Victorian Third Party Access Code for Natural Gas Pipeline Systems: Access Arrangement Information for Principal and Western Transmission Pipelines by Transmission Pipelines Australia Pty Ltd and Transmission Pipelines Australia (Assets) Pty Ltd

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ACCESS ARRANGEMENT INFORMATION FOR PRINCIPAL AND WESTERN TRANSMISSION PIPELINES BY TRANSMISSION PIPELINES AUSTRALIA PTY LTD AND TRANSMISSION PIPELINES AUSTRALIA (ASSETS) PTY LTD

1. Introduction

1.1 Purpose of this document+

This access arrangement information ("Access Arrangement Information") is submitted on 3 November 1997 by Energy Projects Division of the Department of Treasury and Finance, Government of Victoria ("EPD"), on behalf of Transmission Pipelines Australia Pty Ltd ACN 079 089 268 and Transmission Pipelines Australia (Assets) Pty Ltd ACN 079 136 413 (together "TPA" and the "Service Providers") to the Australian Consumer and Competition Commission in accordance with section 2.1 of the proposed Victorian Third Party Access Code for Natural Gas Pipelines ("Victorian Access Code").

This Access Arrangement Information forms Part 2 of the proposed *Access Arrangements* by each of the Service Providers (the "TPA Access Arrangements") as owner of the Principal and Western *Transmission Pipelines* described in Appendix 3 of this Access Arrangement Information (the "Transmission System").

The following sections in the Victorian Access Code set out the requirements for this Access Arrangement Information.

Section 2.6	*Access Arrangement Information must contain such information as in the opinion of the Relevant Regulator would enable Users and Prospective Users to:* *(a) understand the derivation of the elements in the proposed Access Arrangement; and* *(b) form an opinion as to the compliance of the Access Arrangement with the provisions of the Code.*
Section 2.7	*The Access Arrangement Information may include any relevant information but must include at least the information described in Attachment A.*
Section 2.8	*Information included in Access Arrangement Information, including information of a type described in Attachment A, may be categorised or aggregated to the extent necessary to ensure the disclosure of the information is, in the opinion of the Relevant Regulator, not unduly harmful to the legitimate business interests of the Service Provider or a User or Prospective User. However, nothing in this section 2.8 limits the Relevant Regulator's power under section 48ZT of the Gas Industry Act to obtain information, including information in an uncategorised or unaggregated form.*

Appendix 1 to this document shows the information categories listed in Attachment A of the Victorian Access Code and indicates where this information is contained within this document.

In this Access Arrangement Information where a word or phrase is italicised it has the definition given to that word or phrase in the Victorian Access Code unless the context otherwise requires.

1.2 Start date of the TPA Access Arrangement

If approved by the Regulator, the TPA Access Arrangements will take effect on:

(a) for the Principal Transmission System: the date on which the Regulator approves the Access Arrangement or the date on which the MSO Rules commence, whichever is later; and

(b) for the Western Transmission System: the date on which the Regulator approves the Access Arrangement or 1 September 1998, whichever is later.

Prior to this date, TPA will offer transportation services on terms and conditions, and at prices, to be negotiated. As Victorian legislation will not give the right of "contestability" to any parties prior to that date, the practical consequence of this is that TPA will have contracts with the three Victorian gas retailers setting out prices and other terms and conditions. These contracts will have effect until the start date of the relevant *Access Arrangements*.

1.3 Victorian Government's gas reform objectives

The Victorian Government's objectives for the reform of the gas industry are:

(a) to achieve the lowest possible sustainable gas prices for Victorian consumers through competition;

(b) to maximise customer choice;

(c) to provide a more efficient industry and encourage efficient investment;

(d) to provide the framework for an effective and sustainable energy market, integrating gas, electricity and other energy products so customers can better manage their energy purchases;

(e) to ensure a regulatory environment that provides consumers with the best protection in terms of price, service and safety standards;

(f) to ensure the long-term security of supply;

(g) to encourage the development of an efficient national gas market; and

(h) to reduce public sector debt.

There are clearly tensions between some of these objectives. Whenever a trade-off decision involving the reduction of public sector debt has been required, the Victorian Government has consistently regarded that objective as subordinate to the other competition reform objectives.

In order to ensure that the Victorian Government's economic reform objectives are properly reflected in this document, EPD, not TPA, has managed its development.

1.4 Principal and Western Transmission Systems

As described in section 1.5 below, the Victorian Government is introducing an innovative market model to the Principal Transmission System. In relation to the Western Transmission System, however, it is proposed that a more traditional model will be introduced. The Western Transmission System will be initially a *Contract Carriage Pipeline*.

1.5 The gas market model (to apply to Principal Transmission System)

EPD has developed its reform proposals, this document and accompanying regulatory documents after an extensive period of detailed and thorough analysis and consultation. EPD believes that the model proposed, as reflected in this and other *Access Arrangements*, will deliver the Victorian Government's objectives, in particular, the objectives in relation to maximising customer choice thereby leading to the lowest possible sustainable gas prices for consumers.

In assessing the TPA Access Arrangements, and the *Access Arrangements* of Victorian Energy Networks Corporation ("VENCorp") and the gas distributors, it is important to know something of the structure proposed for the Victorian gas industry.

(a) The Victorian Energy Networks Corporation

As part of the reforms, the functions of ownership and operation with respect to the Principal Transmission System will be separated. TPA is the owner of the Transmission System, and VENCorp, which will submit its own *Access Arrangement*, is to operate the Transmission System. The rationale for this stems from the wholesale market being introduced in Victoria.

This proposed wholesale market, which is described in more detail in chapter 7 of EPD's Stage 2 Gas Information Paper, will enable system participants to trade efficiently in gas so as to maintain balance and maximise their commercial opportunities. For the proposed market to operate efficiently, the market and system operator will also operate the Principal Transmission System. In order to give all market participants confidence that they will not be discriminated against, the operator should be independent of market participants, including the owner of the Principal Transmission System.

Participants will pay TPA tariffs as regulated by the Victorian Gas Tariff Order (as amended from time to time) ("Tariff Order") made by Order in Council under the Gas Industry Act 1994 which forms an attachment to the TPA Access Arrangement. In addition to the TPA tariffs, VENCorp will charge system participants on a cost-recovery basis for both its own costs of operation and costs associated with it providing a safe and reliable service. Further details as to the operation and governance of VENCorp are to be found in its *Access Arrangement* and EPD's Stage 2 Gas Information Paper.

Although an *Access Arrangement* is being submitted on behalf of VENCorp at this time, VENCorp will not formally come into being as a legal entity until passage and proclamation of the Gas Industry (Further Amendment) Act 1997, scheduled for 1 December 1997.

(b) The Market Carriage Transportation Model

The MSO Rules, attached to this document, establish that a one zone model will apply initially. That is, although "shadow" prices for every hour in all relevant zones will be published, an ex post optimisation process will derive a single, daily price to apply across the whole system for settlement purposes. The MSO Rules require that a multi-zone and hourly pricing model should apply from December 2000. From this time price difference between the zones will provide pricing signals as to the cost of transporting gas between zones (and as to the need for augmentation).

The Principal Transmission System, in both the one-zone and multi-zone models, will operate pursuant to a "market carriage" form of transportation. That is, parties wishing to ship gas on the system will not need to commit to a certain amount of capacity and sign a corresponding contract (referred to as the "contract carriage" model). Instead, parties will pay a use of system charge which will be based on the user's actual usage of the system.[1] For Tariff D consumers,

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1 In most cases, gas users will be supplied by a retailer. It will be the retailer that is liable to pay transportation charges based on its customers' use of the system.

who are able to manage and vary their loads (currently, approximately the 700 largest customers), charges will be based on the amount of gas transported and the share of the system peak accounted for by the user on the 5 peak days during 1 June and 30 September each year. Charges for all other users will be based on the volume of gas transported throughout the year, that is, with no peak capacity component. All customers will also pay an injection charge based on their usage on the 5 peak injection days.

When the Principal Transmission System is unconstrained, which, on current demand, is virtually every day of the year, charges will be based on the actual volume of gas transported through the Principal Transmission System pursuant to the tariff methodology described above.[2] On days of transmission system constraint, retailers may be liable for further sums depending on the extent to which their customers' usage of the system is above their "right" to it. In the multi-zone model, it is proposed that such a "right" will be defined by the ownership of basis hedges or transmission rights. In the initial one-zone model, this right will be defined by an allocation of "authorised MDQ". The rest of this section describes how the market carriage model will work in the initial market model.

All Tariff V customers will be authorised to the volume of gas they consume, whilst major users, Tariff D customers, will receive an allocation of authorised maximum daily quantity ("MDQ") based on current usage[3].

On days of constraint, VENCorp will solve that constraint using the cheapest available options. These might be bids to interrupt usage (dec bids), LNG or gas from an alternative source to Longford. Generally speaking, users taking above their authorised MDQ on such a day will pay most of the cost of solving the constraint, although TPA or authorised users may also pay some "uplift".

New[4] Tariff D users seeking access to the Principal Transmission System will require approval from VENCorp. If there is available capacity, the new user will receive an allocation of authorised MDQ. If there is not, VENCorp will generally still permit the user to connect to the Principal Transmission System, although without allocating authorised MDQ. Thereafter, such a user can elect not to consume gas on days when a constraint arises or may elect to consume gas and pay its share of uplift (that is, its share of the payments made by VENCorp to parties who assisted in solving the constraint). If a new user's demand is large enough such that its connection to the Principal Transmission System might lead to a significant increase in uplift paid by all existing users, VENCorp has the discretion to allow connection only if the user signs an interruptibility contract agreeing to be interrupted on those occasions that VENCorp requires it. [5]

A contract carriage model, indeed any system which utilises a "take or pay" component, works well where users have certainty that they will be able to use the capacity, that is, because they have "captive" customers, or where the service or commodity purchased is easy to sell in secondary markets. In nearly all gas markets around the world domestic consumers are not able to shop around for their gas supply, and hence they provide a stable customer base for retailers.

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[2] The tariff methodology is described in more detail in section 3.

[3] Whilst the gas user will nominally receive the MDQ allocation, it will be held by the retailer supplying the user so as to determine the retailer's liability to pay "uplift" charges. If the user moves to a new retailer or becomes a direct market participant after contestability, its MDQ authorisation effectively goes with it.

[4] "New" in this context means both users seeking to connect their site to the Transmission or Distribution System for the first time as well as those seeking to modify their existing connection.

[5] This is a simplified description of the market carriage model. A more detailed description, including worked examples, is contained in the EPD discussion document: Framework for Market Carriage and Market Evolution, November 1997.

However, as a market moves towards greater competition, individual shippers have less security and hence less confidence that they will be able to make those sales, although the future physical flows through the pipelines are no more uncertain. This leaves them with substantial risk, which is only partly alleviated by the ability to sell that capacity. This is because secondary markets for pipeline capacity are usually neither very efficient nor "deep".

Another important reason why the traditional contract carriage model is not being utilised on the Principal Transmission System is that it would undermine the effectiveness of the proposed spot market. That is, the contract carriage model requires that capacity is booked between specific injection and delivery points. Where gas is available from more than one source, this requirement would tend to reduce the commercial flexibility of market participants, and make the spot gas market less efficient.

1.6 Tariff setting approach

Tariffs for "tariffed transmission services" provided by TPA (as defined in the Tariff Order) are set using a three stage approach which is summarised below.

Step 1: Set target revenue

Target revenue for TPA is set to allow TPA to earn a reasonable rate of return on the value of its existing assets together with new assets which it is expected will need to be introduced to meet forecast growth in service utilisation. The value of existing assets is based on the optimised depreciated replacement cost ("ODRC") which in some cases is reduced for public policy reasons. Step 1 is described in more detail in Section 2.

Step 2: Set year 1 tariffs

A tariff methodology is used to set tariffs for each tariffed transmission service and at each location on the Transmission System such that:

(a) at forecast demand, TPA will recover target revenue for Year 1; and

(b) users contribute an appropriate share of the cost of the assets and services which are used in providing the relevant tariffed transmission service (cost reflectivity).

The tariff methodology is described in detail in Section 3.

Step 3: Set formulae for tariff and revenue adjustment from year to year

Formulae are set out in the Tariff Order which govern the average tariff revenue from tariffed transmission services that can be recovered in the next year, given the average revenue achieved in previous years and also the maximum amount that individual tariffs can be adjusted from one year to the next. The objectives of these formulae are to:

(a) achieve a clear overall price path that recovers target revenue over the five year period and ensures real gains to customers;

(b) create incentives to grow usage where an increase or decrease in total volumes of gas delivered leads to an increase or decrease in total revenue;

(c) encourage efficiency gains, particularly capital efficiency; and

(d) be consistent with light handed regulation.

Step 3 is described in more detail in Section 4.

1.7 Contact details

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2. Target revenue

2.1 Introduction

Target revenue is set at a level which allows TPA to earn a reasonable rate of return on assets employed in providing tariffed transmission services. This chapter sets out the process that has been undertaken to establish an appropriate level of target revenue for each of the five years covered by each TPA Access Arrangement.

Target revenue is established using the formula given below:

$$TR = AV * WACC + D + OC + NWC * WACC$$

where:

TR = Target revenue;

AV = Asset value - total value of asset employed in providing tariffed services;

WACC = Weighted average cost of capital;

D = Depreciation;

OC = Operational costs; and

NWC = Net working capital.

The method used to calculate the return on and of assets is based on current cost accounting ("CCA") and a real pre-tax weighted average cost of capital. The return on net working capital is calculated using a nominal pre-tax weighted average cost of capital.

In the remainder of this section further detail is provided in relation to important components of the target revenue calculation as follows:

(a) valuation of existing system assets;

(b) valuation of non-system assets;

(c) new assets;

(d) rate of return;

(e) return methodology;

(f) operational costs; and

(g) net working capital.

2.2 Valuation of existing system assets

(a) The ODRC valuation methodology

There are different methodologies that can be employed to determine the initial capital value of the network of pipes comprising the Transmission System. It is important to recognise that there is no "correct" method; choosing and using a valuation methodology involves weighing up various issues and making choices which are highly subjective.

The optimised depreciated replacement cost ("ODRC") methodology involves the following steps:

(1) determine the optimal sizing and configuration for pipeline assets ("Optimisation");

(2) establish the replacement cost ("RC") of each asset; and

(3) depreciate the asset.

These steps are described in more detail below.

Step 1: Asset optimisation

Determine the optimal configuration and sizing of pipeline assets.

Existing assets may be scaled down in size - or removed altogether - where the capacity they provide is not required or is materially in excess of what is required based on existing and forecast near term gas flows.

Step 2: Establish replacement cost

This proceeds in two stages. First of all, a modern engineering equivalent ("MEE") is identified for each asset type. This represents what the asset would be replaced with now, given modern technology and accepted industry practices. Secondly, a standard replacement cost ("SRC") is established for each MEE. This is expressed per unit of length or quantity.

The application of the SRC to the MEE of each existing system asset provides a replacement cost ("RC") for that asset. When applied to the optimised system asset, this approach gives the optimised replacement cost ("ORC").

Step 3: Depreciate the asset

Depreciation is based on a straight-line depreciation profile using a standard economic life ("SEL") for each asset type, together with an estimate of the remaining life ("RL") of each asset. Thus if an asset had a SEL of 40 years and a RL of 10 years, it would be depreciated to 25% of its replacement cost.

Depreciation applied to the RC or ORC of each asset gives the depreciated replacement cost ("DRC") and optimised depreciated replacement cost ("ODRC") for each asset. Target revenue is based on the total ODRC of all assets used to provide tariffed transmission services

(b) Justification for using the ODRC methodology

The Victorian Access Code acknowledges that the initial capital base normally should fall somewhere between an ODRC valuation and an historical cost valuation. EPD has opted to utilise the ODRC method for the following reasons.

(1) Using an ODRC method gives tariffs that provide correct economic signals as to the value of the tariffed transmission service. Using historical costs would significantly undervalue the asset and hence distort users' choices in using existing pipelines rather than alternatives, such as other pipelines, proposed new pipelines, other forms of energy or energy efficiency.

(2) Economic theory states that, in a competitive market, prices will reach equilibrium at a level consistent with using a real rate of return on optimal replacement costs for capital assets. Thus, use of ODRC attempts to replicate the outcome of a competitive market and so is consistent with that objective set out in the Victorian Access Code.

(3) Use of differing accounting policies over time - for example decisions on the extent to which labour costs are capitalised - will leave inconsistencies in the recorded historical costs of different assets. Using ODRC applies a consistent valuation principle to all assets.

(4) A historical cost valuation and depreciation makes assumptions about past recovery of asset costs that are almost certain to be incorrect. That is, the adoption of a historical cost approach implies that the owner of the asset previously charged for its use, and hence recovered its cost, in accordance with the accounting depreciation of the asset and an acceptable nominal rate of return on that asset. This is unlikely to be the case. Virtually all of the TPA pipelines were built by TPA's predecessor, the Gas and Fuel Corporation of Victoria ("GFCV"), in an environment where it was the monopoly transmitter, distributor and retailer of gas. Tariffs were not calculated on the basis of a pre-determined and appropriate return on each of the components used to deliver gas to consumers. Rather, gas prices were determined on the basis of total, bundled costs, the cost of electricity and interstate gas prices, and were kept at uniform levels within each customer class.

(5) The optimisation process ensures that redundant or oversized assets are not included in the capital base and hence are not paid for by users.

(6) Replacement costs are required as a basis for equitably allocating locational costs between users. Allocation on historical cost - depreciated or undepreciated - would make tariffs unfairly dependent on asset age and would lead to rate shock when assets are replaced.

In summary, EPD has opted to use the ODRC methodology on the basis that it provides fair and economically efficient tariffs, whilst also recognising the valuable investment made by taxpayers in building up the asset over many years. This method is used in Victoria and in other States for setting price levels in electricity networks.

(c) Application of the ODRC methodology to Transmission System assets

The firm of Gutteridge, Haskins & Davey Pty Limited ("GHD") was engaged by TPA to determine a valuation of TPA's Transmission System assets on the basis of the ODRC methodology as at 30 June 1997. GHD provided technical expertise in the areas of the engineering assessment of the Transmission System assets, the determination of the replacement costs and economic lives and the provision of specific engineering judgements throughout the valuation exercise.

The ODRC approach measures the cost of replacing the existing network with a new optimised network designed for maximum cost effectiveness, using modern materials and construction techniques. The optimised network has been depreciated to reflect the unexpired economic life of the existing network. In completing the valuation, GHD reviewed and modified the economic life to take into account such factors as technological change, trends and geographical shifts in demand and current estimates of proven and probable reserves in Australia.

Ernst & Young was engaged by TPA to provide some interpretation and clarification of the commercial practices adopted in the ODRC valuation methodology. In particular, Ernst & Young advised TPA as to:

(1) whether the ODRC methodology valuation of TPA's Transmission System assets was consistent with the Victorian Government's objectives for establishing tariffs including:

   (A) taking account of commercial market pressures;

   (B) reflecting the underlying economies of the pipelines;

   (C) facilitating competition; and

   (D) providing appropriate signals to customers and potential developers;

(2) the identification of any assumptions or changes in the valuation approach required to reflect the Victorian Government's objectives; and

(3) the identification of different judgments on asset valuation that could be taken to reflect the terms of reference for the valuation as at 30 June 1997.

Various assumptions were made in undertaking the valuation. These are listed below.

(1) General

(A) The TPA network has been valued on an average SRC and average standard economic life basis. In addition, the ages of some assets have been assessed on an average basis.

(B) Pipelines which are no longer in use and have been abandoned currently contribute no income to the business. These abandoned pipelines are excluded from the ODRC system valuation.

(C) Replacement of the Transmission System is assumed possible in the current regulatory environment and in congested areas.

(2) Optimisation

(A) Locations of existing customers and points of supply were assumed to be fixed with delivery conditions and security of supply maintained.

(B) Duplicate pipeline sections have been reconfigured where single pipelines are appropriate.

(C) Allowance for up to three years of future growth is assumed before pipe sizes are considered to be over optimal capacity.

(D) Optimisation assumes "brownfield" conditions exist, that is, all existing infrastructure (eg roads, footpaths, other services etc) are in place, and the replacement of the Transmission System assets would therefore need to allow for such features.

(3) Replacement cost

The RC assumptions and calculations have been determined by GHD, by detailed cost analysis with indexation to 30 June 1997. The assumptions are listed below.

(A) MEE assets are based on proven technology and accepted as common practice in the industry.

(B) The system operates with protected steel at transmission pressure.

(C) RCs are based on economies of scale (ie. not piecemeal extensions).

(D) The SRC per metre of pipeline is built up from estimates of the material, trench, installation and overhead components which an efficient contractor could reasonably be expected to quote for contracts of a significant scale. A similar approach is applied in determining the unit costs of non-pipeline assets.

(E) SRCs are calculated on the assumption that all existing infrastructure (eg roads, footpaths, other services etc) are in place, and the replacement of the Transmission System assets would therefore need to allow for such features.

(F) Pricing for materials and labour rates is based on typical and sustainable market conditions.

(4) Depreciation

(A) Estimates of economic lives are based on industry experience, pipe life research, standard maintenance practice and specific research undertaken by Saturn Corporate Resources Pty Limited. The report prepared by Saturn determined the extent to which remaining economic lives of the Transmission System would be impacted. It assessed the Transmission System in two components: one having an economic life up to 2030 and the remainder up to the year 2033.

(B) Remaining lives for all assets are calculated as the economic life less the estimated age of the asset.

(C) Minimum remaining lives are assumed for each asset type, indicating that when the asset has reached the end of its "standard" life, if it is still providing gas transmission service then some minimum value will be attributed to it.

(D) The economic lives and minimum remaining lives assumed for the different types of assets are shown in table 2.2(c)(4) below.

Table 2.2(c)(4)

Pipeline Systems	Economic Life (Years)	Minimum Remaining Life (Years)
Principal Transmission System		
Transmission Pipelines	38-60	5
City Gate Regulating Stations	38-60	5
Field Regulating Stations	39-60	5
Compressor Stations	30	5
Odourisation Stations	35	5
Transmission Pressure Services	45	5
Western Transmission System		
Transmission Pipelines	37-47	5
Odourisation Stations	35	5

(d) Summary of valuation

The results of the ODRC valuation of the Transmission System assets are shown in tables 2.2(d)(1), 2.2(d)(2) and 2.2(d)(3) below. The effect of the optimisation is to reduce the replacement cost of system assets from \$643m to \$585m: a reduction of 9%. Depreciation reduces the value of the optimised assets from \$585m to \$357m. EPD has adjusted the ODRC value to \$347m to reflect the Victorian Government's public policy objectives to limit network price differentials at contestability.

Table 2.2(d)(1)

Asset Type As at 1 July 1997	RC[6] $m	DRC[7] $m	ORC[8] $m	ODRC[9] $m	Adjusted ODRC $m
Principal Transmission System					
Transmission Pipelines	548.9	356.0	499.5	306.6	305.4
City Gate Regulating Stations	2.7	1.7	2.7	1.7	1.7
Field Regulating Stations	3.2	2.2	3.2	2.2	2.2
Compressor Stations	60.8	30.8	52.3	22.4	22.4
Odourisation Stations	0.1	0	0.1	0	0
Total Principal Transmission System	**615.7**	**390.7**	**557.8**	**332.9**	**331.7**
Western Transmission System					
Transmission Pipelines	26.7	24.2	26.7	24.2	15.2
Odourisation Stations	0.1	0.1	0.1	0.1	0.1
Total Western Transmission System	**26.8**	**24.3**	**26.8**	**24.3**	**15.3**
Total Asset Value	**642.5**	**415.0**	**584.6**	**357.2**	**347.0**

Table 2.2(d)(2)

Asset Type ODRC ($m) As at 1 July 1997	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	Zone 6	Zone 7	Zone 8	Total
Principal Transmission System									
Transmission Pipelines	30.0	39.5	0	147.6	37.8	19.7	7.7	23.1	305.4
City Gate Regulating Stations				1.7					1.7
Field Regulating Stations				2.2					2.2
Compressor Stations		8.5		11.1		2.8			22.4
Odourisation Stations	0.0								0.0
Total Asset Value	**30.0**	**48.0**	**0**	**162.6**	**37.8**	**22.5**	**7.7**	**23.1**	**331.7**

6 Replacement Cost

7 Depreciated Replacement Cost

8 Optimised Replacement Cost

9 Depreciated Optimised Replacement Cost

Table 2.2(d)(3)

Asset Type ORC ($m) As at 1 July 1997	**Zone 1**	**Zone 2**	**Zone 3**	**Zone 4**	**Zone 5**	**Zone 6**	**Zone 7**	**Zone 8**	**Total**
Principal Transmission System									
Transmission Pipelines	55.1	74.3	3.1	233.2	56.0	31.0	10.6	36.2	499.5
City Gate Regulating Stations				2.7					2.7
Field Regulating Stations				3.2					3.2
Compressor Stations		27.8		18.2		6.3			52.3
Odourisation Stations	0.1								0.1
Total Asset Value	**55.2**	**102.1**	**3.1**	**257.3**	**56.0**	**37.3**	**10.6**	**36.2**	**557.8**

Where: Zone 1 = LaTrobe (includes injection assets);

Zone 2 = West Gippsland (injection assets only as no delivery points in this pricing zone);

Zone 3 = Lurgi;

Zone 4 = Metro;

Zone 5 = Calder;

Zone 6 = South Hume;

Zone 7 = Echuca; and

Zone 8 = North Hume.

For the purposes of determining target revenues the ODRC values as at 1 January 1998 have been used. This has been calculated from the ODRC values as at 1 July 1997 and taking into account depreciation and capital expenditure for the period 1 July 1997 to 31 December 1997. A summary of the asset balances as at 1 January 1998 is set out in table 2.2(d)(4) below.

Table 2.2(d)(4)

Remaining Life	CCA Asset Value $m[1]
Land	7.3
5 Years	2.7
5-20 Years[2]	22.0
33 Years	140.5
36 Years	191.7
	364.2

(1) Nominal dollars as at 31 December 1997.

(2) Weighted average asset life is 14 years.

2.3 Valuation of TPA non-system assets

Independent property valuers, John P. Lovell and Associates, were appointed to undertake a valuation of TPA's land and buildings. The valuations are the lower of:

(a) market value, representing the property as a clean site ready for sale in the open market; or

(b) depreciated replacement value, representing "in use" value to the organisation based on the cost to reinstate existing structure after adjusting for physical depreciation and economic obsolescence.

Table 2.3 sets out TPA's non-system assets as at 1 July 1997.

Other assets are at book value.

Table 2.3

Non-system assets As at 1 July 1997	$m
Land and buildings	14.3
Other assets	2.4
Total non-system assets	**16.7**

2.4 New assets

(a) Approach to valuation

Valuation of new assets is based on the forecast level of capital expenditure required to allow TPA to meet forecast growth in demand for tariffed transmission services. This approach is a consequence of the market carriage approach to provision of services which has been adopted for Victoria as described in Section 1.4 above. Augmentation of existing services is essentially rolled-in to the tariff, so that existing and prospective users will pay a common tariff based on the overall cost of existing and new assets.

Inclusion of augmentation in each TPA Access Arrangement does not represent an obligation on TPA to incur the capital expenditure. It does however amount to an obligation on TPA to deliver the service associated with the augmentation. This provides an incentive on TPA to look for cheaper ways of providing the required service, perhaps involving a reduced level of capital expenditure

(b) Process for determining investment requirements

TPA's business plan for the five years to 31 December 2002 proposed a programme for total capital expenditure for the forthcoming five years of approximately $500m which included some significant new projects including underground storage and the South West Pipeline. EPD engaged the specialist gas engineering consulting firm of Stone & Webster Management Overseas Consultants, Inc ("Stone & Webster") to review these proposals. EPD's aim was to determine whether the forecast expenditure was too conservative and could be reduced. Stone & Webster concluded that, given the security factor built into forecast demand and the ability of the Longford/Dandenong pipeline to deliver significant volumes in excess of requirements, TPA in the past has provided an ample supply of gas, as well as capacity, to meet all the Transmission System's requirements.

On the basis of the Stone & Webster report, capital expenditure for the five years to 31 December 2002 used in the target revenue calculation is as set out in table 2.4(b) below.

Table 2.4(b)

Asset Category	Asset Life	1998 $m	1999 $m	2000 $m	2001 $m	2002 $m	TOTAL $m
Use of system	36 years	18.3	0.1	30.8	0.1	0.1	49.4
	33 years	0.1	0.1	0.1	1.2	0.1	1.6
	30 years	0.7	4.2	2.0	0.9	0.4	8.2
	Other	0.6	0.2	0.2	0.3	0.2	1.5
Total		**19.7**	**4.6**	**33.1**	**2.5**	**0.8**	**60.7**

Note: Includes Murray Valley project. Excludes Interconnect, South West Pipeline and Underground Storage projects.

2.5 Rate of return

(a) Approach taken

The rate of return to be applied to asset values set out above is calculated using a weighted average cost of capital ("WACC") approach. This calculates a weighted average of the cost of debt and the cost of equity, based on a commercially reasonable level of gearing for TPA. The WACC is based on the capital asset pricing model ("CAPM") adjusted for the effects of dividend imputation. Estimates for these variables are based on current levels set in capital markets. The appropriate capital structure and risk premia to be used in these calculations are derived by looking at comparable businesses in Australia and internationally.

The capital structure is derived in section 2.5(b) below. The return on equity is estimated in section 2.5(c). The cost of debt is estimated in section 2.5(d). Finally, the formula for calculating the WACC is described and applied in section 2.5(e).

(b) Capital structure

Gearing is defined as the ratio of debt to total capital, where debt and equity are defined as financial debt less cash, and the value of equity respectively.

Sixty percent (60%) has been chosen as the long term average gearing level. It should be noted that this is an estimated long term average. Initial gearing may be higher but trending down over time.

The long term average gearing level has been determined with reference to the gearing levels of a range of comparable entities throughout the world including Australia, Argentina, New Zealand, the United Kingdom and the United States. The key determinants of the chosen gearing were the levels observed in the privatised Victorian electricity distribution businesses, which exhibited significantly higher gearing levels than those traditionally observed elsewhere.

(c) Return of equity

The post-tax nominal return on equity (r_e) has been derived using the CAPM, which is defined as:

$$r_e = r_f + \beta_e(r_m - r_f)$$

The inputs to the CAPM formula and the assumed values are given in table 2.5(c) below.

Table 2.5(c): CAPM Inputs

Input	Definition	Value
r_f	Risk free rate of return	8.00%
$r_m - r_f$	Market risk premium	6.50%
βe	Equity beta	0.95

(1) Risk free rate

The ideal proxy for the risk free rate would be the yield on a default risk-free bond with the same maturity as TPA's assets. In practice, however, the proxy for the risk free rate is usually defined as the annualised yield to maturity on the longest dated Commonwealth Government bond (September 2009). At the close of trading on 17 October 1997 this yield was 6.3%. Over the past twelve months the weekly closing yield on this bond has ranged from 6.1% to 8.2%.

However, the twelve year maturity of the September 2009 bond is likely to underestimate the true cost of longer term borrowings. US markets, for example, have consistently have built a premium into longer dated bonds with 30 year Treasury notes trading, on average, 45 basis points over 10 year yields over the last five years. As TPA comprises assets with lives substantially exceeding the longest dated Australian Commonwealth Bond, (in most cases relevant assets have an expected economic life of 30-60 years) and given the positive slope in the yield curve, it is considered appropriate to build in a premium to the yield on the longest dated bond. Additionally, given the volatility of bond yields recently it is also considered appropriate to use a twelve month average bond yield as the basis for estimating the risk free rate. Consequently a risk free rate of 8.0% has been chosen to best reflect these factors.

(2) Market risk premium

The market risk premium ("MRP") is the rate of return above the risk free rate that an investor would expect to receive on a fully diversified equity portfolio. It is generally accepted within the corporate finance industry that the long run MRP is between 6% and 7%. Therefore, an MRP of 6.5% has been chosen.

(3) Equity beta

Listed companies with comparable risk profiles provide a useful basis for estimating an equity beta for the entity under consideration. However, because the equity beta of a company will reflect both its business and financial risk an adjustment must be made to remove the effects of capital structure. This is known as "delevering" and is calculated as follows:

(A) raw beta estimates are calculated for the range of comparable companies;

(B) the beta of debt is estimated by reverse-substitution of the cost of debt (derived below) and the risk free rate into the CAPM;

(C) asset betas are then calculated based on the following formula:

$$\beta_a = \beta_e \frac{E}{V} + \beta_d \frac{D}{V}$$

(D) an industry average asset beta can then be estimated by averaging the point estimates for each company; and

(E) again using the above formula the industry average asset beta can be "regeared" or "relevered" based on the financial structure of the company under consideration.

An asset beta of 0.45 has been chosen with reference to a number of local and international comparisons. Regearing the asset beta at a 60% debt level results in an equity beta of 0.95.

(d) Cost of debt

The pre-tax nominal cost of debt has been derived by adding a risk premium to the assumed risk free rate of 8.0%. The risk premium has been determined by benchmarking the cost of debt for comparable companies, with an analysis of the appropriate credit rating.

The two major specialist credit ratings agencies are Standard and Poor's ("S&P") and Moody's. Given the similarity between the two systems this analysis has been restricted to S&P ratings.

The S&P system is divided into two broad ranges:

(1) AAA to BBB which refers to investment grade debt; and

(2) BB to D which indicates speculative grade debt.

Based on the similarities with the recently privatised electricity distribution businesses, existing infrastructure, expected stability of cashflows and the regulated nature of the gas industry, it is assumed that TPA will be rated within the investment grade.

Both public and private debt comparisons suggest a long run debt margin of approximately 60 - 90 basis points for similarly rated debt. Adding this to the risk free rate derived above results in a total cost of debt of 8.60% to 8.90% with a midpoint estimated of 8.75%.

(e) Weighted average cost of capital

Estimates derived in the preceding sections are summarised in table 2.5(e) below.

Table 2.5(e): WACC Inputs

Parameter	Definition	Value
$\frac{E}{V}$	Long term proportion of equity funding	40%
$\frac{D}{V}$	Long term proportion of debt funding	60%
r_e	Post-tax nominal return on equity, pre-imputation	14.19%
r_d	Nominal pre-tax cost of debt	8.75%
T	Corporate tax rate	36%
γ	Proportion of franking credits that are attributed value by shareholders	25%

The benchmark WACC incorporates the effect of dividend imputation, rather than this being built into the cashflows. The imputation adjustment is designed to capture both the "pure" utilisation effect and the effect of the dividend payout ratio. Thus the imputation credit utilisation rate of 25% has been determined in anticipation of:

(1) the expressed ownership structure over the life of each TPA Access Arrangement taking into account current Victorian Government ownership and the Victorian Government's announced intention to privatise the gas businesses it currently owns; and

(2) a low dividend payout ratio relative to free cashflows.

The post-tax nominal WACC is defined by the formula:

$$r_o^i = r_e \frac{(1-T)}{(1-T(1-\gamma))}\frac{E}{V} + r_d(1-T)\frac{D}{V}$$

Applying this formula with the above parameters gives a post-tax nominal WACC of 8.34%. This can be converted to other specifications as described below:

(3) a pre-tax WACC is determined by "grossing up" the post tax WACC by a factor of (1-T); and

(4) a real WACC is determined by applying the Fisher equation using the forecast inflation rate.

Assuming a constant inflation rate of 3% the WACC specifications set out in table 2.5(e) below can be derived.

Table 2.5(e): WACC Specifications

WACC Specification	Value
Post-Tax Nominal	8.34%
Post-Tax Real	5.18%
Pre-Tax Nominal	13.02%
Pre-Tax Real	9.73%

A pre-tax real rate of return of 9.73% is therefore applied to the asset valuation to calculate the return-on-capital element of the target revenue.

2.6 Capital related component of target revenue (*Depreciation Schedule*)

Depreciation Schedule is the term that is used in the Victorian Access Code to describe the means by which a return of and on capital is provided.

There are a number of options for constructing the *Depreciation Schedule*. The following three options were considered by EPD:

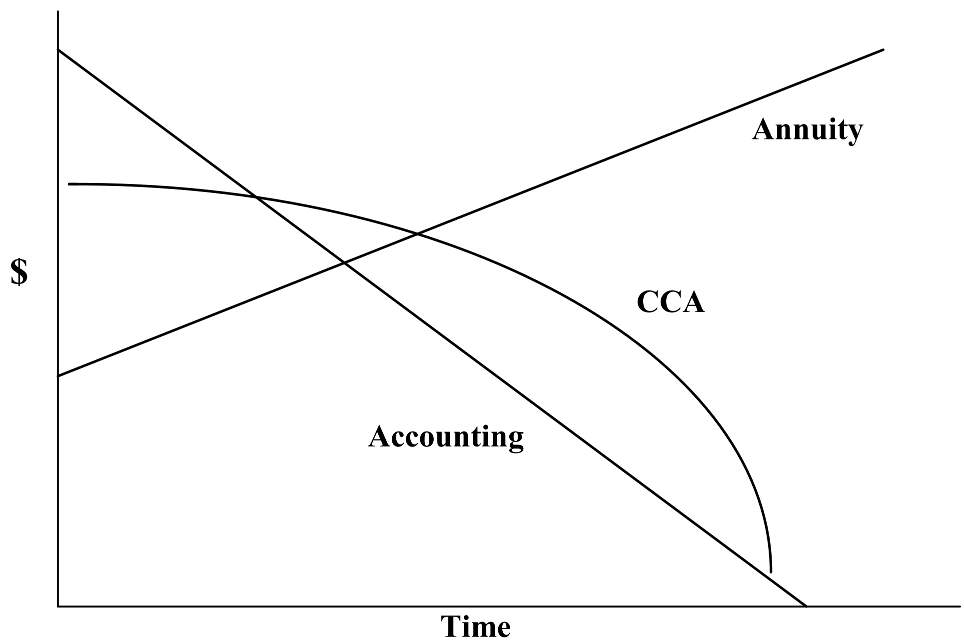
(a) nominal accounting method;

(b) current cost accounting method (real return); and

(c) real annuity method.

Each of these approaches produces an income stream that, when discounted at the appropriate WACC, produces an identical NPV. The difference lies in the timing of the cash flows. The general pattern of each option is illustrated in figure 2.6 below.

Figure 2.6: Target revenue under different methodologies



EPD considered that the CCA method represented a reasonable compromise between:

(a) the economically "rational" annuity approach; and

(b) the capital market preference for a front-ended income stream.

CCA is also a relatively straight forward method for the business and the Regulator and for monitoring by other interested parties.

The CCA method adopted has two components:

(a) depreciation = accounting charge * $(1 + CPI)^n$

(b) return = written down value ("WDV") of assets * real WACC

The WDV of assets is determined as follows:

WDV of assets brought forward * $(1 + CPI)^n$ + 50% of current year capex * (1 + CPI)

The 50% discount on current year capital expenditure is intended to provide for a pattern of expenditure throughout a year.

2.7 Operational costs

Initial forecasts of operational (ie non-capital) costs have been developed by TPA for the five years to 31 December 2002. These forecasts included operating efficiency savings which may be achieved by TPA. EPD have reviewed these forecasts to take into account further estimated efficiency savings. These adjusted forecasts are summarised in table 2.7 below.

Table 2.7

Year ending 31 December ($m)	1998	1999	2000	2001	2002
Operational costs	19.5	19.6	19.4	19.1	19.2

Use of system costs comprise:

(a) "Other Costs" which include occupancy, training, travel, taxes and charges, motor vehicles, fringe benefit tax and other sundry costs. Overheads and marketing expenditure are also included within "other costs" as they are not significant components of overall operational costs.

(b) Operations gas is used by TPA in providing transmission services and includes:

(1) fuel gas for compressors;

(2) compressor station auxiliary gas;

(3) gas venting from regulator controllers; and

(4) operating gas for odourant pumps.

Approximately 90% of operations gas is used for compressor station operation which allows TPA to augment capacity throughout the Transmission System. The TPA compressors are located at Gooding (Gippsland), Wollert and Brooklyn.

Base fuel gas for the operations listed above is included as a common cost in tariff determination. This cost, as per the methodology, is recovered via the anytime charge.

The compressor gas to be used for underground storage operation is not included in tariff determination. The cost of this gas is to be recovered via the anytime charge applicable at Corio during the fill period (October to March).

At present, custody transfer metering between the transmission and distribution systems is incomplete, so that physical loss in the transmission system cannot be measured directly. Until these meters are installed, unaccounted for gas ("UAFG") is based on an estimated loss of 0.2%.

2.8 Return on net working capital

Target revenue includes a return on the net working capital employed in the regulated business. The return provided is based on the nominal pre-tax WACC.

2.9 Target revenue summary

Target revenues for the five year tariffing period are set out in table 2.9 below.

Table 2.9

Year ending 31 December ($m)	1998	1999	2000	2001	2002
Target revenue	70.2	72.2	74.8	77.1	77.3

2.10 Setting X

Target revenue figures are determined as above and supplied to the tariff setting process. Year 1 tariffs are determined by the process described in section 3 (including the levelisation described in section 3.4(b)).

X is initially a derived figure that represents the value that solves the following equation:

$$\begin{aligned} \text{NPV of } TR_{y1\text{-}5} = \text{NPV of } [&RGJ_{y1} * V_{y1} \\ &+ RGJ_{y1} \times (1+CPI-X) * V_{y2} \\ &+ RGJ_{y1} \times (1+CPI-X)^2 * V_{y3} \\ &+ RGJ_{y1} \times (1+CPI-X)^3 * V_{y4} \\ &+ RGJ_{y1} \times (1+CPI-X)^4 * V_{y5}] \end{aligned}$$

Where:

$TR_{y1\text{-}5}$ = Target Revenues for Years 1 to 5;

RGJ_{y1} = Average revenue per GJ of gas consumed for Year 1;

V_{ya} = Forecast gas consumption for Year a (measured by total anytime volume); and

CPI = the change in the Consumer Price Index which is assumed to be 3% per annum.

EPD has then considered the whole process of setting target revenue and the levels of productivity improvement built into the forecasts. In the context of this it has set X at a level that it judges represents best practice for a similar company including foreseeable improvements in best practice over the five year period.

X for TPA for the five year period to 31 December 2002 has been set at 3.4%. This results in a forecast revenue stream based on an annual maximum average charge as set out in table 2.10 below. The target revenue derived has materially the same net present value as the target revenue set out in table 2.9 above.

Table 2.10

Year ending 31 December ($m)	1998	1999	2000	2001	2002
Forecast revenue	70.2	73.1	74.2	76.4	77.4

3. Cost allocation and tariff setting

3.1 Introduction

This section is designed to demonstrate the basis upon which tariffs for tariffed transmission services have been determined. A cost of service model has been adopted: that is, the tariffs have been designed to recover the target revenue as defined and calculated in the previous section, given the forecast utilisation of the various services. Utilisation forecasts are listed in Section 5 below.

The calculation of tariffs proceeds in three main stages which are summarised below. These stages are described in more detail in the remaining clauses of this section.

(a) The target revenue is allocated between the different services provided in earning this revenue. These services are: transmission injection service, transmission delivery service and matched flows. These services are described in the *Tariff Order*.

(b) The target revenue for each service is then further allocated between revenue that should be recovered at peak only ("capacity-driven" costs) and those to be recovered throughout the year ("commodity-driven" costs). These costs are allocated to each offtake point and injection point (as appropriate) across the Transmission System.

(c) Using the forecast levels of utilisation of each service, the total revenue to be recovered at each location is converted to a $/GJ tariff such that, if the outturn is in line with the forecast, the planned costs will be recovered at each location, and the overall target revenue will be recovered.

Tariffs are established for Year 1 (1998) only. In subsequent years, tariffs will be modified in accordance with the regulatory formulae set out in the Tariff Order.

3.2 Pricing principles and approach for tariffed transmission services

(a) Pricing principles

(1) Consistency with Victorian Access Code

It is a requirement that the developed tariffs are consistent with the requirements of the Victorian Access Code. The objectives for a tariff, as stated in the Victorian Access Code, are in summary to:

(A) recover the efficient costs of providing the service;

(B) replicate the outcome of a competitive market;

(C) ensure safe and reliable pipeline operation;

(D) not distort upstream or downstream pipeline investment decisions;

(E) be efficient in level and structure; and

(F) provide incentives to the Service Provider for cost efficiency and market development.

(2) Cost reflectivity

Costs of transmission assets and operation are allocated to users according to their use of those assets and benefit received from operation. This minimises cross subsidies and provides a fair basis for charging.

(3) Efficient pricing signals

As far as possible, tariffs for a particular tariffed transmission service are priced at a level commensurate with the long run marginal cost of providing that service. This allows users to make an efficient decision as to whether to continue to use that service or to seek cheaper alternatives: for example load management or local storage. It also provides appropriate locational signals for new users making siting decisions and to developers in regard to bringing on new gas sources.

(4) Recovery of allowed revenue

TPA will be subject to average revenue-yield regulation which will define the maximum average revenue that TPA is allowed to recover from the sale of tariffed transmission services in a particular year. The revenue regulation aims to allow TPA a reasonable return on assets, whilst providing tariff stability for users and incentives on TPA to improve operational efficiency. Average revenue regulation has been developed by the financial and accounting advisers of EPD. The tariffs are designed to recover the target revenue, based on forecasts of transmission service utilisation.

(5) Price stability

As far as possible, the tariffed prices at each offtake should be stable; that is, while they will change over time, they should not fluctuate capriciously. This is consistent with providing long-run pricing signals and does not prevent bilateral contracts in which charging parameters may fluctuate to a greater extent, reflecting short-run changes in circumstances.

(b) Pricing approach

The approach taken is to separate the target revenue into different cost categories.

These cost categories are identified by separating:

(1) injection costs and delivery costs;

(2) locational costs and common (non-locational) costs; and

(3) peak capacity-driven costs and "anytime" commodity-driven costs.

(1) Injection and delivery costs

These costs and the approach to charging for them are discussed below. Transmission services are defined and charged based on separation of an "injection service" and a "delivery service". This is consistent with the design of the wholesale market, where gas can be pooled as well as traded bilaterally.

Thus, whereas in a traditional transmission model, a user would pay to transport gas from A to B, in the approach described here, the user pays for injection at A and delivery at B. This allows a retailer flexibility to purchase gas from alternative sources. For example, it could instead purchase from C (and pay the injection charge at C) or purchase direct from the Pool (and pay no injection charge[10]).

Injection and delivery costs are separated by defining a "hub" or "balancing point": a physical location in the transmission system[11]. Injection costs are those costs involved in physically transporting gas from the injection point to the hub; delivery costs are those costs involved in physically transporting gas from the hub to the delivery point.

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[10] At least directly, though this would be expected to be included in the Pool prices where relevant.

[11] In the proposed tariffs, the hub is chosen to be located at the Pakenham offtake.

Thus a user paying the injection charge at A and delivery charge at B pays the full cost associated with transport from A to B. However, a purchaser from the Pool only pays directly the costs from the hub to the delivery point.

(2) Matched injection/delivery

In some cases, the physical path from A to B will not go via the hub: for example if A is Longford and B is Maryvale. In this case, the user may arrange a "matched injection/delivery" which specifies the injection and delivery points and ensures that the user pays only the subset of injection or delivery costs required to transport the gas from A to B. The user will be required to show a match between the gas injected at A and the gas delivered at B. Matched injection and delivery are described in more detail in clause 3.5.

(3) Locational and common costs

Locational costs are those which are specific to users in certain locations. In other words, a particular cost is locational if it arises from the provision of transmission service in some areas but not other areas. Typical locational costs would be capital and operational costs arising from pipelines and compressors. Common costs would include corporate overheads and system operation.

Common costs are spread across all users through a "postage stamp" charge: ie a charge which applies equally to all users irrespective of location. Locational costs, on the other hand, will be shared between users who use services which make use of the relevant locational asset. The allocation mechanism is briefly described below.

Locational costs are separated in twenty four, geographically defined, asset groups. Asset groups are then defined as either injection or delivery, based on the definition above. The costs of each asset group then follow the flow of gas into, through and out of the pipelines in that asset group. Gas flows are based on the expected physical flows on the Transmission System.

Therefore, the more remote a delivery point is "downstream" from the hub, the more asset groups are involved in flowing gas between the hub and the delivery point, and hence the higher the charge. The process for allocating locational costs is described in more detail in clause 3.3.

(4) Capacity-driven and commodity-driven costs

Capacity-driven costs are incurred in order to provide transmission capacity - ie the ability to provide gas. Commodity-driven costs only arise when gas actually flows. A third category of costs - administration and management - are incurred irrespective of gas capacity or gas flow.

In order to provide efficient tariffs, capacity-driven costs are allocated to transmission services provided in peak conditions. This is because increased gas flows at peak create a need for additional transmission capacity whereas increased gas flows away from peak do not. Commodity-driven costs are charged at all times, for similar reasons.

3.3 Cost allocation

(a) Overview

The key outcome of the methodology employed is to reflect the users' physical use of the system assets. This is intended to be a proxy for long-run incremental costs of Transmission System use. Users of the Transmission System are those parties that inject gas at the injection points and those who accept delivered gas at the delivery points.

Non-system costs cannot be allocated on a cost-reflective basis and so are allocated on a "common" basis to all gas delivered from the Transmission System.

Cost reflectivity is achieved by dividing the Transmission System into asset groups which are classified by physical characteristics (ie changes in pipeline diameters throughout the Transmission System). This definition results in 24 asset groups, to which a component of the cost-based target revenue is allocated.

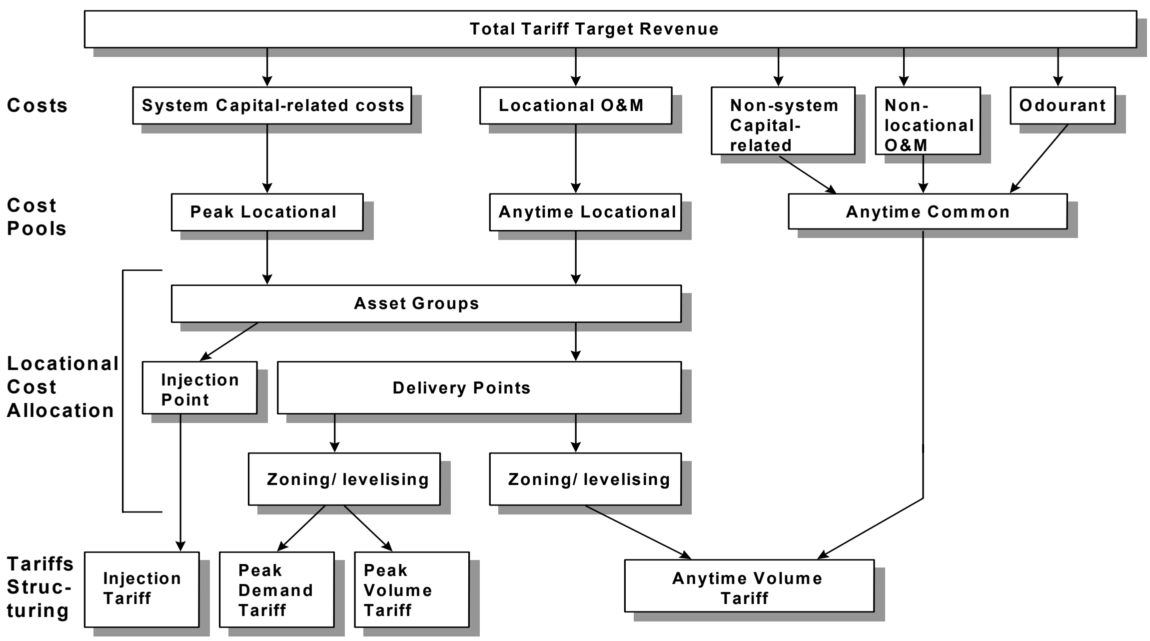
Within the Principal Transmission System there is currently one injection point at Longford and 52 delivery locations (grouped from 106 off-take points). The tariff methodology involves ascertaining the cost of supply from a common reference point, at Pakenham, through asset groups to the delivery locations.

In line with service definitions, injection and delivery assets are separated for cost allocation and tariff charging purposes. Transmission assets upstream of Pakenham are treated as injection assets.

The methodology involves calculating volume-distance (and demand-distance) delivery point costs. These costs are derived from the transmission network target revenue (capital-related and operating and maintenance ("O&M") costs) which are allocated to each costs asset group.

The actual *Reference Tariffs* are set zonally, based on the volume and demand-weighted average of the delivery point allocated costs within each defined zone. A flow diagram of the transmission tariff pricing methodology is shown in flowchart 3.3(a) below:

Flowchart 3.3(a)



The peak demand tariff is paid by Tariff D (demand-metered) customers and the peak volume tariff is paid by Tariff V (volume-metered) customers. Tariff D and Tariff V customers are as defined for distribution charging.

(b) Determining the cost pools

(1) Cost pools

The target revenue is disaggregated into a number of "cost pools[12]", each of which is treated differently in the course of the allocation process which results in the final structured tariffs. The cost pools distinguish costs which are recovered on a "peak" or "anytime" basis, and whether these costs are "locational" or "common".

The cost pools are as set out in table 3.3(b)(1) below:

Table 3.3(b)(1)

Costs	Cost Pool
System capital-related	Peak locational
Non-system capital-related	Anytime common
Locational O & M	Anytime locational
Non-locational O & M	Anytime common

In subsequent steps it will be seen that the system capital-related costs are recovered from peak delivery and injection charges and that peak delivery charges comprise a combination of peak demand and peak volume charges to different customer groups.

(2) Capital-related costs

Capital-related costs comprise the return on capital invested and the return of capital (depreciation). Both calculations are based on the value of assets employed.

Separate capital-related cost calculations have been undertaken for each of the asset classes set out in table 3.3(b)(2) below, based on the net values of those assets, a common "weighted average cost of capital" and the specific total economic lives and remaining lives for the assets in each asset class.

Table 3.3(b)(2)

Asset Class	Cost Pool
Pipeline and Longford regulators	Peak Locational
Compressors	Peak Locational
Longford odourizing plant	Peak Locational
Paraatte odourizing plant	Peak Locational
Land, buildings and other non-system assets	Anytime Common

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[12] The word cost will be used in the remainder of this section to include the "cost of capital" (ie return on capital) and depreciation (ie return of capital) components. Whilst strictly the tariff methodology is an allocation of components of target revenue, this exercise is often referred to as a "cost of supply" and with a cost-based revenue requirement the two are synonymous.

The peak locational costs are allocated to asset groups and subsequently to delivery and injection zones as described in clauses 3.3(c), (d) and (e). The anytime common costs are pooled for subsequent determination of the anytime volume delivery charge (see clause 3.3(f)).

(3) O & M costs

In line with the tariff design objective of cost reflectivity, activity based costing is used to map supply costs back to the "activity" or services. This also vests accountability back to parties who best control the respective cost components to incentivise performance.

The O & M costs are allocated to cost pools as set out in table 3.3(b)(3) below. Note that costs relating to the Principal and Western Transmission Systems are kept separate.

Table 3.3(b)(3)

O & M costs	Cost Pool
Pipeline and Longford Regulators	Anytime Locational
Compressors (including fuel gas)	Anytime Locational
Longford odourizing plant	Anytime Locational
Paraatte odourizing plant	Anytime Locational
Odourant	Anytime Common[13]
Land, buildings and other non-system	Anytime Common
Administration and management	Anytime Common

(c) Allocation of locational costs to asset groups

The locational costs for each transmission system (ie, for the Principal Transmission System and the Western Transmission System) are allocated into 24 defined asset groups, each asset group consisting of a length of pipeline of the same diameter or characteristic between network "nodes".

(1) Allocation of locational capital-related costs to asset groups

The "demand locational" cost pools for each asset class (ie pipelines, compressors and terminal stations) are allocated to each of the 24 asset groups using their respective (gross) ORC.

The apportionment has been based on ORC so that users are charged in relation to the service potential of the assets. By using the ORC, the age of the individual system assets become irrelevant and users of newer parts of the system are not "unfairly" penalised. This becomes a key issue as the assets are depreciated and refurbished/replaced.

Use of the ORC will smooth out variations in the allocation of costs over time (eventually flowing through to tariffs); this will produce greater future price stability and will remove

[13] Because, in the tariff structuring, the Common costs are recovered on a commodity (ie volume) basis, the commodity costs are aggregated into the Common costs pool.

any charge-related interest that users might otherwise have in TPA's replacement decisions.

(2) Allocation of locational O & M costs to asset groups

The "anytime locational" cost pool (comprising locational O & M costs) is allocated to asset groups as set out in table 3.3(c) below.

Table 3.3(c)

O & M related to Asset Classes	Allocation to each Asset Group
Pipeline O&M	Allocated in proportion to the length of pipeline in each asset group in relevant transmission system (Principal or Western).
Compressor O&M	Allocated between compressor stations in accordance with fuel gas usage for each station. The costs for each compressor station are then allocated to the asset group in which the station is located.

(d) Allocation of asset group costs to injection and delivery points

The Longford injection point target revenue is based on capital-related costs for the asset groups employed in transporting gas from Longford to Pakenham (or, for a proportion of the gas, to the delivery points between Longford and Pakenham).

The Western Transmission System does not have an injection charge and all costs are recovered through delivery charges.

Delivery point allocated costs are based on the costs allocated to each of the asset groups employed in transporting gas from Pakenham to each delivery point for the Principal Transmission System. The "peak" and "anytime" cost pools (comprising system capital-related costs and locational O & M costs respectively) are allocated using the same method, but kept separate for subsequently different treatment during the price structuring (see clause 3.4(c)).

For the Western Transmission System, the target revenue is based on transporting gas from the single injection point which is within the delivery zone.

All cost allocation is based on the physical flow of gas through the Transmission System, using the physical load flow.

Peak locational delivery point costs are based on demand-distance relationships. These apply both for delivery to offtake and for demands for gas which is transported through each asset group. Specifically:

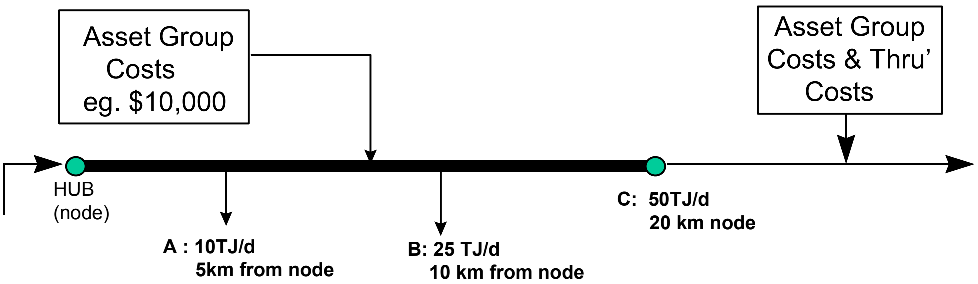
(1) within each asset group, the costs associated with that asset group are allocated to each delivery point on a demand-distance basis;

(2) Asset group costs are also allocated to gas as it flows out of the asset group and into the next asset group ("through costs"), on the same demand-distance basis; and

(3) "through costs" derived from the upstream asset group are allocated to delivery points and through points based on demand only.

Figure 3.3(d) below provides a worked example of this allocation process.

Figure 3.3(d)



Example:

	Volume-Distance Calc.	**Allocated Cost**	**Tariff**
Delivery Point A Delivery Point B Thru Cost	5km * 10 TJ/d = 50 TJ.km 10km * 25 TJ/d = 250 TJ.km 20km * 50 TJ/d = 1,000 TJ.km	(50/1300 * $10,000 = $385) (250/1300 * $10,000 = $1,923) (1,000/1300 * $10,000 = $7,692)	$0.038/GJ $0.077/GJ $0.153/GJ
TOTAL	**1,300 TJ.km**	**$10,000**	

The same process is used for "anytime" volume-related locational costs for each asset group, except that these are allocated based on volume-distance rather than demand-distance.

3.4 Tariff pricing and structure

(a) Zoning

For price structuring purposes, the costs allocated to the 52 delivery points are aggregated into eight transmission pricing zones. These have been chosen to provide a reduced set of tariffs whilst still preserving material cost of supply differences. They are defined on the basis of specific delivery points.

The Victorian gas transmission pricing zones are defined as follows:

<u>Principal Transmission System</u>

Zone 1 : Latrobe

Zone 3 : Lurgi

Zone 4 : Metro

Zone 5 : Calder

Zone 6 : South Hume

Zone 7 : Echuca

Zone 8 : North Hume

<u>Western Transmission System</u>

Zone 9: Western

The transmission pricing zones are shown on a map of Victoria in Appendix 2 to this document.

The result of the locational cost allocation process is:

(1) locational anytime costs for each of the eight transmission pricing zones; and

(2) locational peak demand costs for each of the eight transmission pricing zones.

In addition to the Delivery Point zoned tariffs, other pipelines directly connected to the Transmission System will pay tariffs specific to their connection points. (In the same way that TPA calculates "through costs" where its pipelines extend the Transmission System). This more specific tariff is offered to recognise the impact and nature of these new pipelines, that is they do not supply distribution systems (end-users) directly and the loads at these offtakes could distort the zonal average to be passed through to end-users. Specific transmission pipeline connection tariffs will be published initially for:

(1) Chiltern Valley (for Murray Valley);

(2) Carisbrook (for Wimmera); and

(3) Barnawatha (for interconnect).

(b) Levelisation

Due to the variable nature of planned expenditures and possible gas flow changes on the transmission system, yearly tariffs (if calculated using an annual cost allocation process) at particular delivery points can fluctuate materially - some up and some down - though the average tariff across all delivery points remains reasonably stable. In order to provide tariff stability at each delivery point and not just in aggregate, it was decided to levelise (or smooth out) the tariffs for the period of the Tariff Order.

The first step of the levelisation process involves taking the allocated zonal costs for each of the five years of the Tariff Order period and calculating a net present value ("NPV"), as at 1 January 1998. This was done for each of the eight transmission pricing zones.

A 1998 tariff was then calculated for each of the eight transmission pricing zones, which when indexed annually at the "CPI-X" calculated as part of the regulatory design and applied to forecast volumes for each year, recovers a revenue stream with an equivalent NPV to that calculated in step 1.

This process was undertaken for each component of the structured transmission tariffs.

(c) Tariff structure

Three cost pools are determined, from the steps described in clause 3.3(b) above. These are used to calculate the structured tariffs set out in table 3.4(c) below.

Table 3.4(c)

Cost Pool	Structured Tariff Component
Locational peak	Allocated to each of the eight delivery zones, the three specific transmission pipeline connection points and to the Longford injection point, these costs are the basis for the peak demand, peak volume and peak injection tariffs for each zone
Locational anytime	Allocated to each of the eight delivery zones and the three specific transmission pipeline connection points, these costs are the basis for the anytime locational volume tariff component for each zone
Common anytime	These costs are the basis for an anytime common volume tariff component

For tariff presentation purposes, and because they are charged on the same basis, the locational and common anytime volume tariff components are combined for each transmission pricing zone into a single anytime volume tariff.

Because customers (or their retailers) are to be charged on the bases which reflect their metered levels, the locational peak tariffs for each transmission pricing zone are converted to two tariffs:

(1) peak[14] demand for Tariff D customers; and

(2) peak (winter) volume for Tariff V customers,

as specified for distribution charging purposes and both tariffs are specified for each transmission pricing zone.

In each case, the relevant tariffs are determined by dividing through the costs finally allocated to that tariff, by the charging parameters for that tariff (ie five peak day demands, peak volumes and anytime volumes) estimated for the same year that the target revenue calculation applies to (initially 1998).

3.5 Tariff charging

(a) Charging basis

The proposed basis for TUoS charging is summarised in table 3.5(a) below.

[14] The "peak" period comprises the months of June, July, August and September.

Table 3.5(a)

	Delivery Service Tariff D Customers	Delivery Service Tariff V Customers	Injection Service
Peak Charge	Actual gas delivered on the five days of highest system demand over the peak period (June to September): "Peak Demand"	Actual gas delivered over the peak period (June to September): "Peak Volume"	Actual gas injected on the five Peak Longford Injection days over the peak period (June to September): "Peak Injection"
Anytime Delivery Charge	Actual gas delivered over the calendar year	Actual gas delivered over the calendar year	Not charged for Injection

Consistent with above charging bases, the Transmission Pipeline Supply Point customers and Western Transmission System charges are computed as follows:

(1) Transmission Pipeline Supply customers -five peak days at each Supply Point; and

(2) Western Transmission System - five peak days of the Western Transmission System.

Customers will be categorised into two categories: Tariff D customers and Tariff V customers.

(3) Tariff D customers as defined in the Tariff Order with an annual consumption volume greater than 10,000 GJ or an hourly quantity greater than 10 GJ MHQ (daily metered); and

(4) Tariff V customers as defined in the Tariff Order. These will be all other customers (non daily metered) who will be charged based on volume.

Note that the customers themselves are not directly charged TUoS (unless they become direct pool customers once contestable). Retailers will be charged TUoS, according to the types of customers they supply.

Where the terms "Peak Demand", "Peak Volume" and "Peak Injection" are used below, they are as defined in the above table.

(b) Matched injection and delivery

(1) Matched injections

Where gas is injected upstream from the hub that can be shown to be supplying a customer which is connected to a delivery point on the same pipeline radial also upstream from the hub (ie the hub does not lie on the physical path linking the injection and offtake points), the relevant retailer is entitled to a lower injection tariff: an example would be gas injected at Longford supplying a customer in the LaTrobe pricing zone. Since gas cannot be physically tracked, it is sufficient for the retailer to show that its Peak Injection at the relevant injection point and Peak Demand at the relevant offtake point are both at least equal to the quantity on which a matched injection is claimed.

For example, if retailer X had a Peak Injection of 100TJ at Longford and Peak Demand of 20TJ in the LaTrobe pricing zone, it would be entitled to the matched injection tariff for 20TJ. It would pay the normal injection tariff for the remaining 80TJ.

(2) Matched delivery

Where gas is injected downstream from the hub that can be shown to be supplying a customer which is connected to a delivery point on the same pipeline radial also downstream from the hub (ie the hub does not lie on the physical path linking the injection and offtake points), the relevant retailer is entitled to a lower delivery tariff: an example would be gas injected at Barnawatha (through the NSW interconnect) supplying a customer connected at Wodonga. Since gas cannot be physically tracked, it is sufficient for the retailer to show that the relevant injected and delivered quantities are at least equal to the quantity on which a matched injection is claimed.

Because delivery charges may be levied on Peak Demand or Peak Volume, depending on the customer class, the injection must match in kind to the offtake. So, for example, if a retailer wished to claim the matched delivery tariff for 10TJ of Peak Demand and 200TJ of Peak Volume, it would be required to show that its relevant injection exceeded 10TJ over the peak 5 days and exceeded 200TJ over the winter period. Note that injection contributing to the Peak Injection cannot also be counted towards the injected Peak Volume. Again, any offtakes in excess of that matched with an injection would pay the usual delivery tariff.

(c) Metering and settlement

(1) Defining injected and delivered quantities

Charges will be based on the allocation between retailers of the metered daily quantities at the custody transfer meters ("CTMs") at delivery points and injection points. The allocation will be done as part of the gas settlement process. The quantities referred to below are assumed to be settlement ("UAFG adjusted") volumes

For delivery points, each retailer's allocated daily quantity ("ADQ") will then be split between Tariff D and Tariff V customers. The Tariff D customer daily quantity will be derived by aggregating the actual daily meter reads for all Tariff D customers supplied from the relevant offtake point and by the relevant retailer.

The Tariff V customer quantity will then be deemed to be the residual: ie

Tariff V customer daily quantity = ADQ - Tariff D customer daily quantity

Daily injected quantities will be defined by the wholesale market settlement.

Peak Injection and Peak Demand will be calculated by aggregating the daily quantities over the five days of highest system demand (calculated by aggregating the daily offtake at all the TPA offtake points). Peak Volume will be calculated by summing up the Tariff V customer daily quantity over the peak period.

(2) Payment process

Payment for transmission services will be sculpted based on the forecast load profile over each calendar month commencing 1 January 1998. These payments will recover the anytime, peak delivery and injection charges referred to in Table 3.5(a).

Prior to the beginning of each calendar year each retailer's forecast anytime, peak and injection volumes will be used to estimate that retailers contribution to TUoS revenue. This revenue will then be sculpted based on monthly load forecasts to yield forecast monthly retailer payments.

Each year after the peak winter period, that is, once winter volume and peak data has been collated, actual retailer transmission anytime, peak delivery and injection charges will be calculated and a reconciliation versus forecast payment made.

The reconciliation adjustment will be issued in early December and be payable by year end. Forecast sculpted payments will be payable a month in arrears for services up to the end of November. Anytime payments for December will be payable a month in arrears based on the ADQs from each transmission pricing zone.

4. Tariff path and incentive structure

4.1 Introduction

This section is designed to explain the regulatory revenue control and the considerations that led to its adoption. It also describes the incentive structure built into the revenue control and the effects it is intended to encourage. The average revenue control is set out in schedule 5 of the Tariff Order.

4.2 Regulatory revenue control

(a) Regulatory objectives and assessment criteria

In selecting a revenue control method EPD has given consideration to the following objectives:

(1) to encourage the use of gas where it is economically efficient to do so;

(2) to develop a competitive market at all levels of the gas industry, where this is possible;

(3) to design regulatory structures in monopoly areas that:

   (A) protect customers against monopolistic exploitation; and at the same time

   (B) provide incentives to the owners of monopoly assets to use them efficiently for the benefit of the market as a whole;

(4) to prevent a party, at any level, from acting to prevent the emergence of competitive forces at its own, or any other, level; and

(5) to protect the interests of consumers of gas who have expectations of the gas industry by reason of its past pricing behaviour.

It is generally accepted that the main challenges in the Victorian gas reform centre on three issues:

(1) creating competition at the supply end;

(2) increasing asset efficiency in the transmission and distribution sectors; and

(3) creating effective retail competition.

Following from these objectives and challenges, the following list of criteria have been used for the assessment of regulatory options.

(1) Consumer outcomes:

   (A) effect on initial price levels;

   (B) effect on price paths;

   (C) transparency; and

   (D) simplicity.

(2) Effect on the industry participants:

   (A) behaviours that are rewarded;

   (B) behaviours that are penalised;

   (C) impact on competition at each industry level; and

   (D) impact on viability and risk at each industry level.

(3) Ease of regulation and consistency with the Victorian Access Code.

(b) Options considered

Various options were considered by EPD against these criteria. They were:

(1) A revenue cap

This option was discarded on the basis that it was insufficiently flexible and did not provide appropriate incentives to increase asset efficiency.

(2) A price cap

This option was also discarded. It was considered that it placed an inappropriate level of reliance on the initial forecasts of cost drivers and tariff recovery bases and did not provide flexibility for pricing innovation.

(3) An average revenue yield

This is the selected option.

It was considered that an average revenue yield control in the form of maximum transmission revenue divided by the volume of gas requiring transmission provided a powerful incentive for TPA to encourage additional volume while still providing flexibility to adjust individual tariffs and tariff components over time.

EPD considered that:

(i) An revenue yield control is both simple and transparent.

(ii) The incentive effect of an average revenue yield based on delivered volume has been noted. Loss of volume carries an equally strong penalty. While this involves risk to TPA, it is considered reasonable.

(iii) An average revenue yield is relatively simple to administer from a regulatory point of view. It is consistent with the most recent draft of the National Access Code and the Victorian Access Code.

(c) The regulatory revenue control

The form of the control is set out in Schedule 5 to the Tariff Order.

Its basic forms is a maximum average transmission tariff ("MATT") which is based on a set of average tariff per GJ anytime volume by customer class and transmission pricing zone. MATT is then varied each year by reweighting for forecast gas volumes in each customer class and transmission pricing zone, by CPI-X and by a correction (K) factor (see section 4.2(d) below).

The change in prices allowed in any year is then controlled by requiring the forecast maximum average transmission tariff (FATT) to be equal to or less than MATT.

(d) Correction (K) factor

Transmission revenue is recovered by the application of individual tariff component prices to relevant quantities of the charging parameters (eg. five day MDQ, peak volume etc).

The tariff components are of necessity approved by the Regulator prior to the year to which they apply. To the extent that the actual weightings between charging parameters and the weightings forecast when the tariffs were approved vary, TPA's average revenue may be higher or lower than intended.

Equally, the transmission revenue recovered varies according to in which transmission pricing zones growth in volume does or doesn't occur.

The K factor is intended to adjust for these forms of forecast error in subsequent years.

It does so in a 2 step process:

(1) Ka adjusts for differences between the forecast used to set MATT and the estimated result a year later; and

(2) Kb adjusts for differences between the estimate used to determine Ka and the actual result.

In order to prevent inaccurate forecasts of volumes of gas delivered to interconnected pipelines from distorting the regulatory control, there is a limited right for the Regulator to retrospectively adjust MATT to avoid unwarranted and inequitable K factors.

(e) Rebalancing control

An average revenue yield revenue control approach, on its own, leaves the construction and subsequent variation of tariff components and tariffs to the regulated business. The rationale for this is that it is necessary to provide the regulated business with sufficient flexibility to adjust for better information in relation to cost drivers or for changes in the pattern of cost incurrence.

EPD wishes to provide for a degree of flexibility, but to also protect consumers from substantial movements in tariff components or tariffs. The regulatory regime also includes a rebalancing control in the form of CPI + Y. This control, in effect, prevents TPA from altering any individual tariff component by greater than CPI + Y.

In order to prevent gaining of the regulatory formulae the Regulator will have the right to reject forecasts it is not satisfied with.

4.3 Incentive

With asset related costs (including return) representing around 73% of target revenue, asset efficiency is clearly the most important issue to address in the incentive structure.

The revenue control regime adopted contains incentive for TPA to:

(1) Reduce operating and maintenance expenditure below that forecast.

(2) Reduce the level of capital expenditure below that forecast.

These reductions can only occur to the extent that TPA continues to meet its service envelope and safety obligations.

(3) Increase total volumes of gas transported without inefficient augmention of the Transmission System.

With the volume incentives in place TPA can be expected to, at the very least, actively facilitate the marketing of gas as a fuel source and it may choose to actively market its capacity itself. Alternatively, in the absence of a volume related incentive, TPA could fail to facilitate the marketing of gas thereby undermining achievement of the Victorian Government's objective of a competitive and dynamic gas market.

5. System capacity and volume assumptions

5.1 Description of system capabilities

The Transmission System comprises two networks:

(a) the Principal Transmission System extends from Longford (eastern Victoria) to Geelong (western Victoria) to Ballarat and Bendigo (central Victoria) to Wodonga and Echuca (northern Victoria). Gas to the Principal Transmission System is supplied from the Esso/BHP Bass Strait gasfields; and

(b) the Western Transmission System encompassing supply to Warrnambool, Cobden, Hamilton, Koroit and Portland with gas supplied from Cultus Petroleum operated gasfields at Port Campbell.

The Principal Transmission System extends for 1,392km and operates up to 6,900kPa.

The Western Transmission System extends for 217km and operates up to 10,000kPa.

All pipelines within the Transmission System are protected by corrosion mitigation equipment.

Other than the pipeline assets referred to above, the Principal and Western Transmission Systems contain:

(1) the Dandenong Terminal Station;

(2) Regulator Stations;

(3) 106 offtake points (which will all have custody transfer meters);

(4) 3 compressors (Gooding, Brooklyn and Wollert);

(5) LNG facilities;

(6) Odourization plant at Longford and North Paraatte;

(7) Pipeline easements; and

(8) Line valves.

5.2 Piping system

(a) Maximum delivery capability

Principal Transmission System: 970 TJ/d (Longford-Dandenong)

LNG[15]: 150 TJ/d (Peak Shaving is a competitive service)

Western Transmission System: 35 TJ/d (Currently significant excess capacity)

(b) Pipe sizes

Pipe sizes are set out in Appendix 3.

(c) Transmission volume data

Forecast average daily and peak demand at "city gates" and total annual delivered volume 1998-2002 are set out in table 5.2 (c)(1) below.

---

15 Actual LNG delivery is higher than 150 TJ/d, however operational restrictions are implemented to reserve quantities for the future peak day since fill times are far in excess of delivery times.

Table 5.2 (c)(1)

Demand and Volume	1998[16]	1999	2000	2001	2002
Ave. Demand (TJ/d)	559	585	597	616	627
Peak Demand (TJ/d)[17]	1056	1079	1096	1113	1130
Annual Volume (PJ)[18]	204	213	218	225	229

1998 forecast anytime volume, 5 day demand and peak (winter) volume at each transmission pricing zone are set out in table 5.2 (c)(2) below.

Table 5.2 (c)(2)

Zone	Anytime Volume TJ	5 Day Peak Demand (TJ)	Peak (Winter) Volume (TJ)
LaTrobe	10,769	129	847
Lurgi	1,934	13	441
Metro	166,428	1,297	49,479
Calder	8,257	52	2,864
South Hume	748	5	286
Echuca	4,809	36	651
North Hume	5,828	65	1,266
Western	2,960	29	484
Carisbrook[19]	1,237	38	N/A
Chiltern Valley	349	7	N/A
Barnawatha	835	0	N/A
Total	**204,154**	**1,671**	**56,318**

5.3 Service Envelope

TPA and VENCorp will agree as to the amount of pipeline capacity that TPA will provide to VENCorp under certain variable conditions. This agreement, the Service Envelope Agreement, will establish TPA's obligations, and can be relied upon by VENCorp to seek compensation from TPA where it has not met that obligation. The Service Envelope Agreement is attached as Appendix 4.

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16 Calendar year volumes.

17 Estimates only - not used in tariff setting.

18 Includes transmission pipeline connection loads and UAFG

19 Transmission pipeline connection tariffs apply to Carisbrook, Chiltern Valley and Barnawatha

6. Key performance indicators

6.1 Introduction

(a) Objectives of providing KPIs

The objectives of providing the KPI's as set out in this section are:

(1) to allow interested parties to confirm that operational costs included in the target revenue are reasonable when compared to costs in other Australian gas companies; and

(2) to confirm the overall reasonableness of the revenue and tariff setting approach by comparison of the proposed tariffs with comparable rates in other Australian gas companies.

(b) Data sourcing issues

The level of detail of the comparative analysis of KPIs included in this section has been restricted by the availability of relevant and up-to-date information. Particular problems are that:

(1) industry restructuring in the Australian gas industry has led to a decrease in publicly available information in recent years; and

(2) different approaches to restructuring - and, particularly, the unique industry structure being adopted in Victoria - has made it difficult to compare like with like in respect of the scope of costs and tariffs.

As a result, the figures presented here are at a high level.

(c) Context of KPIs in revenue and tariff setting

It should be stressed that EPD has not relied on KPIs in *setting* transmission revenues and tariffs. As explained in the preceding sections, EPD has used independent experts at each stage of the revenue calculation - setting asset value, capital expenditure and cost of capital - who have used their experience and knowledge to ensure that each element of the target revenue is consistent with international good industry practice. This is considered to be the best approach to ensure that the target revenue as a whole - and hence tariffs - are competitive and realistic.

Therefore, the KPI comparisons presented here are not intended to justify or explain the proposed revenues and tariffs, but rather to allow meaningful comparisons of TPA's cost and revenue forecasts by the Regulator and *Prospective Users*.

6.2 Operational costs

Table 6.2(a) below compares O&M costs of TPA against those of other Australian gas transmission companies. This data is drawn from the BHP submission to IPART, published on page 18 of the draft IPART determination on AGL's Access Undertaking and also from the Australian Gas Association 1996 Statistics. All cost information is in 1997/98 dollars.

Table 6.2(a)

Company	TPA	AlintaGas	Pipeline Auth	PASA
State	Victoria	WA	NSW	SA
Year	95/6	95/6	94/5	94/5
$m	21.4	26.0	19.6	13.1
$m/1000 km	9.7	13.3	10.1	9.9
c/GJ	9.6	17.5	21.3	16.0

Table 6.2(b) below shows the forecast O&M costs for the five years to 2002 that are factored into the target revenue. All cost information is in 1998 dollars.

Table 6.2(b)

Forecast O&M costs	1998	1999	2000	2001	2002
$m	19.5	19.6	19.4	19.1	19.2
$m/1000 km	11.0	11.0	10.9	10.5	10.6
c/GJ	9.6	9.2	8.9	8.5	8.4

6.3 Tariff comparisons

Transmission tariffs cannot be compared directly, due to the vastly different transportation and different pipeline configurations. Instead, table 6.3 below looks at the cost per GJkm of transportation on the major pipelines in Australia. All non-TPA information is obtained from the Australian Gas Association - Gas Supply and Demand Study June 1997. Tariffs are for the year 1997/98, 100% load factor.

Table 6.3

Company	TPA	EAPL	EPIC	EPIC	Alinta
State	VIC	NSW	SA	QLD	WA
From/To	Longford/ Pakenham	Moomba/ Wilton	Moomba/ Adelaide	Ballera/ Wallumbilla	Dampier/ Perth
c/GJkm	0.021	0.054	0.057	0.093	0.100

Appendix 1

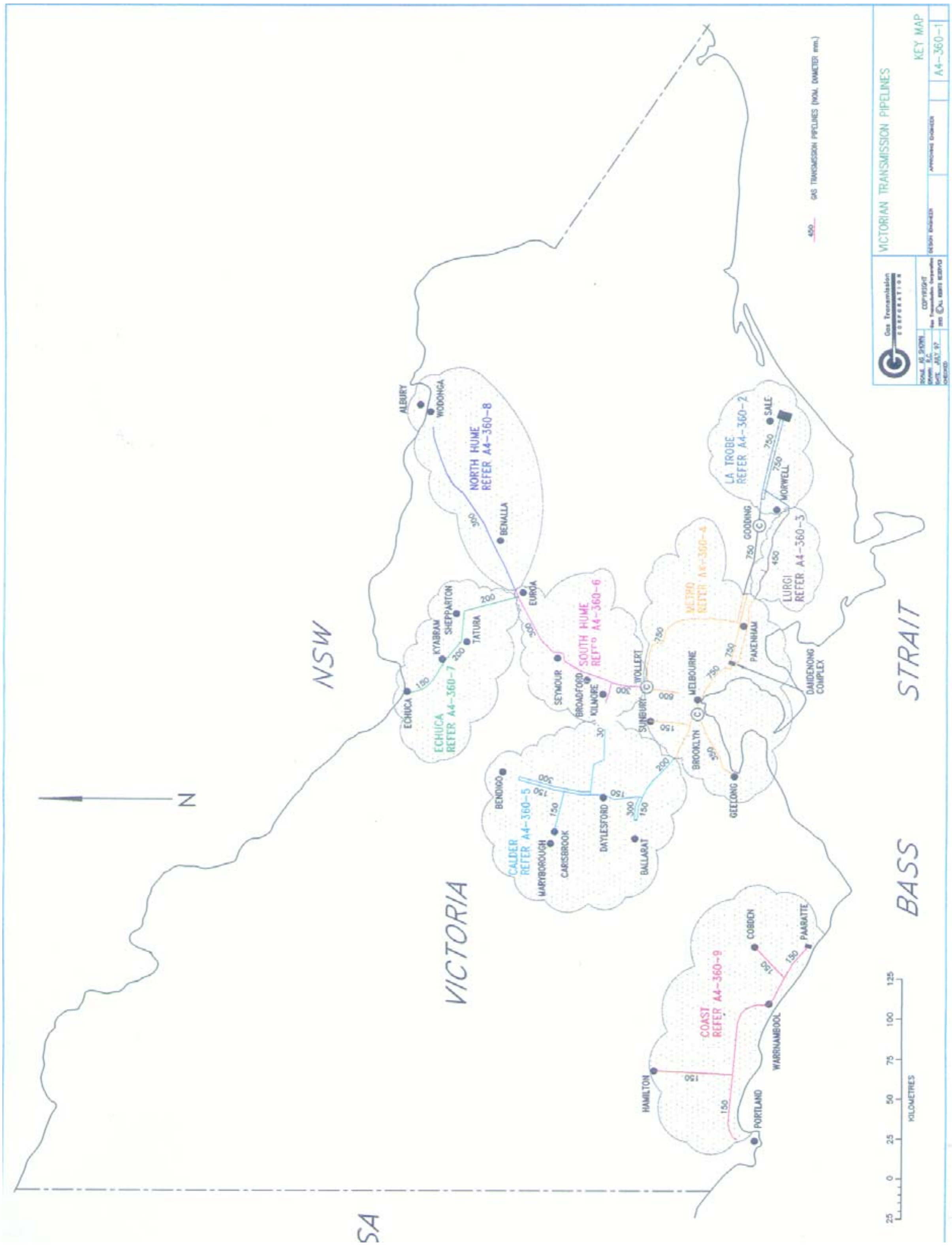
Categories of information to be disclosed by the service provider to interested parties as part of the Access Arrangement Information ("AAI")

Category 1: Information regarding Access & Pricing Principles	**Section reference in AAI**
Tariff determination methodology	2/3/4
Cost allocation approach	3.3
Incentive structures	4.1/4.2/4.3
Category 2: Information regarding Capital Costs	
Asset values for each pricing zone, service or category of asset	2.2/2.3
Information as to asset valuation methodologies - historical cost or asset valuation	2.1/2.2
Assumptions on economic life of asset for depreciation	2.2(c)(4)
Depreciation	2.6
Accumulated depreciation	2.6
Committed capital works and capital investment	2.4
Description of nature and justification for planned capital investment	2.4
Rates of return - on equity and on debt	2.5
Capital structure - debt/equity split assumed	2.5(b)
Equity returns assumed - variables used in derivation	2.5(c)
Debt costs assumed - variables used in derivation	2.5(d)
Category 3: Information regarding Operations & Maintenance	
Fixed versus variable costs	2.7
Cost allocation between zones, services or categories of asset & between regulated/ unregulated	2.7/3.3
Wages & Salaries - by pricing zone, service or category of asset	2.7/3.3
Cost of services by others including rental equipment	2.7
Gas used in operations - unaccounted for gas to be separated from compressor fuel	2.7
Materials & supply	2.7
Property taxes	2.7

Category 4: Information regarding Overheads & Marketing Costs	
Total service provider costs at corporate level	2.7
Allocation of costs between regulated/unregulated segments	2.7
Allocation of costs between particular zones, services or categories of asset	2.7
Category 5: Information regarding System Capacity & Volume Assumptions	
Description of system capabilities	5.2
Map of piping system - pipe sizes, distances and maximum delivery capability	Appendix 3
Average daily and peak demand at “city gates” defined by volume and pressure	5.3(c)(1)
Total annual volume delivered - existing term and expected future volumes	5.3(c)(2)
Annual volume across each pricing zone, service or category of asset	5.3(c)(2)
System load profile by month in each pricing zone, service or category of asset	5.3(c)(3)
Total number of customers in each pricing zone, service or category of asset	N/A
Category 6: Information regarding Key Performance Indicators	
Industry KPIs used by the Service Provider to assess "reasonably incurred" costs	6.3
Service Provider’s KPIs for each pricing zone, service or category of asset	6.2

Appendix 2

Transmission Pricing Zones

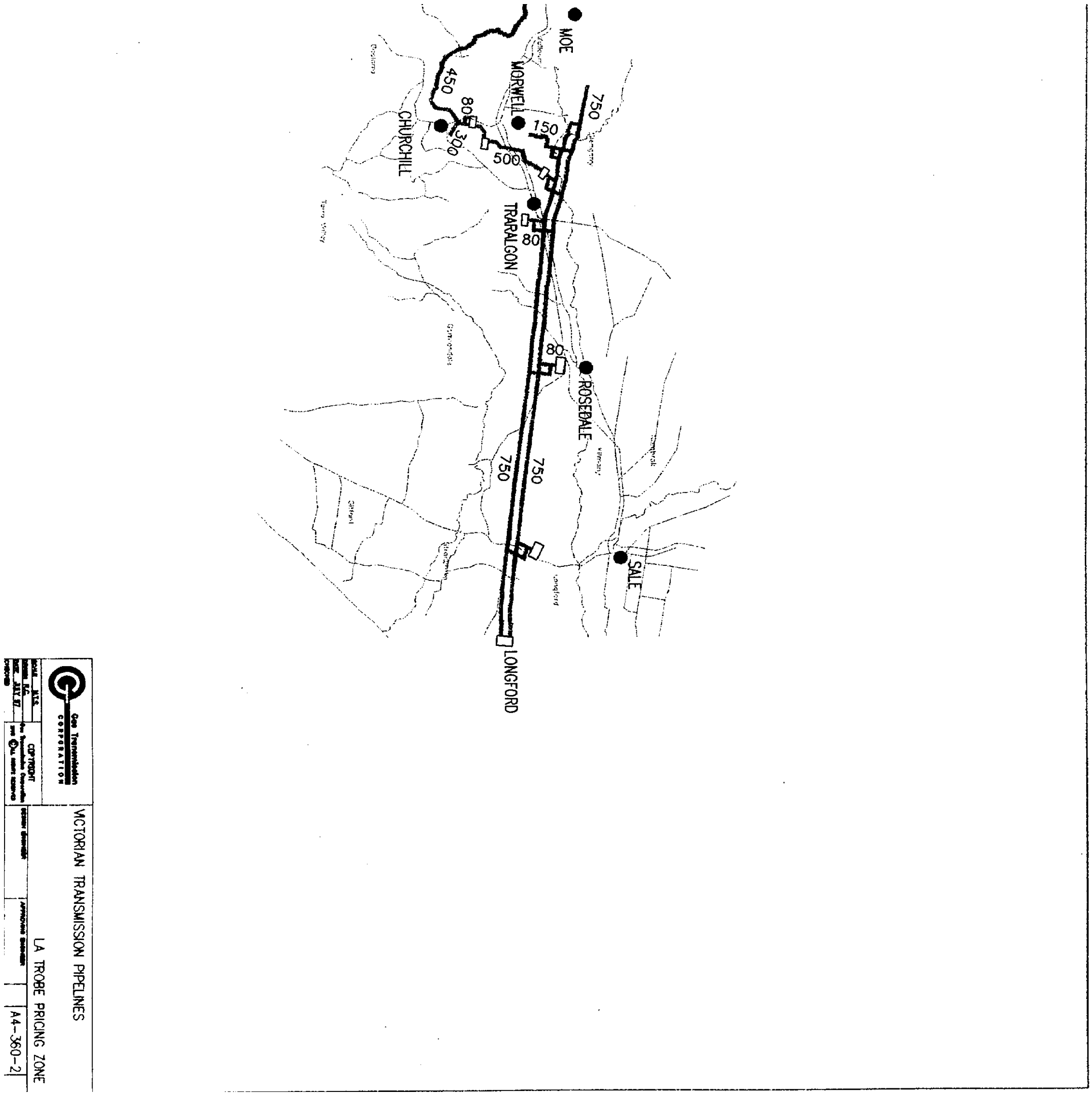


Appendix 3

Description of Transmission System

Pipeline Licence	Location/Route	Length (km)	Pipe Diameter (mm)
	Principal Transmission System		
	Rural Eastern		
Vic: 50	Morwell to Dandenong	126.6	
Vic: 68	Pakenham	1.2	
Vic: 107	Clyde North	2.0	
Vic: 67	Maryvale	5.6	
Vic: 91	Warragul	4.8	
Vic: 75	Longford to Dandenong	173.8	
Vic: 117	Rosedale to Tyers	30. 8	
Vic: 120	Longford to Rosedale	34.3	
Vic: 121	Tyers to Morwell	15.7	
Vic: 135	Bunyip to Pakenham	19.0	
Vic: 141	Pakenham to Wollert	91.0	
	Rural Central Northern		
Vic: 101	Melbourne-Wodonga-Shepparton	303.7	
Vic: 132	Tatura	16.2	
Vic: 136	Tatura to Kyabram	21.3	
Vic: 152	Kyabram to Echuca	30.5	
	Rural Central		
Vic: 78	Brooklyn - Ballarat - Bendigo	180.8	
Vic: 125	Maryborough	33.0	
Vic: 128	Mt Franklin to Kyneton	24.0	
Vic: 131	Mt Franklin to Bendigo	53.0	
Vic: 134	Ballan to Ballarat	23.0	
Vic: 143	Wandong to Kyneton	59.0	
	Rural Western		
Vic: 145	Warrnambool	34.0	
Vic: 155	Allansford to Portland	100.4	
Vic: 168	Cobden	27.7	

Vic: 171	Hamilton	54.6	
	Northern Metropolitan		
Vic: 101	Wollert - Keon Park	14.1	
	South Eastern Metropolitan		
Vic: 36	Dandenong to West Melbourne	34.2	
Vic: 129	Dandenong to Princess Highway	5.0	
	Western Metropolitan		
Vic: 108	South Melbourne to Brooklyn	12.1	
Vic: 122	Derrimut to Sunbury	24.0	
Vic: 124	Newport	1	
Vic: 164	Bay Street to Unichema	0.4	
Vic: 162	Laverton to BHPP	1.6	
Vic: 81	Brooklyn to Corio	50.5	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TRARALGON
ROSEDALE
SALE
LONGFORD
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80
300
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750
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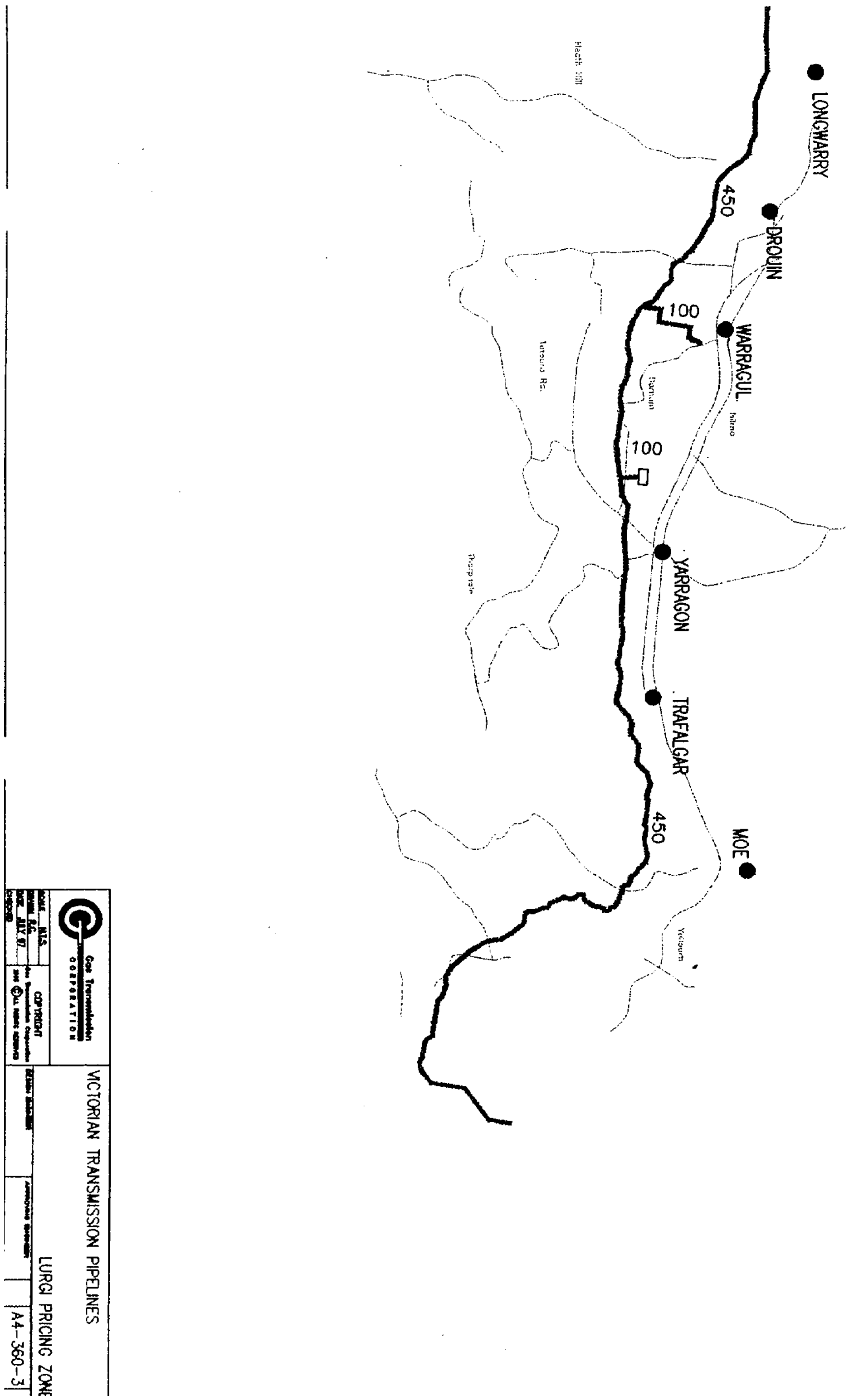
750
750
Gas Transmission Corporation
VICTORIAN TRANSMISSION PIPELINES
LA TROBE PRICING ZONE
A4-360-2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DROUIN
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WARRAGUL
100
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Gas Transmission CORPORATION
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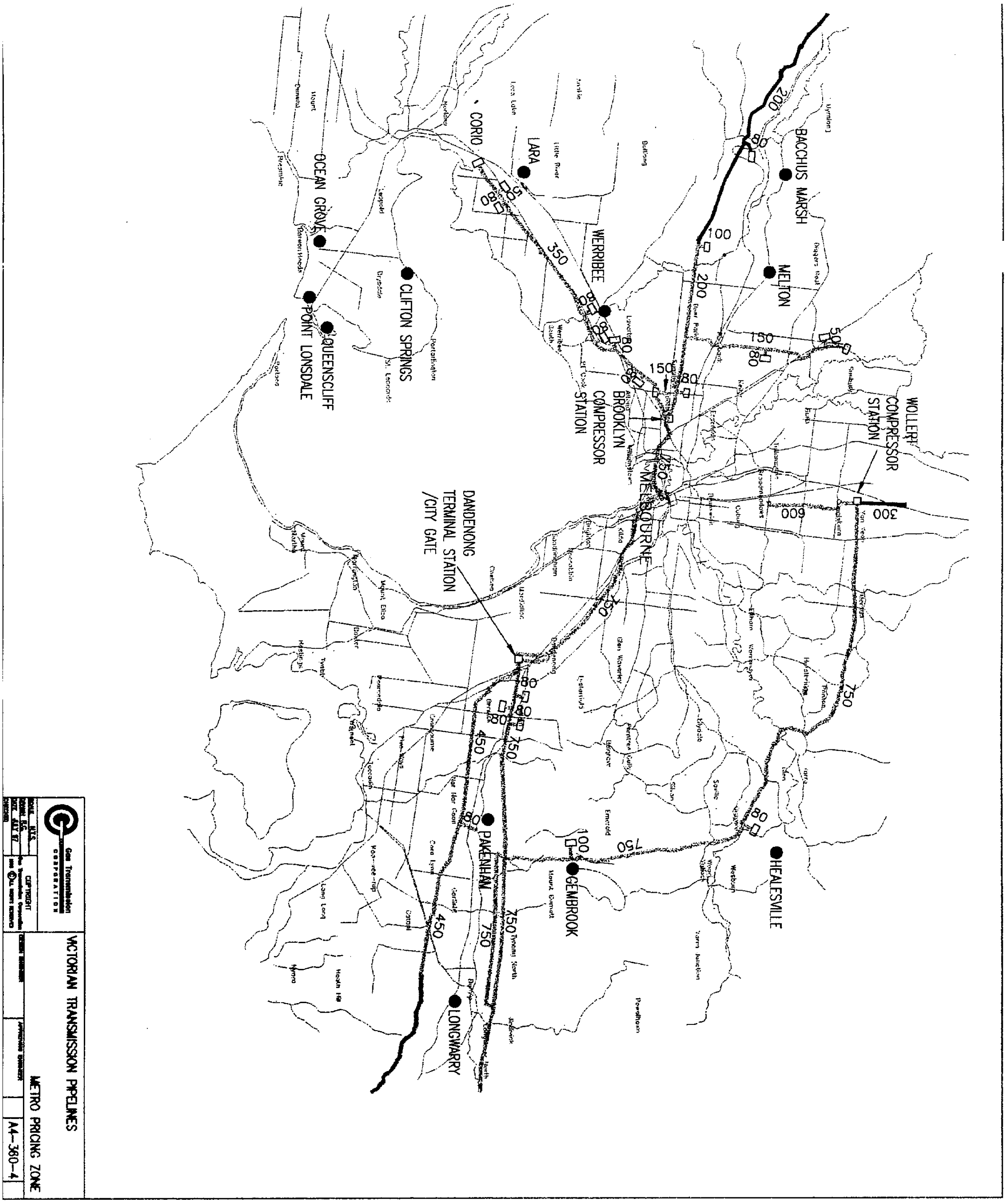
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BACCHUS MARSH
OCEAN GROVE
WERRIBEE
MELTON
CLIFTON SPRINGS
POINT LONSDALE
QUEENSCLIFF
BROOKLYN COMPRESSOR STATION
WOLLERT COMPRESSOR STATION
MELBOURNE
DANDENONG TERMINAL STATION /CITY GATE
PAKENHAM
GEMBROOK
HEALESVILLE
LONGWARRY
VICTORIAN TRANSMISSION PIPELINES
METRO PRICING ZONE
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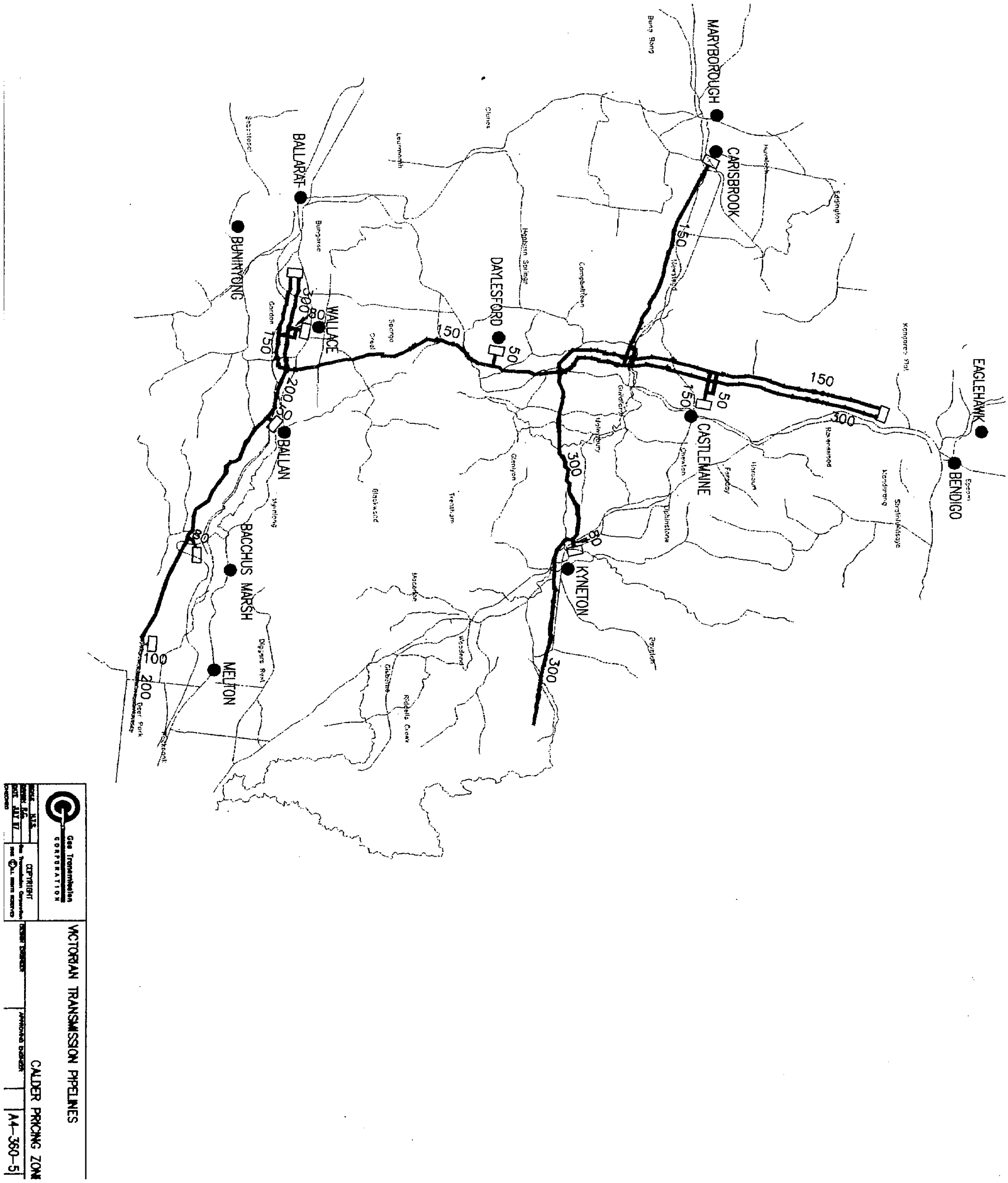
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EAGLEHAWK
CASTLEMAINE
BENDIGO
BALLAN
BACCHUS MARSH
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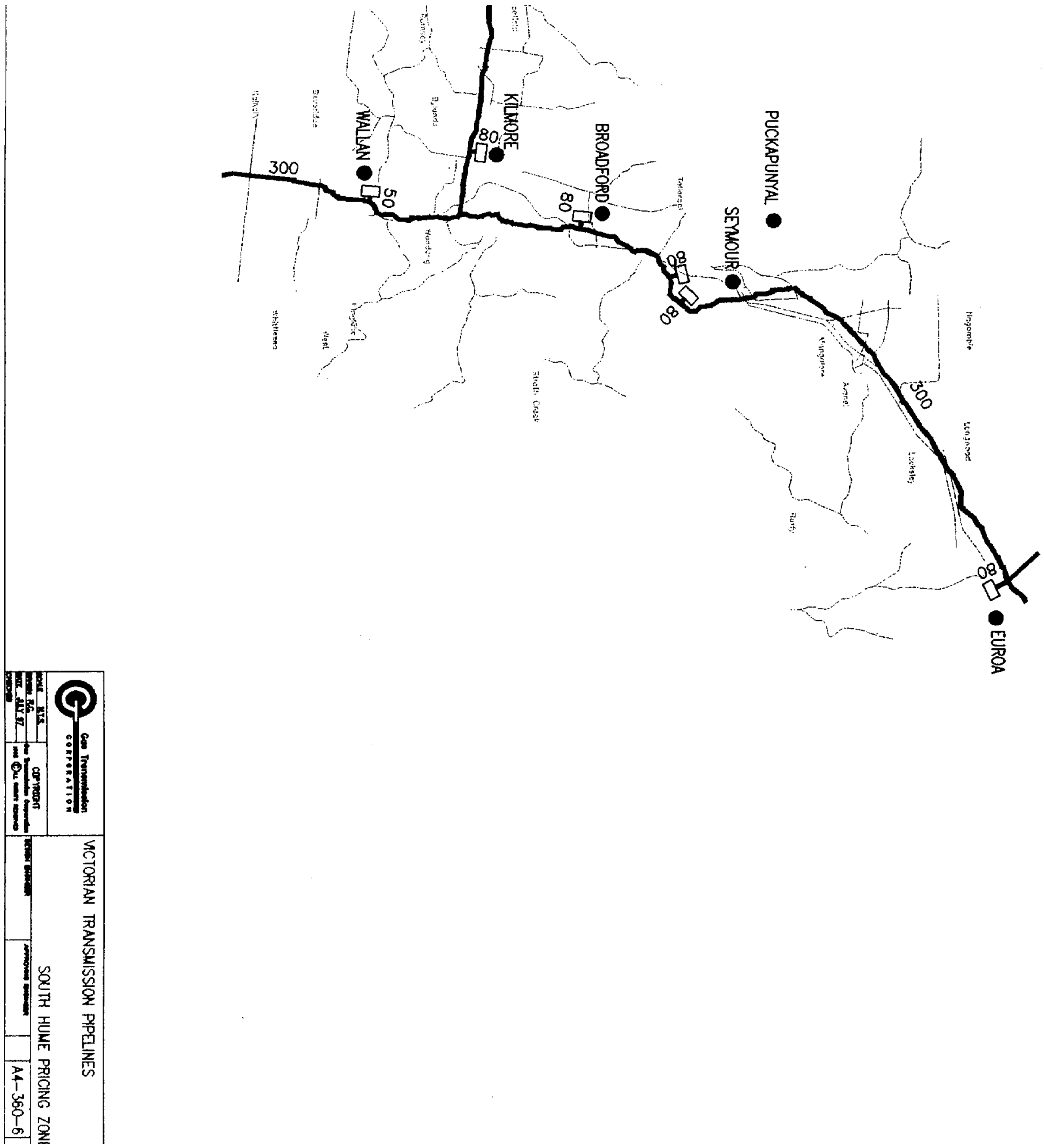
MELTON
Gas Transmission Corporation
VICTORIAN TRANSMISSION PIPELINES
CALDER PRICING ZONE
A4-360-5

Clause *Page*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SOUTH HUME PRICING ZON
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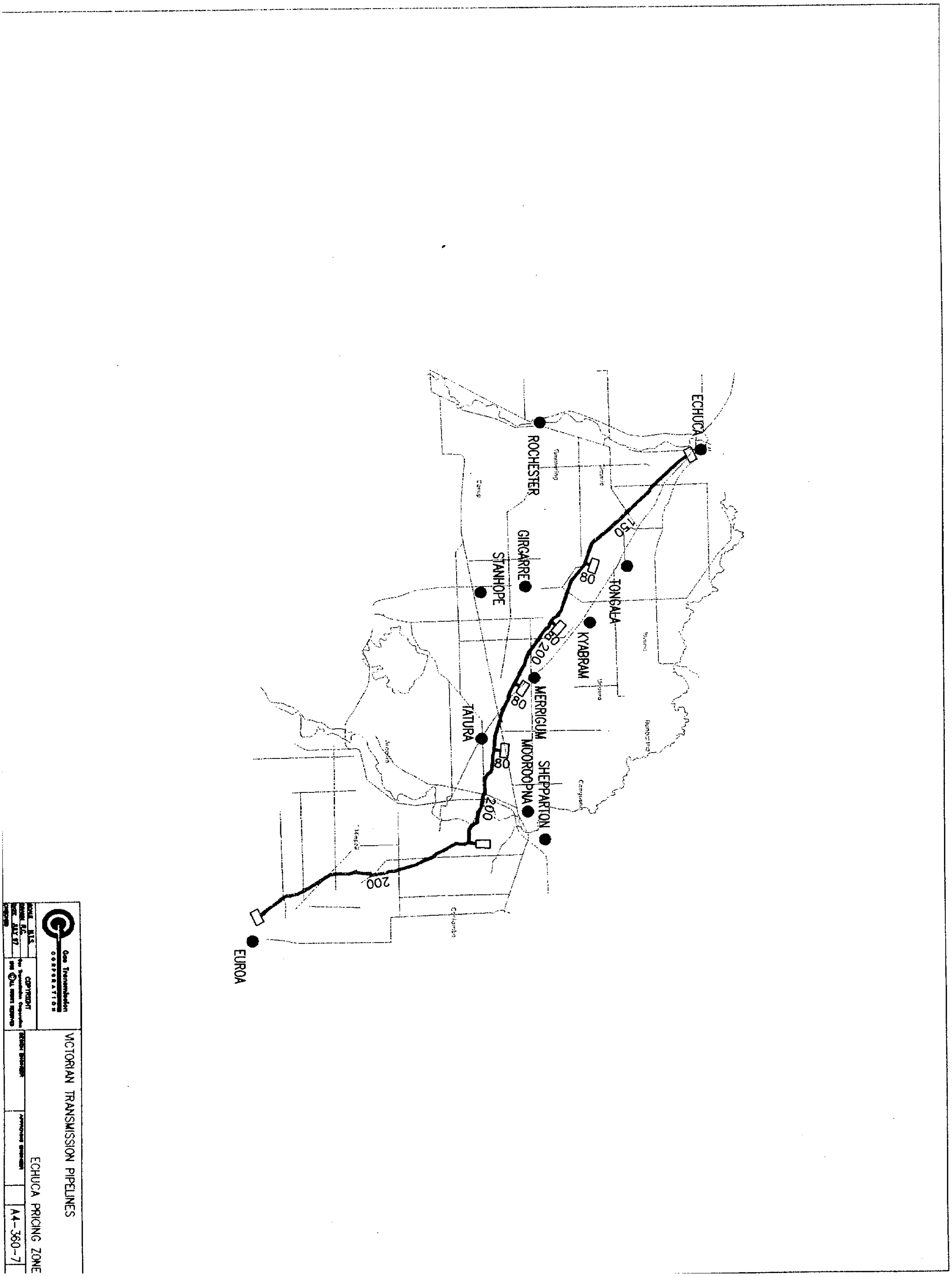
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ROCHESTER
GIRGARRE
STANHOPE
TONGALA
KYABRAM
MERRIGUM
TATURA
MOOROOPNA
SHEPPARTON
EUROA
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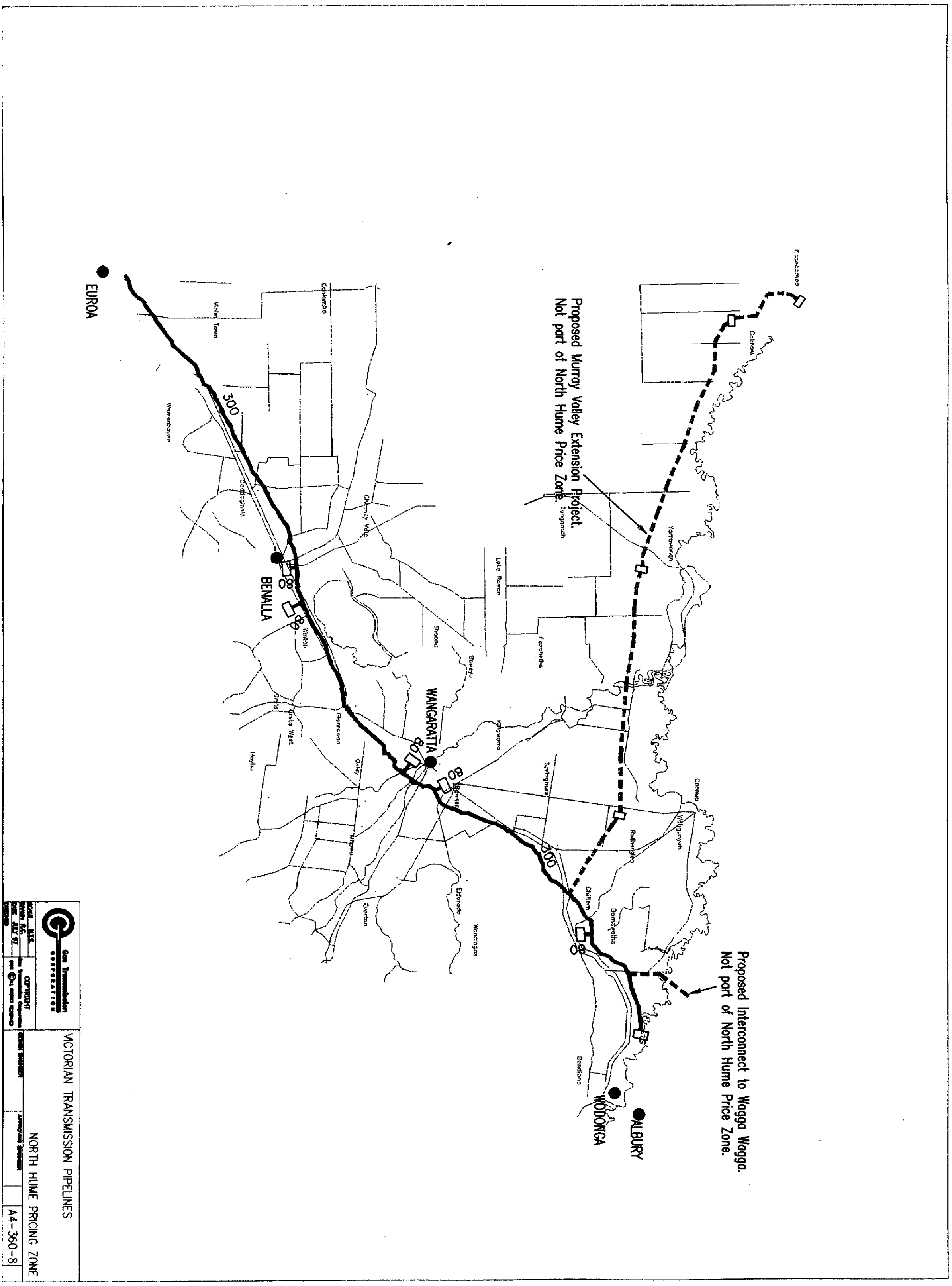
Gas Transmission Corporation
COPYRIGHT
VICTORIAN TRANSMISSION PIPELINES
ECHUCA PRICING ZONE
A4-360-7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WANGARATTA
WODONGA
ALBURY
300
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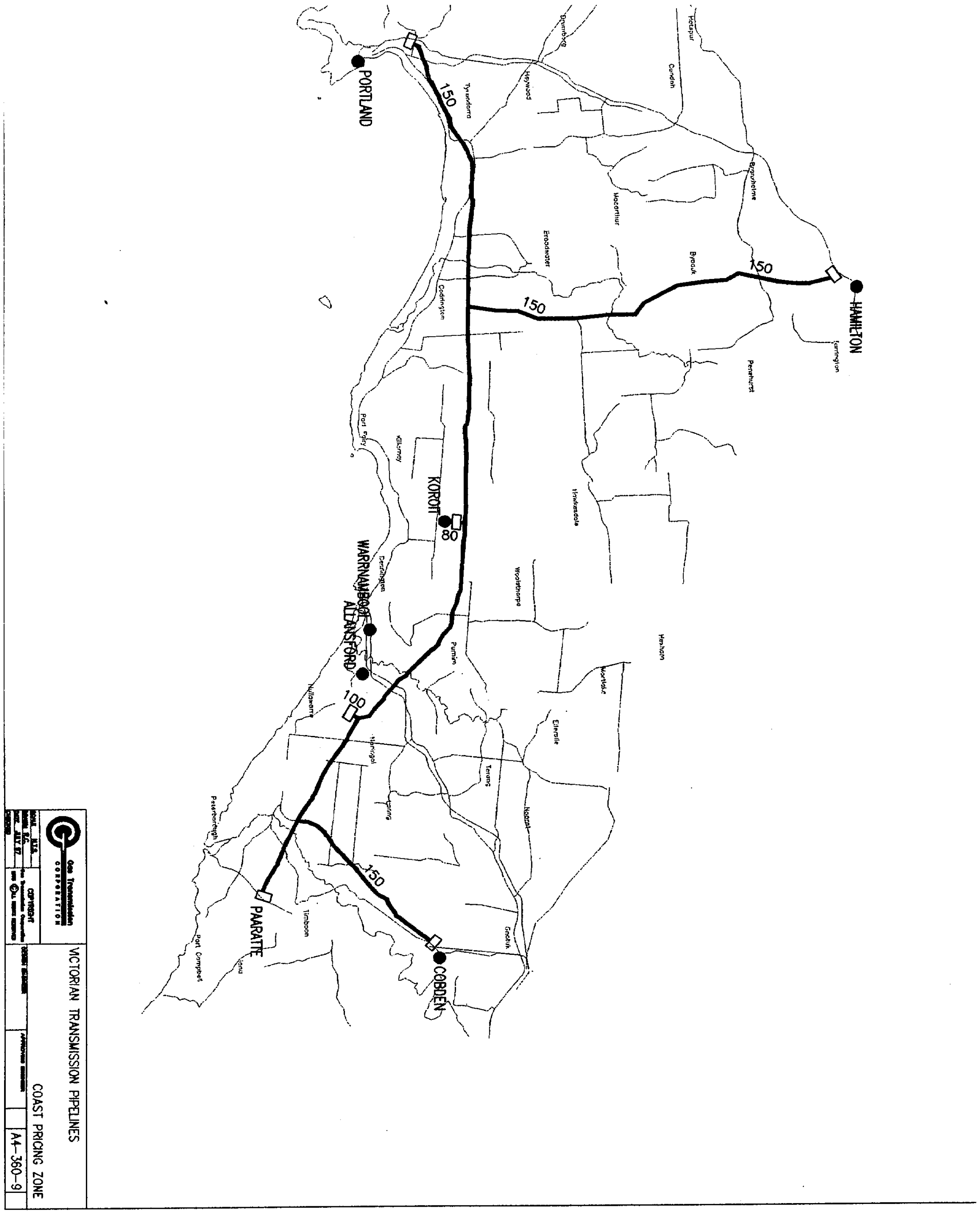
Proposed Murray Valley Extension Project.
Not part of North Hume Price Zone.
Proposed Interconnect to Wagga Wagga.
Not part of North Hume Price Zone.
Gas Transmission Corporation
VICTORIAN TRANSMISSION PIPELINES
NORTH HUME PRICING ZONE
A4-360-8

Clause *Page*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PAARATTE
COBDEN
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VICTORIAN TRANSMISSION PIPELINES
COAST PRICING ZONE
A4-360-9

Appendix 4

Service Envelope Agreement

TPA Service Envelope Agreement

Transmission Pipelines Australia (Assets) Pty Ltd
ACN 079 136 413

Transmission Pipelines Australia Pty Ltd
ACN 079 089 268

and

Victorian Energy Networks Corporation

FREEHILL HOLLINGDALE & PAGE

101 Collins Street Melbourne Victoria 3000 Australia
GPO Box 128A Melbourne 3001
Telephone (03) 9288 1234 Facsimile (03) 9288 1567 DX 240 Melbourne
Reference: JGG:NJO

MELBOURNE SYDNEY PERTH CANBERRA BRISBANE SINGAPORE HANOI HO CHI MINH CITY
CORRESPONDENT OFFICE IN JAKARTA

Table of contents

This TPA Service Envelope Agreement

is made as at 11 December 1997 between the following parties:

1. **Transmission Pipelines Australia Pty Ltd**
   ACN 079 089 268
   of 180 Greens Road, Dandenong, Victoria
   (**TPA**)

2. **Transmission Pipelines Australia (Assets) Pty Ltd**
   ACN 079 136 413
   of 180 Greens Road, Dandenong, Victoria
   (**TPA Assets**)

3. **Victorian Energy Networks Corporation**
   a public authority
   of 433 Smith Street, North Fitzroy, Victoria
   (**VENCorp**)

Recitals

A. TPA Assets, TPA and VENCorp are each gas companies for the purposes of the Act.

B. TPA Assets owns the Pipeline Titles held in relation to the Principal Gas Transmission System.

C. TPA leases the Principal Gas Transmission System for TPA Assets under an operating lease dated as at the Commencement Date between TPA Assets and TPA which enables TPA to provide services to TPA Assets and VENCorp and to users under the Principal Gas Transmission System Access Arrangement.

D. VENCorp is a public authority established under the Act, among other things, to the control the security and operation of the Principal Gas Transmission System.

E. TPA and VENCorp have agreed to enter into this agreement to specify the TPA Service Envelope from time to time which TPA has agreed to make available to VENCorp which will assist VENCorp to carry out and perform its functions under the Act.

The parties agree

in consideration of, among other things, enabling the parties to satisfy their obligations under the Act and the MSO Rules and the mutual promises contained in this agreement:

Definitions

In this agreement:

ACCC means the Australian Competition and Consumer Commission established under the *Trade Practices Act* 1974 (Cth).

Access Code means the Victorian Third Party Access Code for Natural Gas Pipeline Systems established under section 48U of the Act, or the proposed National Third Party Access Code for Natural Gas Pipeline Systems, whichever is applicable at the relevant time.

Act means the *Gas Industry Act* 1994 (Vic).

Augmentation means upgrading the Principal Gas Transmission System by replacing or enhancing existing pipelines, plant or equipment or adding new plant or equipment.

Authorised MDQ is as defined in the MSO Rules.

Commencement Date means the date on which the *Gas Industry (Further Amendment) Act* 1997 comes into force, which date is presently expected to be 11 December 1997.

Curtailment means the curtailment or interruption to the injection or withdrawal of gas to or from the Principal Gas Transmission System which occurs:

1. as a consequence of material damage to Principal Gas Transmission System or a gas pipeline system connected to Principal Gas Transmission System;
2. when VENCorp intervenes or issues an emergency direction whether under the MSO Rules or otherwise;
3. following an emergency proclaimed or declared under the Act or a direction issued under section 149 of the Act; or
4. if planned or unplanned maintenance and testing of the Principal Gas Transmission System is undertaken by TPA in accordance with the Principal Deed and the MSO Rules.

Extension means a transmission pipeline or system of transmission pipelines intended to be connected to the Principal Gas Transmission System to supply gas to areas not previously supplied by the Principal Gas Transmission System.

Force Majeure is as defined in the MSO Rules.

Good Operating Practice means the exercise of that degree of skill, diligence and foresight consistent with the safe operation and prudent practices that reasonably would be accepted by a significant proportion of the providers of transmission pipeline services in Australia.

MSO Rules means the rules made under section 48N of the Act for the regulation of the Market and the operation of the Principal Gas Transmission System and other matters and includes some of the provisions of the draft MSO Rules as lodged with the ACCC as referred to in clause 4 to apply to this agreement in the interim period before the MSO Rules come into effect under the Act.

Pipeline Title means permits to own and use, licences to construct and operate, and licences to operate only, a pipeline as set out in schedule 1 issued under the *Pipelines Act* 1967 (Vic) and which are held by TPA Assets, or are intended to be allocated by statement made under Division 2 of Part 13A of the Act from its predecessor Gas Transmission Corporation, a statutory corporation, to TPA Assets.

Principal Deed means the deed made as at the Commencement Date between the parties as amended from time to time in relation, amongst other things, to the ownership, use, operation and maintenance of the Principal Gas Transmission System.

Principal Gas Transmission System means the gas transmission system as defined in the Principal Gas Transmission System Access Arrangement being the “gas transmission system” as defined in section 3 of the Act as at the Commencement Date, and more particularly described as the system of pipelines the subject of the Pipeline Titles set out in tabular form and depicted on the maps set out in schedule 1 and includes the associated compressors, regulators, metering installations and associated equipment, set out in schedule 1, and any Augmentation or Extension of that system as included in schedule 1 from time to time.

Principal Gas Transmission System Access Arrangement means the arrangement for access for third parties to the Principal Gas Transmission System lodged by TPA and TPA Assets with the Australian Competition and Consumer Commission for approval under section 2.1 of the Access Code.

Procedures Manual means one or more documents prepared by TPA in consultation with VENCorp which set out the procedures to be followed by TPA in the performance of its TPA Service Envelope Obligations.

Procedures Manual Change Request means a written document prepared by a party which sets out:

(a) a proposed amendment to the Procedures Manual;

(b) the reason for the proposed amendment;

(c) the impact that the proposed amendment will have on the operation of this agreement, including any impact on the TPA Service Envelope; and

(d) any other information which the other party reasonably requires.

TPA Service Envelope means the Principal Gas Transmission System and all associated assets as specified in schedule 1 from time to time.

TPA Service Envelope Obligations means the obligation of TPA to make available to VENCorp the TPA Service Envelope during the term of this agreement.

Variation includes an addition, deletion, omission, change or substitution to the TPA Service Envelope.

TPA Service Envelope

Specification of TPA Service Envelope

As at the Commencement Date, the TPA Service Envelope which TPA agrees to make available to VENCorp is:

the Principal Gas Transmission System, including

all associated easements, utilities, works, buildings, control rooms, odourization plant, compressors, regulators, valves, metering installations, telemetry and communication systems, ancillary pipeline equipment and all other fixed assets owned by TPA Assets relating to the Principal Gas Transmission System;

the number, location and limiting specifications of the essential parts of which are specified in schedule 1.

TPA Service Envelope Obligations

TPA must make available the TPA Service Envelope to VENCorp at all times during the term of the Principal Deed in accordance with the Principal Deed and this agreement.

Procedure Manuals

TPA will forthwith, in consultation with VENCorp, establish detailed Procedures Manual of the number, location and limiting specifications of the essential compressors, regulators, metering installations and associated equipment of the Principal Gas Transmission System for the purpose of specifying the TPA Service Envelope in detail.

Until the detailed Procedures Manual are finalised, TPA must provide the TPA Service Envelope in accordance with current Gas Transmission Corporation operating practice and manufacturers recommendations existing at the Commencement Date.

The parties must use their best endeavours to agree the detailed Procedures Manual on or before 1 April 1998.

Each party must comply with any obligations imposed on it by the Procedures Manual.

The Procedures Manual may only be changed pursuant to a Procedures Manual Change Request which has been approved by both Parties.

TPA Service Envelope Availability forecasts

TPA must include the then current system description and specification of the TPA Service Envelope in each annual forecast and monthly forecast provided to VENCorp under clause 5.2 of the MSO Rules.

TPA must provide the additional availability, constraints and maintenance information to VENCorp:

in each annual forecast and monthly forecast provided to VENCorp under clause 5.2 of the MSO Rules; and

in each week-ahead forecast commencing from Monday in each week by the immediately preceding Wednesday.

The parties agree that the obligations of TPA under this clause will commence as at the Commencement Date.

Limitation of liability

TPA will not be liable to VENCorp for failure to provide any part of its TPA Service Envelope;

where TPA is relieved from performance of its obligations because of an event of Force Majeure; or

where an event of Curtailment occurs; or

to the extent that VENCorp otherwise agrees in writing to a temporary reduction in the TPA Service Envelope; or

the failure arises out of any accident or cause which is beyond the control of TPA and which TPA was not able to avoid through the exercise of Good Operating Practice.

Variation of TPA Service Envelope

Augmentation and Extension

TPA Assets and TPA may undertake an Augmentation or Extension of the Principal Gas Transmission System at any time without the approval of VENCorp provided that:

TPA is able at all times to perform and carry out the TPA Service Envelope Obligations; and

the Augmentation or Extension does not affect the operation by VENCorp of the gas scheduling procedures, or the injection and withdrawal of gas to the limit of the total amount of Authorised MDQ, under the MSO Rules.

VENCorp may propose that the TPA Service Envelope be increased by TPA undertaking an Augmentation or Extension of the Principal Gas Transmission System.

TPA must notify VENCorp within 30 days whether it accepts the VENCorp proposed Augmentation or Extension and, if not, the extent to which and reasons it does not accept the Augmentation or Extension.

If TPA is willing to accept undertaking the proposed Augmentation or Extension, TPA and VENCorp must discuss forthwith and agree the amendments to the TPA Service Envelope.

If the parties cannot agree on TPA Service Envelope within 30 days of VENCorp's nomination, then subject to clause 3.3 TPA's decision will prevail, subject to:

TPA giving full consideration to the obligations of VENCorp to perform the VENCorp Functions for the remainder of this agreement; and

such decision not affecting VENCorp's ability to perform its functions under the Act.

TPA cannot be obliged to undertake an Augmentation or Extension of the Principal Gas Transmission System unless it agrees.

Variation procedures

At the same time as TPA is required to give monthly forecasts to VENCorp, TPA may give notice to VENCorp that it wishes to make a Variation to the TPA Service Envelope specifying in detail the Variation that TPA seeks.

VENCorp must notify TPA within 30 days whether it accepts the TPA proposed amendments and, if not, the extent to which and reasons it does not accept the amendments.

VENCorp must agree to the proposed Variation to the TPA Service Envelope within 30 days of being notified of the Variation, unless the proposed Variation;

affects, in the judgment of VENCorp, the ability of VENCorp to perform the VENCorp Functions or its obligations under the MSO Rules including supply of all Authorised MDQ; or

reduces the total Authorised MDQ which is available to be allocated by VENCorp to customers under the MSO Rules to an amount which is unacceptable to VENCorp

in either of which cases TPA must not proceed with the Variation.

VENCorp must not unreasonably object or delay agreement to any Variation which is:

lawfully required by any competent governmental or local authority; or

requested or necessitated due to a potential failure of materials or as a result of the requirements of a regulatory authority.

Failure to reach agreement

If VENCorp and TPA are unable to reach agreement or continue to agree upon the terms of this TPA Service Envelope Agreement, then either party may refer the matter for resolution by a suitably qualified independent person appointed by the ACCC in accordance with the MSO Rules.

Amendment of agreement

Except as set out in the MSO Rules or as required by the ACCC, this agreement may only be amended or supplemented in writing, signed by the parties.

Application of MSO Rules

Notwithstanding that the MSO Rules will not be in effect from the Commencement Date, the parties agree that the following provisions of the MSO Rules will apply to this agreement in the interim period before the MSO Rules come into effect under the Act as if each provision was incorporated into this agreement, namely:

clause 5.2 - Forecasts and planning and maintenance review;

clause 6.7.2(b) - Force Majeure;

clause 10 - Interpretation; and

clause 11 - Glossary.

Force Majeure

General position

Non-performance due to Force Majeure by either party of any obligation or condition required by this agreement to be performed:

will be excused during the time and to the extent that performance is prevented, wholly or in part, by Force Majeure; and

will not to that extent give rise to any liability to the other party for any losses or damages arising out of, or in any way connected with such non-performance.

Notification to other party

If either Party seeks relief from performance of an obligation because of an Event of Force Majeure, the party must:

as soon as reasonably practicable but in any event within two (2) Business Days, give notice to the other party of the occurrence of the event or circumstance claimed to be Force Majeure, including:

full particulars relating to the event or circumstance and the cause of such failure to perform; and

an estimate of the period of time required to remedy such failure to perform;

render the other party reasonable opportunity and assistance to examine and investigate the event or circumstance and the matters which caused the event or circumstance and failure to perform;

exercise reasonable efforts to mitigate or remove the effects of the event or circumstance but excluding any measures which are not economically feasible for the parties; and

give notice immediately to the other party upon termination of the event or circumstance of Force Majeure.

Qualification

No Force Majeure event affecting the performance of any obligation or condition under this agreement by either party operates to prevent a cause of action arising from and after the expiration of the period of time within which by the exercise of reasonable diligence and the employment of all reasonable means, that party could have remedied the situation preventing its performance.

Notices

How notices may be given

A notice, request, demand, consent or approval (each a notice) under this agreement:

must be in writing;

may be signed for the party giving it by the party's authorised officer, attorney or solicitor;

may be delivered personally to the person to whom it is addressed, or left at or sent by prepaid post to the person's address, or faxed to the person's fax number, given below:

if to TPA or TPA Assets:

EPD Gas Project

Address: 180 Greens Road, Dandenong, Victoria

Fax: (03) 9797 5295

Attention: Chief Executive, TPA

if to VENCorp:

Address: 433 Smith Street, North Fitzroy, Victoria

Fax: (03) 9481 9269

Attention: Chief Executive

When notice taken as given

A notice is taken as given by the sender and received by the intended recipient:

if posted, 3 days after posting; and

if faxed, on completion of the transmission,

but if delivery or receipt is on a day which is not a business day of a party or is after 5.00pm at the place of delivery or receipt, it is taken as given at 9.00am on the next business day.

Change of address or fax number

A party may change its address or fax number for notices by giving notice to the other parties.

If notice not received

A notice that is posted is valid even if:

the intended recipient does not receive it; or

it is returned unclaimed to the sender.

Executed as an agreement:

SIGNED
for **Transmission Pipelines Australia Pty Ltd** by its attorney in the presence of:

Witness	Attorney Peter Algernon Franc Hay
Name (please print)	

SIGNED
for **Transmission Pipelines Australia (Assets) Pty Ltd** by its attorney in the presence of:

______________________________	______________________________
Witness	Attorney Peter Algernon Franc Hay
______________________________	
Name (please print)	

The official seal of **VICTORIAN ENERGY NETWORKS CORPORATION** is affixed to this document:

______________________________	______________________________
Secretary	Director
______________________________	______________________________
Name (please print)	Name (please print)

Schedule 1 - TPA Service Envelope

The Principal Gas Transmission System made available by TPA and TPA Assets to VENCorp comprises:

(a) **Transmission System Pipeline**: approximately 1,392km of transmission system pipeline from Longford (eastern Victoria) to Geelong (western Victoria) to Ballarat and Bendigo (central Victoria) to Wodonga and Echuca (northern Victoria) as described in the following attached key plans and associated drawings for each location of the Principal Gas Transmission System:

Key Plans	Ref No.
• Longford - Dandenong - Wollert	A4-363-1
• 750 Ø Dandenong - West Melbourne - Brooklyn	A4-363-2
• Brooklyn - Geelong	A4-363-3
• Ballarat - Bendigo	A4-363-4
• Wollert - Albury - Echuca	A4-363-5

(b) **Compressor Stations**: located at Gooding, Brooklyn and Wollert with all associated plant and equipment required to operate fifteen (15) individual gas powered turbine/compressor units in accordance with the "Compressor Station Key Data Plan" Ref no. A1-301-1.

(c) **Line Valves**: for each sector of the Principal Gas Transmission System as noted within each of the above key plans.

(d) **Pressure Regulators**: installed within the Principal Gas Transmission System for transmission purposes, as noted within each of the above key plans.

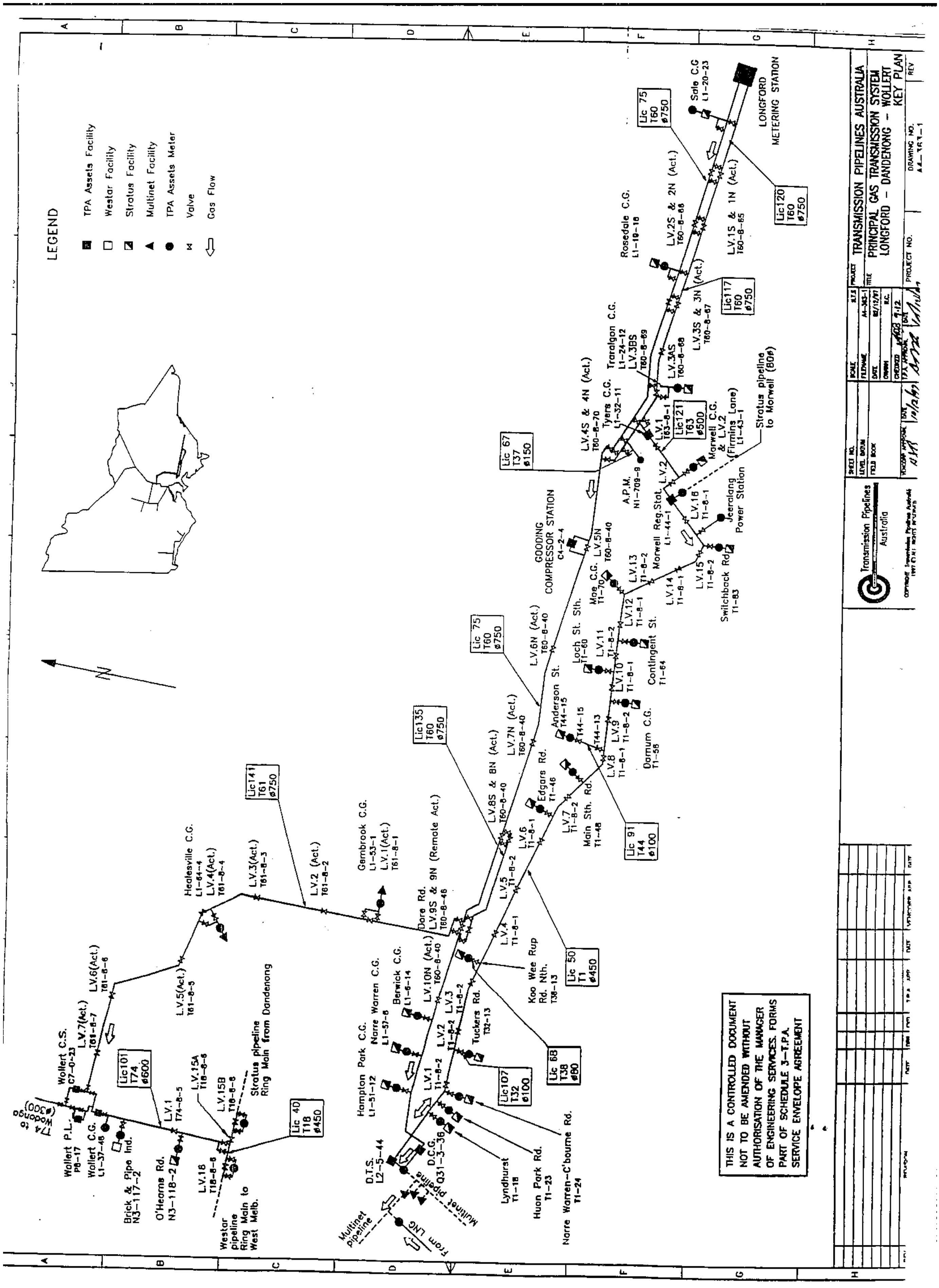
(e) **Connection (Transfer) Points**: are those locations where the interface of Principal Gas Transmission System occurs with other pipelines or pipeline systems for the conveyance of gas beyond the Principal Gas Transmission System as defined within the attached Transfer Point Plans as follows:

Transfer Point Plans	Ref No.
• Longford - Dandenong - Wollert	A4-364-1
• Dandenong - West Melbourne - Brooklyn	A4-364-2
• Brooklyn - Geelong	A4-364-3
• Ballarat - Bendigo	A4-364-4
• Wollert - Albury - Echuca	A4-364-5

(f) **Metering Stations**: those TPA metering facilities installed as custody meter systems at Connection (Transfer) Points, at locations as outlined within the "Transfer Point - Meter Plan" Ref no. A1-301-2 and Transfer Point Definitions S44-28-1.

(g) **Odourization Plant**: that facility located within the Longford Measurement Agency, Longford and all associated equipment required for the injection of odour based materials to meet the requirements of the *Gas Safety Act*, 1997.

Principal Gas Transmission System maps and key plans


LEGEND
TPA Assets Facility
Westar Facility
Stratus Facility
Multinet Facility
TPA Assets Meter
Valve
Gas Flow
LONGFORD METERING STATION
GOODING COMPRESSOR STATION
TRANSMISSION PIPELINES AUSTRALIA
PRINCIPAL GAS TRANSMISSION SYSTEM
LONGFORD - DANDENONG - WOLLERT
KEY PLAN
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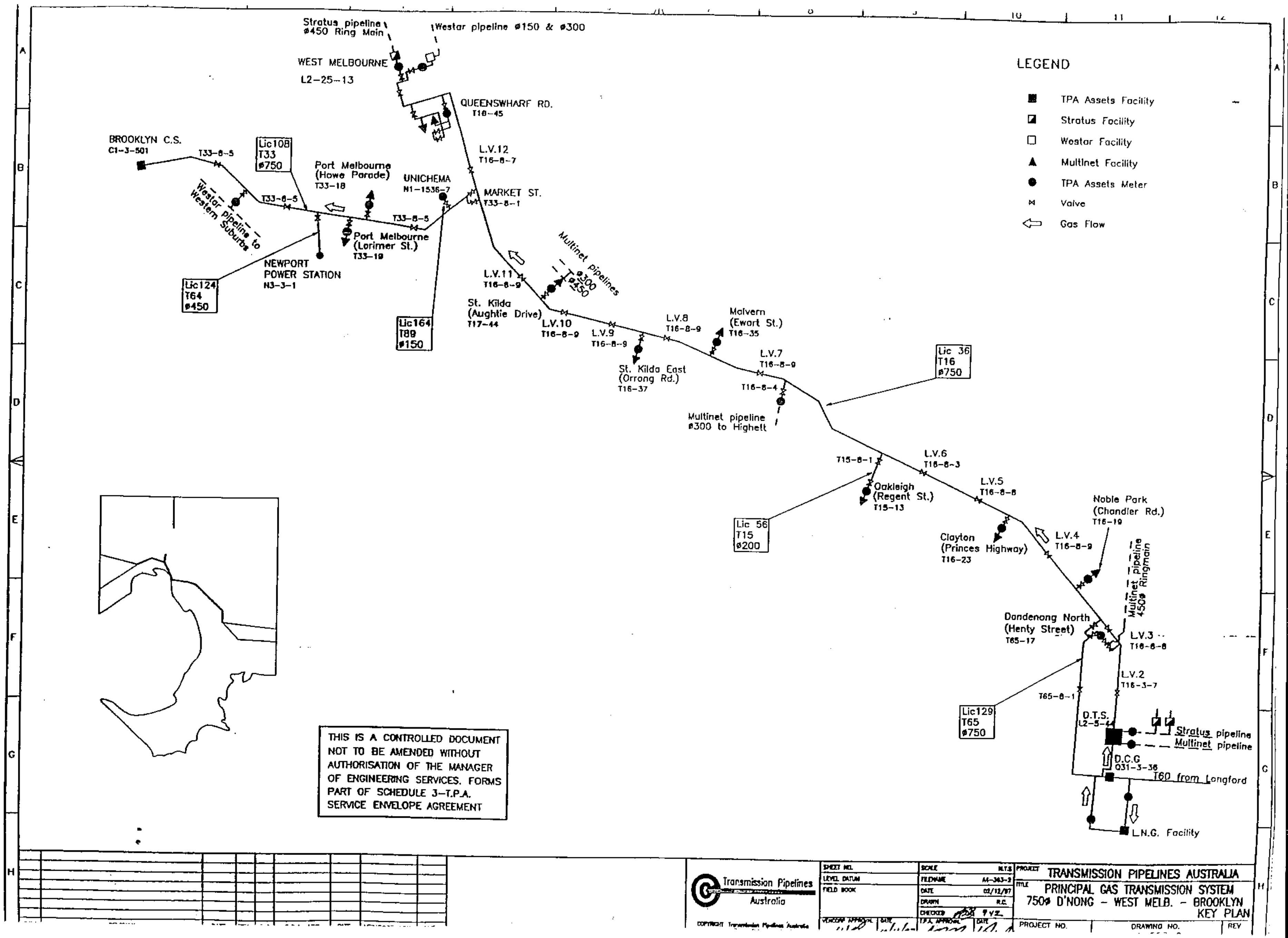
Stratus pipeline ø450 Ring Main
Westar pipeline ø150 & ø300
WEST MELBOURNE
L2-25-13
QUEENSWHARF RD.
T16-45
BROOKLYN C.S.
C1-3-501
T33-8-5
Lic108
T33
ø750
Port Melbourne (Howe Parade)
T33-18
UNICHEMA
N1-1536-7
MARKET ST.
T33-8-1
L.V.12
T16-8-7
Westar pipeline to Western Suburbs
T33-8-5
T33-8-5
Port Melbourne (Lorimer St.)
T33-19
NEWPORT POWER STATION
N3-3-1
Lic124
T64
ø450
Lic164
T89
ø150
L.V.11
T16-8-9
Multinet pipelines
ø300
ø450
St. Kilda (Aughtie Drive)
T17-44
L.V.10
T16-8-9
L.V.9
T16-8-9
St. Kilda East (Orrong Rd.)
T16-37
L.V.8
T16-8-9
Malvern (Ewart St.)
T16-35
L.V.7
T16-8-9
T16-8-4
Multinet pipeline ø300 to Highett
Lic 36
T16
ø750
T15-8-1
Oakleigh (Regent St.)
T15-13
Lic 56
T15
ø200
L.V.6
T16-8-3
L.V.5
T16-8-8
Clayton (Princes Highway)
T16-23
L.V.4
T16-8-9
Noble Park (Chandler Rd.)
T16-19
Multinet pipeline 450ø Ringmain
Dandenong North (Henty Street)
T65-17
L.V.3
T16-8-8
L.V.2
T16-3-7
T65-8-1
Lic129
T65
ø750
D.T.S.
L2-5-4
Stratus pipeline
Multinet pipeline
D.C.G
Q31-3-38
T60 from Longford
L.N.G. Facility
LEGEND
TPA Assets Facility
Stratus Facility
Westar Facility
Multinet Facility
TPA Assets Meter
Valve
Gas Flow
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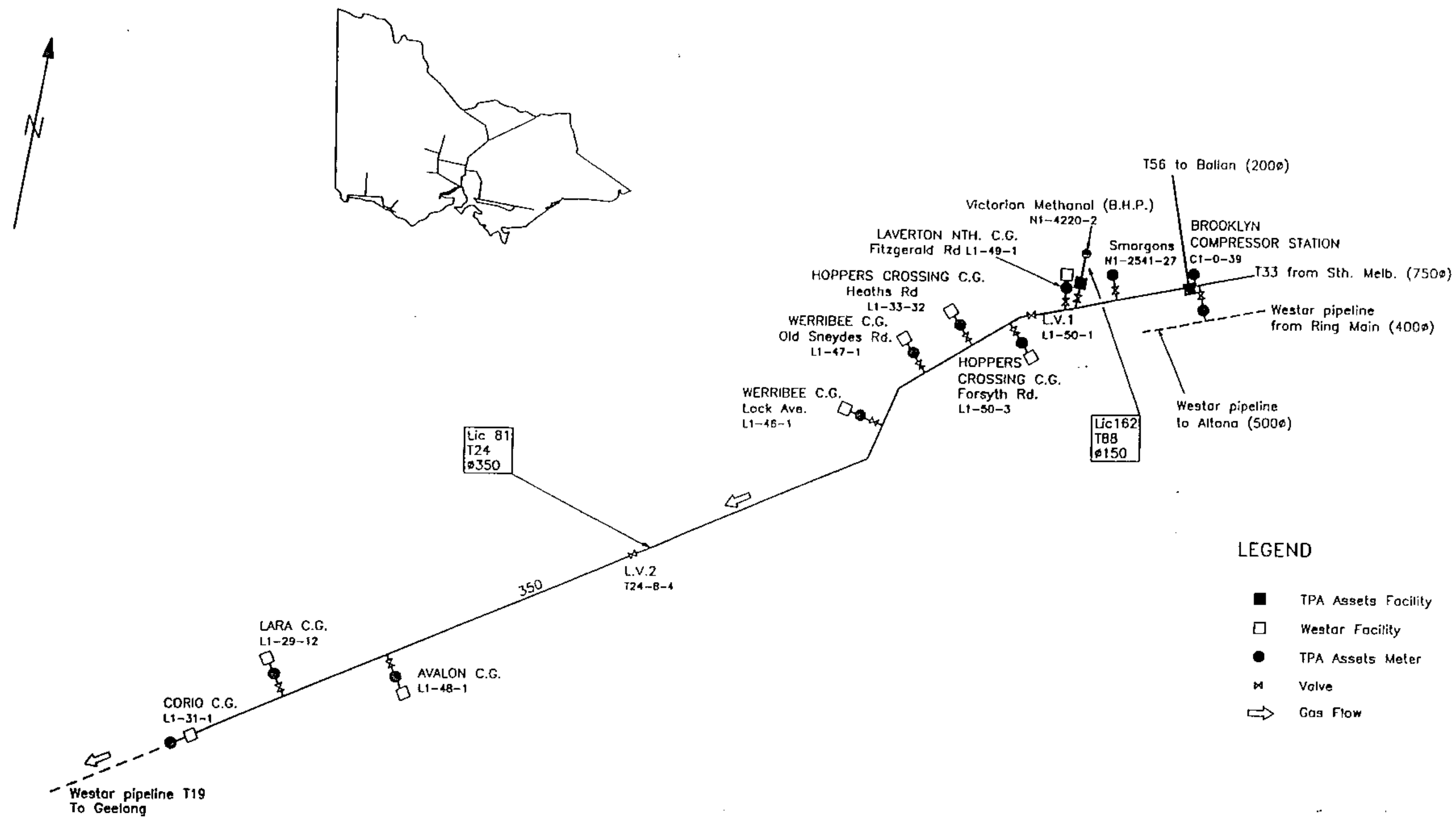
Transmission Pipelines Australia
COPYRIGHT Transmission Pipelines Australia
SHEET NO.
LEVEL DATUM
FIELD BOOK
SCALE N.T.S
FILENAME A4-363-2
DATE 02/12/97
DRAWN R.C.
CHECKED
T.P.A. APPROVAL
PROJECT TRANSMISSION PIPELINES AUSTRALIA
TITLE PRINCIPAL GAS TRANSMISSION SYSTEM 750ø D'NONG - WEST MELB. - BROOKLYN KEY PLAN
PROJECT NO.
DRAWING NO.
REV



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REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

Transmission Pipelines Australia

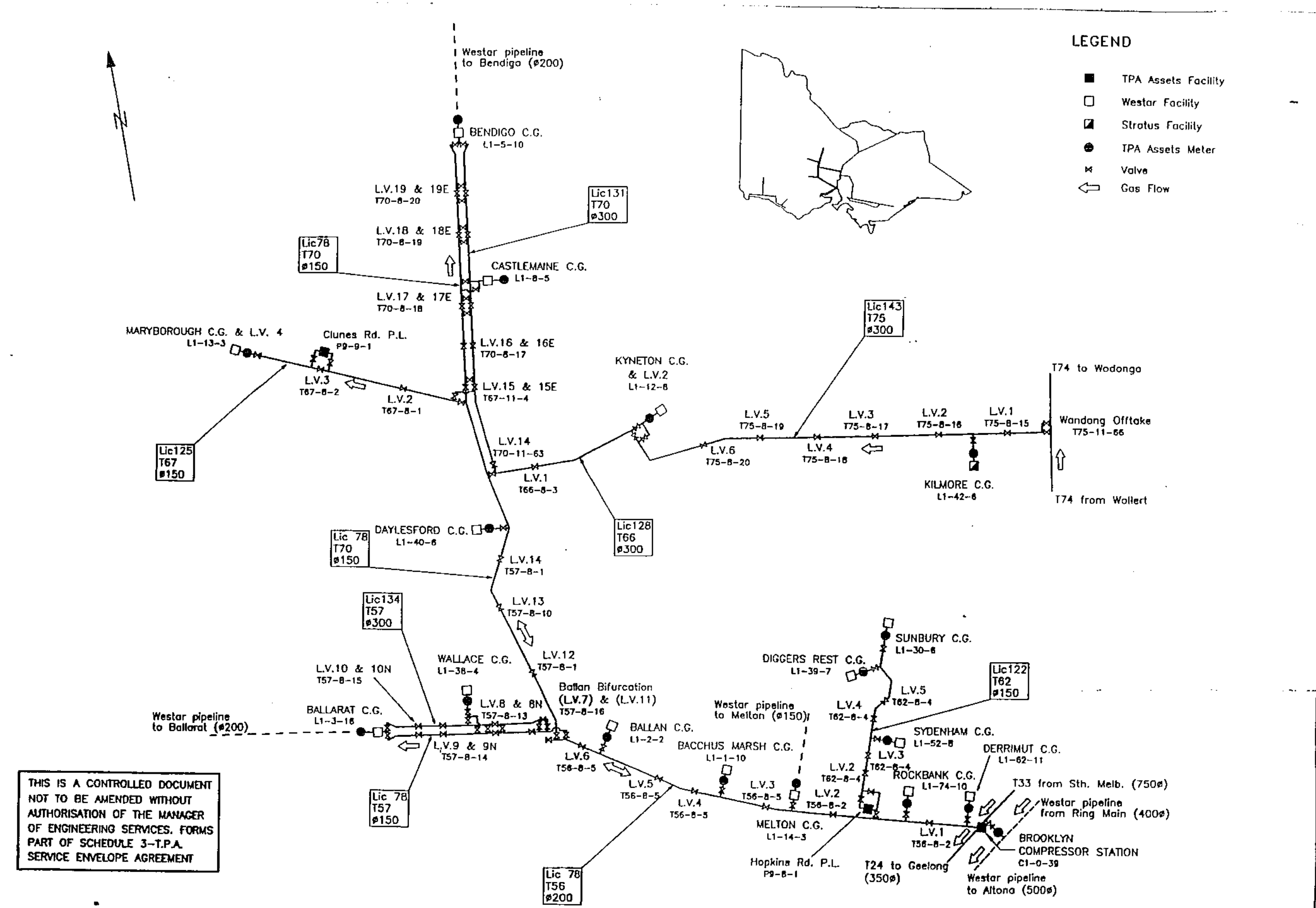
SHEET NO.		SCALE	N.T.S.
LEVEL DATUM		FILENAME	A4-363-3
FIELD BOOK		DATE	02/12/97
		DRAWN	R.C.
		CHECKED	9-12
VENCORP APPROVAL 4/12	DATE 10/12/97	T.P.A. APPROVAL	DATE 10/12/97

PROJECT: TRANSMISSION PIPELINES AUSTRALIA

TITLE: PRINCIPAL GAS TRANSMISSION SYSTEM BROOKLYN - GEELONG

KEY PLAN

PROJECT NO. | DRAWING NO. A4-363-3 | REV



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REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

Transmission Pipelines Australia

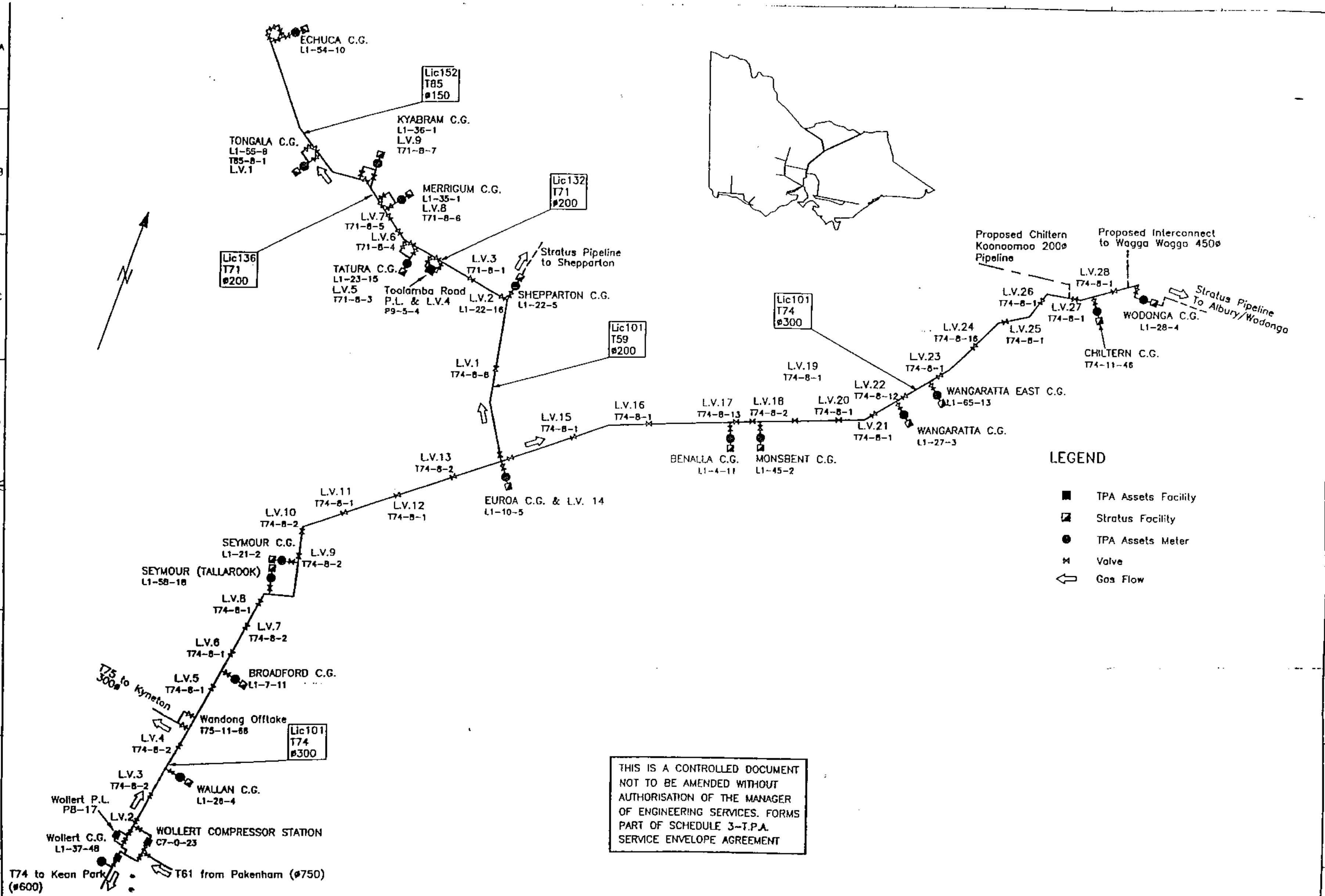
SHEET NO.		SCALE	N.T.S.
LEVEL DATUM		FILENAME	A4-383-4
FIELD BOOK		DATE	02/12/97
		DRAWN	R.C.
		CHECKED	9-12
VENCORP APPROVAL	DATE 10/12/97	T.P.A. APPROVAL	DATE

PROJECT: TRANSMISSION PIPELINES AUSTRALIA

TITLE: PRINCIPAL GAS TRANSMISSION SYSTEM BALLARAT - BENDIGO

KEY PLAN

PROJECT NO. | DRAWING NO. A4-383-4 | REV



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REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

Transmission Pipelines Australia

SHEET NO.		SCALE	N.T.S
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FIELD BOOK		DATE	02/12/97
		DRAWN	R.C.
		CHECKED	9.12
VENCORP APPROVAL	DATE 10/12/97	T.P.A. APPROVAL	DATE

PROJECT: TRANSMISSION PIPELINES AUSTRALIA

TITLE: PRINCIPAL GAS TRANSMISSION SYSTEM WOLLERT - ALBURY - ECHUCA KEY PLAN

PROJECT NO.

DRAWING NO. A4-383-5

REV

STATION	UNIT #	GAS TURBINE				GAS COMPRESSOR		
		ENGINE	Model	Nominal Output Power (kW)	MAX rpm	Model	Stages	MAX rpm
GOODING	1	Centaur	T-4002	2850	15500	C3072-510P	2EE 2EE	15000
GOODING	2	Centaur	T-4002	2850	15500	C3072-510P	2EE 2EE	15000
GOODING	3	Centaur	T-4002	2850	15700	C3072-RHA	2EE 2EE	15000
GOODING	4	Centaur	T-4002	2850	15700	C3072-510P	2EE 2EE	15000
BROOKLYN	4	Saturn	T-1202	850	22300	C1676FDAS528A1	3D 3D 2D 3D 3D 2D 3D 3D 2D / 3D 3D 2D	22300
BROOKLYN	5	Saturn	T-1202	850	22300	C1676FDAS528A1	3D 3D 2D 3D 3D 2D 3D 3D 2D / 3D 3D 2D	22300
BROOKLYN	6	Saturn	T-1202	850	22300	C1685FAA-520A1	2D 3D 3D 3D 2D	22300
BROOKLYN	7	Saturn	T-1202	850	22300	C1685FAA-520A1	2D 3D 3D 3D 2D	22300
BROOKLYN	8	Saturn	T-1202	850	22300	C1684FAA-504A1	3DT 3DT 3DT 3CE	22300
BROOKLYN	9	Saturn	T-1202	850	22300	C1684FAA-504A1	3DT 3DT 3DT 3CE	22300
BROOKLYN	10	Centaur	T-4002	2850	15000	C3064RGA-38CX	2DT 1DT 1DT 3CE	15000
BROOKLYN	11	Centaur	T-4002	2850	15000	C3074RHAS-518CX	2DT 1DE 1DT 3CE 2DT 1DE / 1DT 3CE	15000
WOLLERT	1	Saturn	T-1202	850	22300	C1607FAA-2502B1	2DT 2DT 2DT 3CT 3CT 3CT 2CE	22300
WOLLERT	2	Saturn	T-1202	850	22300	C1607FAA-2502B1	2DT 2DT 2DT 3CT 3CT 3CT 2CE	22300
WOLLERT	3	Saturn	T-1202	850	22300	C1607FAA-2502B1	2DT 2DT 2DT 3CT 3CT 3CT 2CE	22300

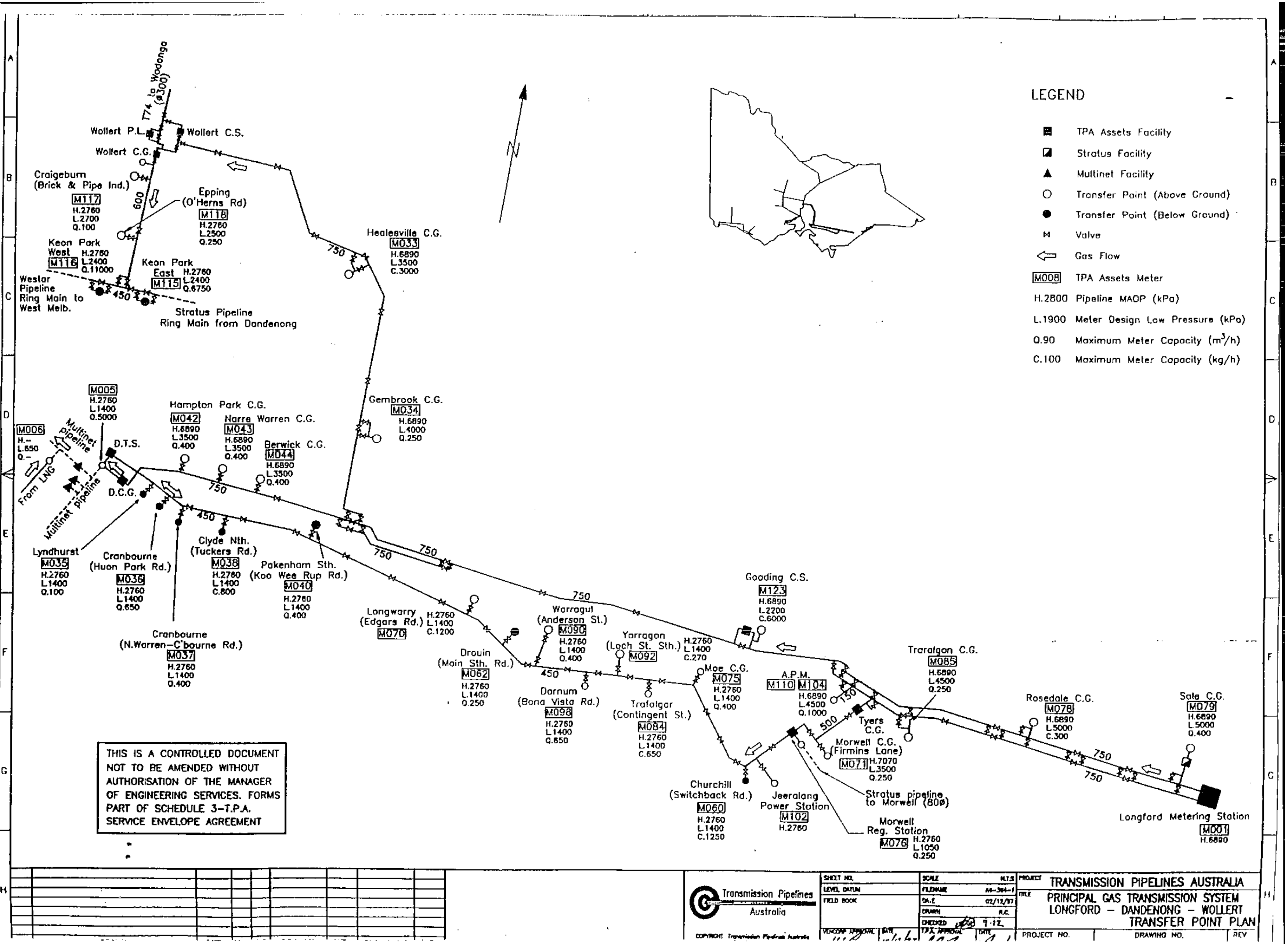
REV	REVISION	DATE	DRN	CKD	T.P.A. APP.	DATE	VENCORP APP.	DATE

Transmission Pipelines Australia

SHEET NO.
LEVEL DATUM
FIELD BOOK
VENCORP APPROVAL
DATE 10/12/97

SCALE N.T.S.
FILENAME A1-301-1
DATE 08/12/97
DRAWN P.C.D.
CHECKED 9-12
T.P.A. APPROVAL
DATE

PROJECT TRANSMISSION PIPELINES AUSTRALIA
TITLE PRINCIPAL GAS TRANSMISSION SYSTEM COMPRESSOR STATIONS KEY DATA PLAN CHART
PROJECT NO.
DRAWING NO. A1-301-1
REV



LEGEND
TPA Assets Facility
Stratus Facility
Multinet Facility
Transfer Point (Above Ground)
Transfer Point (Below Ground)
Valve
Gas Flow
M008 TPA Assets Meter
H.2800 Pipeline MAOP (kPa)
L.1900 Meter Design Low Pressure (kPa)
Q.90 Maximum Meter Capacity (m³/h)
C.100 Maximum Meter Capacity (kg/h)
T74 to Wodonga (ø300)
Wollert P.L.
Wollert C.S.
Wollert C.G.
Craigeburn (Brick & Pipe Ind.) M117 H.2760 L.2700 Q.100
Epping (O'Herns Rd) M118 H.2760 L.2500 Q.250
Keon Park West M116 H.2760 L.2400 Q.11000
Keon Park East M115 H.2760 L.2400 Q.6750
Westar Pipeline Ring Main to West Melb.
Stratus Pipeline Ring Main from Dandenong
Healesville C.G. M033 H.6890 L.3500 C.3000
Gembrook C.G. M034 H.6890 L.4000 Q.250
M005 H.2760 L.1400 Q.5000
M006 H.– L.850 Q.–
Multinet Pipeline
From LNG
Multinet pipeline
D.T.S.
D.C.G.
Hampton Park C.G. M042 H.6890 L.3500 Q.400
Narre Warren C.G. M043 H.6890 L.3500 Q.400
Berwick C.G. M044 H.6890 L.3500 Q.400
Lyndhurst M035 H.2760 L.1400 Q.100
Cranbourne (Huon Park Rd.) M036 H.2760 L.1400 Q.650
Cranbourne (N.Warren–C'bourne Rd.) M037 H.2760 L.1400 Q.400
Clyde Nth. (Tuckers Rd.) M038 H.2760 L.1400 C.800
Pakenham Sth. (Koo Wee Rup Rd.) M040 H.2760 L.1400 Q.400
Longwarry (Edgars Rd.) M070 H.2760 L.1400 C.1200
Drouin (Main Sth. Rd.) M062 H.2760 L.1400 Q.250
Warragul (Anderson St.) M090 H.2760 L.1400 Q.400
Darnum (Bona Vista Rd.) M098 H.2760 L.1400 Q.650
Yarragon (Loch St. Sth.) M092 H.2760 L.1400 C.270
Trafalgar (Contingent St.) M084 H.2760 L.1400 C.650
Moe C.G. M075 H.2760 L.1400 Q.400
Gooding C.S. M123 H.6890 L.2200 C.6000
A.P.M. M110 M104 H.6890 L.4500 Q.1000
Tyers C.G.
Morwell C.G. (Firmins Lane) M071 H.7070 L.3500 Q.250
Churchill (Switchback Rd.) M060 H.2760 L.1400 C.1250
Jeeralang Power Station M102 H.2760
Stratus pipeline to Morwell (80ø)
Morwell Reg. Station M076 H.2760 L.1050 Q.250
Traralgon C.G. M085 H.6890 L.4500 Q.250
Rosedale C.G. M078 H.6890 L.5000 C.300
Sale C.G. M079 H.6890 L.5000 Q.400
Longford Metering Station M001 H.6890
600
450
750
150
500
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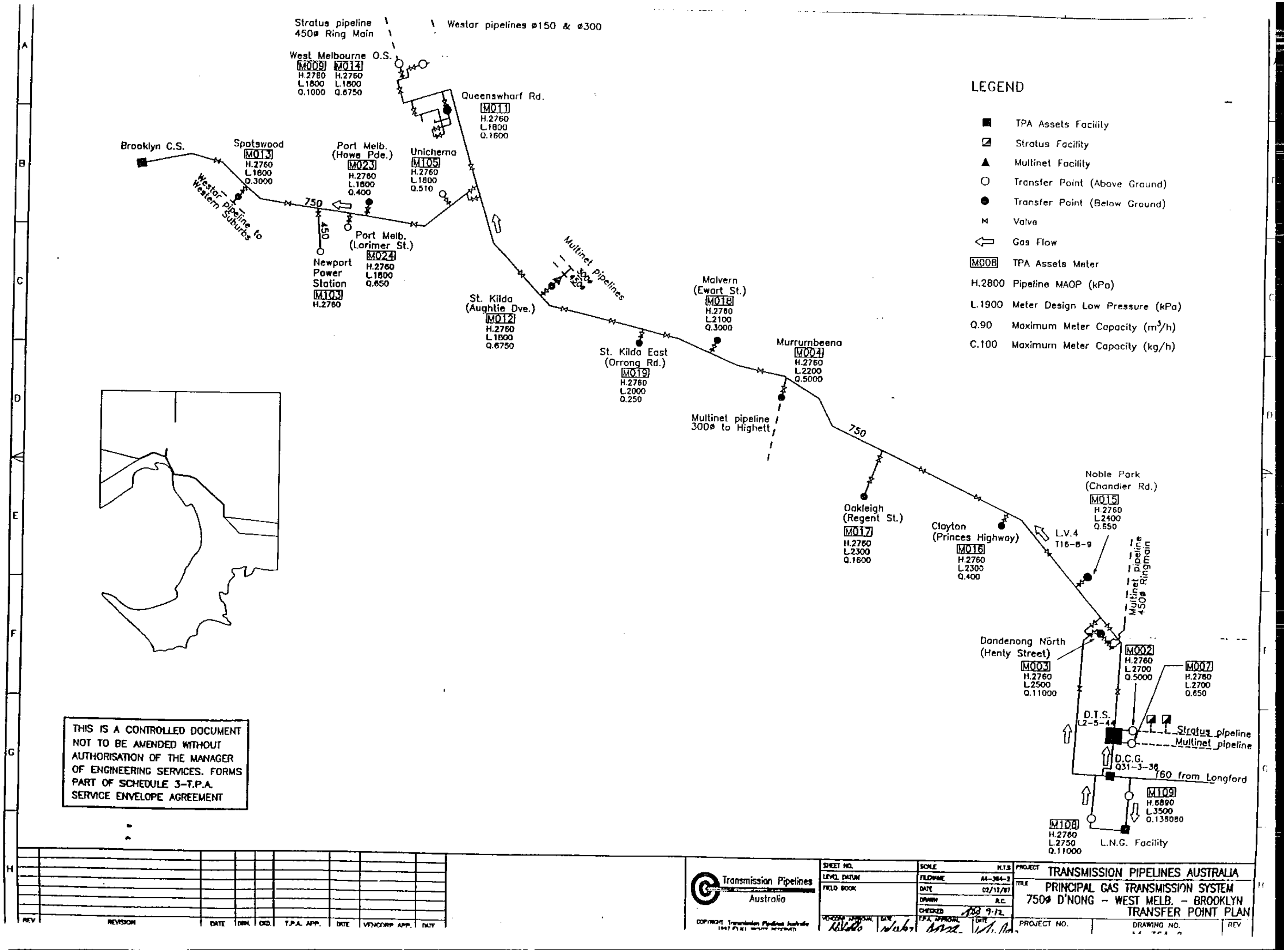
Transmission Pipelines Australia
TRANSMISSION PIPELINES AUSTRALIA
PRINCIPAL GAS TRANSMISSION SYSTEM
LONGFORD – DANDENONG – WOLLERT
TRANSFER POINT PLAN
SCALE N.T.S
DATE 02/12/97
DRAWN R.C.
PROJECT NO.
DRAWING NO.
REV



Stratus pipeline
450ø Ring Main
Westar pipelines ø150 & ø300
West Melbourne O.S.
M009 H.2760 L.1800 Q.1000
M014 H.2760 L.1800 Q.6750
Queenswharf Rd.
M011 H.2760 L.1800 Q.1600
Brooklyn C.S.
Spotswood
M013 H.2760 L.1800 Q.3000
Westar Pipeline to Western Suburbs
Port Melb. (Howe Pde.)
M023 H.2760 L.1800 Q.400
Unicherna
M105 H.2760 L.1800 Q.510
750
450
Newport Power Station
M103 H.2760
Port Melb. (Lorimer St.)
M024 H.2760 L.1800 Q.650
Multinet pipelines
300ø
450ø
St. Kilda (Aughtie Dve.)
M012 H.2760 L.1800 Q.6750
St. Kilda East (Orrong Rd.)
M019 H.2760 L.2000 Q.250
Malvern (Ewart St.)
M018 H.2760 L.2100 Q.3000
Murrumbeena
M004 H.2760 L.2200 Q.5000
Multinet pipeline 300ø to Highett
750
Oakleigh (Regent St.)
M017 H.2760 L.2300 Q.1600
Clayton (Princes Highway)
M016 H.2760 L.2300 Q.400
Noble Park (Chandler Rd.)
M015 H.2760 L.2400 Q.650
L.V.4
T16-8-9
Multinet pipeline
450ø Ringmain
Dandenong North (Henty Street)
M003 H.2760 L.2500 Q.11000
M002 H.2760 L.2700 Q.5000
M007 H.2760 L.2700 Q.650
D.T.S.
L2-5-44
Stratus pipeline
Multinet pipeline
D.C.G.
Q31-3-38
760 from Longford
M109 H.6890 L.3500 Q.138080
M108 H.2760 L.2750 Q.11000
L.N.G. Facility
LEGEND
TPA Assets Facility
Stratus Facility
Multinet Facility
Transfer Point (Above Ground)
Transfer Point (Below Ground)
Valve
Gas Flow
M008 TPA Assets Meter
H.2800 Pipeline MAOP (kPa)
L.1900 Meter Design Low Pressure (kPa)
Q.90 Maximum Meter Capacity (m³/h)
C.100 Maximum Meter Capacity (kg/h)
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REV
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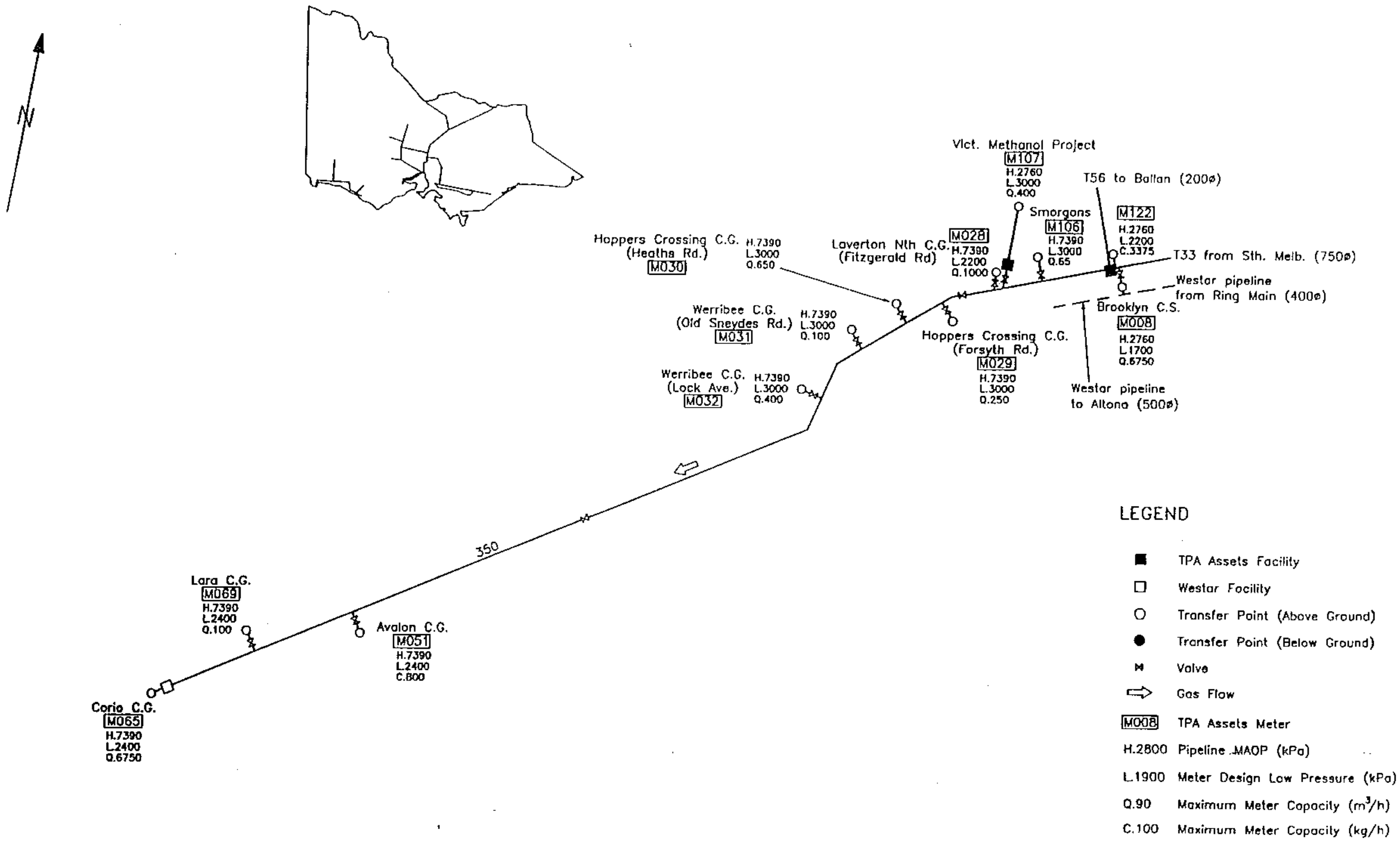
DATE
DRN.
CKD.
T.P.A. APP.
DATE
VENCORP APP.
DATE
Transmission Pipelines Australia
SHEET NO.
LEVEL DATUM
FIELD BOOK
SCALE N.T.S
FILENAME A4-364-2
DATE 02/12/97
DRAWN R.C.
CHECKED
PROJECT TRANSMISSION PIPELINES AUSTRALIA
TITLE PRINCIPAL GAS TRANSMISSION SYSTEM
750ø D'NONG - WEST MELB. - BROOKLYN
TRANSFER POINT PLAN
PROJECT NO.
DRAWING NO.
REV



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REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

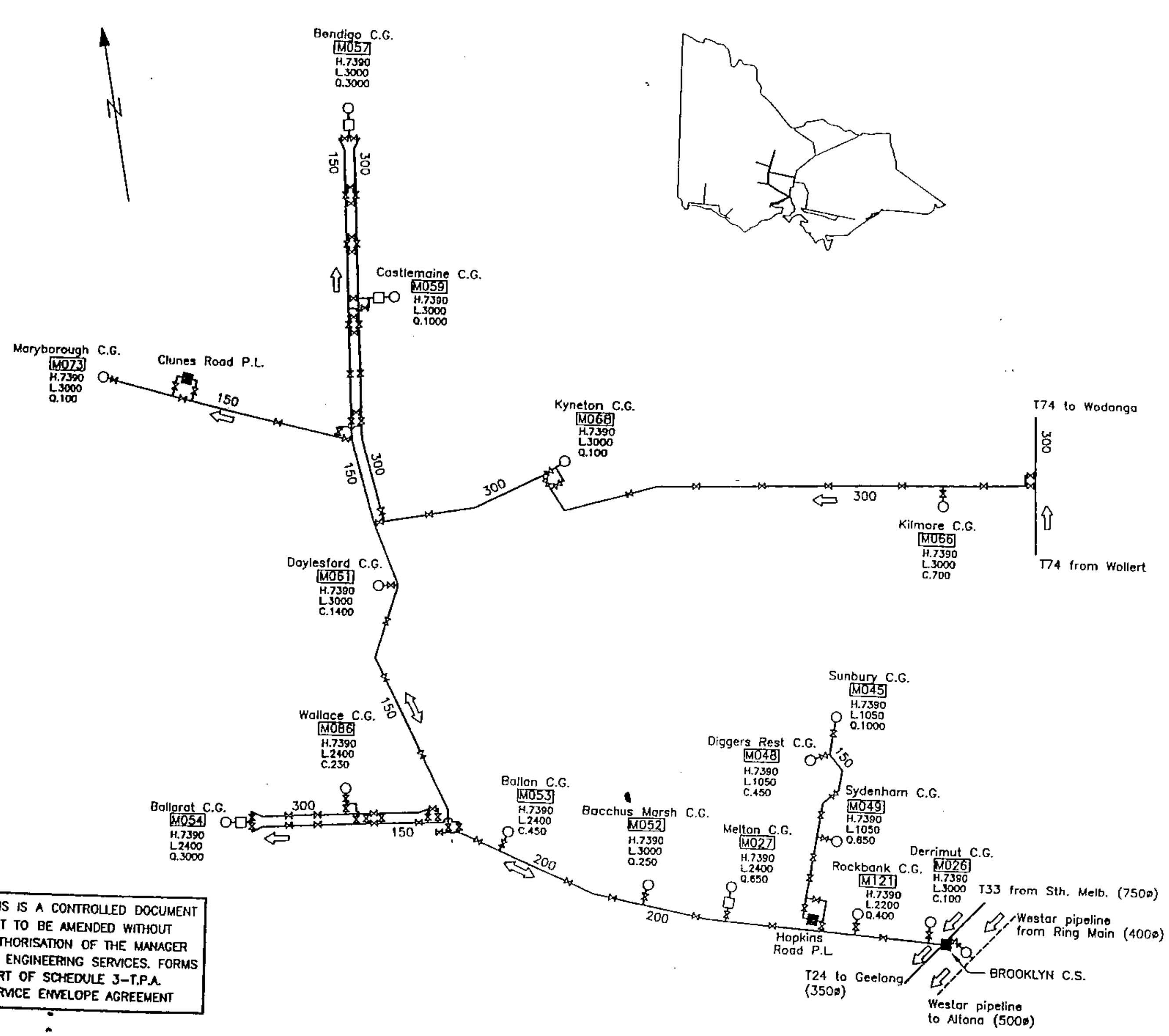
Transmission Pipelines Australia

SHEET NO.		SCALE	N.T.S
LEVEL DATUM		FILENAME	A4-364-3
FIELD BOOK		DATE	02/12/97
		DRAWN	R.C.
		CHECKED	9.12
VENCORP APPROVAL	DATE 10/12/97	T.P.A. APPROVAL	DATE

PROJECT: TRANSMISSION PIPELINES AUSTRALIA

TITLE: PRINCIPAL GAS TRANSMISSION SYSTEM
BROOKLYN – GEELONG
TRANSFER POINT PLAN

PROJECT NO.	DRAWING NO.	REV
	A4-364-3	



LEGEND

■	TPA Assets Facility
□	Westar Facility
○	Transfer Point (Above Ground)
●	Transfer Point (Below Ground)
⋈	Valve
⇦	Gas Flow
$\boxed{M008}$	TPA Assets Meter
H.2800	Pipeline MAOP (kPa)
L.1900	Meter Design Low Pressure (kPa)
Q.90	Maximum Meter Capacity (m^3/h)
C.100	Maximum Meter Capacity (kg/h)

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REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

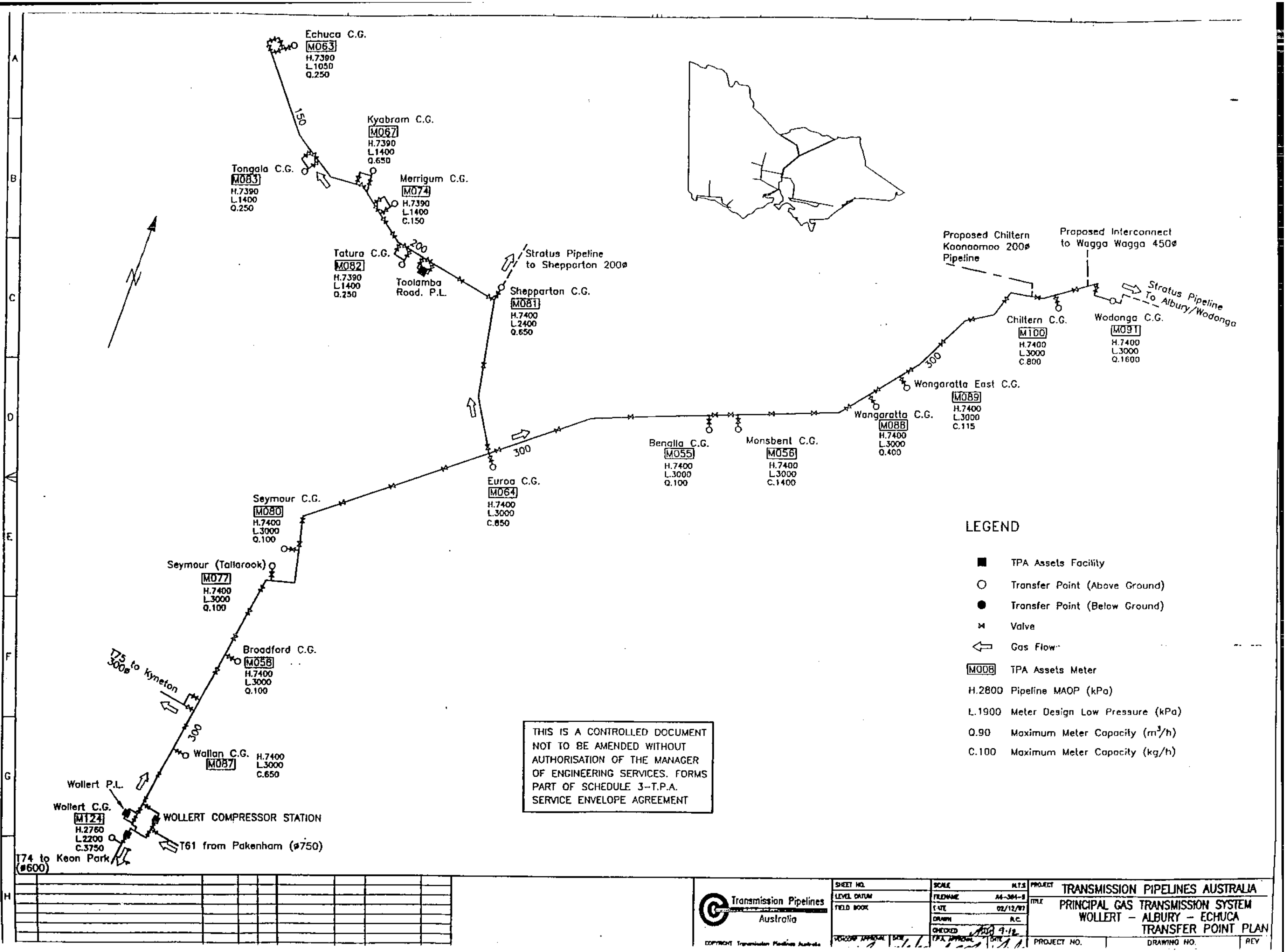
Transmission Pipelines Australia

SHEET NO.		SCALE	N.T.S
LEVEL DATUM		FILENAME	A4-364-4
FIELD BOOK		DATE	02/12/97
		DRAWN	R.C.
VENCORP APPROVAL	DATE 10/12/97	CHECKED	9.12
		T.P.A. APPROVAL	DATE

PROJECT: TRANSMISSION PIPELINES AUSTRALIA

TITLE: PRINCIPAL GAS TRANSMISSION SYSTEM BALLARAT – BENDIGO TRANSFER POINT PLAN

PROJECT NO. | DRAWING NO. A4-364-4 | REV



Echuca C.G.
M063
H.7390
L.1050
Q.250
150
Kyabram C.G.
M067
H.7390
L.1400
Q.650
Tongala C.G.
M083
H.7390
L.1400
Q.250
Merrigum C.G.
M074
H.7390
L.1400
C.150
Tatura C.G.
M082
H.7390
L.1400
Q.250
200
Toolamba Road. P.L.
Stratus Pipeline to Shepparton 200ø
Shepparton C.G.
M081
H.7400
L.2400
Q.650
Proposed Chiltern Koonoomoo 200ø Pipeline
Proposed Interconnect to Wagga Wagga 450ø
Stratus Pipeline To Albury/Wodonga
Chiltern C.G.
M100
H.7400
L.3000
C.800
Wodonga C.G.
M091
H.7400
L.3000
Q.1600
300
Wangaratta East C.G.
M089
H.7400
L.3000
C.115
Wangaratta C.G.
M088
H.7400
L.3000
Q.400
Benalla C.G.
M055
H.7400
L.3000
Q.100
Monsbent C.G.
M056
H.7400
L.3000
C.1400
300
Euroa C.G.
M064
H.7400
L.3000
C.850
Seymour C.G.
M080
H.7400
L.3000
Q.100
Seymour (Tallarook)
M077
H.7400
L.3000
Q.100
Broadford C.G.
M058
H.7400
L.3000
Q.100
T75 to Kyneton 300ø
300
Wallan C.G.
M087
H.7400
L.3000
C.650
Wollert P.L.
Wollert C.G.
M124
H.2760
L.2200
C.3750
WOLLERT COMPRESSOR STATION
T61 from Pakenham (ø750)
T74 to Keon Park (ø600)
LEGEND
TPA Assets Facility
Transfer Point (Above Ground)
Transfer Point (Below Ground)
Valve
Gas Flow
M008 TPA Assets Meter
H.2800 Pipeline MAOP (kPa)
L.1900 Meter Design Low Pressure (kPa)
Q.90 Maximum Meter Capacity (m³/h)
C.100 Maximum Meter Capacity (kg/h)
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SHEET NO.
LEVEL DATUM
FIELD BOOK
SCALE N.T.S
FILENAME A4-384-8
DATE 02/12/97
DRAWN R.C.
CHECKED
PROJECT TRANSMISSION PIPELINES AUSTRALIA
TITLE PRINCIPAL GAS TRANSMISSION SYSTEM WOLLERT – ALBURY – ECHUCA TRANSFER POINT PLAN
PROJECT NO.
DRAWING NO.
REV
A
B
C
D
E
F
G
H

Ref.	Suburb or Town/City	Heating Value Zone	GasChrom Ref No.	Split *	Lic. No.	Supply pipe	Reg No.	Generic Type	New Meter Type
M000	NORTH PAARATTE	Coast	Paaratte	-	145	T81	N.A.		Exist !
M001	LONGFORD METER STATION	Latrobe A	Longford	-	75	T60	PIP		Exist !
M002	DTS (Peninsula)	Metro-South	DTS 2	S	36	T16	N.A.	Special	Ultrasonic
M003	DANDENONG NORTH 450 mm	Metro A	DCG 1	M	36	T16	PIP	3B	Ultrasonic
M004	MURRUMBEENA 300 mm to Highett	Metro A	DCG 1	M	36	T16	N.A.	3B	Ultrasonic
M005	DTS (Lurgi/150mm GMH)	Metro-Cranb	DTS 1	M	50	T01	N.A.	Special	Ultrasonic
M006	DANDENONG (BOC Let Down) (TPA)	Metro-LetDown	DCG 2	M	LNG	Q31	LNG	Special	Ultrasonic
M007	DTS (Edithvale)	Metro-South	DTS 2	M			N.A.	Special	Turbine
M008	BROOKLYN (Comb.d 400 & 500 mm)	Metro-West	DCG 1	W	108	T16	N.A.	Special	Ultrasonic
M009	W Melb-Foots(150TP, 300TP)	Metro A	DCG 1	W				1A	Turbine
M011	MELBOURNE (TP/TP & HP/MP reconfig)	Metro A	DCG 1	S	36	T16	P4-025	Special	Turbine
M012	ST KILDA (upgrade reg for capacity)	Metro A	DCG 1	M	36	T16	P6-013	2B	Ultrasonic
M013	SPOTSWOOD 300mm 2800kPa	Metro-West	DCG 1	W	108	T16/T33	N.A.	3B	Ultrasonic
M014	W Melb-N Melb (450TP, 300HP)	Metro A	DCG 1	S	36	T16	N.A.	1A	Ultrasonic
M015	NOBLE PARK	Metro A	DCG 1	M	36	T16	P4-178	2A	Turbine
M016	CLAYTON	Metro A	DCG 1	M	36	T16	P4-255	2A	Turbine
M017	OAKLEIGH	Metro A	DCG 1	M	38	T16/T15	P4-239	2B	Turbine
M018	MALVERN 2800 kPa	Metro A	DCG 1	M	36	T16	P4-100	2B	Ultrasonic
M019	ST KILDA EAST	Metro A	DCG 1	M	36	T16	P4-160	2A	Turbine
M023	PORT MELBOURNE (Howe Pde)	Metro A	DCG 1	M	36	T33	P2-039	2A	Turbine
M024	PORT MELBOURNE (Lorimer St)	Metro A	DCG 1	M	36	T33	P4-154	1B	Turbine
M026	DERRIMUT	Metro-West	DCG 1	W	122	T56	P4-273	1A	Coriolis
M027	MELTON SOUTH	Calder-Melton	ALGORITHM	W	90	T56	P8-012	Special	Turbine
M028	LAVERTON NORTH (TP/HP)	Metro-West	DCG 1	W	81	T24	P5-015	1A	Turbine
M029	HOPPERS CROSSING (Forsyth Rd)	Metro-West	DCG 1	W	81	T24	P4-128	1A	Turbine
M030	HOPPERS CROSSING (Heaths Rd)	Metro-West	DCG 1	W	81	T24	P4-064	1A	Turbine
M031	WERRIBEE (Old Sneydes Rd)	Metro-West	DCG 1	W	81	T24	P4-237	1A	Turbine
M032	WERRIBEE (Lock Ave)	Metro-West	DCG 1	W	81	T24	P4-157	1A	Turbine
M033	HEALESVILLE	Metro-East	DCG 1	S	141	T61	P5-017	1A	Coriolis
M034	GEMBROOK	Metro-East	DCG 1	H	141	T61	P4-254	1A	Turbine
M035	LYNDHURST	Metro-Cranb	DTS 1	S	50	T01	P4-274	2A	Turbine
M036	CRANBOURNE	Metro-Cranb	DTS 1	S	50	T01	P4-076	2A	Turbine
M037	CRANBOURNE	Metro-Cranb	DTS 1	S	50	T01	P4-170	2A	Turbine
M038	CLYDE NORTH	Metro-Cranb	DTS 1	S	107	T01	P4-166	2A	Coriolis
M040	PAKENHAM SOUTH	Metro-Cranb	DTS 1	S	50	T01	P4-073	2A	Turbine
M042	HAMPTON PARK	Metro-East	DCG 1	S	75	T60	P4-248	1A	Turbine
M043	NARRE WARREN	Metro-East	DCG 1	S	75	T60	P4-261	1A	Turbine
M044	BERWICK	Metro-East	DCG 1	S	75	T60	P4-088	1A	Turbine
M045	SUNBURY	Metro West	DCG 1	W	122	T62	P4-111	1C	Turbine
M048	DIGGERS REST	Metro West	DCG 1	W	122	T62	P4-176	1A	Coriolis
M049	SYDENHAM	Metro West	DCG 1	W	78	T62	P4-251	1A	Turbine
M051	AVALON	Metro-Corio	DCG 1	W	61	T24	P4-190	1A	Coriolis
M052	BACCHUS MARSH	Calder-Melton	ALGORITHM	W	78	T56	P4-104	1C	Turbine
M053	BALLAN	Calder-Melton	ALGORITHM	W	78	T56	P4-103	1A	Coriolis
M054	BALLARAT	Calder-Ballarat	ALGORITHM	W	78	T57	P7-006	Special	Ultrasonic
M055	BENALLA	North Hume-Ben	ALGORITHM	S	101	T74	P4-107	1A	Turbine
M056	BENALLA (Single Customer)	North Hume-Ben	ALGORITHM	S	101	T74	P5-011	1A	Coriolis
M057	BENDIGO	Calder-Bendigo	Wollert	W	78	T57	P7-007	Special	Ultrasonic
M058	BROADFORD	South Hume	Wollert	S	101	T74	P4-090	1A	Turbine
M059	CASTLEMAINE	Calder-Bendigo	Wollert	S	78	T70	P4-105	Special	Turbine
M060	CHURCHILL	Latrobe A	Longford	S	50	T01	P4-116	2A	Coriolis
M061	DAYLESFORD	Calder-Bendigo	Wollert	W	78	T70	P4-177	1A	Coriolis
M062	DROUIN (South)	Lurgi	Longford	S	50	T01	P4-081	2A	Turbine
M063	ECHUCA	Echuca	Wollert	S	152	85	P4-258	1A	Turbine
M064	EUROA	South Hume-Euroa	Wollert	S	101	T74	P4-131	1A	Coriolis
M065	GEELONG (Corio)	Metro-Corio	DCG 1	W	84	T24	P7-002	Special	Ultrasonic
M066	KILMORE	South Hume	Wollert	S	128	T75	P4-232	1A	Coriolis

Ref.	Suburb or Town/City	Heating Value Zone	GasChrom Ref No.	Split *	Lic. No.	Supply pipe	Reg No.	Generic Type	New Meter Type
M067	KYABRAM	Echuca	Wollert	S	136	T86	P4-164	1A	Turbine
M068	KYNETON	Calder-Bendigo	Wollert	W	128	T75	P4-149	1A	Turbine
M069	LARA	Metro-Corio	DCG 1	W	81	T24	P4-142	1C	Turbine
M070	LONGWARRY	Lurgi	Longford	S	50	T01	P4-020	1B	Coriolis
M071	MORWELL (Firmins Lane)	Latrobe A	Longford	S	50	T01	P5-006	1A	Turbine
M073	MARYBOROUGH	Calder-Bendigo	Wollert	W	125	T67	P4-114	1C	Turbine
M074	MERRIGUM	Echuca	Wollert	S	136	T71	P4-163	1A	Coriolis
M075	MOE	Lurgi	Longford	S	50	T01	P4-130	1B	Turbine
M076	MORWELL	Latrobe A	Longford	S	50	T01	N.A.	Special	Turbine
M077	SEYMOUR (TALLAROOK)	South Hume	Wollert	S	101	T74	P5-012	1A	Coriolis
M078	ROSEDALE	Latrobe A	Longford	S	75	T60	P4-148	1A	Coriolis
M079	SALE	Latrobe A	Longford	S	75	T60	P8-014	Special	Turbine
M080	SEYMOUR	South Hume	Wollert	S	101	T74	P4-106	1A	Turbine
M081	SHEPPARTON	Echuca	Wollert	S	132	T59	P8-001	1A	Turbine
M082	TATURA	Echuca	Wollert	S	136	T71	P4-134	1A	Turbine
M083	TONGALA	Echuca	Wollert	S	152	T85	P4-257	1A	Turbine
M084	TRAFALGAR	Lurgi	Longford	S	50	T01	P4-138	1B	Coriolis
M085	TRARALGON	Latrobe A	Longford	S	75	T60	P4-043	1A	Turbine
M086	WALLACE	Calder-Ballarat	ALGORITHM	W	78	T56	P5-007	1A	Coriolis
M087	WALLAN	South Hume	Wollert	S	101	T74	P4-115	1A	Coriolis
M088	WANGARATTA	North Hume-Wan	ALGORITHM	S	101	T74	P4-108	1A	Turbine
M089	WANGARATTA (Single Customer)	North Hume-Wan	ALGORITHM	S	101	T74	P4-281	1A	Coriolis
M090	WARRAGUL	Lurgi	Longford	S	50	T01/T44	P4-140	1B	Turbine
M091	WODONGA	North Hume-Wod	ALGORITHM	S	101	T74	P8-002	1A	Turbine
M092	YARRAGON	Lurgi	Longford	S	50	T01	P4-272	1B	Coriolis
M093	COBDEN	Coast	Paaratte	W	168	T91	P5-014	1A	Turbine
M094	HAMILTON	Coast	Paaratte	W	171	T93	P5-016	1A	Turbine
M095	KOROIT	Coast	Paaratte	W	155	T86	P5-013	1A	Turbine
M096	PORTLAND	Coast	Paaratte	W	155	T86	P8-026	1A	Turbine
M097	ALLANSFORD	Coast	Paaratte	W	145	T81	P5-010	Special	Turbine
M098	DARNUM (New, Single Customer)	Lurgi	Longford	S	50	T01	P5-22	1B	Turbine
M099	CARISBROOK (by Coastal Gas)	Calder-Bendigo	Wollert	W	125	T67	N.A		None
M100	CHILTERN (New, under construction)	North Hume-Wod	ALGORITHM	S	101	T74	P5-21	1A	Coriolis
M102	GENVIC - JEERALANG (TPA)	Latrobe A	Longford		50	T01		Special	Exist !
M103	GENVIC - NEWPORT (TPA)	Metro-Newport	DCG 1		124	T64		Special	Exist !
M104	AMCOR - MARYVALE (TPA)	Latrobe A	Longford		67	T60	N1-0709	Special	Ultrasonic
M105	UNICHEMA - PORT MELBOURNE (TPA)	Metro A	DCG 1		164	T94	N1-1536	Special	Exist !
M106	SMORGONS - LAVERTON NORTH (TPA)	Metro-West	DCG 1		81	T24	N1-2541	Special	Exist !
M107	BHP METHANOL - LAVERTON NORTH (TPA)	Metro-West	DCG 1		162	T66	N1-4220	Special	Exist !
M108	DANDENONG - 2750kPa BOC (TPA)	Metro-LNG	DCG 3		LNG	Q31	LNG	Special	Ultrasonic
M109	DANDENONG - 7000kPa BOC (TPA)	Metro-East	DCG 1		75	Q31	LNG	Special	Coriolis
M111	RUTHERGLEN	Murray Valley	ALGORITHM	S				1C	Turbine
M112	YARRAWONGA	Murray Valley	ALGORITHM	S				1C	Turbine
M113	COBRAM	Murray Valley	ALGORITHM	S				1C	Turbine
M114	KOONOOMOO	Murray Valley	ALGORITHM	S				1C	Turbine
M115	KEON PARK EAST	Metro-North	Wollert	S				3B	Ultrasonic
M116	KEON PARK WEST	Metro-North	Wollert	W				3B	Ultrasonic
M117	CRAIGIEBURN (Single Customer)	Metro-North	Wollert	S			P4-47	1A	Turbine
M118	EPPING	Metro-North	Wollert	S			P4-162	1A	Turbine
M119	TEMPLESTOWE (MULTINET)	Metro-Temple	ALGORITHM	M**				3B	Ultrasonic
M120	NORTH MELBOURNE (STRATUS)	Metro-NM	ALGORITHM	S**				Special	Ultrasonic
M121	ROCKBANK (Boral asphalt)	Metro-West	DCG 1	W	122	T56		1C	Turbine
M122	BROOKLYN C/S (TPA)	Metro-West	DCG 1					1C	Coriolis
M123	GOODING C/S (TPA)	Latrobe-B	Longford					1C	Coriolis
M124	WOLLERT C/S (TPA)	Metro-North	Wollert					Special	Coriolis

* Split: M=Multinet, S=Stratus, W=Westar

REV	REVISION	DATE	DRN.	CKD.	T.P.A. APP.	DATE	VENCORP APP.	DATE

Transmission Pipelines Australia

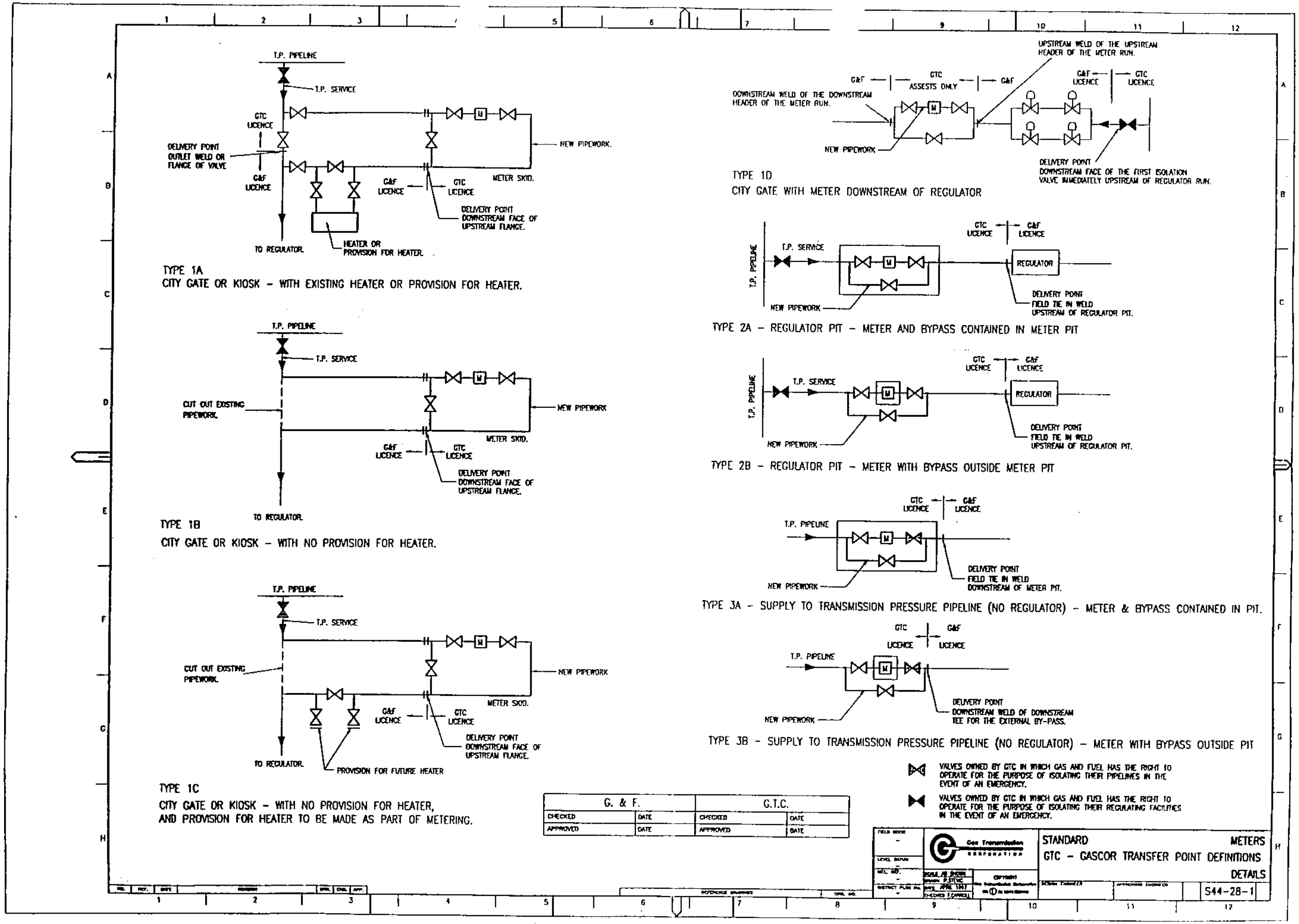
SHEET NO. | LEVEL DATUM | FIELD BOOK | VENCORP APPROVAL 4/13 | DATE 10/12/97

SCALE N.T.S | FILENAME A1-301-2 | DATE 08/12/97 | DRAWN P.C.D. | CHECKED 9-12 | T.P.A. APPROVAL | DATE 11/12/97

PROJECT TRANSMISSION PIPELINES AUSTRALIA

TITLE PRINCIPAL GAS TRANSMISSION SYSTEM AND WESTERN GAS TRANSMISSION SYSTEM TRANSFER POINT METER PLAN CHART

PROJECT NO. | DRAWING NO. A1-301-2 | REV


TYPE 1A
CITY GATE OR KIOSK - WITH EXISTING HEATER OR PROVISION FOR HEATER.
TYPE 1B
CITY GATE OR KIOSK - WITH NO PROVISION FOR HEATER.
TYPE 1C
CITY GATE OR KIOSK - WITH NO PROVISION FOR HEATER, AND PROVISION FOR HEATER TO BE MADE AS PART OF METERING.
T.P. PIPELINE
T.P. SERVICE
GTC LICENCE
G&F LICENCE
DELIVERY POINT OUTLET WELD OR FLANGE OF VALVE
DELIVERY POINT DOWNSTREAM FACE OF UPSTREAM FLANGE.
HEATER OR PROVISION FOR HEATER.
TO REGULATOR.
NEW PIPEWORK.
METER SKID.
CUT OUT EXISTING PIPEWORK.
PROVISION FOR FUTURE HEATER
TYPE 1D
CITY GATE WITH METER DOWNSTREAM OF REGULATOR
GTC ASSESTS ONLY
UPSTREAM WELD OF THE UPSTREAM HEADER OF THE METER RUN.
DOWNSTREAM WELD OF THE DOWNSTREAM HEADER OF THE METER RUN.
DELIVERY POINT DOWNSTREAM FACE OF THE FIRST ISOLATION VALVE IMMEDIATELY UPSTREAM OF REGULATOR RUN.
TYPE 2A - REGULATOR PIT - METER AND BYPASS CONTAINED IN METER PIT
TYPE 2B - REGULATOR PIT - METER WITH BYPASS OUTSIDE METER PIT
REGULATOR
DELIVERY POINT FIELD TIE IN WELD UPSTREAM OF REGULATOR PIT.
TYPE 3A - SUPPLY TO TRANSMISSION PRESSURE PIPELINE (NO REGULATOR) - METER & BYPASS CONTAINED IN PIT.
DELIVERY POINT FIELD TIE IN WELD DOWNSTREAM OF METER PIT.
TYPE 3B - SUPPLY TO TRANSMISSION PRESSURE PIPELINE (NO REGULATOR) - METER WITH BYPASS OUTSIDE PIT
DELIVERY POINT DOWNSTREAM WELD OF DOWNSTREAM TEE FOR THE EXTERNAL BY-PASS.
VALVES OWNED BY GTC IN WHICH GAS AND FUEL HAS THE RIGHT TO OPERATE FOR THE PURPOSE OF ISOLATING THEIR PIPELINES IN THE EVENT OF AN EMERGENCY.
VALVES OWNED BY GTC IN WHICH GAS AND FUEL HAS THE RIGHT TO OPERATE FOR THE PURPOSE OF ISOLATING THEIR REGULATING FACILITIES IN THE EVENT OF AN EMERGENCY.
G. & F.
G.T.C.
CHECKED
APPROVED
DATE
Gas Transmission Corporation
STANDARD
METERS
GTC - GASCOR TRANSFER POINT DEFINITIONS
DETAILS
S44-28-1