GPU GasNet Pty Ltd
Application for Revision to Access Arrangement
Southwest Pipeline

Annexure 1

Description of Assets and Design Philosophy

1 Description of Assets

Prior to the completion of the Southwest Pipeline, the GPU GasNet transmission system consisted of two separate networks, namely the Principal Transmission System supplied from the offshore Bass Strait fields and from NSW, and the smaller Western Transmission System supplied from the onshore Otway basin fields.

The Southwest Pipeline connects these two systems via the Port Campbell reservoirs. The Port Campbell reservoirs include the Western Underground Storage Facility at Iona and a number of small fields in the Otway basin.

The two networks are shown schematically in Figure 1. A detailed map of the Southwest Pipeline is shown in Figure 2.

1.1 *Project Scope*

The cost of the Southwest Pipeline is $82.8 million. The project consisted of four major elements. These were:

1. construction of the 500 mm *Southwest Link* between Lara (on the Principal Transmission System) and Iona (at Port Campbell);
2. completion of the *Western System Link* between Iona and North Paaratte (on the Western Transmission System);
3. installation of associated flow and pressure control facilities; and
4. procurement and installation of the Iona compressors.

The project involved the following activities:

- construction of a large diameter pipeline between Lara and Iona, including the installation of a pigging station, line valves and related pipeline facilities;
- installation of associated pressure and flow control facilities at Brooklyn, Lara, and Iona;
- acquisition of an existing 150 mm diameter gathering line (the ‘old gathering line’) between Iona and North Paaratte and conversion into a licensed transmission pipeline;
- construction of 150 mm extensions of the ‘old gathering line’ at North Paaratte and Iona, and installation of associated valves and pigging facilities;
- installation of two compressors (one back-up) at Iona to facilitate gas flow between Iona and North Paaratte (to be completed by March 2001).

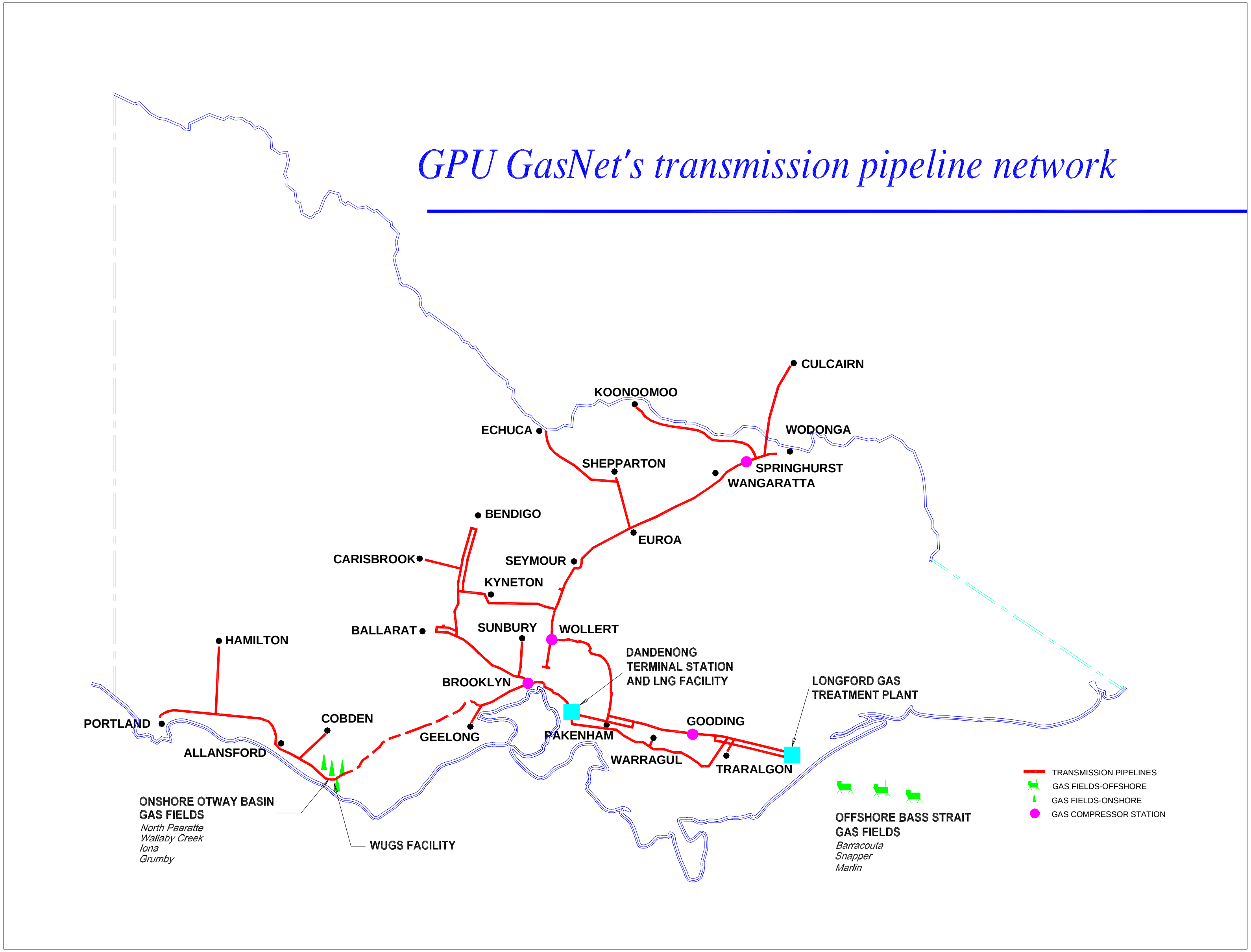
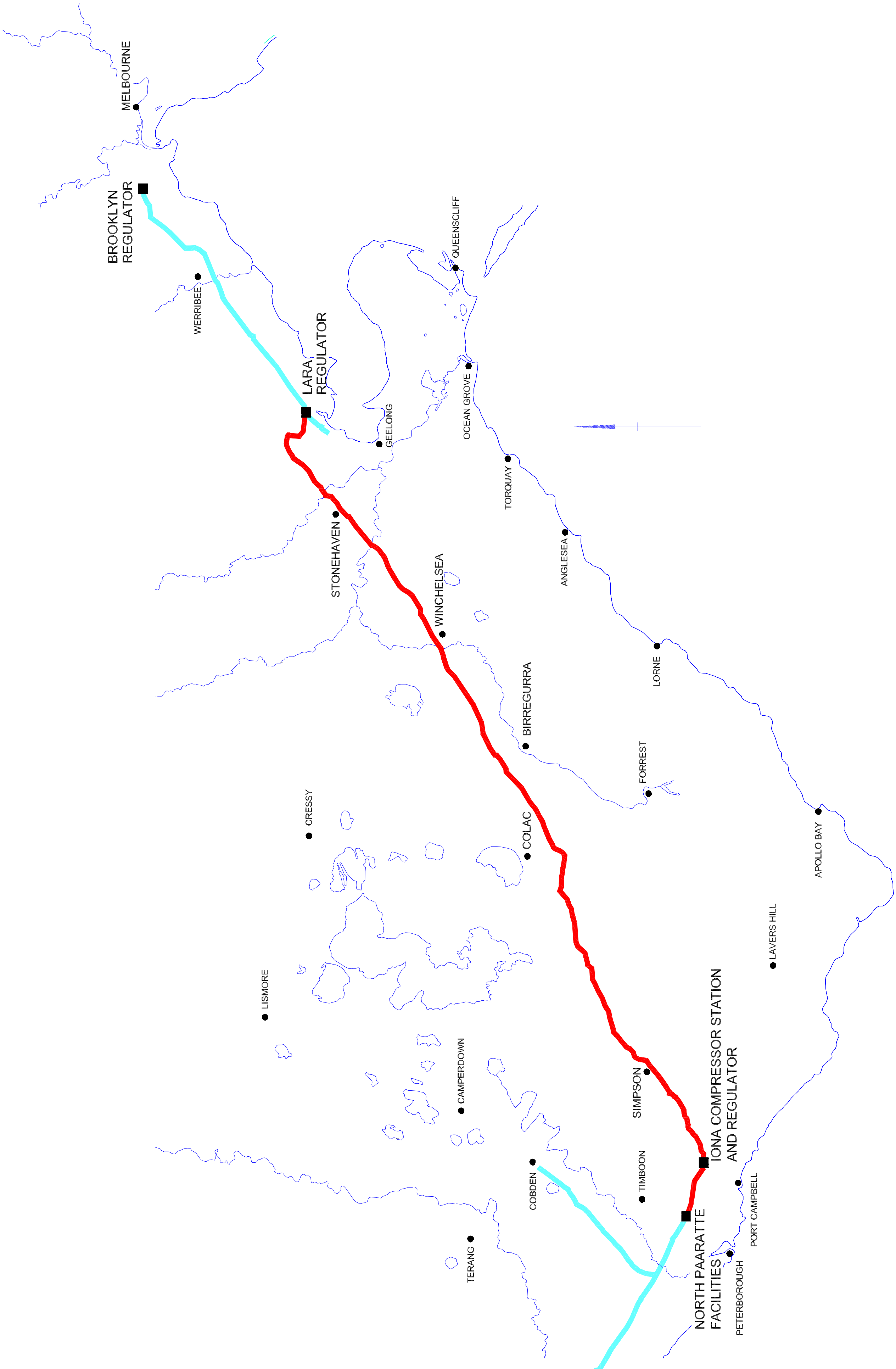


Figure 1 – GPU GasNet Gas Transmission Network

Annexure 1


MELBOURNE
BROOKLYN REGULATOR
WERRIBEE
QUEENSCLIFF
LARA REGULATOR
OCEAN GROVE
GEELONG
TORQUAY
STONEHAVEN
ANGLESEA
WINCHELSEA
LORNE
BIRREGURRA
FORREST
CRESSY
COLAC
APOLLO BAY
LAVERS HILL
LISMORE
CAMPERDOWN
SIMPSON
IONA COMPRESSOR STATION AND REGULATOR
TIMBOON
COBDEN
PORT CAMPBELL
NORTH PAARATTE FACILITIES
PETERBOROUGH
TERANG

1.2 *Southwest Link*

The Southwest Link is a 143.9 km, 500 mm diameter pipeline between Lara and Iona, constructed to a MAOP of 10,000 kPa. The Southwest Link commences on the Brooklyn to Corio pipeline, approximately 2 km south of Lara, where the bi-directional Lara city gate has been installed. The pipeline extends in a westerly and then south westerly direction, passing approximately 6 km south of Colac before reaching the Western Underground Storage ('WUGS') facility at Iona. At Iona, the pipeline links with the 150 mm diameter pipeline (the Western System Link) to North Paaratte.

Along the pipeline route, GPU GasNet has installed five line valves and associated bypass assemblies, three of which have the capability of being remotely actuated. At each line valve location, GPU GasNet has installed branch valves, to provide for ready access to future distribution connections for the supply of gas from the Southwest Link. Line valves are located at Gheringhap, Winchelsea, Birregurra, Colac and Simpson spaced at intervals of about 30 kms. A pigging station is installed at Iona.

1.3 *Western System Link*

In order to provide for the physical link to the Western Transmission System, GPU GasNet acquired the existing 150mm diameter gathering line (the 'old gathering line') between Iona and North Paaratte, under the terms of the Underground Gas Storage Share Sale Agreement. The 'old gathering line' has been converted to transport processed 'dry' gas rather than 'wet' field gas. It was declared to be a transmission pipeline under section 5(1) of the Gas Industry Act 1994 and, by virtue of an approved connection agreement entered into between VENCorp and GPU GasNet pursuant to section 5(3) of that Act, is subject to the Victorian MSO Rules as part of the "Gas Transmission System".

The 'old gathering line' has been extended at each end to provide a connection to the Southwest Link at Iona and to the Western Transmission System at North Paaratte. The extension at North Paaratte required a by-pass around the North Paaratte gas processing facilities owned by Santos and TXU. Pigging facilities have been installed at both Iona and North Paaratte.

The pipeline has a length of 7.8 km and is rated at a MAOP of 7,400 kPa.

1.4 *Associated Facilities*

(a) Background

Associated facilities located at Brooklyn, Lara and Iona are as follows:

- Brooklyn (on the site of the existing Brooklyn compressor station)
  - a city gate, a cross-over pressure limiter, and a gas pre-heater

- Lara
  - a city gate, and a gas pre-heater.

- Iona
  - a city gate, a compressor station, and associated valves and pipework.

(b) Design principles

(i) City gates

In order to meet licence requirements, wherever pipelines of differing MAOP are interconnected (for example, where a pipeline rated at 10,000 kPa connects with a pipeline rated at 7,390 kPa) GPU GasNet requires a city gate facility to be installed to protect the lower rated pipeline from the risk of over-pressurisation and consequent damage. To ensure safe and reliable operation at these points of inter-connection, GPU GasNet employs a (N-2) design philosophy along each regulator run. This means that each regulator run typically consists of an active regulator, a monitoring regulator and a slam shut valve. Uncontrolled gas flow through the regulator run would only occur after all three components failed.

City gates have been installed at the Brooklyn, Lara and Iona locations where a change in MAOP occurs between the upstream and downstream pipelines.

All city gates associated with the Southwest Pipeline project have provision for both pressure and flow control, and are capable of remote set-point operation from the VENCorp control room.

(ii) Pressure Limiters

In situations where two pipelines with the same MAOP interconnect, GPU GasNet may require installation of a pressure limiter to provide for gas pressure control. This is typically to reduce downstream pressures and avoid large pressure reductions at downstream off-takes to the distribution system, which would otherwise require installation of a heater at these points. As the risk of over pressurisation is not a concern in these situations, each regulator run has only one regulator installed.

A pressure limiter has been installed at Brooklyn between the Corio and Ballarat pipelines.

(iii) Heaters

Large pressure drops across city gates and pressure limiters can result in very cold gas temperatures (below zero) at the outlet of the installation, which can lead to the formation of gas condensates and, in extreme cases, brittle failure of the pipework. Heaters are installed to pre-heat the gas at those locations where the pressure drop across the station is likely to cause operational problems. GPU GasNet has installed a heater (of about 500 kW each) at both the Brooklyn and Lara city gate locations.

Depending on their size, heaters are expensive to both install and run. In order to minimise running costs, GPU GasNet has installed a temperature-triggered control system on each heater to avoid running the heaters unnecessarily and consuming excessive fuel gas. This system will help GPU GasNet minimise its fuel gas costs and better meet any station outlet temperature requirements.

(iv) RTU's

In essence, the Remote Telemetry Unit (RTU) acts as the brain of each facility by gathering information at regular intervals including, but not limited to, pressure, temperature and gas flow rates. It then processes the information and relays instructions back to each regulator to enable control of pressure and flow. The RTU is also used to communicate information to VENCorp as required under the MSO Rules.

Bristol RTU's are installed at each of the city gate locations – Brooklyn, Lara, and Iona. Each RTU facility is designed to have 100% redundancy.

(c) Brooklyn City Gate

During winter (when gas is withdrawn from the underground storage at Iona), the Brooklyn City Gate installation is required to transfer gas sourced at Iona from the 7,390 kPa Brooklyn-Corio pipeline into the 2,760 kPa Melbourne-Dandenong pipeline system. A remotely controlled pressure set-point can be used to control gas flow into the Melbourne system. The city gate can pass up to 300,000 sm^3/hr with an expected minimum pressure drop of 300 kPa, and a remotely controllable outlet set-point range of between 2,000 to 2,760 kPa.

The city gate installation consists of:

- four regulator runs, including 3 x 300mm active runs each capable of flowing 100,000 sm^3/hr, and 1 x 200mm redundant run. Space has been made available for two additional runs given the expected future growth in load; and
- one 500 kW heater.

(d) Brooklyn Cross-Over Pressure Limiter

During summer (when gas is injected into the underground storage during the 'refill season'), a pressure limiter is required to increase deliverability to Iona and to mitigate over-packing of the Brooklyn-Ballarat pipeline system. The limiter will pass up to 30,000 sm^3/hr with an expected minimum station pressure drop of 500 kPa. The remotely controllable outlet pressure has a set-point range of between 2,500 to 7,390 kPa. It will be used under the existing standard mode of operation for the Brooklyn station.

The installation consists of two 80 mm regulator runs, each capable of flowing 30,000 sm^3/hr, one of which is a back-up.

(e) Lara City Gate

During winter, this installation is required to control gas supply from the Southwest Link into the Geelong and Ballarat regional centres, and the Brooklyn city gate. It is also required to prevent over-pressurisation of the 7,390 kPa Brooklyn-Corio pipeline system. The Lara city gate regulates gas flow into the Brooklyn-Corio pipeline with a remotely controlled set-point pressure of 2,500 to 7,390 kPa. The city gate can pass up to 400,000 sm^3/hr with an expected minimum pressure drop of 250 kPa. The installation also has the capability to actuate on-off line valves. The design capacity is based on the known daily swing in the load.

The installation also has non-return valves to provide for uni-directional flow from the 7,390 kPa Brooklyn-Corio pipeline into the 10,000 kPa Southwest Link during the off-peak season..

The installation consists of:

- five regulator runs, including 4 x 300 mm active runs each capable of flowing 100,000 sm^3/hr, and 1 x 200 mm redundant run, and a 350 mm non-return valve arrangement which facilitates Underground Storage refill during summer; and
- one 500 kW heater.

(f) Iona City Gate

The Iona city gate is required to control gas supply from the 10,000 kPa Southwest Link into the Western System via the Western System Link, and to prevent over pressurisation of the 7,390 kPa Western System. The Iona city gate can pass up to 30,000 sm^3/hr, and regulates gas flow with a remotely controlled set-point pressure. The maximum set point pressure is 7,390 kPa, and the minimum set point is chosen so as to maintain an outlet temperature above -10^{o}C. The installation also has the capability to remotely actuate on-off line valves.

The installation has a non-return valve to provide for uni-directional flow from the Western System Link into the Southwest Link.

The installation consists of a 150 mm active regulator run, and a 100 mm redundant run, capable of flowing 30,000 sm^3/hr, and a non-return valve arrangement which provides for bi-directional gas flow capability.

(g) Iona Compressor Station

Two 300 kW reciprocating compressors (one active and one backup) are currently on hand and will be installed at the Iona city gate site in February 2001. These GPU GasNet compressors are quite distinct from the WUGS compressors installed at Iona for the purposes of injection and withdrawal from the underground storage fields. The compressor station is designed to compress gas flowing in a westerly direction from Iona to the Western System. With one active unit operating, the station can raise the pressure of gas supplied via the Southwest Link (a minimum of 3,800 kPa at Iona) to a pressure of up to 5,600 kPa, which is sufficient to supply the Western System with the design capacity of 16 TJ/day.

With reversing valves, the active compressor will be capable of compressing gas from the North Paaratte production station (at 5,840 kPa) for delivery into the Southwest Link at up to 10,000 kPa. This will enable sales of up to 12 TJ/day from the North Paaratte fields into the main Victorian market (or 19 TJ/day if both active and backup compressor units are operating).

2 Design Philosophy

The Southwest Pipeline serves a variety of distinct functions in the Victorian market. These include:

i) Connecting the underground storage at Iona to the Victorian market, thereby providing security of supply and enhanced competition in the market. This connection enables large quantities of gas to flow into Melbourne and Geelong during winter (and other times), but it must also allow for refill of the storage during summer.

ii) Connecting the North Paaratte fields to the Iona facility, and from there to the Victorian market.

iii) Providing a supplemental gas supply to the Western System from Longford or Moomba, thereby providing a secure back-up to the existing supply from North Paaratte, and enhancing competition in this system.

The design for this system requires knowledge of the pressures available at each receipt point, and the likely flow requirements. The available pressures may change over time as the gas fields are developed.

The design requirements were initially based on meeting the needs of the Winter '99 project. This project required a production capacity of at least 100 TJ/day from the Port Campbell region, and the ability to deliver this volume into Melbourne via the Southwest Pipeline, using the natural field pressures at the local wellheads.

Beyond 1999, the functional role of the Southwest Pipeline is defined by the pressure available from the underground storage, which is expected to be upgraded to at least 10,000 kPa by May 2001. This will increase the deliverability of the pipeline to 200 TJ/day.

The design philosophies for Winter '99 and beyond are discussed separately below. The sizing of the Southwest Pipeline is discussed in section 2.5.

2.1 *Winter '99 project*

In response to the Longford explosion, the Victorian Government implemented a number of ‘Winter ‘99’ initiatives, including committing GPU GasNet to accelerate the construction and commissioning of the Southwest Pipeline and related facilities by mid-May 1999. A direction pursuant to section 88A of the Gas Industry Act 1994 dated 4 January 1999 was issued directing TPA (now GPU GasNet) to enter into contracts and other arrangements required for construction and commissioning of the Southwest Pipeline and related facilities in order to improve security of gas supply to Victoria for winter 1999.

As a result of the Winter ’99 initiatives, at least 100 TJ/day of deliverability from the Port Campbell gas reservoirs was available to supplement Victorian gas supplies during winter 1999.

Most of the gas made available could be processed through the gas processing facility constructed at Iona by Western Underground Gas Storage Pty Ltd. ('WUGS'), a subsidiary of TXU. This gas consisted of:

- 60 TJ sourced directly from the Iona reservoir (owned by WUGS);
- 25 TJ of wet gas sourced from Boral Energy from the North Paaratte reservoir; and
- approximately 15 TJ of wet gas sourced from Santos.

As a separate project, WUGS constructed a new 300 mm pipeline between North Paaratte to Iona to carry wet gas for processing to the WUGS plant at Iona.

An additional 10 TJ/day of gas processed through the North Paaratte Production Station (NPPS) could be transported as dry gas via the 150 mm Western System Link to Iona and the Southwest Link.

Figure 2 shows a schematic of the facilities installed during the Southwest Pipeline project.

The North Paaratte dry gas was available at a pressure of 6,500 kPa, which was sufficient to enable this gas to flow to Iona where it joined gas from the Iona processing plant provided at a pressure of 6,000 kPa. At a pressure of 6,000 kPa, up to 130 TJ/day of gas could be transported through the 500 mm diameter Southwest Link for delivery to Melbourne and Geelong (although the capacity of the WUGS processing plant was limited to approximately 100 TJ/day and the North Paaratte field to 10 TJ/day).

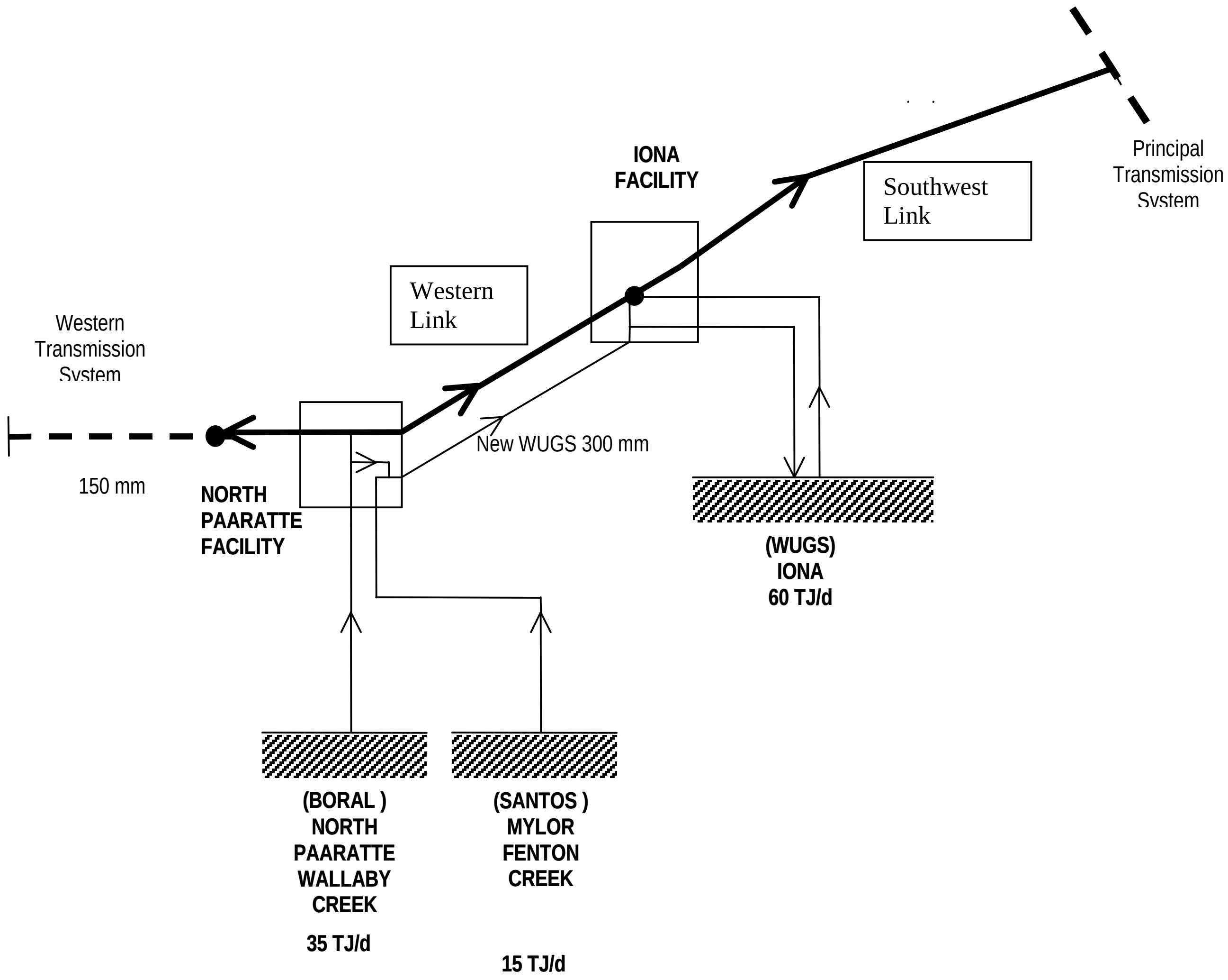


Figure 2 – Winter 1999 Port Campbell Gas Deliverability

2.2 *Future Development*

(a) Western Underground Storage (WUGS) Facility

By 1 October 2000, it is expected that WUGS will be capable of providing:

- capability for gas injections into the Iona reservoir of 50 TJ/day; and
- at least 10 PJ of storage capacity.

By 1 May 2001, it is further expected that WUGS will be capable of providing:

- facilities for the withdrawal of gas from the Iona reservoir and injection into the SWP at a rate of 200 TJ/day; and
- supply of this gas at a pressure of 10,000 kPa.

Provided gas is injected at Iona at a pressure of 10,000 kPa, the 500 mm diameter Southwest Link can deliver approximately 200 TJ/day (based on the expected load distribution between Geelong and Melbourne).

During the off-peak refill season, the Southwest Link can deliver 44-90 TJ/day to Iona at a pressure of at least 3,800 kPa. This pressure is sufficient for the WUGS compressors to inject gas into the storage. However, in order to achieve these flow rates, both the active and backup units at the Brooklyn compressor station are required to be operating. As part of a separate project these units have been re-staged in order to perform this service.

(b) Western System

GPU GasNet understands that the producer at North Paaratte is required to deliver gas into the Western System at a minimum supply pressure of 4,825 kPa. At this supply pressure, the capacity of the Western System is limited to approximately 16 TJ/day during the peak winter period.

If the Western System is to receive gas from Longford, either as a back-up to the North Paaratte plant or as a competitive alternative source of supply, then the pressure available at Iona will have to be boosted from the available minimum of 3,800 kPa to 5,600 kPa (to allow for the pressure drop between Iona and North Paaratte). This pressure lift is achievable at a flow of 16 TJ/day from the 300 kW active compressor to be installed at Iona. This flow is additional to the deliveries into the Underground Storage during the refill season.

North Paaratte currently supplies all the needs of the Western System, but additional gas (if available) could be delivered into Melbourne. This gas can be transported as wet gas to WUGS for subsequent processing, compression and delivery to Melbourne/Geelong via the Southwest Link, or it could be delivered to Iona as dry (processed) gas via the GPU GasNet Western System Link. If this option is utilised then it may be necessary to compress the North Paaratte gas at the Iona compressor station in order to inject the gas into the high pressure (10,000 kPa) Southwest Link. GPU GasNet could operate these compressors in the reverse direction by installing reversing valves.

2.3 Pipeline Capacity Expansion

The Southwest Pipeline has been designed to provide a minimum capacity of:

- 200 TJ/day delivered into Melbourne/Geelong from gas sourced at Iona;
- 44-90 TJ/day delivered to Iona from gas sourced at Lara (subject to conditions in the Principal Transmission System).

GPU GasNet can progressively increase the deliverability of the Southwest Link beyond the minimum capacity by means of transmission system augmentation in order to meet increasing customer demand. The augmentations which increase the easterly flow capacity include looping of the Brooklyn-Lara pipeline, and construction of a new compressor station at Stonehaven.

The capacity for westerly flows can be expanded by installing additional compressor power at Stonehaven, and looping the Brooklyn-Lara pipeline. This will increase the deliverability to the underground storage and the Western System. However the Western System is limited to about 20 TJ/day by the capacity of the existing pipelines in the Western Transmission System.

2.4 *Victorian Gas Market - Supply/Demand Balance*

The potential utilisation of the South West Pipeline in an average winter has been discussed in ***Annexure 3***. However, in order to determine the need for new capacity, the relevant issue is the likely utilisation of the South West Pipeline in severe winters, when all available gas supplies may be called upon. A reasonable scenario of supply and demand is presented below based on conservative assumptions of the supply capability at each injection point, and based on the 1 in 20 peak day forecast from the VENCorp 1999 Annual Planning Review. Assuming that Longford injections are held fixed, and assuming that the Southwest Pipeline supplies any shortfalls, the forecast 1-in-20 winter peak day requirement for the Victorian gas market can only be met with augmentation of the underground storage and the South West Pipeline capacity from 2003. This shortfall is shown in Table 1 below.

The gas supply forecast assumes:

- supply from Longford is reduced to 860 TJ/day as projected in the VENCorp Annual Planning Review. It is assumed for the sake of this exercise that Longford does not increase supply, although clearly if the underground storage cannot be expanded to meet the full demand requirements, there is a possibility of increased supply being made available at Longford;

- Culcairn injections initially at the currently contracted volumes, and growing to the capacity limit available with the Springhurst compressor; and

- full use of available LNG in a 1 in 20 winter;

Forecast gas demand includes gas for power generation, exports to NSW, and a possible new load at Geelong utilising gas from the Minerva field at Port Campbell.

Table 1 - Victorian Gas Supply/Demand Balance (Severe Winter)

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Firm Demand (Principal Transmission System)											
Peak Day 1 in 20	1119	1130	1158	1189	1222	1253	1284	1316	1349	1383	1417
Power Gen.	70	25	30	35	40	45	46	48	49	51	52
Other (Geelong)	0	0	0	0	0	0	50	50	50	50	50
NSW	5	7	8	10	12	12	12	12	12	12	12
Total Peak 1/20	1194	1162	1196	1234	1274	1310	1392	1426	1460	1495	1531
Supply (excluding Southwest Pipeline)											
Longford	989	860	860	860	860	860	860	860	860	860	860
LNG	150	150	150	150	150	150	150	150	150	150	150
NSW	14	20	26	32	38	44	50	50	50	50	50
Total Supply	1153	1030	1036	1042	1048	1054	1060	1060	1060	1060	1060
Shortfall (potential SWP)	41	132	160	192	226	256	332	366	400	435	471

Assumptions - Demand

Base forecast from VENCorp 1999 Planning Review

Power Generation - 2000 experience and various sources.

Other - Assumed new load at Geelong to utilise Minerva gas

No supply to South Australia

Western System supplied from local fields

Assumptions - Supply

Assume full use of LNG in a 1/20 winter.

Assume Longford as per VENCorp Annual Planning Review

Assume Culcairn injections as per current contracts, increasing to available capacity using Springhurst compressor

2.5 *Sizing of the Southwest Pipeline*

(a) Southwest Link

The selection of a pipeline with a diameter of 500 mm between Lara and Iona was made on the basis of the design capacity of the underground storage, the anticipated need for this capacity in the market, and the efficient development of this pipeline over time.

The initial design capacity of the Western Underground Storage is understood to be 200 TJ/day (to be in place by winter 2001). This quantity can be delivered by a 500 mm pipeline but not by a 450 mm pipeline. The capacity of the 500 mm pipeline can be expanded to 300 TJ/day with additional expenditure on the Brooklyn loop[1], and to 415 TJ/day with installation of the Stonehaven compressor.

A smaller pipeline option (such as a 450mm pipeline) was rejected because it could not have carried 200 TJ/day without additional expenditure of at least $28 million for a partial Brooklyn loop. This cost is well in excess of the additional cost of a 500 mm pipeline.

The capacity of a 450 mm Southwest Pipeline could have be expanded to 240 TJ/day by completing the Brooklyn-Lara loop. In order to expand the capacity beyond this level, the Stonehaven compressor would have been required, taking the capacity to 345 TJ/day (compared with 415 TJ/day for a 500 mm pipeline). For loads above 345 TJ/day, a duplication of the pipeline would be required, which would most likely make this capacity expansion uneconomic.

The market need for a pipeline capacity of 200 TJ/day on the Southwest Pipeline is demonstrated in Table 1. This (most recent) forecast shows a potential need for at least 200 TJ/day of capacity by 2004, or by 2003 if Culcairn injections are assumed to equal the current injection level (14 TJ/day). The best forecast which was available at the time of the Southwest Pipeline construction project was the VENCorp December 1998 forecast. This shows a higher peak demand than the most recent forecast, implying, at the time, a potential need for at least 200 TJ/day through the Southwest Pipeline by 2002.

Therefore on the basis of the information available at the time, it was reasonable to install a 500 mm pipeline rather than a smaller 450 mm pipeline. Moreover, to have built the smaller diameter pipeline would have closed off the option of economical expansion of the Southwest Pipeline and thereby created a barrier to vigorous competition.

(b) Western System Link

The 150 mm Western System Link between Iona and North Paaratte was purchased *in situ*. The pipeline has the same diameter as the pipelines in the Western System. This sizing was considered adequate considering the likely demand in the Western System, which is at most 16 TJ/day. Whatever the diameter of the pipeline, compression is needed between Iona and North Paaratte, given that the Western System requires 4,825 kPa in order to deliver 16 TJ/day, whereas the available pressure at Iona has a potential minimum pressure of 3,800 kPa. Any saving in compressor power would not have warranted the additional cost of constructing a 200 mm pipeline. Therefore, GPU GasNet considers that the strategy of purchasing the existing pipeline was prudent.

[1] The Brooklyn loop is an augmentation of the existing pipeline between Brooklyn and Lara (Geelong). It is required to increase the capacity of the Southwest Pipeline for deliveries into Melbourne. It can be installed in two sections if required, from Brooklyn to Paradise Rd. to Lara.

Appendix 1 Southwest Link Technical Specifications

The Technical specifications of the South West Link are summarised below.

Pipeline Item	**Specification**	**Comment(s)**
Pipe Nominal Bore	500mm	
Pipe Wall Thickness	9mm 10.8mm 12.7mm	General conditions 10 km upstream and downstream of Compressor Stations, Road and Rail Crossings Horizontal Directional Drilled, (HDD) crossings, line valve/pig trap installations
Pipe Steel Grade	X-70 X60	General HDD crossings, line valve/pig trap installations
Maximum Allowable Operating Pressure (MAOP)	10,000 kPa	
Specified Minimum Yield Stress (SMYS)	482/413 mPa	
Minimum Allowable Operating Temperature (MAOT)	-10 degC	
Pipe Cover	900mm 1,200mm	Rural Semi Rural, Road Crossings
Pipe Coating	Fusion Bonded Epoxy	
Joint Coating	Heat Shrink Sleeves	
Concrete Slabbing	Road reserves, Rail Crossings	
Concrete Weight Coating	In swampy areas and water crossings not done by HDD where the pipe is likely to have negative buoyancy	
Marker Tape	All locations except bores, encasing pipes and water courses which all flooded during construction	
Cold Bend	40D bends based on location	
Induction bends	Not less than 8D	To allow for future intelligent pigging operations
Line Valves	5 strategically located valves	
Line Valve Installation	Below ground	
Pig Traps	One permanent receiver at Iona	
Cathodic Protection	Anode beds Corrosion protection test points	Two (Inverleigh and Whitlesea Roads) 1 per kilometer

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Annexure 2

Revised Reference Tariffs

1 Injection Tariffs

The current and revised Reference tariffs for the Longford injection zone for the year 1999, and the Reference tariff for the new Southwest zone in the year 1999, are shown in Table 1. The tariffs both before and after GST are shown. These tariffs will apply in the calendar years 2001 and 2002 only and will be escalated according to the tariff rebalancing formulae shown below.

The billing procedure (monthly billing on a forecast profile with a wash-up in December) for the revised and new tariffs is identical to that described in the existing Tariff Order for the Longford injection tariff. The revisions for these charges will take effect from the January 2001 billing period.

Table 1 Revised Tariffs for Injections at Longford or Port Campbell Injection Points

For withdrawal in a transmission zone or at a transmission pipeline supply point	*Transmission demand tariff component **1999** ($/GJ, for 5 day joint injection MDQ) (Pre-GST)*	*Transmission demand tariff component **1999** ($/GJ, for 5 day joint injection MDQ) (Post-GST)*	*Matched injection factor*
All except LaTrobe and Lurgi transmission zones	2.9013	3.1862	
LaTrobe zone	2.9013	3.1862	.293
Lurgi zone	2.9013	3.1862	.324
Western Transmission System transmission pipeline supply point	2.9013	3.1862	1.0

The 5-day joint injection MDQ is defined as the quantity of gas (in GJ) injected on behalf of a Customer at both of the Longford injection point and the Port Campbell injection point during the 5 gas days in the peak period when the 5 highest daily quantities of gas (in GJ) were injected at the Longford and Port Campbell injection points considered together.

The Port Campbell injection point is defined as the existing injection points at Iona and North Paaratte and any new injection point installed on the Southwest Pipeline within 5 km of either existing point.

The Lurgi and LaTrobe matched injection factors apply only to matched injections at Longford. The Western Transmission System matched injection factor applies only to matched injections at Port Campbell.

2 Withdrawal Tariffs

For withdrawals from the Southwest zone, the applicable transmission tariff volume component ("Anytime" charge) is shown in Table 2. It is identical to the approved "Anytime" charge for the Metro zone in the year 2000. The default charge may be reduced to the "matched booking" rate if the Market Participant can show that the withdrawals are matched (on a daily basis) to injections at Port Campbell.

The billing procedures for this tariff component are unchanged from those described in the existing Tariff Order. The tariff is applicable to supply points or transmission pipeline supply points in the Southwest zone from 1 October 2000.

Table 2 Withdrawal charges (Year 2000) from Southwest zone.

Transmission zone	*Standard* *Transmission volume tariff component- calendar year ($/GJ) Post-GST*	*Matched booking* *Transmission volume tariff component- calendar year ($/GJ)* *Post-GST*
Southwest	$0.1200/GJ	$0.0848/GJ

The Southwest zone is defined as any existing or new transmission supply point or transmission pipeline supply point on the Southwest Link or the Western link. When the Western Transmission System is connected to the Principal Transmission System (anticipated for February 2001) then the connection point between the Western Link and the Western Transmission System at North Paaratte will become the Western Transmission System transmission pipeline supply point.

The matched booking tariff is applicable if the withdrawals from the Southwest zone are matched on a daily basis to injections at Port Campbell.

3 Price Control Factors

The revised price control factors are shown in Table 3.

Table 3 Revised Price Control Factors (pre-GST)

	1998	1999	2000	2001	2002
CPI (Sept-Sept)		1.73%	6.85%	2.50%	2.50%
X-factor	0.027	0.027	0.027	0.027	0.027
Cumulative factor	1	0.9903	1.0314	1.0293	1.0273
ATT (original Tariff Order) $99/GJ			**0.300980**	**0.297838**	**0.298204**
ATT (revised for roll-in of Interconnect) $99/GJ			**0.324652**	**0.328948**	**0.329300**
Incremental Revenue Southwest Pipeline $			-	5,807,317	6,585,740
Total Annual Volumes (excl. Western System) (GJ)			212,422,315	219,776,594	223,640,341
Incremental ATT $/GJ			0.0000000	0.0264237	0.0294479
Incremental ATT (lagged CPI) $99/GJ			**0.000000**	**0.025619**	**0.028608**
Revised ATT $99/GJ			**0.324652**	**0.354567**	**0.357908**

The average revenue price control formulae remain the same as those specified in the Tariff Order. The revenues from which the Forecast Average Transmission Tariff (FATT) are calculated will include revenues from the revised Longford injection tariff and the new Port Campbell injection tariff in the years 2001 and 2002. The FATT will also include additional revenues from withdrawals at existing and new supply points and the Western Transmission System transmission pipeline supply point in the Southwest zone. However in keeping with the procedure used in the current Tariff Order, the revenues from withdrawals at Iona are excluded from the price control formulae.

4 Rebalancing Control Formulae

The Longford and Port Campbell injection charges have been specified in $1999. The maximum allowed tariff for the calendar years 2001 is the escalation of the 1999 tariff at CPI+1% over each of the two years 2000 and 2001, using the lagged CPI escalation rate as defined in the Tariff Order. The 2002 tariff is limited to an escalation of CPI+1% over the approved year 2001 tariff.

The withdrawal charges have been specified in year 2000. The standard charge is equal the Metro "Anytime" tariff for that year, as approved by the ACCC. The maximum allowed tariff in subsequent years is this tariff escalated at CPI-1.7%. The matched booking tariff rebalancing control is equivalent to the standard tariff control.

5 The GST "Price Spike"

The tariffs quoted above have been calculated on the basis of the forecast CPI, and then back-dated to the years 1999 and 2000. The tariffs for the year 2001 must be submitted to the ACCC for approval under the terms of the Tariff Order. The Tariff Order requires that the ACCC must be satisfied that the price control and tariff rebalancing formulae have been applied correctly.

Under the provisions of the tariff order, the GPU GasNet tariffs for the year 2001 will be escalated by the CPI growth rate between September 1999 and September 2000. As such, these tariffs will include the impact of the GST price spike on the CPI for September 2000 and subsequent quarters.

The ACCC has indicated that in approving the year 2001 tariffs it will not approve a full pass through of the GST spike to the extent of 2.75% less than the actual CPI escalation rate. GPU GasNet is disputing this decision. The actual escalation to be adopted for the year 2001 will incorporate the outcome of the resolution of this dispute.

GPU GasNet Pty Ltd
Application for Revision to Access Arrangement
Southwest Pipeline

Annexure 3

Supplementary Access Arrangement Information

1 Introduction

GPU GasNet proposes to include the capital cost of the South West Pipeline within the GPU GasNet Capital Base. The Capital Base will be augmented by the capital cost of each asset from the date when each asset was available for use. The approved depreciation schedule will commence on these dates. The capital costs to be included in the Capital Base are:

Table 1: Capital Costs

	Capital Cost	Date included
Southwest Pipeline Long-Life assets (excluding Iona Compressor)	$70.9 m	31 May 1999
Southwest Pipeline Short-Life assets (RTUs, heaters)	$0.7 m	31 December 1999
Iona Compressor	$3.9 m	28 February 2001
Total	$75.5 m	

Note: the cost of the Southwest Pipeline has been reduced from the actual capital cost by a contribution of $7.3M from the Victorian Government.

The inclusion of these assets in the Capital Base will require a revision to the approved Reference Tariffs described in the (revised) Victorian Gas Industry Tariff Order 1998. This Annexure 3 describes the changes required to the published zonal Reference Tariffs, and introduces a new "*Southwest zone*" within which a new zonal tariff will apply. The amendments to the relevant price control factors for the years 2000 to 2002 inclusive are also included.

The revised Reference Tariffs will apply from 1 October 2000. The capital costs in Table 1 have been depreciated from the commissioning dates of each asset to 1 October 2000 using the conventional real, straight-line depreciation methodology. These calculations are shown in section 5 of this Annexure 3. The opening values of the New Facilities Investment as used for tariff calculations are shown in Table 2.

Table 2: Opening Capital Costs

	Capital Cost	Opening date
South West Pipeline (excluding Iona Compressor)	$73.02 m	1 October 2000
Iona Compressor	$3.90 m	1 March 2000

This supplementary Access Arrangement Information must be read in conjunction with the original Access Arrangement Information approved by the Commission on 16 December 1998, the Application for Revision for the Interconnect Assets approved on 28 April 1999, and the Application for Revision to Access Arrangement to which this document is Annexed.

2 Tariff Proposal

The revised Reference Tariffs will recover the capital cost of the included assets, and the forecasted incremental operating and maintenance costs over time.

A detailed break-down of the prudent costs of the Southwest Pipeline assets is shown in section 7 of the Application for Revision. ***Annexure 1*** and ***Annexure 5*** provide a justification of the prudence of the investment.

The revised tariff rates are shown in ***Annexure 2***. The revised tariffs will apply from 1 October 2000.

All tariff calculations utilise the same current cost accounting methodology as employed in the original Access Arrangement. As such, all asset values, depreciation and return on assets are escalated at the CPI each year. The full CPI including the GST ‘spike’ has been used in these calculations. The treatment of the CPI spike is described in ***Annexure 2***.

The design principles and derivation of these rates are described in the following sections.

3 Tariff Design

3.1 *Tariff Principles*

In establishing a Reference Tariff for the Southwest Pipeline, and in amending the existing Reference Tariffs for the Principal Transmission System, GPU GasNet will observe the following general principles.

(a) The Southwest zone Reference Tariff, and the amended existing Reference Tariffs, should retain the features of the existing tariff design, specifically:

- a zonal system,
- distinct injection and withdrawal zones,
- revenues recovered from actual flows, and
- demand charges based on flows on the 5 peak days.

(b) The design should endeavour to facilitate and encourage competition in the market for gas supply.

(c) The incentive structure of the existing tariff model should be retained.

3.2 *Roll-in of Assets*

GPU GasNet has chosen to roll-in the Southwest Pipeline assets under the System-Wide Benefits test, on the basis of the arguments presented in section 5 of the Application. In summary, these arguments are:

1. The Southwest Pipeline has already provided system security benefits as part of the Winter '99 project, and will continue to provide significant security benefits to all Victorian gas users on an on-going basis.

2. The Southwest Pipeline facilitates well-head supply competition by making gas from the Otway basin available for sale in the Victorian market where, in the absence of the Southwest Pipeline, these fields might not be developed.

3. The Southwest Pipeline facilitates competition for seasonal and peak supplies between the Western Underground Storage and Longford. In the absence of this competition, the Longford producers have the opportunity to exert considerable market power.

Given that GPU GasNet has chosen to roll-in the New Facilities Investment under the System-Wide Benefits test, GPU GasNet is free to choose from a number of options for allocating costs amongst users and in setting tariffs.

This freedom in tariff setting may be compared with the situation that would prevail if GPU GasNet had proposed a ‘stand-alone’ tariff for the Southwest Pipeline. In this case the existing Reference Tariffs in zones outside the Southwest Pipeline cannot be altered.

Whilst the Code does not provide guidance as to the appropriate tariff and cost allocation principles for assets which are rolled-in under the System-Wide Benefits test, GPU GasNet believes that the tariff design should attempt to:

- support and enhance the system-wide benefits that justified the roll-in of the assets;
- minimise any increase in existing Reference Tariff components, and align these to the benefits flowing from the system-wide benefits; and
- maintain a sustainable tariff path without real increases over the lifetime of the assets.

GPU GasNet has chosen a tariff design which reasonably satisfies these objectives.

3.3 *Tariff Options*

The simplest option is to derive a stand-alone tariff for the Southwest Pipeline which recovers the incremental capital and operating costs from the flows forecast on the pipeline. However, based on the forecasted flows on the Southwest Pipeline, the tariff derived from this method would be 3 to 4 times higher than the Longford injection tariff (depending on the treatment of depreciation and contracted revenues). This would be a barrier to use of the underground storage and the small fields in the Otway basin, and would therefore substantially inhibit competition.

In large part this difference between the South West Pipeline and Longford tariffs is not due to any underlying economic fundamentals, but is simply a vintage effect arising from the fact that the Longford pipeline is highly depreciated whereas the Southwest Pipeline is new capital. The pipeline from Longford to Pakenham[2] has a length of 141 km, which is almost equal to the length of the Southwest Pipeline from Iona to Lara which is 144 km.

An alternative option is to employ the cost allocation methodology used to establish the current Reference Tariffs. All assets at the beginning of the regulatory period in 1998 were valued at their Optimised Replacement Cost (ORC) and those values were then scaled down as a group so that the group value equaled the total Depreciated Optimised Replacement Cost (DORC) of all assets. This method ignores the vintage of each asset and assigns the same proportion of depreciation to each asset irrespective of the actual age of that asset. Thus older assets are written down by the same proportion as relatively new assets.

If this option was selected, the Southwest Pipeline would be written down by approximately 40%, and all other assets would be revalued up by 8%. Whilst this option is in keeping with the original philosophy of the tariff model, and is generally accepted as a legitimate means for cost allocation where vintage bias is a concern, it is not the preferred option for GPU GasNet. The effect of this method is to transfer the deemed Southwest Pipeline depreciation costs onto the withdrawal tariffs in all zones, whereas the decision to use the Southwest Pipeline is principally a choice of supply point between Port Campbell and Longford.

[2] This is the asset which is recovered by the Longford injection charge.

GPU GasNet's preferred option is to strike a single injection charge applicable to both the Longford and Port Campbell injection points. This will have the effect of making users indifferent to the choice of supply point, at least as far as transmission costs are concerned. The method establishes a "*level playing field*" between the main supply points in the winter period.

The advantages of this approach are:

1. The gas sourcing decision is independent of the transmission price (this is reasonable considering that the transmission distances are almost equivalent).

   - Hence the GPU GasNet transmission tariffs will facilitate "competitive neutrality".

2. The benefits and costs are aligned. The security and competition benefits are system-wide and hence costs should be borne by all users. The combined Longford and Port Campbell injection points will supply approximately 98% of the peak gas consumed in Victoria, hence the costs are allocated in line with the benefits.

3. The transmission tariff for injections from Culcairn is not increased, which is appropriate since this supply source has the added cost burden of the EAPL Moomba to Culcairn tariff. Hence this strategy does not disadvantage suppliers from Moomba.

This option results in a single injection charge which is higher than the current Longford injection charge.

3.4 *Back-Loading*

GPU GasNet has attempted to minimise the increase in the Longford injection charge by employing the following procedures:

1. The asset is depreciated from June 1999 to October 2000. This depreciation is not recovered from the Reference Tariff.

2. The depreciation in the first three years October 2000-December 2002 is substantially deferred to future years. Under the conventional real, straight-line approach, the depreciation over the first three years is $5.54 m (see Table 7). GPU GasNet proposes negative depreciation of $2.7 m, which amounts to a deferral of $8.24 m in total depreciation claims. This strategy more closely matches the revenue requirement to the rate of growth of the load and avoids the disadvantages and inefficiencies of front-loaded tariffs on new pipelines with relatively low initial flows.

3. In the longer term at subsequent regulatory resets, GPU GasNet intends to levelize the revenue requirement in real terms to year 20 of the 34 year economic life of the Southwest Pipeline assets. This back-loading is effected by further deferring depreciation from the first decade to the second. It should be noted that this levelization procedure is not a “fixed principle” as contemplated by the Code, and GPU GasNet may propose alternative depreciation profiles at the regulatory reset in 2002, but it is the intention of GPU GasNet at this point in time. The actual procedure at the regulatory reset will of course depend on the outlook at that time for economic life, injection volumes from various sources, the growth and disposition of load, the likely level of rate shock, investments in new assets etc.

GPU GasNet has employed a back-loading procedure for the South West Pipeline assets in order to facilitate competition and encourage flows on the South West Pipeline. However it is understood that this procedure increases the risk profile of these assets, since the recovery of capital costs has been partially deferred to the future, and is therefore subject to increased market and regulatory risks. This additional risk is willingly undertaken in the context of this roll-in Application because the proposed tariffs significantly improve the likelihood of reasonable flows on the Southwest Pipeline, and hence the recovery of the investment.

3.5 *Tariff Structure*

GPU GasNet will establish a new tariff zone (the "*Southwest zone*") and an injection point in that zone (the "*Port Campbell injection point*") which will encompass both the Iona and North Paaratte receipt points.

Retailers who inject at Port Campbell will bear an *injection charge* identical to the revised Longford injection charge in structure and level. This charge will be calculated so as to recover the combined revenue requirement associated with both pipelines from the joint flows on these pipelines.

The procedure which equalises the Port Campbell and Longford injection charges involves constructing a joint asset group consisting of the Longford and Southwest Pipelines, and a joint injection volume which is the total injections into both pipelines on the five peak injection days. The principle of a ‘joint injection’ pipeline implies that the relevant peak days are those with the five maximum combined injections from Longford and Port Campbell.

The Southwest Pipeline is operated by VENCorp under the Market Carriage system, which implies that there is a logical disconnect between injections and withdrawals (that is, withdrawal tariffs are paid irrespective of where the gas may have been supplied, and gas injection tariffs are paid irrespective of where the gas is intended to be delivered). However, the Western System zone is normally supplied from North Paaratte and in this case the Southwest Pipeline assets are not utilised. Therefore the Retailers who inject at Port Campbell to supply the Western System zone will not pay that part of the Port Campbell injection charge which can be matched to their withdrawals in the Western System zone.

A tariff must also be specified for withdrawals from off-takes in the Southwest zone itself. This includes withdrawals at Iona to refill the underground storage, and future off-takes anticipated at Colac, Simpson, Lara and other towns on the pipeline route.

The withdrawals at Iona which refill the underground storage are a special case. This off-take clearly uses the facilities of the Principal Transmission System to transport gas in the summer from Longford via Lara to Iona. The Metro "Anytime" charge is already applicable (under the current Tariff Order) at Lara for flows into the South West Pipeline. This charge recovers the non-locational operating costs, and the locational operating costs associated with passage through the Metro zone. This charge will be retained, but will be applied to withdrawals at Iona rather than at Lara.

For those towns on the pipeline route which connect to the Southwest Pipeline and withdraw gas, no demand charge will be applicable, since the capital costs are fully recovered from the injection charge. However, all off-takes on the Southwest Pipeline will be levied a charge equivalent to the Metro "Anytime" rate, on the assumption that the non-peak flows are sourced from the Metro zone via Lara. However, a matched withdrawal rebate will be offered if withdrawals at these off-takes (including refill of the Underground Storage) are matched to injections from Port Campbell. The rebate will equal the locational component of the Metro "Anytime" charge (which recovers the operating costs specifically associated with transmission through the Metro zone). The remaining non-locational "Anytime" charge is paid by all withdrawals from the Principal Transmission System regardless of the location.

The transfer point at North Paaratte between the Southwest Pipeline and the Western Transmission System will be designated as a new transmission pipeline supply point.

3.6 *Price Control Procedures*

GPU GasNet operates under an *average revenue* price control model. In simple terms, GPU GasNet can earn an "allowed revenue" each year, which is simply the product of a Maximum Average Transmission Tariff (MATT), and the total volume transmitted through the Principal Transmission System. If the average revenue actually received is higher (lower) than the MATT, the MATT for the next year is decreased (increased) to make up the difference. Thus the *structure of incentives* on GPU GasNet is to seek higher annual volume deliveries, rather than deliveries in high tariff zones or from one injection point or the other.

GPU GasNet has chosen to retain this price control model for the augmented Principal Transmission System. The Average Transmission Tariffs published in the Tariff Order will be augmented by the net revenue requirement of the South West Pipeline. The average revenue price control applies to the withdrawal volumes from the Principal Transmission System, and it is not proposed to alter these forecasts. The details of the calculation are described in section 4.6 below.

However, in calculating the revised tariffs for the Port Campbell and Longford injection points, GPU GasNet has used the latest forecast of injection volumes. This has no substantive effect on the revenues received by GPU GasNet (which are ultimately based on the delivered volumes). However:

- it presents users with a more reasonable and cost reflective injection tariff, and
- it minimises the extent to which delivery tariffs will be adjusted through the price control procedures, since the revised forecast volumes will be more closely aligned to the actual expected flows.

4 Tariff Derivation

4.1 *Procedure – Revised Injection tariff*

The revised injection tariff for the Longford and Port Campbell injection points is calculated by the following procedure.

1. Calculate the sum of the revenue requirements of the Longford injection pipeline and the South West Pipeline for the years 2000 to 2002 inclusive (sections 4.2 and 4.3).

2. Forecast the combined injection volumes from Longford and Port Campbell on the 5 peak injection days (section 4.4).

3. Levelize the tariff from 2001 to 2002 at an escalation rate of CPI (section 4.5).

4. Back-date the revised injection tariff to the year 1999. The tariffs for the years 2001 and 2002 are then determined by applying the modified price control procedures each year (section 4.6).

4.2 *Revenue Requirement - Longford Injection Pipeline*

The original tariff for the Longford injection point was designed to recover the full revenue requirement of the Longford injection pipeline over the period 1998 to 2002. A levelized tariff (CPI-2.7%) was derived taking into account the forecast reduction in injections from 990 TJ/day (in 1998, 1999 and 2000) to 853 TJ/day (in 2001 and 2002).

Since the revenues for 1999 and 2000 are deemed to have been recovered at the published tariff, the appropriate revenue requirement for 2001 and 2002 is the forecasted revenue based on the product of the published tariff (escalated each year at CPI-2.7%) and the forecasted injection volume (from the existing tariff model).

The published injection tariff slightly over-recovers the revenue requirement since a matched injection rebate is paid to withdrawals in the Latrobe and Lurgi zones. The forecast rebates are deducted from the forecast injection revenues to derive the revenue requirement.

Table 5 shows the relevant forecast revenues for 2000 to 2002.

4.3 *Revenue Requirement - Southwest Pipeline*

The revenue requirement for the South West Pipeline has been derived from the following financial and economic parameters:

- a capital investment of 75.5m;
- commissioning of the South West Pipeline in June 1999 and the Iona compressors in March 2000;
- an opening asset value obtained by depreciating the capital investment from the commissioning date to the tariff commencement date, using real, straight-line depreciation;
- incremental annual operating/maintenance costs of $0.35m;
- a real pre-tax WACC of 7.75%; and
- an economic life ending in 2033 (as for the main assets of the Principal Transmission System).

Table 6 shows the determinants of the revenue requirement calculated from these parameters. The standard methodology has been employed with the exception that the depreciation profile for the assets has been modified in order to back-load the tariff. Table 7 shows the depreciation amounts claimed for 2000, 2001 and 2002, compared with the amounts that would be claimed under conventional straight-line depreciation (which applies to all other GPU GasNet assets).

4.4 *Volume Forecast*

As stated in section 3.6 above, GPU GasNet has chosen to employ an updated forecast of gas injections from Longford and Port Campbell. Table 8 shows the details of this forecast.

The key assumptions used to construct this forecast are:

- peak day forecasts from the 1999 VENCorp Annual Planning Review;
- peak gas use in power generation based on internal assessments;
- exports of 7-8 TJ/day to NSW based on the current flows.

It is assumed that this load is supplied principally from Longford and the South West Pipeline, with small supplementary volumes provided from imports through Culcairn and injections of LNG.

- imports from Culcairn are assumed to be 20 TJ/day, based on the current contracted amounts and additional volumes forecasted by VENCorp;
- LNG use is assumed to be 25 TJ over the 5 winter peak days (this is a small quantity compared to the available quantity of 452 TJ, but LNG has a high marginal cost, and it is likely that a large proportion will be reserved to supply ‘needle peaks’ in colder than average winters); and
- no interruption is assumed, given the availability of relatively economical gas from many sources (that is, the transmission capacity is adequate to supply the average winter loads without augmentation).

The peak day volumes are converted to the average volume over the 5 peak days by multiplying by a factor of 95.4%, which is derived from the daily load profile provided by VENCorp.

4.5 *Joint Injection Tariff*

The joint injection tariff is derived from the combined revenue requirements and the joint injection volumes of the Longford and Southwest Pipelines.

The tariff is levelized at an escalation rate of CPI. This compares to the standard escalation rate of CPI-2.7% which is used for all other Reference tariffs, and reflects the intention to back-load the revised tariffs. The levelized tariff, when applied to the forecast injection volumes, generates revenues with the same NPV as the forecast revenue requirement over the period October 2000 to December 2002.

This procedure is identical to that employed to derive the existing Reference Tariffs in each zone.

Table 9(a) shows the forecast revenues that result from this procedure, compared to the forecast revenue requirement. Table 9(b) shows this tariff back-dated (using the forecast and actual CPI from Table 3) to the calendar year 1999.

4.6 *Revised Price Control Parameters*

The Victorian Gas Industry Tariff Order 1998 specifies the parameters and formulae that control the re-setting of tariffs each year. The principal control parameter is the Average Transmission Tariff (ATT) which is published in the Tariff Order for the years 2000 to 2002 inclusive. The ATT is the average price which will generate the forecast revenues if the forecast annual volumes are achieved. The ATT factors must be revised to include the increase in forecast revenues arising from the recovery of the additional costs of the Southwest Pipeline. The forecast delivery volumes have not changed from those used in the original Access Arrangement.

The method to calculate the revised ATT factors is:

- Determine incremental forecast revenues.
- Calculate revised Average Transmission Tariffs by dividing the forecast system withdrawal volumes into the adjusted revenues.
- Adjust back by the CPI-X escalator, where X is 2.7%.

Table 10 calculates the revised ATT factors, and adjusts back by the CPI-X escalator. The revised ATT factors will replace the values appearing in the Tariff Order (as revised for the Interconnect Roll-in Application).

Each tariff component is subject to an annual rebalancing control. A Y-factor will also apply to the combined Longford/Southwest Pipeline injection tariff, which restricts the amount by which this tariff can increase in any given year. This will be set at 1.0%. Since the joint tariff has been calculated to escalate at CPI under standard conditions, the maximum annual escalation which is allowed by the price control formulae is CPI+1.0% from the year 1999 value shown in Table 9(b) and ***Annexure 2***.

4.7 *Long-term Trends*

Table 11 below shows a projection of peak flows through the Longford and Southwest Pipelines, based on the same assumptions as stated previously. The Table also shows a projection of the Longford and Southwest Pipeline revenue requirements based on a levelized revenue requirement for the Southwest Pipeline, and including additional forecast capital expenditure at the Gooding compressor station on the Longford pipeline.

The results demonstrate that the joint injection tariff will not increase more than marginally at the next regulatory reset. Projections beyond 2007 show a real decline in the joint injection tariff.

The assumptions in Table 11 do not allow for the possibility that gas from Port Campbell and Longford may be transported to South Australia via a new pipeline from Port Campbell to Adelaide. This pipeline is at present purely speculative. However, if it were to be built and if it required gas transportation from Longford across the system to Port Campbell, then the flow dynamics through the Southwest Pipeline would change significantly.

There is relatively little transportation capacity from Longford to Port Campbell in the off-peak season under the current system configuration. The constraint arises from the narrow pipeline between Brooklyn and Lara and the lack of sufficient power at Brooklyn compressor station. A firm supply from Longford to Port Campbell would require significant reinforcements, of the order of $35m to $125m, depending on the load. In some scenarios, it is possible that the predominant flow on the Southwest Pipeline would be in a westerly direction and occur in summer.

It is possible to maintain the strategy of equal injection charges from Longford and Port Campbell under this scenario. One possibility is to introduce a commodity charge on westerly flows (in summer) comparable to the peak injection charge in an easterly direction. This relatively small charge would not recover the required new investments, but the remainder could be recovered from a Surcharge on the withdrawals into a new South Australia pipeline, which would minimise the impact of this development on existing tariffs.

5 Tariff Data

Table 3: CPI Assumptions

	1999	2000	2001	2002
Dec-Dec	1.80%	6.91%	2.50%	2.50%
Sept-Sept	1.73%	6.85%	2.5%	2.5%

Source:
Actuals to June 2000, VENCorp forecast Sept and Dec 2000, then 2.5% thereafter.
CPI includes GST spike in Sept. 2000

Table 4: Asset Opening Values - Southwest Pipeline (excl. Iona compressor)

As at end:	May 1999	Dec 31 1999	Sept 30 2000 (opening asset value)	Dec 31 2000
Long life asset value (at period end)	70.9	70.41	72.34	73.06
Depreciation (over period)		1.24	1.68	0.53
Short life asset value (at period end)		0.70	0.68	0.67
Depreciation (over period)			0.06	0.02

Table 5: Target Revenue for the Longford Injection Pipeline

	2000	2001	2002
Longford tariff	$2.238/GJ	$2.331/GJ	$2.326/GJ
Forecast Volumes (5 day peaks)	4950 TJ	4265 TJ	4265 TJ
Revenue before matched injection rebate	$11.079m	$9.942m	$9.922m
Matched injection rebate	$0.387m	$0.416m	$0.429m
Effective Volume Adjustment for rebates	173 TJ	178 TJ	186 TJ
Adjusted target revenue	$10.692m	$9.525m	$9.493m

Note:
The model assumes CPI-X with an X-factor of 2.7%.
Volume forecast is as in original tariff model.
Year 2000 Longford tariff is before any K-factor corrections (based on CPI-2.7% from published 1999 tariff).

Table 6: Target Revenue for the Southwest Pipeline

	Sept 30 2000 $m	Dec 31 2000 $m	Dec 31 2001 $m	Dec 31 2002 $m
Asset value	73.02	74.59	81.60	84.84
Capex (Iona compressor)		3.85		
Depreciation		-0.300	-1.200	-1.200
Return on Assets		1.411	6.231	6.482
O&M		0.041	0.243	0.264
Fuel		0.013	0.094	0.105
Total		1.164	5.368	5.651

Notes:
Depreciation and return commence on 30 September for the long-life Southwest Pipeline assets, 31 December for the heaters and RTUs, and 28 February for the Iona compressor.
Depreciation amounts are selected to minimise the tariff change at the beginning of the next regulatory period.

Table 7: Alternative Depreciation Profiles and Asset Values for the Southwest Pipeline Compared

	Opening Value $m	Oct-Dec 2000 $m	Jan-Dec 2001 $m	Jan-Dec 2002 $m
Asset (end period)	73.02	74.59	81.60	84.84
Proposed Depreciation		-0.300	-1.200	-1.200
Asset (end period)	73.02	73.74	77.07	76.46
Straight-Line Depreciation		0.549	2.466	2.528

Table 8: Peak Day Volume Forecast - Average Winter

	2001 TJ	2002 TJ
Demand:		
Peak Day (VENCorp 1 in 2; excl. Western)	1050	1075
Average over 5 peak days	1001	1025
Power Generation	25	30
NSW Exports	7	8
Total Demand (1 in 2 winter)	1033	1063
Supply:		
(average 5 peak day supply)		
Culcairn	20	26
LNG	5	5
Net Supply from Longford/Port Campbell	1008	1032
5 Day Peak Supply Longford/Port Campbell	**5040**	**5160**

Table 9 (a): Calculation of Joint Longford/Port Campbell Tariff

	2000	2001	2002
Longford Rev. Req.	$0m	$9.525m	$9.493m
Southwest Pipeline Rev. Req.	$1.164m	$5.368m	$5.651m
Combined Rev. Req.	$1.164m	$14.893m	$15.144m
Peak 5-day Volumes	-	5040 TJ	5160 TJ
Adjustment for Matched Injection rebate		178 TJ	186 TJ
Net 5-day Peak Volumes		4862 TJ	4974 TJ
Joint Injection Tariff	-	3.1537 $/GJ	3.2326 $/GJ
Joint Tariff Revenue	-	$15.332m	$16.078m

Notes:
Injection rebate proportions in Latrobe and Lurgi zones are not changed from Tariff Order.
NPV of joint injection revenues is equal to the NPV of the combined revenue requirement at nominal WACC of 10.44%.
Revenue requirement escalation is based on December CPI escalator.
Tariff escalation is based on September CPI lagged one year, as per Tariff Order.

Table 9 (b): Calculation of Joint Longford/Port Campbell Tariff

	1999	**2000**	**2001**	**2002**
CPI (Sept)- lagged	-	1.73%	6.85%	2.5%
CPI	1	1.0173	1.0870	1.1142
Joint Injection Tariff	**2.9013 $/GJ**	2.9515 $/GJ	3.1537 $/GJ	3.2326 $/GJ

Notes:
Tariff is escalated at CPI using the lagged September CPI, as per Tariff Order.

Table 10: Calculation of Revised ATT

	2000	**2001**	**2002**
Incremental Revenues ($m)	0	5.8072	6.5856
Volume (PJ)	212.422	219.777	223.640
Incremental ATT ($/GJ)	0.0000000	0.0264237	0.0294479
CPI (Sept)- lagged one year	1.73%	6.85%	2.5%
Adj. Factor (CPI-X)	0.9903	1.0314	1.0294
Incremental ATTs ($(99)/GJ)	0.000000	0.025619	0.028608
Published ATTs (Revised) ($(99)/GJ)	0.324652	0.328948	0.329300
Revised ATTs ($(99)/GJ)	0.324652	0.354567	0.357908

Note: The adjustment factor in 1999 is 1, and in subsequent years is adjusted by (1+CPI-X), where X is 2.7%

Table 11: Long Term Projection

	2001	2002	2003	2004	2005	2006	2007
Peak Day Demand (TJ)							
VENCorp Forecast (average 1-in-2 demand over 5 days)	1001	1025	1054	1082	1110	1139	1169
Power Generation	25	30	35	40	45	45	45
NSW Exports	7	8	10	12	12	12	12
New Geelong						50	50
Total Demand	1033	1063	1099	1134	1167	1246	1276

	2001	2002	2003	2004	2005	2006	2007
Supply (TJ)							
Culcairn	20	26	32	38	44	50	50
LNG	5	5	5	5	5	5	5
Longford/Southwest Pipeline	**1008**	**1032**	**1062**	**1091**	**1118**	**1191**	**1221**
Injections adjusted for Lurgi/Latrobe zones	972	995	1024	1053	1078	1150	1179
Joint Target Revenue $m	15.33	16.08	17.48	18.42	19.33	21.14	22.21
Tariff (over 5 days) $/GJ	3.154	3.233	3.414	3.499	3.587	3.676	3.768
Real Tariff $(2001)/GJ	**3.154**	**3.154**	**3.249**	**3.249**	**3.249**	**3.249**	**3.249**

Note:
Tariff is levelized separately in 2000-2002 and 2003-2007
Correction for Lurgi/Latrobe zones allows for a payment of matched injection rebate.

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Annexure 4

Extensions/Expansions Policy

1 Coverage

(a) Subject to clause 5.7.1(c), an extension or expansion to the Principal Transmission System is covered by this Access Arrangement.

(b) Prior to an extension or expansion coming into service, TPA will give notice to the Regulator specifying:

(1) the location of the *extension* or *expansion*;

(2) its costs;

(3) its length;

(4) any other matter TPA considers relevant.

(c) Subject to clause 5.7.1(d), a significant extension will not be covered by this Access Arrangement if TPA gives written notice to the Regulator (which notice may be given together with a notice under clause 5.7.1(b)) before the extension comes into service that the extension will not form part of this Access Arrangement.

(d) Clause 5.7.1(c) does not apply where:

(1) a party successfully seeks *coverage* of the *extension* under section 1 of the Victorian Access Code; or

(2) the *extension* was assumed and included in the calculation of the *Reference Tariffs.*

(e) For the purposes of clause 5.7.1(c), a significant extension is an extension where:

(1) the cost of the *New Facility* which comprises the *extension* is greater than $5 million; or

(2) the *extension* exceeds 10 kilometres in length.

(f) Notwithstanding any of the preceding provisions of this clause 5.7.1, the extension representing the natural gas pipeline extending from Barnawartha (Vic) to Culcairn (NSW) (“the Interconnect”) shall be dealt with in the following way:

(1) a notice under paragraph 5.7.1(b) shall be deemed to have been given;

(2) no notice under paragraph 5.7.1(c) shall be given.

2 Effect of Extension/Expansion on Reference Tariffs

(a) Where the *New Facilities Investment* passes the *Economic Feasibility Test*, the *New Facility* is included in the *Capital Base* and is charged the *Reference Tariffs*.

(b) Where the *New Facilities Investment* does not pass the *Economic Feasibility Test*, the standard procedure is that:

(1) a proportion of the *New Facility* corresponding to the proportion of the *New Facilities Investment* that passes the *Economic Feasibility Test* is included in the *Capital Base* and is charged the *Reference Tariffs*; and

(2) the proportion of the *New Facilities Investment* that does not pass the *Economic Feasibility Test* may, at TPA's election, be -

(A) recovered by a *Surcharge* approved by the *Regulator* under section 8.25 of the Victorian Access Code and levied on *Users* of *Incremental Capacity*;

(B) recovered by a *Capital Contribution* a *User* agrees to pay TPA which may be assumed to be a *Surcharge*;

(C) included in a *Speculative Investment Fund* under clause 5.3.4 of the *Reference Tariff Policy*; or

(D) recovered by a combination of these options.

(c) *New Facilities Investment* that does not pass the *Economic Feasibility Test* may be recovered outside the standard procedure in clause 5.7.2(b) where:

(1) TPA and/or *Users* satisfy the Regulator that the *New Facilities Investment* passes the *System-Wide Benefits Test*, in which case the Regulator may approve higher *Reference Tariffs* for all *Users* and the *New Facility* may be included in the *Capital Base*; or

(2) the *New Facility* is able to be included in the *Capital Base* on grounds that it is necessary to maintain the safety, integrity or contracted capacity of the Reference Services.

3 Submissions to vary an Access Arrangement

For the avoidance of doubt:

(a) if, pursuant to the *Extension*/*Expansion* Policy set out in the clauses above, an *extension* or *expansion* becomes covered by this Access Arrangement, that coverage shall not be deemed to be a change to this Access Arrangement;

(b) if pursuant to this clause or to the *Extension*/*Expansion* Policy set out in the clauses above, a *Surcharge* is to be applied, the application of that *Surcharge* shall not be deemed to be a change to this Access Arrangement;

(c) notwithstanding clause 5.7.3(b) above, solely for the purposes of public consultation, a notice given under section 8.25 of the Victorian Access Code, shall be treated with as if it were the submission of a revision under section 2.28 of that Code; and

(d) where any submission to vary this Access Arrangement has the consequence that Reference Tariffs will be changed, section 2 of the Victorian Access Code shall apply.

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Annexure 5

Capital Cost Benchmarking Analysis

1 Summary

The capital cost of the Southwest Pipeline has been evaluated by comparison with the construction costs of a range of oil and gas transmission pipelines built in Australia since 1980. The data has been obtained from a paper presented to the 1998 APIA convention by Philip Venton (consulting Engineer). In order to compare costs on a consistent basis, a unit cost has been calculated by dividing the capital costs of each pipeline by the pipeline length in km and the pipeline outside diameter in mm. All costs have been expressed in constant dollars by escalating the cost by the CPI between the date of construction and 1999.

As might be expected the normalised pipeline costs show a wide dispersion, since all relevant variables have not been controlled for in the analysis. However with the exception of a small number of outliers, the unit costs show a general decline over time which suggests improvements in technology and procedures. The average unit cost over the period 1989 to 1999 is $812/mmDia/Km with a standard deviation of $163/mmDia/Km.

The unit cost for the Southwest Pipeline is $820/mmDia/Km which is therefore consistent with the norms of the last ten years.

2 Methodology

Ideally, a benchmarking exercise for the Southwest Pipeline would attempt to compare the cost of this pipeline with the costs of pipelines of similar length and diameter, built under similar conditions, and with a similar number of line valves, pigging stations etc. There is insufficient data to conduct this form of analysis, so the next best alternative is to normalise the data with a suitable 'catchall' variable. The most frequently used variable in the gas industry is the cost of constructing one kilometre of pipeline of 1mm outside diameter. This unit cost is given as $/mmDia/Km.

Australian industry experience is available in the form of a paper presented by Philip Venton at the International Convention of the Australian Pipeline Industry Association (APIA) in Brisbane in November 1998. This paper provides data for a number of oil, gas and other pipelines built since 1980 in Australia. This data is reproduced in Table 1. Venton has converted the actual unit pipeline costs to constant $1995 using the Australian CPI series.

The raw data has been filtered in two ways. Firstly, pipelines where the actual construction cost is unavailable due to confidentiality restrictions have been removed (it should be noted that the Venton paper had access to a greater data set for analysis purposes only; also GPU GasNet has provided the costs for the Chiltern Valley-Koonoomoo pipeline). Secondly, all pipelines of diameter 150 mm or less have been removed. This is done to make the data more representative, since the construction costs of the smaller diameter pipelines are significantly different from the so-called 'big-inch' pipelines. The filtered data, converted to $1999, is shown in Table 2.

It should be noted that the data set does not include any pipelines greater than 500 mm in diameter in the last ten years. Therefore the results cannot be used to evaluate the costs of larger diameter pipelines, for which significantly different construction techniques may be required. Similarly, this data does not include very high pressure Class 900 pipelines which will be more representative of the trends in pipeline technology in the future. These pipelines require special materials and construction techniques, and although they may be more costly on a unit cost basis, they are more efficient given the greater capacity of these pipelines for the same diameter. For example, the Optimized Replacement Cost estimated for the Moomba-Wilton pipeline (as presented in the EAPL Access Arrangement Information) is significantly higher than the benchmarks discussed here.

3 Southwest Pipeline Unit Cost

The unit cost for the Southwest Pipeline is calculated as follows:

The Southwest Pipeline consists of a DN 500 pipeline of outside diameter 508 mm and length 143.9 km, and a DN 150 pipeline of outside diameter 168 mm and length 7.8 km.

The actual pipeline cost was $61.1 million. This includes all line and branch valves, pigging facilities and SCADA controls, but does not include the specially designed receipt and flow control facilities, the Iona compressor, or the additional facilities external to the pipeline at Brooklyn.

Unit Cost	=	$61.1 million/(508mm*143.9 + 168mm*7.8)	
	=	$821/mmDia/Km	($20,860/inDia/Km)

4 Comparison with Industry Experience

The filtered unit cost data from Table 2 has been plotted against year of construction in Figure 1. Pipelines with unit costs over $3000/mmDia/Km have been excluded because their inclusion may be distorting the database.

The results show a general decline in pipeline costs over time. The average unit cost over the last ten years is $812/mmDia/Km with a standard deviation of $163/mmDia/Km. The Southwest Pipeline at $821/mmDia/Km compares favourably with these results, indicating that the Southwest Pipeline is representative of average construction conditions.

The average of $812/mmDia/Km or $20,625/inDia/Km is consistent with the benchmarks suggested by a range of parties in the Draft Decision to the Epic Energy Access Arrangement proposal for the Moomba-Adelaide pipeline. Given the relatively small size of the data sample, the average unit cost calculated from the sample should not be construed as definitive, and it is reasonable to also consider other inputs and industry experience.

It should be recalled that this data analysis only applies to pipelines in the range 200-500mm diameter, and does not apply to Class 900 pipelines (operating pressures around 14,000 kPa). The data is also biased downward by the inclusion of oil and other pipelines.

A word of caution is required in interpreting this data. The results show a wide range of dispersion about the mean. This demonstrates that uncontrolled variables are present in the data. For example the following factors can bear on the final construction cost:

- the level of development and land-use en route,
- the number of road, rail and river crossings,
- the terrain (eg. rock, rock floaters, sandy soil),
- the foreign exchange rate,
- the level of supply and demand for pipe and for construction crews.

Road, rail and river crossings require heavier wall construction and special welding techniques. The presence of rock is a major cause of higher construction costs, whilst land-use affects the cost of easements and the cost of route re-instatement. Pipeline experience generally is that the difference between good and very poor conditions could amount to a factor of two in the unit costs.

Based on the specific conditions applicable to the Southwest Pipeline our assessment is that the route conditions were average to poor (rock floaters over half the route and moderately intensive agricultural land use), but that the supply and demand conditions for pipe supply and construction crews were favourable. Hence the costs are about average amongst current best practice.

It must be emphasised that most of these variables are not within the control of the pipeline company and that therefore there will be cases when the variables go against the pipeline company in terms of construction cost. Hence there will always be limits to the effectiveness of benchmarking until such time as the impact of each variable can be better understood in quantitative terms.

5 Facilities Costs

A breakdown of the special facilities is shown below. These costs are the adjusted costs after deducting estimates of the acceleration costs applicable to each facility. The specific design and functional requirement of each facility is described in detail in Annexure 1.

Facility	**Cost $ million**
Brooklyn City Gate	4.15
Lara City Gate	3.93
Iona City Gate	2.48
Iona Reciprocating Compressor (2 * 300kW)	3.87
Total	**14.43**

Factors which impinge on the costs of the regulator facilities include:

- the need for redundant regulator runs and over-pressure protection where the regulator facility connects pipelines with different Maximum Allowable Operating Pressures,
- the high volumes of gas which must be carried through the Brooklyn and Lara regulators,
- the provision of both flow and pressure control,
- the requirement for remote operation,
- the need for heaters to ensure delivery of gas at acceptable temperatures into distribution systems, and
- the provisions for reverse flow at the Iona and Lara regulators.

GPU GasNet is not aware of any benchmarking analysis that can be applied to facilities such as those installed on the Southwest Pipeline. The costs are directly related to the specific design requirement of each facility. Nevertheless, GPU GasNet believes that the costs, adjusted for the effects of accelerated design and construction, are reasonable and prudent.

Table 1 Australian Transmission Pipeline Data

Pipeline	State	Product	Year Completed	Length (Km)	Nominal Diameter mm	Cost When Constructed $M	Unit Cost in 1995 Dollars $/mmDia/Km
Dalton to Canberra	ACT	Gas	1981	58	250	9.0	1389
Young to Wagga	NSW	Gas	1981	130	300	21.0	1219
Moomba to Stoney Point	SA	Petroleum	1982	660	350	96.0	905
Plumpton to Hexham	NSW	Gas	1982	172	500	83.7	2121
Silverwater to Wickham	NSW	Refined	1982	25	350	16.1	4005
			1983	141	300	65.0	3150
Dampier to Perth	WA	Gas	1983	1480	650	930.0	1891
Jackson to Moonie	QLD	Crude Oil	1983	800	300	130.0	996
Palm Valley to Alice Springs	NT	Petroleum	1983	150	200		
Karratha to Cape Lambert	WA	Gas	1984	57	250	7.1	848
Mereenie to Alice Springs	NT	Petroleum	1985	270	200	23.5	708
Amadeus Basin to Darwin	NT	Gas	1986	1100 400 100	350 300 250	255.0	752
Young to Lithgow	NSW	Gas	1987	212	150	35.0	1081
Carnarvon Lateral	WA	Gas	1988	171	150	14.3	697
Whyalla Lateral	SA	Gas	1989	71	200	14.0	1175
Wallumbilla to Gladstone	QLD	Gas	1990	530	300	103.0	725
Katnook to Mt Gambier &	SA	Gas	1991	67.5	150 90	5.5	546
Gladstone to Rockhampton	QLD	Gas	1991	96	200	17.0	928
Tubridgi Pipeline	WA	Gas	1991	88	150	7.0	543
Ballera(QGC) to Moomba	QLD/SA	Gas/Liquids	1993	180	400	40.0	610
Kutubu(Onshore)	PNG	Crude Oil	1993	161	500	288.3	3929
Junee to Griffith	NSW	Gas	1993	170	150	20.0	780
Riverlands	SA	Gas	1994	240	100	10.0	400
Daly Waters to Macarthur	NT	Gas	1995	323	150		
Gilmore to Barcaldine	QLD	Gas	1995	238	150	14.5	370
Karratha to Port Hedland	WA	Gas	1995	213	450	70.0	762
Goldfields Gas Transmission	WA	Gas	1996	520 860 48	400 350 250	456.0	880
Moomba to Botany	SA/QLD/N	Ethane	1996	1375	200	200.0	676
Ballera to Wallumbilla	QLD	Gas	1996	756	400		
Ballera to Mt Isa	QLD	Gas	1997	841	300	180.0	664
Fairview Lateral	QLD	Gas	1997	26	200	4.1	734
Cheepie-Barcaldine	QLD	Gas	1997	150	100		
Roma-Brisbane Loops	QLD	Gas	1998	55	400	13.5	604
Marsden-Dubbo	NSW	Gas	1998	130 125	200 150	33.0	666
Wagga-Albury	NSW	Gas	1998	151	450	51.0	739
Carisbrook-Horsham	VIC	Gas	1998	200	200		
Chiltern Valley	VIC	Gas	1998	103.1	200	15.4	685
GGT-Anaconda	WA	Gas	1998	85	200		
Leinster-Cawse	WA	Gas	1998	36	100		
GGT-Jundee	WA	Gas	1998	45	100		
NWSG-MLV23	WA	Gas	1998	27	600		
Gatton-Gympie	QLD	Gas	1998	239	150		
Century-Karumba	QLD	Zinc Conc.	1998	304	300	70.0	711

Source: Australian Transmission Pipeline Costs 1976-1998 Philip Venton, APIA International Convention 1998
(Specific notes may be obtained from original paper).
NB: Blank spaces refers to data not available for confidentiality reasons.

Table 2 Filtered Pipeline Unit Cost Data

Pipeline	State	Product	Year Completed	Length (Km)	Nominal Diameter mm	Cost When Constructed $M	Unit Cost in 1999 Dollars $/mmDia/Km
Dalton to Canberra	ACT	Gas	1981	58	250	9.0	1495
Young to Wagga	NSW	Gas	1981	130	300	21.0	1312
Moomba to Stoney Point	SA	Petroleum	1982	660	350	96.0	974
Plumpton to Hexham	NSW	Gas	1982	172	500	83.7	2282
Silverwater to Wickham	NSW	Refined	1982 1983	25 141	350 300	16.1 65.0	4309 3389
Dampier to Perth	WA	Gas	1983	1480	650	930.0	2035
Jackson to Moonie	QLD	Crude Oil	1983	800	300	130.0	1072
Karratha to Cape Lambert	WA	Gas	1984	57	250	7.1	912
Mereenie to Alice Springs	NT	Petroleum	1985	270	200	23.5	762
Amadeus Basin to Darwin	NT	Gas	1986	1,100 400 100	350 300 250	255.0	809
Whyalla Lateral	SA	Gas	1989	71	200	14.0	1264
Wallumbilla to Gladstone	QLD	Gas	1990	530	300	103.0	780
Gladstone to Rockhampton	QLD	Gas	1991	96	200	17.0	999
Ballera(QGC) to Moomba	QLD/SA	Gas/Liquids	1993	180	400	40.0	656
Kutubu(Onshore)	PNG	Crude Oil	1993	161	500	288.3	4228
Karratha to Port Hedland	WA	Gas	1995	213	450	70.0	820
Goldfields Gas Transmission	WA	Gas	1996	520 860 48	400 350 250	456.0	947
Moomba to Botany	SA/QLD/N	Ethane	1996	1375	200	200.0	727
Ballera to Mt Isa	QLD	Gas	1997	841	300	180.0	714
Fairview Lateral	QLD	Gas	1997	26	200	4.1	790
Roma-Brisbane Loops	QLD	Gas	1998	55	400	13.5	650
Marsden-Dubbo	NSW	Gas	1998	130 125	200 150	33.0	717
Wagga-Albury	NSW	Gas	1998	151	450	51.0	795
Chiltern Valley	VIC	Gas	1998	103.1	200	15.4	737
Century-Karumba	QLD	Zinc Conc.	1998	304	300	70.0	765

Filtered for data not available, and for pipelines of diameter less than or equal to 150 mm.
Original data in $1995 converted to $1999 by Australian CPI.

Average Unit Cost 1989 -1998 = $812/mmDia/Km ($20,625/inDia/Km)
Standard deviation = $163/mmDia/Km ($4140/inDia/Km)

Figure 1 Pipeline Unit Costs versus Year of Construction