POTENTIAL *ENERGY*

UPPER SPENCER GULF COMMON PURPOSE GROUP

INCREASED GAS SUPPLY TO THE UPPER SPENCER GULF

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EXECUTIVE SUMMARY

Currently there exists a 150 mm lateral off the Moomba Adelaide Pipeline from Whyte Yarcowie to Port Pirie, and a 200 mm pipeline from Port Pirie to Whyalla, crossing Spencer Gulf. The gas pipeline from Whyte Yarcowie to Port Pirie is operating at close to capacity. The pipeline from Port Pirie to Whyalla has spare capacity, although it is effectively not available due to the current limitation on transporting gas to Port Pirie. Expansion of existing customers and the potential for new gas consuming industry in the Upper Spencer Gulf has led to a request to assess the options to provide additional capacity. This report documents an Engineering Study that determines the potential maximum capacity of each existing lateral based on compression only, and the capital required to supply additional gas through the pipelines. This report also includes a Gas Supply Study that reviews the potential for future supply of gas to the Upper Spence Gulf and future gas prices.

The Engineering Study determined indicative pipeline sizes and costs for a number of strategies for capacity development. The current gas capacity of the Whyte Yarcowie - Port Pirie - Whyalla lateral was determined to be 7.7 PJ/year. The study concluded that the capacity of the Whyte Yarcowie to Port Pirie lateral could be increased to 11 PJ/year (40 % capacity increase) via the addition of compression at Whyte Yarcowie for a capital cost of approximately (AUD 2011) $5.9 million. The maximum capacity of the existing lateral from Port Pirie to Whyalla was found to be up to 19.6 PJ/year, assuming adequate gas at maximum pressure is available at Port Pirie.

The study also estimated the capital costs for supply of an additional 10, 30 and 60 PJ/year of gas, using combinations of looping pipelines and compression. On a per PJ/year of capacity basis, the capital cost of expansion ranges from $2.4 million to $3.4 million, where smaller increments in capacity are more expensive to implement (on a PJ/year basis) than larger increments. If initially upgrading the current pipeline system for additional 10 or 30 PJ/year, a development path should be selected so as to allow for further development in the future. The study recommends an alternate development option which although requiring higher capital upfront, provides a staged development path consistent with achieving the final 60 PJ/year of additional capacity. Capital costs shown below are preliminary (± 30 %), and a more detailed analysis would be required to increase their accuracy.

Capacity Increase (PJ/year)	Single Stage Capital Cost (AUD 2011 $million)	Incremental 3-Stage Capital Cost (AUD 2011 $million)
10	33.6	48.6
30	80.9	55.4
60	143.7	39.7
Total	**-**	**143.7**

The Gas Supply Study concluded that there is likely to be strong growth in gas demand in Eastern Australia over the next decade, largely due to the start-up of major liquefied natural gas (LNG) projects in Queensland. Eastern Australia gas reserves are at their highest level ever, as a result of gas reserves (particularly coal seam gas (CSG)) being proven up in anticipation of the major LNG export projects proceeding. There is, therefore, expected to be adequate gas supply to meet demand in Eastern Australia for the foreseeable future. Gas supply to South Australia is likely to continue to be sourced from the Otway Basin (Victoria) and Cooper Basin (South Australia and South West Queensland), and increasingly from CSG from the Surat-Bowen Basin (Eastern Queensland). However over the medium to long term, South Australia is likely to increasingly become at a gas price disadvantage due to the increasing need to transport gas from distant reserves.

The future price of gas in Australia is expected to be largely influenced by the alternative LNG market for gas, the likely introduction of a carbon tax, the development of higher cost gas reserves and limited gas producer competition. In consideration of these influences, the price of gas is estimated to increase by 3 – 5 % (real) per annum over the next 10 years to between $5.00 and $6.50 per GJ (when considering a wholesale price at Whyte Yarcowie). Gas supply contracts with terms of up to about 5 years have become typical, as the industry awaits some clarity on the magnitude of future gas price increases, which may adversely affect the ability of major gas-consuming projects to commit to major developments.

Unless Government support for expansion of the Whyte Yarcowie - Port Pirie - Whyalla gas pipeline is forthcoming, gas consuming industries considering establishing in the Upper Spencer Gulf would also have the price disadvantage of the cost of the expansion of the pipeline. Without Government support, in order to offset this potential competitive disadvantage, such an industry would require some other competitive advantage or it would need to be somewhat indifferent to the cost of gas.

CONTENTS

1 INTRODUCTION

In 2003 / 2004 Potential Energy and GPA Engineering undertook a study for the Upper Spencer Gulf Common Purpose Group, entitled "The Case for Increasing Natural Gas to the Upper Spencer Gulf".

GPA Engineering and Potential Energy have been requested to review this study by updating the cost estimates to give an up-to-date assessment of the capital required to increase the gas supply to the Upper Spencer Gulf (USG). Furthermore, a current review of potential gas supply and gas prices in South Australia was also requested.

Currently there exists a DN150 lateral from the Moomba Adelaide Pipeline (MAP) running from Whyte Yarcowie to Port Pirie and an existing DN200 pipeline running from Port Pirie to Whyalla, crossing Spencer Gulf.

The current major users of gas from this lateral in the Upper Spencer Gulf include One Steel in Whyalla, Nyrstar at Port Pirie, Santos at Port Bonython, as well as a number of smaller industrial and commercial operations at Whyalla and Port Pirie. Expansion of existing customers and the potential for new gas consuming industry in the Upper Spencer Gulf has led to a request to assess the options to provide additional capacity.

Figure 1 below shows the location and route of the existing lateral from Whyte Yarcowie to Port Pirie, and from Port Pirie to Whyalla, in relation to industry in the region. The existing lateral is highlighted in green.

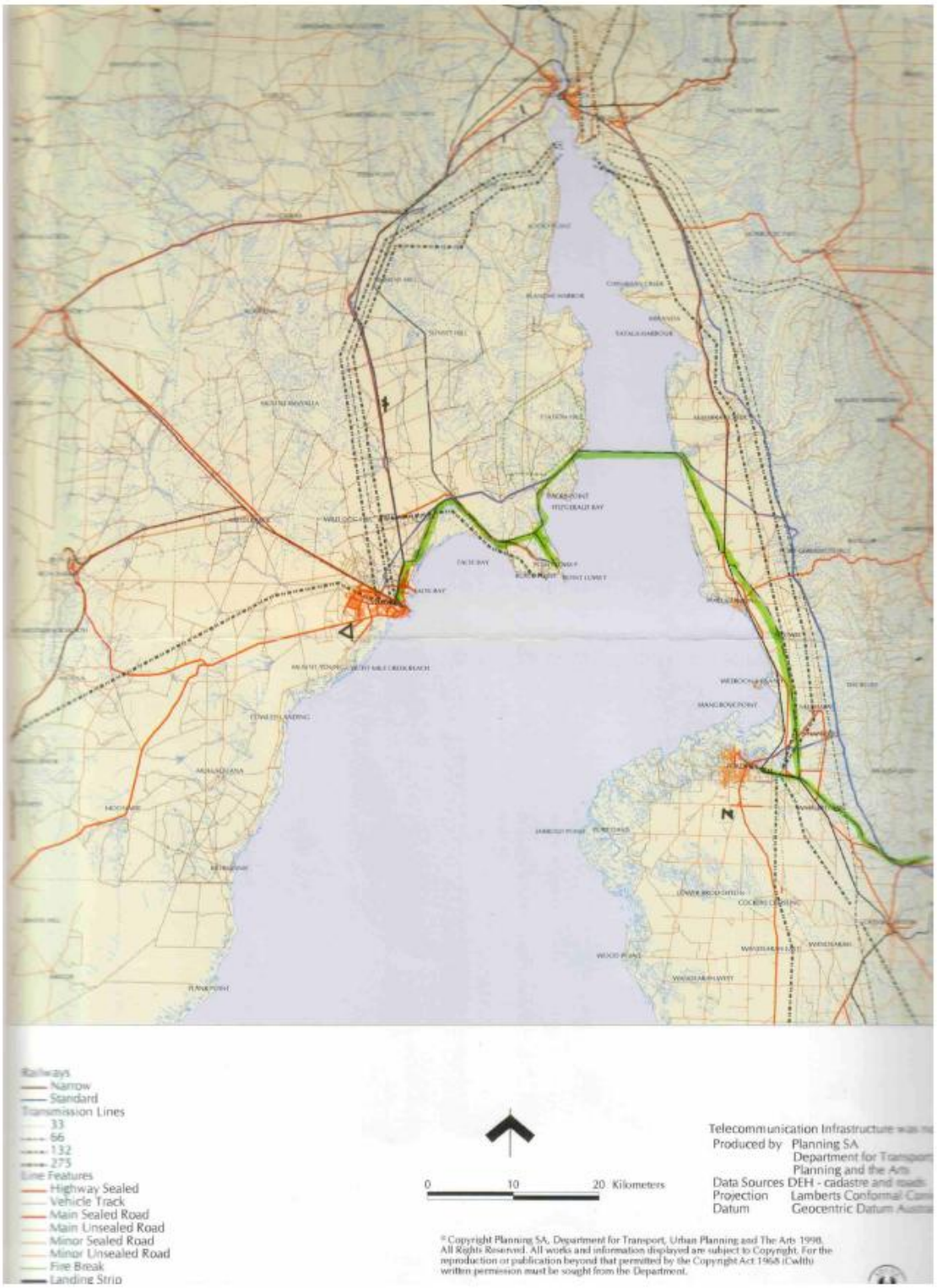


Figure 1. Map of existing lateral

There are two stages to this study; an Engineering Study, in which the options available to increase the capacity to the Upper Spencer Gulf and their associated capital costs were determined, and a Gas Supply Study.

The intent of the Engineering Study was to determine the following:

1. Capacity of the existing 150 mm pipeline to Port Pirie if compression were installed,
2. Capital cost to supply an additional 10 PJ per annum,
3. Capital cost to supply an additional 30 PJ per annum,
4. Capital cost to supply an additional 60 PJ per annum,
5. Capacity of the existing 200 mm pipeline to Whyalla assuming infinitely available gas at Port Pirie.

The engineering study evaluated options to achieve the above capacity increases. This report provides a summary scope and estimated cost (± 30 %) for the best option in each case study.

The intent of the Gas Supply Study was to provide a brief review of:

1. Potential sources for future supply of gas to South Australia,
2. Current and future gas pricing,

The gas supply study also assessed the likely trends in the Eastern Australia gas market over the next 20 years, and the implications of those trends for gas consuming industry in the Upper Spencer Gulf.

2 ENGINEERING STUDY

2.1 METHODOLOGY

2.1.1 Pipeline Modelling

Aspen HYSYS Simulation (Vol. 7.2) was used to model the five design cases, based on known and assumed design data. For the HYSYS Modelling, the Peng Robinson equation of state was used, and the Beggs and Brill pipeline correlation. For cases studies 2 to 4, as described in Section 1, the required increased gas capacity was achieved by either:

- Using additional piping to loop all of, or sections of, each pipe length, or
- Using compressor stations at the start or end of each pipe length or mid-way along the existing pipeline, or
- A combination of the above.

There exists a DN100 pipeline looping from Port Pirie to Whyalla, initially installed as a possible future liquids line. The use of this line to increase capacity to Whyalla was not considered in the modelling as for all increased capacity cases, as a looped line from Port Pirie would need to be much larger than DN100.

2.1.1.1 DESIGN DATA

This study was based on the following design data (as per the 2003 study):

- The length of the pipeline from Whyte Yarcowie to Port Pirie is 73.0 km
- The length of the pipeline from Port Pirie to Whyalla is 87.8 km

The existing pipelines have dimensions as shown in Table 1 below:

Table 1. Existing pipeline dimensions

	Whyte Yarcowie to Port Pirie	Port Pirie to Whyalla
Pipe Size	DN150	DN200
Inner Diameter (mm)	159.5	210.5
Outer Diameter (mm)	168.3	219.1
Wall Thickness (mm)	4.4	4.3

2.1.1.2 ASSUMPTIONS

The capacity models assume the following:

- The inlet pressure at the Whyte Yarcowie off-take (from the MAP) is 8,200 kPag. Although the minimum pressure in the MAP is 5,500 kPag, compressor stations located along the MAP maintain normal pipeline operating pressures around 8,200 kPag.

- The maximum allowable operating pressure (MAOP) of all pipelines is 10,130 kPag. The operating pressure used in the pipeline modelling is 9,117 kPag, 10 % lower than the MAOP.

- The minimum required gas discharge pressure at Port Pirie and Whyalla is 3,500 kPag. This allows for a 500 kPag pressure drop through metering stations at the discharge, and a 3,000 kPag gas delivery pressure to the end user e.g., gas turbine. This is also in accordance with the expected required pressure for industry in the Port Pirie and Whyalla areas.

- The relative roughness of the existing pipelines is 0.03 mm.

- The gas composition was based on a standard Moomba gas composition, as shown in Table 2 below:

Table 2. Gas composition

Component	Mole %
Methane	95.709
Ethane	2.369
Propane	0.071
Iso-Butane	0.004
Neo-Butane	0.008
Iso-Pentane	0.002
Neo-Pentane	0.006
Hexane	0.016
Nitrogen	1.274
Carbon Dioxide	0.541
TOTAL	**100.00**

- The heating value of the gas is 37.84 MJ/Sm^3, based on the standard Moomba gas composition.

- The existing and new pipelines have no insulation, and are buried at a depth of 1.0 m, with ground temperature 14 ^{o}C.

- The split of gas at Port Pirie is 1.1 PJ/year to Port Pirie, and 5.6 PJ/year to Whyalla, based on the previous study's normal capacity of 6.7 PJ/year. This split of gas of 16.9 % of the total inlet flowrate to Port Pirie and 83.1 % of the total inlet flowrate to Whyalla has been maintained in all cases.

- From inspection of maps of the existing DN200 pipeline from Port Pirie to Whyalla (87.8 km), it is assumed that the pipeline from Port Pirie to the edge of the Gulf is approximately 40.0 km, the pipeline under the Gulf is approximately 12.8 km, and the pipeline from the other side of the Gulf to Whyalla is approximately 35.0 km. See Figure 1 previously.

2.1.2 Cost Estimates

2.1.2.1 INTRODUCTION

Preliminary capital costs were determined for each supply capacity case. Operating costs, maintenance and likely tariffs involved with the pipeline modification are beyond the scope of the study. All costs are listed in 2011 Australian dollars, and exclude GST.

2.1.2.2 PIPELINE LOOPING

It was assumed that the new pipelines would be constructed of X60 steel, therefore, for estimating the wall thickness, the specified minimum yield strength (SMYS) is 60,000 psi, or 413.7 MPa. The design pressure of the new pipelines is the same as the existing pipelines, at 10.13 MPa. The calculated wall thickness was increased by 1 mm to be conservative, and allow for detailed design calculations that have not been completed at this stage, including wall thickness for bending, external interference, road crossings, where some sections will be heavy wall.

The capital cost of the pipelines was estimated using the following prices, as used in previous projects undertaken by GPA:

- Cost of steel: $2,500 per tonne
- Cost of pipeline coating: $45.33 per m^2
- Cost of pipeline construction: $20,840 per km of distance, per inch diameter

The cost of hot taps from the MAP to accommodate the increased inlet capacity, as well as hot taps off the laterals for pipeline looping, was estimated at a cost of $200,000 per hot tap.

The existing end-of-line off-take facilities at Port Pirie and Whyalla would not be sufficient for the increased capacity of case studies 2, 3 and 4. The cost of metering and regulating stations was scaled using capacity from previous work by GPA at $12 million for 280 TJ/day, using an index factor of 0.6. This allowance in the cost estimates is expected to cover a single off-take meter station or multiple off-takes to new customers having the same total capacity.

For cases that required looping pipe under the Gulf, the cost of laying the pipeline underwater was estimated at a cost of $952,000 per km of underwater pipeline, for all pipe diameters. This estimate includes the cost of onshore site preparation, relevant seabed surveys, trenching and burial, and underwater installation using barges. The cost of permits required for laying pipelines across the Gulf was estimated to be $521,000, as used in previous projects undertaken by GPA. In addition, the cost of 300 m of horizontal directional drilling (HDD) required for the beach crossings at each side of the Gulf, was estimated at $722,300 per 300 m HDD.

Furthermore, project costs for the pipeline, expressed as a percentage of the pipe material and construction costs are shown in Table 3 below. See Appendix 8 for more details.

Table 3. Pipeline cost factors

Cost	Factor	Reference
Engineering	6.5 %	Materials and Construction Cost
Construction Contingencies	7.5 %	Construction Cost
Pipeline Material Contingencies	7.5 %	Materials Cost
Underwater Installation Contingencies	20 %	Underwater Installation Cost
Project Management	7.5 %	Materials, Construction and Engineering Cost (and Underwater Installation Cost if relevant)
Insurance	1 %	Materials, Construction and Engineering Cost (and Underwater Installation Cost if relevant)

2.1.2.3 COMPRESSORS

Purchase costs for compressor stations were obtained from budget quotations from a single vendor. Typical costs for compressors, based on power, are shown in Table 4 below.

Table 4. Typical compressor costs

Power (MW)	Cost ex works ($million AUD 2011)
1.21	2.02
3.52	3.91
4.60	4.47
7.50	5.04
10.70	7.07
17.19	9.06

The cost of the compressor station materials, including after-coolers, vessels, sound proof enclosures etc., were determined from budget quotations from a single vendor, while other project costs were estimated as a percentage of the compressor purchase cost, as shown below in Table 5. Commissioning was estimated at 60 days costing $2,000 per day. See Appendix 8 for more details.

Table 5. Compressor cost factors

Cost	Factor	Reference
Freight	10 %	Purchase cost (ex works)
Compressor Installation	7 %	Purchase cost and Equipment Cost
Mechanical Construction	15 %	Purchase cost, Equipment and Installation Cost
I & E Construction	12 %	Purchase cost, Equipment and Installation Cost
Civil Construction	10 %	Purchase cost, Equipment and Installation Cost
EPCM	10 %	Purchase cost, Equipment, Installation and Construction Cost
O/H and Management	5 %	Purchase cost, Equipment, Installation, Construction and EPCM Cost
Contingencies	30 %	Purchase cost, Materials, Installation, Construction and EPCM Cost

2.2 MODELLING AND COST ESTIMATE RESULTS

2.2.1 Base Case

2.2.1.1 PROCESS MODELLING

The base case, or current normal operation of the pipelines, was determined by adjusting the inlet flowrate, at 8,200 kPag (the normal pipeline inlet pressure), to the maximum flow to achieve a discharge pressure of 3,500 kPag at Port Pirie. Results are shown below in Table 6. The HYSYS model and relevant calculations are displayed in Appendix 2.

Table 6. Base case capacity

	Sm^3/hour	TJ/day	PJ/year
Capacity to Port Pirie	3,926	3.56	1.30
Capacity to Whyalla	19,273	17.50	6.39
Total Capacity	23,200	21.10	7.70

Therefore, for case studies 2, 3 and 4, for an additional capacity of 10, 30 and 60 PJ/year respectively, the required capacities are shown in Table 7 below.

Table 7. Required total capacities for case studies 2, 3 and 4

	Sm^3/hour	TJ/day	PJ/year
Case 2 (+10 PJ/year)	53,415	48.51	17.70
Case 3 (+30 PJ/year)	113,658	103.22	37.70
Case 4 (+60 PJ/year)	204,093	185.35	67.70

2.2.2 Case Study 1

2.2.2.1 PIPELINE MODELLING

Case study 1 was to determine the capacity of the existing DN150 pipeline to Port Pirie using compression. The HYSYS model is shown in Appendix 3. Table 8 below shows the results for case study 1. This is an increase of 3.32 PJ/year (9.09 TJ/day) from the base case.

Table 8. Results for case study 1

Inlet Pressure	9,117 kPag
Compressor Duty	116.2 kW *
Pressure at Port Pirie	3,500 kPag
Capacity	33,220 Sm^3/hr 30.17 TJ/day 11.02 PJ/yr

* All modelling was based on an inlet pressure at Whyte Yarcowie (from the MAP) of 8,200 kPag, the normal operating pressure. The actual installed power of the compressor at Whyte Yarcowie for case study 1 would be required to be greater than 116.2 kW, in order to accommodate the minimum MAP pressure of 5,500 kPag.

The discharge pressure at Port Pirie of 3,500 kPag indicates that at this increased capacity, there will be no gas flow to Whyalla, unless a compressor or looping pipeline is installed at Port Pirie, as concluded in the following case studies 2, 3 and 4. It should be noted that the 2003 study investigated using a compressor at the midpoint between Whyte Yarcowie and Port Pirie, at Gladstone and concluded that a 670 kW compressor would be required to increase the capacity through the lateral to 30.9 TJ/day, discharging at Port Pirie at 5,720 kPag, using an inlet pressure of 8,200 kPag.

2.2.2.2 COST ESTIMATE

The capital cost for this upgrade is estimated at $5.9 million, as shown in Appendix 8. Details of the off-take metering facilities are unknown. This cost estimate was based on the assumption the capacity of the existing off-take facilities is adequate for this increased capacity.

2.2.2.3 SUMMARY SCOPE

A summary of the scope of work required to add compression onto the pipeline at Port Pirie, for case study 1 is as follows:

- Install a compressor station (minimum 116 kW) at Whyte Yarcowie.
- Review and increase if necessary the capacity of the existing end of line facility at Whyte Yarcowie; which may require the installation of a new end of line facility to be tied into the existing facility.
- Review and increase if necessary the capacity of the existing end of line facility at Port Pirie; which may require the installation of a new end of line facility to be tied into the existing facility.

2.2.3 Case Study 2

2.2.3.1 PIPELINE MODELLING

Case study 2 was to determine the capital cost to supply an additional 10 PJ per annum of gas, i.e. 17.7 PJ/year. The HYSYS models and results are shown in Appendix 4. The options that were considered for case study 2 in order to achieve the extra 10 PJ/year, are shown diagrammatically in the (not-to-scale) Figure 2, showing the positions and sizes of looping pipes and compressors, as well as their location relative to the Gulf. In addition, Table 10 to follow, describes these options, shows their results and outlines the feasibility of the option.

Table 9 below summarises the gas capacity to Port Pirie and Whyalla for case 2.

Table 9. Summary of case study 2

	PJ/year	TJ/day	Sm^3/hour
Total Capacity	17.70	48.51	53,415
Capacity to Port Pirie	2.99	8.19	9,016
Capacity to Whyalla	14.71	40.26	44,330

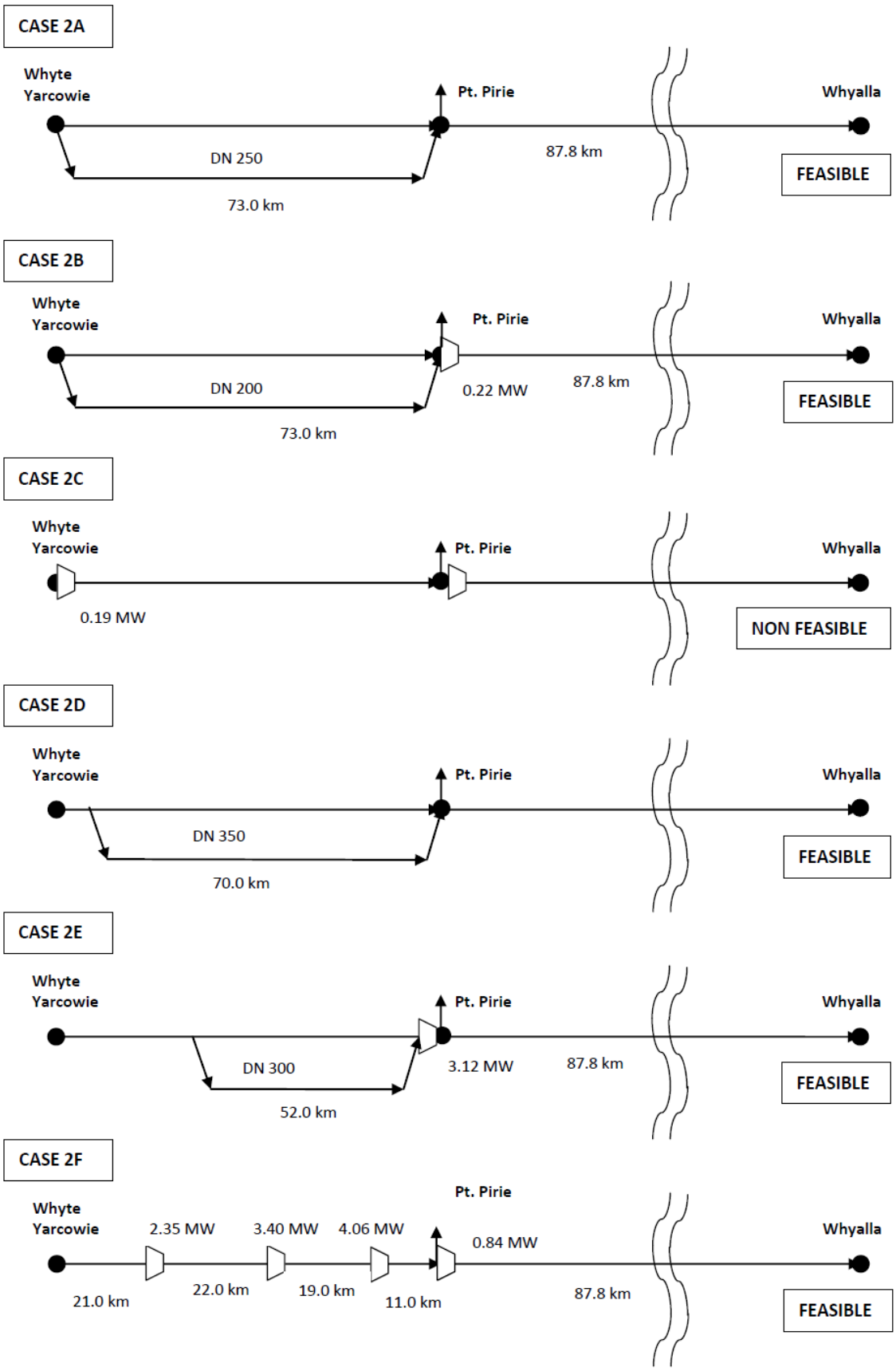


Figure 2. Schematics of options for case study 2

Table 10. Options considered for case study 2

	Option	Results	Notes
A	Loop entire Whyte Yarcowie to Port Pirie pipeline section. No compression.	Pipe size of loop: DN250 Length of loop: 73.0 km	A smaller pipe size will result in a too low discharge pressure at Whyalla.
B	Loop entire Whyte Yarcowie to Port Pirie Section with a smaller pipe size, and therefore using a compressor at Port Pirie to ensure gas flows to Whyalla and discharges above minimum pressure.	Pipe size of loop: DN200 Length of loop: 73.0 km Compressor duty: 0.22 MW	N/A
C	Compressor at Whyte Yarcowie and compressor at Port Pirie, both to the maximum design pressure. No looped sections.	N/A	Gas flow cannot pass through section of existing pipe to Port Pirie, even at maximum design pressure. Therefore, will need some looping in first pipe section, or compressors downstream from Whyte Yarcowie.
D	Looped section starting at the maximum distance downstream of Whyte Yarcowie, using DN350 pipework. No compression.	Pipe size of loop: DN350 Length of loop: 70.0 km	N/A
E	Looped section starting at the maximum distance downstream of Whyte Yarcowie to Port Pirie. Compressor at Port Pirie.	Pipe size of loop: DN300 Length of loop: 52.0 km Compressor duty: 3.12 MW	The length of the loop could be optimized against the compressor duty.
F	Compressors at maximum distances apart on the existing pipeline from Whyte Yarcowie to Port Pirie, and a compressor at Port Pirie.	Compressor 1 duty: 2.35 MW Compressor 2 duty: 3.40 MW Compressor 3 duty: 4.06 MW Compressor 4 duty: 0.84 MW	N/A

2.2.3.2 COST ESTIMATE

Case study 2 identified five feasible options for achieving the extra capacity of 10 PJ/year. The capital cost estimates for the feasible options are shown in Table 11 below. See Appendix 8 for calculation details.

Table 11. Capital costs for case study 2

	Cost of Pipeline(s) ($million AUD 2011)	Cost of Compressor(s) ($million AUD 2011)	Total Capital Cost ($million AUD 2011)
2A	34.3	N/A	34.3
2B	27.7	5.9	33.6
2D	46.8	N/A	48.6
2E	31.0	10.4	41.4
2F	N/A	39.3	38.3

Therefore, based on these preliminary capital cost estimates, it is recommended that Option B be used to achieve the required extra 10 PJ/year. However due to the accuracy of the cost estimates, further design and optimisation may be required to distinguish between Option A and B.

2.2.3.3 SUMMARY SCOPE

A summary of the scope of work required to achieve an additional 10 PJ/year of gas based on Option B is as follows:

- A new and larger connection (via a hot tap) off the Moomba Adelaide Pipeline.
- Increase the capacity of the existing off-take metering facility at Whyte Yarcowie; for which the cost of a new off-take facility has been included in the cost estimate.
- Install a new pig launcher station at Whyte Yarcowie.
- Install a new DN200, 73 km pipeline from Whyte Yarcowie to Port Pirie within the existing pipeline easement.

- Install a new pig receiver station at Port Pirie.
- Install a compressor station at Port Pirie.
- Increase the capacity of the existing off-take facility at Port Pirie; for which the cost of a new off-take facility has been included in the cost estimate.
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.2.4 Case Study 3

2.2.4.1 PROCESS MODELLING

Case study 3 was to determine the capital cost to supply an additional 30 PJ per annum of gas, i.e. 37.7 PJ/year. The HYSYS models and results are shown in Appendix 5.

The options that were considered for case study 3 in order to achieve the extra 30 PJ/year are shown diagrammatically in the (not-to-scale) Figure 3, showing the positions and sizes of looping pipes and compressors, as well as their location relative to the Gulf. In addition, Table 13 to follow, describes these options, shows their results and outlines the feasibility of the option.

Table 12 below summarises the gas capacity to Port Pirie and Whyalla for case 3.

Table 12. Summary of case study 3

	PJ/year	TJ/day	Sm^3/hour
Total Capacity	37.70	103.22	113,658
Capacity to Port Pirie	6.37	17.45	19,210
Capacity to Whyalla	31.33	85.77	94,440

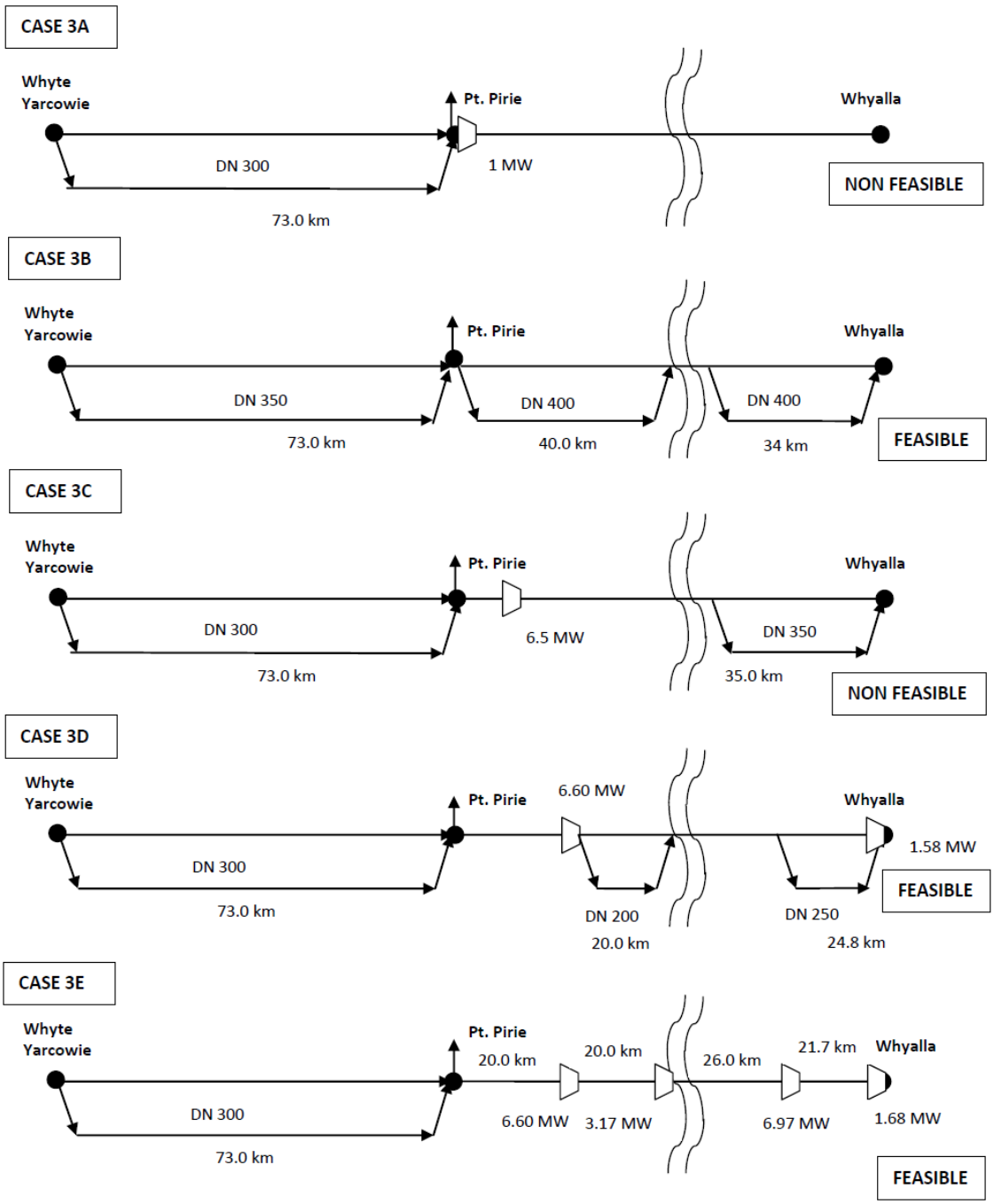


Figure 3. Schematics of options for case study 3

Table 13. Options considered for case study 3

	Option	Results	Notes
A	Loop entire Whyte Yarcowie to Port Pirie pipeline section. Compressor at Port Pirie to maximum design pressure.	N/A	Gas flow cannot pass through second section of existing pipe, even with compression at Port Pirie to the maximum design pressure of the pipeline. Therefore, a loop of some length is required on pipeline to Whyalla, or compressors along existing pipeline.
B	Loop entire length of Whyte Yarcowie to Port Pirie section using DN350 pipe. Loop the minimum lengths of Port Pirie to Whyalla pipeline section, at either side of the Gulf using DN400 pipe.	Pipe size of 1st loop: DN350 Pipe size of 2nd loop: DN400 Pipe size of 3rd loop: DN400 Length of 1st loop: 73.0 km Length of 2nd loop: 40.0 km Length of 3rd loop: 34.0 km	N/A
C	Loop entire Whyte Yarcowie to Port Pirie section, compressor at maximum distance downstream of Port Pirie, and loop from the Gulf to Whyalla.	N/A	Gas flow cannot pass through section of existing pipe under the Gulf even when compressed to maximum design pressure of pipeline.
D	Loop entire Whyte Yarcowie to Port Pirie section, compressor maximum distance downstream of Port Pirie and loop from the compressor to the Gulf, and from the Gulf to Whyalla.	Pipe size of 1st loop: DN300 Pipe size of 2nd loop: DN200 Pipe size of 3rd loop: DN250 Length of 1st loop: 73.0 km Length of 2nd loop: 20.0 km Length of 3rd loop: 24.8 km Compressor 1 duty: 6.60 MW Compressor 2 duty: 1.58 MW	The length of the second loop could be optimized against the compressor duty. Compressor 2 is required to ensure discharge pressure at Whyalla is above the minimum.
E	Loop entire Whyte Yarcowie to Port Pirie section, compressors maximum distances apart from Port Pirie to Whyalla.	Pipe size of 1st loop: DN300 Length of 1st loop: 73.0 km Compressor 1 duty: 6.90 MW Compressor 2 duty: 3.17 MW Compressor 3 duty: 6.97 MW Compressor 4 duty: 1.68 MW	Compressor 2 is required at the start of the Gulf so that the gas can pass through the entire pipeline section under the water. Compressor 4 is required to ensure discharge pressure at Whyalla is above the minimum.

2.2.4.2 COST ESTIMATE

Case study 3 identified three feasible options for achieving the extra capacity of 30 PJ/year. The capital cost estimates for the feasible options are shown in Table 14 below. See Appendix 8 for calculation details.

Table 14. Capital costs for case study 3

	Cost of Pipeline(s) ($million AUD 2011)	Cost of Compressor(s) ($million AUD 2011)	Total Capital Cost ($million AUD 2011)
3B	104.0	N/A	104.0
3D	61.1	19.8	80.9
3E	44.2	39.7	83.9

Therefore, based on these preliminary capital cost estimates, it is recommended that Option D be used to achieve the required extra 30 PJ/year. However due to the accuracy of the cost estimates, further design and optimisation may be required to distinguish between Option D and E.

2.2.4.3 SUMMARY SCOPE

A summary of the scope of work required to achieve an additional 30 PJ/year of gas based on Option D is as follows:

- A new and larger connection (via a hot tap) off the Moomba Adelaide Pipeline.
- Increase the capacity of the existing off-take facility at Whyte Yarcowie; for which the cost of a new off-take facility has been included in the cost estimate.
- Install a new pig launcher station at Whyte Yarcowie.
- Install a new DN300, 73 km pipeline from Whyte Yarcowie to Port Pirie along the existing pipeline easement.
- Install a new pig receiver station at Port Pirie.
- Increase the capacity of the existing off-take facility at Port Pirie; for which the cost of a new off-take facility has been included in the cost estimate.

- Perform a hot tap to connect to the existing Port Pirie to Whyalla Pipeline 20 km upstream of the Gulf.
- Install a pig launcher station 20 km upstream of the Gulf.
- Install a compressor station 20 km upstream of the Gulf.
- Install a new DN200, 20 km pipeline from 20 km upstream of the Gulf to the Gulf within the existing pipeline easement.
- Perform a hot tap to connect to the existing Port Pirie to Whyalla Pipeline at a site adjacent to the inlet to the Gulf.
- Install a pig receiver station at a site adjacent to the inlet to the Gulf.
- Perform a hot tap off the existing Port Pirie to Whyalla Pipeline 25 km upstream of Whyalla.
- Install a pig launcher station 25 km upstream of Whyalla.
- Install a new DN250, 22 km pipeline from 20 km upstream of Whyalla to Whyalla within the existing pipeline easement.
- Install a pig receiver station at Whyalla.
- Install a compressor station at Whyalla.
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.2.5 Case Study 4

2.2.5.1 PROCESS MODELLING

Case study 4 was to determine the capital cost to supply an additional 60 PJ per annum of gas, i.e. 67.7 PJ/year. The HYSYS models and results are shown in Appendix 6.

The options that were considered for case study 4 in order to achieve the extra 60 PJ/year, are shown diagrammatically in the (not-to-scale) Figure 4 below, showing the positions and sizes of looping pipes and compressors, as well as their location relative to the Gulf. In addition, Table 16 to follow, describes these options, shows their results and outlines the feasibility of the option.

Table 15 below summarises the gas capacity to Port Pirie and Whyalla for case study 4.

Table 15. Summary of case study 4

	PJ/year	TJ/day	Sm^3/hour
Total Capacity	67.70	185.35	204,093
Capacity to Port Pirie	11.44	31.32	34,490
Capacity to Whyalla	56.26	154.02	169,600

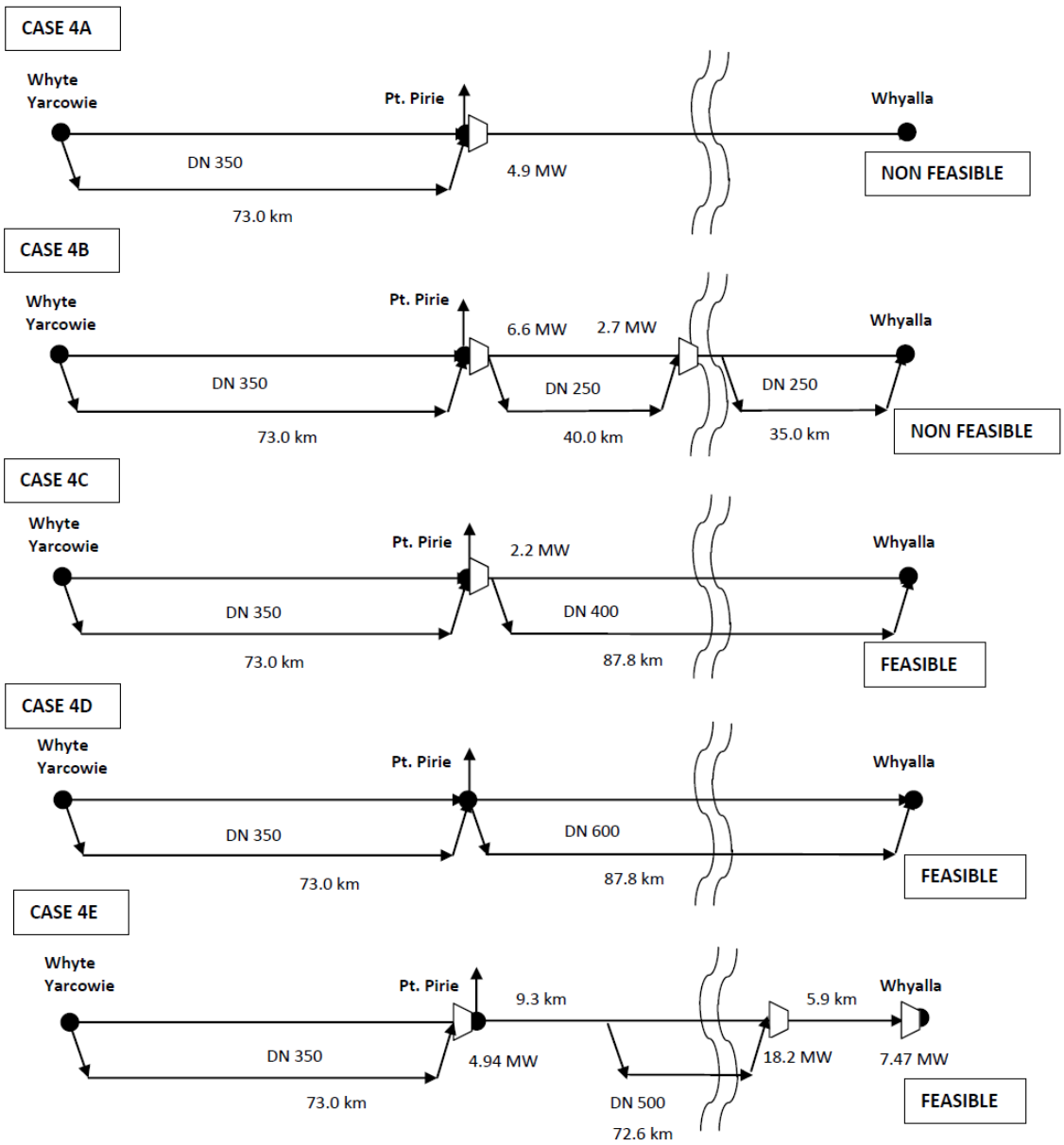


Figure 4. Schematics of options for case study 4

Table 16. Options considered for case study 4

	Option	Results	Notes
A	Loop entire Whyte Yarcowie to Port Pirie pipeline section. Compressor at Port Pirie to maximum design pressure	N/A	Gas flow cannot pass through second section of existing pipe, even with compression at Port Pirie to maximum design pressure. Therefore, a loop is required on pipeline to Whyalla, or compressors along pipeline.
B	Loop entire length of Whyte Yarcowie to Port Pirie section with compressor at Port Pirie. Loop from Port Pirie to the Gulf, compressor at start of Gulf and loop from Gulf to Whyalla. No looping under the Gulf.	N/A	Gas flow cannot pass through the single section of existing pipe under the Gulf even with prior compression to the maximum design pressure of the pipeline. Therefore, a loop will be required under the Gulf.
C	Loop entire Whyte Yarcowie to Port Pirie section, compressor at Port Pirie, and loop from Port Pirie to Whyalla (under the Gulf).	Pipe size of 1st loop: DN350 Pipe size of 2nd loop: DN400 Length of 1st loop: 73.0 km Length of 2nd loop: 87.8 km Compressor duty: 2.2 MW	The length of the second loop could be optimized against the compressor duty.
D	Loop entire section of Whyte Yarcowie to Port Pirie, and loop entire section of Port Pirie to Whyalla (under Gulf).	Pipe size of 1st loop: DN350 Pipe size of 2nd loop: DN600 Length of 1st loop: 73.0 km Length of 2nd loop: 87.8 km	DN600 pipe may result in increased constructability issues. This would require further investigation if this option was selected.
E	Loop entire section of Whyte Yarcowie to Port Pirie, and use compressors along the length of Port Pirie to Whyalla pipeline, using a loop under the Gulf (as the gas cannot pass through the single section of pipe under the Gulf, even with compression).	Pipe size of 1st loop: DN350 Pipe size of 2nd loop: DN500 Length of 1st loop: 73.0 km Length of 2nd loop: 72.6 km Compressor 1 duty: 4.94 MW Compressor 2 duty: 18.2 MW Compressor 3 duty: 7.47 MW	A compressor is required at Whyalla in order to achieve the minimum discharge pressure of 3,500 kPag.

2.2.5.2 COST ESTIMATE

Case study 4 identified three feasible options for achieving the extra capacity of 60 PJ/year. The capital cost estimates for the feasible options are shown in Table 17 below. These costs include the higher expense for HDD and laying pipework under the Gulf. See Appendix 8 for calculation details.

Table 17. Capital costs for case study 4

	Cost of Pipeline(s) ($million AUD 2011)	Cost of Compressor(s) ($million AUD 2011)	Total Capital Cost ($million AUD 2011)
4C	135.0	8.7	143.7
4D	170.1	N/A	170.1
4E	141.2	42.1	183.3

Therefore, based on these preliminary cost estimates, it is recommended that Option C be used to achieve the required extra 60 PJ/year.

2.2.5.3 SUMMARY SCOPE

A summary of the scope of work required to achieve an additional 60 PJ/year of gas based on Option C is as follows:

- A new and larger connection (via a hot tap) off the Moomba Adelaide Pipeline.
- Increase the capacity of the existing off-take facility at Whyte Yarcowie; for which the cost of a new off-take facility has been included in the cost estimate.
- Install a new pig launcher station at Whyte Yarcowie.
- Install a new DN350, 73 km pipeline from Whyte Yarcowie to Port Pirie within the existing pipeline easement.
- Install a new pig receiver station at Port Pirie.
- Increase the capacity of the existing off-take facility at Port Pirie; for which the cost of a new off-take facility has been included in the cost estimate.
- Install a new compressor station at Port Pirie.

- Install a new pig launcher station at Port Pirie.
- Install a new DN400, 87.8 km pipeline from Port Pirie to Whyalla within the existing pipeline easement. This will include crossing the Gulf which will require a horizontal directional drill across the beach at each end.
- Install a pig receiver station at Whyalla.
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.2.6 Case Study 5

2.2.6.1 PROCESS MODELLING

Case study 5 was to determine the capacity of the existing DN200 pipeline from Port Pirie to Whyalla, assuming infinitely available gas at Port Pirie. Using a compressor at Port Pirie to the maximum design pressure to simulate the maximum gas flow from Port Pirie, the maximum capacity to Whyalla was determined. The HYSYS model is displayed in Appendix 7. Results of the model are displayed in Table 18 below.

Table 18. Results for case study 5

Inlet Pressure	9,117 kPag
Capacity to Whyalla	59,100 Sm^3/hr 53.67 TJ/day 19.60 PJ/yr

This is an increase of 13.21 PJ/year (36.17 TJ/day) of gas to Whyalla, from the base conditions.

The 2003 study concluded that the capacity of the DN200 pipeline could be increased to up to 60 – 70 TJ/day, using a 155 kW compressor at Port Pirie. This result was based on a compressor discharge pressure of 10,100 kPag, and a pipeline discharge pressure at Whyalla of 2,500 kPag. The study team considers a pressure of 2,500 kPag at Whyalla would be insufficient to supply gas to a large turbine power generation facility and has therefore used a minimum pressure of

3,500 kPag. The slightly lower capacity of 53.67 TJ/day calculated in case study 5 above, is based on a more realistic compressor discharge pressure of 9,117 kPag (10 % lower than the MAOP of the pipe), and the higher discharge pressure to Whyalla of 3,500 kPag.

Using multiple compressors along the pipeline from Port Pirie to Whyalla could also increase the capacity to Whyalla to over 30 PJ/year, as shown in case study 3E previously, however this would be inefficient due to the substantial fuel consumption of the compressors.

The existing end of line facilities at Whyalla would not be sufficient for the increased capacity of case study 5. The cost of upgrading, replacing or adding to the metering and regulating stations at Whyalla, as well as the compressor at Port Pirie would need to be taken into account when assessing this cost.

2.3 DEVELOPMENT PLAN

The cheapest option and the required scope of work for each increase in capacity case (10, 30 and 60 PJ per annum) has been considered separately and discussed above in Section 2.2. This approach assumes a decision is made up front on the required gas capacity increase without considering future expansions. If it is considered feasible in the future that an increase in capacity of 60 PJ/year may be required, then a development plan should be implemented which considers a gradual increase of capacity from the base case to 10 PJ/year, to 30 PJ/year, and finally to 60 PJ/year. This approach would ensure early stages of development are consistent with achievement of the final total increase of 60 PJ/year.

A possible staged development plan is outlined below.

2.3.1 Additional 10 PJ/year

While a DN200 pipe (and compressor at Port Pirie) is required to achieve only an additional 10 PJ/year, as outlined in case 2A, it is recommended that the best option for achieving a 10 PJ/year increase, while considering future capacity increases to 60 PJ/year, is to increase install a DN350 loop from Whyte Yarcowie to Port Pirie. Case 2D determined that a 70 km DN350 pipe starting 3 km downstream of Whyte Yarcowie would cost approximately $46.8 million was, as shown in Figure 5 below, however in order to allow further capacity increases to 60 PJ/year, the pipeline would need to be constructed the over the entire 73 km from Whyte Yarcowie to Port Pirie, at a cost of approximately $46.8 million.

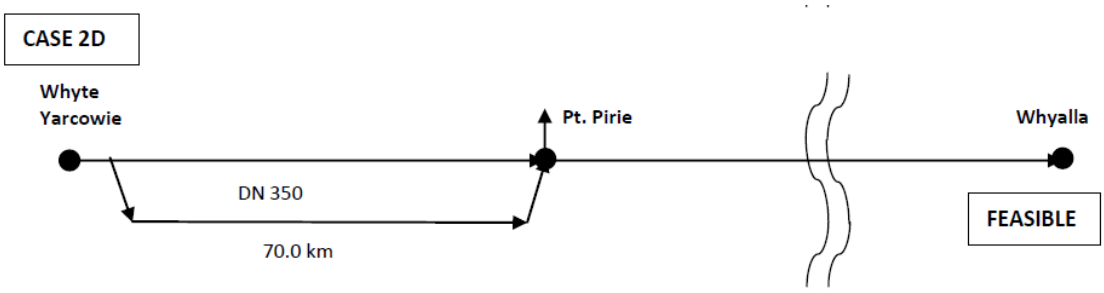


Figure 5. Case 2D for additional 10 PJ/year

2.3.2 Additional 30 PJ/year

The best option for progressively achieving an additional 30 PJ/year while considering further future capacity increases to 60 PJ/year is by installing a DN350 loop from Whyte Yarcowie to Port Pirie and installing two looping sections of DN400 pipe, one for a length of 40 km from Port Pirie to the Gulf and one for a length of 34 km upstream of Whyalla at cost of $104.0 million, as shown in Figure 6 below.

If the additional 10 PJ/year option discussed above is completed, the additional cost to upgrade to a further 20 PJ/year would be approximately $57.2 million.

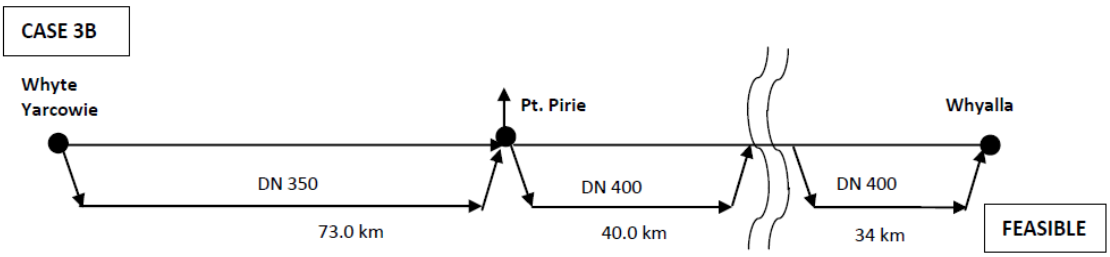


Figure 6. Case 3B for additional 30 PJ/year

2.3.3 Additional 60 PJ/year

An additional 60 PJ/year could then be achieved by completing the remaining DN400 loop from Port Pirie to Whyalla, and installing a compressor at Whyte Yarcowie of 2.2 MW, as shown in Figure 7 below. This would cost a total of $143.7 million if completed as a single project.

If the additional 30 PJ/year option discussed above in Section 2.3.2 is completed, the additional cost to upgrade to a further 30 PJ/year would be approximately $39.7 million.

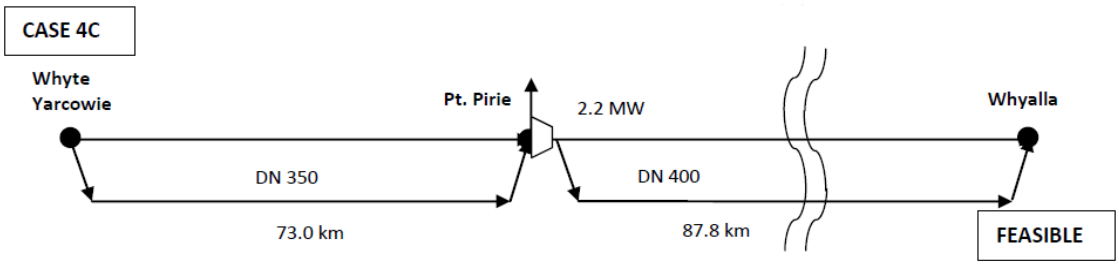


Figure 7. Case 4C for additional 60 PJ/year

2.3.4 Summary Scope of Work for Progressive Capacity Increase

2.3.4.1 ADDITIONAL 10 PJ/YEAR

- A new and larger connection (via a hot tap) off the Moomba Adelaide Pipeline.
- Increase the capacity of the existing off-take facility at Whyte Yarcowie; for which the cost of a new off-take facility has been included in the cost estimate.
- Install a new pig launcher station at Whyte Yarcowie.
- Install a new DN350, 73 km pipeline from Whyte Yarcowie to Port Pirie within the existing pipeline easement.
- Install a new pig receiver station at Port Pirie.
- Increase the capacity of the existing off-take facility at Port Pirie; for which the cost of a new off-take facility has been included in the cost estimate.
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.3.4.2 ADDITIONAL 30 PJ/YEAR (FURTHER 20 PJ/YEAR)

- Increase the capacity of the existing off-take facility at Whyte Yarcowie and Port Pirie if required; for which the cost of a new off-take facility has been included in the cost estimate.
- Perform a hot tap to connect to the existing Port Pirie to Whyalla Pipeline at Port Pirie.
- Install a pig launcher station at Port Pirie.
- Install a new DN400, 40 km pipeline from Port Pirie to the Gulf within the existing pipeline easement.

- Perform a hot tap to connect to the existing Port Pirie to Whyalla Pipeline at a site adjacent to the inlet to the Gulf.
- Install a pig receiver station at a site adjacent to the inlet to the Gulf.
- Perform a hot tap to connect to the existing Port Pirie to Whyalla Pipeline 34 km upstream of Whyalla.
- Install a pig launcher station 34 km upstream of Whyalla.
- Install a new DN400, 34 km pipeline from 34 km upstream of Whyalla to Whyalla within the existing pipeline easement.
- Install a pig receiver station at Whyalla.
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.3.4.3 ADDITIONAL 60 PJ/YEAR (FURTHER 30 PJ/YEAR)

- Increase the capacity of the existing off-take facility at Whyte Yarcowie and Port Pirie if required; for which the cost of a new off-take facility has been included in the cost estimate.
- Install DN400 pipeline across the Gulf, which ties-into the existing looping pipeline which finishes at the Gulf, and the existing looping pipeline which starts 34 km upstream of Whyalla
- Increase the capacity of the existing off-take facility at Whyalla; for which the cost of a new off-take facility has been included in the cost estimate.

2.4 ENGINEERING STUDY CONCLUSIONS

The existing capacity of the Whyte Yarcowie - Port Pirie - Whyalla lateral was determined to be 7.7 PJ/year (1.3 PJ/year to Port Pirie and 6.4 PJ/year to Whyalla). The Engineering Study confirmed each of the capacity increases for case studies 2, 3 and 4, were able to be achieved through compression and/ or looping of the existing pipelines. In particular, the case studies provided the following conclusions:

- Case study 1 showed that a 116.2 kW compressor at Whyte Yarcowie was required to achieve a maximum capacity of 11.0 PJ/year (40 % capacity increase), at a cost of $5.9 million.
- Case study 2 showed that the most economical solution for an additional capacity of 10 PJ/year was using a 73 km, DN200 looping pipeline from Whyte Yarcowie to Port Pirie, with a 219 kW compressor at Port Pirie. This was for an approximate capital cost of $33.6 million.
- Case study 2 showed that the most economical solution for an additional capacity of 30 PJ/year was using three looping pipelines and two compressors. A 73 km, DN300 pipeline from Whyte Yarcowie to Port Pirie, a 40 km, DN200 pipeline from 20 km upstream of the gulf to the start of the gulf, and a 24.8 km, DN250 pipeline from 24.8 km upstream of Whyalla to Whyalla, as well as a 6.6 MW compressor 20 km upstream of the start of the gulf and a 1.6 MW compressor at Whyalla. The capital required for this development was estimated at approximately $80.9 million.
- Case study 4 showed that the most economical solution for an additional capacity of 60 PJ/year was using a 73 km, DN350 looping pipeline from Whyte Yarcowie to Port Pirie, a 2.2 MW compressor at Port Pirie, and an 87.8 km, DN400 looping pipeline from Port Pirie to Whyalla. This was for an approximate capital cost of $143.7 million.
- Case study 5 showed that the maximum capacity of the lateral from Port Pirie to Whyalla was 19.6 PJ/year, providing infinite available gas at Port Pirie.

On a per PJ/year of capacity basis, the capital cost of expansion ranges from $2.4 million to $3.4 million; smaller increments in capacity are more expensive (on a PJ/year basis) than larger increments.

If initially upgrading the current pipeline system for additional 10 or 30 PJ/year, a development path should be selected so as to allow for further development in the future. An alternate development option has been proposed, which although requires higher capital upfront, provides a staged development path consistent with achieving the final 60 PJ/year of additional capacity as designed in case study 4.

While the cost estimate results shows the capital required for each option relative to the other options, the costs are preliminary (± 30%), and a more detailed analysis would be required to increase the accuracy of the costs. Looping of the pipeline across the Gulf is expensive and should be avoided unless absolutely necessary to meet capacity.

3 GAS SUPPLY STUDY

3.1 INTRODUCTION

The scope of the gas supply study component of this report is to provide a brief review of:

1. Potential sources for future supply of gas to South Australia,
2. Current and future gas pricing.

The Whyte Yarcowie - Port Pirie - Whyalla gas pipeline (or lateral) is part of the Moomba Adelaide Pipeline system (MAP), which, in turn, is part of the Eastern Australia gas transmission network and gas market, as shown in Figure 8 below.

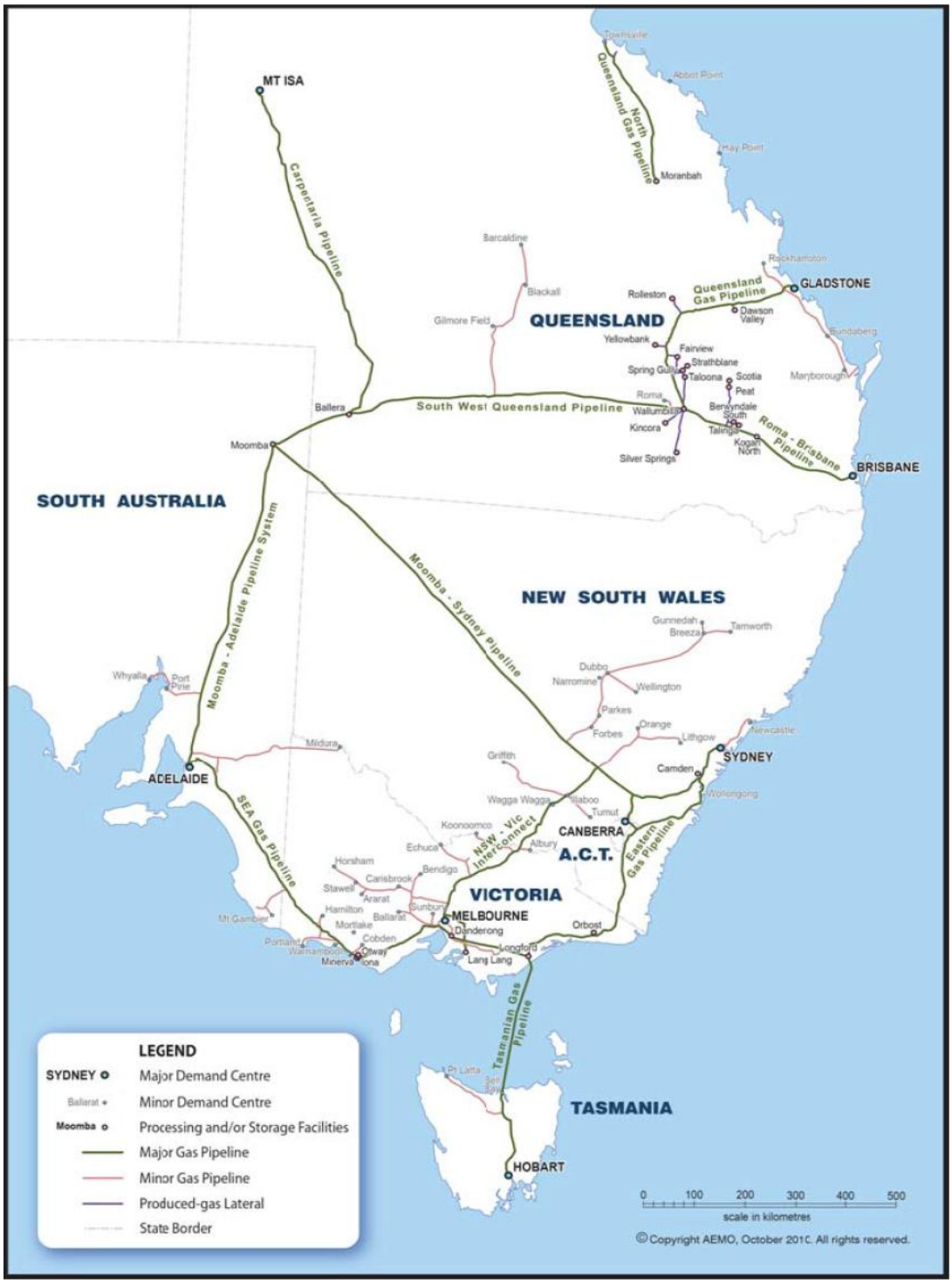


Figure 8. Eastern Australia gas transmission network[1]

[1] Australian Energy Market Operator (AEMO), 2010 Gas Statement of Opportunities (GSOO), Figure 2-3

There have been substantial changes to the Eastern Australia gas market and for the outlook for the future supply of gas to South Australia since the preparation of the previous report "The Case for Increasing Natural Gas to the Upper Spencer Gulf", dated January 2004;

- Prior to 2004 the sole source of gas supply to South Australia[2] was the Cooper Basin via the MAP;
- In January 2004 the SEAGas Pipeline from Victoria to Adelaide was commissioned, facilitating the supply of Victorian gas (from the Otway and Gippsland Basins) to South Australia;
- In 2009 the QSN Link pipeline[3] from Ballera (in south west Queensland) to Moomba was commissioned, facilitating the supply of gas from eastern Queensland (in particular, the growing coal seam gas (CSG, sometimes referred to as CSM, coal seam methane) production from the Surat-Bowen Basin) to South Australia and NSW;
- In addition to the creation of the Eastern Australia gas market (through the construction of these two pipelines), the most significant change in the past 7 years in the Eastern Australia gas market has been the proving-up of massive CSG reserves and the anticipated supply of CSG to numerous multibillion dollar liquefied natural gas (LNG) export projects (located at Gladstone) currently in various stages of development.

In considering the potential sources for future supply of gas to South Australia, consideration will not be given to the vast reserves of gas off the coast of western and northern Australia, as, because of the gas resources available and expected to be developed in Eastern Australia, connection of the Eastern Australia gas transmission network to western or northern Australia is not likely for several decades.

Consideration of (a) the potential sources of future supply of gas to South Australia, and (b) likely future gas prices, also needs to take into account future gas demand and consumption of existing gas reserves and the location of gas reserves likely to supply South Australia in the longer term.

[2] Other than the south east of South Australia

[3] QSN: Queensland / South Australia / New South Wales Link

3.2 GAS DEMAND AND SUPPLY OUTLOOK

3.2.1 Gas Demand

Since 1998 / 1999, gas consumption (in Australia) has increased at an average annual rate of 3 % a year (to 2009-10), compared with an average rate of 1.7 % for coal and 1.6 % for petroleum products[4].

The Australian Energy Market Operator (AEMO) forecasts Eastern Australia domestic gas consumption (i.e., excluding gas for export) to grow at between 3.1 % and 4.9 % per annum, with the largest area of growth being gas-powered electricity generation[5]. Figure 9 below shows AEMO's forecast to 2030 of three scenarios based on high, medium and low economic growth and varying carbon policy responses.

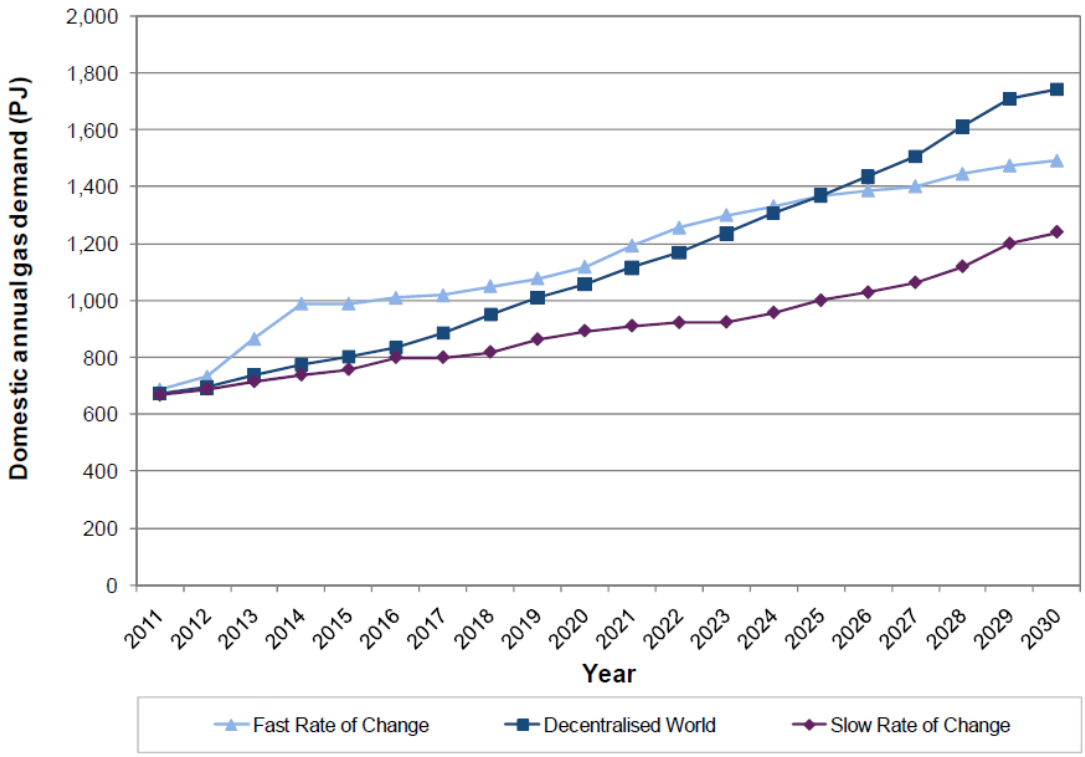


Figure 9. Eastern Australia annual domestic gas demand 2011 to 2030 [6]

[4] Energy in Australia 2011, Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), March 2011, p45

[5] AEMO, 2010 GSOO Executive Summary, p17

[6] AEMO, 2010 GSOO Executive Summary, Figure 8

Some other forecasters have strong growth in Eastern Australia domestic gas consumption until 2020 and 2026, but lower growth (or even negative growth) thereafter, on the assumption that carbon capture and storage will become viable and economic (versus gas) leading to increased use of coal for power generation[7].

Export LNG projects have the potential to double Eastern Australia's overall gas demand by 2030. Figure 10 below shows AEMO's mid-growth scenario (Decentralised World scenario) including gas for LNG export.

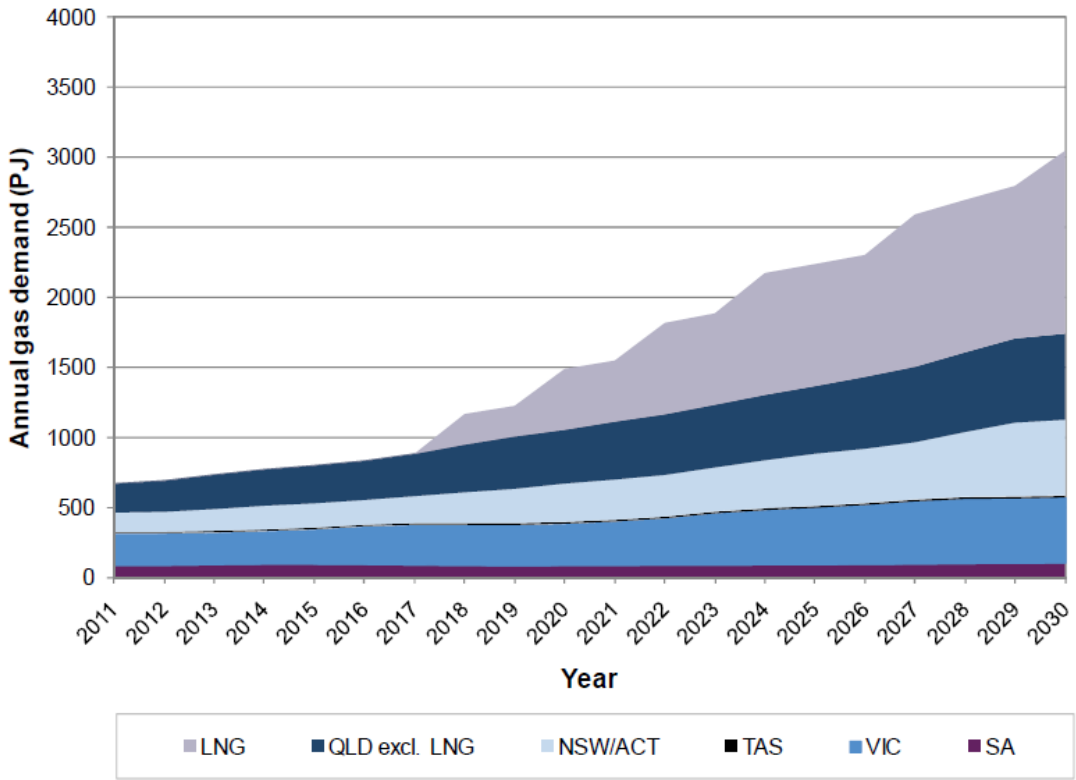


Figure 10. Eastern Australia gas demand, including LNG export (Decentralised World scenario) [8]

ABARES (Australian Bureau of Agricultural and Resource Economics and Sciences) forecasts Eastern Australia gas demand (including LNG exports) to grow by 6.7 % per annum by 2029-2030 [9], to 2,861 PJ, similar to the AEMO scenario shown in

[7] Annual Gas Market Review, Report to Queensland DEEDI by MMA, 23 June 2010, pp 26 & 28

[8] AEMO, 2010 GSOO, Figure 5-5

[9] Australian Energy Projections to 2029-30, Australian Bureau of Agricultural and Resource Economics and Sciences (ABARES), March 2010, p45

Figure 10 above. AEMO's high growth scenario (Fast Rate of Change scenario) has gas demand approximately 20 % higher by 2030 than the scenario shown above.

3.2.2 Gas Supply

From the inception of the natural gas industry in Eastern Australia over 40 years ago until about 5 years ago, the major producing gas basins have been the Gippsland Basin (offshore Victoria), the Cooper Basin (and overlying Eromanga Basin) (north east South Australia and south west Queensland), the Surat Basin in eastern Queensland, and more recently the Otway Basin (offshore Victoria). Over the past five years CSG from the Surat-Bowen Basin in eastern Queensland has assumed growing significance. (See Figure 11 below, showing petroleum basin locations).

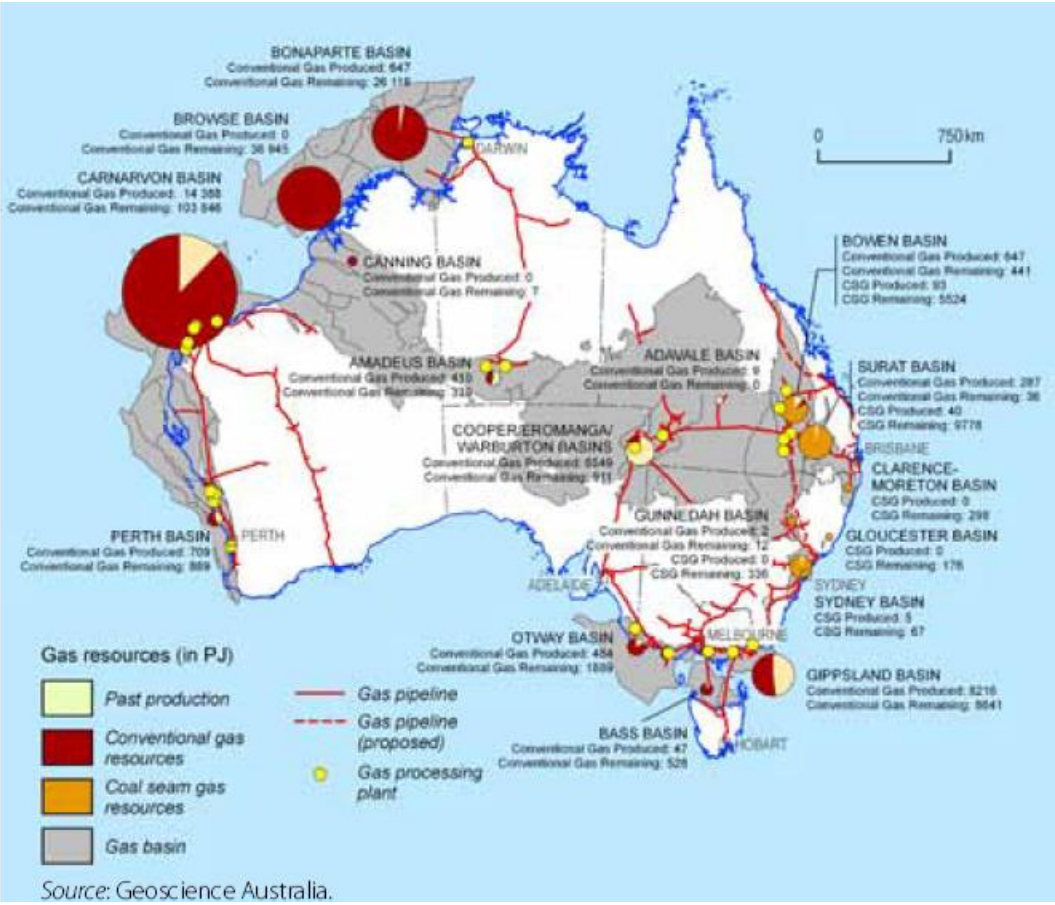


Figure 11. Australia's petroleum producing basins and gas infrastructure [10]

[10] Energy in Australia 2011, ABARES, March 2011, p51

Until about 2005, remaining gas reserves in Eastern Australia remained comparatively static. That is, gas producers "proved up" additional gas reserves at approximately the rate required to replace gas production (see the dashed line showing remaining 2P gas reserves[11] in Figure 12 below). The ratio of 2P reserves to current production remained at about 20 years.

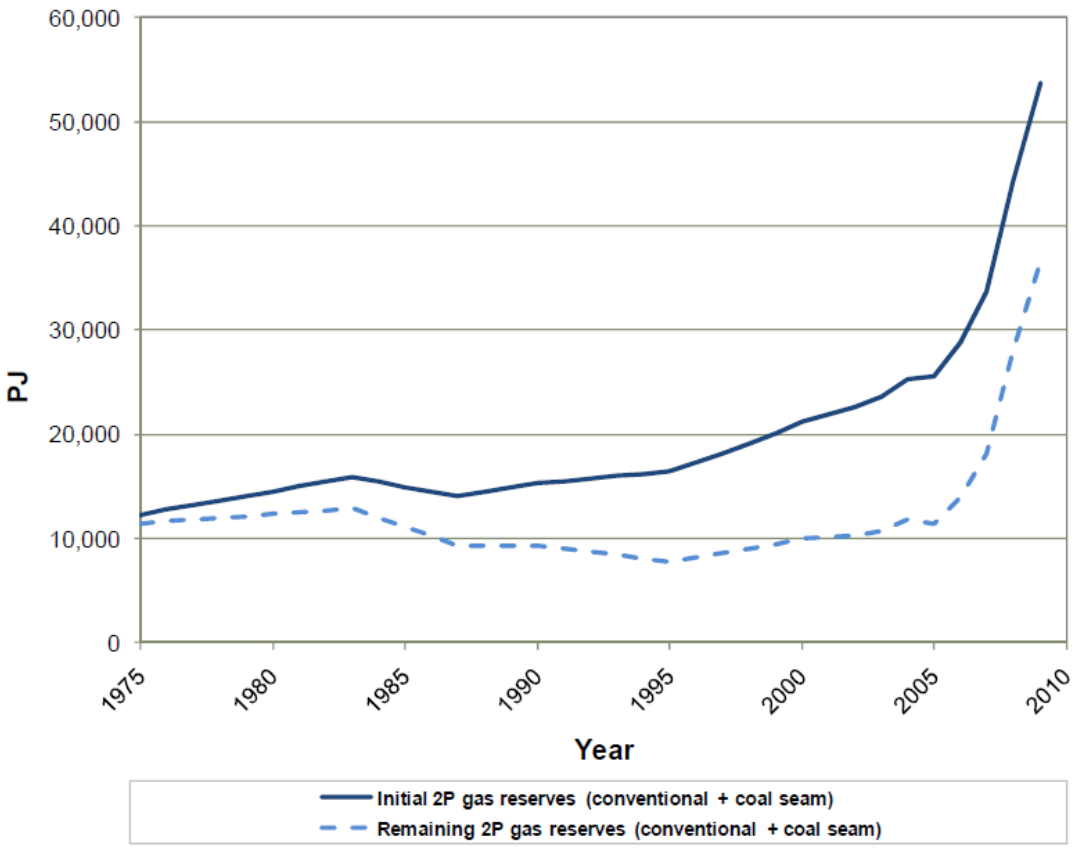


Figure 12. Eastern Australia initial and remaining 2P gas reserves, 1975 – 2009 [12]

As shown, from 2005 Eastern Australia's remaining gas reserves have increased from around 10,000 PJ to over 35,000 PJ. This substantial increase has primarily occurred as a result of the proving up of CSG reserves in the Surat-Bowen Basin, in order to provide the reserves base needed before commitments to the major proposed LNG export projects at Gladstone.

[11] 2P reserves: proved plus probable reserves: a gas industry classification of gas resources that have been appraised or developed to give reasonable certainty of the quantity of gas present

[12] AEMO, 2010 GSOO, Figure 3.3

As can be seen in Figure 13 below, the Surat-Bowen Basin now (as at end 2009) dominates Eastern Australia's gas reserves representing about 65 % of total remaining gas reserves.

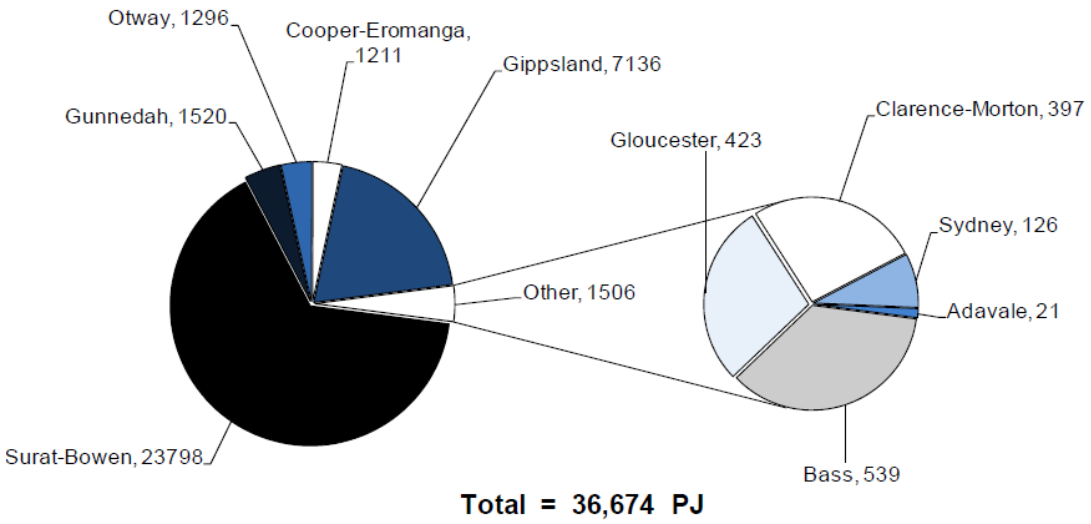


Figure 13. Remaining 2P gas reserves by basin as at 31 December 2009, Eastern Australia (PJ) [13]

In addition to the existing gas reserves, there are substantial potential additional gas resources. For example, Santos claims that there is potential for a further 250 Tcf (or approximately 250,000 PJ) of CSG in Eastern Australia (in addition to existing gas reserves), as shown below.

[13] AEMO, 2010 GSOO Executive Summary, Figure 3

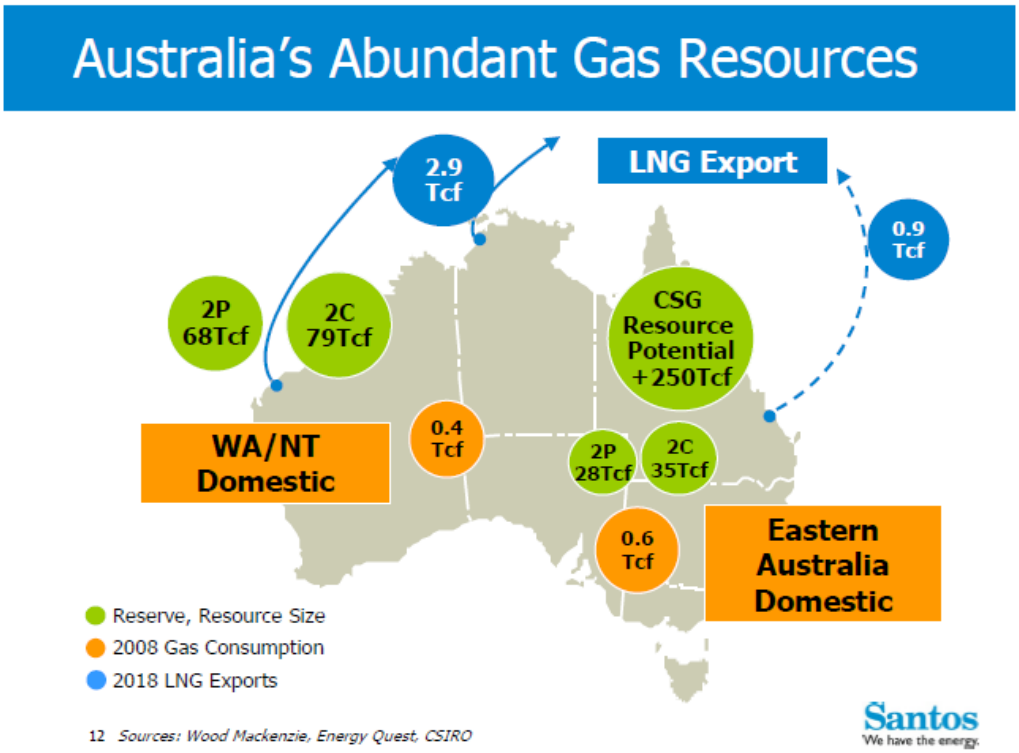


Figure 14. Santos' estimate of CSG potential in Eastern Australia [14]

In the view of AEMO, in the high and medium growth scenarios, over the next 3 years significant further gas reserves will be proved up – to support a higher number of LNG export projects than in the low growth scenario; and in subsequent years gas reserves will be proved up and/ or developed at a rate similar to the rate of production, so that total remaining reserves remains relatively static in each scenario from 2014 (see Figure 15 below).

[14] Santos Limited, Melbourne Mining Club Presentation, 4 February 2010

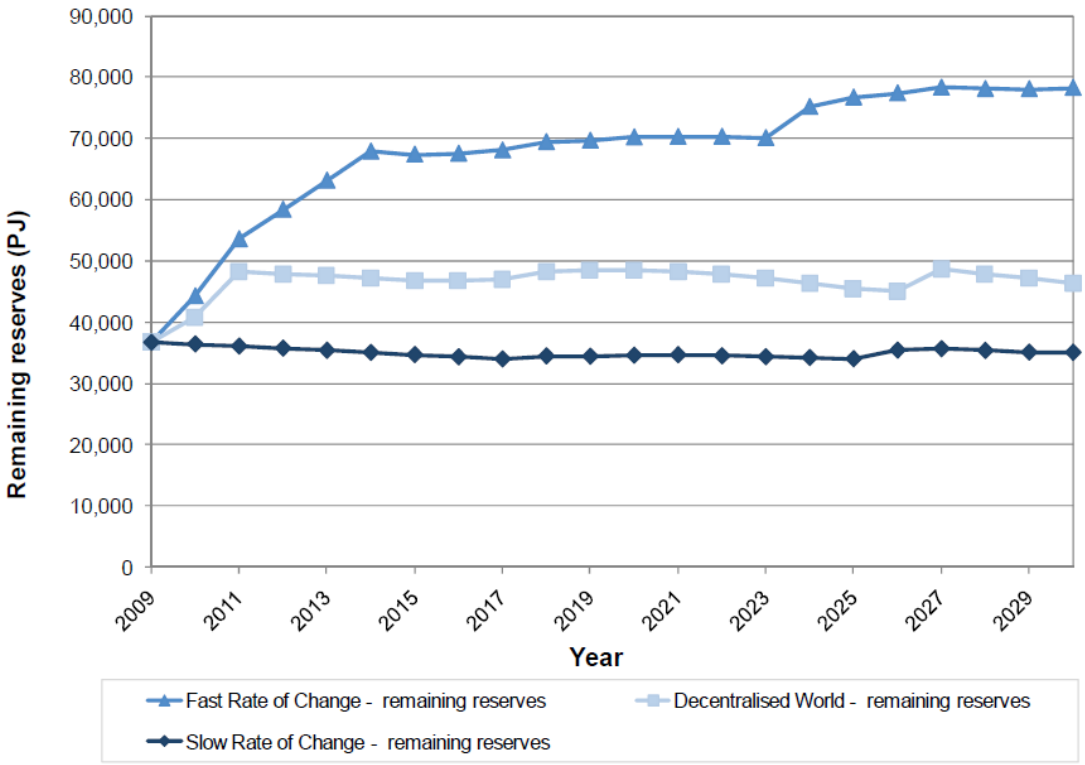


Figure 15. Remaining gas reserves in Eastern Australia to 2030 [15]

AEMO's forecast of gas reserves by location (see Figure 16 below), shows gas reserves to supply Eastern Australia increasingly dominated by Queensland CSG, together with a contribution from New South Wales CSG, while declines in remaining reserves in South Australia (Cooper Basin) and Victoria (Gippsland and Otway Basins) continue.

[15] AEMO, 2010 GSOO Executive Summary, Figure 5

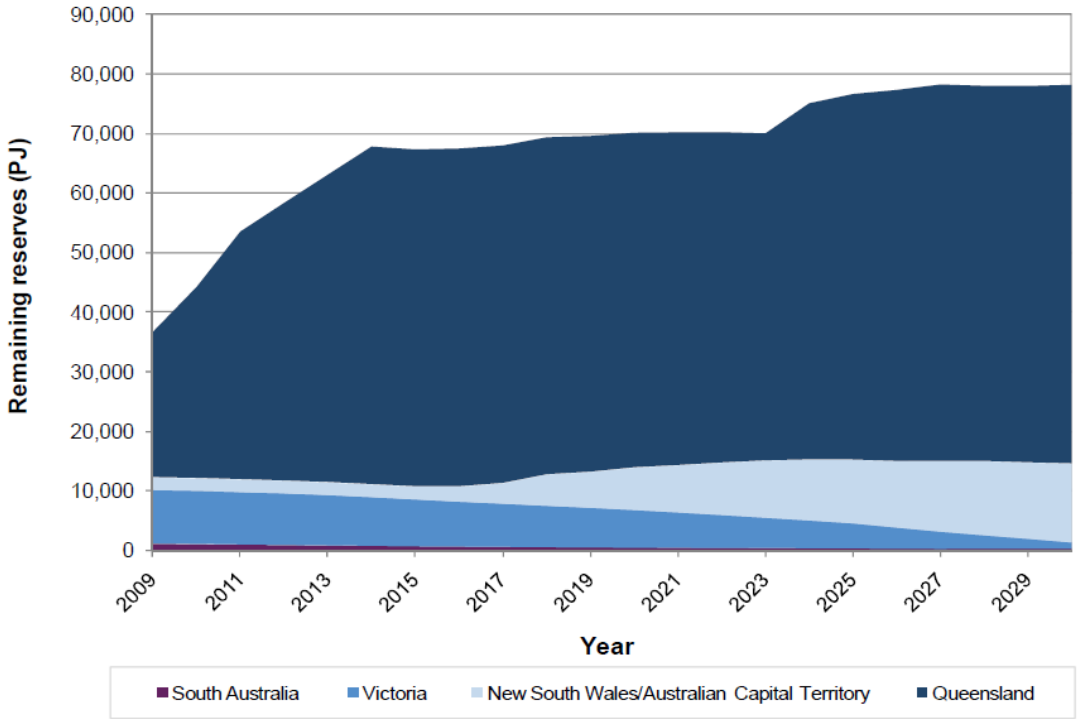


Figure 16. Remaining gas reserves in Eastern Australia to 2030, by State, Fast Rate of Change Scenario [16]

Contrary to AEMO's view of the projected decline in Cooper Basin reserves, Santos is of the view that substantial undeveloped, "unconventional"[17] gas could be developed in the Cooper Basin. Santos, together with Beach Petroleum and other licence holders in the Cooper Basin, are hoping to demonstrate that shale gas and tight gas can be economically developed. The potential suggested by Santos is approximately equivalent to the current total 2P remaining gas reserves in Eastern Australia (see Figure 17 below).

[16] AEMO, 2010 GSOO Executive Summary, Figure 6

[17] Shale gas and deeper tight (i.e., low permeability) gas

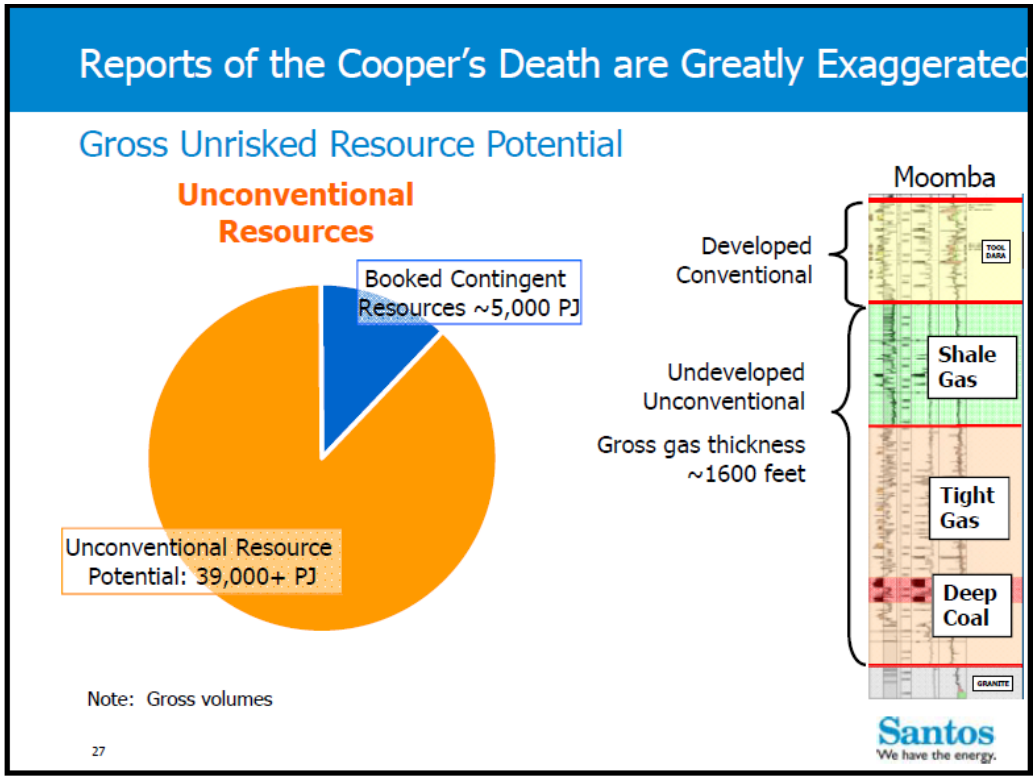


Figure 17. Cooper Basin Unconventional Gas Potential [18]

It is, however, generally acknowledged that the costs of extracting unconventional gas are higher than for conventional gas reserves. Santos has claimed that higher gas prices are required to justify production of unconventional gas:

> "For some time Santos and other partners in the Cooper Basin have highlighted the enormous potential of infill drilling and unconventional gas if a sufficiently attractive price could be established".[19]

> "Mr Knox has said previously that the "unconventional" shale and Cooper Basin gas that is difficult to extract, could be profitable if domestic gas prices rose to about $6 per gigajoule, up from the $4 per gigajoule Santos currently receives." [20]

[18] Santos Limited, Investor Presentation, March 2011

[19] Santos to supply 750 PJ of portfolio gas to GLNG. Santos Limited announcement, 25 October 2010

[20] The Australian, 26 October 2010

3.2.3 Gas Supply Summary

Remaining gas reserves in Eastern Australia compared to projected demand indicate that there are substantial gas reserves available to supply the Eastern Australia gas market for the foreseeable future, with the likelihood that further gas reserves can be proved up in future years at a rate that at least matches the rate of production.

The interconnected gas pipeline system now in place in Eastern Australia facilitates the delivery to South Australia of gas from all major gas producing areas.

Although gas reserves in South Australia's traditional sources of supply have been and are expected to continue declining, large volumes of CSG have been proven up in Queensland and unconventional gas in the Cooper Basin also has potential.

3.3 GAS PRICES

3.3.1 Current Gas Prices

Gas prices can be considered at various points in the supply chain including:

- Ex-field gas prices, or the price received by a gas producer at or near the outlet of gas processing facilities (e.g., price received by Cooper Basin gas producers at the outlet of the Moomba plant);
- Wholesale gas prices (in a given market location), or the price of gas including the cost of transmission from the production facility to a particular market location (also known as the "city gate" price) (e.g., at a delivery point on the MAP);
- Retail gas price, or the price of gas delivered to a customer, including distribution network charges and retailer's costs and margins. Retail gas prices vary considerably between the price for a residential customer (where the wholesale gas price might be only 20 % of the retail gas price), and the price for a large industrial customer (where the wholesale gas price might be 80 % to 95 % of the retail price – key determinants being the extent of use of the distribution system and the size of customer).

For the purpose of this analysis, the wholesale price of gas at the Whyte Yarcowie lateral on the MAP will be considered. The reasons for choosing this location are:

- The relevant market is in the Upper Spencer Gulf area, e.g., Port Pirie or Whyalla;
- Gas is assumed to be transported via the MAP to Whyte Yarcowie;
- Because this study is considering various options for expansion of the lateral from Whyte Yarcowie, the cost of transporting gas from Whyte Yarcowie is a function of the expansion undertaken.

Note all dollar amounts listed in the following sections are in 2011 Australian dollars, unless stated otherwise.

Ex-producer gas prices were generally stable throughout the 1990's. Gas was generally sold by producers under long term (10+ years) gas supply contracts which

provided for gas price escalation at or slightly below CPI (Consumer Price Index). With the negotiation of new contracts in the early 2000's, and the review of prices under price review provisions in some older, long term contracts, there was pressure from producers for higher prices. Justification was that existing sources of supply, such as the Cooper Basin, were mature, production was starting to decline and production costs were increasing; and new fields being developed, such as the offshore Otway Basin fields, were more expensive to develop. As a result, gas prices under new contracts have typically resulted in real price increases of around 10 % each 5 years since the stable prices of the 1990's.

This has resulted in an estimated average ex-field gas prices in Eastern Australia of approximately $3.50 per GJ to $4.00 per GJ (AUD 2011) (average), implying a current wholesale (Whyte Yarcowie) gas price of approximately $4.00 per GJ to $4.50 per GJ.

By world standards, such gas prices remain low. The graph below shows average gas prices in various countries in 2009 US$ per GJ. Note that for the period shown, the A$ / US$ exchange rate was substantially lower than its current near-parity level.

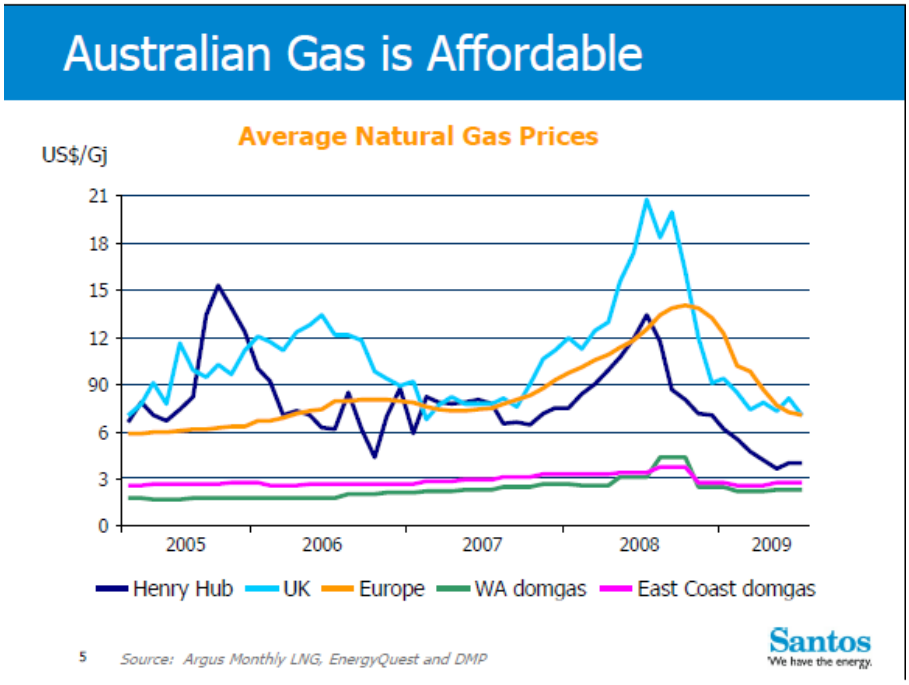


Figure 18. Comparison of Australian gas prices with US, UK and Europe [21]

[21] Gas: Australia's AAA Advantage, Presentation at APPEA by David Knox, MD Santos Limited, 19 May 2010 (Note: Henry Hub is a major US gas pricing point)

3.3.2 Influences on Future Gas Prices

3.3.2.1 EXPORT LNG NETBACK

The likely development of the major LNG export projects at Gladstone provides gas producers with a market for their gas based on international LNG pricing. The first LNG project in Gladstone could be on-stream in 2014. LNG is typically priced based on a percentage of world oil prices in the relevant market (e.g., Japan). There are substantial costs to liquefy and transport LNG. The "netback" price is an estimate of the ex-field value being received by a gas producer when supplying gas for an LNG export project[22].

Table 19. Estimates based on US $75 and US $100 / bbl oil price

Crude oil price (US$ / bbl)	**75**	**100**
LNG price : oil price ratio[23]	75 – 90 %	70 – 85 %
LNG price (US$ / boe)	56 - 68	70 - 85
Conversion to GJ (US$ / GJ)	9 - 11	12 - 14
Less liquefaction, shipping, etc.	2.5 - 3.5	3 - 4
Less transmission to Gladstone	~ 0.5	~ 0.5
Netback at field value (US / $GJ)	**6 - 8**	**8 – 10**

As shown in Table 19 above, assuming the A$ / US$ stays around parity, CSG gas producers in the Surat-Bowen Basin are likely to receive value of $6 to $10 per GJ, ex-field, for their gas, as feedstock for an LNG export project, depending on oil prices.

[22] Most of the LNG projects under development will be supplied from gas reserves owned by the same joint venture as the LNG processing facility, so that there are usually no gas supply contracts specifying the netback price.

[23] The LNG : oil price ratio in LNG supply contracts has varied depending on the supply / demand balance in the LNG market. The ratio typically has a cap / collar arrangement so that at higher prices the ratio reduces and at lower prices it increases.

Gas producers who have previously supplied the domestic gas market will (if LNG projects proceed), have the opportunity to achieve a price for their gas related to world oil prices.

The extent to which the netback value of CSG supplied to LNG projects will impact on domestic gas prices in Eastern Australia is complex, and subject to much debate in the gas industry. Factors include:

- The supply / demand balance for LNG in the international market (which influences the LNG price: oil price ratio in LNG contracts); the current (March 2011) Japanese nuclear power situation could increase the demand for LNG in the Asian region, resulting in increased demand and higher LNG prices;
- The price of crude oil, and the A$ / US$ exchange rate;
- The supply / demand balance for gas in Queensland (e.g., availability of gas not dedicated to LNG);
- The supply / demand balance for gas in south east Australia;
- The potential benefits some gas producers would perceive of selling gas that does not require a capital-intensive LNG project, and is not exposed to international pricing and markets;
- The potential for "surplus" CSG not immediately required for LNG, needing to find a market[24];
- The extent of competition between gas producers.

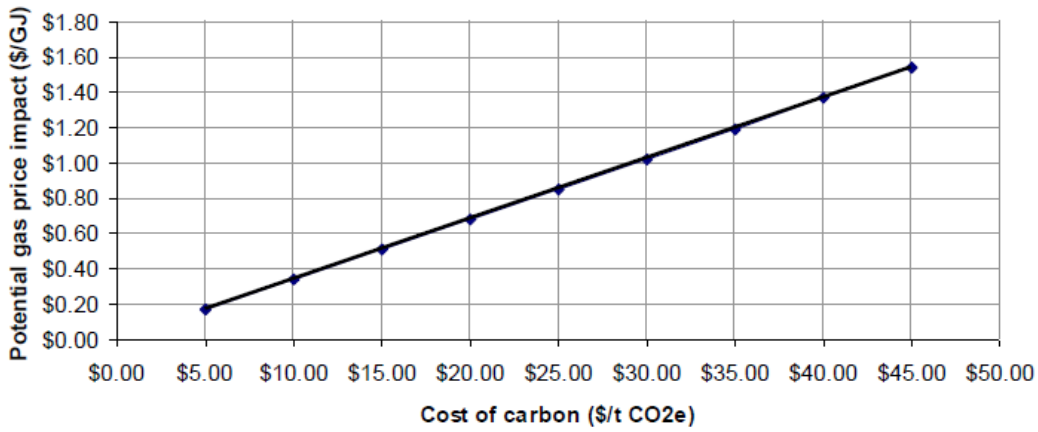
As discussed below, the net impact of the above factors is expected to result in significant increases over the next decade in the cost of gas supplied to Eastern Australia.

[24] CSG production is evidently not able to be varied as readily as for conventional gas production; in the lead-up to the start-up of an LNG project, there can be substantial "ramp-up" gas available for supply to other gas users.

3.3.2.2 CARBON EMISSIONS POLICY

A carbon tax and other policies to reduce the emission of carbon dioxide (CO_2) are expected to increase the demand for gas for electricity generation, at least for the next decade, because of the lower CO_2 emissions from gas-fired generation compared to coal-fired. In addition to the higher demand for gas, a carbon tax changes the relative competitiveness of gas versus coal, such that gas producers can demand a higher price for gas, while still remaining competitive with coal, after carbon tax effects are taken into account.

Numerous energy industry analysts have produced estimates of the potential impact on gas prices of a price on carbon. Figure 19 below shows ACIL Tasman's estimates, depending on the level of a price on carbon. At a price (tax) on carbon of $20 to $30 per tonne of CO_2, ACIL Tasman estimate that gas prices will increase by $0.70 to $1.00 per GJ.



Data source: ACIL Tasman analysis

Figure 19. Potential gas price impacts at different cost of carbon [25]

Other analysts have estimated higher impacts. Engineroom Infrastructure Consulting[26] has estimated the initial impact of a carbon tax at $1.60 per GJ increasing to $1.93 per GJ in 2015 and to $2.44 per GJ in 2020. Note, however, that

[25] Gas Demand Study – An assessment of demand for Coal Seam Gas and pipeline services in Central Queensland, ACIL Tasman, 9 December 2009, Figure 4

[26] Gas pricing – Cost Drivers and Scenarios for Future Price Directions, 12 October 2009

they do not see the impact of a price on carbon being cumulative with the impact on domestic gas prices arising from the netback of gas for LNG.

In the longer term (perhaps 10 to 15 years) it is anticipated that carbon capture and storage will become viable and economic (versus gas prices then applying) leading to increased use of coal for power generation and consequent downward pressure on gas prices.

3.3.2.3 CHANGING CONTRACTUAL AND COMPETITIVE ENVIRONMENT

Historically in Australia, gas producers and major gas consumers or retailers / distributors have entered into long term gas supply contracts; e.g., 10 to 20 years. Such long term contracts are now becoming unusual. In recent years producers have typically offered contracts of only up to 5 to 10 years, and have been unwilling to contract for longer terms that were common in the past. There has also been the introduction of a daily "spot" market.

Last year a Short Term Trading Market (STMM) for Adelaide was introduced and up to 10 % to 20 % of gas demand is being traded on the STMM. Prices are quite volatile, influenced by daily supply / demand balances. For example, during February and March 2011, the Adelaide network STMM price range was $2.73 per GJ to $4.92 per GJ, with an average around $3.40 per GJ. Victorian and Sydney STMMs also operate.

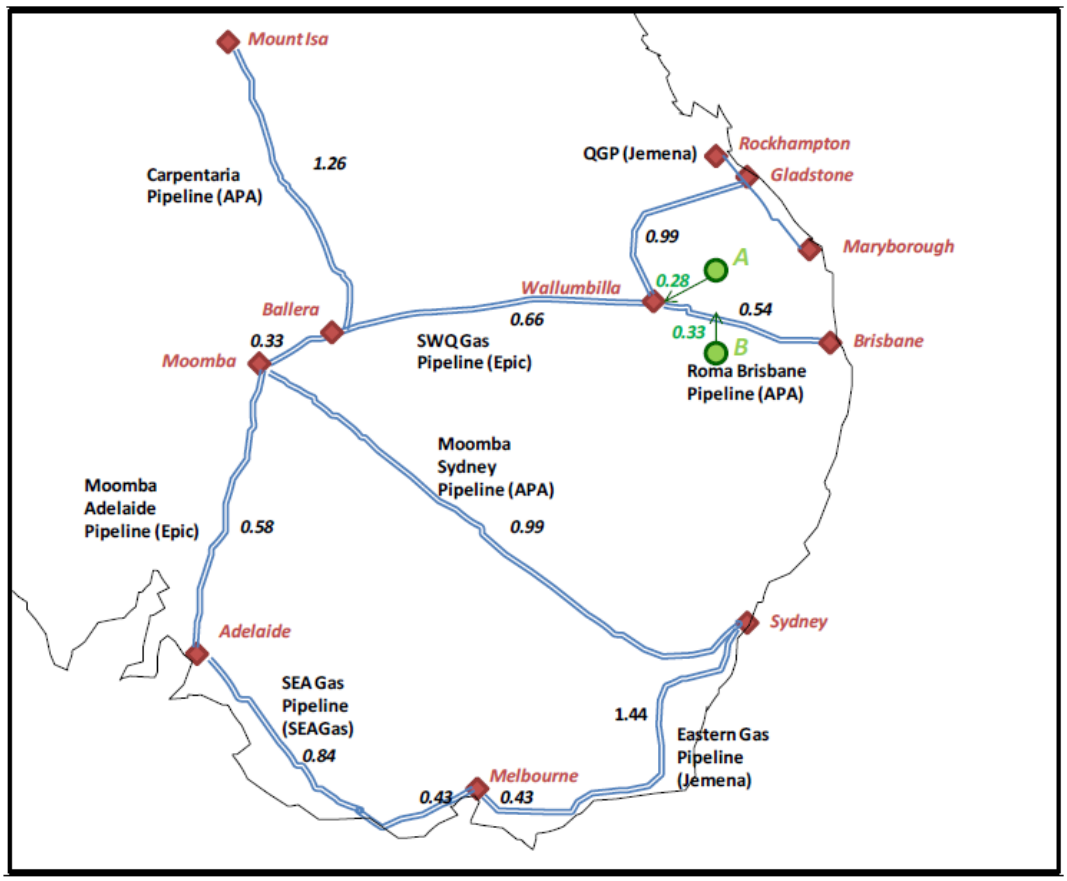
Two of the major gas producers involved in the Gladstone LNG projects, Santos and Origin Energy, are also the major producers in the Cooper and Otway Basins. A clear focus of those producers is proving up sufficient gas reserves to justify investment decisions on their LNG projects. As a result, their interest in the domestic gas market appears to be waning (at least for the present). A prime example of this reduced interest in the domestic gas market was Santos' announcement last October[27] that it was to supply 750 PJ of Cooper Basin gas to its Gladstone LNG project. This a substantial proportion of remaining Cooper Basin gas reserves that

[27] Santos to supply 750 PJ of portfolio gas to GLNG, Santos Limited announcement, 25 October 2010

would have otherwise been expected to be available to supply the domestic gas market (in particular, South Australia)[28].

As detailed in Section 3.2.2 previously, over time CSG from the Surat-Bowen Basin in eastern Queensland is likely to become the dominant source of gas supply to Eastern Australia. If purchasing gas from the Surat–Bowen Basin for supply to South Australia, additional transmission charges would be incurred. As shown on the map below (Figure 20), the cost to transport gas from the Surat–Bowen Basin to Moomba, assuming transmission capacity was available, (for onward transmission via MAP) is approximately $1 per GJ (AUD 2009). Even if gas were to be contracted for supply from the Cooper Basin, in a low competition environment, a Cooper Basin producer, knowing the cost of the alternative source of supply, may be able to extract a price for its gas equivalent to that of CSG delivered to Moomba.

[28] Note that Cooper Basin gas may not physically flow to Gladstone; Santos may enter into "swap" arrangements with gas producers who have contracted to supply Surat- Bowen Basin CSG to south east Australia gas markets via Moomba.



Note: Indicative tariffs (A$/GJ, real 2009) for 80% load factor gas supply
Source: ACIL Tasman GMG Australia modelling

Figure 20. Eastern Australia Gas Transmission Pipeline Tariffs [29]

3.3.3 Likely Trends in Future Gas Prices and Implications for Industry

As discussed above, factors influencing future gas prices in South Australia include:

- Current gas prices are low by world standards;
- There are or will be upward pressure on gas prices from:
  - alternative higher value markets for gas, in particular, LNG,
  - growth in domestic use of gas for gas-fired electricity generation,
  - the additional value attributable to gas versus coal if a price on carbon is introduced,

[29] Gas Demand Study – An assessment of demand for Coal Seam Gas and pipeline services in Central Queensland, ACIL Tasman, 9 December 2009, Figure 19

- a tightening supply / demand balance in the Eastern Australia gas market (e.g., Cooper Basin gas reserves dedicated to LNG),
- higher costs of production for unconventional gas that may become available from the Cooper Basin,
- limited competition between gas producers;

- Possible supply of gas to South Australia from more distant supply sources, incurring higher transmission costs.

There is considerable variance between the many players in the gas industry as to the impact of these factors on future Eastern Australia gas prices, as shown in Figure 21 and Figure 22 below. Although the extent of increase varies, all the forecasts show increasing gas prices. (Note that the forecasts shown are not on a consistent basis).

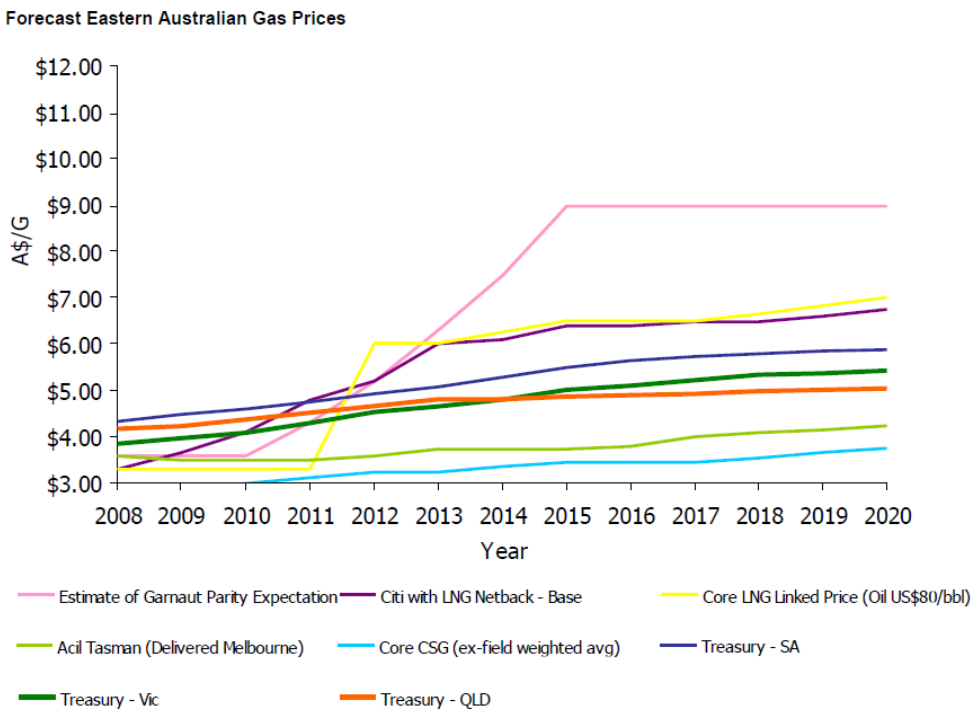


Figure 21. Forecast Eastern Australia Gas Prices by a range of gas industry analysts and stakeholders [30]

[30] Santos Limited Energy White Paper Public Submission, Santos Limited, 2009

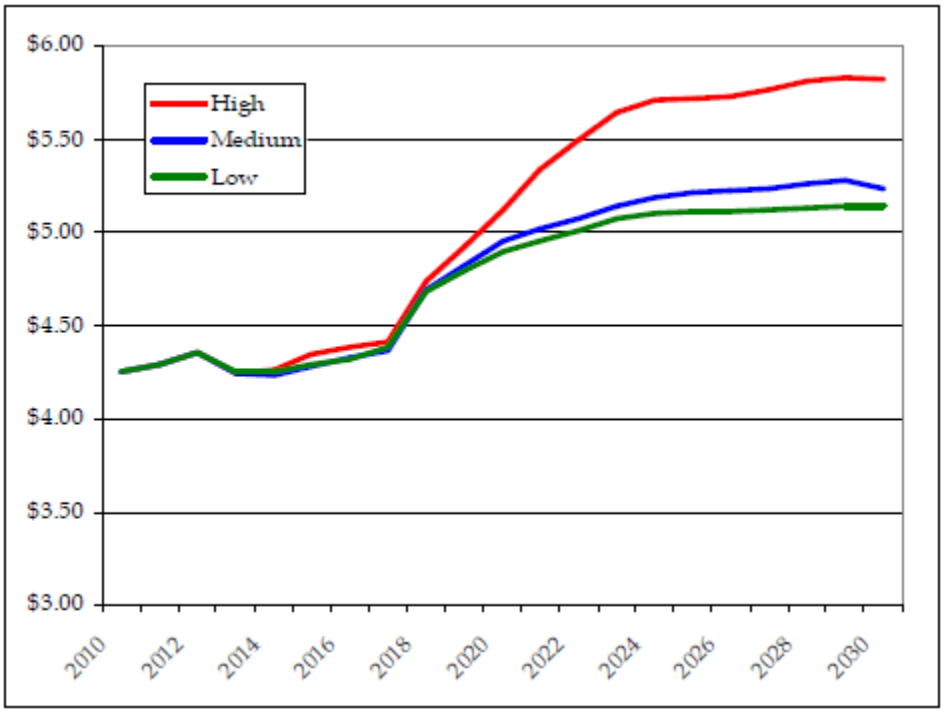


Figure 22. Average contract prices Southern States aggregate ($/ GJ, 2010$ real) [31]

3.3.4 Gas Prices Summary

Our view is that the effect of all these factors will result in ex-field gas prices increasing by an average of 3 % to 5 % real per annum for the next 8 to 10 years, so that by 2020, ex-field gas prices will have increased to $4.50 per GJ to $6 per GJ (AUD 2011), implying a wholesale (Whyte Yarcowie) gas price of approximately $5.00 per GJ to $6.50 per GJ (AUD 2011).

Gas price increases can be expected to occur in a stepped rather than consistent (year by year) basis. Typically in an environment of increasing gas prices, new contracts are at prices materially higher than average prices, so that average gas prices lag new contract prices.

In addition to the expected increasing costs of gas, a further significant implication for industry of the changing gas market, is the current unwillingness of gas producers to

[31] Annual Gas Market Review, Report to Queensland DEEDI by MMA, 23 June 2010, Figure 6-19. Prices include transmission costs.

enter into long term domestic gas supply contracts (e.g., beyond 5 years). The likely reason for this attitude is that producers are also uncertain about the future level of gas prices, and, although long term gas contracts can include price re-openers (e.g., gas price review and arbitration provisions), such provisions do not give certainty and can be out of producers' control (e.g., in arbitration proceedings). Also, the major gas producers supplying the South Australian market (Santos and Origin Energy) are focusing on proving up gas reserves for their export LNG projects, and gas contracted elsewhere reduces gas reserves that can be counted towards reserves available to supply a LNG project.

Typically a proponent of a major new gas-consuming project seeks a long term gas supply arrangement before committing to a major development. If the current attitude of gas producers to long term domestic gas supply arrangements is maintained, proponents of major gas-consuming projects may find difficulty in obtaining finance (for example), and be unwilling or unable to proceed.

3.4 GAS SUPPLY STUDY CONCLUSIONS

The Gas Supply Study has concluded as follows:

- The gas industry in Eastern Australia continues to experience substantial, rapid change: substantial increases in gas reserves not envisaged even 10 years ago; development of major LNG export projects; the implications for the value of gas as export LNG of oil prices around ~US $100 / bbl; the uncertain implications of the possible introduction of a price on carbon and the potential for carbon capture and storage to become feasible. These factors (and others) make predicting where future gas prices are heading very difficult. These uncertainties may significantly alter the forecasts and conclusions arrived at in this report.
- Strong growth in gas demand in Eastern Australia is forecast for the next decade, as major LNG export projects are expected to commence operation from 2014. Additional gas-fired electricity generation will also add to demand.
- The Eastern Australia gas reserves to production ratio is now higher than at any time in the past 20 years, as a result of gas reserves (primarily CSG) being proven up in anticipation of the major LNG export projects proceeding.
- Further increases in CSG reserves can be expected in Queensland and, to a lesser extent, in New South Wales. In addition, unconventional gas in the Cooper Basin has the potential to become another source of gas.
- These developments indicate that there is adequate gas supply to meet market demand in Eastern Australia for the foreseeable future. Gas supply to South Australia is likely to continue to be sourced from the Otway and Cooper Basins, and increasingly (in the long term) from CSG from the Surat-Bowen Basin (Eastern Queensland).
- There is significant upward pressure on Eastern Australia's historically cheap (by world standards) domestic gas prices. Influences on gas prices include the alternative LNG market for gas, implications of the likely introduction of a price on carbon, the development of higher cost gas reserves and limited gas producer competition. The implications of these and other factors are the

subject of much debate in the industry, with views on future gas prices varying significantly.

- Overall, our view is that Eastern Australia gas prices are likely to increase over the next 8 to 10 years by an average of 3 % to 5 % (real) per annum, although increases can be expected to occur in a stepped rather than consistent (year by year) basis.
- This magnitude of increase would result in gas prices (i.e., wholesale gas price at Whyte Yarcowie) increasing from the current $4.00 per GJ to $4.50 per GJ (average) to $5.00 per GJ to $6.50 per GJ (AUD 2011) by 2020.
- In addition to significant increases in the cost of gas, gas-consuming industry appears likely, for the near term, to only be able to secure gas supply contracts for terms of up to about 5 years, as the industry awaits some clarity on the magnitude of gas price increases. Contracts of this duration may adversely affect the ability of major gas-consuming project proponents to commit to major developments.
- Because of the changes to gas supply and demand in Eastern Australia, South Australia is likely (over the medium to long term) to increasingly become at a gas price disadvantage compared with many other locations in Eastern Australia, as the availability of conventional gas from the Cooper Basin reduces, to be replaced by higher cost unconventional gas (from the Cooper Basin) and/ or gas transported from more distant reserves (e.g., Queensland CSG).
- Unless Government support for expansion of the Port Pirie and Whyalla gas pipeline is forthcoming, industry that would consume significant quantities of gas which is considering establishing in the Upper Spencer Gulf would also have the price disadvantage of the cost of the expansion of the pipeline (the extent of the price disadvantage would require further analysis and estimation of commercial pipeline transportation charges).
- If Government support is not forthcoming, industry that would consume significant volumes of gas would, in order to offset the potential competitive disadvantage of the cost of gas, either require some other competitive advantage to locate in the Upper Spencer Gulf area (such as proximity to that industry's market, or proximity of other inputs (e.g., ore for mineral processing), or it would need to be somewhat indifferent to the cost of gas

(e.g., gas not a major input cost). Detailed economic analysis on an industry specific or project specific basis would be needed to determine the significance of the relative competitive advantages and disadvantages.

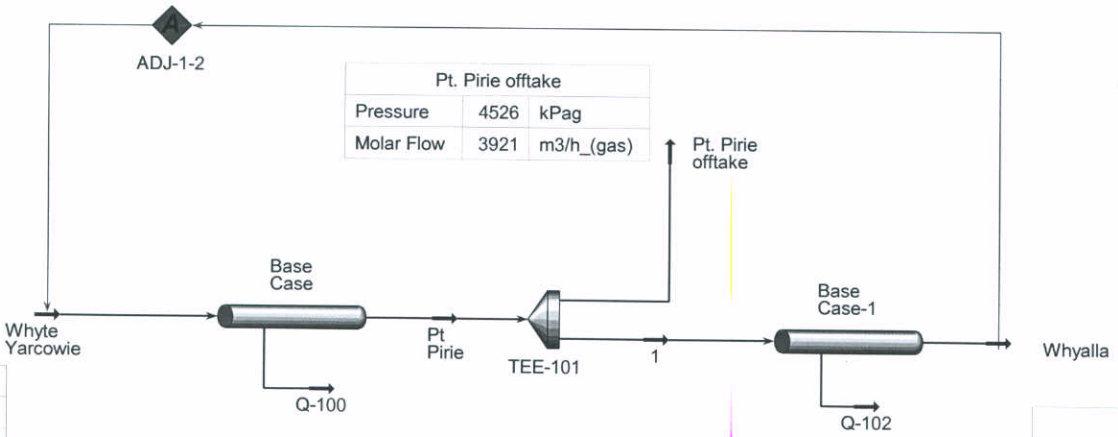
4 LIST OF APPENDICIES

1. Abbreviation Index
2. Base Case HYSYS Model and Calculation Spreadsheet
3. Case Study 1 HYSYS Model
4. Case Study 2 HYSYS Model and Results
5. Case Study 3 HYSYS Model and Results
6. Case Study 4 HYSYS Model and Results
7. Case Study 5 HYSYS Model
8. Capital Cost Calculation Spreadsheets

APPENDIX 1. ABBREVIATION INDEX

Abbreviation	Description
2P	Proved Plus Probable Reserves
A$	Australian Dollar
ABARES	Australian Bureau of Agricultural and Resource Economics and Sciences
AEMO	Australian Energy Market Operator
AUD	Australian Dollar
bbl	Barrel (of oil)
boe	Barrel of Oil Equivalent
CPI	Consumer Price Index
CSG	Coal Seam Gas
CSM	Coal Seam Methane
DN	Nominal Pipe size
GJ	Gigajoule (1 GJ = 10^9 J)
GLNG	Gladstone Liquefied Natural Gas Project
GSOO	Gas Statement of Opportunities
HDD	Horizontal Directional Drill
LNG	Liquefied Natural Gas
MAOP	Maximum Allowable Operating Pressure
MAP	Moomba Adelaide Pipeline
PJ	Petajoule (1 PJ = 10^3 TJ = 10^{15} J)
Sm^3	Standard Cubic Meters (at 25 ^oC and 1 atm conditions)
STTM	Short Term Trading Market
Tcf	Trillion cubic feet
TJ	Terajoule (1 TJ = 10^{12} J)
US$	United States Dollar
USG	Upper Spencer Gulf

APPENDIX 2. BASE CASE



Whyte Yarcowie		
Pressure	8200	kPag
Molar Flow	2.320e+004	m3/h_(gas)

Whyalla		
Pressure	3500	kPag
Molar Flow	1.928e+004	m3/h_(gas)

BASE CASE CALCULATIONS

Heating Value of Gas	37.84	MJ/Sm^3	From gas composition
Total Gas Used at Whyalla	5.400	PJ/yr	2003 Study
	16,279.5	Sm^3/hr	-
Total Gas Used at Pt Pirie	1.100	PJ/yr	2003 Study
	3,316.2	Sm^3/hr	-
Ratio of Pt Pirie/Whyalla flow	0.16923	-	-
Total Gas Used	6.50	PJ/yr	-
	19,595.7	Sm^3/hr	-
Exisiting Pipe Length from WY to Pt Pirie	73	km	2003 Study Calculations
Exisiting Pipe Length from Pt Pirie to Whyalla	87.8	km	2003 Study Calculations
WY to Pt Pirie Outer Diameter	168.3	mm	DN150 pipe
WY to Pt Pirie Internal Diameter	159.5	mm	2003 Study Calculations
WY to Pt Pirie Wall Thickness	4.4	mm	-
Pt Pirie to Whyalla Outer Diameter	219.1	mm	DN200 Pipe
Pt Pirie to Whyalla Internal Diameter	210.5	mm	2003 Study Calculations
Pt Pirie to Whyalla Wall Thickness	4.3	mm	-
Minimum Inlet Pressure	5,500	kPag	Minimum used in 2003 Study Calculations
Normal Operating Inlet Pressure	8,200	kPag	Normal used in 2003 Study Calculations
MAOP of Exisiting Pipelines	10,130	kPag	MAOP of pipeline - 2003 Study Final Report
MAOP of exisiting pipeines, less 10%	9,117	kPag	-
Minimum Discharge Pressure	3,500	kPag	Standard gas transmission line min discharge pressure

Normal Capacity (8,200 kPag Inlet)

Normal Total Capacity	23,200.0	Sm^3/hr
	7.696	PJ/yr
	21.07	TJ/d
Current Capacity to Port Pirie	3,926.2	Sm^3/hr
	1.302	PJ/yr
Current Capacity to Whyalla	19,273.8	Sm^3/hr
	6.393	PJ/yr

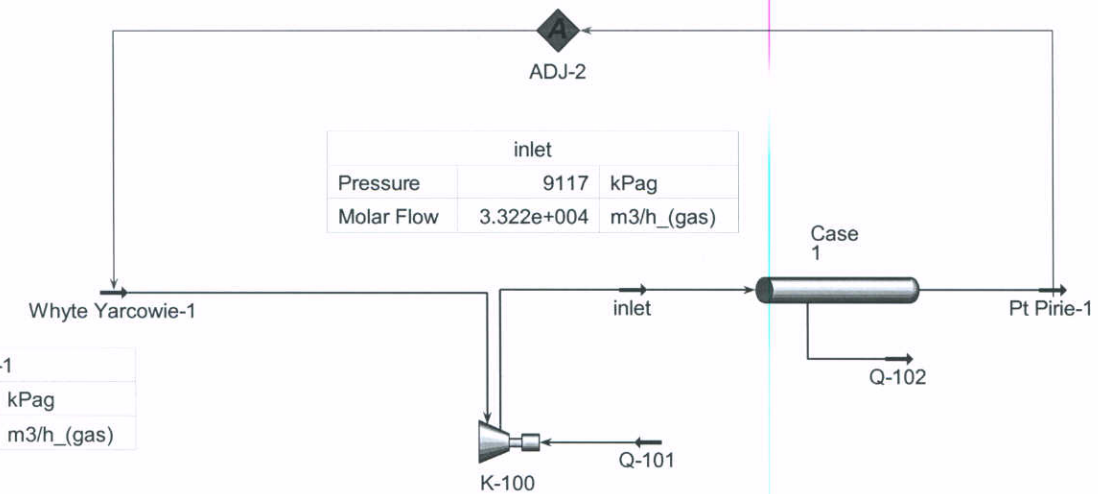
Minimum Capacity (5,500 kPag Inlet)

Minimum Total Capacity	12,930.0	Sm^3/hr
	4.289	PJ/yr
	11.74	TJ/d
Current Capacity to Port Pirie	2,188.2	Sm^3/hr
	0.726	PJ/yr
Current Capacity to Whyalla	10,741.8	Sm^3/hr
	3.563	PJ/yr

Maximum Capacity (9,117 kPag Inlet)

Maximum Total Capacity	26,540.0	Sm^3/hr
	8.803	PJ/yr
	24.10	TJ/d
Current Capacity to Port Pirie	4,491.4	Sm^3/hr
	1.490	PJ/yr
Current Capacity to Whyalla	22,048.6	Sm^3/hr
	7.314	PJ/yr

APPENDIX 3. CASE STUDY 1



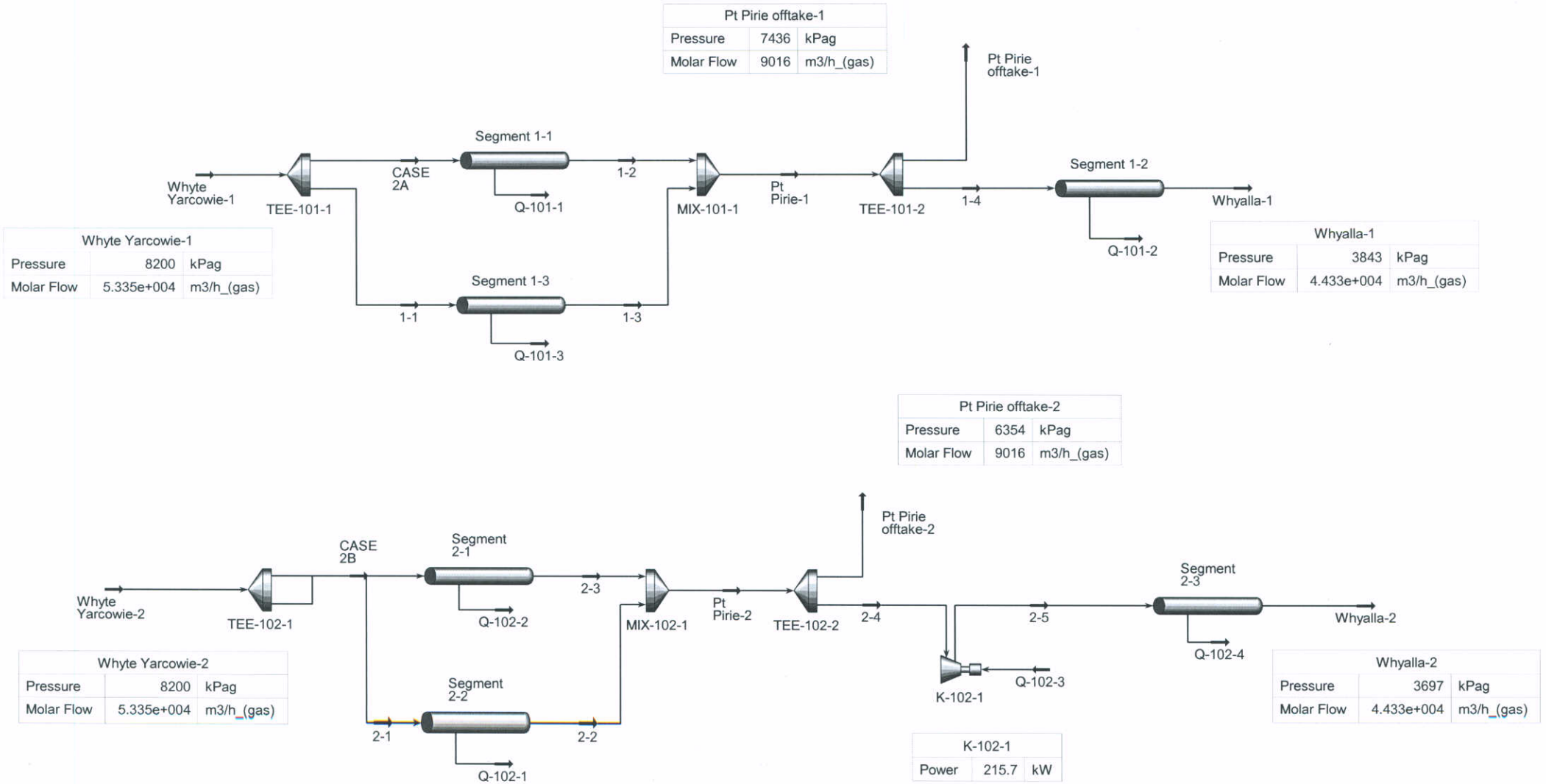
inlet		
Pressure	9117	kPag
Molar Flow	3.322e+004	m3/h_(gas)

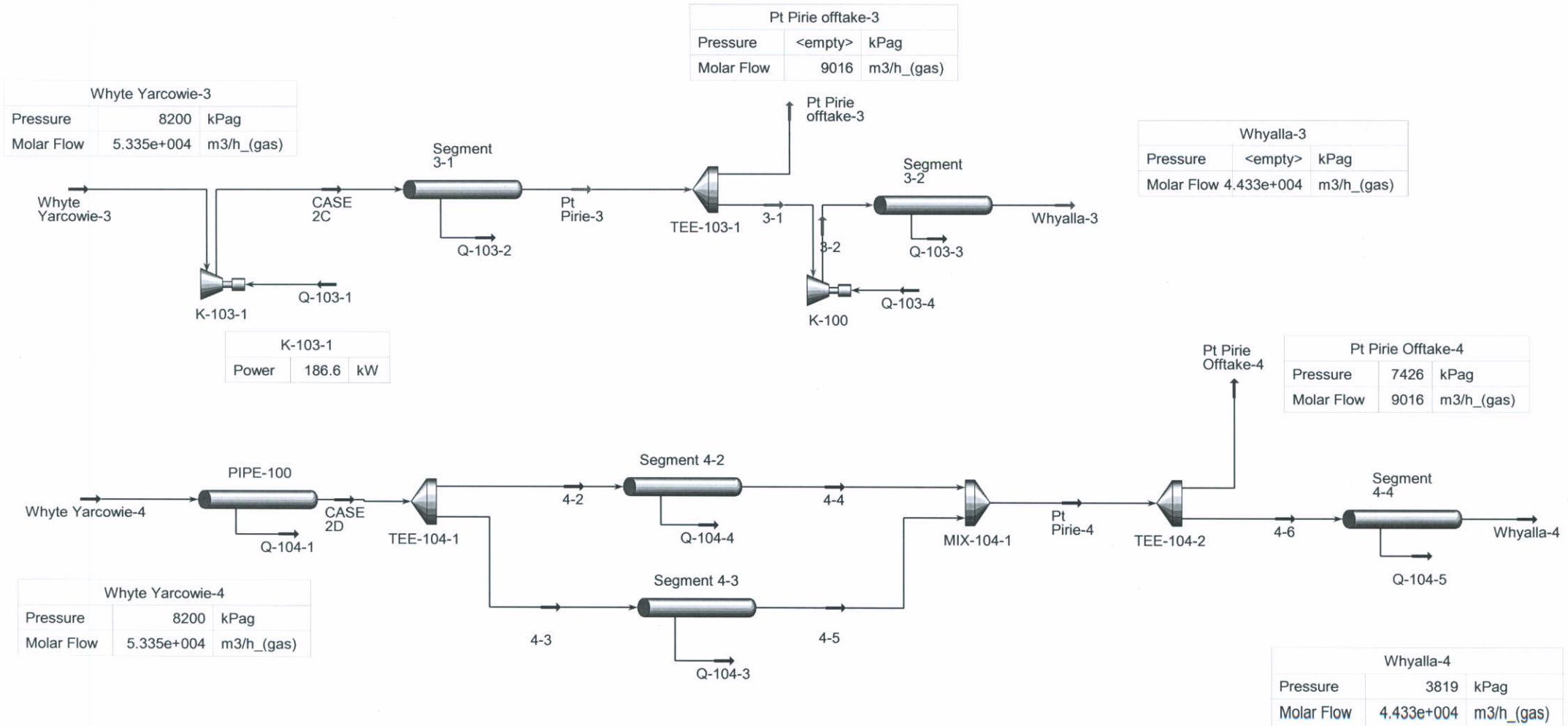
Whyte Yarcowie-1		
Pressure	8200	kPag
Molar Flow	3.322e+004	m3/h_(gas)

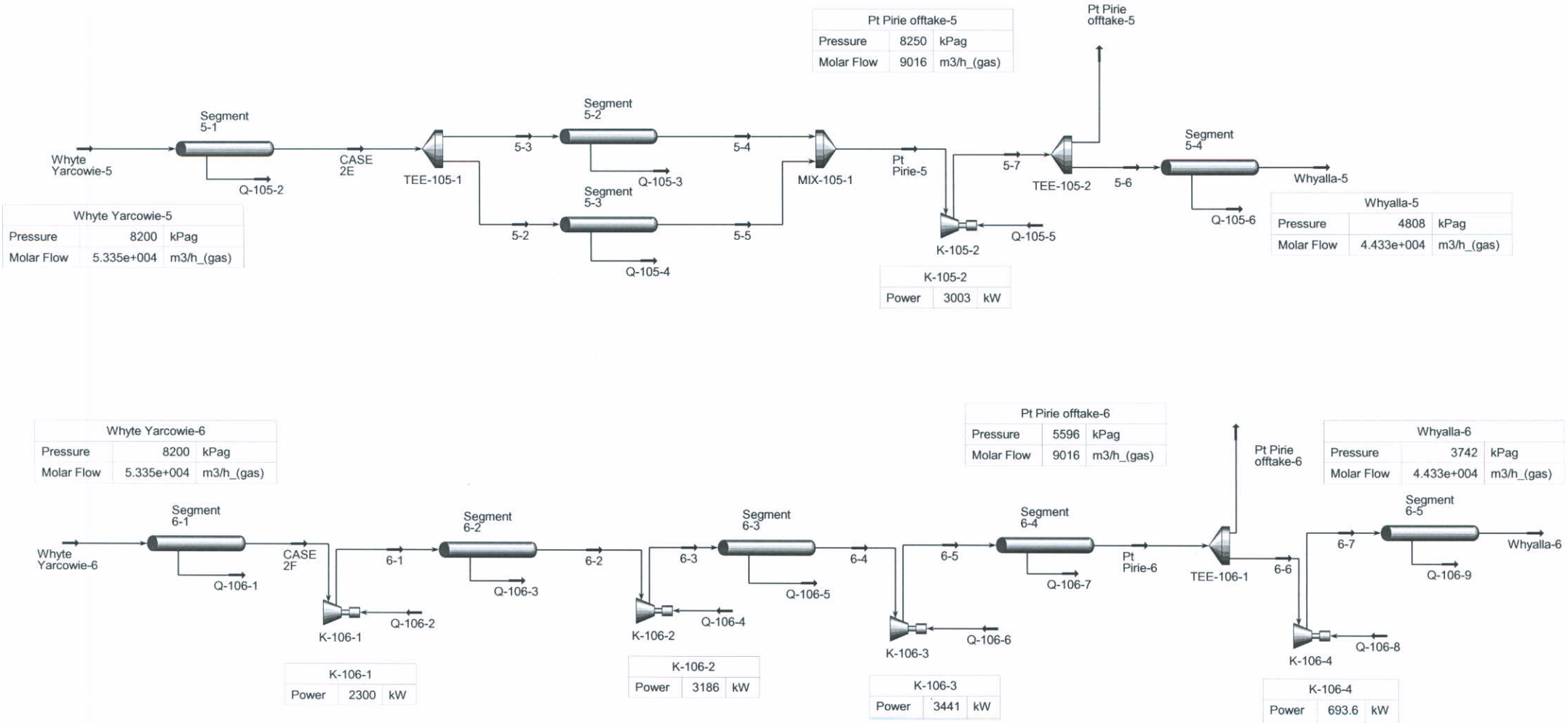
Pt Pirie-1		
Pressure	3500	kPag
Molar Flow	3.322e+004	m3/h_(gas)

K-100		
Power	116.2	kW

APPENDIX 4. CASE STUDY 2


Pt Pirie offtake-1
Pressure 7436 kPag
Molar Flow 9016 m3/h_(gas)
Pt Pirie offtake-1
Segment 1-1
Whyte Yarcowie-1
TEE-101-1
CASE 2A
Q-101-1
1-2
MIX-101-1
Pt Pirie-1
TEE-101-2
1-4
Segment 1-2
Whyalla-1
Q-101-2
Whyte Yarcowie-1
Pressure 8200 kPag
Molar Flow 5.335e+004 m3/h_(gas)
Segment 1-3
1-1
1-3
Q-101-3
Whyalla-1
Pressure 3843 kPag
Molar Flow 4.433e+004 m3/h_(gas)
Pt Pirie offtake-2
Pressure 6354 kPag
Molar Flow 9016 m3/h_(gas)
Pt Pirie offtake-2
CASE 2B
Segment 2-1
Whyte Yarcowie-2
TEE-102-1
Q-102-2
2-3
MIX-102-1
Pt Pirie-2
TEE-102-2
2-4
2-5
Segment 2-3
Whyalla-2
Q-102-4
Q-102-3
K-102-1
Whyte Yarcowie-2
Pressure 8200 kPag
Molar Flow 5.335e+004 m3/h_(gas)
Segment 2-2
2-1
2-2
Q-102-1
K-102-1
Power 215.7 kW
Whyalla-2
Pressure 3697 kPag
Molar Flow 4.433e+004 m3/h_(gas)


Pt Pirie offtake-3
Pressure <empty> kPag
Molar Flow 9016 m3/h_(gas)
Whyte Yarcowie-3
Pressure 8200 kPag
Molar Flow 5.335e+004 m3/h_(gas)
Whyalla-3
Pressure <empty> kPag
Molar Flow 4.433e+004 m3/h_(gas)
Pt Pirie offtake-3
Segment 3-1
Segment 3-2
Whyte Yarcowie-3
CASE 2C
Pt Pirie-3
TEE-103-1
3-1
3-2
Whyalla-3
Q-103-2
Q-103-3
Q-103-1
Q-103-4
K-103-1
K-100
K-103-1
Power 186.6 kW
Pt Pirie Offtake-4
Pressure 7426 kPag
Molar Flow 9016 m3/h_(gas)
Pt Pirie Offtake-4
PIPE-100
Segment 4-2
Segment 4-4
Whyte Yarcowie-4
CASE 2D
4-2
4-4
Pt Pirie-4
4-6
Whyalla-4
Q-104-1
TEE-104-1
Q-104-4
MIX-104-1
TEE-104-2
Q-104-5
Whyte Yarcowie-4
Pressure 8200 kPag
Molar Flow 5.335e+004 m3/h_(gas)
Segment 4-3
4-3
4-5
Q-104-3
Whyalla-4
Pressure 3819 kPag
Molar Flow 4.433e+004 m3/h_(gas)



Whyte Yarcowie-5		
Pressure	8200	kPag
Molar Flow	5.335e+004	m3/h_(gas)

Pt Pirie offtake-5		
Pressure	8250	kPag
Molar Flow	9016	m3/h_(gas)

K-105-2		
Power	3003	kW

Whyalla-5		
Pressure	4808	kPag
Molar Flow	4.433e+004	m3/h_(gas)

Whyte Yarcowie-6		
Pressure	8200	kPag
Molar Flow	5.335e+004	m3/h_(gas)

Pt Pirie offtake-6		
Pressure	5596	kPag
Molar Flow	9016	m3/h_(gas)

Whyalla-6		
Pressure	3742	kPag
Molar Flow	4.433e+004	m3/h_(gas)

K-106-1		
Power	2300	kW

K-106-2		
Power	3186	kW

K-106-3		
Power	3441	kW

K-106-4		
Power	693.6	kW

CASE STUDY 2 RESULTS

Required Capacity

Base Case + 10 PJ per year	17.696	PJ/yr
	53,347.2	Sm^3/hr
	48.45	TJ/d
Flowrate to Port Pirie	9,028.0	Sm^3/hr
	2.995	PJ/yr
Flowrate to Whyalla	44,319.2	Sm^3/hr
	14.701	PJ/yr

CASE A

Pipe size required for Loop	DN 250	
Length of required Loop	73.0	km
Discharge Pressure at Port Pirie	7,432	kPag
Discharge Pressure at Whyalla	3,807	kPag
Flowrate to Port Pirie	9016	Sm^3/hr
	2.991	PJ/yr
Flowrate to Whyalla	44330	Sm^3/hr
	14.705	PJ/yr

CASE B

Pipe size required for Loop	DN 200	
Length required for Loop	73.0	km
Compressor Duty	218.8	kW
	0.219	MW
Discharge Pressure at Port Pirie	6,343	kPag
Discharge Pressure at Whyalla	3,667	kPag
Flowrate to Port Pirie	9,016.0	Sm^3/hr
	2.991	PJ/yr
Flowrate to Whyalla	44,330.0	Sm^3/hr
	14.705	PJ/yr

CASE D

Pipe size required for Loop	DN 350	
Pipe size required for Loop	70.0	km
Discharge Pressure at Port Pirie	7,426	kPag
Discharge Pressure at Whyalla	3,819	kPag
Flowrate to Port Pirie	9016	Sm^3/hr
	2.991	PJ/yr
Flowrate to Whyalla	44330	Sm^3/hr
	14.705	PJ/yr

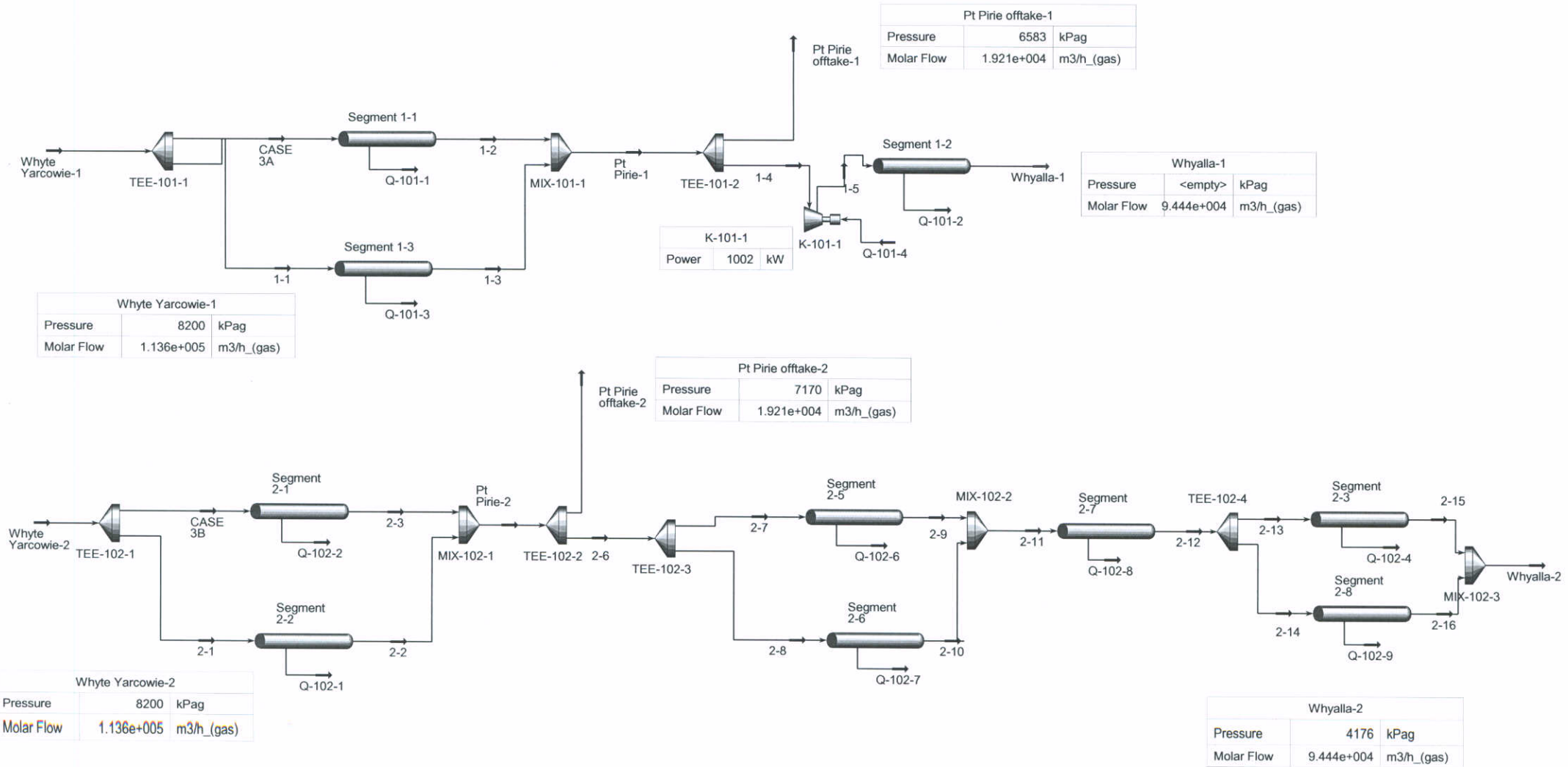
CASE E

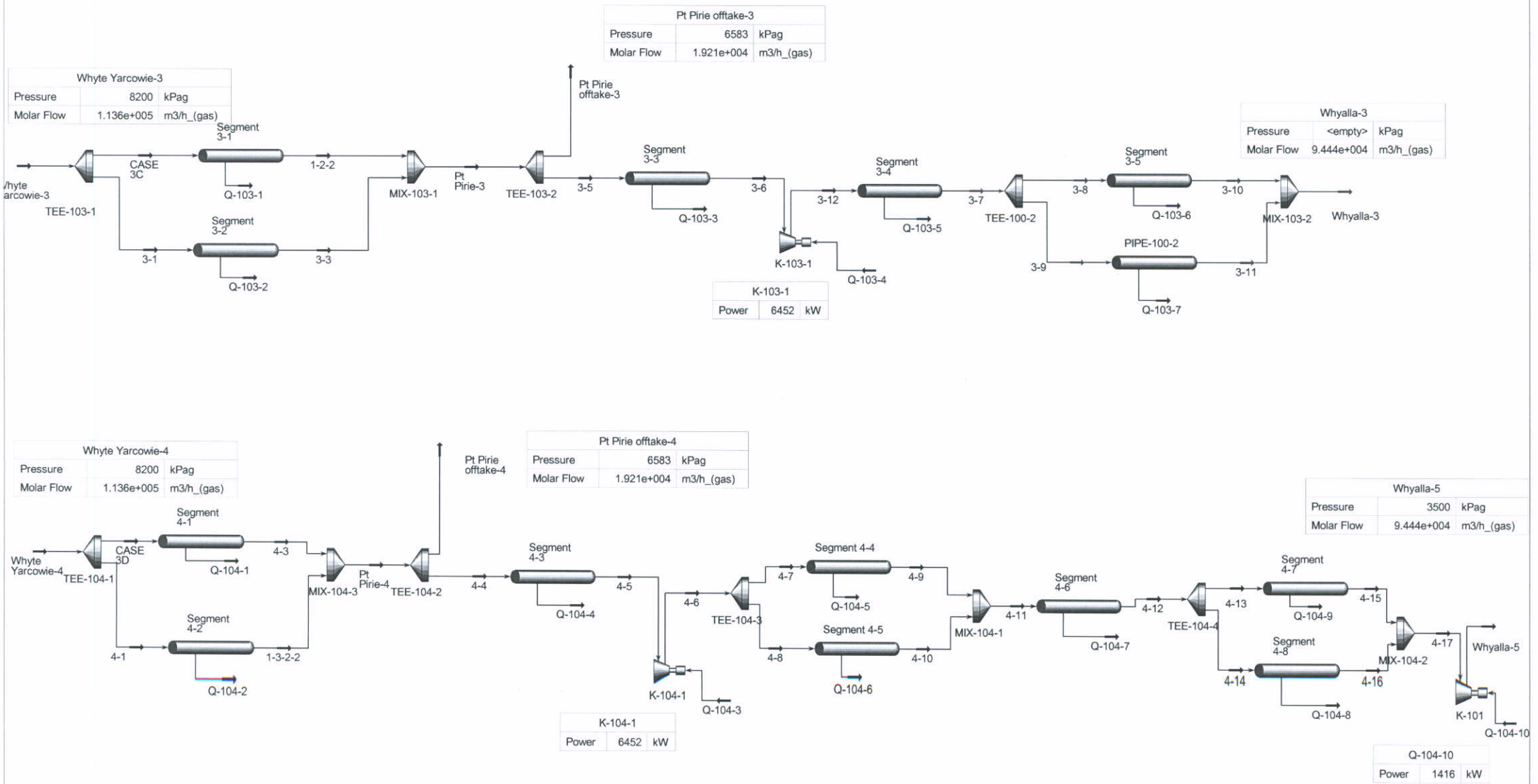
Pipe size required for Loop	DN 300	
Length required for Loop	52.0	km
Compressor Duty	3,115.0	kW
	3.12	MW
Discharge Pressure at Port Pirie	8,250	kPag
Discharge Pressure at Whyalla	3,580	kPag
Flowrate to Port Pirie	9,016.0	Sm^3/hr
	2.991	PJ/yr
Flowrate to Whyalla	44,330.0	Sm^3/hr
	14.705	PJ/yr

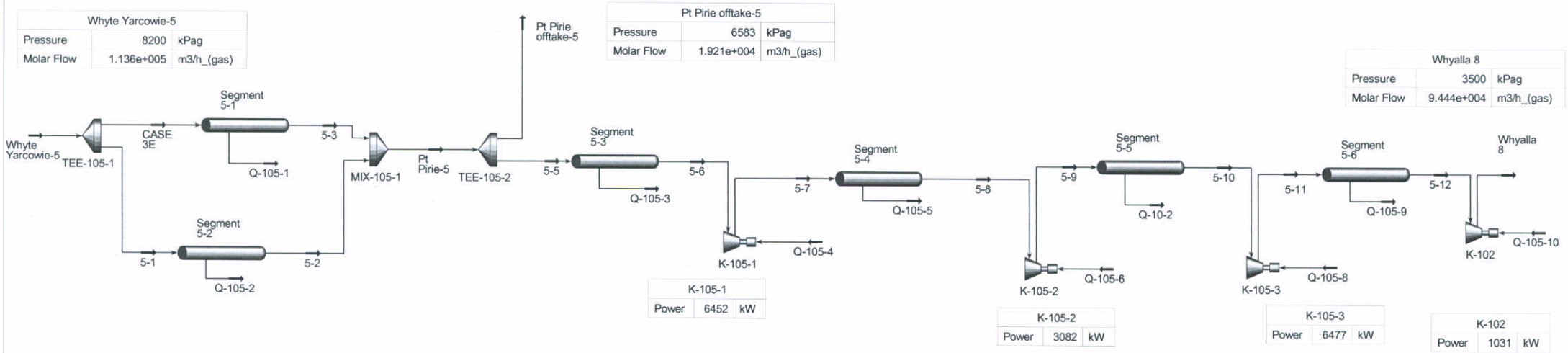
CASE F

Compressor 1 Duty	2,350.0	kW
	2.35	MW
Compressor 2 Duty	3,402.0	kW
	3.40	MW
Compressor 3 Duty	4,059.0	kW
	4.06	MW
Compressor 4 Duty	843.8	kW
	0.8438	MW
Discharge Pressure at Port Pirie	5,324	kPag
Discharge Pressure at Whyalla	3,608	kPag
Flowrate to Port Pirie	9,016.0	Sm^3/hr
	2.991	PJ/yr
Flowrate to Whyalla	44,330.0	Sm^3/hr
	14.705	PJ/yr

APPENDIX 5. CASE STUDY 3


Pt Pirie offtake-1
Pressure 6583 kPag
Molar Flow 1.921e+004 m3/h_(gas)
Pt Pirie offtake-1
Segment 1-1
Whyte Yarcowie-1
TEE-101-1
CASE 3A
1-2
Q-101-1
MIX-101-1
Pt Pirie-1
TEE-101-2
1-4
1-5
Segment 1-2
Whyalla-1
Q-101-2
K-101-1
Q-101-4
K-101-1
Power 1002 kW
Segment 1-3
1-1
1-3
Q-101-3
Whyte Yarcowie-1
Pressure 8200 kPag
Molar Flow 1.136e+005 m3/h_(gas)
Whyalla-1
Pressure <empty> kPag
Molar Flow 9.444e+004 m3/h_(gas)
Pt Pirie offtake-2
Pressure 7170 kPag
Molar Flow 1.921e+004 m3/h_(gas)
Pt Pirie offtake-2
Segment 2-1
Whyte Yarcowie-2
TEE-102-1
CASE 3B
2-3
Q-102-2
Pt Pirie-2
MIX-102-1
TEE-102-2
2-6
TEE-102-3
2-7
Segment 2-5
2-9
Q-102-6
MIX-102-2
2-11
Segment 2-7
Q-102-8
2-12
TEE-102-4
2-13
Segment 2-3
2-15
Q-102-4
Whyalla-2
MIX-102-3
Segment 2-8
2-14
2-16
Q-102-9
Segment 2-6
2-8
2-10
Q-102-7
Segment 2-2
2-1
2-2
Q-102-1
Whyte Yarcowie-2
Pressure 8200 kPag
Molar Flow 1.136e+005 m3/h_(gas)
Whyalla-2
Pressure 4176 kPag
Molar Flow 9.444e+004 m3/h_(gas)


Whyte Yarcowie-3
Pressure 8200 kPag
Molar Flow 1.136e+005 m3/h_(gas)
Pt Pirie offtake-3
Pressure 6583 kPag
Molar Flow 1.921e+004 m3/h_(gas)
Whyalla-3
Pressure <empty> kPag
Molar Flow 9.444e+004 m3/h_(gas)
K-103-1
Power 6452 kW
Whyte Yarcowie-4
Pressure 8200 kPag
Molar Flow 1.136e+005 m3/h_(gas)
Pt Pirie offtake-4
Pressure 6583 kPag
Molar Flow 1.921e+004 m3/h_(gas)
Whyalla-5
Pressure 3500 kPag
Molar Flow 9.444e+004 m3/h_(gas)
K-104-1
Power 6452 kW
Q-104-10
Power 1416 kW
Whyte Yarcowie-3
TEE-103-1
CASE 3C
Segment 3-1
Segment 3-2
Q-103-1
Q-103-2
1-2-2
3-1
3-3
MIX-103-1
Pt Pirie-3
TEE-103-2
3-5
Segment 3-3
Q-103-3
3-6
K-103-1
Q-103-4
3-12
Segment 3-4
Q-103-5
3-7
TEE-100-2
3-8
Segment 3-5
Q-103-6
3-10
MIX-103-2
Whyalla-3
3-9
PIPE-100-2
Q-103-7
3-11
Whyte Yarcowie-4
TEE-104-1
CASE 3D
Segment 4-1
Segment 4-2
Q-104-1
Q-104-2
4-3
4-1
1-3-2-2
MIX-104-3
Pt Pirie-4
TEE-104-2
4-4
Segment 4-3
Q-104-4
4-5
K-104-1
Q-104-3
4-6
TEE-104-3
4-7
Segment 4-4
Q-104-5
4-9
4-8
Segment 4-5
Q-104-6
4-10
MIX-104-1
4-11
Segment 4-6
Q-104-7
4-12
TEE-104-4
4-13
Segment 4-7
Q-104-9
4-15
4-14
Segment 4-8
Q-104-8
4-16
MIX-104-2
4-17
Whyalla-5
K-101
Q-104-10


Whyte Yarcowie-5
Pressure 8200 kPag
Molar Flow 1.136e+005 m3/h_(gas)
Pt Pirie offtake-5
Pressure 6583 kPag
Molar Flow 1.921e+004 m3/h_(gas)
Whyalla 8
Pressure 3500 kPag
Molar Flow 9.444e+004 m3/h_(gas)
Whyte Yarcowie-5
TEE-105-1
CASE 3E
Segment 5-1
Q-105-1
5-3
Segment 5-2
5-1
5-2
Q-105-2
MIX-105-1
Pt Pirie-5
TEE-105-2
Pt Pirie offtake-5
5-5
Segment 5-3
5-6
Q-105-3
K-105-1
Q-105-4
K-105-1
Power 6452 kW
5-7
Segment 5-4
Q-105-5
5-8
K-105-2
Q-105-6
K-105-2
Power 3082 kW
5-9
Segment 5-5
Q-10-2
5-10
K-105-3
Q-105-8
K-105-3
Power 6477 kW
5-11
Segment 5-6
Q-105-9
5-12
K-102
Q-105-10
K-102
Power 1031 kW
Whyalla 8

CASE STUDY 3 RESULTS

Required Capacity

Base Case + 30 PJ per year	37.696	PJ/yr
	113,641.7	Sm^3/hr
	103.20	TJ/d
Flowrate to Port Pirie	19,231.7	Sm^3/hr
	6.379	PJ/yr
Flowrate to Whyalla	94,410.0	Sm^3/hr
	31.316	PJ/yr

CASE B

Pipe size required for Loop 1	DN 350	
Length required for Loop 1	73.0	km
Pipe size required for Loop 2	DN 400	
Length required for Loop 2	40.0	km
Pipe size required for Loop 3	DN 400	
Length required for Loop 3	34.0	km
Discharge Pressure at Port Pirie	7,170	kPag
Discharge Pressure at Whyalla	4,176	kPag
Flowrate to Port Pirie	19,210.0	Sm^3/hr
	6.372	PJ/yr
Flowrate to Whyalla	94,440.0	Sm^3/hr
	31.326	PJ/yr

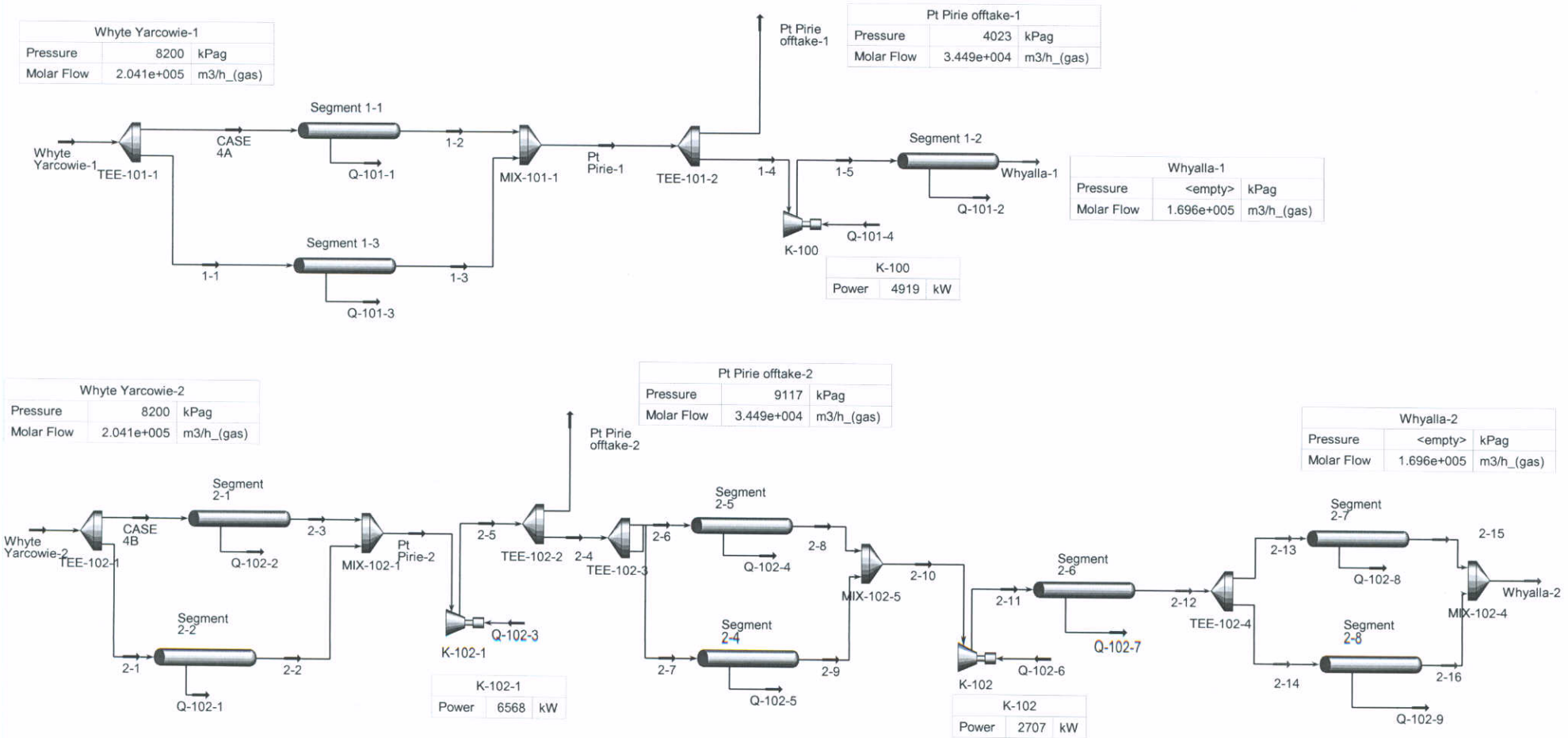
CASE D

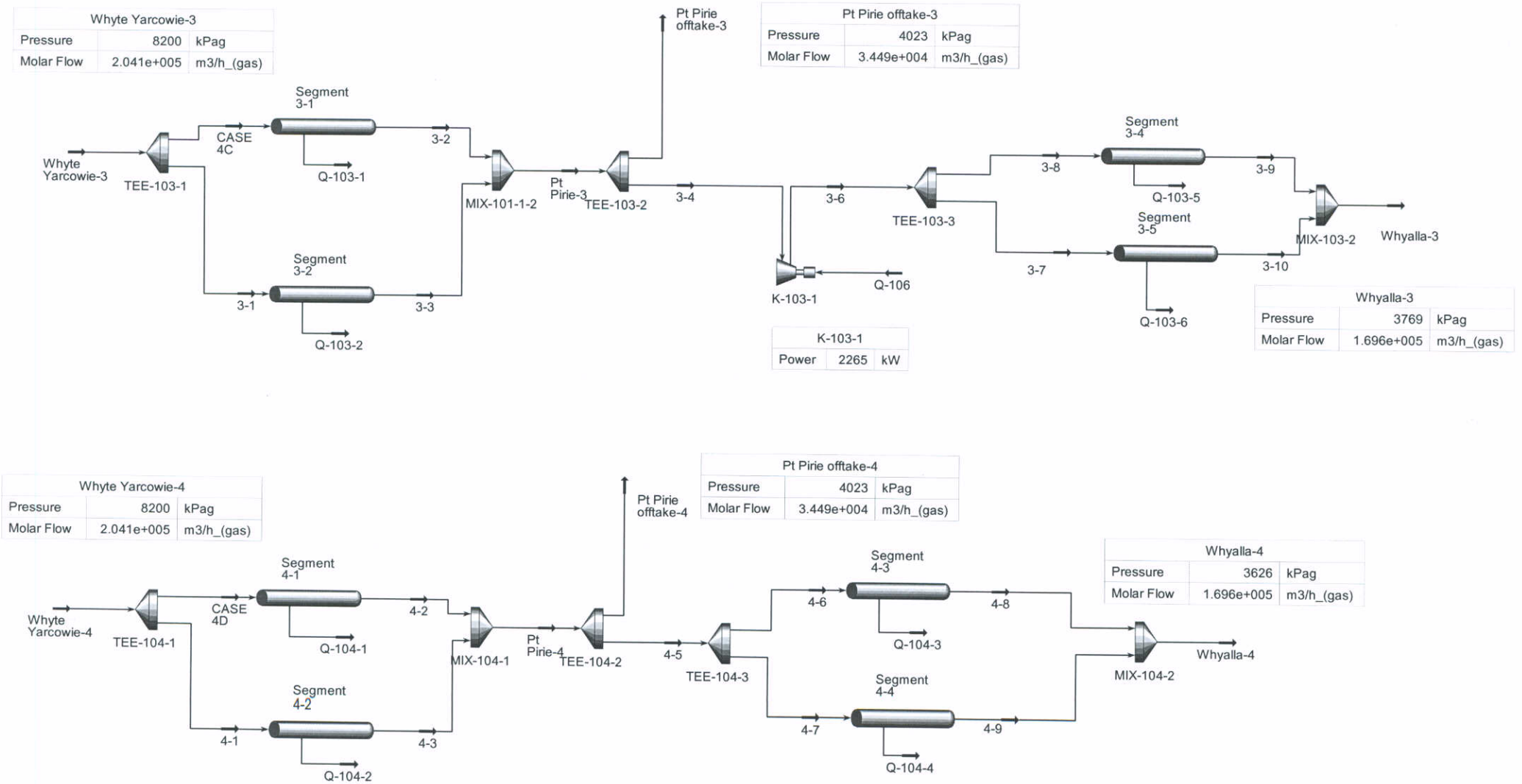
Pipe size required for Loop 1	DN 300	
Length required for Loop 1	73.0	km
Pipe size required for Loop 2	DN 200	
Length required for Loop 2	20.0	km
Pipe size required for Loop 3	DN 250	
Length required for Loop 3	24.8	km
Compressor 1 Duty	6,596.0	kW
	6.60	MW
Compressor 2 Duty	1,575.0	kW
	1.58	MW
Discharge Pressure at Port Pirie	6,579	kPag
Discharge Pressure at Whyalla	3,500	kPag
Flowrate to Port Pirie	19,210.0	Sm^3/hr
	6.372	PJ/yr
Flowrate to Whyalla	94,440.0	Sm^3/hr
	31.326	PJ/yr

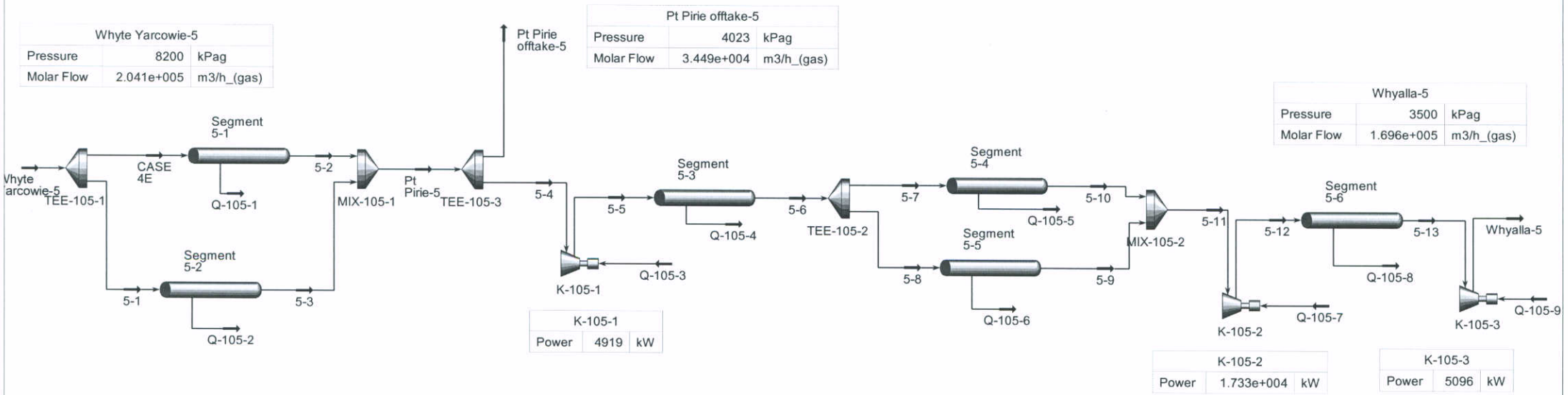
CASE E

Pipe size required for Loop	DN 300	
Length required for Loop	73.0	km
Compressor 1 Duty	6,596.0	kW
	6.60	MW
Compressor 2 Duty	3,170.0	kW
	3.17	MW
Compressor 3 Duty	6,970.0	kW
	6.97	MW
Compressor 4 Duty	1,683.0	kW
	1.68	MW
Discharge Pressure at Port Pirie	6,579	kPag
Discharge Pressure at Whyalla	3,500	kPag
Flowrate to Port Pirie	19,210.0	Sm^3/hr
	6.372	PJ/yr
Flowrate to Whyalla	94,440.0	Sm^3/hr
	31.326	PJ/yr

APPENDIX 6. CASE STUDY 4


Whyte Yarcowie-1
Pressure 8200 kPag
Molar Flow 2.041e+005 m3/h_(gas)
Pt Pirie offtake-1
Pressure 4023 kPag
Molar Flow 3.449e+004 m3/h_(gas)
Whyalla-1
Pressure <empty> kPag
Molar Flow 1.696e+005 m3/h_(gas)
K-100
Power 4919 kW
Whyte Yarcowie-2
Pressure 8200 kPag
Molar Flow 2.041e+005 m3/h_(gas)
Pt Pirie offtake-2
Pressure 9117 kPag
Molar Flow 3.449e+004 m3/h_(gas)
Whyalla-2
Pressure <empty> kPag
Molar Flow 1.696e+005 m3/h_(gas)
K-102-1
Power 6568 kW
K-102
Power 2707 kW
Whyte Yarcowie-1
TEE-101-1
CASE 4A
Segment 1-1
Q-101-1
1-2
MIX-101-1
Pt Pirie-1
TEE-101-2
Pt Pirie offtake-1
1-4
1-5
Segment 1-2
Whyalla-1
Q-101-2
Q-101-4
K-100
1-1
Segment 1-3
1-3
Q-101-3
Whyte Yarcowie-2
TEE-102-1
CASE 4B
Segment 2-1
Q-102-2
2-3
MIX-102-1
Pt Pirie-2
2-5
TEE-102-2
Pt Pirie offtake-2
2-4
TEE-102-3
2-6
Segment 2-5
Q-102-4
2-8
MIX-102-5
2-10
2-11
Segment 2-6
Q-102-7
2-12
TEE-102-4
2-13
Segment 2-7
Q-102-8
2-15
Whyalla-2
MIX-102-4
Segment 2-2
2-1
2-2
Q-102-1
K-102-1
Q-102-3
Segment 2-4
2-7
2-9
Q-102-5
K-102
Q-102-6
2-14
Segment 2-8
2-16
Q-102-9


Whyte Yarcowie-3
Pressure 8200 kPag
Molar Flow 2.041e+005 m3/h_(gas)
Whyte Yarcowie-3
TEE-103-1
CASE 4C
Segment 3-1
Q-103-1
3-2
Segment 3-2
3-1
3-3
Q-103-2
MIX-101-1-2
Pt Pirie-3
TEE-103-2
Pt Pirie offtake-3
Pt Pirie offtake-3
Pressure 4023 kPag
Molar Flow 3.449e+004 m3/h_(gas)
3-4
3-6
K-103-1
Q-106
K-103-1
Power 2265 kW
TEE-103-3
3-8
Segment 3-4
Q-103-5
3-9
3-7
Segment 3-5
Q-103-6
3-10
MIX-103-2
Whyalla-3
Whyalla-3
Pressure 3769 kPag
Molar Flow 1.696e+005 m3/h_(gas)
Whyte Yarcowie-4
Pressure 8200 kPag
Molar Flow 2.041e+005 m3/h_(gas)
Whyte Yarcowie-4
TEE-104-1
CASE 4D
Segment 4-1
Q-104-1
4-2
Segment 4-2
4-1
4-3
Q-104-2
MIX-104-1
Pt Pirie-4
TEE-104-2
Pt Pirie offtake-4
Pt Pirie offtake-4
Pressure 4023 kPag
Molar Flow 3.449e+004 m3/h_(gas)
4-5
TEE-104-3
4-6
Segment 4-3
Q-104-3
4-8
4-7
Segment 4-4
Q-104-4
4-9
MIX-104-2
Whyalla-4
Whyalla-4
Pressure 3626 kPag
Molar Flow 1.696e+005 m3/h_(gas)


Whyte Yarcowie-5
Pressure 8200 kPag
Molar Flow 2.041e+005 m3/h_(gas)
Pt Pirie offtake-5
Pressure 4023 kPag
Molar Flow 3.449e+004 m3/h_(gas)
Whyalla-5
Pressure 3500 kPag
Molar Flow 1.696e+005 m3/h_(gas)
Whyte Yarcowie-5
TEE-105-1
CASE 4E
Segment 5-1
Q-105-1
5-2
MIX-105-1
Pt Pirie-5
TEE-105-3
Pt Pirie offtake-5
5-4
5-1
Segment 5-2
5-3
Q-105-2
5-5
Segment 5-3
Q-105-4
5-6
K-105-1
Q-105-3
K-105-1
Power 4919 kW
TEE-105-2
5-7
Segment 5-4
Q-105-5
5-10
5-8
Segment 5-5
Q-105-6
5-9
MIX-105-2
5-11
K-105-2
Q-105-7
K-105-2
Power 1.733e+004 kW
5-12
Segment 5-6
Q-105-8
5-13
Whyalla-5
K-105-3
Q-105-9
K-105-3
Power 5096 kW

CASE STUDY 4 RESULTS

Required Capacity

Base Case + 60 PJ per year	67.696	PJ/yr
	204,083.4	Sm^3/hr
	185.34	TJ/d
Flowrate to Port Pirie	34,537.2	Sm^3/hr
	11.456	PJ/yr
Flowrate to Whyalla	169,546.2	Sm^3/hr
	56.239	PJ/yr

CASE C

Pipe size required for Loop 1	DN 350	
Length required for Loop 1	73.0	km
Pipe size required for Loop 2	DN 400	
Length required for Loop 2	87.8	km
Compressor Duty	2,265.0	kW
	2.27	MW
Discharge Pressure at Port Pirie	4,023	kPag
Discharge Pressure at Whyalla	3,769	kPag
Flowrate to Port Pirie	34,490.0	Sm^3/hr
	11.441	PJ/yr
Flowrate to Whyalla	169,600.0	Sm^3/hr
	56.257	PJ/yr

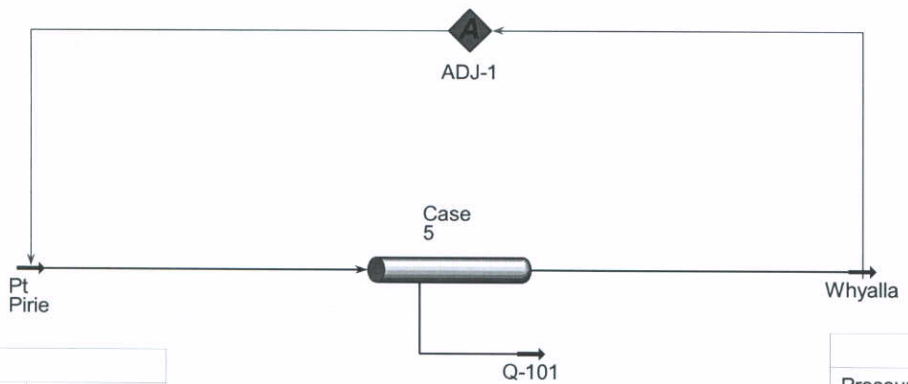
CASE D

Pipe size required for Loop 1	DN 350	
Length required for Loop 1	73.0	km
Pipe size required for Loop 2	DN 600	
Length required for Loop 2	87.8	km
Discharge Pressure at Port Pirie	4,014	kPag
Discharge Pressure at Whyalla	3,616	kPag
Flowrate to Port Pirie	17,590.0	Sm^3/hr
	5.835	PJ/yr
Flowrate to Whyalla	86,490.0	Sm^3/hr
	28.689	PJ/yr

CASE E

Pipe size required for Loop 1	DN 350	
Length required for Loop 1	73.0	km
Pipe size required for Loop 2	DN 500	
Length required for Loop 2	72.6	km
Compressor 1 Duty	4,937.0	kW
	4.94	MW
Compressor 2 Duty	18,200.0	kW
	18.20	MW
Compressor 3 Duty	7,474.0	kW
	7.47	MW
Discharge Pressure at Port Pirie	4,014	kPag
Discharge Pressure at Whyalla	3,500	kPag
Flowrate to Port Pirie	17,590.0	Sm^3/hr
	5.835	PJ/yr
Flowrate to Whyalla	86,490.0	Sm^3/hr
	28.689	PJ/yr

APPENDIX 7. CASE STUDY 5



Pt Pirie		
Pressure	9117	kPag
Molar Flow	5.910e+004	m3/h_(gas)

Whyalla		
Pressure	3500	kPag
Molar Flow	5.910e+004	m3/h_(gas)

APPENDIX 8. CAPITAL COST ESTIMATE

COST ESTIMATE FOR CASE 1

Compressor Costing	Factor	Cost
Duty (kW)		116.2
Duty (MW)		0.12
Cost ex works (AUD 2011)		$2,020,200
Freight	10%	$202,020
Aftercooler		$100,000
Filter Separator		$100,000
Enclosure		$200,000
Purchase Cost and Materials (AUD 2011)		**$2,622,220**
Compressor Installation	7%	$183,555
Purchase Cost, Materials and Installation (AUD 2011)		**$2,805,775**
Mechanical Construction	15%	$420,866
I & E Construction	12%	$336,693
Civil Construction	10%	$280,578
Total Construction (AUD 2011)		**$1,038,137**
Purchase Cost, Materials, Installation and Construction (AUD 2011)		**$3,843,912**
EPCM	10%	$384,391
Commisioning	60	$120,000
Purchase Cost, Materials, Installation, Construction and Engineering (AUD 2011)		**$4,348,304**
O/H and Management	5%	$217,415
Contingencies	30%	$1,304,491
COMPRESSOR COST (AUD 2011)		**$5,870,210**
TOTAL COMPRESSOR COST (AUD 2001)		**$5,870,210**

PIPELINE COST ESTIMATE FOR CASE 2

Pipeline Costing	Factor	2A Loop 1	2B Loop 1	2D Loop 1	2E Loop 1	2F Loop 1
Length (km)		73.0	73.0	70.0	52.0	N/A
Pipe Size		DN 250	DN 200	DN 350	DN 300	
Outer Diameter (mm)		250	200	350	300	
Outer Diameter (in)		10.0	8.0	14.0	12.0	
Wall Thickness (mm)	413.7	4.83	4.06	6.36	5.59	
Weight of Steel (tonnes)		2,130.0	1,432.3	3,770.6	2,110.8	
Cost of Steel	$2,500	$5,324,967	$3,580,866	$9,426,485	$5,277,053	
Area to be Coated (m^2)		57,334.1	45,867.3	76,969.0	49,008.8	
Coating Cost	$45.33	$2,598,953	$2,079,163	$3,489,006	$2,221,571	
Construction Cost	$20,840	$15,213,200	$12,170,560	$20,423,200	$13,004,160	
Materials and Construction Cost (AUD 2011)		**$23,137,120**	**$17,830,589**	**$33,338,690**	**$20,502,784**	
Engineering Costs	6.5%	$1,503,913	$1,158,988	$2,167,015	$1,332,681	
Materials, Construction and Engineering Costs (AUD 2011)		**$24,641,033**	**$18,989,577**	**$35,505,705**	**$21,835,464**	
Cost of Hot Tap from MAP	$200,000	$200,000	$200,000	$200,000	$200,000	
Cost of Hot Tap for Pipe Looping	$200,000	$400,000	$400,000	$400,000	$400,000	
Contruction Contingencies	7.5%	$1,140,990	$912,792	$1,531,740	$975,312	
Pipeline Material Contingencies	7.5%	$594,294	$424,502	$968,662	$562,397	
Total Contingencies (AUD 2011)		**$1,735,284**	**$1,337,294**	**$2,500,402**	**$1,537,709**	
Project Management	7.5%	$1,848,077	$1,424,218	$2,662,928	$1,637,660	
Insurance	1%	$246,410	$189,896	$355,057	$218,355	
PIPELINE LOOP COST (AUD 2011)		**$29,070,804**	**$22,540,986**	**$41,624,092**	**$25,829,188**	
End of Line Facilities Cost at Port Pirie	8.20	$1,442,696	$1,442,696	$1,442,696	$1,442,696	
End of Line Facilities Cost at Whyalla	40.25	$3,747,537	$3,747,537	$3,747,537	$3,747,537	
TOTAL PIPELINE COST (AUD 2001)		**$34,261,037**	**$27,731,218**	**$46,814,325**	**$31,019,421**	**$0**

PIPELINE COST ESTIMATE FOR CASE 3

Pipeline Costing	Factor	3B			3D			3E
		Loop 1	Loop 2	Loop 3	Loop 1	Loop 2	Loop 3	Loop 1
Length (km)		73.0	40.0	34.0	73.0	20.0	24.8	73.0
Pipe Size		DN 350	DN 400	DN 400	DN 300	DN 200	DN 250	DN 300
Outer Diameter (mm)		350.0	400	400	300.0	200	250	300.0
Outer Diameter (in)		14.0	16.0	16.0	12.0	8.0	10.0	12.0
Wall Thickness (mm)	413.7	6.36	7.12	7.12	5.59	4.06	4.83	5.59
Weight of Steel (tonnes)		3,932.2	2,759.9	2,345.9	2,963.3	392.4	723.6	2,963.3
Cost of Steel	$2,500	$9,830,477	$6,899,664	$5,864,714	$7,408,170	$981,059	$1,809,030	$7,408,170
Area to be Coated (m^2)		80,267.7	50,265.5	42,725.7	68,800.9	12,566.4	19,477.9	68,800.9
Coating Cost	$45.33	$3,638,534	$2,278,534	$1,936,754	$3,118,744	$569,634	$882,932	$3,118,744
Construction Cost	$20,840	$21,298,480	$13,337,600	$11,336,960	$18,255,840	$3,334,400	$5,168,320	$18,255,840
Materials and Construction Cost (AUD 2011)		**$34,767,491**	**$22,515,798**	**$19,138,429**	**$28,782,754**	**$4,885,093**	**$7,860,282**	**$28,782,754**
Engineering Costs	6.5%	$2,259,887	$1,463,527	$1,243,998	$1,870,879	$317,531	$510,918	$1,870,879
Material, Construction and Engineering Costs (AUD 2011)		**$37,027,378**	**$23,979,325**	**$20,382,426**	**$30,653,633**	**$5,202,624**	**$8,371,200**	**$30,653,633**
Cost of Hot Tap from MAP	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Cost of Hot Tap for Pipe Looping	$200,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Contruction Contingencies	7.5%	$1,597,386	$1,000,320	$850,272	$1,369,188	$250,080	$387,624	$1,369,188
Pipeline Material Contingencies	7.5%	$1,010,176	$688,365	$585,110	$789,519	$116,302	$201,897	$789,519
Total Contingencies (AUD 2011)		**$2,607,562**	**$1,688,685**	**$1,435,382**	**$2,158,707**	**$366,382**	**$589,521**	**$2,158,707**
Project Management	7.5%	$2,777,053	$1,798,449	$1,528,682	$2,299,022	$390,197	$627,840	$2,299,022
Insurance	1%	$370,274	$239,793	$203,824	$306,536	$52,026	$83,712	$306,536
PIPELINE LOOP COST (AUD 2011)		**$43,382,267**	**$28,306,253**	**$24,150,315**	**$36,017,898**	**$6,611,229**	**$10,272,273**	**$36,017,898**
End of Line Facilities Cost at Port Pirie	17.46			$2,270,455			$2,270,455	$2,270,455
End of Line Facilities Cost at Whyalla	85.74			$5,899,246			$5,899,246	$5,899,246
TOTAL PIPELINE COST (AUD 2001)				**$104,008,536**			**$61,071,102**	**$44,187,600**

PIPELINE COST ESTIMATE FOR CASE 4

Pipeline Costing	Factor	4C			4D			4E		
		Loop 1	Loop 2	Loop 2	Loop 1	Loop 2	Loop 2	Loop 1	Loop 2	Loop 2
			On Land	Under Water		On Land	Under Water		On Land	Under Water
Length (km)		73.0	75.0	12.8	73.0	75.0	12.8	73.0	59.8	12.8
Pipe Size		DN 350	DN 400	DN 400	DN 350	DN 600	0	DN 350	DN 500	0
Outer Diameter (mm)		350	400	400	300	600	600	350	500	500
Outer Diameter (in)		14.0	16.0	16.0	12.0	24	24	14.0	20.0	20.0
Wall Thickness (mm)	413.7	6.36	7.12	7.12	5.59	10.18	10.18	6.36	8.65	8.65
Weight of Steel (tonnes)		3,932.2	5,174.7	883.2	2,963.3	11,107.6	1,895.7	3,932.2	6,269.0	1,341.9
Cost of Steel	$2,500	$9,830,477	$12,936,870	$2,207,892	$7,408,170	$27,769,069	$4,739,255	$9,830,477	$15,672,529	$3,354,655
Area to be Coated (m^2)		80,267.7	94,247.8	16,085.0	68,800.9	141,371.7	24,127.4	80,267.7	93,933.6	20,106.2
Coating Cost	$45.33	$3,638,534	$4,272,252	$729,131	$3,118,744	$6,408,378	$1,093,696	$3,638,534	$4,258,011	$911,414
Construction Cost	$20,840	$21,298,480	$25,008,000	$4,268,032	$18,255,840	$37,512,000	$6,402,048	$21,298,480	$24,924,640	$5,335,040
Materials and Construction Cost (AUD 2011)		**$34,767,491**	**$42,217,122**	**$7,205,055**	**$28,782,754**	**$71,689,447**	**$12,234,999**	**$34,767,491**	**$44,855,180**	**$9,601,109**
Engineering Costs	6.5%	$2,259,887	$2,744,113	$468,329	$1,870,879	$4,659,814	$795,275	$2,259,887	$2,915,587	$624,072
Material, Construction and Engineering Costs (AUD 2011)		**$37,027,378**	**$44,961,235**	**$7,673,384**	**$30,653,633**	**$76,349,261**	**$13,030,274**	**$37,027,378**	**$47,770,767**	**$10,225,181**
Cost of Hot Tap from MAP	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Cost of Hot Tap for Pipe Looping	$200,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
HDD Cost	$722,304	N/A	N/A	$1,444,607	N/A	N/A	$1,444,607	N/A	N/A	$1,444,607
Laying Pipeline Underwater Cost	$951,945	N/A	N/A	$12,184,896	N/A	N/A	$12,184,896	N/A	N/A	$12,184,896
Underwater Installation Cost (AUD 2011)		**N/A**	**N/A**	**$13,629,503**	**N/A**	**N/A**	**$13,629,503**	**N/A**	**N/A**	**$13,629,503**
Material, Construction, Engineering and Underwater Inst. Cost (AUD 2011)		**$37,027,378**	**$44,961,235**	**$21,302,887**	**$30,653,633**	**$76,349,261**	**$26,659,777**	**$37,027,378**	**$47,770,767**	**$23,854,684**
Contruction Contingencies	7.5%	$1,597,386	$1,875,600	$320,102	$1,369,188	$2,813,400	$480,154	$1,597,386	$1,869,348	$400,128
Pipeline Material Contingencies	7.5%	$1,010,176	$1,290,684	$220,277	$789,519	$2,563,309	$437,471	$1,010,176	$1,494,791	$319,955
Underwater Installation Contingencies	20%	N/A	N/A	$2,725,901	N/A	N/A	$2,725,901	N/A	N/A	$2,725,901
Total Contingencies (AUD 2011)		**$2,607,562**	**$3,166,284**	**$3,266,280**	**$2,158,707**	**$5,376,709**	**$3,643,526**	**$2,607,562**	**$3,364,139**	**$3,445,984**
Project Management	7.5%	$2,777,053	$3,372,093	$1,597,717	$2,299,022	$5,726,195	$1,999,483	$2,777,053	$3,582,808	$1,789,101
Insurance	1%	$370,274	$449,612	$213,029	$306,536	$763,493	$266,598	$370,274	$477,708	$238,547
Permitting for Underwater Installation	$521,000	N/A	N/A	$521,000	N/A	N/A	$521,000	N/A	N/A	$521,000
PIPELINE LOOP COST (AUD 2011)		**$43,382,267**	**$52,549,224**	**$27,500,913**	**$36,017,898**	**$88,815,657**	**$33,690,384**	**$43,382,267**	**$55,795,421**	**$30,449,316**
End of Line Facilities Cost at Port Pirie	31.36			$3,226,354			$3,226,354			$3,226,354
End of Line Facilities Cost at Whyalla	153.97			$8,382,008			$8,382,008			$8,382,008
TOTAL PIPELINE COST (AUD 2001)				**$135,040,766**			**$170,132,302**			**$141,235,366**

COMPRESSORS COST ESTIMATE FOR CASE 2

Compressor Costing	Factor	2A	2B	2D	2E	2F			
		Compressor 1	Compressor 1	Compressor 1	Compressor 1	Compressor 1	Compressor 2	Compressor 3	Compressor 4
Duty (kW)		N/A	218.8	N/A	3,115.0	2,350.0	3,402.0	4,059.0	843.8
Duty (MW)			0.22		3.12	2.35	3.40	4.06	0.84
Cost ex works (AUD 2011)			$2,020,200		$3,896,100	$3,896,100	$3,896,100	$4,473,300	$2,020,200
Freight	10%		$202,020		$389,610	$389,610	$389,610	$447,330	$202,020
Aftercooler			$100,000		$100,000	$100,000	$100,000	$100,000	$100,000
Filter Separator			$100,000		$100,000	$100,000	$100,000	$100,000	$100,000
Enclosure			$200,000		$200,000	$200,000	$200,000	$200,000	$200,000
Purchase Cost and Materials (AUD 2011)			**$2,622,220**		**$4,685,710**	**$4,685,710**	**$4,685,710**	**$5,320,630**	**$2,622,220**
Compressor Installation	7%		$183,555		$328,000	$328,000	$328,000	$372,444	$183,555
Purchase Cost, Materials and Installation (AUD 2011)			**$2,805,775**		**$5,013,710**	**$5,013,710**	**$5,013,710**	**$5,693,074**	**$2,805,775**
Mechanical Construction	15%		$420,866		$752,056	$752,056	$752,056	$853,961	$420,866
I & E Construction	12%		$336,693		$601,645	$601,645	$601,645	$683,169	$336,693
Civil Construction	10%		$280,578		$501,371	$501,371	$501,371	$569,307	$280,578
Total Construction (AUD 2011)			**$1,038,137**		**$1,855,073**	**$1,855,073**	**$1,855,073**	**$2,106,437**	**$1,038,137**
Purchase Cost, Materials, Installation and Construction (AUD 2011)			**$3,843,912**		**$6,868,782**	**$6,868,782**	**$6,868,782**	**$7,799,512**	**$3,843,912**
EPCM	10%		$384,391		$686,878	$686,878	$686,878	$779,951	$384,391
Commisioning	60		$120,000		$120,000	$120,000	$120,000	$120,000	$120,000
Purchase Cost, Materials, Installation, Construction and Engineering (AUD 2011)			**$4,348,304**		**$7,675,661**	**$7,675,661**	**$7,675,661**	**$8,699,463**	**$4,348,304**
O/H and Management	5%		$217,415		$383,783	$383,783	$383,783	$434,973	$217,415
Contingencies	30%		$1,304,491		$2,302,698	$2,302,698	$2,302,698	$2,609,839	$1,304,491
COMPRESSOR COST (AUD 2011)			**$5,870,210**		**$10,362,142**	**$10,362,142**	**$10,362,142**	**$11,744,275**	**$5,870,210**
TOTAL COMPRESSOR COST (AUD 2001)		**$0**	**$5,870,210**	**$0**	**$10,362,142**				**$38,338,768**

COMPRESSORS COST ESTIMATE FOR CASE 3

Compressor Costing	Factor	3B	3D		3E			
		Compressor 1	Compressor 1	Compressor 2	Compressor 1	Compressor 2	Compressor 3	Compressor 4
Duty (kW)		N/A	6,596.0	1,575.0	6,596.0	3,170.0	6,970.0	1,683.0
Duty (MW)			6.60	1.58	6.60	3.17	6.97	1.68
Cost ex works (AUD 2011)			$5,040,900	$3,896,100	$5,040,900	$3,896,100	$5,040,900	$3,896,100
Freight	10%		$504,090	$389,610	$504,090	$389,610	$504,090	$389,610
Aftercooler			$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
Filter Separator			$100,000	$100,000	$100,000	$100,000	$100,000	$100,000
Enclosure			$200,000	$200,000	$200,000	$200,000	$200,000	$200,000
Purchase Cost and Materials (AUD 2011)			**$5,944,990**	**$4,685,710**	**$5,944,990**	**$4,685,710**	**$5,944,990**	**$4,685,710**
Compressor Installation	7%		$416,149	$328,000	$416,149	$328,000	$416,149	$328,000
Purchase Cost, Materials and Installation (AUD 2011)			**$6,361,139**	**$5,013,710**	**$6,361,139**	**$5,013,710**	**$6,361,139**	**$5,013,710**
Mechanical Construction	15%		$954,171	$752,056	$954,171	$752,056	$954,171	$752,056
I & E Construction	12%		$763,337	$601,645	$763,337	$601,645	$763,337	$601,645
Civil Construction	10%		$636,114	$501,371	$636,114	$501,371	$636,114	$501,371
Total Construction (AUD 2011)			**$2,353,622**	**$1,855,073**	**$2,353,622**	**$1,855,073**	**$2,353,622**	**$1,855,073**
Purchase Cost, Materials, Installation and Construction (AUD 2011)			**$7,394,522**	**$5,751,173**	**$7,394,522**	**$5,751,173**	**$7,394,522**	**$5,751,173**
EPCM	10%		$739,452	$575,117	$739,452	$575,117	$739,452	$575,117
Commisioning	60		$120,000	$120,000	$120,000	$120,000	$120,000	$120,000
Purchase Cost, Materials, Installation, Construction and Engineering (AUD 2011)			**$8,253,974**	**$6,446,290**	**$8,253,974**	**$6,446,290**	**$8,253,974**	**$6,446,290**
O/H and Management	5%		$412,699	$322,314	$412,699	$322,314	$412,699	$322,314
Contingencies	30%		$2,476,192	$1,933,887	$2,476,192	$1,933,887	$2,476,192	$1,933,887
COMPRESSOR COST (AUD 2011)			**$11,142,864**	**$8,702,491**	**$11,142,864**	**$8,702,491**	**$11,142,864**	**$8,702,491**
TOTAL COMPRESSOR COST (AUD 2001)		**$0**		**$19,845,356**				**$39,690,712**

COMPRESSORS COST ESTIMATE FOR CASE 4

Compressor Costing	Factor	4C	4D	4E		
		Compressor 1	Compressor 1	Compressor 1	Compressor 2	Compressor 3
Duty (kW)		2,265.0	N/A	4,937.0	18,200.0	7,474.0
Duty (MW)		2.27		4.94	18.20	7.47
Cost ex works (AUD 2011)		$3,896,100		$5,040,900	$9,062,050	$5,040,900
Freight	10%	$389,610		$504,090	$906,205	$504,090
Aftercooler		$100,000		$100,000	$150,000	$100,000
Filter Separator		$100,000		$100,000	$150,000	$100,000
Enclosure		$200,000		$200,000	$200,000	$200,000
Purchase Cost and Materials (AUD 2011)		**$4,685,710**		**$5,944,990**	**$10,468,255**	**$5,944,990**
Compressor Installation	7%	$328,000		$416,149	$732,778	$416,149
Purchase Cost, Materials and Installation (AUD 2011)		**$5,013,710**		**$6,361,139**	**$11,201,033**	**$6,361,139**
Mechanical Construction	15%	$752,056		$954,171	$1,680,155	$954,171
I & E Construction	12%	$601,645		$763,337	$1,344,124	$763,337
Civil Construction	10%	$501,371		$636,114	$1,120,103	$636,114
Total Construction (AUD 2011)		**$1,855,073**		**$2,353,622**	**$4,144,382**	**$2,353,622**
Purchase Cost, Materials, Installation and Construction (AUD 2011)		**$5,751,173**		**$7,394,522**	**$13,206,432**	**$7,394,522**
EPCM	10%	$575,117		$739,452	$1,320,643	$739,452
Commisioning	60	$120,000		$120,000	$120,000	$120,000
Purchase Cost, Materials, Installation, Construction and Engineering (AUD 2011)		**$6,446,290**		**$8,253,974**	**$14,647,075**	**$8,253,974**
O/H and Management	5%	$322,314		$412,699	$732,354	$412,699
Contingencies	30%	$1,933,887		$2,476,192	$4,394,123	$2,476,192
COMPRESSOR COST (AUD 2011)		**$8,702,491**		**$11,142,864**	**$19,773,552**	**$11,142,864**
TOTAL COMPRESSOR COST (AUD 2001)		**$8,702,491**	**$0**			**$42,059,281**

TOTAL COSTS

Option	Pipeline Cost	Compressor Cost	TOTAL COST	
	$million (AUD 2011)	$million (AUD 2011)	(AUD 2011)	$million (AUD 2011)
2A	$34.3	$0.0	$34,261,037	$34.3
2B	$27.7	$5.9	$33,601,428	$33.6
2D	$46.8	$0.0	$46,814,325	$46.8
2E	$31.0	$10.4	$41,381,562	$41.4
2F	$0.0	$38.3	$38,338,768	$38.3
3B	$104.0	$0.0	$104,008,536	$104.0
3D	$61.1	$19.8	$80,916,458	$80.9
3E	$44.2	$39.7	$83,878,311	$83.9
4C	$135.0	$8.7	$143,743,258	$143.7
4D	$170.1	$0.0	$170,132,302	$170.1
4E	$141.2	$42.1	$183,294,647	$183.3