedule that would guarantee protection for consumers. It was a sale that would guarantee other people multi-user third party access under the National Third Party Access Code for Natural Gas Pipeline Systems.*" [6]

The Government's policy decision was quite clear – it wanted tariffs to be around $1/GJ to Perth. [7]

The Government sought to ensure that bidder's bids were assessed on both price and compliance with the tariff policy. Bidders were required to set out their tariff structure in their bids and this tariff structure then formed part of the Asset Sale Agreement as Schedule 39.

Subsequently, the GPSSC subjected the bids it received to close scrutiny to determine whether the proposed tariff structure and the proposed purchase price, along with the bidder's financing structure meant it would be viable. Epic Energy's bid was understood by the Minister, and was subjected to such scrutiny. As the Minister for Energy explained in the debate on 14 June 2000:

> "*Epic Energy's proposed tariff would come down to $1, so it complied with the policy position of the Government. There was no argument about that; it would be $1 and that is why I regulated for $1. It foreshadowed that it would be proposing tariff increases of two-thirds of the consumer price index in subsequent years. Two-thirds of CPI means that if inflation is 3 per cent, tariffs might go up 2 per cent. That is what it foreshadowed. With regard to a long-term price strategy that it might pursue, I have said publicly that I was comfortable with that, because it implied that the real cost of gas transport would continuously fall. It had fallen 20 per cent by the sale process and it*

6 Hansard, 14 June 2000, page 7655.

7 See statements by the Minister for Energy in the debate on 14 June 2000:
"The Government's position, which was reflected in various announcements and all the tender documentation, was that the price of gas transport should fall by 20 per cent at the point of sale from $1.20 to $1.11, then to $1." (Hansard, 14 June 2000, page 7656.)
"As I explained, a number of policy matters during the sale process were reflected by the sale steering committee. The major policy matter was the decline in tariffs, which was subsequently regulated from $1.20 to $1." (Hansard, 14 June 2000, page 7660.)
"The Government's policy decision that bidders would bid on a set of conditions was put out to all bidders. The prime condition was that transport tariffs would fall to $1 for the national access code." (Hansard, 14 June 2000, page 7661.)

> *would continue to fall year after year by one-third of CPI, because its increase could be only two-thirds*." [8]
>
> "*They were required to do that to demonstrate to the gas sale steering committee that, given the price they bid and the price they proposed as tariffs, they would* receive *an acceptable rate of return on the asset. In other words, they had to demonstrate that they could not only buy the asset, but also operate it profitably and not expose anyone to an unforeseen risk of failure of the business or unanticipated demands for tariff increases.*" [9]
>
> *"In its requirements on bidders, the sale steering committee, through its information memorandum and whatever other documentation was involved, also required that people provide indications on such issues as tariff, expansion capacities and the like. The reason for that was to check the veracity and the robustness, if one likes, of the bid. The Government would not accept a bid which could not be sustained. Therefore, it would have to know what that bid implied, and the bidders would have to demonstrate a proposed scenario of tariffs which would stack up and demonstrate to the sales committee that such a scenario of tariffs would give a return which would enable the money, the $2 407m, to be serviced. In other words, the Government was not about setting up the gas industry in this State for a shock. On gas tariffs, it wanted to be satisfied that the bidders' scenario was compatible with the price. It also wanted to be satisfied about capacity."* [10]

The Government was quite definite that it was not interested in tariffs either lower or higher than the policy decision of $1/GJ to Perth. As the Minister put it, they only wanted people bidding on price:

> "*Mr BARNETT: And we made a decision to drop it to a dollar. That is the commitment. It was possible to bid a high price and a high transport charge or a low price and a low transport charge. Surely members opposite do not think I did not realise that in 1997. We did not want people bidding on price and transport; therefore, logically, the Government made a policy decision on the transport charge which was to go from $1.20 to $1. Members opposite could argue we should have made the charge 90¢. That would be a fair argument. Right or wrong I made a policy decision, supported by Cabinet, that we reduce the tariff from $1.20 to $1 and invited people to bid against that. We wanted them to bid against one area on price. We did not want them bidding on a range of criteria.*
> *Mr Ripper: They would be expecting to earn a rate of return on their investment over a considerable period, so they would have understood that policy decision would last.*
> *Mr BARNETT: Why does the member for Belmont think they were not challenged? That is why the sale steering committee required people to indicate a scenario, not a contractual issue, for tariffs. We wanted to ensure their bid was sustainable. These are not my calculations; they are based on Epic's financial modelling. Epic prepared a model of the value of the pipeline, its contracts and its prospects for growth, and fed in assumptions about the Australian dollar, interest rates and many other factors. It came up with a figure*

8 Hansard, 14 June 2000, page 7657.
9 Hansard, 14 June 2000, page 7655.
10 Hansard, 14 June 2000, page 7660.

> *- I do not know whether it added to it - of $2 407m based against a certain fall in tariff from $1.20 to $1.*" [11]

The Minister made it very clear that he and the GPSSC were satisfied that what Epic Energy put forward in Schedule 39 met the policy criteria in relation to tariff and sustainability.[12] In fact he went further and indicated that a bid of less than $1/GJ to Perth was not acceptable to the Government, as it would represent a moving of the goal posts:

> "*The Government's policy decision that bidders would bid on a set of conditions was put out to all bidders. The prime condition was that transport tariffs would fall to $1 for the national access code. One does not, at the conclusion of a sale process, suddenly change the rules of the game. To entertain bids on a range of issues or criteria would have changed the rules of the game and would have aborted the sales process*." [13]

> "*Mr Ripper: You are keeping secret the potential for having accepted a lower price for the pipeline and a lower transport tariff. You are not revealing the trade offers the Government had before it on this matter.*
> *Mr BARNETT: I was not conducting a sale process that was subject to alteration halfway through.*" [14]

Nor was a bid of higher than that set out in Schedule 39 of the Asset Sale Agreement acceptable:

> "*Epic justified that to the sale steering committee based on a price scenario with which we were compatible. Had Epic said it would pay $2 407m, but it would need to increase gas transport by 10 per cent a year, clearly, its bid would not have been accepted. That was the process*." [15]

Epic Energy has sought with the Access Arrangement to do no more than was contained in Schedule 39 to the DBNGP Asset Sale Agreement, with some refinement coming from experience. As the Minister for Energy himself acknowledged:

> *"I do not have any problem personally with what Epic proposes, . . . "* [16]

(b) **Code Requirements**

Section 8.10 of the Code sets out the factors that should be considered in establishing the initial capital base for a pipeline that was in existence at the commencement of the Code.

Epic Energy has considered all of the factors listed in Sections 8.10(a) – (j) of the Code in establishing the initial capital base for the DBNGP, which was a pipeline in existence at the commencement of the Code in Western Australia.

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11 Hansard, 14 June 2000, page 7662.

12 See the Minister for Energy's comments in the debate on 14 June 2000 quoted above and also where he said, "[Epic] came up with a figure - I do not know whether it added to it - of $2 407m based against a certain fall in tariff from $1.20 to $1. Epic justified that to the sale steering committee based on a price scenario with which we were compatible." (Hansard, 14 June 2000, page .7662.)

13 Hansard, 14 June 2000, page 7661.

14 Hansard, 14 June 2000, page 7662.

15 Hansard, 14 June 2000, page 7662.

16 Hansard, 14 June 2000, page 7658.

A number of the factors listed in Sections 8.10(a) – (j) of the Code are of particular importance in establishing the initial capital base for the Pipeline. These are discussed below.

(c) **Epic Energy's Acquisition of the DBNGP**

The DBNGP was constructed and initially operated by SECWA. On 1 January 1995, SECWA's gas transmission assets, including the DBNGP, were transferred to the Gas Corporation, a state-owned enterprise created by the *Gas Corporation Act 1994* ("1994 Act"). The Gas Corporation, trading as AlintaGas, operated the DBNGP under a third party access regime established by the 1994 Act and the GTRs. Prior to 1 January 1995, there were no statutory third party access rights to the DBNGP. The Pipeline had been constructed and operated by SECWA for the purpose of transporting its own gas. SECWA had, however, entered into contracts with three parties which granted those parties rights to have gas transported using the DBNGP.

Epic Energy acquired the DBNGP from AlintaGas on 25 March 1998.

Although it was the seller of the DBNGP, AlintaGas was formally directed to make the sale, by the Minister for Energy, in accordance with Section 6(2) of the *Dampier to Bunbury Pipeline Act 1997* ("DBP Act"). AlintaGas did not manage or control the process of Pipeline sale.

The legislation that enabled the sale to occur – the DBP Act – was developed by the Government of Western Australia. The Government established the GPSSC to manage and control the sale process. The GPSSC comprised senior officers within government; it was not an AlintaGas committee. Although AlintaGas was the initial recipient of the sale proceeds, it was directed by the Minister for Energy to disburse the net proceeds (after retirement of DBNGP debt) to the State.

The legal entity that sold the DBNGP was AlintaGas, but the method by which the Pipeline was sold, and the final terms and conditions on which it was acquired by Epic Energy, were determined by the Government of Western Australia through the GPSSC.

The DBNGP was sold through a multi-stage competitive bidding process. The number of bidders was progressively reduced through the stages.

The Government's objectives in selling the Pipeline through this multi-stage competitive process were set out in the GPSCC's letter covering transmittal of copies of the sale Information Memorandum to Epic Energy. The letter, dated 8 September 1997, advised that the Government was seeking to maximise the proceeds from the sale of the DBNGP within the context of pursuing certain other policy objectives. These other objectives were:

- enhancing the operating efficiency and utilisation of the pipeline;
- reducing gas transmission prices;
- reducing future demands on State capital;
- reducing the State's exposure to the business risks of the DBNGP;
- minimising the impact of the sale on the workforce of AlintaGas' transmission division; and

- reducing the potential for conflicts of interest which might potentially compromise the efficient operation of the DBNGP and the operation of a competitive gas market in the State.

The same letter also set out the form of the sale process. The process was to comprise the following three phases:

- Phase I: interested parties to register interest;
- Phase II: submission of non-binding bids; and
- Phase III: due diligence and submission of final bids.

A complying non-binding bid submitted during Phase II was to indicate, among other things:

- the price offered for the DBNGP;
- the estimated path of tariffs for the next 10 years and the principal assumptions underlying those tariffs;
- the assumed growth in demand for gas transportation capacity in the DBNGP over the next 10 years; and
- Pipeline expansion plans indicating a readiness to support economic development in the State.

In evaluating the non-binding bids, and in determining the parties to be invited to participate in Phase III, the Government indicated that it would consider the bid price and the bidder's ability to best meet the other objectives set for the sale process.

Among these other objectives, a reduction in gas transmission prices was of major importance to the Government. As stated, a complying non-binding bid was required to set out the estimated path of tariffs for the next 10 years, and the principal assumptions underlying those tariffs under the Government's Transitional Access Regime, and under the new regulatory regime that was expected to govern future ownership and operation of the DBNGP. The GPSSC advised:

> *"The tariffs detailed under this requirement will not be binding upon the Acquirer but will be used by the GPSSC to evaluate the deliverability of Non Binding Bids and the consistency of Non Binding Bids with the State's objectives."* [17]

While indicating that such tariffs would not be binding, under the sale process as structured, these tariffs would become the proposed tariffs of a Final Bid unless they were expressly modified in the final bid document. As is discussed below, they would become, in accordance with part (b) of clause 9 to Schedule 5 of the *Dampier to Bunbury Natural Gas Pipeline Asset Sale Agreement* ("Asset Sale Agreement"), tariffs that the Government might freely disclose in proceedings before the Regulator.[18]

Both the bid price, and future Pipeline tariffs, were critical factors in the Government's decision making for its sale of the DBNGP.

[17] 7 September 1997.
[18] The Asset Sale Agreement is discussed in section 3.1(c) below.

The importance of the bid price was made clear by the Minister for Energy in a media statement issued on 22 May 1997. The Minister stated:

> *"It is imperative the Government sells the pipeline to deliver the highest possible return to WA taxpayers who have owned this asset since it was built in 1984."*

At the same time, the Government was concerned with securing lower gas transmission tariffs. In his 22 May 1997 media statement, the Minister continued:

> *"As well, new regulations would enforce a set of reference tariffs for the first two years of operation under private ownership, declining over the period 1998 to 2000. This would see transport costs decline from around $1.25 per gigajoule at present to around $1 per gigajoule by the year 2000."*

The Government was of the view that it could achieve both a high sale price for the DBNGP, and a significant reduction in gas transmission tariffs, and was expecting those tariffs to fall to about $1.00/GJ.

This view was reinforced by the Minister for Energy in the media statement that announced the issue of the sale Information Memorandum. The Minister stated:

> *"The sale of the Dampier-to-Bunbury Natural Gas Pipeline has the potential to realise the highest sale price for a State-owned asset in WA's history."* [19]

He further commented:

> *"I am confident the sale will deliver a substantial return to WA taxpayers on their investment. The price at which the pipeline eventually sells will depend on its future earnings potential as determined by the prospective bidders which have registered their interest."*

Prospective bidders were directed, by the Minister, to focus on the DBNGP as a strategic asset servicing the requirements of gas users in the State so that they might fully recognise this future earnings potential in their bid prices.

The Minister also advised:

> *"Based on preliminary work undertaken by AlintaGas and work independently commissioned by the Gas Pipeline Sale Steering Committee, it is currently anticipated that the cap on tariffs for a full haul firm service at a 100 per cent load factor will be $1.24/GJ for 1998 and $1.12/GJ for 1999. From the year 2000, the State is planning to adopt the National Access Code and tariffs could fall to around $1/GJ."*

The lowering of the gas transmission tariff to about $1.00/GJ would, in the Government's view, encourage downstream processing activities using gas, protect long term gas supplies, and maintain prices at which gas could be delivered to households and small businesses.

[19] 7 September 1997.

In its structuring and execution of the DBNGP sale process, the Government of Western Australia sought to achieve the highest possible sale price for the Pipeline, and a reduction in gas transmission tariffs to about $1.00/GJ.

That view is reinforced by recent statements by the Minister for Energy which are set out in section 3.1(e) below.

(d) **The Government's Required Tariff, the Asset Sale Agreement, and Tariff Path**

The Government of Western Australia was able to secure a high price from its sale of the DBNGP because it had formed a view of the reduction in the level of gas transmission tariffs necessary to stimulate the use of gas in the State. The Government believed, and widely disclosed its belief, that a full haul firm service tariff of about $1.00/GJ to Perth by 2000 was required.

A tariff of about $1.00/GJ was expected to be consistent with the tariffs that would result from application of the Code after 1 January 2000.

Support for a tariff of about $1.00/GJ was obtained from Price Waterhouse, the Government's expert adviser on tariff and regulatory matters. In its August 1997 report to the GPSSC, Price Waterhouse concluded that:

> *"… a gas transmission tariff of around $1/GJ commencing at 1 January 2000 was a reasonable and supportable tariff for "firm full haul transmission capacity" under the Draft Code. The analysis suggested that the tariff could lie anywhere within the broad range of $0.71/GJ to $1.12/GJ for firm, full haul transmission capacity and that values between $0.88/GJ to $0.98/GJ could be argued."*

The Price Waterhouse report was placed in the Pipeline sale data rooms, and was therefore available to all parties submitting Final Bids for the DBNGP.

The report also noted that the objectives of the Code, and the objectives of the *Competition Principles Agreement* that provides the policy framework within which the Code was developed, were multiple, and trade-offs would have to be made. In particular, in view of the significant tariff reduction being sought by the Government, a careful balance would be required such that:

> *"… a purchaser of the DBNGP can be assured of acquiring an asset subject to stable regulation allowing the development of a stable and viable business."*

On 3 March 1998, the Government of Western Australia announced its sale of the DBNGP to Epic Energy. The sale to Epic Energy reflected a particular balance between the Government's objectives of securing a high sale price and a reduction in gas transmission tariffs. The point of that balance is reflected in the Asset Sale Agreement.

Epic Energy was not a party to the deliberations in which the point of balance was determined. Nevertheless, an important insight into those deliberations is revealed by the outcome of the final bidding process. Epic Energy submitted, and believes that other bidders similarly submitted, both complying and non-complying final bids. Details of Epic Energy's various bids have been provided to the Regulator. As the Asset Sale Agreement reflects, the Government of Western Australia sought to maximise the proceeds from the sale of the DBNGP by accepting a particular purchase price and a particular tariff and tariff path. Epic Energy assumes that the complying and non-complying bids from competing bidders were assessed from the same perspective.

In the Asset Sale Agreement, the Government of Western Australia undertook to sell the DBNGP to Epic Energy, in accordance with the offer made by Epic Energy in its Non-Binding Bid Submission (submitted on 24 October 1997) and its Final Bid Submission (submitted on 28 February 1998), for a purchase price of $2,407.0 million.

Epic Energy gave, in the Asset Sale Agreement, certain warranties as Buyer and these included warranties concerning its proposed gas transmission tariffs and future tariff path.

Clause 9 of Schedule 5 to the Asset Sale Agreement stated:

> *"The Final Bid Information contains details of the tariff rates for gas transmission and tariff path which the Buyer has indicated to the Seller it proposes to apply in the conduct of the business of the DBNGP Assets:*
>
> *(a) which, based upon all information available to the Buyer, reflect tariffs for gas transmission that will provide the Buyer with an acceptable return on investment; and*
>
> *(b) which, the Seller may (and the Buyer irrevocably authorises the Seller to) freely disclose to any Governmental Agency or generally in the course of any public enquiry or other determination process relating to tariff rates for gas transmission."*

The proposed gas transmission tariffs, and proposed tariff path, were set out in Schedule 39 to the Asset Sale Agreement. Schedule 39 cross-referred to clause 9 of Schedule 5.

The tariffs, and the tariff path, were to provide Epic Energy with an acceptable return on its investment in the DBNGP. At the same time, by including paragraph (b), the Government was clearly of the view that Epic Energy should be bound by Schedule 39, and intimated that it would hold Epic Energy to Schedule 39 in respect of any access arrangement it might seek to have approved under the Code.

Schedule 39 to the Asset Sale Agreement indicates that the tariffs and the tariff path were predicated on a number of general principles and guidelines that were incorporated in Epic Energy's Final Bid Submission. In particular:

- Epic Energy would expand the capacity of the DBNGP to meet the requirements of new loads, provided the capacity enhancements were commercially viable;

- from 1 January 2000 onwards, Epic Energy would submit, in accordance with the Code, access principles and tariffs for approval by the Regulator at scheduled regulatory reviews; and

- tariffs proposed for approval by the Regulator would provide for the recovery of prudently incurred costs, including a reasonable rate of return on investment over the full term of the asset's economic life.

In addition to the general principles and guidelines, the following more specific principles for the proposed path of future tariffs were set down:

- from 1 January 2000, the tariff path would be based on escalation at a percentage of CPI;

- from 1 January 2000, the Tranche method (introduced by the GTRs) would not be used to define capacity in the pipeline;

- new shippers, and existing shippers switching to the reference service, would be able to provide their own compressor fuel;

- certain tariff setting principles (including the capital recovery mechanism, risk premium on WACC and asset life) to be included in the DBNGP Access Arrangement would be fixed for a period which exceeds the period of scheduled regulatory reviews;

- the capital recovery mechanism would be structured so that it was consistent with efficient growth of the market over the economic life of the asset; and

- the tariff structure would include zonal tariffs which reflected the cost of providing service.

The proposed tariffs and the tariff path were to be for a forward haul firm service. In addition, Epic Energy would offer a forward haul interruptible service, an authorised overrun service, and a backhaul transportation service.

From 1 January 2000, the tariff for forward haul firm service, from receipt points upstream of Compressor Station 2 to a delivery point at Kwinana Junction (at 100 per cent load factor) would be $1.00/GJ.

The forward haul firm service tariff would comprise three separate charges, all of which would be assessed on a zonal basis. The components of the tariff were to be:

- a pipeline capacity charge (MDQ based);

- a pipeline commodity charge (throughput based); and

- a compression charge (MDQ based).

A shipper facilities charge, recovering the costs of shipper specific laterals and metering, was also to apply.

Ten zones, the boundaries of which were defined by compressor stations, were adopted for pricing purposes. Zone 1 was to be a gas gathering (or production header) zone, and would include Compressor Station 1. Zone 9, which extended from Compressor Station 9 to Kwinana Junction, included delivery points in the Perth metropolitan area. The tariff of $1.00/GJ was to apply for gas transportation from receipt points in Zone 1 to delivery points in Zone 9.

Zone 10 extended from Kwinana Junction south to the pipeline end at Main Line Valve 157A near Bunbury. The tariff for forward haul firm service from a receipt point in Zone 1 to a delivery point in Zone 10 would be around $1.08/GJ from 1 January 2000.

Forward haul firm service tariffs would be increased annually, but the increases would be subject to a price cap. Schedule 39 limited the tariff increases to no more than 67% of the increase in CPI.

Epic Energy's determination of the tariffs in Schedule 39, and of the future tariff path, were consistent with the approach that had been taken by the Government's own advisers. These determinations used the depreciated optimised replacement cost valuation of the Pipeline prepared by engineering consultants CMPS&F and used by Price Waterhouse in its August 1997 report. Furthermore, they used forecasts that had been provided by the Government, and they used principles consistent with those adopted by Price Waterhouse for estimation of the cost of capital.

As noted in the next section, the Minister for Energy has recently confirmed that the Government and the GPSSC believed the tariff and tariff path set out in Schedule 39 were acceptable to them, and consistent with the Government's policy objectives.

(e) **Regulatory Compact between Epic Energy and the Government of Western Australia**

Through the way in which it structured and executed the sale process, the Government of Western Australia was able to secure a purchase price of $2,407.0 million for the DBNGP. With the money it received, the Government has been able to:

- repay some $1.8 billion of State debt and significantly reduce the burden of public debt on all Western Australians; and
- fund education, health and infrastructure initiatives[20] in the 1998/99 and 1999/2000 State Budgets without the need for concomitant increases in State debt.[21]

As the Minister for Energy acknowledged in a statement to Parliament on conclusion of the sale process on 11 June 1998:

> *"The sale is widely recognised as an outstanding success for this State in realising value back to the community from its substantial investment over time to establish energy infrastructure."*

[20] Note also the Premier's announcement, on 4 July 2000, of the Perth Convention and Exhibition Centre to be funded using $110 million of the proceeds from the DBNGP sale.

[21] The importance of the proceeds from DBNGP sale for achieving a reduction in State debt was discussed by the Premier in his 1998 Budget Speech. The subsequent use the Government has made, on behalf of the community, of the proceeds from pipeline sale was discussed by the Minister for Energy in recent Parliamentary debate on the proposed sale of AlintaGas:

> *"Yes. We retired a significant part of direct and general government debt out of the sale of the Dampier-Bunbury natural gas pipeline. One can assume part of the proceeds will be used to retire government debt. I hope the temptation to rush out and spend it all is resisted. The proceeds should also allow some worthwhile works to be undertaken within the community. That is a decision for Cabinet to make at the appropriate time. As a result of the sale of the Dampier-Bunbury natural gas pipeline, two broader community benefits were achieved. A total of $100m was put into computers, technology and schools. We put 26 000 computers into government schools over four years and 6 000 computers into non-government schools. In a sense, the pipeline was a community-owned asset and the distribution of the proceeds went to everyone, both government and non-government schoolchildren. That program has very strong community support and is producing substantial educational benefits. It was decided to allocate $100m to the development of a convention centre for Perth. There is some controversy about that, but there is no doubt that the one piece of major tourism infrastructure lacking in this State is a convention centre. Such a facility is important to attract conferences and activities to Perth the benefits of which will then feed out into regional areas. No convention centre in Australia has been built without public support. They are in the nature of infrastructure items. Convention centres are not basic infrastructure like roads, railways and power stations, but they fall into that spectrum. A world-class convention centre is essential for the development of the tourism and convention business within the State. It will not be profitable on its own; it will require support. Given public support which ultimately may be recovered, the convention centre will be competitive in bidding for events and it will bring great economic benefits to the members of the community who use it."* (Hansard, 9 September 1999.)

For its part, Epic Energy indicated that it stood ready to make further investments in the DBNGP as economic development in other sectors of the State's economy created new demand for gas transmission capacity. At the time, based on the Government's own forecasts, Epic Energy predicted that investments in pipeline expansion could total $837 million by 2007.

Epic Energy's commitment to expansion was noted by the Premier in his media statement on the outcome of Pipeline sale issued on 3 March 1998. Subsequently, the Minister for Energy advised Parliament that:

> *"Epic Energy Australia has also made a commitment to spend up to $874 m through to the year 2007 in order to double the capacity of the pipeline to meet the potential growth in the demand for gas in the mid west and south west of the State."* [22]

Epic Energy has already commenced delivering on its commitments. It is now close to completing a further expansion of DBNGP capacity requiring investment of over $120 million in additional compression plant and looping of the Pipeline. The expansion will provide the gas transportation capacity needed to meet new industrial demands in 1999 and 2000.

To further support its focus on Western Australia, Epic Energy committed to moving its corporate office to Perth, and that move has now been completed. There will be further strengthening of Epic Energy's presence in Perth in the years to come.

The benefits to the broader community from the reduction in State debt, and from the Government's education, health and infrastructure initiatives have been made possible by Epic Energy's purchase price of $2,407.0 million. The continued expansion of the DBNGP will also assist the economic development of Western Australia. Underpinning both the purchase price and the commitment to expansion is a revenue stream based on the tariffs set out in Schedule 39 of the Asset Sale Agreement, and on a price path which would see increases in those tariffs capped at 67 per cent of the increase in CPI.

Epic Energy acknowledges that there was no express contractual commitment between it and the Government in the Asset Sale Agreement regarding the implementation of the Schedule 39 tariff path. That is equally true of the other Epic Energy "commitments" referred to above. However, they are all part of the "regulatory compact" between Epic Energy and the Government of Western Australia arising out of the DBNGP sale process. At the core of this regulatory compact are the price paid for the DBNGP, and the tariffs and tariff path that support that price.

Epic Energy accepts the risk that, at least in the short term, economic development in Western Australia might not support – and, in fact, has not supported - the substantial growth in gas demand indicated by forecasts made during the DBNGP sale process. That is, Epic Energy accepts the risk that the growth in gas demand may not yield a revenue stream consistent with the price it paid for the Pipeline. Acceptance, by the buyer of an asset, of the risk that forecasts of future demand for the asset's services may not be realised, is normal commercial practice.

The tariffs and the future tariff path are another matter. Putting to one side the negative impact of growth in the demand for gas transmission capacity not materialising as predicted, Epic Energy must be able to rely on the tariffs and the tariff path of Schedule 39 of the Asset Sale Agreement. It is those tariffs, and that tariff path, that allow Epic

[22] Ministerial Statement, 10 March 1998, Hansard, page 138.

Energy to obtain the revenue stream consistent with the price it paid for the DBNGP. The tariffs and the tariff path are an essential part of the regulatory compact. This cannot be ignored. To do so would shift substantially the distribution of risk between Epic Energy and the Government. The Government's sale process and the success of it was anchored by the regulatory compact which enabled Epic Energy and its bankers to have a reasonable expectation that the purchase price could be supported.

Epic Energy invested $2,407.0 million in the DBNGP, and gave a commitment to expand the capacity of the pipeline, on the basis of being able to rely on:

- a tariff of $1.00/GJ to Kwinana Junction;
- a tariff of $1.08/GJ to delivery points downstream of Kwinana Junction;
- and a tariff path that would see tariffs rise annually by no more than 67 per cent of the increase in CPI.

The Government of Western Australia accepted a purchase price of $2,407.0 million for the DBNGP because Epic Energy's complying bid was superior to any other bid, and was consistent with a level of tariffs expected to encourage downstream processing activities, protect long term gas supplies, and maintain prices at which gas is delivered to households and small businesses.

The Government could have structured and executed the pipeline sale process in a different way. It could have sought lower gas transmission tariffs by reducing the emphasis it placed on achieving the highest possible sale price. Alternatively, it could have sought a higher price by accepting a lower reduction – or even an increase in – gas transmission tariffs. In either case, a different regulatory compact would have been the result.

In the event, the Government of Western Australia chose to structure and execute the DBNGP sale process in a way that delivered the sale price, and tariffs and tariff path supporting that sale price, now reflected in the Asset Sale Agreement. There may have been an element of rent seeking in the way in which the sale process was structured and executed, and that may now be reflected in the balance between the purchase price and the proposed tariffs. However, as the Minister for Energy has strongly argued, this is an issue of public policy making. It is an issue that must be dealt with by the Government itself, and not by the Regulator:

> *"The role of the regulator is to be a regulator, not to be a price or policy maker. We have to be very conscious that the regulatory regime and the regulator does not start to become the policy maker. That is a province of Government, not in a selfish way, but it is something that has to reflect a range and a balance of economic and social objectives."* [23]

Epic Energy notes that the Government continues to refer to the elements of the regulatory compact. The Government refers to the common understandings and expectations that developed between it and prospective purchasers of the DBNGP during the Pipeline sale process (and without which the sale process could not have proceeded). For example, in responding to questions from the Opposition on 14 March 2000, the Minister for Energy advised:

[23] Australian Institute of Energy. *Address by the Hon Colin Barnett, Western Australian Minister for Energy*. Perth, Friday 26 March 1999.

"*I can explain the broad background to the sale and what occurred. The bidders, including Epic Energy, were asked to bid on a number of features. One obvious one and the most important component was price; a second related to service standards and the like; a third related to the price, not only what they would pay for it but the cost of the transport of gas; a fourth related to commitments to expanding pipeline capacity. Therefore the price paid for the pipeline was by far the most important criteria. However, there were three other components: The first was the bid of $2 407m; the second was a commitment to spend some $875m on effectively expanding and duplicating the pipeline capacity over an eight-year period; and the third related to the transport tariff. At the time of the sale, the cost of transporting gas was $1.19 per gigajoule to the south west. Under the bid put in by Epic, the price would fall from $1.19 to $1.10 to $1, and that has happened; in other words, the bid was composed of price, top dollar, an expansion commitment on investment and a 20 per cent reduction in tariff . . . Yes, it is true that we could have traded off. We could have gone back to Epic and said that we would take a lower price for the State in exchange for giving transporters of gas a lower tariff."* [24]

"We made the judgment that a high price for taxpayers and the community of Western Australia was the first and most important component. If at the same time we doubled the pipeline capacity and delivered a 20 per cent cut in transport tariffs, it was a very good deal." [25]

"The tariff schedule put in by Epic included a proposal that the price of gas would fall from $1.20 to $1.10 to $1. That was a schedule that was generally put forward by government to all bidders as an expectation. That was the broad understanding." [26]

At the time of the DBNGP sale process, both Epic Energy and the Government of Western Australia believed that the core of their regulatory compact was consistent with the requirements of the Code. In particular, the tariffs and the tariff path were believed to be consistent with application of the Code's cost of service approach based on a common set of forecasts of future gas demand, a depreciated optimised replacement cost valuation of the pipeline, a rate of return determined in accordance with then accepted methods, and estimates which had been made of future non-capital costs.

Circumstances have now changed in a number of respects. Forecasts of gas demand have been revised downward consistent with a lower than anticipated level of activity in the Western Australian economy. The process of sale has placed a value on the DBNGP.

Nevertheless, Epic Energy's regulatory compact with the Government of Western Australia remains. Epic Energy has recognised that in the establishing the initial capital base for the DBNGP.

(f) **Asset Valuation and Initial Capital Base**

Although the gas transmission tariffs and the tariff path are core elements of the regulatory compact between Epic Energy and the Government of Western Australia, an initial capital base must be determined for the DBNGP because a basis must now be

[24] Hansard, 14 March 2000, page 4963, question no. 543.
[25] Hansard, 14 March 2000, page 4963, question no. 543.
[26] Hansard, 16 March 2000, page 5198, question no. 575.

established for a complete determination of reference tariffs for the current Access Arrangement Period and for future periods.

As discussed above, the Government of Western Australia, through the process of Pipeline sale, placed a particular value on the DBNGP. That value was sought to achieve a balance between the interests of users and prospective users of the Pipeline, and the wider public interest. Strategic decisions of this type cannot be reduced to assessments based on simple calculations of costs and benefits. They are decisions that the Government is elected to make on behalf of the community.

Accordingly, it is the value the Government placed on the Pipeline that must now be used in setting the initial capital base for the DBNGP.

Epic Energy has therefore established the initial capital base – the value of capital assets comprising the DBNGP at 1 January 2000 – as:

- the price at which Epic Energy purchased the Pipeline from the State; plus
- Epic Energy's acquisition costs (net of any associated revenues); plus
- capital expenditure by Epic Energy, from the date of its acquisition of the DBNGP to 31 December 1999; less
- depreciation charges for the period from the date of Epic Energy's acquisition of the DBNGP to 31 December 1999, determined (using the annuity method) for both the assets acquired, and the assets created by Epic Energy's capital expenditure.

The resulting initial capital base is $2,570.3 million.

Establishing the initial capital base in this way is consistent with the requirements of Section 8.10 of the Code. Section 8.10(j) of the Code identifies as one of the factors that should be considered in establishing the initial capital base "*the price paid for any asset recently purchased by the service provider and the circumstances of that purchase*". Given the structure of the sale process and the way in which it was executed, the price Epic Energy paid for the DBNGP is the critical factor to be considered in establishing the initial capital base for the Pipeline. To give precedence to any of the other factors of Section 8.10 of the Code would lead away from the policy outcomes legitimately sought by the Government, and away from the regulatory compact, a compact from which the State has now received the benefits it sought in a variety of forms.

Through its establishing the initial capital base for the DBNGP in the way set out above, Epic Energy is able to implement the tariffs and the tariff path of the regulatory compact as the Reference Tariff and tariff path of the proposed Access Arrangement. The tariffs and the tariff path of Schedule 39 of the Asset Sale Agreement are linked directly to the price Epic Energy paid for the DBNGP through an assessment of Pipeline value made at the time of sale. At the time of the Pipeline sale, Epic Energy determined, using forecasts of pipeline throughput that had been provided by the Government, that those tariffs and the tariff path would provide a revenue stream that would support a purchase price of approximately $2,400 million, and (nominal) capital expenditure over ten years from the date of acquisition totalling $875 million.

If the tariffs and the tariff path of the regulatory compact are implemented as the Reference Tariff and the tariff path of the proposed Access Arrangement, and the forecasts of throughput made at the time of Pipeline sale are realised, Epic Energy's shareholders should recover their total investment in the DBNGP.

In maintaining its commitment to the regulatory compact, Epic Energy will not seek to increase its tariffs or change the tariff path for a period of at least 20 years. Although the Access Arrangement will be reviewed by the Regulator at intervals of five years, and changes may be made to the reference service to reflect changing market conditions, there will be no increase in the tariff or change in the tariff path resulting from changes in the capital base.

Epic Energy believes the tariffs and the tariff path should remain fixed for a period of 20 years from the date of its purchase of the DBNGP. Financial analyses undertaken to support a major acquisition usually use a time horizon of 20 years. A shorter time horizon results in excessive weight being placed on an uncertain residual. A longer time horizon requires specific forecasts for increasingly uncertain events. Financial analyses undertaken by Epic Energy and its financial advisers immediately prior to the sale of the DBNGP used a time horizon of 20 years.

With the tariffs to follow a tariff path that is fixed for an extended period, Epic Energy may not recover the capital charges on the initial capital base, and on the capital base in subsequent years, if the growth in demand for gas transportation services does not follow the path forecast at the time of DBNGP sale. Any shortfall in capital recovery is to be treated, in accordance with a regulatory model developed by Epic Energy's regulatory adviser, The Brattle Group, as economic depreciation, and added back to the capital base.[27] The use of an economic rather than an accounting concept of depreciation allows postponement of recovery of a part of the capital base until that recovery is warranted by growth in transportation demand. Higher demand allows Epic Energy to receive higher revenues and recover capital without an increase in the absolute level of tariffs. Furthermore, although the tariffs may not exceed the upper limit imposed by the tariff path, they may fall below that upper limit if increases in demand for gas transportation services are expected to result in depreciation charges that recover investment in the DBNGP before the Pipeline reaches the end of its economic life.

With the tariffs and the tariff path fixed in accordance with the regulatory compact, Epic Energy's shareholders bear the "volume risk" associated with market growth. If the demand for gas transportation grows in the way expected at the time of the DBNGP sale, shareholders should recover their investment in the Pipeline. If the market does not grow as expected, a part of the price paid by Epic Energy for the DBNGP will be shown to have been an imprudent investment for which shareholders will not be compensated.

Given the valuation placed on the Pipeline by the competitive bidding process structured and executed by the Government of Western Australia, the use of either of the valuation methodologies described in Sections 8.10(a) and 8.10(b) of the Code is not appropriate for the DBNGP Access Arrangement. As a result Epic Energy did not include, in its proposed Access Arrangement Information, submitted to the Regulator on 15 December 1999, asset valuations using those methodologies.

In some submissions that have been made to the Regulator on the DBNGP Access Arrangement, suggestions were made by interested parties that the Access

[27] The regulatory model is described in The Brattle Group's report *Proposed Regulatory Model for the Dampier to Bunbury Natural Gas Pipeline*, October 1999. This report is attached as Appendix 4. Details of the depreciation method are provided in section 3.4 of this Access Arrangement Information.

Arrangement Information should include asset values established using the methodologies of Sections 8.10(a) and (b) of the Code. In response to those suggestions, the Regulator formally requested Epic Energy to resubmit the proposed Access Arrangement Information to "include estimates of the DAC and DORC valuations". (The Regulator used the terms "DAC" and "DORC" to mean the methodologies under Sections 8.10(a) and (b) of the Code.)

Epic Energy does not accept that the Regulator's decision to require resubmission of the proposed Access Arrangement Information with the inclusion of estimates of values under Sections 8.10(a) and (b) of the Code is correct. Epic Energy is firmly of the view (and has received legal advice to the effect) that the Code does not require, and the Regulator has no power to require, Epic Energy to include such information in the Access Arrangement Information.

Epic Energy notes that the proposed Access Arrangement Information for the Parmelia Pipeline did not include a valuation under Section 8.10(a) of the Code. In his Draft Decision on the proposed Access Arrangement for the Pipeline, dated 27 October 1999, the Regulator did not require the service provider to resubmit its Access Arrangement Information with such a valuation. The Regulator simply developed his own estimate, and stated that in the Draft Decision. The approach taken there was similar to the approach taken by the Australian Consumer and Competition Commission ("ACCC") in its Final Decision on the Access Arrangement for the Central West Pipeline. Again, the service provider did not include a valuation under Section 8.10(a) of the Code. The ACCC did not require resubmission of the Access Arrangement Information with such a valuation; it merely made its own estimate and published that in the Final Decision.

Nevertheless, Epic Energy states, on a "without prejudice" basis, the following estimates:

(a) *"the value that would result from taking the actual capital cost of the Covered Pipeline and subtracting the accumulated depreciation for those assets charged to Users (or thought to have been charged to Users) prior to the commencement of the Code"* - $2,466.1 million; and

(b) *"the value that would result from applying the "depreciated optimised replacement cost" methodology in valuing the Covered Pipeline"* - $1,368.4 million.

The interpretation of Section 8.10(a) of the Code is not without argument. In providing the estimate in (a) above, Epic Energy has applied the "actual capital cost" as being the actual cost to it as the Service Provider. In the case of depreciation "charged to Users (or thought to have been charged to Users)" Epic Energy has estimated the amount of depreciation it believes SECWA and AlintaGas (as prior owners of the DBNGP) have collected from third parties (including the Trading Division of AlintaGas) and added the amount of depreciation recovered by Epic Energy from third parties since it has owned the DBNGP.

Epic Energy believes that is the correct interpretation of Section 8.10(a) of the Code. However, Epic Energy is aware that, in the past, people have generally applied "actual cost" as "historical cost". While Epic Energy does not believe that interpretation is correct, on a "without prejudice" basis, it has estimated a value based on the actual cost of capital of the original assets of the DBNGP, and assets from subsequent enhancements/expansions of the Pipeline, at the time when each of them first entered service. When taken with the method for accounting for depreciation described above, which is as prescribed by Section 8.10(a) of the Code, the estimate is: $1,331.5 million. That is a very rough estimate as Epic Energy did not obtain records from AlintaGas which would enable estimation with any degree of accuracy.

Each of these estimates is as at 1 January 2000. Epic Energy makes no warranty or representation as to the accuracy of these estimates and all implied warranties or representations are expressly excluded to the extent permitted by law. The estimates are provided in good faith. No liability will be accepted by Epic Energy for any loss or expense of any nature whatsoever (including consequential loss) arising directly or indirectly from reliance on or use of those estimates.

Section 8.11 of the Code provides bounds within which the initial capital base for an existing covered pipeline would "normally occur". The initial capital base normally should not fall outside the range of values determined in accordance with Sections 8.10(a) and 8.10(b) of the Code. However, the Code does not make these bounds mandatory, and in fact, in Section 8.10 of the Code prescribes a number of other factors to be taken into account in setting the initial capital base. The competitive bidding process through which Epic Energy acquired the DBNGP removed the initial capital base from within the indicative bounds of Section 8.11 of the Code.

Section 8.10(c) of the Code indicates that consideration should be given to the application of other well recognised asset valuation methodologies in establishing the initial capital base for a pipeline that was in existence at commencement of the Code. Again, Epic Energy is of the view that, given the valuation placed on the DBNGP by the competitive bidding process structured and executed by the Government of Western Australia, the use of other valuation methodologies is not appropriate for the Access Arrangement. The Government could have structured and executed the Pipeline sale process in a different way and, in so doing, caused a different value to be placed on the DBNGP. It could have sought lower tariffs by reducing the emphasis it placed on achieving the highest possible sale price. Alternatively, it could have sought a higher price by accepting a lower reduction – or even an increase – in tariffs. It chose not to do so.

In establishing the initial capital base, consideration is also to be given, in accordance with Section 8.10(e) of the Code, to international best practice of pipelines in comparable situations. The issue of international best practice is discussed in The Brattle Group report on regulatory asset valuation attached as Appendix 4. In that report, The Brattle Group notes that there are precedents, both in the United States and in the United Kingdom, for an approach in which regulated assets, subject to specified initial tariffs and specified future tariff paths, are valued at purchase price. In these circumstances, any shortfall in capital recovery is capitalised for subsequent recovery as sales of the services provided using the assets in question grow. If, given the specified initial tariffs and specified tariff path, sales growth fails to materialise, it is investors, and not users of the services, who bear the cost.

Section 8.10(e) of the Code further requires that, in establishing the initial capital base, consideration be given to the impact on the international competitiveness of energy consuming industries. Deriving the initial capital base from the DBNGP purchase price, and accepting that its shareholders bear the volume risk, allows Epic Energy to implement the tariffs and the tariff path of the regulatory compact. It permits the lowering of transmission tariffs to the levels the Government of Western Australia, and its advisers, considered were necessary to encouraging downstream processing activities that would use gas.

Furthermore, derivation of the initial capital base from the DBNGP purchase price, and implementation of the tariffs and the tariff path of the regulatory compact, allow the lowering of gas transmission tariffs consistent with the expectations of persons under the previous regulatory regime for the Pipeline.

Epic Energy notes that Section 8.10(g) of the Code requires that, in establishing the initial capital base, consideration be given to the “reasonable expectations” of shippers and prospective shippers. Public statements made by the Government during the DBNGP sale process were a significant factor in the formation of shipper expectations. In these statements, the Government signalled to shippers (and to potential purchasers of the Pipeline) that it was seeking a tariff of **about** $1.00 per GJ. Future tariffs were never precisely stated. Epic Energy questions the reasonableness of forming precise expectations - as precise, for example, as a “T1-equivalent postage stamp service tariff of no more than $1.00 per GJ” - about such a commercially important matter as tariffs on the basis of these public statements. The Government’s own view on the meaning of “tariffs of about $1.00 per GJ” seems to have crystallised only on the signing of the Asset Sale Agreement, and with its acknowledgement of the tariffs of Schedule 39. In these circumstances, the tariffs of the regulatory compact, $1.00 per GJ for gas transportation from Zone 1 (the production/gathering zone) to Zone 9 (the Perth metropolitan area), and a tariff of about $1.08/GJ from Zone 1 to Zone 10 (downstream of Kwinana Junction), are consistent with the reasonable expectations of shippers and prospective shippers.

In the context of application of Section 8.10(g) of the Code, Epic Energy totally rejects any inference that $1.00 per GJ is a reasonable tariff expectation because $1.00 per GJ is currently applicable under the Dampier to Bunbury Pipeline Regulations 1998. No such tariff appears in those regulations. The $1.00 per GJ was promulgated at 3.45 pm on 31 December 1999 by the Government using its powers under the Gas Pipelines Access (Western Australia) Act 1998 to amend the "repealed access regime". That tariff was set against Epic Energy's opposition, without its agreement, and without any consideration being given to Epic Energy’s business position. It was arbitrarily set without any consideration of Epic Energy’s case or economic or other analysis. The amount cannot, therefore, set any precedent and, in fact, is entirely inconsistent with, the statement of the Minister for Energy quoted above. Epic Energy continues to maintain that in promulgating the $1.00 per GJ, the State has acted contrary to its expectations and understandings.

The tariffs of the regulatory compact – $1.00/GJ for gas transportation from receipt points in Zone 1 to delivery points in Zone 9, and $1.08/GJ for transportation to delivery points in Zone 10 – were also expected, by the Government and its advisers, to protect long term gas supplies. They were expected to be consistent with the economically efficient utilisation of gas resources as required by Section 8.10(h) of the Code. In summary, Epic Energy has established an initial capital base of $2.570.3 million for the DBNGP. This initial capital base derives from Epic Energy’s purchase price of $2,407 million. An initial capital base which recognises Epic Energy’s purchase price (and subsequent investment in the DBNGP) allows implementation of the tariffs and tariff path of the regulatory compact with the State as the reference tariff and tariff path of the proposed Access Arrangement for the Pipeline. In establishing the initial capital base, consideration was given to the factors listed in Section 8.10 of the Code.

Epic Energy does not claim that the regulatory compact is more than a set of common understandings and expectations. It is not, in any sense, an agreement legally binding on the parties.

Nevertheless, consideration must be given to the common understandings and expectations of the regulatory compact in assessing the proposed DBNGP Access Arrangement. In particular, the regulatory compact is important in assessing the way in which Epic Energy has established the initial capital base for the Pipeline in accordance with Section 8.10 of the Code. Obligations on the Regulator to do so derive, not from the regulatory compact, but from Sections 2.24 and 8 of the Code. This is not an issue of what is legally binding. It is an issue of what is appropriate given the circumstances in which Epic Energy acquired the DBNGP from the State of Western Australia.

3.2 Asset Value by Pricing Zone and Category of Asset – COS Method

At the time of its acquisition of the DBNGP, Epic Energy engaged valuers Edward Rushton Australia Pty Limited to establish a detailed valuation of Pipeline assets consistent with the purchase price plus (net) costs of acquisition not included in the purchase price. This detailed valuation of assets has been used to assign values to the main groups of assets which comprise the initial capital base. The assignment of purchase value to asset groups, and the adjustments for depreciation and capital expenditure for the period from the date of acquisition to 1 January 2000, are set out in Table 3.1.

Table 3.1a - Initial Capital Base

	Acquisition Cost $m
DBNGP purchase price	2,407.00
Net Adjustments	42.49
Total Acquisition Costs	2,449.49

Table 3.1b - Initial Capital Base

	Acquisition Cost $m	Depreciation to 31 December 1999 $m	Capital Expenditure to 31 December 1999 $m	Asset Value 31 December 1999 $m
Asset value				
Pipeline assets				
Zone 1a	32.96	0.02	0.24	33.18
Zone 1b	300.63	0.15	0.24	300.72
Zone 2	162.18	0.08	0.48	162.58
Zone 3	162.72	0.08	0.48	163.12
Zone 4	163.14	0.08	0.48	163.54
Zone 4a	67.49	0.03	0.00	67.46
Zone 5	165.72	0.08	0.48	166.11
Zone 6	167.52	0.08	0.48	167.92
Zone 7	188.80	0.09	0.71	189.42
Zone 8	168.83	0.08	0.48	169.23
Zone 9	228.94	0.11	0.48	229.31
Zone 10	262.74	0.13	27.73	290.34
Compression assets				
Compressor station 1	24.35	0.55	0.00	23.80
Compressor station 2	8.72	0.44	27.00	35.28
Compressor station 3	44.47	1.34	0.54	43.67
Compressor station 4	7.95	0.40	17.66	25.21
Compressor station 5	45.48	1.03	0.00	44.45
Compressor station 6	48.79	0.90	1.25	49.14
Compressor station 7	6.96	0.36	27.00	33.61
Compressor station 8	45.85	1.04	0.54	45.35
Compressor station 9	47.44	0.55	3.76	50.65
Compressor station 10	0.00	0.01	14.55	14.54
Metering assets	26.53	0.08	2.39	28.84
Other assets				
Depreciable	65.45	0.34	13.99	79.11
Non-depreciable	5.82	0.00	0.00	5.82
Total	2,449.49	8.07	140.96	2,582.38

3.3 Asset Value by Pricing Zone and Category of Asset – NPV Method

The initial Capital Base for the DBNGP for the purposes of determining the Total Revenue under the NPV method is $2,100 million established in accordance with the Code.

The allocation of the initial Capital Base to pricing zones and category of asset is as shown in Table 3.2.

Table 3.2 - Access Arrangement Information
Initial capital base

Asset value	Asset Value 31 December 1999 $M
PIPELINE ASSETS	
Zone 1a	24.96
Zone 1b	210.57
Zone 2	114.63
Zone 3	115.11
Zone 4	115.31
Zone 4a	20.91
Zone 5	117.12
Zone 6	118.40
Zone 7	133.20
Zone 8	119.42
Zone 9	601.87
Zone 10	68.24
COMPRESSION ASSETS	
CS1	17.19
CS2	19.78
CS3	31.82
CS4	19.24
CS5	32.11
CS6	35.42
CS7	18.54
CS8	32.79
CS9	36.43
CS10	10.68
METERING ASSETS	23.24
OTHER ASSETS	
Depreciable	57.05
Non-Depreciable	5.96
TOTAL	2,100.00

3.4 Assumptions on Economic Lives of Assets for Depreciation

The economic life and average remaining life of the assets comprising the DBNGP are set out in Table 3.3. The economic life has been used to determine depreciation of the assets comprising the DBNGP.

Table 3.3 - Economic Life and Average Remaining Life of DBNGP At 1 January 2000

Asset Group	Economic Life (years)	Average Remaining Life (years)
Pipeline assets	70	55
Compression assets	30	19
Metering assets	50	40
Other assets	50	37

3.5 Depreciation – COS Method

As described in section 3.1(f), the initial capital base for the DBNGP was derived from the price Epic Energy paid for the pipeline, plus certain costs of acquisition (less minor adjustments after sale), as shown in Table 3.1a. Tariffs determined from that initial capital base would be higher than the tariffs Epic Energy committed to at the time of pipeline sale, and a lower initial Reference Tariff is advanced in the Access Arrangement. In consequence, revenue from delivery of the Reference Service at the Reference Tariff is likely to be insufficient to recover the capital charges (asset return and depreciation) on the initial capital base, and on the capital base in subsequent years, without growth in the demand for gas transmission services.

Epic Energy will, in these circumstances, treat any shortfall in the recovery of its capital charges by way of "economic depreciation". Economic depreciation is determined as the difference between the revenue expected given the Reference Tariff and the price path of the Access Arrangement, and the sum of the return on the capital base, depreciation of physical asset account balance and the non-capital costs.

The use of economic depreciation allows postponement of recovery of a part of the capital base until that recovery is warranted by growth in demand for gas transmission services. Higher demand allows Epic Energy to receive higher revenues and recover capital without an increase in the absolute level of tariffs. The required depreciation schedule has the effect of allowing the reference tariff to change over time "in a manner that is consistent with the efficient growth of the market for the Services provided by the Pipeline (and which may involve a substantial portion of the depreciation taking place in future periods…)"(Code, Section 8.33(a)).

Epic Energy's regulatory asset accounting is shown in Table 3.4.

Table 3.4 - DBNGP regulatory asset accounting

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m	2005	2006	2007	2008	2009
Beginning of year balance										
Physical asset account	2,582.38	2,580.43	2,580.48	2,580.15	2,575.24	2,564.69	2,737.85	2,744.46	2,728.65	2,835.58
Deferred recovery account	0.00	94.77	200.11	316.30	439.95	570.86	707.60	856.55	1,031.10	1,217.35
Capital base	2,582.38	2,675.20	2,780.59	2,896.45	3,015.20	3,135.55	3,445.45	3,601.01	3,759.75	4,052.93
Return on capital base	267.85	277.48	288.41	300.43	312.74	325.23	357.37	373.50	389.97	420.38
Depreciation: physical asset account	8.88	9.81	10.86	12.02	13.28	14.67	17.16	18.94	20.91	23.09
Capital expenditure	6.93	9.87	10.53	7.11	2.73	187.83	23.76	3.13	127.83	132.70
Depreciation: deferred recovery account	-94.77	-105.34	-116.19	-123.65	-130.91	-136.74	-148.96	-174.54	-186.25	-200.68
End of year balance										
Physical asset account	2,580.43	2,580.48	2,580.15	2,575.24	2,564.69	2,737.85	2,744.46	2,728.65	2,835.58	2,945.19
Deferred recovery account	94.77	200.11	316.30	439.95	570.86	707.60	856.55	1,031.10	1,217.35	1,418.04
	2,675.20	2,780.59	2,896.45	3,015.20	3,135.55	3,445.45	3,601.01	3,759.75	4,052.93	4,363.23

The capital base for the DBNGP in each year is the sum of two components. The first of these is a physical asset account balance. The physical asset account balance is the written down value of the physical assets that form the pipeline.

The second component of the capital base is a deferred recovery account balance. The balance in the deferred recovery account at the end of any year is the accumulated economic depreciation to the end of that year.

Initially, economic depreciation is negative (revenue from sale of the Reference Service at the Reference Tariff is not sufficient to recover the sum of the return on the capital base, the depreciation of the physical account balance and the non-capital costs). The deferred recovery account balance therefore rises. With future growth in the demand for gas transmission services, higher revenues will allow the recovery of capital without requiring an increase in the absolute level of the Reference Tariff.

Economic depreciation will increase, becoming positive, and reducing the balance in the deferred recovery account.

The “economic life” of the deferred recovery “asset” can be considered the economic life of the pipeline itself. If the deferred recovery account balance is reduced to zero before the end of the economic life, there is scope for subsequent reductions in the Reference Tariff.

If the deferred recovery account balance has not been reduced to zero by the end of the life of the asset, a part of the price paid by Epic Energy for the DBNGP will represent an “imprudent investment” for which shareholders will not be compensated. That is, Epic Energy’s shareholders will continue to bear a “volume risk” associated with the pipeline until the deferred recovery account balance is zero. If expected growth in the demand for gas transmission services fails to materialise, shareholders will be unable to fully recover their investment.

For a more detailed discussion of this approach, see The Brattle Group report in Appendix 4.

Depreciation of the physical asset account has been calculated using the annuity method. In the application of this method, physical asset values are adjusted each year to take into account any capital expenditure on new facilities. Depreciation is calculated on the capital base and the planned investment in new facilities during the period of the Access Arrangement. Assets are depreciated over the lives shown in Table 3.3. A separate depreciation schedule has been constructed for each of the principal groups of assets – pipeline, compression, metering, and other. Within the pipeline assets, depreciation schedules have been constructed for each zone; within compression assets, depreciation schedules have been constructed for each compressor station; and within metering assets, depreciation schedules have been constructed for each delivery point.

The Depreciation Schedule required by the Code is set out in Table 2.2.

3.6 Depreciation – NPV Method

Depreciation over the Access Arrangement Period for each asset or group of assets that form part of the Capital Base is:

(i) for an asset that was in existence at the commencement of the Access Arrangement Period, the difference between the value of that asset in the Capital Base at the commencement of the Access Arrangement Period and the value of that asset that is reflected in the Residual Value; and

(ii) for any capital expenditure during the Access Arrangement Period, the difference between the actual or forecast cost of the capital expenditure (whichever is relevant) and the value of the new facility created by that capital expenditure is reflected in the Residual Value.

The Residual Value of the DBNGP will reflect depreciation that meets the principles of sections 8.33 (a), (b) and (d) of the Code.

The depreciation schedule required by the Code for the NPV method is set out in table 3.5.

**Table 3.5 - Access Arrangement Information
DBNGP regulatory asset accounting**

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m	2005 $m	2006 $m	2007 $m	2008 $m	2009 $m
CAPITAL BASE										
Pipeline, CS1 and CS2 and other assets	1,859.72	1,899.91	1,946.50	1,994.96	2,043.61	2,087.84	2,201.96	2,267.03	2,312.33	2,481.43
Compressor stations (excluding CS1 and CS2	217.04	218.04	220.32	226.17	228.61	230.36	354.74	365.01	375.90	391.43
Metering	23.24	23.48	23.78	24.08	24.39	24.70	25.08	25.47	25.87	26.26
	2,100.00	2,141.43	2,190.59	2,245.21	2,296.60	2,342.90	2,581.78	2,657.51	2,714.10	2,899.12
ECONOMIC DEPRECIATION										
Pipeline, CS1 and CS2 and other assets	-34.15	-38.67	-41.36	-43.06	-43.33	-52.80	-41.31	-42.17	-41.27	-45.69
Compressor stations (excluding CS1 and CS2	-0.11	-0.15	-2.00	-0.48	0.27	2.13	-10.27	-10.90	-15.53	-8.79
Metering	-0.24	-0.25	-0.25	-0.26	-0.25	-0.39	-0.39	-0.39	-0.39	-0.40
	-34.50	-39.07	-43.61	-43.80	-43.32	-51.06	-51.97	-53.46	-57.19	-54.88
CAPITAL EXPENDITURE										
Pipeline, CS1 and CS2 and other assets	6.05	7.91	7.10	5.59	0.91	61.32	23.76	3.13	127.83	132.70
Compressor stations (excluding CS1 and CS2	0.89	2.13	3.85	1.96	2.02	126.51	0.00	0.00	0.00	0.00
Metering	0.00	0.05	0.05	0.05	0.05	0.00	0.00	0.00	0.00	0.00
	6.93	10.09	11.01	7.60	2.98	187.83	23.76	3.13	127.83	132.70
RESIDUAL VALUE										
Pipeline, CS1 and CS2 and other assets	1,899.91	1,946.50	1,994.96	2,043.61	2,087.84	2,201.96	2,267.03	2,312.33	2,481.43	2,659.83
Compressor stations (excluding CS1 and CS2	218.04	220.32	226.17	228.61	230.36	354.74	365.01	375.90	391.43	400.23
Metering	23.48	23.78	24.08	24.39	24.70	25.08	25.47	25.87	26.26	26.65
	2,141.43	2,190.59	2,245.21	2,296.60	2,342.90	2,581.78	2,657.51	2,714.10	2,899.12	3,086.71

3.7 Return on Capital Base – COS Method

Epic Energy's return on the capital base of the DBNGP has been determined by applying a pre-tax nominal rate of return (weighted average cost of capital; see section 3.8 below) to the sum of the balances in the physical asset account and the deferred recovery account. For tariff determination, asset returns have been separately determined for each pipeline zone, each compressor station, and each delivery point facility.

The return on the capital base based on the COS method is summarised in Table 2.2.

3.8 Committed Capital Works and Capital Investment

Section 8.20 of the Code permits forecast capital expenditure on new facilities to be taken into account in determining the Reference Tariff, provided that the expenditure is reasonably expected to meet the requirements of Section 8.16 of the Code when the investment is forecast to occur.

Forecast capital expenditure on new facilities taken into account in determining the Firm Service Reference Tariff is summarised in Table 3.6.

Table 3.6 -Forecast capital expenditure
Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m
Pipeline	0.50	2.55	0.91	0.33	0.12
Compressor stations	0.89	2.13	3.85	1.96	2.02
Metering	0.00	0.05	0.05	0.05	0.05
Other	5.54	5.35	6.19	5.26	0.79
Total	6.93	10.09	11.01	7.60	2.98

	2005 $m	2006 $m	2007 $m	2008 $m	2009 $m
Pipeline	58.34	20.70	0.00	124.63	129.41
Compressor stations	126.51	0.00	0.00	0.00	0.00
Metering	0.00	0.00	0.00	0.00	0.00
Other	2.98	3.05	3.13	3.21	3.29
Total	187.83	23.76	3.13	127.83	132.70

3.9 Description of and Justification for Planned Capital Investment

The planned new facilities investment for the DBNGP is described below under the following headings:

- Compressor Stations
- Pipeline

- Meter Stations
- Communication Systems
- SCADA field and master station equipment
- IS and IT
- Plant and Equipment
- Buildings and grounds
- Greenhouse Gas Emission

The new facilities investment is considered justified on the basis that:

- it is required to maintain the level of service being afforded on the DBNGP;
- it will aid in the provision of a lower cost of service particularly with the improved availability of equipment with less manpower requirements; and
- it is required to maintain the safety (of people, equipment and the environment), and the integrity, of the DBNGP

While most of the investment refer specifically to the DBNGP, the IT and IS investment does include the corporate network of Epic Energy and for the purpose of this exercise, 50% of cost is allocated to the DBNGP.

The figures in the text and the tables will differ as the figures in the tables have been escalated by forecast CPI being 2.5% per annum.

(a) **Compressor Stations**

(i) **Additional Turbine/Compressor upgrade**

This project was budgeted to cost $124M and while construction work and commissioning are expected to be completed on the SW loop, CS10 and CS4 by the end of 1999, work will continue into 2000 for:

In 2000, there will be an uprating of Solar Mars unit at CS5/2 at a cost of $700,000.

In 2001, the following work is expected:

- Completion of warranty related work and as builts at cost of $250,000
- Uprating of Solar Mars unit at CS5/1 at cost of $700,000

In 2002, the last of the Solar Mars units at CS8/1 and CS1 will be up rated at cost of $700,000 each.

The amount of $700,000 allowed for the uprating of the existing Solar Mars 90 units relate to the components of existing gas turbine machines that will replaced by more durable components required to operate at higher temperatures.

Increasing availability of existing compressors will be achieved by introduction of:

- Improved maintenance methods, reduction in offline work with introduction of more on line maintenance. In addition, there will be a small additional capital investment associated with:

- Rationalisation of unit and station emergency shut down systems
- The replacement of redundant series 2000 barriers with more versatile and modern ones

- Engineering out of obsolete control systems that are no longer compatible with new systems

The program will also require the introduction of high tech condition monitoring equipment.

It is forecast that this part of the project will cost:

It is forecast that this work will cost $100,000 for control view upgrade and $250,000 for condition monitoring equipment in 2001.

In summary, the Stage 3A capital investment to deliver firm 78 TJ/day of capacity to the South West will cost:

	2000	2001	2002	2003	2004
Nth Compression		0.26			
Mars upgrade	0.71	0.73	1.49		
Control View		0.10			
Condition monitoring		0.26			

(ii) **Fitness for purpose project**

Epic Energy has already undertaken a feasibility program of reviewing the pipeline conditions to determine the extent of pipeline integrity and the safety factor built into the system as part of its License Obligation to confirm fit for purpose for the current design intent.

In addition, information gained from this program positions Epic to effectively plan any future enhancement capabilities with the lowest sustainable cost of service delivery.

To finalise this program, $600,000 is forecast for 2000.

	2000	2001	2002	2003	2004
Fit for Purpose	0.61				

(iii) **Other compressor station capital investment**

The nine compressor stations are a mixture of three stages of DBNGP enhancement programs and in the next 5 years, the following investments are forecast:

(A) Replacement of UPS System

The Compressor Station UPS system relies on 24 V battery banks for the supply of DC power for instrumentation and control systems power requirements. It is expected that battery banks with the type of load in existence at Compressor Stations will be replaced every 10 years. This will translate to $150,000 in all years from 2001 onwards

	2000	2001	2002	2003	2004
UPS upgrade		0.16	0.16	0.16	0.17

(B) Upgrading of Airstrips

The existing airstrips were installed to cope with the transport of employees in an unmanned operation. With the review of manning requirements to improve on Compressor performance, airstrips at CS2 and CS5 will be upgraded to all weather strips to enable the ferrying of employees and equipment to site.

This civil works is expected to cost $200,000 per airstrip and will be implemented in 2001 and 2002.

Helipads will be also be upgraded at these sites with equipment to allow for night landing.

This project is expected to cost $50,000 per station and will be implemented at CS1, CS4 and CS8

	2000	2001	2002	2003	2004
Upgrade airstrip		0.21	0.21		
Helipads	0.15				

(C) Water Treatment Plants

Water treatment plants are an essential part of the operation of the DBNGP. Most of the bores have been in operation since the life of the pipeline.

It is forecast that new bores will be developed to maintain adequate water supply and several bores will be sunk at CS1, CS4, CS5 and CS6.

The cost of these bores is forecast to be $50,000 per station.

	2000	2001	2002	2003	2004
		0.05	0.05	0.05	0.06

(D) Air conditioning units

Air conditioning units are an essential component of compressor station operation. The life of condensers and compressors are estimated to be 10 years and systems at will be replaced in the next 5 years with more robust and less maintenance requirements that the existing systems.

The new systems will cost $50,000 per site

	2000	2001	2002	2003	2004
Air con system		0.05	0.05	0.05	0.06

(E) Compressor Station facilities

To facilitate manning of compressor stations, additional facilities will be added to allow for employees living conditions. These include:

- Provision of Epic's corporate facilities like Maximo, Peoplesoft, GIS and electronic mailing system $110,000
- Provision of additional recreational facilities and training facilities on site at cost of $50,000 in 2001

Costs include physical hardware for compressor stations to access the corporate network as well as the development and implementation of thin client technology to improve access speeds to corporate data. Epic is using citrix server farms to enable this access. This need has resulted from the shift to a field based operation rather than a depot based one.

This is estimated to cost

	2000	2001	2002	2003	2004
Epic Corp Syst	$0.11m				
Rec facilities		0.05			

(F) Upgrade of Station MMI's

The requirement for replacement of both hardware and software of the existing MMI's is brought about by the age of the existing equipment and the ability to source suitable hardware.

The expected replacement cost is around $20,000 per MMI without no engineering time applied.

The project will be staggered over time with the engineering and testing being carried out in 2001 with replacement being staggered over 4 years.

Project funding:

Year 2000 0
Year 2001 $30,000, engineering
Year 2002 $100,000 CS1, 2,3
Year 2003 $80,000 CS4, 5
Year 2004 $100,000 CS7, 8,10

	2000	2001	2002	2003	2004
Engineering					
CS1,2,3		0.03	0.11		
CS4,5				0.09	

CS7,8,10					0.11

(b) **Pipeline**

(i) **Land Management**

The management of land use, exposures to environmental damage and monitoring of issues that impact on spread of die back and weed control will continue to form a major part of the operation of the DBNGP.

It is forecast that the introduction of an Epic GIS system to manage these issues will cost $100,000 to implement. The GIS will also indirectly result in the reduction in construction costs with more streamlined system for data capture.

	2000	2001	2002	2003	2004
GIS	0.06				

(ii) **Flood Damage Mitigation**

All of the expenditure indicated for this item is capital associated with the prevention of or minimisation of future flood damage. The repair of pipeline flood damage is not included in this item.

Flood damage mitigation will be implemented to minimise damage to the pipeline and pipeline exposure. Areas where there is susceptibility to erosion particularly riverbanks will be enhanced on an ongoing basis.

The scope will require installation of revetment control banks at critical river banks and sections of the pipeline.

The ongoing nature of this capital expenditure reflects the annual and geographical variability of weather conditions meaning, that all areas subject to flood damage are not revealed at the one time.

It is expected this will cost $50,000 a year to implement.

	2000	2001	2002	2003	2004
Flood mitigation		0.05	0.05	0.05	0.06

(iii) **Corrosion protection**

The coating system on the DBNGP remains well protected although evidence of coating failure is evident at sections of the pipeline.

The monitoring of CP systems is conducted on an annual basis and results of those surveys will dictate the additional protection that will be required.

The work proposed is additional groundbeds and cathodic protection facilities to supplement existing cathodic protection facilities as the pipeline coating deteriorates with age and exposure to environmental and other deteriorating influences. The need for such reinforcement was based on Epic Energy's assessment as a prudent operator of such pipelines.

This will require installation of groundbeds in between existing ones to supplement potential drops. An allocation of $20,000 per year from 2002 is forecast.

	2000	2001	2002	2003	2004
CP upgrades			0.02	0.02	$0.02

(iv) **Encroachment of land use onto the easement**

As more and more development encroaches onto the easement, additional protection to the integrity of the pipeline will be required.

AS2885 has developed methodologies for pipeline risk assessments and mitigation methods have been recommended.

Certain sections of the pipeline may be required to have concrete slab protection and based on encroachment progress to date, an allocation of $200,000 every second year is forecast.

	2000	2001	2002	2003	2004
Pipe protection		0.21		0.22	

(v) **Mainline Valve and Repeater Sites**

(A) CCVTS

All mainline valves north of Kwinana Junction are installed with remote monitoring and control facilities.

Power generation equipment are old technology and equipment obsolescence is inevitable. Closed Circuit Vapour Turbines control system which form the main prime power supply will be gradually replaced in the next 5 years.

There are 24 CCVTs installed on the DBNGP and it planned to replace the control systems at cost of $10,000 in the next 5 years.

	2000	2001	2002	2003	2004
CCVT upgrades			0.09	0.09	0.09

(B) 10 kW GEAs

GEAs are installed as back up power supplies. Being in standby mode for most of the time, the seals on these units have begun to show signs of wear and are a cause of environmental concern because of oil leaks. It is planned to gradually replace seals on these units in the next 5 year at a cost of $5,000 per unit. There are 34 10 kW GGGEAs installed on the DBNGP.

	2000	2001	2002	2003	2004
CCVT upgrades		0.04	0.04	0.04	

(C) MLV and Repeater Earthing systems

Earthing systems were installed for equipment and personal protection at all sites powered. The life of earthing systems particularly in corrosive sites are close to 15 years and some sites have earthing systems that have deteriorated and will require replacement.

It is expected that several sites will have earthing systems repaired at $15,000 per site. There are a total of 24 sites between Dampier Facilities and MLV91 that may be affected. The plan is to allow for 10 sites to have earthing replaced in the next 5 years.

Earthing systems installed at these sites form the basis for equipment protection during faults and also provides step and touch protection to personnel.

	2000	**2001**	**2002**	**2003**	**2004**
MLV earthing	0.03	0.03	0.03	0.03	0.03

(c) **Meter Stations**

(i) **Noise Control due to urban encroachment**

The DBNGP was constructed some 15 years ago when the path selected through the metropolitan area was relatively less populated.

In the last 5 years has seen the increase in urban development both industrially and domestically where encroachment onto the pipeline easement and even more so at meter stations. The DBNGP meter stations have pressure regulators which are rated for certain level of noise and as more of these dwellings move closer to them, new low noise regulators have to be fitted and in some locations it is expected to have the site fully enclosed with brick walls to attenuate noise.

The sites expected to be affected include Harrow Road, Welshpool, Forestdale and Russell Road meter stations.

It is forecast that one site will be upgraded for low noise operation per year for the next 5 years at a cost of $50,000 per site

	2000	**2001**	**2002**	**2003**	**2004**
MS noise attenuation		0.05	0.05	0.05	0.06

(ii) **Installation of flares for control of vented odorised gas**

In much the same way as the above stations will be affected by noise levels, it is forecast that most of our maintenance work in the metropolitan areas will not for environmental reasons allow for raw venting of gas let alone odorised ones.

This section has allow for the installation of portable flares at some of our key locations to minimise this effect and avoid public nuisance at cost of $20,000

	2000	2001	2002	2003	2004
Portable Flares		0.02			

(iii) **Sulphur deposition mitigation program**

Sulphur deposition on internals of equipment has been a problem for the DBNGP for many years but has continued to be on the increase of recent. Elemental sulphur generally forms at pressure regulation points such as pressure controllers and fuel control valves for gas turbines. To date the problems has been managed through increasing the frequency at which maintenance is performed.

The problems associated with fuel control valves to the gas turbines has deteriorated to the point that numerous unplanned shutdowns are forced on operating units and while these have not impacted on capacity, as the market improves and improved reliability required, these forced outages will impact on delivery.

Each time a unit trips, it requires at least one person to travel to site, investigate and rectify the fault and return the unit to service.

It was planned to conduct a feasibility study in 2000 with the view of development of a solution to this problem. Preliminary assessment indicate that if the DBNGP can not resolve this problem from the source, then small processing plants may be installed at each of the compressor stations to strip the sulphur from the gas stream.

Epic Energy has allowed for $1,000,000 in 2001 and $1,000,000 in 2002 for this work.

	2000	2001	2002	2003	2004
Sulphur deposition mitigation plan		1.04	1.06		

(d) **Communication Systems**

(i) **Upgrading/replacement of the analogue microwave system north of Perth**

The existing analog microwave system has been in service for over 14 years with the original design criteria established in 1980. The technology is based around voice circuits with limited high bandwidth data and no digital data capability. This limitation has caused and will cause Epic Energy to engineer in solutions that are both expensive and complex.

Epic Energy contracts its share of the maintenance costs to Western Power that maintains their own share as well. This arrangement is due to the limited services providers that could maintain this system particularly in remote areas of the DBNGP.

Upgrading of the DBNGP microwave communications system may involve alternative means of providing communications. Feasibility studies have been conducted on a number of proposals for the overall communications upgrade since 1999 but none have proved financially viable to date.

The studies have shown that the satellite option is technically flawed in that it does not provide all the necessary services for voice communications and fails to deliver the reliability and availability for control of the pipeline. In addition the operating costs of satellite services to compressor stations, main line valves and meter stations are significantly higher than that of a microwave radio bearer. Satellite option into compressor stations is seen as a short term solution given the high incremental costs for increased bandwidth.

The upgrading/replacement program is aimed at providing Epic Energy with either its own digital system or a system that is provided by a Communications Service Provider. This will give Epic Energy the independence required to operate is business asset's at a reduced annual cost.

The plan is based over 4 years with the 1st year aimed at carrying out a review and feasibility study, with the new system being in service by the end of the 2003 calendar year.

Projected funding is as:

Year 2000	$250,000	feasibility study
Year 2001	$3.8m	R0/1 to CS3
Year 2002	$4.7m	CS3 to CS7
Year 2003	$3.8m	CS7 to GHD

	2000	2001	2002	2003	2004
Feasibility	0.25m				
Upgrade R0-CS3		3.94			
Upgrade CS3-CS7			5.00		
Upgrade CS7-GHD				4.14	

(ii) **Upgrading/replacement of VHF systems for mobile coverage**

Epic Energy uses both VHF mobile radio, Satellite and Mobile phones to provide voice communications to its mobile staff.

Optus Satellite phones are installed in all field vehicles to provide the coverage in remote areas not covered by either VHF or Digital mobile networks. This service has proven unreliable.

The existing VHF mobile radio systems consists of single channel base stations interconnected by a microwave VF circuit. Epic Energy operates Operations and Maintenance channels requiring the use of separate base stations.

Each time a call is made each base station is required to be keyed up and rebroadcast the message. This is an inefficient system which draws off power from the batteries and compounds the noise and delays on the channel.

Epic Energy currently owns and operates this system with maintenance being carried out by Western Power.

The upgrade/replacement program will review the use of newer VHF trunked mobile radios and CDMA mobile phones to provide improved voice data communications at a reduced annual operating cost. Trunked radio tracks the vehicle by the use of a control channel and when private calls are originated only the originating and destination transmitters are keyed up. All other transmitters in the system are not required. This tracking feature is available to a base station operator for monitoring of locations.

The program is aimed at providing Epic Energy with a system with the following features:

- private party calls
- group calls
- all station calls
- vehicle tracking
- data calls
- message facilities
- reduced annual operating cost

The plan is based over 4 years with the 1st year aimed at carrying out a review and feasibility study, with the new system being in service by the end of the 2003 calendar year.

Projected funding is as:

Year 2000	Included in Analog study	
Year 2001	$200,000	R0/1 to CS3
Year 2002	$250,000	CS3 to CS7
Year 2003	$200,000	CS7 to GHD

	2000	2001	2002	2003	2004
Feasibility					
Upgrade R0-CS3		0.21			
Upgrade CS3-CS7			0.27		
Upgrade CS7-GHD				0.22	

(e) **SCADA Field Equipment**

(i) **Upgrading of Remote Terminal Units (RTU)**

The fields RTU's will be progressively replaced as follows:

Technology development has resulted in smarter devices such as PLC have superseded the role and functions of RTU's. With the advent of these new equipment, Epic has been able to introduce new technology with new installations where PLCs are the main interface link between remote master station and field equipment.

As new equipment are manufactured and improved communications systems available, the technical and economic life of RTUs will be reviewed where suitable alternatives have to be invested for the next generation of equipment to services the DBNGP.

Potential problems to be circumvented by the replacement program include:

- age and replacement parts for some models are limited
- reduction or loss of maintenance experience
- existing Conitel protocol used on RTUs are difficult to transport on newer digital networks
- specialist tooling required for some models.

To date there has been replacement of the RTUs at radio sites S1,S2,S3,S4,S5,S6 and S7. At these sites, the UHF radio links used for SCADA communications operated on the 800MHz band. Telstra procured the ownership of transmission rights in this band forcing Epic Energy and other users to progressively vacate the 800MHz band. The most economical solution was replacing the 800MHz analogue radio with digital 900MHz radios, but this was incompatible with the Conitel protocol used by the old RTUs. This required replacing the RTUs with a type that could be supported over the new radio link.

Projected funding is as:

Year 2001	$300,000	R0/1 to CS3, Perth area
Year 2002	$250,000	CS3 to CS7
Year 2003	$200,000	CS7 to GHD
Year 2005	$300,000	R0/1 to CS3
Year 2006	$250,000	CS3 to CS7
Year 2007	$200,000	CS7 to MLV118

	2000	2001	2002	2003	2004
R0-CS3 & Metro area		$0.31m			
CS3-CS7			0.27		
CS7-GHD				0.22	

(f) **IS and IT**

(i) **Customer Reporting System (CRS)**

Epic has been developed a customer reporting system (formerly Gas Transmission Information System) to process, manage and provide in a timely manner the reporting of data and information in relation to the transportation services of the DBNGP both for external and internal customers business requirements. The CRS has addressed the deficiencies of the previous system and is efficient and accurate.

This system was prepared cognisant of the regulated transmission business and Epic's ability to respond quickly to changes in regulation and market expectations.

The CRS system will have an Electronic Bulletin Board interface that will enable all shippers to interact with Epic over the Internet.

The cost of development and implementation of this system is forecast to be $2,400,000 and mostly will fall into year 2000 financial year.

	2000	2001	2002	2003	2004
CRS	2.43				

(ii) **Computer systems**

Epic Energy's computer system will continue to be revised and upgraded to maintain the level of support dictated by the business. They include the following:

- the upgrading of the Novell Netware 5 Network at a cost of $20,000;
- the upgrading of Zenworks v2 – a remote distribution software which enables remote work station software to be updated from a central location whenever remote work stations log on to the network. This system needs to be continually upgrade to support the business at a cost of $50,000;
- Epic's remote work station hardware and PCs will need to be continually updated as technology gets updated at a cost of $300,000;
- an allocation has been made for the integration of Epic's Computerised Maintenance Management System with the Financial System (Peoplesoft) at $200,000; and
- an allocation has been made for the systems enhancement to Peoplesoft at $300,000.

	2000	2001	2002	2003	2004
Novell Netware	0.02				
Zenworks	0.05				
PC upgrade	0.30	0.16	0.16	0.16	0.17
Maximo/Peoplesoft interface	0.10				
Upgrade Peoplesoft	0.15				

(iii) **Information Management System**

Epic Energy will be establishing a mechanism for managing its information asset. This project aims to bring together the definition, storage, centralisation, reproduction and dissemination of business information.

Information covers policies, procedures, operating instructions, financial information, working papers, guidelines, drawings and plans. The project will involve defining owners, documentation framework, access and security rights to categories of information and building an intranet to maximise use of IT infrastructure.

This capital project will cost $500,000 and is expected to be expended in 2000.

	2000	2001	2002	2003	2004
Information Management System	0.51				

(iv) **SCADA master station additional protocols**

Additional protocols will be required due to changes to the communications infrastructure.

It is expected that an additional protocol and suitable hardware will be in the vicinity of $75,000.

Project funding is as:

Year 2001 $75,000

	2000	2001	2002	2003	2004
Master station protocols		0.08			

(v) **SCADA Master Station back up system – visibility to CS6 and CS9**

SCADA communications to CS6 and CS9 were revised as part of Stage 2 enhancement to be based on Modbus RTU protocol with the LNA master station communicating directly with each major PLC at site for reliability and availability reasons. The LNA master station and Jandakot EBS and other communications facilities were to under go a major upgrade as part of Stage 2 to provide modbus coms capability.

Towards the latter stages of Stage 2 due to the delays of this work, AlintaGas put in place a D20 protocol converter at the Perth SCADA master station so that CS6 and 9 could be accessed via main control centre master station existing Conitel communications capability.

The LNA master station has been recently upgraded to Valmet SCADA but only upgrade the master station and the Jandakot EBS and did not pick up the upgrades to support the CS6 and CS9 modbus communications and the interim D20 protocol converters were effectively permanent installations.

This proposal will:

- Eliminate the existing reliability issues with D20 protocol converters and allow Valmet master station to communicate directly to the site PLCs as originally intended
- Enable modbus channels to be provided with Epic corporate LAN communications server access via the Bunbury and Karratha for EBS access
- Enable the standardisation of the CS6 and 9 SCADA databases with CS2,4 and 7

This work is expected to cost $100,000.

	2000	2001	2002	2003	2004
EBS visibility to CS6 and 9	0.10				

(g) **Plant and Equipment**

(i) **Motor Vehicles**

Epic Energy owns and operates a fleet of vehicles and plant for the on going maintenance activities of the DBNGP.

While the current list of vehicles has been established prior to the sale, there will be ongoing review of the requirements and is expected that while the number of vehicles used will dramatically reduced in 2000, hence the nil allocation, the remaining fleet will be replaced on phased out arrangement.

It is planned that from 2001 onwards, six vehicles will be replaced on an annual basis and an allocation of $250,000 is forecast.

	2000	2001	2002	2003	2004
Vehicles		0.26	0.27	0.27	0.28

(ii) **Field Tools and Equipment**

There is an ongoing requirement to maintain and update the tools used on the DBNGP. Tools like people are the mainstays of our maintenance program.

Maintenance of tools and equipment will be required on an annual basis at $50K per year

	2000	2001	2002	2003	2004
Tools and Equipment	0.05	0.05	0.05	0.05	0.05

(iii) **Tools and Equipment**

There is an ongoing requirement to maintain and update the tools used on the DBNGP. Tools like people are the mainstay of our maintenance program.

Following the recent re organisation of the maintenance teams there will be an initial investment of $282,000 in 2000 to set these teams up with new tools and equipment and is forecast that each year following, Epic Energy will require $50,000 to maintain them.

	2000	2001	2002	2003	2004
Tools and Equipment	0.29	0.05	0.05	0.05	0.06

(iv) **Inventory Management**

Inventory management will review the cost and availability of spare parts. The range of equipment installed on the DBNGP will continue to be reviewed to ensure equipment standardisation hence optimisation of spare parts can be implemented.

As equipment become redundant due to supply or suppliers provide new spare parts, the inventory holding of the DBNGP will be revised and new spare parts get introduced. It is forecast that an allocation of $200,000 per year to accommodate new parts will be required. This allocation is in keeping with the history of inventory movements where redundant stock are salvaged at market value and new stock items added into the inventory asset.

	2000	2001	2002	2003	2004
Inventory movement	0.20	0.21	0.21	0.22	0.22

(v) **Emergency Response Communication Caravan**

This vehicle will provide and maintain essential voice and data facilities for any emergency/crisis that may occur involving Epic Energy assets. Such crisis included disruption to either the gas path or to the communication path thus requiring this vehicle to operate as a link within the radio network.

The caravan will produce its own power requirements capable of supporting the established communications and support equipment.

Project funding:

Year 2001 $60,000 provision for portable antenna, base stations, chargers, batteries and power generation.

	2000	2001	2002	2003	2004
Emergency Response Communication Mobile		0.06			

(h) **Buildings and Grounds**

(i) **Corporate Head Office and Depots**

As the organisation grow and change, there will be a requirement to continue to revise the plans for Head Office and Depot offices and buildings.

An allocation has been made for the review of the Jandakot Depot in 2000 following the rationalisation of the other two depots:

Remodelling of the offices	$50,000
Building of the new warehouse	$250,000

	2000	2001	2002	2003	2004
Buildings	0.30	0.10	0.11	0.11	0.11

(ii) **Security System**

With the pending sale of AlintaGas, the security of the Jandakot depot will be reviewed. This will include improved fencing arrangements, security for after hours.

It is expected that this will cost about $100,000.

	2000	2001	2002	2003	2004
Security		0.10			

(i) **Greenhouse Gas Emission**

(i) **NOX/SOX Emission control for gas turbines**

Emission control of green house gases on the DBNGP will be developed as part of Epic's commitment to the Environment.

Gas Turbines installed at compressor stations north of CS9 do not have NOX and SOX emission control equipment. While future new enhancement will have these as part of the installation, there will be a requirement to retrofit this equipment on existing equipment and this will be gradually installed in the next 5 years.

	2000	2001	2002	2003	2004
NOX/SOX control		0.56	1.60	1.64	1.68

3.10 Capital Expansion Program 2005 to 2009

(a) DBNGP Forecast Capacity Increases

The 2 primary drivers for additional capacity are power generation and increased alumina production. The other, but lesser, driver is organic growth in the retail gas market.

[Deleted – Confidential and Commercial in Confidence]

Expansion Stage	Year	Capacity TJ/day	Capex ($M 2003)
3b	2004	0	10
4	2006	76	287
5	2009	37	111
Total		**113**	**408**

Each stage is justified as follows.

- **Stage 3b**

  [Deleted – Confidential and Commercial in Confidence]

- **Stage 4**

  [Deleted – Confidential and Commercial in Confidence]

- **Stage 5**

  By 2009 the capacity required by the retail gas market will exceed that contracted by existing retailers. Therefore, an expansion of pipeline capacity to ensure firm service for the retail market has been included in Stage 5.

  [Deleted – Confidential and Commercial in Confidence]

Stay-in-business capital expenditure forecast

In addition to planned new facilities investment to expand the DBNGP over the period 2005 to 2009, Epic Energy will have an on-going requirement to invest in facilities that maintain the safety and integrity of the pipeline, and maintain its ability to provide the capacity under contract to shippers.

A detailed program of work has not yet been developed and approved, but Epic Energy's forward planning assumes "stay-in-business" capital expenditure of about $3 million per year. This expenditure is shown under the heading "Other assets" in Table 3.6 above.

3.11 Rates of Return on Equity and on Debt – COS Method

As noted in section 3.7, under the COS method the return on the capital base for the DBNGP, has been determined by applying a rate of return to the sum of the physical asset and deferred recovery account balances at the end of each year. Epic Energy has used, as the rate of return to be applied to the capital base, a weighted average of the returns applicable to the equity and debt used to finance its assets.

Epic Energy's weighted average of returns – its weighted average cost of capital (WACC) – has been computed by its expert regulatory adviser, The Brattle Group. The Brattle Group's WACC determination is summarised in Table 3.7. The method used to determine the WACC, and the assumptions made in respect of capital structure, equity returns and debt returns, are detailed in The Brattle Group's report attached as Appendix 2.

There is a degree of uncertainty associated with each of the estimates used as an input to a WACC calculation. The Brattle Group has, therefore, adopted the practice of rounding cost of capital determinations to the nearest quarter point. The Brattle Group's recommended pre tax real WACC for use in developing the reference tariff of the proposed DBNGP Access Arrangement is, in consequence, 8.5% (and not the 8.60% shown in Table 3.7). Epic Energy has used a pre tax real WACC of 8.5% in determining return on capital base for the DBNGP under the COS method.

Table 3.7 - Determination of the Weighted Average Cost of Capital for the DBNGP – COS Method

Parameter	Line no.	Parameter Value	Calculation
Equity beta			
Asset beta	[1]	0.58	Input
Debt beta	[2]	0.12	Input
Debt to assets ratio	[3]	55.00%	Input
Equity to assets ratio	[4]	45.00%	1 - [3]
Equity beta	[5]	1.15	[1] + ([1] - [2]) x [3]/[4]
Cost of equity			
Risk free rate	[6]	4.80	Input
Market risk premium	[7]	6.50%	Input
Cost of equity	[8]	12.30%	[6] + [5] x [7]
Cost of debt			
Risk free rate	[6]	4.80%	
Corporate debt premium	[9]	1.20%	Input
Cost of debt	[10]	6.00%	[6] + [9]
Post tax nominal WACC			
Company tax rate	[11]	31.40%	Input
Dividend payout ratio	[12]	70.00%	Input
Value of imputation credits	[13]	44.00%	Input
Post tax nominal WACC	[14]	7.11%	[8] x [4] x (1 - [11])/(1 - [12] x [13]) x [11] + [10] x (1 - [11]) x [3]
Pre tax real WACC			
Real risk free rate	[15]	2.97%	Input
Inflation rate	[16]	1.78%	(1 + [6])/(1 + [15]) - 1
Post-tax real	[17]	5.24%	(1 + [14])/(1 + [16]) - 1
Post-tax real (Myers et al)	[18]	5.34%	[17] x (1 - [16])
Pre-tax nominal	[19]	10.37%	[8] x [4]/(1 - [11] x (1 - [12] x [13])) + [10] x [3]
Pre tax real	[20]	7.78%	[18]/(1 - [11])

3.12 Rates of Return on Equity and on Debt – NPV Method

Total Revenue calculated under the NPV method has been done so that, during the Access Arrangement Period, the present value of the Total Revenue:

(i) less the present value of the forecast capital expenditure,
(ii) less the present value of the non-capital costs,
(iii) plus the present value of the Residual Value,
(iv) less the Capital Base, at the commence of the Access Arrangement Period is equal to zero.

The discount rate used in the present value calculations referred to in the previous paragraph is a pre-tax nominal weighted average of the returns applicable to equity and debt which provides Epic Energy with a return consistent with the principles in sections 8.30 and 8.31 of the Code.

The return on equity referred to in the previous paragraph has been determined using the capital asset pricing model.

The return on debt referred to in the previous paragraph has been determined as the sum of a risk free rate of return and the estimated corporate debt margin.

The Residual Value at the end of the Access Arrangement Period has been calculated consistently with the principles in Section 8 of the Code.

The calculation of the Rate of Return used under the NPV method is summarised in Table 3.8.

Table 3.7 - Determination of the Weighted Average Cost of Capital for the DBNGP – NPV Method

Parameter	Line no.	Parameter Value	Calculation
Equity beta			
Asset beta	[1]	0.58	Input
Debt beta	[2]	0.12	Input
Debt to assets ratio	[3]	55.00%	Input
Equity to assets ratio	[4]	45.00%	1 - [3]
Equity beta	[5]	1.15	[1] + ([1] - [2]) x [3]/[4]
Cost of equity			
Risk free rate	[6]	4.80	Input
Market risk premium	[7]	6.50%	Input
Cost of equity	[8]	12.30	[6] + [5] x [7]
Cost of debt			
Risk free rate	[6]	4.80%	
Corporate debt premium	[9]	1.20%	Input
Cost of debt	[10]	6.00%	[6] + [9]
Post tax nominal WACC			
Company tax rate	[11]	31.40%	Input
Dividend payout ratio	[12]	70.00%	Input
Value of imputation credits	[13]	44.00%	Input
Post tax nominal WACC	[14]	7.11%	[8] x [4] x (1 - [11])/(1 - [12] x [13]) x [11] + [10] x (1 - [11]) x [3]
Pre tax real WACC			
Real risk free rate	[15]	2.97%	Input
Inflation rate	[16]	1.78%	(1 + [6])/(1 + [15]) - 1
Post-tax real	[17]	5.24%	(1 + [14])/(1 + [16]) - 1
Post-tax real (Myers et al)	[18]	5.34%	[17] x (1 - [16])
Pre-tax nominal	[19]	10.37%	[8] x [4]/(1 - [11] x (1 - [12] x [13])) + [10] x [3]
Pre tax real	[20]	7.78%	[18]/(1 - [11])

4. INFORMATION REGARDING OPERATIONS AND MAINTENANCE

4.1 Non-Capital Costs

Epic Energy expects to incur the non-capital costs shown in Table 4.1 in the provision of the Reference Service and Non-Reference Services during the Access Arrangement Period.

Table 4.1 - Non-capital costs incurred in providing services
Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m	2005 $m	2006 $m	2007 $m	2008 $m	2009 $m
Wages and salaries	9.92	10.17	10.42	10.68	10.95	11.22	11.50	11.79	12.09	12.39
Materials and services	10.84	11.86	14.19	14.15	13.84	14.19	14.54	14.90	15.28	15.66
Property taxes	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.06	0.07	0.07
Marketing	0.45	0.46	0.47	0.48	0.50	0.51	0.53	0.54	0.55	0.57
Corporate overheads	3.95	3.94	4.21	4.27	4.30	4.41	4.52	4.63	4.75	4.86
Gas used in operations	13.90	14.80	15.40	16.50	17.20	16.53	18.41	32.47	26.81	30.33
Total	39.11	41.28	44.74	46.14	46.84	46.92	49.56	64.39	59.55	63.88

4.2 Gas Used in Operations

Gas used in operations comprises compressor fuel, and a smaller quantity of gas used in blowdowns and purges during the commissioning and maintenance of facilities.

Compressor fuel use is estimated from the expected utilisation of compression plant at the ten compressor stations on the DBNGP. The expected plant utilisation is determined from the forecast volumes required at delivery points. These forecast volumes are set out in section 6.

Epic Energy has estimated that on average through the Access Arrangement Period, approximately 1.1 TJ/d of gas will be used in blowdowns and purges.

Epic Energy currently purchases gas used in operations under long term contracts, from AlintaGas, and also from the Harriet Joint Venture. Due to the obligations under the first of those contracts, it is not possible for Epic Energy to contemplate adopting an approach of shippers providing compressor fuel gas prior to at least 2005.

4.3 Unaccounted for Gas

Epic Energy has made no allowance for unaccounted for gas. Epic Energy believes that as an efficient pipeline operator it should always be striving to reduce the level of unaccounted for gas to zero.

4.4 Fixed Versus Variable Costs

The costs associated with the operation and maintenance of a gas transmission pipeline system are predominantly fixed. In the short term, 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 compressor fuel.

DBNGP compressor fuel costs comprise between 32% and 35% of total non-capital costs associated with the DBNGP, and between 6% and 7% of the forecast total cost of providing the Reference Service.

4.5 Cost Allocations Between Services and Categories of Asset and Between Regulated and Unregulated Business Segments

The DBNGP operates only as a regulated business. There is no further allocation of non-capital costs to regulated and unregulated business segments.

5. INFORMATION REGARDING OVERHEADS AND MARKETING

5.1 Total Costs at Corporate Level

Costs directly attributable to an individual business unit within the Epic Energy group are allocated directly to that business unit. Certain specific executive and administration costs not directly attributable to individual business units are allocated to all of the business units within the group. These executive and administration costs are captured by Epic Energy Corporate and Shared Services Pty Ltd ("CSS") within the group structure. The entire cost of CSS is allocated to business units as follows:

(a) costs associated with CSS administration and human resources activities are allocated on a pro rata basis to the group's operations in South Australia, Queensland and Western Australia, with the allocation being based on the proportion of total labour costs incurred in each region;

(b) costs of the remaining CSS activities – treasury, information technology, corporate finance, legal, commercial services, marketing services, and engineering – are allocated on a pro rata basis to the group's operations in South Australia, Queensland and Western Australia, with the allocation being based on the proportion of total operating and maintenance costs (excluding fuel costs) incurred in each region.

Total costs at corporate level, and the proportion of those costs allocated to operations on the DBNGP – are shown in Table 5.1

Table 5.1 - Total costs at corporate level and allocation to the DBNGP

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009
Total costs at corporate level	$6.7m	$6.7m	$6.9m	$7.1m	$7.3m	7.93	8.13	8.33	8.54	8.76
Proportion allocated to DBNGP	59.2%	59.3%	61.3%	60.3%	58.8%	55.6%	55.6%	55.6%	55.6%	55.6%
Corporate overheads	$4.0m	$3.9m	$4.2m	$4.3m	$4.3m	4.41	4.52	4.63	4.75	4.86

5.2 Allocation of Costs between Regulated and Unregulated Business Segments

The DBNGP operates only as a regulated business. There is no further allocation of marketing costs and corporate overheads to regulated and unregulated business segments.

5.3 Allocation of Costs between Services and Categories of Asset

The allocation of overhead and marketing costs is a part of the overall allocation of costs described in section 2.4.

6. INFORMATION REGARDING SYSTEM CAPACITY AND VOLUME ASSUMPTIONS

6.1 System Description

A comprehensive description of the DBNGP is set out in Appendix 1. This description will appear on the EBB and the Epic Energy website and will be updated from time to time.

6.2 Description of Pipeline Capabilities

The GTR's and the Transitional Regime used the tranche method to determine the DBNGP's firm full haul capacity on a seasonal basis. The capacity of the DBNGP varies with ambient operating conditions, with January being the lowest monthly capacity.

The firm capacity available in the DBNGP is based on the lowest monthly average capacity of existing shippers on the DBNGP.

The firm capacity available in the DBNGP has been calculated on the basis of deliveries downstream of CS9. Any additional capacity which is taken upstream of CS9 will result in a corresponding decrease of available capacity downstream of CS9.

The estimated capacity available in the DBNGP on any Day may vary depending on the actual ambient operating conditions.

The availability of compressor units on the DBNGP is an important factor in maintaining capacity in the DBNGP. Availability levels of 98% for 10MW units and 96% for LM500 units have been assumed in calculating the capacity in the DBNGP.

In addition, the DBNGP downstream of Kwinana Junction is essentially a series of laterals, each having differing levels of available capacity. As a result, the pipeline capacity is calculated at Kwinana Junction.

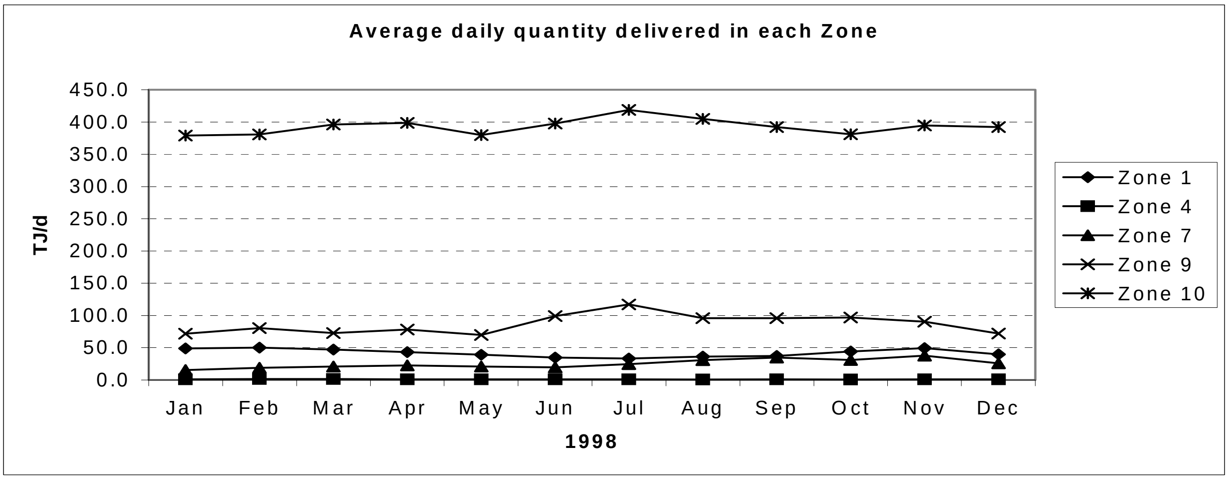
6.3 Average Daily and Peak Demands

Average daily quantities of gas delivered for the year ending 31 December 1998 are set out in Table 6.1 and Figure 6.1. They are based on a zonal approach consistent with the approach in the Access Arrangement.

Table 6.1 -
Average daily quantity delivered in each Zone –
Year ended 31 December 1998

	Jan TJ/d	Feb TJ/d	Mar TJ/d	Apr TJ/d	May TJ/d	Jun TJ/d	Jul TJ/d	Aug TJ/d	Sep TJ/d	Oct TJ/d	Nov TJ/d	Dec TJ/d
Zone 1	48.9	50.0	47.4	43.2	39.2	34.8	33.5	36.1	37.3	44.3	49.3	39.8
Zone 2	-	-	-	-	-	-	-	-	-	-	-	-
Zone 3	-	-	-	-	-	-	-	-	-	-	-	-
Zone 4	1.1	1.4	1.4	1.2	1.2	1.0	0.9	0.9	0.9	0.9	1.0	1.1
Zone 5	-	-	-	-	-	-	-	-	-	-	-	-
Zone 6	-	-	-	-	-	-	-	-	-	-	-	-
Zone 7	15.3	18.9	20.7	22.6	20.8	19.7	24.7	30.7	34.7	31.2	37.6	25.9
Zone 8	-	-	-	-	-	-	-	-	-	-	-	-
Zone 9	71.8	80.7	72.8	78.3	70.1	99.3	117.2	96.1	96.0	97.1	90.6	72.1
Zone 10	379.0	380.6	396.3	398.7	379.5	397.8	419.0	404.9	392.1	381.0	394.5	392.0

Figure 6.1

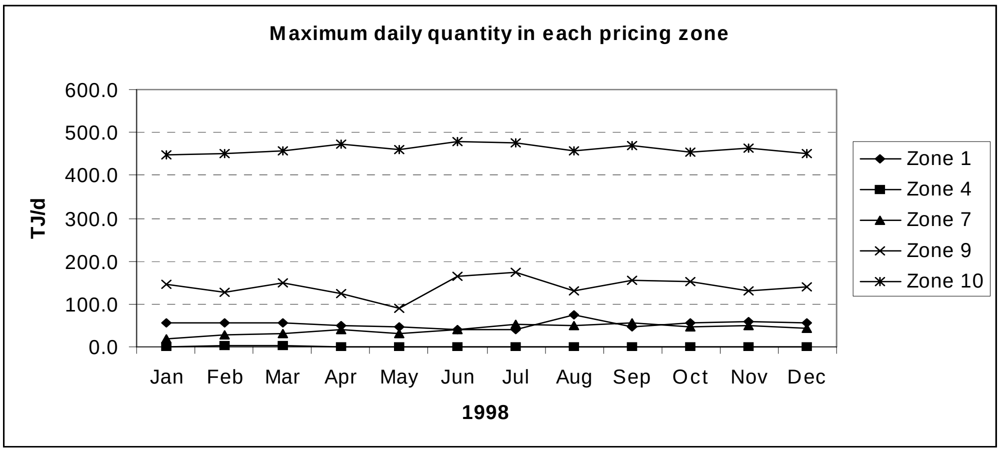


The maximum daily quantities of gas delivered by Zone for the year ended 1998 are set out in Table 6.2 and Figure 6.2.

Table 6.2 - Maximum daily quantity delivered in each pricing zone
Year ended 31 December 1998

	Jan TJ/d	Feb TJ/d	Mar TJ/d	Apr TJ/d	May TJ/d	Jun TJ/d	Jul TJ/d	Aug TJ/d	Sep TJ/d	Oct TJ/d	Nov TJ/d	Dec TJ/d
Zone 1	56.9	56.7	57.4	51.1	46.7	41.1	40.8	74.8	46.6	55.0	60.2	54.7
Zone 2	-	-	-	-	-	-	-	-	-	-	-	-
Zone 3	-	-	-	-	-	-	-	-	-	-	-	-
Zone 4	1.5	1.6	1.6	1.6	1.4	1.2	1.1	1.0	1.0	1.1	1.3	1.4
Zone 5	-	-	-	-	-	-	-	-	-	-	-	-
Zone 6	-	-	-	-	-	-	-	-	-	-	-	-
Zone 7	18.7	28.3	32.2	41.0	31.3	40.9	54.1	51.1	54.7	48.0	50.8	43.4
Zone 8	-	-	-	-	-	-	-	-	-	-	-	-
Zone 9	145.9	127.6	150.3	125.6	90.8	164.6	174.8	130.0	155.5	151.0	130.9	139.5
Zone 10	447.2	451.7	455.4	471.3	459.9	479.6	474.4	458.4	470.7	454.4	464.6	450.3

Figure 6.2



6.4 Annual Capacity and Volume Forecasts by Pricing Zone

Forecasts of capacity to be contracted during the Access Arrangement Period, and forecasts of the volumes of gas expected to be delivered using that capacity, are shown in Table 6.3 and 6.4 respectively. These forecasts are based on obligations that Epic Energy has to provide pipeline capacity under its current gas transportation contracts (that is, exempt, GTR and Transitional Regime contracts), and shippers' expectations of the utilisation of that capacity. No new demand for transportation of significant quantities of gas can be assumed with any confidence during the Access Arrangement Period.

Table 6.3 - Annual Capacity Forecasts by Pricing Zone
Annual Capacity Forecasts by Pricing Zone

Delivery point capacity	2000 TJ/d	2001 TJ/d	2002 TJ/d	2003 TJ/d	2004 TJ/d
Zone 1a	48.0	48.0	48.0	48.0	48.0
Zone 1b	0.0	0.0	0.0	0.0	0.0
Zone 2	0.0	0.0	0.0	0.0	0.0
Zone 3	0.0	0.0	0.0	0.0	0.0
Zone 4	1.5	1.5	1.5	1.5	1.5
Zone 5	0.0	0.0	0.0	0.0	0.0
Zone 6	0.0	0.0	0.0	0.0	0.0
Zone 7	18.6	18.6	18.6	16.8	15.6
Zone 8	0.0	0.0	0.0	0.0	0.0
Zone 9	57.0	57.0	57.0	57.0	57.0
Zone 10	469.7	467.9	469.8	479.0	485.9
Zones 1a – 10	594.8	593.0	594.8	602.3	608.0

Delivery point capacity	2005 TJ/d	2006 TJ/d	2007 TJ/d	2008 TJ/d	2009 TJ/d
Zone 1a	133.8	130.8	130.8	130.8	130.8
Zone 1b	0.0	0.0	0.0	0.0	0.0
Zone 2	0.0	0.0	0.0	0.0	0.0
Zone 3	0.0	0.0	0.0	0.0	0.0
Zone 4	0.0	0.0	0.0	0.0	0.0
Zone 4a	1.5	1.5	1.5	1.5	1.5
Zone 5	0.0	0.0	0.0	0.0	0.0
Zone 6	0.0	0.0	0.0	0.0	0.0
Zone 7	25.4	25.4	15.6	15.6	15.6
Zone 8	0.0	0.0	0.0	0.0	0.0
Zone 9	57.0	97.1	95.1	95.4	105.7
Zone 10	509.3	535.2	547.4	547.1	573.8
Zones 1a – 10	727.0	793.0	790.4	790.4	827.4

Table 6.4 - Annual Volume Forecasts by Pricing Zone

Table 6.4

Annual Volume Forecasts by Pricing Zone

Delivery point volumes	**2000 TJ/d**	**2001 TJ/d**	**2002 TJ/d**	**2003 TJ/d**	**2004 TJ/d**
Zone 1a	26.0	25.1	25.3	25.3	25.3
Zone 1b	0.0	0.0	0.0	0.0	0.0
Zone 2	0.0	0.0	0.0	0.0	0.0
Zone 3	0.0	0.0	0.0	0.0	0.0
Zone 4	1.5	1.5	1.5	1.5	1.5
Zone 5	0.0	0.0	0.0	0.0	0.0
Zone 6	0.0	0.0	0.0	0.0	0.0
Zone 7	17.6	19.6	19.8	18.1	16.8
Zone 8	0.0	0.0	0.0	0.0	0.0
Zone 9	76.0	77.4	78.4	79.4	80.4
Zone 10	411.7	416.6	417.0	428.0	434.1
Zones 1a – 10	532.8	540.2	542.0	552.3	558.1

Delivery point volumes	**2005 TJ/d**	**2006 TJ/d**	**2007 TJ/d**	**2008 TJ/d**	**2009 TJ/d**
Zone 1a	124.8	124.8	121.8	121.8	121.8
Zone 1b	0.0	0.0	0.0	0.0	0.0
Zone 2	0.0	0.0	0.0	0.0	0.0
Zone 3	0.0	0.0	0.0	0.0	0.0
Zone 4	0.0	0.0	0.0	0.0	0.0
Zone 4a	1.0	1.0	1.0	1.0	1.0
Zone 5	0.0	0.0	0.0	0.0	0.0
Zone 6	0.0	0.0	0.0	0.0	0.0
Zone 7	24.3	24.4	14.7	11.5	14.8
Zone 8	0.0	0.0	0.0	0.0	0.0
Zone 9	67.2	89.5	97.1	84.6	102.6
Zone 10	456.4	464.5	528.5	532.0	546.1
Zones 1a – 10	673.7	704.2	763.1	750.9	786.3

6.5 Total Number of Customers in Each Pricing Zone, Service and Category of Asset

The delivery points in each pricing zone, and the number of shippers at each point, are shown in Table 6.5.

Table 6.5 - Numbers of delivery points

Zone	Delivery point	Number of shippers
1a	Hamersley Iron	2
	Robe River	2
	Port Hedland	0
1b		
2		
3		
4		
4a	Carnarvon Power Station	1
5		
6	Eradu Road	1
7		
	Geraldton (Nangetty Road)	1
	Mungarra	1
	Pye Road	1
	Mondarra	2
	Mount Adams Road	1
	Eneabba	1
8		
9	Muchea	1
	Pinjar	2
	Della Road	1
	Ellenbrook	1
	Harrow Street	1
	Caversham	1
	Welshpool	1
	Forrestdale	1
	Russell Road	1
10	Wesfarmers LPG	1
	Australian Gold Reagents	1
	Alcoa Kwinana	1
	Kwinana Power Station	2
	Barter Road/HiSmelt	1
	Mission Energy Cogeneration	3
	Kwinana Beach Road	1
	Rockingham	1
	WMC	1
	Pinjarra	1
	Alcoa Pinjarra	1
	Oakley Road	1
	Harvey	1
	Worsley	1
	South West Cogeneration	1
	Kemerton	1
	Clifton Road	1

7. INFORMATION REGARDING KEY PERFORMANCE INDICATORS

7.1 Introduction

Attachment A to the Code requires Epic Energy to provide information regarding key performance indicators. More specifically, the Code seeks information on:

(a) Industry KPI's used by the Service Provider to justify "reasonably incurred costs"; and

(b) Service provider's KPI's for each pricing zone, service or category of asset.

It is Epic Energy's view that there are no useful comparators of pipelines in Australia. This is borne out by the lack of key performance measures for operating pipelines either by the AGA or APIA.

Firm Services for pipelines that are currently covered in Australia vary in content and degree of service.

7.2 Key Performance Measures for Pipelines

Due to the lack of industry comparators for pipeline performance and evidenced by the lack of information available from the APIA or AGA peak gas industry bodies, Epic proposes the following KPI to measure its 'reasonably incurred costs'.

Level of interruption to its Firm Service

The firm capacity available in the DBNGP is based on the lowest monthly average capacity of existing shippers on the DBNGP.

Epic proposes to measure its performance in the delivery of the total full haul average capacity downstream of CS9.

It will not interrupt this volume transferred downstream of CS9 to more than 1% of MDQ per annum

In addition, as Epic has designed and will operate the services to a target level of availabilities that will ensure Firm Service does not get interrupted more than 1% of MDQ in a year. [Availability is defined as out of service hours over available hours]

It will report on the availability of the compressors as follows:

Availability of large units on average will be 98%
Availability of small units will be 96%

(b) **Using KPIs in setting price controls**

To develop reliable benchmark information, the appropriate cost and accounting data for all companies in the comparison group must be captured in a consistent manner, over an extended period of time. In addition, appropriate adjustments must be made for differences in companies' physical characteristics, including but not limited to, the ability to trade-off between capital and operating expenditures. For example, distinguishing factors that must be taken into account include:

- pipeline design, construction and operation;
- the grade of steel used in construction and the protection mechanisms;
- the operating pressure;
- impact on service standards in the event of a compressor failure;
- management of the impact of operational difficulties; and
- the size of the market served.

In light of the above, Epic Energy suggests that there are too many differences of a geographic, historic, political, operational and physical nature in the Australian pipeline sector, to permit benchmarks to be used to actually set the level of allowable costs in the business.

(b) **International Comparators**

Using international rather than domestic comparators is not a solution as was concluded by regulators in the U.K. For example, U.S. transmission companies tend to have large differences in environmental and physical characteristics, e.g. they are much more integrated within networks than is the case in Australia.

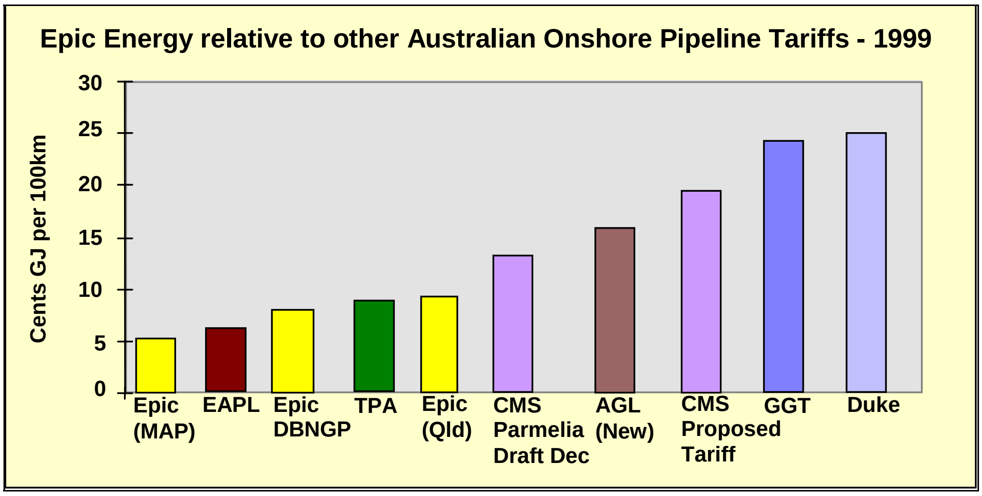
(c) **Pipelines in Australia**

Figure 7.1 shows that Epic Energy's tariffs are amongst the most competitive in Australia on a pipeline kilometre basis.

However, The figure cannot show the true cost to maintain and operate a gas transmission pipeline as key data such as geographic location, number, size and location of compressors, geographic location of main customers and so on are not reflected in that data.

The DBNGP is located in some of the most remote and culturally significant areas in Australia, as well as operating 10 compressor stations. The cost to operate and maintain compressor facilities adds significantly to a pipeline operating and maintenance costs.

Figure 7.1 -
Comparison of Transmission Tariffs



7.3 Conclusion

In summary, it is Epic Energy's view that the requirements of Category 6 of Attachment A of the Code should be modified to enable pipelines to develop quality of service standards and supporting measurement data. This would have the following advantages:

- Category 6 information would be more useful to interested parties than the present cost comparisons which are only a partial and potentially misleading analysis;
- Over time, Access Arrangements would begin to find consistent national service standards which reflect the level of the Reference Tariffs;
- Interested parties and regulators would be able to track quality of service performance through the period of the access arrangement; and
- A framework could be developed for understanding the link between asset and operating cost requirements, service levels and Reference Tariffs.

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

APPENDIX 1

PROPOSED DBNGP SYSTEM:
DESCRIPTION OF THE GAS TRANSMISSION SYSTEM AS AT 1 JANUARY 2000

Revised Proposed Access Arrangement Information
8 August 2003

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TABLE OF CONTENTS

1. INTRODUCTION

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 DBNGP's receipt points, delivery points and notional delivery points.

Section 3 describes the major component parts of the DBNGP.

Section 4 provides the route map for the DBNGP.

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

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

For the purposes of this System Description:

“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 Epic Energy under the Access Contract. Table 1 defines each of the receipt points in the gas transmission system.

“delivery point” means a flange or joint, notional delivery point or other point specified in an Access Contract as a point at which Epic Energy delivers gas to the shipper under the Access contract. Table 2 defines each of the delivery points.

“notional delivery point” means the point for a distribution sub-network at which the Shipper has Delivery Point MDQ in respect of that sub-network. Each notional delivery 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 serve to identify points of branching from the main pipeline.

	Inline metering facility
KJ-A	Kwinana Junction Meter Station M2A
•	Compressor Stationn
PS	Power Station

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

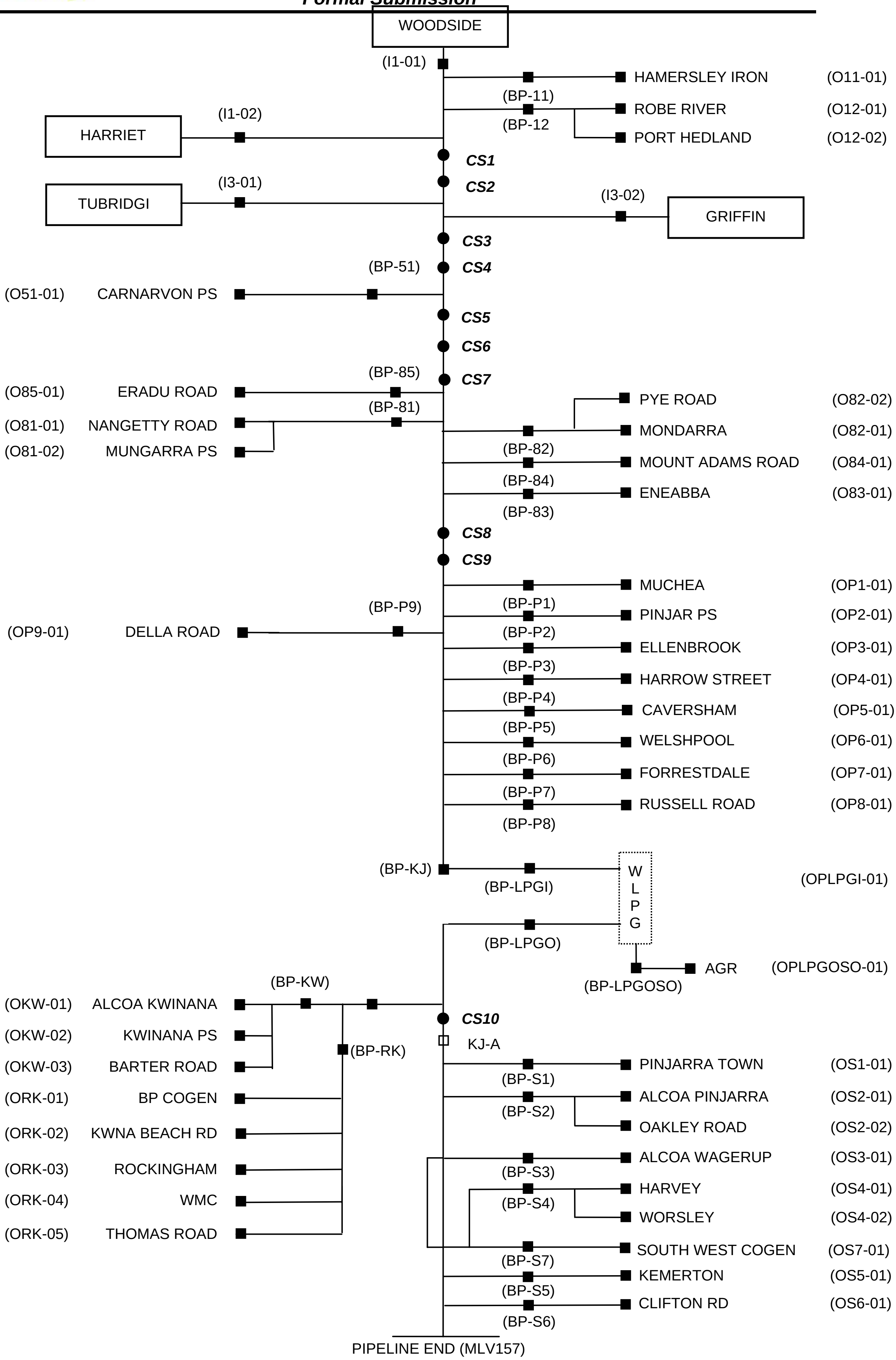
WOODSIDE
(I1-01)
HAMERSLEY IRON (O11-01)
(BP-11)
ROBE RIVER (O12-01)
(BP-12
PORT HEDLAND (O12-02)
HARRIET
(I1-02)
CS1
CS2
TUBRIDGI
(I3-01)
(I3-02)
GRIFFIN
CS3
CS4
(BP-51)
(O51-01) CARNARVON PS
CS5
CS6
(BP-85)
CS7
(O85-01) ERADU ROAD
(BP-81)
(O81-01) NANGETTY ROAD
(O81-02) MUNGARRA PS
PYE ROAD (O82-02)
MONDARRA (O82-01)
(BP-82)
MOUNT ADAMS ROAD (O84-01)
(BP-84)
ENEABBA (O83-01)
(BP-83)
CS8
CS9
MUCHEA (OP1-01)
(BP-P9)
(BP-P1)
PINJAR PS (OP2-01)
(OP9-01) DELLA ROAD
(BP-P2)
ELLENBROOK (OP3-01)
(BP-P3)
HARROW STREET (OP4-01)
(BP-P4)
CAVERSHAM (OP5-01)
(BP-P5)
WELSHPOOL (OP6-01)
(BP-P6)
FORRESTDALE (OP7-01)
(BP-P7)
RUSSELL ROAD (OP8-01)
(BP-P8)
(BP-KJ)
(BP-LPGI)
W L P G
(OPLPGI-01)
(BP-LPGO)
AGR (OPLPGOSO-01)
(BP-LPGOSO)
(BP-KW)
(OKW-01) ALCOA KWINANA
CS10
(OKW-02) KWINANA PS
KJ-A
(BP-RK)
(OKW-03) BARTER ROAD
PINJARRA TOWN (OS1-01)
(BP-S1)
(ORK-01) BP COGEN
ALCOA PINJARRA (OS2-01)
(BP-S2)
(ORK-02) KWNA BEACH RD
OAKLEY ROAD (OS2-02)
(ORK-03) ROCKINGHAM
ALCOA WAGERUP (OS3-01)
(BP-S3)
(ORK-04) WMC
HARVEY (OS4-01)
(BP-S4)
WORSLEY (OS4-02)
(ORK-05) THOMAS ROAD
SOUTH WEST COGEN (OS7-01)
(BP-S7)
KEMERTON (OS5-01)
(BP-S5)
CLIFTON RD (OS6-01)
(BP-S6)
PIPELINE END (MLV157)

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.
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.

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

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
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.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
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.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
Branching Point MLV122	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.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
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.
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.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
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.

TABLE 3 - GAS TRANSMISSION SYSTEM: NOTIONAL DELIVERY POINTS

NOTIONAL DELIVERY POINT	ASSOCIATED DELIVERY POINT/S	TRANSMISSION 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 Della Road	OP4-01 OP5-01 To be confirmed
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

NDP - “name”   Notional delivery point - “name”

3. DESCRIPTION OF THE DBNGP: COMPONENT PARTS

The principal component parts of the gas transmission system 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.

General Description

The gas transmission system 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 gas transmission system 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 gas transmission system. 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:

- **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.

- **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 (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.

- **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.

TABLE 4 - MAIN LINE: PHYSICAL CHARACTERISTICS

SECTION:	**DAMPIER TO KWINANA JUNCTION**	
Length Nominal size Wall thickness Steel type MAOP	1,311.2km 660mm 8.74mm API 5LX 65 DSAW 8,480kPa (gauge)	87.4km 660mm 12.7mm API 5LX 65 DSAW 8,480kPa (gauge)
SECTION:	**KWINANA JUNCTION - WLPG PLANT – KWINANA JUNCTION**	
Length Nominal size Wall thickness Steel type MAOP	6.4km 660mm 14.27mm API 5LX 65 DSAW 8,480kPa (gauge)	
SECTION:	**KWINANA JUNCTION TO MAIN LINE VALVE 141**	
Length Nominal size Wall thickness Steel type MAOP	10.8km 500mm 7.94mm API 5LX 65 DSAW 6,890kPa (gauge)	
SECTION:	**MAIN LINE VALVE 141 TO MAIN LINE VALVE 150**	
Length Nominal size Wall thickness Steel type MAOP	73.5km 500mm 5.56mm API 5LX 65 DSAW 6,890kPa (gauge)	
SECTION:	**MAIN LINE VALVE 150 TO MAIN LINE VALVE 154**	
Length Nominal size Wall thickness Steel type MAOP	23.9km 250mm 4.80mm API 5LX 52 ERW 6,890kPa (gauge)	
SECTION:	**MAIN LINE VALVE 154 TO MAIN LINE VALVE 157A**	
Length Nominal size Wall thickness Steel type MAOP	16.9km 200mm 4.80mm API 5LX 52 ERW 6,890kPa (gauge)	

TABLE 5 - GAS TRANSMISSION SYSTEM LATERALS

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)	
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)	
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)	

TABLE 5 - GAS TRANSMISSION SYSTEM LATERALS (CONTINUED)

RUSSELL ROAD			
Length Nominal size Wall Thickness Steel Type MAOP	7.3km 300mm 9.5mm API 5LX 46 ERW 6,890kPa (gauge)		
KWINANA WEST			
Length Nominal size Wall Thickness Steel Type MAOP	2.0km 500mm 7.9mm API 5LX 65DSAW 6,890kPa (gauge)	2.8km 350mm 9.5mm API 5LX 52 ERW 6,890kPa (gauge)	1.5km 200mm 8.7mm API Grade B ERW 6,890kPa (gauge)
ROCKINGHAM			
Length Nominal size Wall Thickness Steel Type MAOP	3.2km 300mm 9.5mm API 5LX 46 ERW 6,890kPa (gauge)	2.6km 150mm 6.4mm API 5L Grade B ERW 6,890kPa (gauge)	
KNC/BP (Part of Rockingham Lateral Located Downstream of Mason Road Delivery Station)			
Length Nominal size Wall Thickness Steel Type MAOP	1.6km 250mm 9.3mm API 5LX 42 ERW 6,890kPa (gauge)		
COGEN (Part of Rockingham Lateral Located Downstream of Cogen Delivery Station)			
Length Nominal size Wall Thickness Steel Type MAOP	0.9km 200mm 8.2mm API 5LX 42 ERW 6,890kPa (gauge)		
TIWEST COGENERATION LATERAL (Part of Rockingham Lateral)			
Length Nominal size Wall Thickness Steel Type MAOP	0.58km 150mm 7.1mm API 5LX 42 ERW 6,890kPa (gauge)		

TABLE 5 - GAS TRANSMISSION SYSTEM LATERALS (CONTINUED)

ALCOA PINJARRA		
Length Nominal size Wall Thickness Steel Type MAOP	2.5km 300mm 7.1mm API 5L Grade B ERW 6,890kPa (gauge)	2.9km 300mm 9.5mm API 5LX 52 ERW 6,890kPa (gauge)
ALCOA WAGERUP		
Length Nominal size Wall Thickness Steel Type MAOP	8.0km 350mm 7.1mm API 5L Grade B ERW 6,890kPa (gauge)	1.5km 350mm 9.5mm API 5LX 42 ERW 6,890kPa (gauge)
WORSLEY		
Length Nominal size Wall Thickness Steel Type MAOP	32.9km 250mm 4.8mm API 5LX 52 ERW 6,890kPa (gauge)	
SOUTH WEST COGENERATION LATERAL		
Length Nominal size Wall Thickness Steel Type MAOP	32.9km 450mm 6.35mm API 5LX 60 ERW 8,280kPa (gauge)	

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 summary of compression plant is presented in Table 6.

Additional gas turbines are currently being installed at CS2, CS4 and CS7 as part of Epic Energy's Stage 3a upgrade to the DBNGP. These new turbines should be installed and commissioned between January and June 2000

TABLE 6 - COMPRESSOR STATIONS

COMPRESSOR STATION	DISTANCE FROM DAMPIER (KM)	GAS TURBINE DRIVER	
1	137.2	Solar Mars 12600hp	(9MW)
2	272.1	General Electric Model LM500	(4MW)
3	409.3	Unit 1: Solar Mars 12600hp Unit 2: General Electric Model LM500 (4MW)	(9MW)
4	546.9	General Electric Model LM500	(4MW)
5	684.8	Unit 1: Solar Mars 12600hp Unit 2: Solar Mars 12600hp	(9MW) (9MW)
6	824.9	Unit 1: General Electric Model LM500 Unit 2: Nuovo Pignone PGT10	(4MW) (10MW)
7	966.6	General Electric Model LM500	(4MW)
8	1114.1	Unit 1: Solar Mars 12600hp Unit 2: Solar Mars 12600hp	(9MW) (9MW)
9	1256.8	Nuovo Pignone PGT10	(10MW)
10	1402.3	Unit 1: Solar Centaur 4700hp Unit 2: Solar Centaur 4700hp	(3.5MW) (3.5MW)

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.

Delivery Point Facilities and Receipt Point Facilities

Epic Energy owns and operates Delivery Point Facilities on the DBNGP. Receipt Point Facilities are located upstream of the receipt points to the DBNGP and are owned and operated by parties other than Epic Energy.

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

(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.

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. PIPELINE ROUTE MAPS

Pipeline route maps are provided as Appendix 3.

DAMPIER TO BUNBURY NATURAL GAS PIPELINE

APPENDIX 2

BRATTLE GROUP REPORT ON COST OF CAPITAL

Revised Proposed Access Arrangement Information
8 August 2003

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DAMPIER TO BUNBURY NATURAL GAS PIPELINE

APPENDIX 3

DBNGP MAPS

Revised Proposed Access Arrangement Information
8 August 2003

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DAMPIER TO BUNBURY NATURAL GAS PIPELINE

APPENDIX 4

BRATTLE GROUP REPORT ON REGULATORY MODEL FOR THE DBNGP

Revised Proposed Access Arrangement Information
8 August 2003

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