15 December 1999

1. INTRODUCTION

1.1 This Access Arrangement Information is submitted by Epic Energy in support of its Access Arrangement lodged with the Regulator on the same date.

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

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 GTR's 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.

Epic Energy's successful bid for the DBNGP of $2.407 billion 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 subsection 2.2 of this Access Arrangement Information. 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 of this Access Arrangement Information.

(b) **Non Reference Services**

In addition to the Reference Service, Epic Energy is prepared to negotiate Non-Reference Services. Some of these Services which Epic Energy believes may be interest to shippers are Secondary Market Service, Seasonal Service and Park and Loan Service. These services will be offered as rebateable services. Other Non-Reference Services may also be offered as rebateable services. The Non-Reference Services offered by Epic Energy are intended to cater to prospective shippers on an individual basis.

(i) **Secondary Market Service**

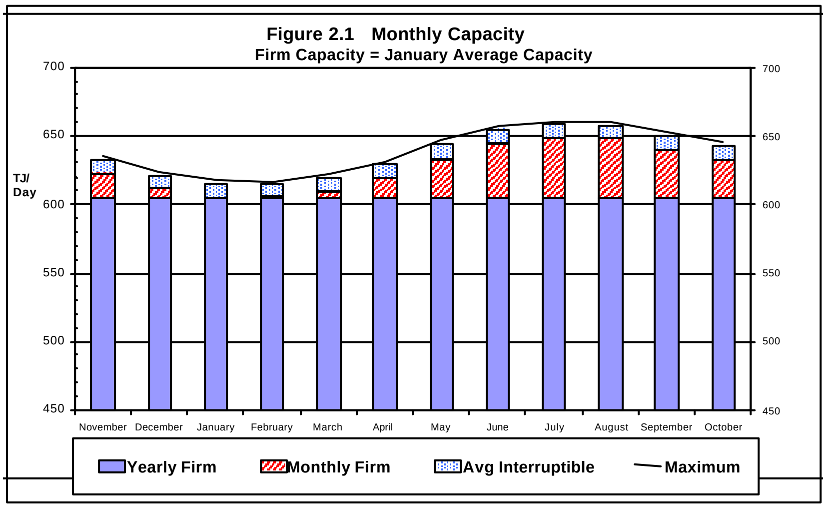
Epic Energy supports a secondary, or "spot", market for gas using unutilised capacity on the DBNGP. Shippers with unutilised Firm Service capacity will be able to "post" all or any part of that unutilised capacity for a day in the Secondary Market, and sell it to Approved Third Parties on a firm basis.

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.

(c) In addition to the rebateable 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 10 Zones for pricing purposes; 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 10 pricing zones. 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
1 Subzone 1a	30 km downstream of Dampier receipt point	30 km	Hamersley Iron Robe River Port Hedland
1 Subzone 1b	1 km downstream of CS2 downstream isolating valve (MLV 30)	244 km	
2	1 km downstream of CS3 downstream isolating valve (MLV 42)	137 km	

Zone	Downstream Zone Boundary	Zone Length	Delivery Points In Zone
3	1 km downstream of CS4 downstream isolating valve (MLV 54)	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 CS6 downstream isolating valve (MLV 78)	140 km	
6	1 km downstream of CS7 downstream isolating valve (MLV 90)	142 km	
7	1 km downstream of CS8 downstream isolating valve (MLV 102)	147 km	Geraldton (Nangetty Road) Eradu 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

Zone	Downstream Zone Boundary	Zone Length	Delivery Points In Zone
			Main line South: Alcoa Pinjarra Oakley Road Alcoa Wagerup Harvey Worsley South West Cogeneration Kemerton Clifton Road

Zone 1, which has two subzones (1a and 1b), is a gas production/gathering zone. All users of the Reference Service supply gas into the DNBGP at receipt points located within Zone 1.

Subzone 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 Subzone 1a. Gas is delivered from the pipeline, into the Pilbara region of Western Australia, from delivery points in Subzone 1a.

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

Zones downstream of Zone 1 (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 Tarff comprises a multi-part tariff as follows:

(i) **Gas Receipt Charge**

The Gas Receipt Charge payable by a shipper is the product of the Gas Receipt Charge rate and the Shipper's MDQ.

(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 of this Access Arrangement Information. Determination of the Reference Tariff is set out in section 2.5.

(e) **Gas Quality**

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.

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

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
Forecast Total Costs of Providing Services
Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m
Return on capital base					
Physical asset account					
Pipeline	235.89	235.94	235.97	235.99	236.04
Compressor stations	39.51	41.80	42.27	42.75	42.93
Metering	3.24	3.24	3.25	3.25	3.26
Other assets	9.55	10.15	10.76	11.47	12.07
Deferred recovery account	0.00	14.89	29.88	46.68	64.46
Depreciation					
Physical asset account					
Pipeline assets	0.03	0.03	0.04	0.04	0.05
Compressor stations	0.32	0.36	0.40	0.45	0.50
Metering	0.01	0.01	0.01	0.01	0.01
Other assets	0.03	0.04	0.05	0.06	0.06
Non-capital costs					
Pipeline maintenance	10.64	10.49	10.77	11.08	11.43
Compressor maintenance	3.63	3.73	5.83	6.39	5.77
Compressor fuel	13.05	13.95	14.28	15.47	16.34
Other costs	11.80	13.11	13.85	13.20	13.29
Total	327.70	347.74	367.36	386.83	406.20

The methods by which the return on the capital base and depreciation have been determined are set out in Section 3 of this Access Arrangement Information. The principal components of non-capital costs are set out in Sections 4 and 5.

2.4 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 2.3.

Table 2.3
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 *Recovery basis* Passthrough MDQ in each zone
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
Gas receipt charge rate *Recovers* Other assets return Other assets depreciation Other non-capital costs *Recovery basis* Delivery point MDQ
Delivery point charge *Recovers* Metering assets return by delivery point Metering assets depreciation by delivery point *Recovery basis* Fixed charge

Asset-related costs (asset return and depreciation) have been allocated directly to each of the component charges of the Reference Tariff. Epic Energy's asset register allows identification of asset costs by pipeline zone, by individual compressor station and by meter station. Asset returns and depreciation have therefore been determined by zone, by compressor station and by meter station.

Epic Energy captures some pipeline maintenance costs by region as the DBNGP is divided into four regions for maintenance management purposes. Some pipeline maintenance costs are captured only on a total system basis. Maintenance costs in each of these two groups have been allocated to zones on the basis of zone length either as a proportion of the length of the maintenance region in which the zone is located, or as a proportion of the total length of the pipeline.

Compressor station maintenance costs, and compressor station fuel costs, have been estimated for individual compressor stations, and these costs have, as appropriate, been allocated directly to each of the component charges of the Reference Tariff.

The costs recovered through the Pipeline Capacity Charge – pipeline asset return, pipeline asset depreciation, and pipeline maintenance costs – 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 – compression station asset return, compressor station asset depreciation, and compressor station maintenance costs 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.

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.

Costs which are not specifically identifiable as pipeline costs, compressor station costs, and metering costs are recovered through the Gas Receipt Charge. These costs, which include allocated corporate overheads, head office costs, the costs of system operation, and marketing costs, are semi-fixed costs. They do not vary directly with pipeline throughput. Nor do they vary with the distance over which gas is transported. They have been recovered on the basis of shippers' contracted capacity requirements in the DBNGP (and not on the basis of the zones in which that capacity is utilised).

2.5 Reference Tariff Determination

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 now determined from the forecast total cost of service set out in Table 2.2, using the cost allocation approach described in section 2.4, would be significantly higher than the tariff expected by the Government, and by shippers using the pipeline.

The tariff for Firm Service to delivery points in Zone 9 (between Compressor Station 9 and Kwinana Junction) would be approximately $1.41/GJ, and the tariff for Firm Service transportation to delivery points in Zone 10 would be approximately $1.62/GJ.

To satisfy its commitment to the Government of Western Australia at the time of the sale of the DBNGP, Epic Energy has made pro rata adjustments to the tariffs determined from its forecast total cost of providing services using the pipeline. These pro rata adjustments yield an initial Reference Tariff with the following attributes:

(a) for gas transportation from a receipt point in Zone 1 to a delivery point in Zone 9, (for a shipper with a load factor of 100 per cent), the aggregate of the tariff components described in section 2.2 is $1.00/GJ as at 1 January 2000; and

(b) for gas transportation from a receipt point in Zone 1 to a delivery point in Zone 10, (for a shipper with a load factor of 100 per cent), the aggregate of the tariff components described in section 2.2 is $1.08/GJ as at 1 January 2000.

(c) The components of the initial Reference Tariff are set out in the Tariff Schedule.

As discussed in section 3.4, the lowering of the Reference Tariff to a level consistent with the commitment given to the Government of Western Australia at the time of the DBNGP sale, is effected through a postponement of recovery of part of the capital costs until that recovery is warranted by growth in demand for gas transmission services.

2.6 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 3.4).

It should be noted that Threshhold 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

Section 8.11 of the Code provides bounds within which the initial capital base for an existing covered pipeline would "normally occur". However, the Code does not make these bounds mandatory, and in fact, in Section 8.10 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.

In the context of a competitive bidding process, the critical factor to be considered in establishing the initial capital base is the price Epic Energy paid for the DBNGP. This is consistent with Code requirements. Section 8.10(j) 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". However, other requirements in Section 8.10 of the Code also apply (such as paragraphs (c), (e), (f), (g) and (h)).

Accordingly, Epic Energy has established an initial capital base for the DBNGP which derives from its purchase price of $2.407 billion and from consideration of the circumstances surrounding the DBNGP sale by the State.

At the time of its acquisition of the DBNGP, Epic Energy engaged valuers Edward Rushton Australia Pty Limited to establish a detailed set of asset values consistent with the DBNGP purchase price plus other costs of acquisition not included in the purchase price.

This detailed set of asset values, adjusted for depreciation and new capital expenditure from the date of purchase to commencement of the Access Arrangement, is the initial capital base for the DBNGP.

3.2 Initial Capital Base

The initial capital base for the DBNGP is 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	0.00	0.24	33.20
Zone 1b	300.63	0.02	0.24	300.85
Zone 2	162.18	0.01	0.48	162.65
Zone 3	162.72	0.01	0.48	163.19
Zone 4	163.14	0.01	0.48	163.61
Zone 4a	67.49	0.00	0.00	67.49
Zone 5	165.72	0.01	0.48	166.19
Zone 6	167.52	0.01	0.48	167.99
Zone 7	188.80	0.01	0.71	189.50
Zone 8	168.83	0.01	0.48	169.30
Zone 9	228.94	0.01	0.48	229.41
Zone 10	262.74	0.01	27.73	290.45
Compression assets				
Compressor station 1	24.35	0.05	0.00	24.30
Compressor station 2	8.72	0.04	17.66	26.34
Compressor station 3	44.47	0.11	0.54	44.90
Compressor station 4	7.95	0.04	17.66	25.57
Compressor station 5	45.48	0.09	0.00	45.39
Compressor station 6	48.79	0.08	1.25	49.96
Compressor station 7	6.96	0.03	17.66	24.59
Compressor station 8	45.85	0.09	0.54	46.30
Compressor station 9	47.44	0.05	3.76	51.15
Compressor station 10	0.00	0.00	13.91	13.91
Metering assets	26.53	0.01	2.39	28.90
Other assets				
Depreciable	65.45	0.07	13.99	79.37
Non-depreciable	5.82	0.00	0.00	5.82
Total	2,449.49	0.78	121.63	2,570.34

3.3 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 3.2. The economic life has been used to determine depreciation of the assets comprising the DBNGP.

Table 3.2
Economic Life and Average Remaining Life of DBNGP
At 1 January 2000

Asset Group	Economic Life (years)	Average Remaining Life (years)
Pipeline assets	100	86
Compression assets	57	49
Metering assets	71	63
Other assets	50	39

3.4 Depreciation

As described in section 3.2, 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 3.1. 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 capital expenditure on new facilities, return on the capital base 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 3.3

Table 3.3
DBNGP regulatory asset accounting

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m
Beginning of year balance					
Physical asset account	2,570.34	2,596.47	2,606.41	2,617.27	2,624.62
Deferred recovery account	0.00	132.83	266.52	416.29	574.92
Capital base	2,570.34	2,729.30	2,872.93	3,033.57	3,199.54
Return on capital base	288.20	306.02	322.13	340.14	358.75
Depreciation: physical asset account	0.39	0.44	0.49	0.55	0.62
Capital expenditure	26.51	10.38	11.35	7.90	3.16
Depreciation: deferred recovery account	-132.83	-133.69	-149.77	-158.63	-166.77
End of year balance					
Physical asset account	2,596.47	2,606.41	2,617.27	2,624.62	2,627.17
Deferred recovery account	132.83	266.52	416.29	574.92	741.69

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 and the non-capital costs, and to cover capital expenditure on new facilities. 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.

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 3.2. 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.

3.5 Return on Capital Base

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 is summarised in Table 2.2.

3.6 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 3.5.

Table 3.5
Forecast capital expenditure
Year ending 31 December

	2000 $m	2001 $m	2002 $m	2003 $m	2004 $m
Pipeline	0.44	0.33	0.21	0.44	0.18
Compressor stations	20.70	4.51	4.73	2.00	2.07
Metering	0.00	0.05	0.05	0.05	0.06
Other	5.38	5.48	6.35	5.42	0.86
Total	26.52	10.37	11.34	7.91	3.17

3.7 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

And are considered justified on the basis that:

- they are required to maintain the level of service being afforded on the DBNGP
- they aid in the provision of a lower cost of service particularly with the improved availability of equipment with less manpower requirements resulting from the re organisation of Operations
- they are required to maintain the safety (people, equipment and environment) and 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**

The stage 3A-enhancement program was initiated in 1998 following requests from shippers for additional capacity in the DBNGP. These capacities were requested by:

- Worsley Refinery
- South West Cogeneration Joint Venture
- CSBP
- Alcoa Wagerup Cogeneration Plant

To deliver this capacity an enhancement program on the DBNGP was implemented as follows:

To deliver the capacities at the required pressures to the south west loads:

- A 58-kilometre loop was installed between Wagerup West and Worsley Meter Station; and

- A new compressor station was constructed at CS 10 in Kwinana

This enhancement option was considered the most economical option compared to looping large sections up stream of Kwinana and the 58-kilometre loop from Wagerup West. The option provided the best combination of a lower capital investment but a higher operating cost where as looping only option would have resulted in a much higher capital investment but lower operating cost.

The second part of the enhancement was to increase the transport capability of the northern section of the DBNGP by:

- Increasing compression power at CS2, 4 and 7 with the installation of 3 new 10 MW capacity Solar Mars units at each site;

- Increasing the availability of compressors of new and existing compressor units at all compressor stations at CS1 to CS9;

- And the uprating of the existing Solar 90 units to 100 already installed between CS1 and CS9

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:

- The construction and commissioning of compressors at CS2 and CS7 at cost of $18.855M

- The final payments for CS10 at cost of $632,000

- Uprating of Solar Mars unit at CS5/2 at 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	$19.09m	0.26			
CS10	0.64				
Mars upgrade	0.71	0.73	1.49		
Control View		0.10			
Condition Mont		0.26			

(ii) **WLPG Heat Exchanger project**

The WLPG contract as prepared by AlintaGas required for the gas entry into the WLPG plant to be at no less than 10 degrees and no more than 40 degrees.

With the commissioning and operation of CS9 and the higher temperatures experienced into the plant, lower temperatures are being experienced into the plant and for 4 to 5 months of the year, gas is being delivered into the plant at lower than 10 degrees.

This project is to install a gas to gas heat exchanger inlet to the plant at a cost of $400,000

	2000	2001	2002	2003	2004
WLPG Heater	$0.40m				

(iii) **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	$0.61m				

(iv) **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		$0.16m	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		$0.21m	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**
		$0.05m	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		$0.05m	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

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		$0.03m	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	$0.06m				

(ii) **Flood Damage Mitigation**

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.

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

	2000	2001	2002	2003	2004
Flood mitigation		$0.05m	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.

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			$0.02m	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			$0.09m	0.09	0.09

(B) **10KW GEAs**

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

	2000	2001	2002	2003	2004
10KW GEA upgrades		$0.04m	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	$0.03m	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		$0.05m	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		$0.02m			

(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 is 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		$1.04m	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.

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	As above				
Upgrade R0-CS3		$0.21m			
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.

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

	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 developing 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.

This system is being 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	$2.43m				

(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
- An allocation has been made for the systems enhancement to Peoplesoft at $300,000

	2000	**2001**	**2002**	**2003**	**2004**
Novell Netware	$0.02m				
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 infra structure.

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

	2000	**2001**	**2002**	**2003**	**2004**
Information Management System	$0.51m				

(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		$0.08m			

(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 center 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	$0.10m				

(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		$0.26m	0.27	0.27	0.28

(ii) **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	$0.29m	0.05	0.05	0.05	0.06

(iii) **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	$0.20m	0.21	0.21	0.22	0.22

(iv) **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, batterys and power generation.

	2000	2001	2002	2003	2004
Emergency Response Communication Mobile		$0.06m			

(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 ware house $250,000

	2000	2001	2002	2003	2004
Buildings	$0.30m	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		$0.10m			

(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		$0.56m	1.60	1.64	1.68

3.8 Rates of Return on Equity and on Debt

As noted in section 3.5, 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.

Table 3.7
Determination of the Weighted Average Cost of Capital for the DBNGP

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]	6.40%	
Market risk premium	[7]	6.50%	
Cost of equity	[8]	13.90%	[6] + [5] x [7]
Cost of debt			
Risk free rate	[6]	6.40%	
Corporate debt premium	[9]	1.20%	
Cost of debt	[10]	7.60%	[6] + [9]
Post tax nominal WACC			
Company tax rate	[11]	36.00%	Input
Dividend payout ratio	[12]	70.00%	Input
Value of imputation credits	[13]	44.00%	Input
Post tax nominal WACC	[14]	8.00%	[4] x [8]/(1 - (1 - [12] x [13]) + [3] x [10] x (1 - [11])
Pre tax real WACC			
Inflation rate	[15]	2.50%	Input
Fisher equation	[16]	5.37%	(1 + [14])/(1 + [15]) - 1
Myers et al.	[17]	5.50%	[16] x (1 + [15])
Pre tax real WACC	[18]	8.60%	[17]/(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
Wages and salaries	9.92	10.17	10.42	10.68	10.95
Materials and services	10.84	11.86	14.19	14.15	13.84
Property taxes	0.05	0.05	0.05	0.06	0.06
Marketing	0.45	0.46	0.47	0.48	0.50
Corporate overheads	3.95	3.94	4.21	4.27	4.30
Gas used in operations	13.90	14.80	15.40	16.50	17.20
Total	39.11	41.28	44.74	46.14	46.84

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 the Harriet Joint Venture.

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 the Corporate and Shared Services ("CSS") unit within the group structure. The entire cost of CSS is allocated to other 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
Total costs at corporate level	$6.7m	$6.7m	$6.9m	$7.1m	$7.3m
Proportion allocated to DBNGP	59.2%	59.3%	61.3%	60.3%	58.8%
Corporate overheads	$4.0m	$3.9m	$4.2m	$4.3m	$4.3m

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 subsection 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.

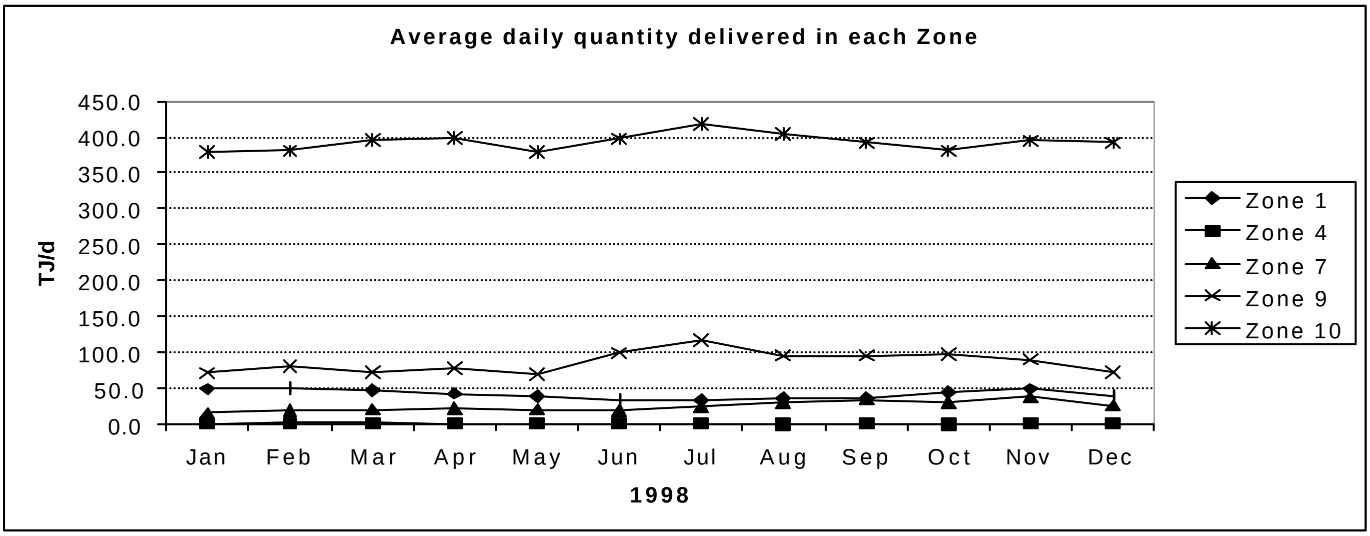
6.3 Average Daily and Peak Demands

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

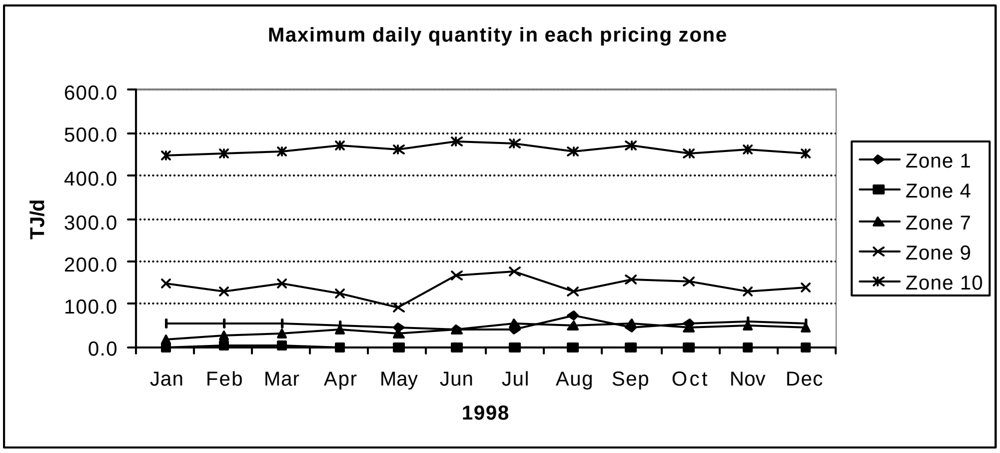


The maximum daily quantities of gas delivered by Zone for the year ended 1998 are set out in Table 6.2 and Figure 6.2.

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

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

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

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 Robe River Port Hedland	2 2 0
1b		
2		
3		
4		
4a	Carnarvon Power Station	1
5		
6		
7	Eradu Road Geraldton (Nangetty Road) Mungarra Pye Road Mondarra Mount Adams Road Eneabba	1 1 1 1 2 1 1
8		
9	Muchea Pinjar Della Road Ellenbrook Harrow Street Caversham Welshpool Forrestdale Russell Road	1 2 1 1 1 1 1 1 1
10	Wesfarmers LPG Australian Gold Reagents Alcoa Kwinana Kwinana Power Station Barter Road/HiSmelt Mission Energy Cogeneration Kwinana Beach Road Rockingham WMC Pinjarra Alcoa Pinjarra Oakley Road Harvey Worsley South West Cogeneration Kemerton Clifton Road	1 1 1 2 1 3 1 1 1 1 1 1 1 1 1 1 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 in Australia at this time, and it has therefore not sought to use KPI data in setting or justifying the proposed Reference Tariffs. It is hoped that in the future quality of service comparators will exist to enable meaningful comparison between separate pipeline systems and companies.

7.2 Key Performance Measures for Pipelines

(a) **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.

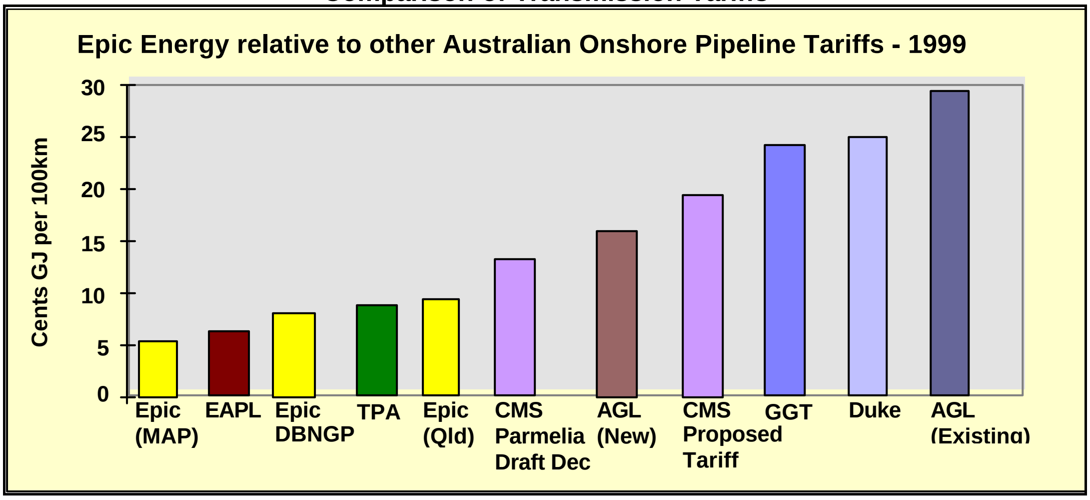
(c) **Pipelines in Australia**

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

However, The table 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.

Table 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

Submission Version
15 December 1999

Epic Energy (WA) Transmission Pty Ltd
ACN 081 609 190
Level 7
239 Adelaide Terrace
PERTH WA 6000
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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.

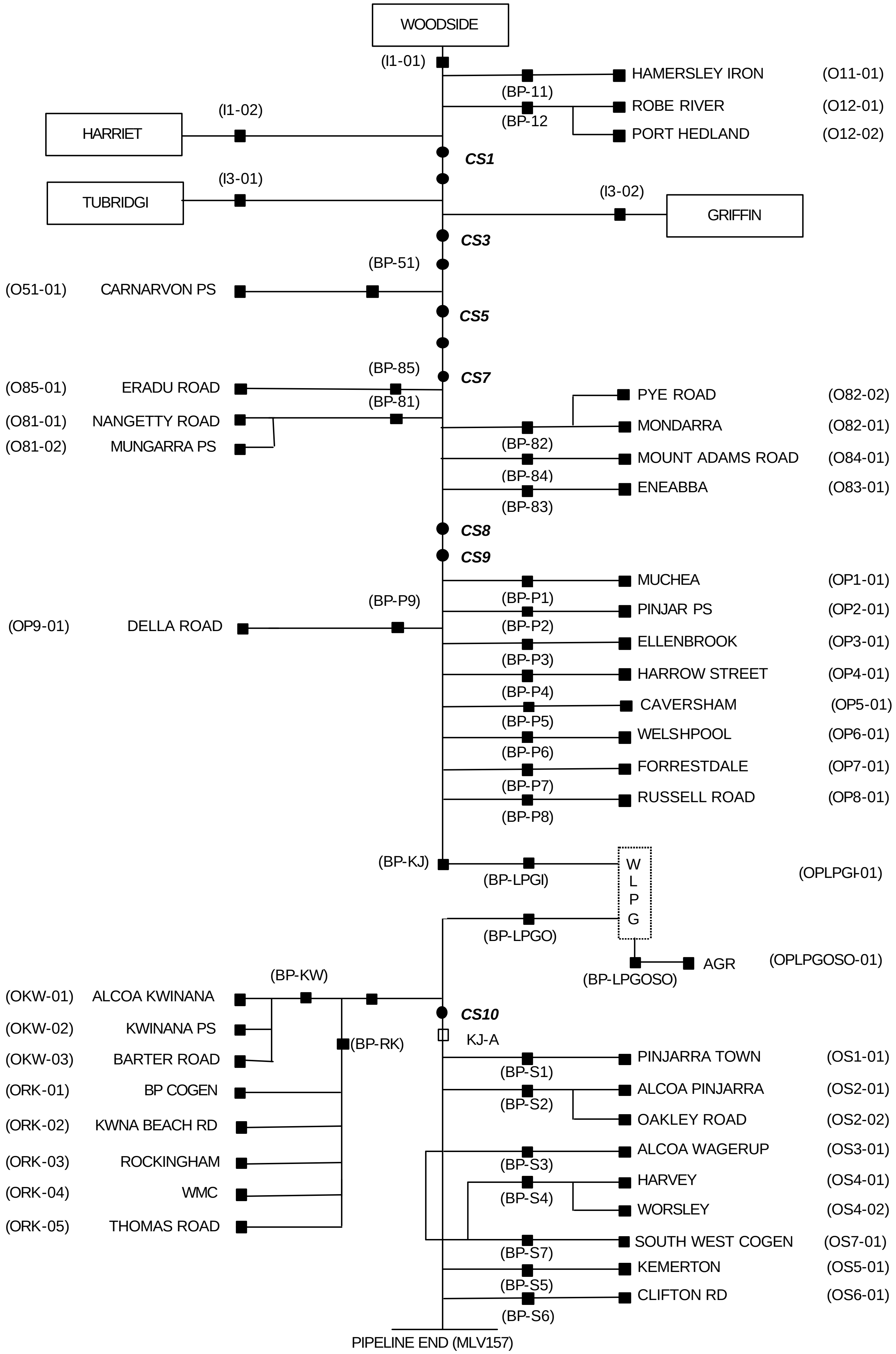
"notional delivery point" means the point for a distribution sub-network at which the Shipper has Delivery Point MDQ in respect of that sub-network. Each notional delivery point is defined in Table 3 which also shows the associated delivery points.

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

• CSn Compressor Station n
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
TUBRIDGI
(I3-01)
(I3-02)
GRIFFIN
CS3
(BP-51)
(O51-01) CARNARVON PS
CS5
(BP-85)
CS7
(O85-01) ERADU ROAD
(BP-81)
PYE ROAD (O82-02)
(O81-01) NANGETTY ROAD
MONDARRA (O82-01)
(O81-02) MUNGARRA PS
(BP-82)
MOUNT ADAMS ROAD (O84-01)
(BP-84)
ENEABBA (O83-01)
(BP-83)
CS8
CS9
MUCHEA (OP1-01)
(BP-P1)
(BP-P9)
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)
PINJARRA TOWN (OS1-01)
(OKW-03) BARTER ROAD
(BP-S1)
(ORK-01) BP COGEN
ALCOA PINJARRA (OS2-01)
(BP-S2)
(ORK-02) KWNA BEACH RD
OAKLEY ROAD (OS2-02)
ALCOA WAGERUP (OS3-01)
(ORK-03) ROCKINGHAM
(BP-S3)
HARVEY (OS4-01)
(ORK-04) WMC
(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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
Branching Point MLV93	BP-84	1054.211	This is a branching point located at the first insulating joint on the supply line to the meter station. The insulating joint is located in the MLV93 compound.
Mount Adams Road	O84-01	1054.216	Delivery point is at the first insulation joint located downstream of Mount Adams Road meter station located inside the MLV 93 compound.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
Branching Point MLV120	BP-P6	1359.664	This is a branching point located at the first reducer downstream of valves HV100A and HV100B inside the MLV120 compound.
Welshpool	OP6-01	1359.714	Delivery point is on the upstream side of the second delivery valve located downstream of the odorant injection facility.
Branching 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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
Kwinana Beach Road	ORK-02	1409.647	Delivery point comprises the upstream flange of the second valve located downstream of the pig receiver of the BP Kwinana lateral and the first insulation gasket downstream of the first valve located downstream of the pig receiver of the BP Kwinana lateral.
Rockingham	ORK-03	1410.857	Delivery point comprises the: i) upstream flange of the meter station delivery valve located downstream of the odorant injection facilities. ii) upstream flange of the second valve located downstream of the CSBP pipe.
WMC	ORK-04	1410.837	Delivery point comprises the upstream side of the second isolating valve located on the WMC boundary for the high pressure line and the insulation joint located upstream of the second isolation valve for the low pressure line.
Branching Point Kwinana West	BP-KW	1405.217	This is a branching point located at 500 to 300 reducer located upstream of valves KLV3 and KLV4.
Alcoa Kwinana	OKW-01	1410.557	Delivery point comprises the delivery flanges on the downstream side of the meter station delivery valves HV601A and HV601B.
Kwinana Power Station	OKW-02	1409.651	Delivery point is at the insulating gasket on the downstream side of the meter station delivery valve HV501A.
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.

LOCATION	POINT DESIGNATION	DISTANCE FROM DAMPIER (Pipeline kilometres)	DESCRIPTION
Branching Point South 4	BP-S4	1513.630	This is a branching point located at the first tee upstream of the insulation joint adjacent to MLV154 located inside the MLV154 compound.
Harvey	OS4-01	1522.096	Delivery point is at the upstream flange of the isolation valve located downstream of the odorant injection facility.
Worsley	OS4-02	1546.620	Delivery point is at the flange downstream of the insulation joint located downstream of the meter station delivery valve.
Branching Point South 7	BP-S7	1513.635	This is a branching point located on the tee at the junction of the SW loop and the Worsley Cogeneration lateral, below ground in the MLV154/155 compound.
South West Cogeneration	OS7-01	1546.000	Delivery point is at the first insulating flange located downstream of the meter skids.
Branching Point South 5	BP-S5	1525.104	This is a branching point located on the downstream side of the offtake valve HV1 located inside the Kemerton meter station.
Kemerton	OS5-01	1525.124	Delivery point is at the upstream flange of the valve located downstream of the insulation joint.
Branching Point South 6	BP-S6	1530.439	This is a branching point located at the first reducer downstream of MLV156 and situated in the Clifton Road compound.
Clifton Road	OS6-01	1530.457	Delivery point is at the first insulating joint located downstream of the odorant injection facility.

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	OP4-01 OP5-01
NGP - South Metro	Welshpool Forrestdale Russell Road	OP6-01 OP7-01 OP8-01
NGP - Barter Road	Barter Road	OKW-03
NGP - Rockingham	Rockingham	ORK-03
NGP - Pinjarra	Pinjarra Town Oakley Road	OS1-01 OS2-02
NGP - Harvey	Harvey	OS4-01
NGP - Kemerton	Kemerton	OS5-01
NGP - Clifton Road	Clifton Road	OS6-01

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	2.5km	2.9km
Nominal size	300mm	300mm
Wall Thickness	7.1mm	9.5mm
Steel Type	API 5L Grade B ERW	API 5LX 52 ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)
ALCOA WAGERUP		
Length	8.0km	1.5km
Nominal size	350mm	350mm
Wall Thickness	7.1mm	9.5mm
Steel Type	API 5L Grade B ERW	API 5LX 42 ERW
MAOP	6,890kPa (gauge)	6,890kPa (gauge)
WORSLEY		
Length	32.9km	
Nominal size	250mm	
Wall Thickness	4.8mm	
Steel Type	API 5LX 52 ERW	
MAOP	6,890kPa (gauge)	
SOUTH WEST COGENERATION LATERAL		
Length	32.9km	
Nominal size	450mm	
Wall Thickness	6.35mm	
Steel Type	API 5LX 60 ERW	
MAOP	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	(9MW) (4MW)
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

Submission Version
15 December 1999

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DAMPIER TO BUNBURY NATURAL GAS PIPELINE

APPENDIX 3

DBNGP MAPS

Submission Version
15 December 1999

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DAMPIER TO BUNBURY NATURAL GAS PIPELINE

PROPOSED ACCESS ARRANGEMENT INFORMATION UNDER THE NATIONAL ACCESS CODE

Submission Version
15 December 1999

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