4 ENERGY AVAILABILITY

4.1 Coal

4.1.1 Key Observations

a) Coal Resources are Plentiful

The resources of coal available for use within the south west coast region, and which can be produced using open-cut mining methods, are plentiful. The developed resources of the Collie Basin are themselves sufficient to supply existing levels of demand for in excess of 60 years.

b) Transportation Cost Considerations

Transportation costs may be of the order of $0.20 to $0.40 per GJ of coal per 100 kilometres, and therefore add significantly to the delivered cost of coal. The development and use of Eneabba coal is therefore likely to be more attractive for coal-based minerals developments located to the north of Perth than the use of Collie coal.

c) Coal Price Influences

The major component of the cost of coal is the cost of overburden removal. Increased coal production levels, which allow better utilisation of overburden removal equipment, will assist in achieving coal price improvements.

Other initiatives aimed at increasing opportunities for use of Collie coal or at promoting competition between suppliers are also commendable.

d) Poised for Coal Price Reductions

Coal prices (excluding transport) of $1.75/GJ or lower are likely to be achievable from either the Collie Basin or from resources to the north of Perth.

4.1.2 Industry Overview

As shown in Figure 4.1, there are numerous identified coalfields within the south west coast region of Western Australia, of which about 40% would be mineable using open-cut methods.

Coal mining activities are presently carried out within the Collie Basin by the privately owned Griffin Coal Mining Company Pty Limited (‘Griffin’) and by Wesfarmers Premier Coal Limited (‘Premier’)[45]. Mining is by means of open-cut, truck and shovel methods although underground mining was also carried out until 1994.

[45] Premier is a subsidiary of Wesfarmers Ltd.

Collie coals are sub-bituminous. They are well suited for use in thermal applications (such as electricity generation or steam raising) and a range of modern metallurgical processes, but are not directly[46] suitable for use in traditional coking applications. This is reflected in the composition of the present market for coal in the south west coast region, as set out in table 4.1.

Customer	Demand (Mtpa)
Western Power Corporation	4.50[47]
Worsley Alumina	0.80
Iluka (Capel and Narngulu)	0.35
TiWest Joint Venture	0.15
Cockburn Cement	0.20
Total Collie Basin Coal	6.00
Simcoa - New Zealand coal[48]	<0.01
HIsmelt - Queensland coal[49]	0.50
Total Coal Use in WA	6.50

Table 4.1: Composition of Western Australian Coal Market

Griffin and Premier have roughly equal shares of the present market for Collie Basin coal, although Griffin supplies a greater portion of the smaller (non-Western Power) customers. Premier's output will fall in 2006 when Western Power's purchase commitment declines.

Indications are that, at present production levels, prevailing coal prices average around $45 per tonne ($2.25/GJ), excluding transport.

Coal is delivered by conveyor or truck to base-load power stations located in the Collie Basin. Otherwise it is typically transported by road or rail from Collie to customers' premises. Rail freight charges are estimated[50] to be between $0.04 and $0.08 per tonne per kilometre, although indications are that prevailing rates in the Eneabba - Geraldton region are higher than this.

[46] That is, without some degree of beneficiation, processes for which are being investigated (as discussed in Section 4.1.4.)
[47] This will fall by 1.00 Mtpa (ie, to 3.5 Mtpa) at mid 2006.
[48] Simcoa imports small quantities of low-ash metallurgical coal which is blended with Collie coal for use in silicon manufacture.
[49] At the time of this report the HIsmelt facility was being commissioned to operate on coal imported from Queensland.
[50] This estimate reflects prevailing rail transportation rates as indicated by Griffin and Premier.

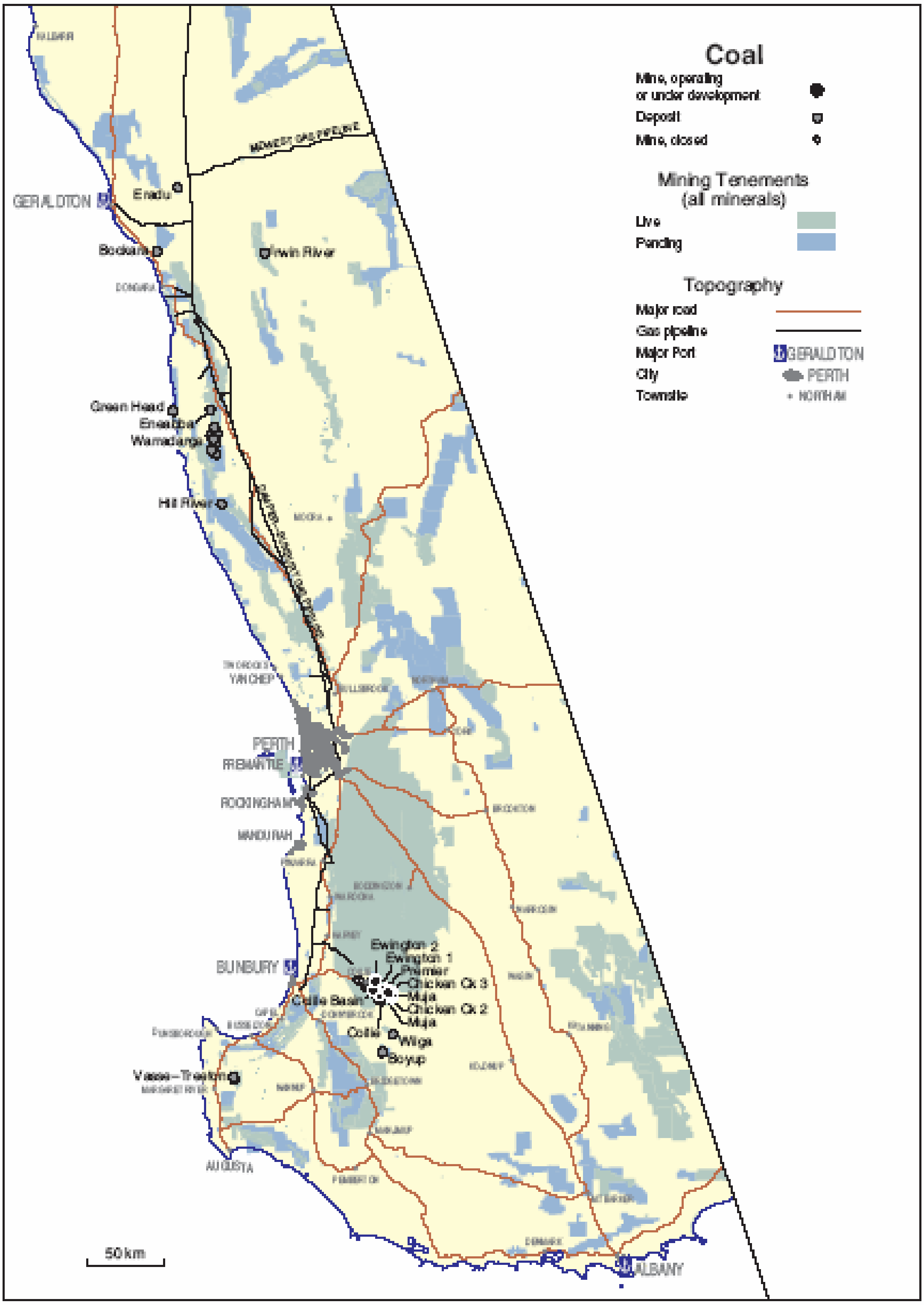

Figure 4.1: Coal Resources of the Study Region

4.1.3 Potential for Expanded Production of Coal

Figure 4.1 shows the location of significant coal resources of the south west coast region. Of these, the resources of the Collie and northern Perth Basins, which are suited to production by open-cut methods[51], offer the greatest potential for development to supply the energy requirements of new minerals development projects.

The coal resources of the Wilga and Boyup sub-basins, which are also suited to open-cut mining, are not of immediate interest as the economics of establishing a new operation in the vicinity of an existing, expandable operation are not compelling.

While the Vasse-Treeton coal resource is not mineable by open-cut methods, it may be a source of coal seam methane. This opportunity is discussed in Section 4.2.

Comparative data on the extent and quality of coal from the locations of primary interest for coal production is presented in Table 4.2. Prospects for expanded production of coal from the tabulated locations are reviewed in the following sub-sections.

Area	Northern Perth Basin	Collie Basin
Open-cut Resource	> 100 Mt	400 Mt
Coal Type	Sub-bituminous	
Ash Content (typical)	17%	5-12%
Volatiles Content (typical)	24%	27%
Moisture content (typical)	26-30%	25%
Hardgrove Grindability Index	85-100	45-65
Heating Value	15-17 MJ/kg	19- 20 MJ/kg

Table 4.2: Coal Quantities and Qualities[52]

The higher ash content of Eneabba coal (relative to Collie coal) means that the costs of using it in certain applications (such as for electricity generation) will be marginally higher[53].

[51] Open-cut mining is lower cost than underground mining. For example, refer to ‘Fact Sheet 12 - Coal’ prepared by the Department of Minerals and Energy, Western Australia, 4/96.
[52] The primary source of data for preparation of Table 4.2 was information published by the Department of Industry and Resources. Some information has however been sourced from coal mining companies and lease-holders.
[53] For a given power station size, the tonnages of coal to be handled will be about 20% greater and additional operating costs (eg, for ash-handling and soot-blowing) will be incurred.

4.1.4 Development of Northern Perth Basin Coal Resource

The coal resource of the northern Perth Basin represents a significant prospective energy source even though some 600 Mt of coal within the Hill River deposit is sterilised (since it is located within a State Reserve). Development of the northern Perth Basin coal reserves could be particularly attractive as an energy source for coal-based minerals developments to the north of Perth. Freight costs from the existing coal mining operations of Collie to locations north of Perth would otherwise add of the order of $1.00/GJ to $2.00/GJ to the delivered cost of coal.

Aviva Corporation Ltd is promoting development of its ‘Central West’ coal resource, which lies within existing mining lease areas at Eneabba. Although mine development studies have yet to be completed, the unconsolidated nature of the overburden in the Eneabba area means that a dozer-trap operation (whereby overburden is pushed by bulldozer into a truck loading facility) may have application. The use of dozer-traps is increasingly popular. Aviva estimates that a dozer-trap facility may be able to handle around 10 million bank cubic metres (‘bcm’) of overburden per year a cost below $1.50/bcm.

For an overburden ratio[54] of 7:1, coal production costs might, in order of magnitude terms, be as set out in Table 4.3 assuming a production level of the order of 1.5 Mtpa (which would allow good utilisation of the dozer trap).

Cost component	$/t
Pre-strip and rehabilitation	0.50
Overburden Removal	10.50
Coal recovery	1.50
Coal crushing	0.80
Coal washing[55]	1.00
Conveying and miscellaneous	0.75
Owner’s costs and notional margin	5.75
Royalty	2.30
Total cost including margin	23.10

Table 4.3: Eneabba Coal Production Cost Estimate

[54] The overburden ratio is the ratio of the number of bank cubic metres of overburden that must be removed for each tonne of coal produced.

[55] An allowance is made for coal washing in view of the relatively high ash content of Central West coal.

The coal price set out in Table 4.3 is equivalent to $1.35/GJ. Achievement of this pricing level will be dependent upon production levels being high enough to allow economies of scale to be realised in terms of both the size and configuration of facilities installed and its utilisation. At a nominal minimum coal production level of 0.5 Mtpa, the coal cost might be increased by at least 20% and potentially by as much as 50% (ie, to between $27.50/tonne and $35.00/tonne, or $1.60/GJ to $2.05/GJ) owing to the lower utilisation of dozer-trap and other facilities. The cost and availability of Eneabba coal is illustrated in Figure 4.2. The cross-hatched area in Figure 4.2 represents possible production, dependent upon the realised capacity of the dozer-trap.

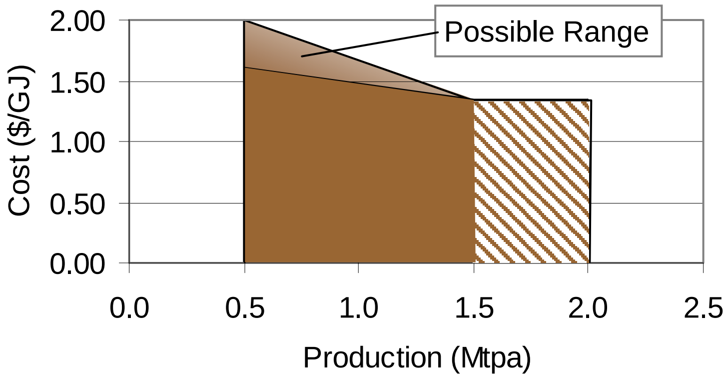

Figure 4.2: Cost and Availability of Eneabba Coal

4.1.5 Collie Basin Initiatives

The most significant component of the cost of producing coal is the cost of removing overburden and interburden from above and between the coal seams to be produced. For the existing coal mining operations in Collie, initiatives that can improve the efficiency, and hence lower the cost, of overburden removal are of particular interest.

Griffin and Premier both employ truck and shovel mining methods, whereby overburden is loaded onto dump-trucks by means of excavators or front-end loaders. Griffin uses diesel-engine powered hydraulic excavators, while Premier has moved to the use of electric shovels.

Figure 4.3: Overburden loading by front-end loader
Photograph courtesy Griffin Coal

The principal items of equipment in use by Griffin and Premier are summarised in table 4.4.

Equipment Lists	
Griffin	1 x Liebherr hydraulic excavator, 34 m^3 capacity 3 x Demag hydraulic excavators, 19 m^3 capacity 2 x hydraulic excavators, 14 m^3 capacity 1 x Komatsu front-end loader, 20 m^3 capacity 1 x Dresser front-end loader, 17 m^3 capacity 7x Liebherr dump trucks, 218 T capacity 9 x Dresser dump trucks, 172 T capacity
Premier	3 X P & H electric shovels, 36 m^3 capacity 2 X Hitachi Hydraulic excavators, 15 m^3 capacity 1 X Caterpillar front-end loader, 21 m^3 capacity 14 X 218 T dump trucks (Komatsu and Euclid)

Table 4.4: Principal Equipment in Use at Collie

The potential exists for either company to achieve lower average coal production costs with increased coal production levels.

a) Wesfarmers Premier Coal Limited

At present coal production levels, Premier moves up to 25 million bcmpa of overburden (equivalent to around 8 bcmpa for each shovel operation). In contrast, the overburden handling capability of the existing equipment fleet should approach 35 million bcmpa[56] which, at an overburden ratio up to 7:1, would allow the production of some 5 Mtpa of coal[57].

Figure 4.4: Overburden loading by electric shovel
Photograph courtesy of Premier Coal

Estimates of coal production costs at various levels of production, prepared on the basis of Australian coal industry indicative information, are set out in Table 4.5.

[56] An indicative overburden handling capability for a truck and shovel operation is around 11 million bcmpa. Refer to 'Inaugural UNSW / Mitsubishi Lecture', May 2004, Paul Westcott.
[57] This estimate confirms statements of Mr David Robb (Managing Director of Wesfarmers Energy) in Sydney on 4 May 2004. Mr Robb indicated that, with current equipment, Premier should be able to produce 5 Mtpa of coal.

Operation	Present	Expanded
Annual Production of Coal	3.5 Mt	5.0 Mt
Dewatering, Pre-strip, Rehabilitation	$1.30/t	$1.00/t
Overburden removal - Operating cost - Capital servicing - Total Contribution to coal cost[58]	 $1.90/bcm $1.20/bcm $3.10/bcm $21.70/t	 $1.60/bcm $0.95/bcm $2.35/bcm $16.45/t
Coal Recovery	$1.50/t	$1.50/t
Coal crushing and handling	$2.90/t	$2.10/t
Royalty	$2.30/t	$2.30/t
Allowance for corporate and overhead costs	$1.70/t	$1.50/t
Notional Margin[59]	$5.00/t	$5.00/t
Total production cost	$36.40/t	$29.85/t

Table 4.5: Coal Production Costs

There would appear to be significant scope for Premier to achieve coal prices below present market levels.

b) Griffin Coal

Griffin carries out open-cut mining operations at two locations, referred to as Muja and Ewington. The Muja operation is approaching the end of its life which means that coal production activities will eventually be focussed on the Ewington location, expanded as necessary.

Although Griffin's existing overburden removal and coal production equipment is relatively well utilised, with an increase in coal production quantities the potential could exist at Griffin's Ewington operation to use a dragline as the primary means of overburden removal (with retention of some truck and shovel capacity to provide flexibility of mine development and operations). The introduction of draglines has not been possible historically owing to a combination of factors including low coal tonnages and, in particular, the depth and geometry of the Muja open-cut mine.

[58] Assuming 7:1 overburden ratio.
[59] The amount by which the selling price of coal exceeds the costs of producing it will be dependent upon a range of factors, including competitive pressures.

The introduction of a dragline would reduce the cost of overburden removal, as illustrated in Table 4.6 (on the basis of Australian coal industry indicative information).

Operation	Dragline	Truck and Shovel
Nominal Capacity	25 Mbcm	11 Mbcm
Capital Cost	$75 M	$30 M
Overburden Removal Cost	< $1.45/bcm[60]	$2.35/bcm

Table 4.6: Dragline V's Truck and Shovel Operations

For an expanded Griffin operation involving a combination of dragline and truck and shovel overburden removal, coal production costs might be as set out in Table 4.7. It is again apparent that considerable scope exists for achieving lower coal prices, particularly as the scale of mining operations increases.

Activity	$/t
Pre-strip	0.30
Dewatering	0.40
Overburden removal	13.50
Coal recovery	1.50
Rehabilitation	0.30
Crushing and handling	2.10
Royalty	2.30
Admin and management	1.50
Notional Margin	5.00
Total production cost	28.90

Table 4.7: Griffin Coal Production Cost

Recognising the magnitude of benefits that are estimated to be achievable through increase in the production of coal, consideration needs to be given to initiatives that might contribute to the achievement of scale economies. Possible initiatives include, but need not be limited to, the following.

Consideration could be given to rationalisation (ie, integration) of the operations of Griffin and Premier so as to allow better utilisation of plant and equipment. To realise scale economies without loss of competitive pressures, a joint

[60] Overburden removal costs as low as $1.00/bcm are quoted.

venture approach where (as practised in the petroleum industry) each venturer is responsible for marketing of its share of production, could be considered.

Western Power is presently soliciting proposals for supply of coal post 2010, when all of its existing purchase commitments expire. It is understood at least one other major coal purchaser is also reviewing its arrangements for coal purchases in a similar timeframe. These joint initiatives may intensify competitive pressures, leading to lower margins than may have been historically achievable.

There may be scope, and both Griffin and Premier are investigating opportunities, to pursue initiatives that lead to an expansion of present markets. Several initiatives are of particular interest.

- Coal Char

  The relatively high volatiles content of Collie coal limits its suitability for use in applications where the coal is to be used as a reductant[61]. The production of coal char (from which moisture and volatile components have been driven off to leave a carbon-rich char) may expand the range of possible uses of Collie coal. For example, coal char may be suitable for use in the HIsmelt process to avoid import of coal from Jellinbah.

  Premier is investigating prospects for production of coal char and has committed to the development of a 50,000 tpa demonstration plant to prove the commerciality of the product. If successful, in excess of 1.6 Mtpa of Collie coal would be required to displace imported coal[62]. Subject to the outcome of the Western Power process described above[63], this would allow Premier to achieve a high utilisation of its present mining equipment.

- Coal Briquettes

  Collie coal is prone to spontaneous combustion (ie, self ignition) when exposed to air, which renders it unsuitable for export.

  Griffin, together with the Australian Coal Association Research Program (‘ACARP’), the CSIRO and others, has carried out research[64] into the potential for binderless briquetting of Collie coals to create a product that has size, specific energy and spontaneous combustion characteristics suited for use in a variety of metallurgical processes and for export. Apart from a reduction in moisture, the briquettes produced by ACARP

[61] This is because rapid combustion of the volatile components can lead to process instability.
[62] This assumes a doubling of the capacity of the HIsmelt plant, as discussed in Section 3.3.8.
[63] That is, provided Premier’s underlying production level is such that, after displacement of imported coal, there is still an increase in total production.
[64] ACARP Project C3100, ‘Agglomeration & Stabilisation of Collie Coals by Binderless Briquetting’, K Clark, R Meakins, M Attalla & K Craig, published 1 December 1997.

retained the chemical nature[65] and hence the volatility of the coal but had a reduced susceptibility to spontaneous combustion. A briquette plant operating cost of the order of $10/t was indicated.

Griffin has a pilot briquette production plant in operation and has produced substantial quantities of briquettes for testing by customers. A key, initial target market for briquettes is the synthetic rutile operations of the south west coast region. As discussed in Section 3.5.6(b), there appears to be scope to achieve increased synthetic rutile production if process heat losses associated with evaporation of water from coal feed can be avoided.

Success with this initiative would not lead to a major increase in coal requirements. It could however pave the way to identification of alternative and possibly export markets for Collie coal.

- Coal Gasification

  Coal gasification involves the partial or complete conversion of coal into combustible gases. These gases can then be used as feedstocks (for example, for production of liquids) or as a fuel.

  Through a process referred to as integrated gasification combined cycle (‘IGCC’), coal gasification is being investigated as means for achieving improved efficiency of coal use for electricity generation. The IGCC process, if operated with oxygen rather than air, may also facilitate the capture of carbon dioxide for environmental reasons[66]. In view of the high cost of IGCC technologies, detailed consideration of the concept is not warranted for this Study.

  With ongoing technological developments, opportunities for use of coal gasification related initiatives may emerge within the study region. Accordingly, development should be monitored.

Overall, the estimated cost and availability of additional coal from the Collie Basin is as illustrated in Figure 4.5.

[65] That is, the chemical composition of the coal, including its carbon and hydrogen content, is not changed.

[66] By operating the process with oxygen rather than air the concentration of carbon dioxide in the combusted gas stream is significantly increased, thereby facilitating its removal from the gas stream.

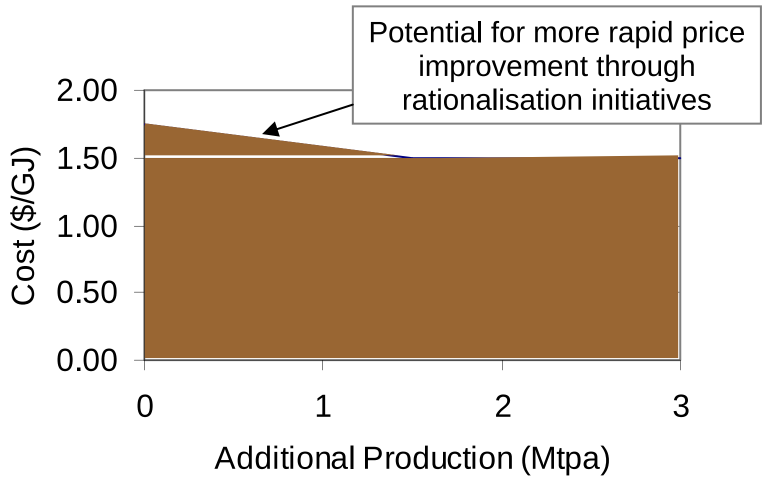

Figure 4.5: Availability and Cost of Additional Collie Basin Coal

4.1.6 Other Considerations

Coals of the Collie and northern Perth Basins are free of methane which means the principal environmental consequence associated with their use is the emission of carbon dioxide. Indicative, point-of-burn[67] carbon dioxide emissions for coals typical of those in the south west coast region are depicted in Figure 4.6. Information relating to the financial impact of possible carbon taxes is provided in Section 7 of this Report.

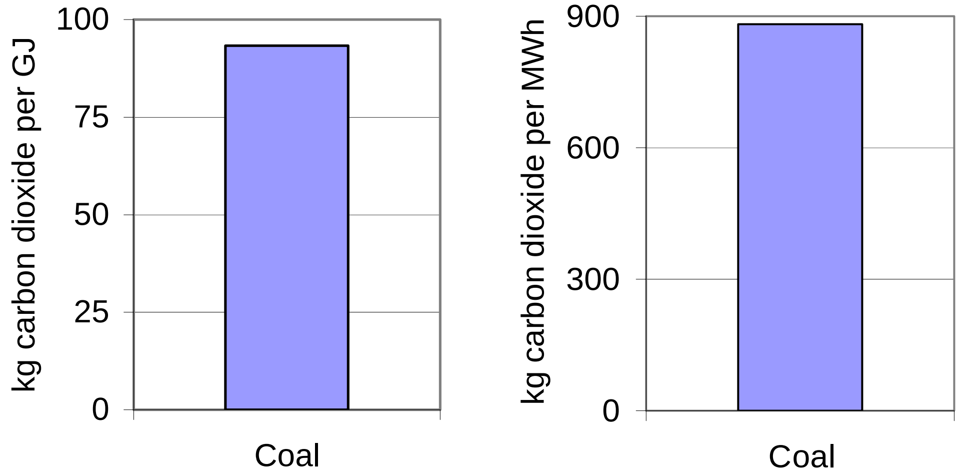

Figure 4.6: Carbon Dioxide Produced From Combustion of Coal

[67] Point-of-burn emissions figures show the emissions associated with combustion. No allowance is made for emissions associated with upstream (ie, mining, processing or transportation) activities.

4.1.7 Potential Delivered Coal Costs

Table 4.8 provides an indication of the level of prices that may be achievable through new or expanded coal production operations to supply loads within the south west coast region.

Coal Source	Price ($/GJ)	Quantity (Mtpa)
Eneabba	2.05 - 1.35	0.5 - 1.5
Collie	1.75 - 1.50	as required

Table 4.8: Availability and Price of Coal

It is necessary to add freight costs to the tabulated figures if the prospective load is removed from the coal production source. Coal transportation cost expectations are illustrated in Figure 4.7.

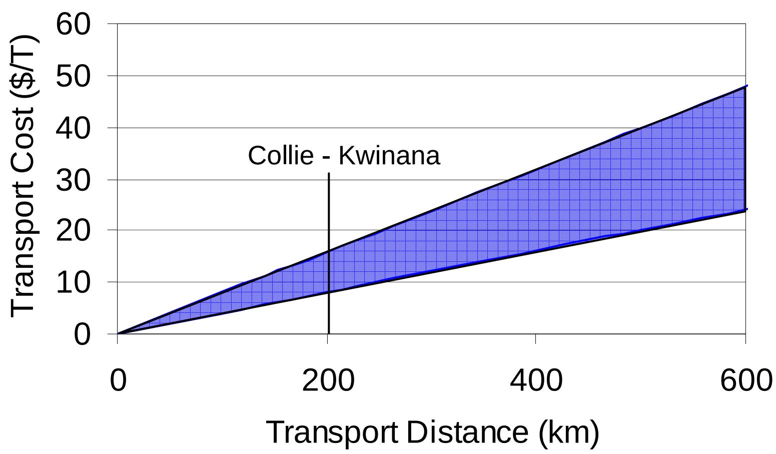

Figure 4.7: Indicative Coal Transportation Costs

4.2 Natural Gas

4.2.1 Key Observations

a) Historic Availability of Gas for Minerals Development

With the development of the Dongara gas resource in 1971 and later, as the availability of gas from Dongara was in decline, the North West Shelf project, gas has been available to support minerals and other developments in the south west coast region of Western Australia. At the same time, the presence of substantial minerals related loads was fundamental to the economics of the gas project developments.

b) Future Availability of Gas

Ongoing development of gas reserves will need to take place in a timely manner to ensure that gas continues to be available in quantities to meet existing and expanded domestic market requirements. The most likely sources of gas for future supply are located in the Carnarvon and Perth Basins. Carnarvon Basin sources include ongoing development of the North West Shelf and Varanus Island projects, as well as new developments (eg, Gorgon).

The availability of gas at internationally competitive prices will help to attract new industry to the State and to the south west coast of the region.

c) Gas Prices Competitive Despite Future Upward Pressure

The high value of export, liquefied natural gas markets combined with the need for development of offshore gas reserves in increasing water depths may lead to upward pressure on the price of gas from major, Carnarvon Basin sources of gas supply for domestic markets. In order of magnitude terms, gas prices may tend toward a price level around $2.50/GJ (not including transportation to the southwest).

Although the projected level of delivered gas prices is marginally higher than the level of prices that have been achievable in the south west coast region, it remains competitive by Australian and international standards.

d) Contingent Opportunities to Source Gas at Lower Prices

The upward pressure on gas prices may be moderated if, and to the extent that, gas is available from a number of sources.

More importantly however, for very large, base-load users of gas the prospect may exist for gas to be sourced at prices below those generally prevailing. Indicatively, prices of the order of $1.85/GJ (excluding gas transportation) might be achievable from major producers, such as the North West Shelf Project or the proposed Gorgon project, that have quantities of gas available in excess of what is required to meet other domestic and LNG supply commitments.

e) Possible Gorgon Project Opportunity

The size of the Gorgon resource is such that it will have gas reserves available in excess of what might be marketable as LNG in the medium to long term. 2,000 PJ of gas from the project have been allocated for potential domestic use. There may be a window of opportunity for procurement of gas on terms more attractive than those otherwise available in the south west coast region. This will be dependent upon sufficient load being aggregated to underwrite the costs of developing infrastructure to supply the domestic gas market.

A go-ahead of the Gorgon project will be dependent upon LNG markets being secured for gas from the project. Prospects for securing new LNG markets are reasonable and it is possible the Gorgon project could commence operation by around 2010.

f) Gas Transmission Must be Expanded

To deliver gas from the Carnarvon Basin to the south west coast region expansion of the capacity of the Dampier to Bunbury gas pipeline (‘DBNGP’), or bypass of it, will be required. The economics of expanding the capacity of the pipeline are attractive.

Tariffs for use of the DBNGP are presently around $1.17/GJ (at a 90% load factor) although lower tariffs could be achievable with expansion or bypass of the pipeline. It will be important that the benefits of expansion economies flow through to tariffs for the DBNGP.

g) Gas Price for New Minerals Development

Gas might be available for a substantive, base-load application at a delivered price (that is, including transportation costs) of the order of $2.60/GJ although to achieve this price level will require favourable outcomes in relation to both the cost of gas and the cost of gas transportation. Alcoa’s arrangements for use of the DBNGP mean it is well placed to achieve such an outcome.

h) Role of Perth Basin Gas

Gas from the relatively lightly explored Perth Basin could contribute to ongoing market development should a large commercial resource(s) be identified. Perth Basin exploration and development activity should therefore be encouraged.

4.2.2 Introduction

Western Australia is well endowed with natural gas, with in excess of 70% of Australia’s commercial gas reserves being located within sedimentary basins off the northwest coast of the state, some 1,500 kilometres from the study region. Key features of the state's gas industry are depicted in Figure 4.8[68].

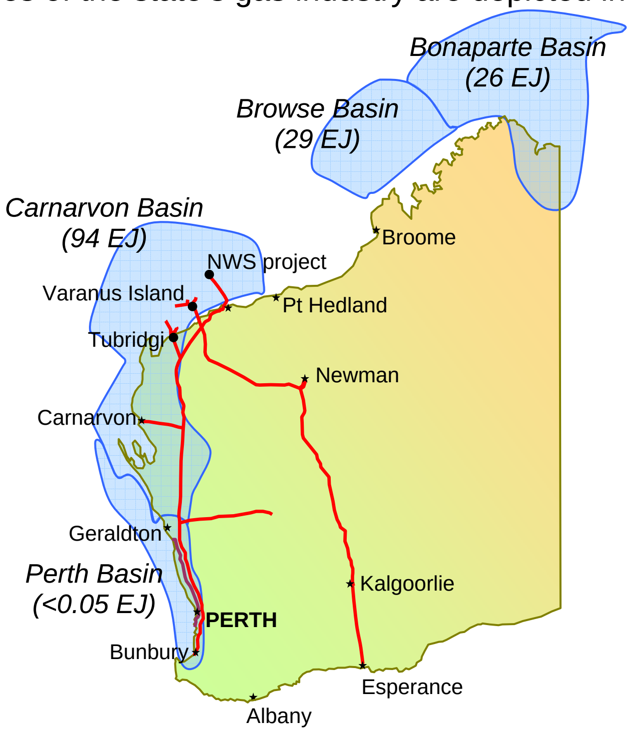

Figure 4.8: Sedimentary Basins and Gas Transmission Infrastructure[69]

Unlike other Australian states, the plentiful availability of gas has, since the early 1990's, allowed Western Australia to enjoy a competitive gas market - one in which there is healthy competition between producers of gas. As shown in Figure 4.9, the state's gas market is the largest of any Australian state. The availability of gas at internationally competitive prices has stimulated growth of the Western Australian gas market, particularly though use of gas in minerals projects. At the same time, development of remote gas production and pipeline infrastructure has been underpinned through the foundation gas purchase commitments of large minerals projects.

[68] Much of the Bonaparte Basin gas reserves lie within the joint development area that is the subject of dispute with East Timor.
[69] Gas resource information includes developed and undeveloped reserves and contingent resources at a 50% level of confidence. Information from DoIR and the AGA has been converted to exajoules (EJ).

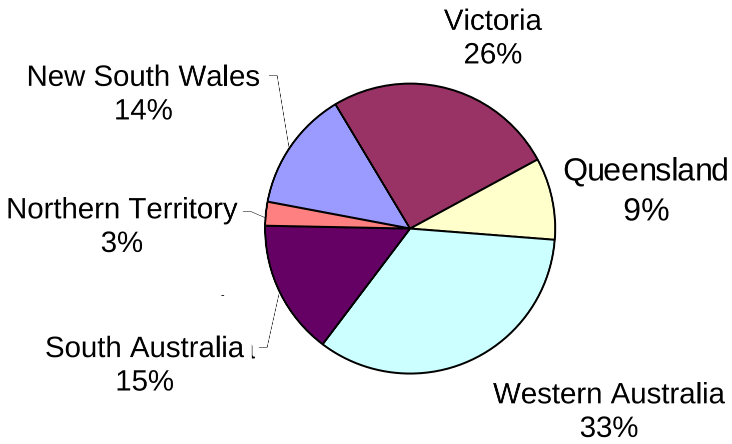

Figure 4.9: Australian Gas Demands by State[70]

Looking to the future, it is likely there will be continued and potentially competing demands for gas from Western Australian reserves. Growth of high-value, liquefied natural gas markets is expected to be strong and, in addition to use of gas in Western Australia, domestic opportunities might include delivery of gas to the eastern seaboard.

This section of the Report investigates the likely availability and price of gas as a basis for ongoing (near to medium term) use within and continued development of the south west coast region.

4.2.3 Industry Overview

Delivery of natural gas to the south west coast region commenced in 1971 following commissioning of the Parmelia Pipeline[71] to deliver gas from the Dongara gasfield, approximately 350 kilometres north of Perth. Natural gas from Dongara was used to displace manufactured gas that had been used in small commercial and residential applications, but was primarily destined for industrial applications. In fact, around 60% of gas delivered through the Parmelia Pipeline was used by a single customer (Alcoa) for the manufacture of alumina. Alcoa's gas requirement was fundamental to the economics of the Dongara gasfield and Parmelia Pipeline developments, evidencing a relationship that was of continued importance in development of energy infrastructure to service the south west of the state.

In 1984, following commissioning of the Dampier to Bunbury gas pipeline ('DBNGP'), gas from the North West Shelf ('NWS') joint venture replaced gas from the declining Dongara gasfield as the primary source of natural gas supply

[70] Source: ABARE data for 2001-02

[71] The Parmelia Pipeline was originally known as the West Australian Natural Gas Pipeline (the 'WANG' Pipeline) and was developed by West Australian Petroleum Pty Limited. It was renamed the Parmelia Pipeline in 1997 following its acquisition by CMS Gas Transmission Australia.

for the south west of the state. As with the development of Dongara gas in 1971, the involvement of industry was fundamental to the economics of delivering gas some 1500 kilometres from Dampier to Perth and Bunbury. Fifty percent of the capacity of the DBNGP was underwritten by Alcoa. The overall viability of the NWS project was also dependent upon commitments for export of liquefied natural gas ('LNG') to Japan.

The involvement of industry has also been important in facilitating the installation of a network of gas pipeline infrastructure around the state[72] that has allowed continued growth of the Western Australian market.

The Tubridgi (1991), Harriet (1992) and East Spar (1996) gasfields were subsequently developed when market opportunities (of a size sufficient to underwrite their development costs) were secured. The foundation load for the Tubridgi and Harriet projects was the then State Energy Commission of Western Australia ('SECWA') while the East Spar project was developed to supply gas through the Goldfields Gas Pipeline to major mineral processing loads.

Against this backdrop, key features of the Western Australian gas industry as it exists today are set out below.

a) Gas Production

Although a number of gas reserves within the Perth and Carnarvon Basins are presently developed and producing gas for supply to domestic and LNG markets, the backbone of the Western Australian gas industry as it exists today is undoubtedly the Carnarvon Basin. The gas producers of the Carnarvon Basin have a track-record of successful development of gas reserves to meet market requirements.

Comparative, historic rates of gas production are set out in Table 4.9.

[72] For example, pipeline extensions north to Port Hedland and Telfer, east to Newman and Kalgoorlie and south to Capel were underwritten by the gas demand of minerals projects.

Gas Production Location	Production[73] (TJ/d)
North West Shelf project	2,300
Produced via Varanus Island Hub	210
Produced via Tubridgi Hub	40
Perth Basin	20
Total	2570

Table 4.9: Comparative Rates of Gas Production

b) Market Size

The extensive Western Australian gas resource is the source of supply of gas for both domestic markets and the growing LNG export industry.

It is necessary to take LNG exports into account when assessing energy related aspects of minerals development in the south west of the state since:

- LNG sales opportunities are fundamental to the economics of developing large offshore gas resources, like the NWS project; and
- the commitment of gas for export as LNG can have an impact upon the availability and price of gas for domestic market use.

Around 440 PJ (equivalent to 1,200 TJ/d) of gas was exported as LNG in 2003 and around 870 TJ/d was supplied to domestic markets, two-thirds of which were located in the south west of the state. Commitments are in place for LNG exports to rise by in excess of 50% from 2004 to 2007. The domestic market will also grow in the near term as several new loads in the Pilbara region start taking deliveries of gas.

c) Gas Transportation

The location of Western Australia's major gas resources means there has been, and is expected to continue to be, a need for long-distance gas pipeline infrastructure to deliver gas to gas-based developments in the south west of the state.

The DBNGP has been progressively expanded (through the installation of intermediate compression facilities) so that it now has a capacity of the order of

[73] Figures shown represent average daily gas production for 2003, derived from DoIR published data. The figures include gas used in oil and gas production activities, gas used in LNG manufacture and gas exported as LNG.

600 TJ/d[74]. The pipeline is now fully compressed, although some compressor stations do not have adequate redundant capacity installed (which means a portion of the capacity of the pipeline is interruptible). Further increases in the capacity of the pipeline to deliver gas to the south west will require looping of the DBNGP. Alternatively, if sufficient load is available, the construction of a new pipeline might also be considered.

d) Market Regulation

The Western Australian gas market has been deregulated since 31 May 2004, meaning all gas consumers have freedom of choice regarding their gas purchase arrangements[75]. Regulatory and market management arrangements have been established for residential and small business customers (consuming less than 1 TJa). An understanding of these arrangements is not necessary for the purposes of this report.

4.2.4 Prospective Sources of Gas

Figure 4.10 shows the distribution of Western Australia's gas resources by sedimentary basin. The resource estimates presented in the figure are the aggregate of developed and undeveloped reserves and contingent resources, all at a 90% confidence level[76]. The figure does not make any allowance for prospective (ie, as yet undiscovered) gas reserves. The potential exists for further, significant discoveries of gas, particularly within the offshore Carnarvon Basin. Although prospective discoveries cannot be relied upon for the purpose of this Report, where new discoveries could influence the availability or cost of gas for new minerals developments, they are briefly investigated.

[74] This figure approximates the capacity of the pipeline that will, in the absence of second-order outages, be available under summer conditions. In comparison, the capacity determined probabilistically in accordance with the *Gas Transmission Regulations 1994* is 573 TJ/d.
[75] Western Power Corporation is presently precluded from supplying gas to smaller customers.
[76] Figure 4.10 is based upon information published by the Department of Industry and Resources. The information has been adjusted to conform with the resource and reserves assessment and classification system as approved by the Society of Petroleum Engineers and the World Petroleum Congresses. Appendix 4 provides an overview of that assessment and classification system. The figure of 1.7 EJ for the Perth Basin is inclusive of gas estimated to be contained within the Whicher Range resource.

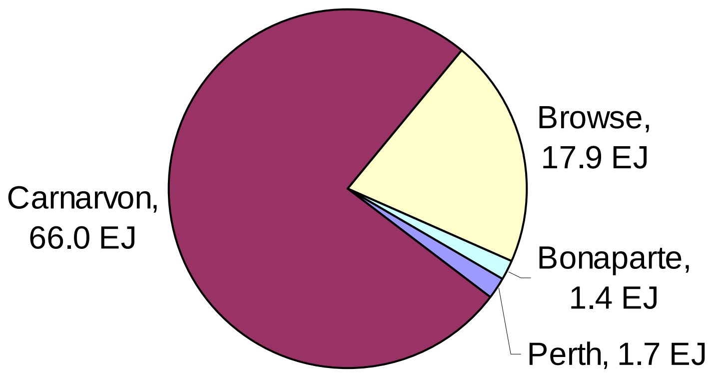

Figure 4.10: Gas Resources by Basin

While Figure 4.10 highlights the significance of the Carnarvon Basin gas resource, it affords no insight regarding the likely ongoing availability of gas for minerals development in the south west coast region. To determine this, it is necessary to investigate whether, and in what quantities and at what price, gas is likely to be available from developed and developable gas resources.

With reference to figure 4.11 on the following page, prospective sources of gas for minerals development in the south west coast region are reviewed below.

a) Perth Basin

Since the Perth Basin lies within the study region[77], existing and potential resources of gas from within the Basin are of particular interest. Production of gas from reserves within the Perth Basin could lead to increased competition between gas suppliers and would also enhance the security of gas supply to south west markets.

The Perth Basin lies south of latitude 27^{o}S and covers about 100,000 square kilometres extending from the Yilgarn Craton in the east to the edge of the continental shelf in the west. The onshore area consists of farming and shrub lands and is readily accessible. The basin is close to petroleum industry infrastructure, including the Dampier to Bunbury and Parmelia gas pipelines and trucking facilities to BP’s Kwinana Oil Refinery. The proximity of existing infrastructure and readily available markets can facilitate monetisation of oil or gas reserves as they are discovered.

[77] Gas resources available from within the study region will have a significantly reduced need for long-distance transportation (relative to gas from resources outside the study region).

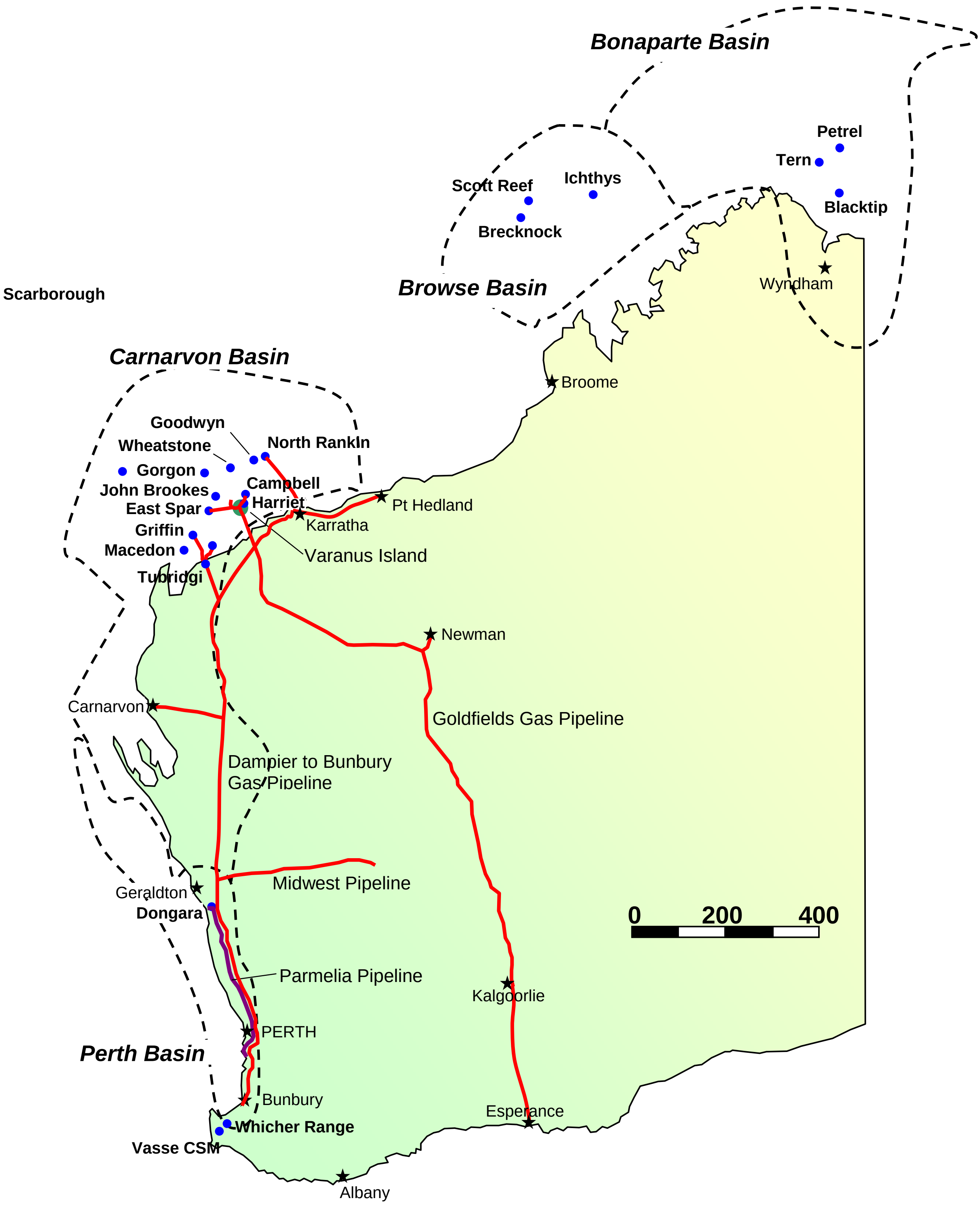

Figure 4.11: Western Australian Gas Resources and Pipelines

For clarity of presentation, not all gas fields or reservoirs are shown

Exploration activity within the Perth Basin commenced around 1951 when gravity surveys were conducted in the northern onshore area. Subsequently, WAPET was the first company to explore the acreage with gravity and seismic surveys. WAPET drilled stratigraphic wells across the onshore northern Perth Basin in the late 1950's and drilled the first wildcat hole, Eneabba 1 in 1961.

Drilling activity has been concentrated in the onshore part of the basin with about 200 wells drilled to date, compared with 24 wells offshore. Three-quarters of these wells and the majority of the known hydrocarbon accumulations are in the northern part of the Basin.

Twelve commercial hydrocarbon fields and numerous additional discoveries (some very small) have been made. WAPET was responsible for the discovery of the majority of the fields, the largest being the Dongara Gas Field, which was contained around 0.5 EJ of gas and was the first source of gas supply to the south west coast region. Other notable discoveries include the Woodada gasfield by Hughes and Hughes Oil and Gas and the Beharra Springs gasfield by Barrack. Exploration in the Perth Basin has been revitalised in recent years with the discovery of the Hovea oilfield by ARC Energy Limited ('ARC'), the Beharra Springs North gasfield by Origin Energy, the Jingemia oilfield by Origin Energy, and the offshore Cliff Head oilfield by Roc Oil.

Petroleum-systems analysis indicates that mature source rocks are widespread, reservoirs are abundant, and structures are well timed for hydrocarbon entrapment. There are many untested hydrocarbon prospects in the Perth Basin. The logistics and economics of potential oil and gas discoveries are very positive, particularly since the deregulation of Western Australian gas markets in 1988.

<u>Northern Perth Basin</u>

While all available gas reserves of the northern Perth Basin are presently committed for supply, prospects for further discoveries of gas within the Basin are good[78], as demonstrated by the recent drilling successes[79] of ARC. In addition there are substantial but presently uncommercial resources of gas within the region[80] that might prove to be recoverable through the application of new drilling methods or as technological developments occur.

[78] The historical rate of success of drilling in the northern part of the Perth Basin is about 1 in 10. A higher success rate is expected through application of three-dimensional seismic surveys. Source: "Summary of petroleum prospectivity, onshore Western Australian and State waters, 2004", Department of Industry and Resources Western Australia.
[79] The Xyris gasfield, recently developed by Arc Energy, was the first greenfields gas production development in the Perth Basin since 1990.
[80] For example, the Warro resource southeast of Dongara is estimated to contain several exajoules of gas in very tight formations.

ARC, the dominant holder of exploration acreage in the onshore, northern Perth Basin, has applied modern exploration techniques to identify a number of exploration prospects, as depicted in Figure 4.12.

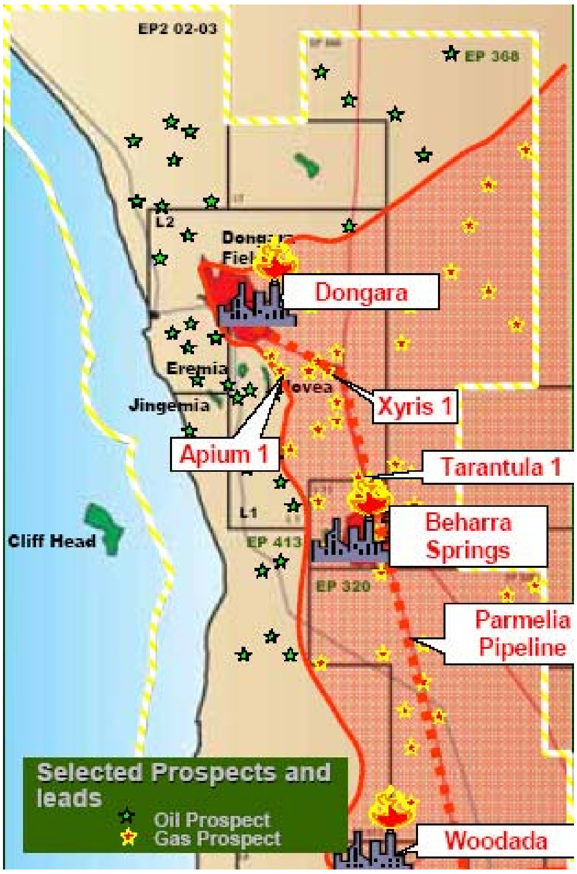

Figure 4.12: Northern Perth Basin Exploration Prospects

Based upon the areal extent of the various prospects, backed by experience to date, it would appear that new discoveries of gas may be in the 10 to 15 PJ size range. Even though a number of new discoveries could be made, their size and their proximity to existing infrastructure and markets means that gas from them will inevitably be used to compete on a price-taking basis in the south west gas market, rather than to stimulate new developments requiring lower gas prices. For example, Figure 4.13 illustrates the extent of the south west coast gas market that is not contracted for long-term supply[81]. The shaded area in Figure 4.13 alone represents a market totalling approximately 1 EJ.

[81] Figure 4.13 is based upon south west coast gas market commitments as set out in Tables 4.10 and 4.11 plus a nominal 3% pa allowance for market growth. The large increase in uncontracted market that occurs in 2021 is primarily associated with expiry of gas contracts of Alcoa and Alinta Limited. The increase in 2026 is associated with expiry of Western Power's gas purchase arrangement.

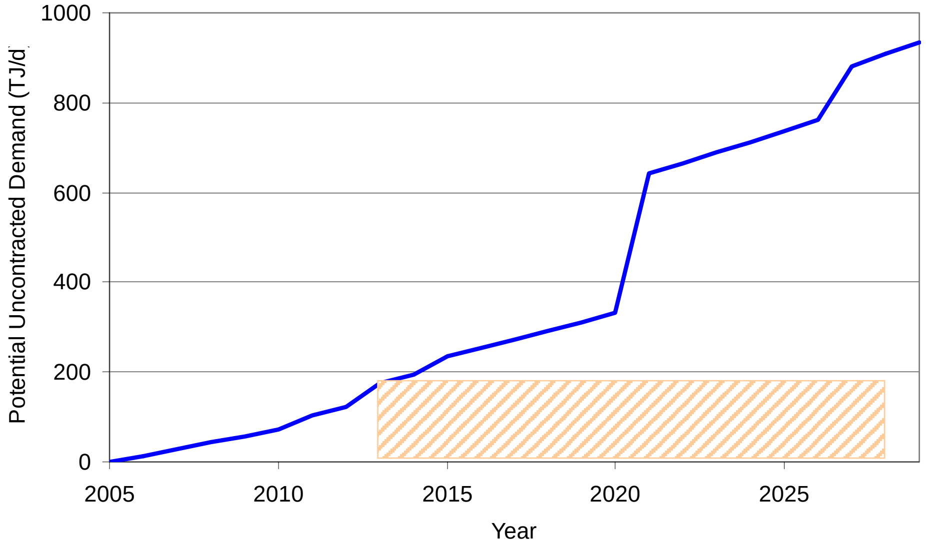

Figure 4.13: Estimated Uncontracted South West Coast Gas Market

Despite the proximity of gas pipeline infrastructure providing ready access to gas markets, Perth Basin gas producers face the challenging economics of developing small resources of gas. This was illustrated by the Hovea oilfield development from which associated gas (of the order of 1 TJ/d) was flared, despite the project being only a short distance from the Parmelia gas pipeline. The economics of gas production are affected by processing and gas lateral cost which, in turn, can be affected by technical regulatory requirements. Consideration needs to be given to the following two matters:

- The use of alternate gas transportation methods needs to be better investigated in order to avoid possible stranding or flaring of small or associated gas reserves. For example, Figure 4.14 provides an indication of the relative economics of gas transportation by various means.

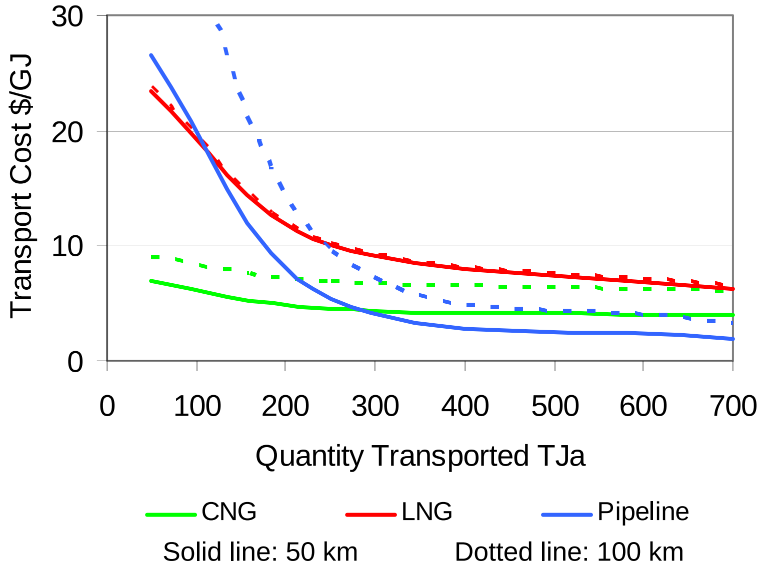

Figure 4.14: Order of Magnitude Gas Transportation Costs[82]

- It is desirable that technical regulatory requirements (eg, relating to the specification of field facilities) do not lead to costs being incurred unnecessarily. It has been suggested that equipment suitable for use in other countries often requires expensive refitting before it is acceptable for use in WA.

On balance, given the likely transportation cost advantage of Perth Basin gas (relative to gas from the Carnarvon Basin) the prospects for new Perth Basin gas discoveries to be successfully marketed into the existing south west coast region gas market are excellent. This might be expected to provide clear incentive for Perth Basin gas exploration activities. At the same time though, it means that there is unlikely to be much, if any, incentive to sell gas at prices that are significantly below prevailing market levels.

From a practical commercial perspective, marketing of gas on a price setting basis would probably only be considered if the availability of Perth Basin gas was materially in excess of that which might be readily sold into the existing market. In order of magnitude terms, this would require several exajoules of gas (ie, four to six times as much gas as was originally recoverable from the Dongara reservoir) to be proven. While such an outcome would have desirable consequences in terms of price competition, it is considered unlikely.

There are also prospects for discovery and development of additional oil fields within the northern Perth Basin. Oil discoveries, whilst of value to the study region, are not of interest as a prospective energy source for use in development of other mineral resources of the study region. Subject to commercial factors relating to recovery of the costs of developing small

[82] Figure 4.12 is from the report titled 'Facilitating the Development of Natural Gas in North Eastern New South Wales', prepared by Sleeman Consulting in March 2004.

reserves and the availability of transport infrastructure, oil is readily marketable within or as an export from the study region.

Southern Perth Basin

The Permian and Cretaceous stratigraphic and structural evolution of the southern Perth Basin is similar to that of the northern Perth Basin, but marine intervals are not present in the south, where continental depositional environments dominated until the late Neocomian. Consequently, thick regional shales are absent and the area has poor sealing potential. On the other hand, potential reservoirs, source rocks for both gas and oil, and anticlinal traps are well documented. There has however been little exploration activity in the region and, although hydrocarbon shows have been encountered in several wells, no commercial discoveries have been made to date.

There is an estimated 1.8 EJ of gas trapped within tight formations in the Whicher Range gas field, located inland from Busselton within the Perth Basin. Amity Oil Limited has endeavoured to commercialise this resource through application of a number of alternative drilling and well-completion techniques, all without success. Other initiatives such as directional drilling, may be worthy of investigation.

The potential may also exist for production of coal seam methane from the Vasse Shelf coal resource, which extends from Busselton to Augusta and which has a rank and depth consistent with the requirements for coal seam methane.

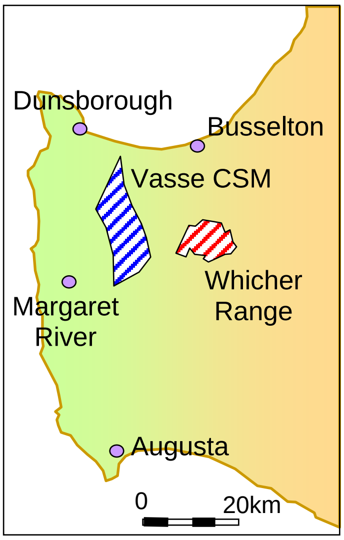

Figure 4.15 Whicher Range Gas and Vasse CSM Prospects

Coal seam methane is a natural gas formed in association with the coalification process[83]. However, unlike conventional natural gas, which is trapped within the pore space of a reservoir rock to which it has migrated, coal seam methane

[83] The process of compaction and heating of organic matter by which coal is created.

is adsorbed to the surface of the coal from which it was created, and is held there by hydrostatic pressure.

The coal acts as both source rock and reservoir rock. Coal has a large internal surface area and, as a result, is able to adsorb significant quantities of gas. Coal seams can store several times the quantity of gas that would be stored in a conventional sandstone reservoir under comparable conditions of porosity and pressure.

Westralian Gas and Power is preparing to carry out drilling activities to investigate the extent and producibility of the Vasse coal seam methane resource. Drilling and completion costs of around $90,000, cased to 400m, have been suggested. This level of cost would be consistent with expenditure in coal seam methane developments on the east coast of Australia.

Should economic rates of gas production be achieved from either or both of the Whicher Range gas resource or the Vasse Shelf coal seam methane prospect, marketing of the gas in a manner similar to that of northern Perth Basin gas (ie, sales to premium markets, most likely toward the southern end of the DBNGP) would be envisaged. However, if the upside potential of these projects is realised [84] or new, substantial gas discoveries made, a more aggressive marketing approach might be warranted. This could conceivably involve sales of gas at price levels necessary to compete with incumbent, major suppliers of gas and, in turn (through price competition), provide a significant stimulus to market development.

It is desirable that further exploration in the southern Perth Basin, and continued pursuit of the Whicher Range natural gas and Vasse coal seam methane initiatives, be encouraged.

b) North West Shelf Project

The NWS project is the state's largest supplier of gas, and routinely supplies up to 600 TJ/d of gas for domestic market use. Gas is also exported as LNG.

The NWS project produces gas from reservoirs located around 130 kilometres off the coast of WA, to the northwest of Karratha. The area contains some 16 petroleum reservoirs of which six have been developed, including the three largest - North Rankin (5.7 EJ[85]), Perseus (7.4 EJ) and Goodwyn (3.8 EJ). The remaining, undeveloped reservoirs are small in size[86] compared to those that

[84] For example, 1750 PJ of economic reserves at Whicher Range would be sufficient to supply a 240 TJ/d market (equivalent to around 1,200 MW electrical demand if used in combined cycle plant) for 20 years, which represents but a portion of the available (ie, uncontracted) south west coast market. As depicted in Figure 4.13, the potential market is significant.

[85] Reserves of gas at the beginning on 2004, as published by the Department of Industry and Resources in trillions of cubic feet (TCF) at a 90% confidence level, have been converted to exajoules.

[86] Of the remaining reservoirs Angel, the largest, has probable reserves of 1.8 TCF while the others are all smaller than 0.6 EJ. In the aggregate they contain around 4 EJ (at a 50% confidence level)

are already developed and, as a result, the unit costs of recovering gas from them are unlikely to be lower than present cost levels (despite the presence of established downstream infrastructure).

As depicted in Figure 4.16, the proven gas reserves available from the NWS project amount to around 20 EJ. A further 6.5 EJ of probable reserves is also likely to be available.

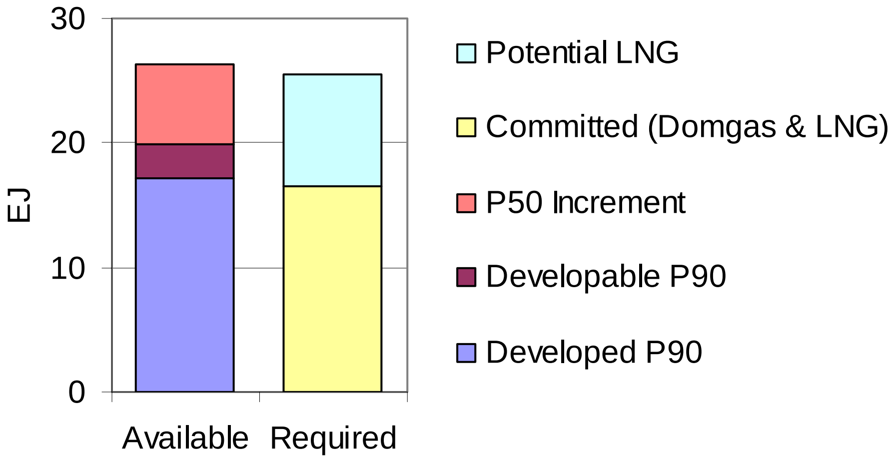

Figure 4.16: NWS Project Gas Reserves and Commitments

In comparison, firm commitments for sales of NWS gas are estimated to be around 16.5 EJ, including gas required to meet domestic gas sales commitments, as set out in Table 4.10, and LNG sales commitments, as depicted in Figure 4.17. This is roughly equivalent to the extent of proven reserves that are presently developed for production.

The NWS Project participants expect that ongoing development of gas reserves will take place as necessary to meet market requirements and is understood to be considering an expansion of processing capacity to allow a substantial (circa 25%) increase in deliverability of gas for domestic market use. However, the availability and price of gas for new minerals developments in the south west coast region may be dependent upon factors including the following.

- Relative attractiveness of market opportunities

  There could be a trade-off between the value of gas in domestic markets and its value[87] in export markets. This trade-off will be influenced by the relative timing of the respective market opportunities and the extent, if any, to which gas reserves are constrained.

[87] The relative value of domestic versus LNG gas sales is investigated in the Attachment to this Section. All else being equal, LNG sales are arguably of higher value than domestic gas sales.

- Allocation of gas reserves

  Expansions of LNG sales commitments and/or investment in additional LNG infrastructure will require dedication of reserves, potentially limiting the availability of gas for domestic market use.

Purchaser	Contract Expiry	Quantity TJ/d
Alcoa	2020	175
Alinta	2010/12/20	105/90/60
BHP Billiton	2013	110
Edison Mission	2012	8
Hamersley Iron	2010	10
Robe River Iron	2005	5
Western Power	2026	~ 95

Table 4.10: NWS Gas Domestic Sales Commitments

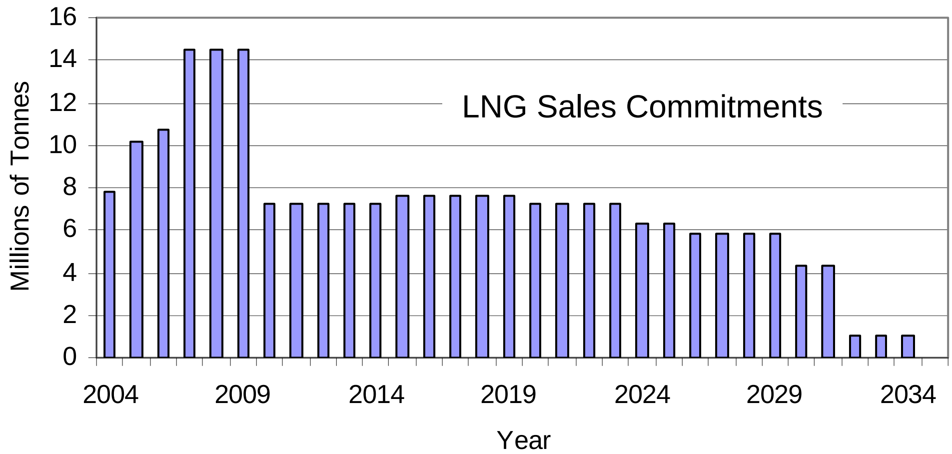

Figure 4.17: NWS Project LNG Sales Commitments

It is anticipated that the drop off of LNG sales that occurs in 2010 in Figure 4.17 (as a result of expiry of existing LNG sales contracts) will not, in practice, occur. It is likely that contract renewals, extensions or replacements may be negotiated, leading to a requirement for additional reserves dedication. To fully utilise the existing[88] LNG production facilities for the next 25 years (with some subsequent tapering-off of production to match contract commitments[89]) would require of the order of an additional 4.5 EJ of reserves to be committed. This alone is equivalent to the remaining balance of uncommitted, proven gas

[88] The existing trains are trains 1 to 4. Indications are that the potential might exist for construction of a fifth train to commence operation around 2008/09.
[89] Commitments for supply of LNG to Osaka gas run until 2034.

reserves. If construction of a fifth LNG train proceeds, a further 4.5 EJ of reserves might at least be required (giving a total additional LNG commitment of 9.0 EJ, shown as 'Potential LNG' in Figure 4.4), and requiring dedication of most of the present, probable reserves of the NWS Project.

A comprehensive 3D seismic programme is presently underway with the following, two-fold objective. First, improved definition of the extent of the known gas reservoirs may allow an upgrading of proven and probable gas reserves. Second, new exploration targets may be identified that, if successfully proven-up, could be produced through the NWS facilities.

In addition, the potential exists for gas from other permit areas to be developed and produced through the North West Shelf facilities[90].

On balance, these initiatives will probably ensure gas is available for supply to meet existing and expanded domestic market requirements. This being the case, it is conceivable that a large, base-load gas user may be able to purchase gas at a price below that applying for the wider market[91].

However, if significant alternative sources of gas supply are not developed there could be a tightening of gas supply to domestic markets leading to upward pressure on gas prices.

c) Gasfields Surrounding Varanus Island

While the Harriet and East Spar projects are separately owned and contracted, they are both operated by Apache Energy with processing and compression taking place on Varanus Island. For convenience they are, along with the John Brookes gasfield (presently being developed), considered together in this report.

The remaining proven reserves of the Harriet, East Spar, John Brookes and associated smaller fields (including undeveloped reservoirs[92] that could be produced via Varanus Island) total around 1.9 EJ, as depicted in Figure 4.18.

A further 0.4 EJ of probable reserves is likely to be available subject to reservoir performance. This excludes any probable reserves of the East Spar reservoir which has experienced earlier than expected water breakthrough[93] (that is,

[90] For example, gas from the recently discovered Wheatstone reservoir, 70 kilometres southwest of Goodwyn, could conceivably be produced through the North West Shelf project facilities.
[91] For example, it is understood the Methanex project that was proposed for the Burrup secured gas at prices that allowed methanol production to be economic but that the project failed for reasons other than gas price.
[92] Although ownership arrangements differ, the Reindeer reservoir has been included in this category on the basis that it could be produced via Varanus Island. Development of the additional reserves of gas is expected to proceed as required to meet gas supply commitments.
[93] Santos, a participant in the East Spar project, announced on 23 July 2004 that it had experienced problems with earlier than expected water breakthrough at the East Spar gasfield. Information regarding the extent of the problem is not available.

production of water from gas wells which restricts and can ultimately prevent gas production).

The proponents of the Varanus Island based gas projects also have plans to undertake gas oriented exploration. Prospects for the identification of further reserves of gas are considered to be good.

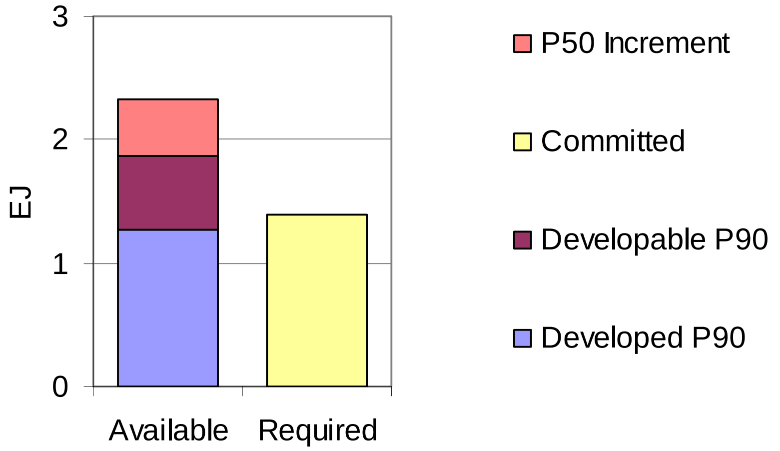

Figure 4.18: Varanus Island Gas Reserves and Commitments

Firm commitments for supply of gas reserves produced via Varanus Island are estimated to be of the order of 1.4 EJ which means gas could be available for supply under new or extended gas sales arrangements. However, it is unlikely that gas would be offered at prices that would facilitate new minerals developments in the south west coast region since:

- increased water depths and/or distances from Varanus Island lead might lead to increased reservoir development costs; and
- as is evident from Table 4.10 and 4.11, in the short to medium term there will be numerous opportunities to contract for supply of gas to existing users whose gas purchase arrangements are due for renewal.

Purchaser	Contract Expiry	Quantity TJ/d
Alinta	2014	23
BHP Billiton	2006	7
Origin Energy	2014	13
Centaur	n/a	5
Epic Energy	2006	3
Great Central Mines	-	2
Newmont Gold	2006	15
Plutonic	-	3
South West Cogen	2020 est	32
Wesfarmers	2020 est	22
WMC	2006	37
Wiluna Mines	2007	2
Other Unidentified	-	90
Telfer	2020-2030	22
Burrup Fertilisers	2029	80
EDL	2025	5

Table 4.11: Gas Sales Commitments for Gas Produced Via Varanus

As for the North West Shelf project, there may be upward pressure on the price of gas resources supplied via Varanus Island. It is estimated gas prices tending towards $2.50/GJ[94] could be sought in the medium term as development of more remote reserves of gas becomes necessary.

d) Gorgon Project

The Gorgon gasfield is one of the largest ever discovered in Australia. It is located about 130 kilometres offshore from the WA coast in water depths ranging between 120 and 300 metres. The probable resources of the Gorgon and surrounding fields (together comprising the Gorgon Project) total 28 EJ.

[94] This figure reflects information from industry sources confirmed through independent modelling of reservoir development costs.

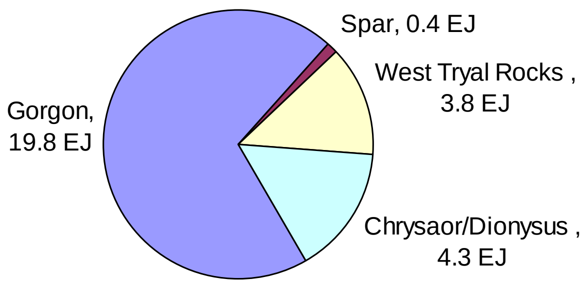

Figure 4.19: Gorgon Project Probable Resources

Development of the Gorgon and surrounding gasfields could pave the way for future development of the Greater Gorgon area, which includes gasfields located offshore from Gorgon in water depths exceeding 1,000 metres. The probable resources of the combined projects exceed 55 EJ, as illustrated in Figure 4.20.

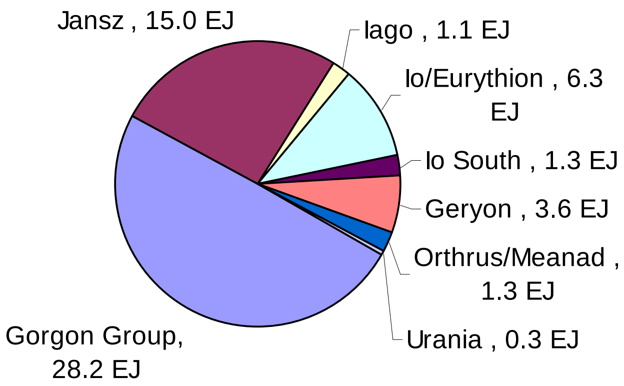

Figure 4.20: Combined Gorgon and Greater Gorgon Probable Resources

Development of the Gorgon gasfields is dependent upon commitments being secured for the sale of LNG in quantities to achieve commerciality. With reference to Attachment 1 to this Section, there are reasonable prospects that a sufficient level of LNG sales commitments will be achieved and that the Gorgon project may commence production around 2010. A go-ahead of the project will pave the way for supply of gas for domestic purposes, and 2,000 PJ (ie, 2 EJ) of gas has been earmarked for this purpose. The Gorgon project proponents are required (under the terms of the State Agreement) to actively seek domestic markets. Expansion of LNG sales will not be allowed until domestic sales are established (or their lack of viability demonstrated).

A review of Gorgon gas pricing considerations is presented in Appendix 5. It is estimated there may be an opportunity for a large, base-load gas user that, through its gas purchase commitment, underwrites [95] development of domgas infrastructure, to procure gas at a price below that prevailing for the broader market place. The level of price will depend upon a range of factors but a price of the order of $1.85/GJ (representing the lower end of possible prices) may be achievable. This price level would reflect the foundation nature of the large load and the capital and operating efficiencies of a base-load operation. It is not expected this level of price would be generally available.

e) Other Carnarvon Basin Sources

Although there are numerous, other prospective sources of gas within the Carnarvon Basin it is unlikely, for the following reasons, that gas would be available from them at prices below present market levels (estimated to be of the order of $2.15/GJ to $2.30/GJ, excluding transmission costs).

The economics of deep-water, offshore projects will most likely be dependent upon the following.

- If the resource is to be developed on a stand-alone basis, large foundation sales arrangements, probably for LNG, will be required to underwrite project development costs. However, unlike Gorgon, other major gas resources of the Carnarvon Basin may not have the level of gas reserves that would justify complementary sales of gas to domestic markets.
- In some cases, the use of floating production, storage and offtake ('FPSO') techniques may contribute to project economics, but would mean gas is not available for onshore use.
- Development of gas resources for delivery through existing infrastructure, such as that of the North West Shelf project, may in some case be an option. In consideration of project development costs, infrastructure capacity constraints and access costs, and LNG- domestic gas trade-offs, it is not envisaged developments of this nature will allow delivery of gas at prices below prevailing levels.

The opportunity might also exist to acquire supplies of gas from new developments of small, near-shore reservoirs, such as Macedon, and/or in the form of associated gas from oil production projects, such as Enfield. The economics of new project developments will be affected by factors including the size of the gas resource, its distance from existing infrastructure (such as the Tubridgi Project) through which gas might be deliverable, and the presence of other accumulations of gas that might be developed simultaneously (so as to

[95] The gas requirement of a large user could represent a foundation load of sufficient size to underwrite investment in domgas infrastructure.

achieve better economies). There are no development prospects that presently hold-out the prospect of proving low-cost supplies of gas.

Conceptually, development of the Macedon field would be by means of sub-sea well completions with a multi-phase[96] flowline to a location onshore, near Tubridgi. The flowline would be large in diameter (notionally 600 mm) to avoid the need for expensive, offshore compression. It is estimated that development costs for a project of this nature would approach $300 million, including onshore compression. Indications are[97] that gas prices approaching $2.50/GJ (delivered into the DBNGP), could be required for the Macedon project to be viable at a gas production rate of the order of 150 TJ/d initially, declining progressively over the life of the project.

Prospects may, from time to time arise for associated gas from oil production projects to be delivered for domestic market use as an alternative to other acceptable means of handling the gas, such as reinjection. Economic considerations relating to production of associated gas might typically take into account the avoided costs of such alternatives.

Associated gas lends itself to opportunistic purchase by large energy consumers that can take the gas as part of a gas supply portfolio.

f) Browse and Bonaparte Basins

The gas reserves of the Browse and Bonaparte Basins may be sufficient to support further development of LNG export markets or might in some cases be developable to supply onshore markets (eg, development of Blacktip to supply gas to Gove Alumina in the Northern Territory). However, owing to the remote location of these resources, gas is unlikely to be available from them at prices that are competitive with gas from Carnarvon Basin sources.

4.2.5 Gas Transmission

The major prospective source of gas for use in mineral related developments in the south west coast region is the Gorgon project. Gas from the Gorgon project will need to be delivered to the south west of the state through the DBNGP, or through a new pipeline that bypasses the DBNGP.

The average capacity of the DBNGP, as it is currently configured, is around 220 PJ/a (600 TJ/d) although, as shown in Figure 4.21, the actual capacity of the pipeline is higher during winter months when the power output of gas compressors on the pipeline is higher[98]. At present, all of the available capacity of the DBNGP is contracted.

[96] Combined gas, water and condensate (if any is present).
[97] On the basis of information from industry sources backed by modelling of the economics of the Macedon project.
[98] Lower atmospheric temperatures during winter mean the power output of gas turbines driving compressors on the DBNGP is higher during winter. More gas can therefore be moved through the pipeline.

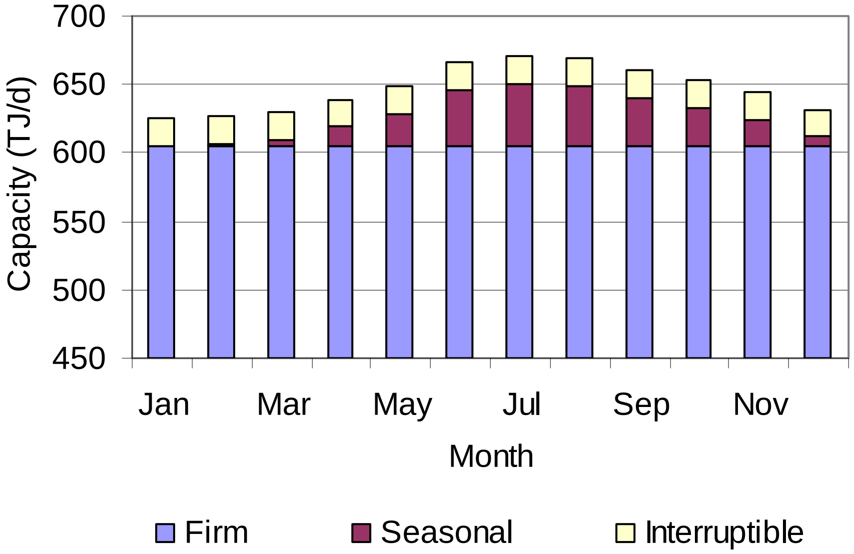

Figure 4.21: DBNGP Capacity by Month[99]

It will be necessary for the capacity of the DBNGP to be expanded if it is to be used to deliver gas to the south west for new mineral related developments.

There are two ways in which the capacity of a gas pipeline can be expanded to meet increases in the requirement for transportation of gas through it. First, compression facilities can installed along the length of the pipeline to maintain gas pressure within the pipeline and allow additional gas to be transported. Second, the pipeline can be looped (through the progressive addition of a second pipeline alongside the original pipeline).

The DBNGP is already fully compressed, although it does not have spare compression equipment at each compressor station. This means the full capacity of the pipeline is not always available. Capacity that is dependent upon the availability of a single compressor is interruptible (and is depicted as 'interruptible' in Figure 4.21).

While the installation of some additional spare compression would lead to an increase in the firm capacity of the DBNGP[100], to increase the capacity of the DBNGP it will be necessary to install pipeline loops downstream of each existing compressor station. The greater the length of loop line installed downstream of each compressor station, the greater the capacity increase achievable.

[99] The capacity graph is replicated from information provided in the Access Arrangement Information for the DBNGP.

[100] The installation of additional compression equipment to achieve improved reliability of gas transportation through the DBNGP is an essential first step to be taken prior to looping of the pipeline.

On the basis that the DBNGP is already fully compressed, an indicative ongoing capacity expansion programme for the DBNGP could be expected to incorporate the following steps[101], as depicted in Figure 4.22.

- first, progressive looping of the pipeline;
- second, installation of additional compression power, in order to utilise the full capability of the loop line. At this stage the capacity of the DBNGP will be at least doubled; and
- potentially, isolation of the loop line from the original line, and re-rating of the loop line to operate at, say, 15.3 MPa instead of 8.48 MPa.

Isolation of the loop line from the original line also presents the opportunity to deliver differing qualities of gas to the south west coast region. Large industrial gas consumers might be able to use gas of a quality that is not suitable for distribution system use. The reduced processing requirement could allow a net reduction in the delivered price of gas for those applications.

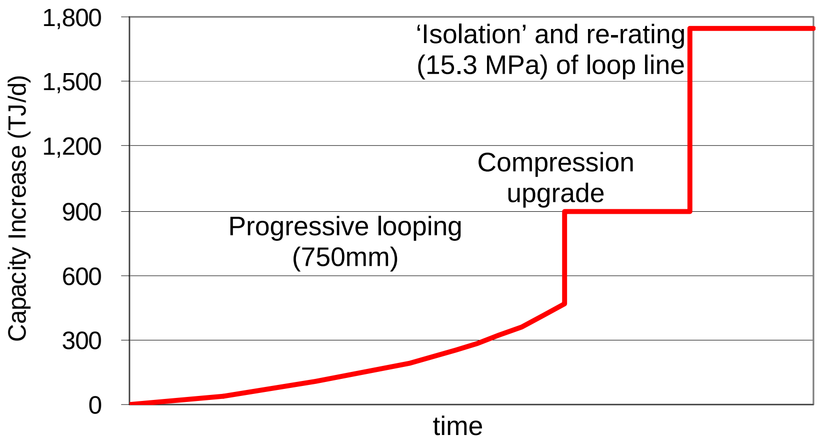

Figure 4.22: Hypothetical DBNGP Expansion Programme

Expansion of the capacity of the DBNGP should lead to tariff outcomes that are more attractive than can be achieved through construction of a new pipeline. This is because capital expenditure can be staged to match market requirements although, in marginal terms, the greatest benefits of a looping programme are realised on completion of the programme. On the basis of industry indicative capital costs, for a looping programme that is designed to increase the full-haul[102] capacity of the DBNGP by 300 TJ/d, marginal tariffs[103] for the additional capacity might be of the order of $0.90/GJ (with indexation at 50% CPI).

[101] On the basis that the present compression redundancy issues are first addressed.
[102] 'Full-haul' refers to transportation of gas along the full length of the DBNGP.
[103] The tariff estimation has been done on the basis of a rate of return of 8%.

For comparative purposes, as an alternative to expansion of the capacity of the DBNGP the option could exist to construct new pipeline capacity to bypass the DBNGP. A nominal 600 mm diameter pipeline rated at 15.3 MPa would have capacity in free-flow mode (ie, no intermediated compressors installed) to comfortably deliver 100 PJ/a of gas to the south west of the state. With compression installed the capacity of the pipeline could be more than doubled. In order of magnitude terms, for pipeline throughput commitments of 300 TJ/d initially, growing at 3% per annum to 430 TJ/d, an effective, marginal gas transportation tariff (ie, for the incremental capacity) of better than $0.85/GJ could be achievable[104]. A proportionate reduction in average tariffs could therefore be expected. Further expansion would allow further economies to be realised.

Tariffs for the DBNGP are presently subject to regulatory and appeals[105] processes. It is likely however that tariff levels will not exceed $1.00/GJ (as at 1 January 2000, at 100% load factor). Allowing for indexation (at 67% CPI) the estimated tariff level for 2004 is $1.06/GJ. At a load factor[106] of 90%, which is typical of what may be achievable by a minerals processing operation, the effective gas transportation tariff is $1.17/GJ.

It is clearly desirable that the outcome of the present regulatory and appeals processes not prevent a flow on to gas users of the marginal benefits realisable as the capacity of the DBNGP is expanded.

In relation to gas supply for certain minerals development opportunities, it is understood[107] that Alcoa has a de-facto equity position in relation to the DBNGP and that tariffs paid by it for use of the pipeline are established to cover the cost of any capital spent on the pipeline plus a profit margin to the operator and the operating expenses pro-rated to usage. Reflecting this, historic tariffs paid by Alcoa have evidently included a significant premium (reportedly as much as 40%) above those paid by other users of the pipeline.

It might be expected therefore that pipeline expansion economies should, at least, be available to Alcoa for gas transported to meet its requirements.

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[104] This tariff is based upon indexation to reflect movements in the Consumer Price Index, and assumes a nominal post-tax rate of return of 7%, which is marginally higher than the allowable return for the DBNGP as determined by the Western Australian Regulator.

[105] Applications for review of the DBNGP tariff decision, made by the Western Australian Independent Gas Pipelines Access Regulator, have been lodged with the Western Australian Gas Review Board. The proceedings have yet to be progressed.

[106] The load factor is the ratio of a gas user's average gas requirement to its peak requirement. Pipeline capacity reserved and paid for to meet peak requirements is not fully utilised, hence the actual cost of gas transport is higher than the quoted tariff.

[107] Refer to Alcoa of Australia's submission of 15 September 2003 to the Productivity Commission' Review of the Gas Access Regime, which is available electronically.

4.2.6 Other Considerations

Indicative, point-of-burn carbon dioxide emissions for natural gas are depicted in Figure 4.23. Information relating to the financial impact of possible carbon taxes is provided in Section 7 of this Report.

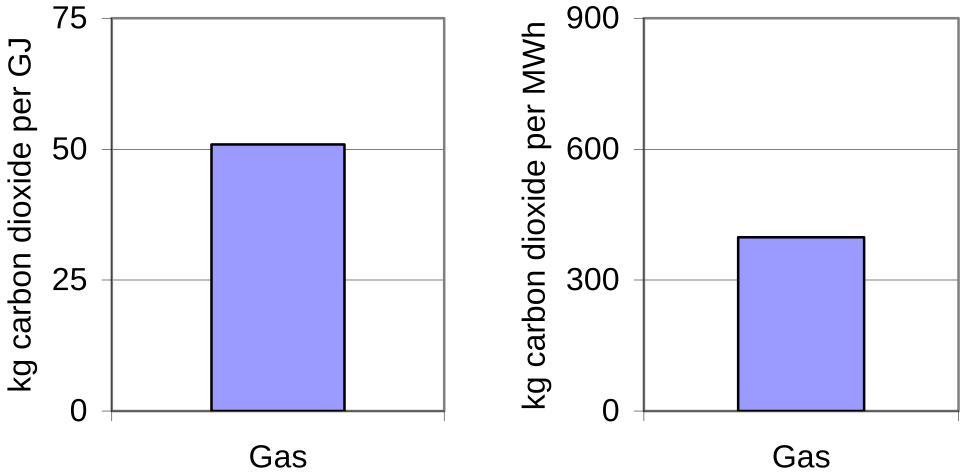

Figure 4.23: Carbon Dioxide Produced From Combustion of Natural Gas

4.2.7 Potential Delivered Gas Costs

Table 4.12 provides an indication of the quantities and possible delivered prices of gas that might be available for use in the south west coast region.

Gas Source	Price ($/GJ)	Quantity (TJ/d)
Gorgon project and possible NWS (for a large, base-load offtake)	2.60 - 3.05	200+
Carnarvon Basin Production	2.90 - 3.70	> 100
Macedon and similar developments	3.25 - 3.70	~ 100
Perth Basin generally	< 3.00	Limited
Perth Basin - Major Discovery	2.50	100 +

Table 4.12: Availability and Delivered Price of Gas

The following considerations are important in understanding the information set out in Table 4.12.

- In the case of gas from Carnarvon Basin sources, the tabulated prices include a range of allowances (from $0.75/GJ to $1.20/GJ) for gas transportation. This reflects possible outcomes in relation to flow-on of pipeline expansion benefits and/or bypass pipeline initiatives

- In addition to the effect of variations in the cost of gas transportation, the delivered cost of gas from existing Carnarvon Basin sources takes into account possible competitive pressures. That is, to achieve prices at the lower end of the range will be dependent upon timely development of new sources of gas supply so as to ensure continued competition between gas suppliers. The higher end of the price range may eventuate if there is a tightening of gas supply, leading to upward pressure on gas prices.

- The price indicated for the Gorgon project is envisaged as being available to a large, base-load gas user that provides a foundation load sufficient to allow the domestic phase of the Gorgon project to proceed. Subject to the availability of gas reserves, the potential should also exist for gas to be sourced on similar terms from the North West Shelf project .

- Gas from the Perth Basin is indicated as being available in modest quantities at price levels that are attractive relative to the price of gas from the Carnarvon Basin. However, it is recognised that, should a major Perth Basin gas resource be discovered and/or commercialised, gas is likely to be available at prices that could further stimulate market development.

The forecast availability and price of gas that might be available for use in the south west coast region, as set out in Table 4.12, is illustrated in Figure 4.23.

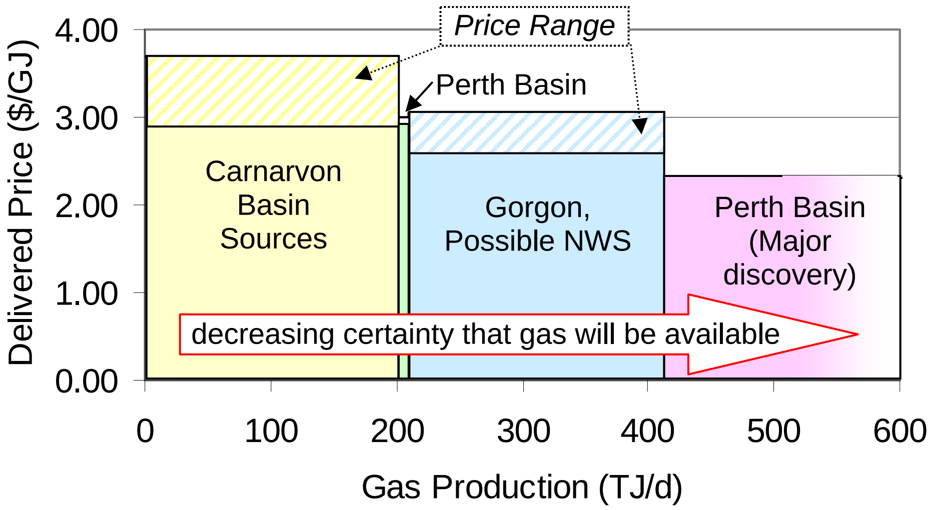

Figure 4.23: Availability and Delivered Cost of Additional Gas

Technical developments (for example, improved methods for production of gas from tight formations) may change the relative economics or affect the viability of individual projects but, for the foreseeable future, are unlikely to alter the observations set out above.

4.3 Electricity

4.3.1 Key Observations

a) Scope for Improved Utilisation of Base-load Generation

In view of the significant seasonal and daily variability of electricity demand in Western Australia, Western Power Corporation's base-load generating equipment is not fully utilised. Western Power could be particularly well placed to supply electricity on competitive terms to new base load applications, particularly if they are interruptible.

b) Electricity Transmission Cost Considerations

Electricity transmission costs represent a potentially significant portion of the delivered cost of electricity, particularly toward the extremities of the South West Interconnected System.

On-site generation of electricity (if possible) is therefore likely to yield the lowest electricity cost for new or expanded electricity-intensive minerals developments. Uncertainty regarding future transmission use-of-system charges and, in particular, loss factors reinforce this conclusion.

c) Potential Electricity Prices

On the basis of potential coal and gas price levels, electricity prices of around 4.0 c/kWh, +/- 0.3 c/kWh, would appear to be achievable. This figure does not include transmission costs or back-up/spinning reserve charges, if applicable.

d) Alcoa Well Placed

Alcoa has the opportunity to reconfigure its cogeneration operations to generate additional electricity at particularly attractive level of cost in the Western Australian context. Generation costs below 3.0 c/kWh are potentially achievable.

4.3.2 Industry Overview

The south west coast region is serviced by an interconnected electricity system, referred to as the South West Interconnected System ('SWIS'). The SWIS serves some 830,000 customers, most of whom are in the Perth metropolitan area. A number of larger mining and mineral processing operations are connected to the SWIS but generate their own electricity in on-site facilities.

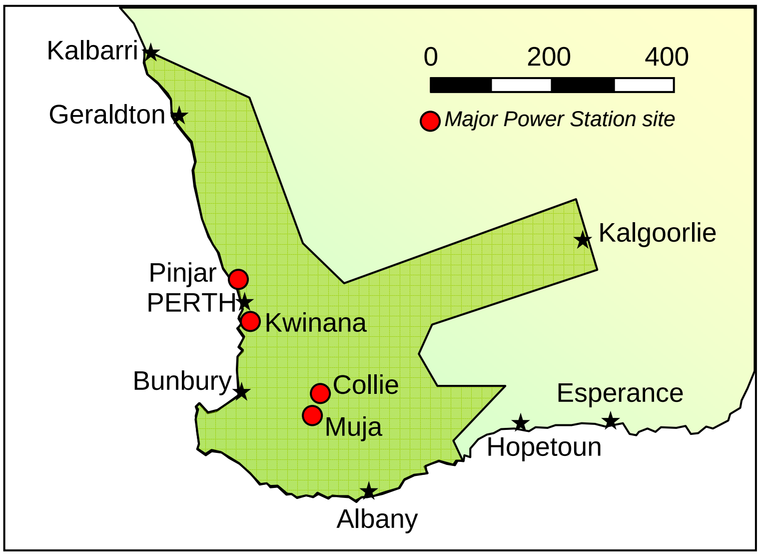

Figure 4.24 South West Interconnected Electricity System

The SWIS is owned and operated by Western Power Corporation ('WPC'). All large users of electricity have open-access to the transmission system[108] (allowing them to purchase their requirements from electricity generators of their choice). For the purpose of this Report, the SWIS is effectively open-access.

Generating capacity presently connected to the SWIS is as set out in Table 4.13[109]. WPC is the major generator and supplier of electricity to the SWIS. WPC is presently managing a process to procure capacity and electrical energy from a private, base-load power station to be constructed to supply the SWIS for a period of 25 years commencing December 2008. The power station, to be in the size range 300 MW to 330 MW, will be fuelled by either coal or gas.

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[108] At present, users with an annual electricity consumption exceeding 300 MWh (ie, an average load of just over 34 kW) have access to the distribution system. The threshold size will fall to 50 MWh (5.7 kW average) on 1 January 2005. No programme for further opening up of access has yet been promulgated.

[109] The table includes generating facilities of size greater than 30MW. The table includes capacity presently being developed (namely the Transfield and Alinta Limited facilities) but does not include the proposed new private base-load power station.

Generator	Size (MW)	Type	Fuel
Western Power			
Muja	1040	Steam	Coal
Collie	330	Steam	Coal
Kwinana	900	Steam	Gas or Oil[110]
Cockburn	240	Combined Cycle	Gas
Pinjar	586	Open Cycle GT	Gas
Mungarra	112	Open Cycle GT	Gas
Kalgoorlie	60	Open Cycle GT	Distillate
Alcoa			
Wagerup	98	Cogeneration	Gas
Pinjarra	95	Cogeneration	Gas or Oil
Kwinana	61	Cogeneration	Gas
Worsley	128	Cogeneration	Coal
Mission Energy	120	Cogeneration	Gas or LPG
South West JV	120	Cogeneration	Gas
TiWest Joint Venture	36	Cogeneration	Gas
Goldfields Power	110	Open Cycle GT	Gas
Southern Cross	76	Open Cycle GT	Gas
Under Construction			
Transfield	260	Open Cycle GT	Gas or Distillate
Alinta	140	Cogeneration	Gas

Table 4.13: Electricity Generating Capacity on the SWIS

The profile of the combined electrical loads connected to the SWIS is characterised by significant seasonal and daily variability[111]. The system peak electricity demand occurs in summer, with a secondary peak in winter, for only a small number of hours and days per year.

As a result:

- considerable investment has been, and will continue to be, made in generating capacity to ensure peak demands can be reliably met; and
- the low, overnight levels of electricity demand tend to limit the level of capacity factor (ie, plant utilisation) achievable for base load generating plant.

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[110] The Kwinana Power Station can, in part, be fuelled by coal. However, environmental constraints mean this fuelling option is likely to be short-lived.
[111] The variability is evidenced by the system load factor, which is of the order of 50%.

4.3.3 Opportunities for Expansion

Although there is a wide range of options available for generation of electricity to meet the requirements of new or expanded minerals related developments, for analysis they may be conveniently categorised according to the interruptibility of the load to be supplied and the location of the generating facility, as illustrated in Table 4.14.

	Interruptible Load	
Power Station Location	no	yes
Integrated with WPC System	*Option 1*	
Stand-alone	*Option 2*	

Table 4.14: Indicative Electricity Generation Options

For a load that is not interruptible it is necessary to install, or have access to, back-up electricity generation facilities. For both options, a variety of generating technologies and fuel types are available. In this section, consideration is given to the use of coal or gas for electricity generation. Alternative technologies are addressed in Section 4.4.

In addition to the considerations referred to in Table 4.14, electricity generation costs are also affected by factors such as return requirement, project life and load factor. For this Study a load factor of 90%, reflecting what is routinely achievable with mining and mineral processing operations, and a return requirement of 8% over 20 years have been assumed.

<u>Option 1: Generation of Electricity as part of Integrated System</u>

Generation of electricity as part WPC's integrated system has potential advantages in that:

- the overall capacity factor[112] of the system will be improved; and
- a whole-of-system approach can be adopted to determine not only an optimal power station expansion programme (including plant type and timing) but also an optimised plant despatch regime.

For small to medium incremental loads (up to a total of perhaps several hundred megawatts) it is important that these considerations be taken into account. To supply such loads WPC might only need to install peaking capacity, for intermittent use during peak periods, since the majority of the additional electrical load might be supplied from existing base-load generating plant that is, otherwise, not fully utilised.

[112] The capacity factor is a measure of the level utilisation of generating facilities on the system. For each generator within the system the capacity factor is the average quantity of electricity generated divided by the maximum quantity that could be generated.

Using a computer model developed to approximate the likely operation of the WPC generation system, the estimated cost of generating additional electricity to meet small to medium load increments is as set out in Table 4.15[113]. The Table does not take electricity transmission costs into account. These are addressed in Section 4.3.3.

Item	Amount (c/kWh)
Fuel: - coal (10%) - gas, open cycle or Kwinana (35%) - gas, combined cycle (55%) estimated weighted average fuel cost	 1.40 3.42 2.27 2.59
Incremental Operations and Maintenance	0.42
Capital Servicing (peaking capacity)	0.77
Total Cost for New Non-interruptible load	3.78

Table 4.15: Marginal Cost of Electricity Generation

Significantly, if the incremental load to be supplied is interruptible[114] the installation of peaking capacity (as provided for in Table 4.15) might not be required. The marginal cost of electricity might then fall to around 3.0 c/kWh. Provided electricity selling prices in excess of this figure are achieved the improved utilisation of existing base load capacity would deliver a net benefit to WPC. For the purpose of this report it is assumed a figure of the order of 3.5 c/kWh (excluding electricity transmission) might be achievable.

For loads that are not interruptible the cost set out in Table 4.15, which is exclusive of any margin or return on capital investment, is no more attractive than costs that are likely to be achievable on a stand-alone basis (as reviewed below). This is because of the predicted dependence upon open-cycle and gas fired steam cycle plant for a sizeable portion of the incremental electricity generation.

For large incremental loads more significant, base-load plant additions will probably be required and the cost of additional electricity will tend towards that of stand-alone generation, which is addressed below.

<u>Option 2: Stand-alone Electricity Generation</u>

Stand-alone electricity generation facilities could be developed on, or adjacent to, the site of the electrical load to be supplied or could be developed at a

[113] Fuel costs assumed in development of the table are as used in development of Table 4.16. These costs are likely to be lower than the level of costs presently achieved by WPC.

[114] Interruptible in this context refers to a load to which the supply of electricity can be interrupted in the event that WPC has insufficient generating capacity available to supply its total electricity demand.

separate location, in which case electricity transmission costs will also be incurred. In either case, if the electrical load is not interruptible there is also a need to take back-up generation requirements into account.

Details of the electricity generation options that are of potential interest for this Report are summarised in Table 4.16. The tabulated figures are applicable for large loads only. For smaller large (indicatively lees than 100 MW) supply by means of Option 1 (above) is appropriate.

Item	Gas, Open Cycle GT	Gas, Combined Cycle GT	Coal, Steam Cycle	Gas, Cogen[115] (Alcoa)
Capital cost ($/kW)[116]	600	1000	1450	900
Efficiency[117]	30%	46%	38%	75%
Operating Cost (c/kWh)[118]	0.4	0.5	0.8	0.4
Fuel Cost (c/kWh)[119]	3.42	2.27	1.40	1.25
Capital Servicing[120] (c/kWh)	0.77	1.28	1.85	1.15
Electricity Cost (c/kWh)	4.59	4.05	4.05	3.00[121]

Table 4.16: Principal Electricity Generation Options

The electricity cost estimates set out in Table 4.16 do not make any provision for the cost of back-up generation or other services[122], should they be required. The cost of back-up will be dependent upon factors including the size of generating unit to be backed-up relative to the size of the electrical load to be supplied. There is a published 'Standby Generation Capacity Price' for the

[115] Cogeneration (cogen) involves the coincident generation of electricity and supply of heat. High levels of efficiency can be achieved, particularly when the latent heat contained within steam can be recovered.
[116] The tabulated capital costs are for a greenfields development and are, therefore, inclusive of owner's costs, such as land acquisition, permitting and approvals, etc. Lower figures (which do not include these costs) are often quoted.
[117] The efficiency figures are expressed in terms of electricity sent-out (ie, available for sale) relative to the higher heating value (HHV) of the fuel used. In the case of cogeneration, the efficiency figure includes both electricity and steam sent-out.
[118] There are fixed and variable components to the operating and maintenance costs.
[119] Fuel prices of $2.90/GJ for gas open cycle and combined cycle (based upon the low end of potential delivered gas prices), $2.60/GJ for gas cogeneration (based upon what may be achievable by Alcoa) and $1.50/GJ for coal have been used.
[120] The tabulated figures are based upon an after-tax, nominal project return of 8% over 20 years and assume a capacity factor of 90%. No specific provision has been made for recurring overheads (such as administrative costs or insurance).
[121] The electricity cost is dependent upon the energy balance of the cogeneration facility (ie, relativity of electricity versus steam production) and the quality and value of the steam produced. The quoted electricity tariff is based upon steam with a useful energy content of 3GJ/t and a value of $9/t.
[122] Other services are referred to as ancillary services in the terms and conditions for access to the SWIS. They include the provision of spinning reserve services.

SWIS system that is equivalent to around 0.2 c/kWh at a load factor of 90%. However, back-up costs for a large load (like an aluminium smelter), supplied by a number of individual generating units with open-cycle capacity installed on-site for back-up purposes, could be less than 0.1 c/kWh.

The sensitivities of the estimated electricity generation costs to variations in input assumptions are demonstrated in Figures 4.25 and 4.26 for the gas (combined cycle) and coal (steam cycle) options, respectively.

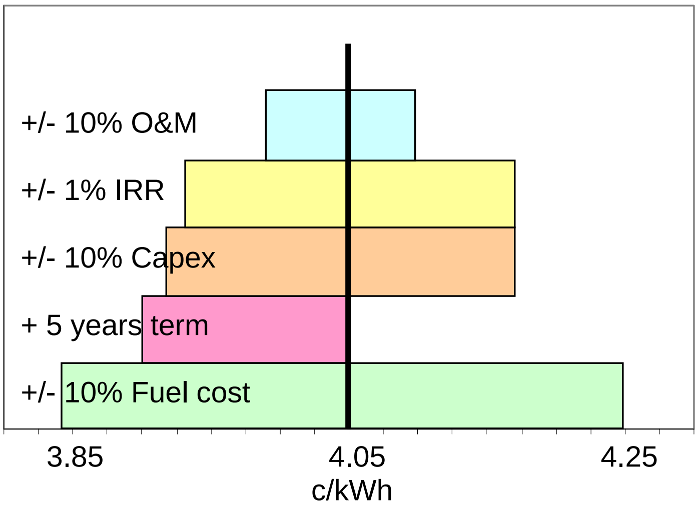


Figure 4.25: Electricity Cost Sensitivities – Gas Combined Cycle

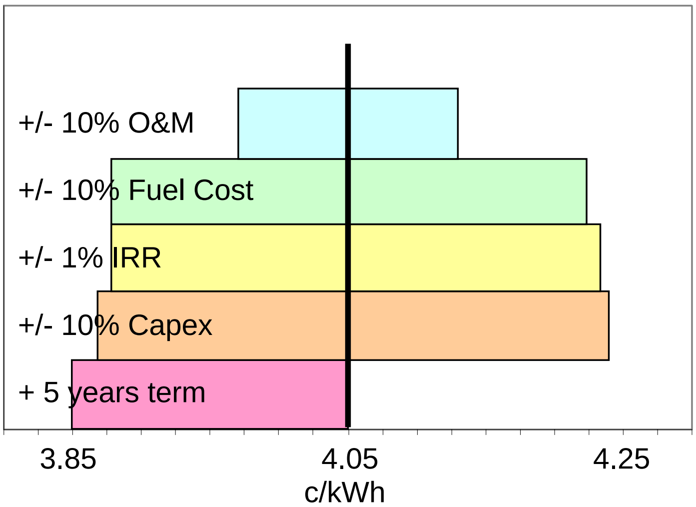
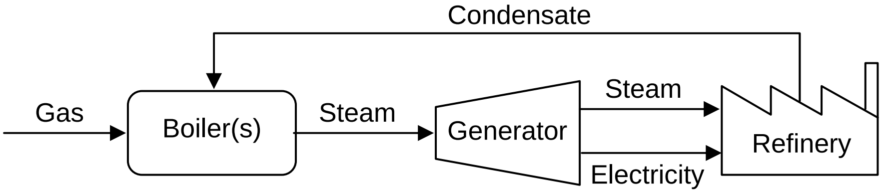


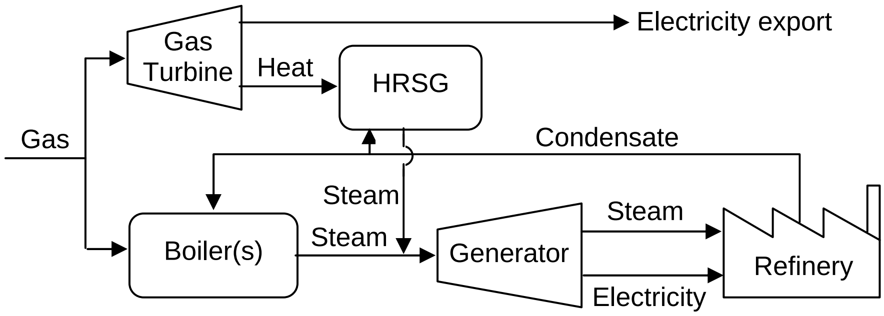
Figure 4.26: Electricity Cost Sensitivities – Coal, Steam Cycle

The cost of electricity from a combined cycle gas power station exhibits considerable sensitivity to changes in fuel costs, while the coal fired steam cycle plant shows sensitivity to capital related factors (eg, amortisation period and actual capital cost). If a coal fired power station investment decision is based upon a 25 year project life, required tariffs would fall by 5% to 3.85 c/kWh.

The potential for cogeneration of electricity is particularly important in the case of Alcoa. Alcoa's alumina refineries in the southwest of the state already operate on a cogeneration basis[123], achieving efficiencies of the order of 80%. The opportunity exists, and is already being developed by Alinta Limited ('Alinta') through arrangements with Alcoa, for reconfiguration of the Alcoa operation to increase electricity production. In essence, the reconfiguration involves the installation of gas turbines to generate electricity, with the waste heat from the turbines then used to make steam (by means of heat recovery steam generators) for use in the refinery process. This is illustrated conceptually in Figure 4.27.



Existing Operation



Reconfigured Operation

Figure 4.27: Alcoa Reconfiguration to Increase Electricity Output

In carrying out the reconfiguration, the number of existing boilers to be kept in operation will be reduced (as steam will instead be produced by the heat recovery steam generators). This offset means the marginal operating and maintenance costs of the additional equipment may be lower than if it was truly stand-alone. In addition, since the new facilities are added to an existing site that has, among other things, connections to the SWIS, the capital costs of the development can be expected to be lower than they would be for a stand alone, greenfields project.

[123] Gas is used by Alcoa to make steam. The steam is used initially to generate electricity and then it is used in the alumina refinery process.

Having regard for the factors set out above and in section 4.2, it is estimated that Alcoa may be uniquely placed to generate electricity for marginal costs of the order of 3.0 c/kWh $^{+}/_{-}$ 10%[124].

4.3.4 Electricity Transmission

Electricity transmission 'use-of-system' charges are based upon supply voltage, the location of the load and the location of the electricity supply source. The various cost components are subject to annual review. Figures used in this report are based upon those published by WPC for 2004/05.

For loads of the size and voltage (66 kV or greater) contemplated in the Report, the cost of moving electricity through the transmission system to a load from a generator is the sum of exit point and entry point charges. In some cases (for example, transmission of electricity to the north of Perth) the availability of capacity in the SWIS may be limited. This matter is addressed further in Section 7.

Estimates of the exit point charges are set out in Table 4.17 and estimates of the entry point charges are set out in Table 4.18.

Location of Load	Control System Service Fee	Use of System Charge ($/kW)	Common Service Charge	Total cost at 90% L.F. (c/kWh)	Loss Factor (Adj.)
Albany	$3.73 per kW of demand	41.62	$14.93 per kW of demand	0.76	4.9%
Kemerton		7.50 (est)		0.33	1.0%
Kwinana		4.00 - 7.00		0.29 - 0.33	4.1%
Northam		27.39		0.58	7.5%
Eneabba		27.82		0.59	16.8%
Geraldton		33.52		0.66	21.5%

Table 4.17: Estimated Exit Point Charges

For many exit point locations, particularly those to the north of Perth, the value of electricity losses[125] can be considerably in excess of the total cost of using the transmission system.

[124] The electricity price achievable by Alcoa will of course depend upon the gas price achievable (in turn dependent upon both gas purchase and gas transportation costs) as well as capital and O&M credits identifiable through reconfiguration of its existing operations, the level of efficiency ultimately achievable and the value of steam produced.

[125] To compensate for transmission system losses, more electricity must be supplied into the system than is delivered from it. The cost of the losses referred to here is the cost of purchasing the additional electricity.

Generator Location	Connection Charge	Use of System Charge ($/kW)	Total Cost at 90% L.F. (c/kWh)	Loss Factor (Adj.)
Collie	Assumed [126] $1,500 pa per MW	8.76	0.13	0%
Eneabba		1.75 (est)	0.04	16.8%
Kwinana		5.23	0.09	3.7%

Table 4.18: Estimated Entry Point Charges

In addition to the charges set out in Table 4.18, generators supplying electricity into the SWIS are required to pay a spinning reserve charge, The cost of spinning reserve varies depending upon the size of load to be serviced but, for indicative purposes, a figure of 0.1 c/kWh is reasonable. Self-generators (ie, that are not connected to the SWIS) will not have to pay spinning reserve charges.

Loss factors published by WPC show the system losses at any point relative to the Muja Power Station reference point (where the loss factor is 1). The figures set out in Tables 4.17 and 4.18 have been adjusted to show losses as a percentage. The high loss factor applying to entry points in the Eneabba locality means that 'credits' (equivalent to losses that are avoided) will be received for electricity delivered into the transmission system in that locality. That is, for each unit of electricity entering the system, 1.168 units will effectively be available for delivery, although the exit point loss factor must also be taken into account.

The net costs of using the SWIS are, for a range of indicative entry and exit points, presented in Table 4.19 together with net loss factors.

[126] On the basis of charges quoted for existing power stations and having regard for the size of those power stations, the tabulated estimate of the connection charge has been interpolated.

Tariff c/kWh (loss %)		Electricity Source (location)		
		Collie	Eneabba	Kwinana
Load	Albany	0.89 (4.9%)	0.79 (-11.9%)	0.85 (1.2%)
	Kemerton	0.46 (1.0%)	0.37 (-15.8%)	0.42 (-2.7%)
	Kwinana	0.44 (4.1%)	0.35 (-12.7%)	0.40 (0.4%)
	Northam	0.71 (7.5%)	0.62 (-9.3%)	0.67 (3.8%)
	Eneabba	0.72 (16.8%)	0.63 (0.0%)	0.68 (13.1%)
	Geraldton	0.79 (21.5%)	0.70 (4.7%)	0.75 (17.8%)

Table 4.19: Overall Costs of Using SWIS

For locations toward the extremities of the SWIS, electricity transmission costs and losses will represent a not insignificant portion of the cost of electricity.

In the case of WPC, which has power stations at a number of locations, the cost of using the SWIS will be dependent upon the mix (and hence location) of plant that is operated to supply a particular load.

Whilst the tabulated values are based upon information current at the time of this Report, should new mining, mineral processing or other developments proceed and, as a result, materially alter the performance of the electricity transmission system, adjustment of published charges and loss factors will follow. For example, the development of a power station at Eneabba could be expected to lead to a marked reduction in loss factors for the Eneabba and surrounding areas (including Geraldton).

4.3.5 Delivered Electricity Costs

Having regard for the information set out in Sections 4.3.2 and 4.3.3, indicative prices at which electricity might be available at various locations, having regard also for the source of the electricity, are set out in Table 4.20. For the purpose of Table 4.20, stand-alone electricity generating costs as set out in Table 4.16 have been used. No allowance has been made for back-up or spinning reserve costs.

		Electricity Source (fuel and location)			
		Coal		Gas	
		Collie	Eneabba	Eneabba	Kwinana
Load	Albany	5.14	4.36	4.36	4.95
	Kemerton	4.55	3.78	3.78	4.36
	Kwinana	4.66	3.89	3.89	4.47
	Northam	5.06	4.29	4.29	4.87
	Eneabba	5.45	4.68	4.68	5.26
	Geraldton	5.71	4.94	4.94	5.52

Table 4.20: Estimated Delivered Costs of Electricity

In view of high loss factor that applies to the Eneabba region, Eneabba stands out as a low cost power generation location[127]. However, as noted in section 4.3.3, the loss factor is not sustainable. Development of a power station at Eneabba could be expected to lead to revision of loss factors[128], thereby removing much of the apparent advantage of the Eneabba location. A long-term power station investment decision would need to take account of anticipated revisions of loss factors that might result from development of the power station.

On balance, subject to fuel availability and cost, the preferred location for new power generation facilities to supply a large mining or mineral processing development will be on the site of the development[129]. This is illustrated in Table 4.21 for supply of electricity to Kemerton from a range of possible power station locations. In preparing Table 4.21 the same delivered gas price has been assumed for each of Eneabba, Kwinana and Kemerton.

[127] The high loss factor means that, relative to other locations to the south of the study region, more of the electricity generated by a power station in Eneabba would be delivered to customers (rather than used to overcome transmission line losses).
[128] If a base-load power station is built at Eneabba the transmission system performance will change and the loss factor for the Eneabba location would most likely be reduced.
[129] The information set out in this report is necessarily general in nature. For smaller loads it will not be possible to achieve the generation costs set out in Table 4.16. There will be a trade off between the costs of electricity transmission and generation cost considerations that will need to be assessed on a project by project basis.

Power Station Location and Type	Delivered Electricity Cost c/kWh
On-site at Kemerton - gas	**4.05**
Collie - coal	4.55
Eneabba - coal (with -15.8% loss factor) (no loss factor)	3.78 4.42
Eneabba - gas (with -15.8% loss factor) (no loss factor)	3.78 4.42
Kwinana - gas	4.36

Table 4.21: Predicted Costs of Electricity at Kemerton

On-site generation of electricity avoids uncontrollable risks associated with the level of electricity transmission system charges and loss factors. This observation is, however, subject to fuel cost considerations, particularly in the case of gas.

There may be a trade-off between:

- the cost of transmitting electricity from a proposed power station to a proposed load; and
- the cost of transporting gas for on-site generation.

For example, ignoring loss factors, the cost of transmission of electricity from Eneabba to Kemerton would be around 0.37 c/kWh. This is equivalent in fuel cost terms to about \$0.45/GJ for combined cycle gas plant. In comparison, on the basis of published tariffs for use of the DBNGP[130], the additional cost of gas at Kemerton versus Eneabba would be approximately \$0.09/GJ. For this scenario, it would be preferable to transport gas over an extra distance to allow on-site generation than to generate off-site and make use of electricity transmission.

Similarly, the cost of transmission of electricity from Collie to Kemerton (ignoring losses) is around 0.46 c/kWh which is equivalent to about \$9.50/tonne of coal and which exceeds the cost of railing coal from Collie to Bunbury.

[130] Access Arrangement for the Dampier to Bunbury Natural Gas Pipeline - Annexure A, December 2003.

4.4 Alternative Energy Sources

4.4.1 Key Observations

a) Use of Renewable Energy Increasingly Attractive

Environmental considerations, to the extent they are reinforced by the Australian Government's Mandatory Renewable Energy Targets ('MRETs'), make the use of renewable energy forms increasingly attractive.

Geothermal energy, windpower and potentially wave energy may have prospects for expanded future use if further technological developments and cost reductions are achieved.

b) Gas and Coal Lowest Cost

Self-generation applications, and the use of energy for heat rather than electricity generation, are not subject to the Mandatory Renewable Energy Targets but are able to create Renewable Energy Certificates. For such applications (and also for electricity purchased on a wholesale basis in excess of MRETs) the lowest cost energy source will, in the near to medium term, continue to be gas or coal.

4.4.2 Overview

In Sections 4.1, 4.2 and 4.3 of this Report, the availability and cost of coal and gas and, in turn, of electricity generated using these fuels is discussed. This section provides a review of alternatives to the use of coal or gas including, in particular, renewable energy.

The SWIS is operated on an open-access basis, allowing users of electricity to purchase their requirements from electricity generators of their choice. Generating capacity presently connected to the SWIS is as set out in table 4.13[131]. WPC is the major generator and supplier of electricity.

4.4.3 Non-renewable Alternatives

Liquid fuels and nuclear power are non-renewable alternatives to the use of coal or gas. They are non-renewable since the resources on which they are dependent have a finite extent.

The use of liquid fuels is not worthy of investigation for this Report. The high price of liquid fuels means their use is not attractive.

Although nuclear power does not contribute to air pollution or greenhouse gas emissions the identification of an acceptable environmental solution to disposal

[131] The table includes generating facilities of size greater than 30MW. The table includes capacity presently being developed (namely the Transfield and Alinta Limited facilities).

of radioactive nuclear waste is elusive. Government policy does not support the use of nuclear energy and it is therefore not reviewed for the purpose of this Report.

4.4.4 Renewable Energy

Unlike gas or coal, renewable energy comes from resources that are being continually replenished. In view of the environmental and sustainability benefits of renewable energy forms, they have an increasingly important role to play in meeting future energy needs.

Through the *Renewable Energy (Electricity) Act 2000* and the *Renewable Energy (Electricity) (Charge) Act 2000*, the Australian Government has obliged wholesale purchasers of electricity to contribute to the generation of annual quantities of renewable energy that increase progressively to 9,500 GWh (ie, an annual average generation of 1085 MW) for the whole of Australia by 2010. Parties purchasing electricity on a wholesale basis through the SWIS are subject to these Mandatory Renewable Energy Targets, but self-generators[132] are not.

In 2004, 1.25% of all electricity purchased must be from renewable sources and Renewable Energy Certificates ('RECs') must be surrendered by wholesale purchasers of electricity to demonstrate that this target has been achieved. RECs are created by generators of renewable electricity and are tradeable. A penalty of $40/MWh (4.0 c/kWh) is incurred if the required number of RECs is not surrendered by a wholesale purchaser of electricity[133].

By 2010, the target (9500 GWh) level of renewable electricity for the whole of Australia will represent more than 4.0%[134] of wholesale electricity purchases. For Western Australia, this percentage will equate to less than 100 MW (average) of renewable electricity generation for the year.

An overview of the key renewable energy initiatives being pursued or having potential in the south west coast region follows.

Wind Power

Within the south west coast region there is one existing windfarm of significance - a 21.6 MW facility owned and operated by Western Power Corporation at Albany.

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[132] Self-generation occurs when there is a direct link can between the generation and use of electricity by the same party. A 'direct link' requires that the electricity generation and consumption sites either be within 1 kilometre of each other or be connected by a single-purpose transmission line.

[133] There is some flexibility in relation to the obligation to surrender RECs. On an annual basis, a leeway of 10% is allowed and, if a shortfall is incurred but is made up within a three-year period any penalty incurred will be refunded.

[134] An explanation of the calculation of the required percentage of renewable electricity may be found in 'The Cost of Increasing the Mandatory Renewable Energy Target', The Australian Wind Energy Association, November 2003, page 7.

Figure 4.28: Albany Windfarm
Photograph source: Australian Wind Energy Association

Development of a number of new facilities is proceeding or proposed, including:

- A windfarm development up to 100 MW in size has been proposed by Energy Visions Pty Ltd for Coronation Beach, north of Geraldton.
- An 80 MW windfarm has been proposed by Stanwell Corporation in alliance with Griffin Energy for Emu Downs, near Dandaragan.
- Development of a 30 MW to 60 MW windfarm has been proposed by Wind Energy Corporation for development at Mumbida, 40 kilometres southeast of Geraldton.
- Wind Power Pty Ltd has proposed the development of a 50 MW windfarm at Scott River, to the Northeast of Augusta.
- Renewable Power Ventures is developing a 90 MW windfarm at Walkaway, 35 kilometres southeast of Geraldton. Electrical output from the project has been contracted to Alinta, while The Australian Gas Light Company ('AGL') will purchase up to 50% of the RECs created by the project.

Although the affordability of harnessing wind energy has improved significantly over recent years as turbine sizes have increased, the technology remains highly capital intensive. The capital cost of the projects outlined above has been, or is predicted to be, around $2,100 per kilowatt of installed capacity. Electricity costs are likely to be around 7.5 c/kWh to 9.0 c/kWh[135]. This figure makes no provision for electricity supply back-up arrangements that are needed in view of the interruptible nature of wind power.

[135] Electricity cost estimate from 'Cost Convergence of Windpower and Convention al Electricity Generation in Australia, Australian Wind Energy Association, June 2004, figures from Australian Industry and Australian Clean Energy Future as provided on pages 15-16.

While wind power may be a potentially attractive supplement to other sources of energy as a component of a wholesale electricity supply portfolio (particularly with regard for the Mandatory Renewable Energy Targets) in view of its inherently interruptible nature any system into which it is supplied must have sufficient reserve[136] capacity available to provide cover during periods when wind power is not available. The cost figures set out above do not include the cost of reserve capacity. Having regard for the full costs of wind power, it does not provide a basis for development of electricity-intensive minerals development initiatives.

Solar Energy

Solar energy can be captured and used for heating purposes, including for generation of electricity by thermal means[137], or can be used to generate electricity by photo-voltaic means. In either case, solar energy has the advantages that it is non-polluting, has few or no moving parts and, therefore, requires little maintenance or supervision. However, solar energy applications are disadvantaged in that they are interruptible, which means supplementary generation or energy storage facilities are required, they require large areas of land and they have a high capital cost.

At present the principal applications for use of solar energy are for electricity generation in remote areas or for hot water in residential and small commercial or industrial applications. This has been recognised in Australian Government's Energy White Paper, 'Securing Australia's Energy Future', which set aside $75 million to fund solar city trials. The trials will involve the use of cost-reflective pricing signals to stimulate demand management and energy efficiency initiatives.

For larger scale applications, solar energy costs are not competitive with conventional energy forms. For example:

- Solarbuzz Incorporated routinely surveys around 120 companies involved in the solar photo-voltaic industry and, on the basis of information gathered, publishes a global solar electricity price index. For August 2004 the index was 20.35 USc/kWh (approaching 30 c/kWh), based upon a capital cost of around $7,000/kW of capacity.

- Estimates of the cost of electricity from a solar-thermal power station are subject to considerable variability. The Queensland Department of Natural Resources and Mines suggests costs in the range 18 c/kWh to 25 c/kWh.

[136] Spinning reserve (ie, the spare capacity of plant that is running but not fully loaded) is required to cover for instantaneous variations in wind power output. The costs of providing spinning reserve

[137] Solar-thermal electricity generation typically involves the use of mirrors to concentrate onto a receiver in which steam is generated to drive a turbine. Non-concentrating technologies also exist, namely thermal chimneys and solar ponds.

Hydrogen

Hydrogen is the most abundant element on earth. It can be produced through the electrolysis of water and it has numerous advantages as an energy source. In particular, it can be used as a transport fuel and, when combusted it produces water vapour only (ie, no carbon monoxide or carbon dioxide).

While hydrogen-based technologies and fuel-cells will undoubtedly be a key component of a sustainable energy future, detailed consideration of them for the purpose of this report would be premature.

Hydro power

Hydropower is not considered to be a realistic option for the south west coast region.

Geothermal

Geothermal energy is derived from the heat contained within the earth.

Traditionally, geothermal energy has been harnessed at sites (eg, volcanic regions) where water moving under natural hydrostatic pressure through hot rocks is heated and turned to steam. There are no such sites in the south west coast region.

Alternatively, the internal heat of the earth may be harnessed using Hot Dry Rock ('HDR') technology. This involves drilling holes into, and fracturing, hot rock (typically granite) several kilometres below the earth's surface. Water is then pumped into the hot rock to be returned through a second hole as steam. Figure 4.29 shows the estimated temperature of the earth's crusts across Australia at a depth of 5 kilometres.

Figure 4.29 suggests there may be locations in the northern Perth Basin that might have a temperature gradient high enough to allow application of HDR techniques. The potential resource of the region is estimated to be 49 EJ[138] which, subject to the suitability of the geology of the region, would be sufficient to supply the electricity requirements of the SWIS for in excess of 100 years.

[138] Figure from ERDC report 243, 1994, as quoted by Australian National University.

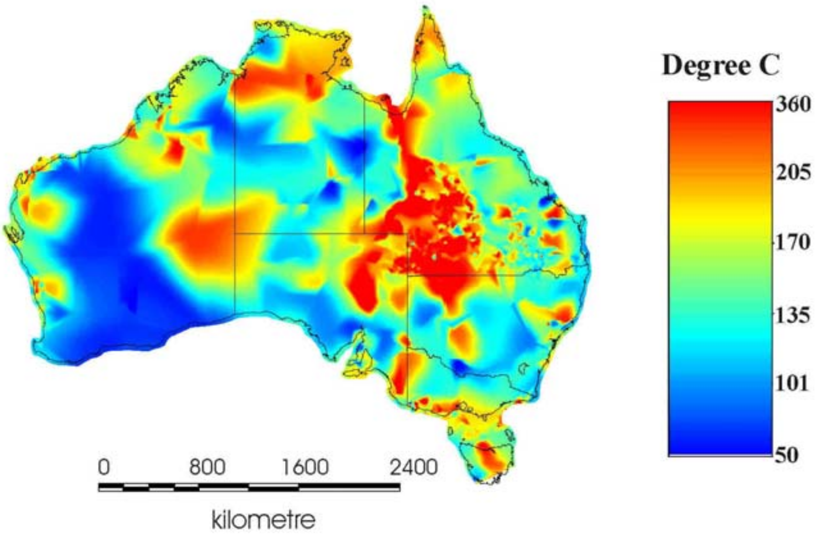

Figure 4.29: Earth Temperatures at 5 km Depth
Source: Australian National University

The estimated break-even electricity price[139] for electricity from an HDR project proposed by Geodynamics Limited for Cooper Basin is 6.2 c/kWh initially, at demonstration plant stage, falling to 4.0 c/kWh at full scale production. This figure has yet to be demonstrated but, if it proves to be achievable, there may eventually be considerable merit in further pursuit of the HDR opportunity within WA. Geothermal energy also has a distinct reliability advantage over other renewable energy sources since it can be despatched[140] as necessary to meet system requirements.

At the present time though, the cost and unproven nature of the technology mean it is not recommended as a basis for stimulus of minerals development opportunities in the south west coast region.

Bioenergy

The term 'bioenergy' refers to energy derived from biomass, which, in turn, is organic material that has (through the process of photosynthesis) solar energy stored within it. Biomass can be used in a number of ways including combustion, biochemical processes (for example, to produce ethanol or methane) and processing to extract oils. To be considered as sustainable, biomass that is used as a source of energy must be 'cropped'.

Due to its low cost and renewable nature, biomass now accounts for almost 15% of the world's total energy supply and as much as 35% in developing countries (where it is mostly used for cooking and heating).

[139] 'Australia's first hot dry rock geothermal energy extraction project is up and running in granite beneath the Cooper Basin, NE South Australia', *Chopra, P., & Wyborn, D.*, Ishihara Symposium, Macquarie University, July 22-24, 2003, page 43.
[140] That is, operated when it is required rather than when the energy form (eg, wind) is available.

WPC has entered into agreements with Pinetec Ltd pursuant to which WPC will co-fire in its Muja Power Station boilers some 80,000 tonnes per annum of pine sawmill residues from a sawmill facility to be established adjacent to the power station. WPC has also developed an Integrated Wood Processing ('IWP') demonstration bioenergy operation at Narrogin, just to the east of the study region. The IWP operation processes mallee trees to produce eucalypt oil, activated carbon and electricity.

BioEnergy Australia Ltd has proposed development of a further bioenergy project, similar to the IWP operation, based upon 9000 hectares of plantations.

The cost of electricity generated from biomass is estimated to be in the range 5c/kWh to 15c/kWh[141].

<u>Ocean Energy</u>

The ocean's tides, caused by the gravitational pull of the moon and the sun, and waves, caused by wind, are potential sources of energy.

Tidal energy is similar to hyro-electric energy except that the motive force (a change in water elevation) is caused by the fluctuation between low and high tides. Tidal opportunities exist in northwest WA where tidal movements are high, and there are large inlets that could potentially be dammed to allow the tidal energy to be harnessed. The remote nature of these locations means they are not suited to supply of electricity for the south west coast region.

Wave energy potential could exist off the south west coast although the regions of greatest potential are typically between the 40° and 60° latitudes. At present, electricity from wave energy is more expensive that electricity from conventional or other renewable energy sources. Figures in the range 7 c/kWh to 12 c/kWh are quoted[142]. This does not include the cost of reserve capacity to provide cover for interruptions to the supply of wave energy.

4.4.5 Comparison of Alternatives

Table 4.22 and Figure 4.30 provide a comparison of the order of magnitude costs of alternative sources of electricity as reviewed in this Section.

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[141] CSIRO Factsheet, 'Bioenergy', available at www.energy.csiro.au

[142] For example, this is the range of costs suggested as achievable using technology developed by Ocean Power Technologies (Australia) Pty Ltd with support from the Australian Government's Renewable Energy Industry Program.

Electricity Source	Cost c/kWh
Gas combined cycle	3.8
Coal (steam cycle)	4.3
Geothermal	4.0 – 6.2
Wind power	7.5 – 9.0
Wave energy	7.0 – 12.0
Bioenergy	5.0 – 15.0
Solar-thermal	18.0 – 25.0
Solar photo-voltaic	30

Table 4.22: Comparison of Predicted Electricity Costs

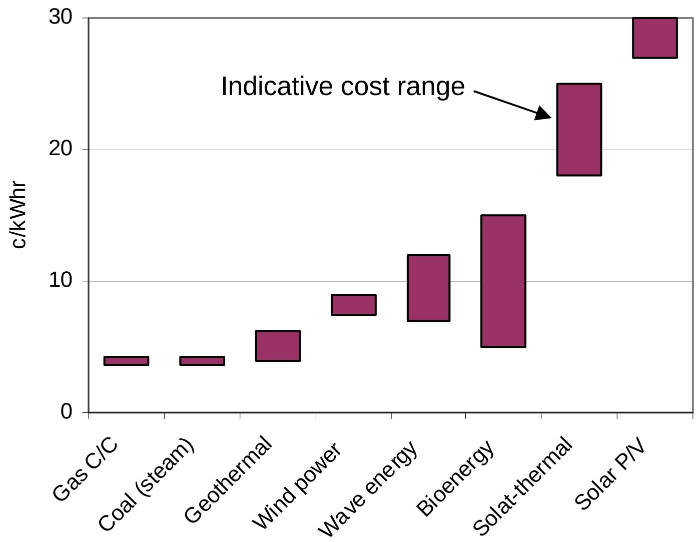

Figure 4.30: Comparison of Predicted Electricity Costs

The use of gas and coal offers the most reliable source of competitively priced electricity.

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5 ACHIEVING TARGET ENERGY PRICES

5.1 Analysis of Minerals Development Opportunities

Table 3.23 provided a summary of the type, quantity and price of energy required in order for the identified minerals development opportunities to be capable of achieving viability in the south west coast region. Of course, there are numerous factors in addition to energy prices[143] that affect a project's viability and, even if the identified target levels of energy price are achieved, there is no certainty that a particular opportunity will proceed.

An overall comparison of the target energy prices as set out in Table 3.23 may be facilitated by determining the primary fuel (ie, coal or gas) prices that are needed[144] to achieve the target electricity prices. Conversion of target electricity prices into target primary fuel prices can be achieved using the relationships[145] presented in Figure 5.1. For example, generation of electricity at a cost of 4.0 c/kWh might be achieved in a coal fired plant if coal is available at around $1.50/GJ or in a combined cycle gas plant if gas is available at around $2.80/GJ.

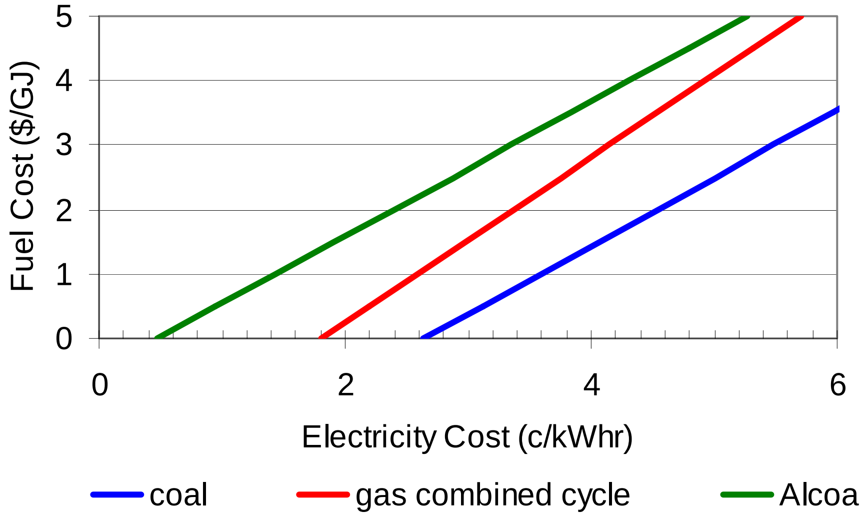

Figure 5.1: Relationship Between Fuel Costs and Electricity Costs

On this basis, indicative estimates of the total primary fuel quantities and prices that are required in order for the identified development opportunities to be

[143] For example, factors such as possible development incentives in other locations will affect the international competitiveness of the south west coast region.
[144] Having regard for the location of load relative to potential primary fuel sources, and for electricity transmission implications.
[145] The fuel price - electricity price relationships presented in Figure 5.1 are based upon the electricity generation costs and efficiencies set out in Section 4.3 and, in particular, Table 4.16.

viable are presented in Figure 5.2. To assist in understanding Figure 5.2, the following explanatory comments are proffered.

- Figure 5.2 is intended to provide an indicative representation of the primary energy requirements of different projects.
- Smaller projects (in terms of energy requirement) have been grouped for presentation purposes.
- Where a project can use either coal or gas (or electricity derived from either coal or gas) the requisite value for both fuels is depicted. The target (maximum) coal price is represented by the top of the ivory shaded area while the target (maximum) gas price is represented by the top of the turquoise area.
- Gas based electricity generation has been assumed to be by means of combined cycle plant except in the case of the aluminium smelter, where cogeneration has been assumed.

5.2 Potential Sources of Energy for Minerals Developments

A comparison of the fuel requirements depicted in Figure 5.2 with the predicted availability and price of coal and gas, as presented in section 4, supports the following observations regarding the potential for procurement of energy at the target prices required to allow the viability of the identified development opportunities to be realised.

a) Alumina Production

Reflecting the established international competitiveness of the Western Australian alumina industry, the projected expansions of alumina production, from the current level of 11.2 Mtpa to 14.5 Mtpa by 2010, are viable at the present levels of gas and coal prices. This is illustrated in Figure 5.3. Lower energy prices, if achieved, will enhance this competitiveness.

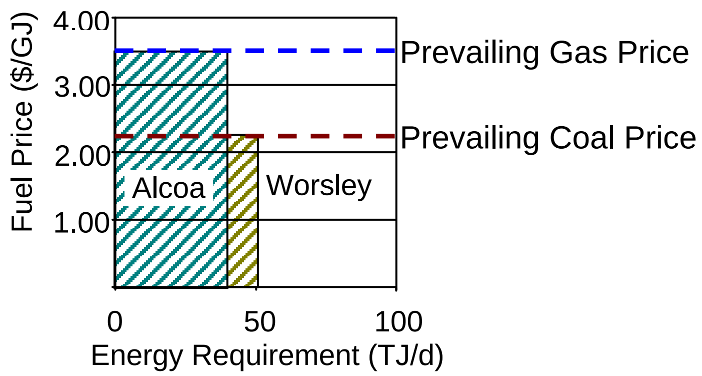

Figure 5.3: Achievable V's Target Energy Prices - Alumina

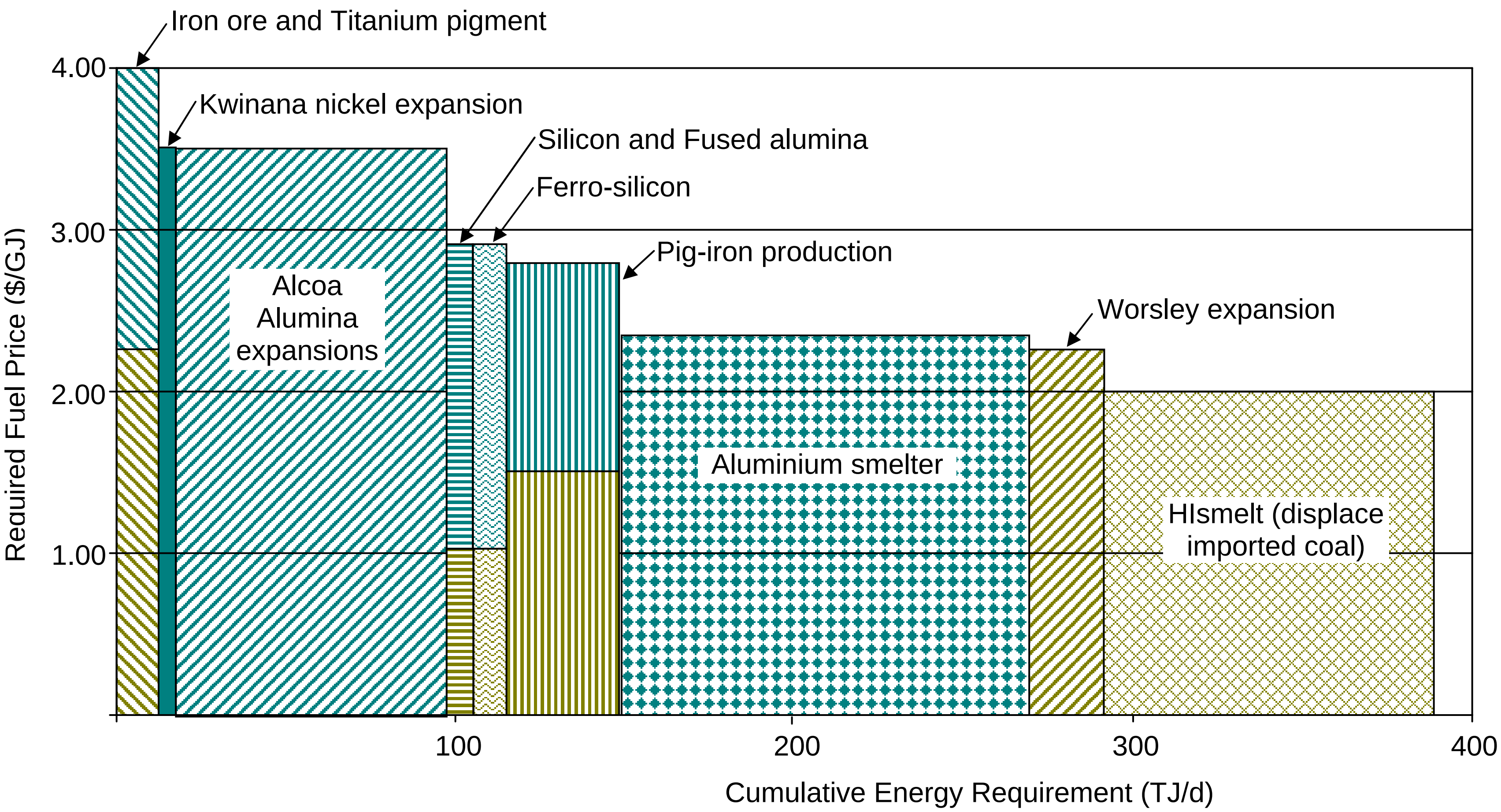

Figure 5.2: Requisite Fuel Prices and Quantities

b) Iron Ore Production in the Mid West

Continued growth of iron-ore production, including commencement of magnetite export, would (as illustrated in Figure 5.4) appear to be viable at prevailing energy price levels. Of greater significance to these projects will be the need for further infrastructure development. Should coal based pig-iron production take place in the Mid West, the potential for generation of electricity using process waste-heat could be expected to improve the competitiveness of regional iron-ore production.

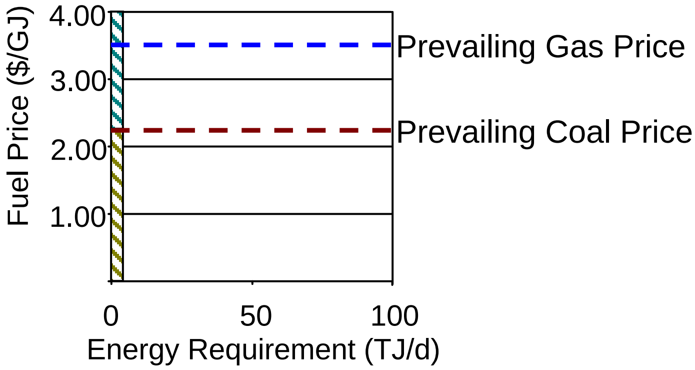

Figure 5.4: Achievable V's Target Energy Prices - Iron Ore

c) Kwinana Nickel Refinery

The projected expansion of KNR production from 70 kt in 2004 to 95 kt in 2010 is also achievable at current energy price levels within the study region. This is illustrated in Figure 5.5.

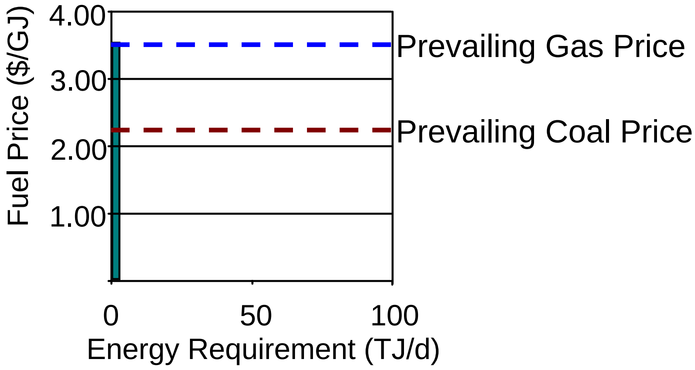

Figure 5.5: Achievable V's Target Energy Prices - Nickel Refining

d) HIsmelt - Displacement of Imported Coal

The HIsmelt process is scheduled to commence production at a rate of 0.8 Mtpa early in 2005 with a projected upgrade to between 1.5 and 1.6 Mtpa by 2008. Coal for the HIsmelt process will be imported from Queensland.

Subject to confirmation of technical feasibility, the potential exists for coal char produced from Collie coal to replace the imported coal. As illustrated in figure 5.6, indications are that Collie coal will be available at price levels that will make this attractive. The increase in production of Collie coal that would result from displacement of the imported coal will itself contribute to achievement of improved economies of production of Collie coal.

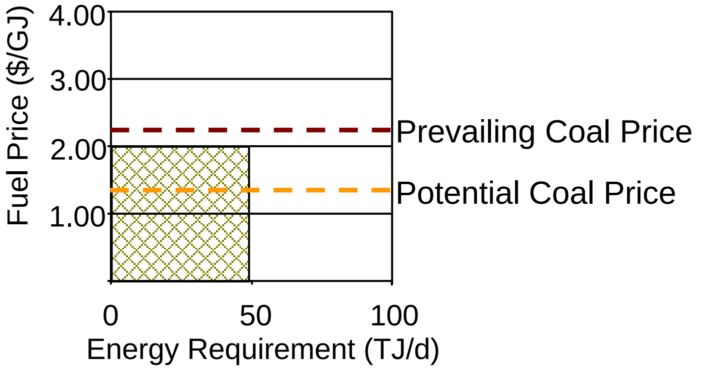

Figure 5.6: Achievable V's Target Energy Prices - HIsmelt

e) Synthetic Rutile

Subject to confirmation of technical feasibility, the use of briquettes or coal char (produced from Collie coal) to achieve a significant increase in the productivity of existing synthetic rutile facilities is likely to be attractive at present levels of coal price (after allowing for briquette or char production costs). Success with this initiative will lead to only a marginal increase in coal requirements. Hence, this initiative is not separately represented in Figure 5.2.

f) Silicon Smelter Expansion

Within the limits of accuracy of the cost estimates developed for this Study, the potential would appear to exist for generation of electricity at a price level that will ensure expansion of the silicon smelter is prospectively viable.

The potential for achievement of electricity price levels that meet the target requirement for expansion of the silicon smelter will be improved if the interruptible nature of the silicon smelter load is taken into account and/or electricity is generated at a high level of efficiency (ie, cogeneration).

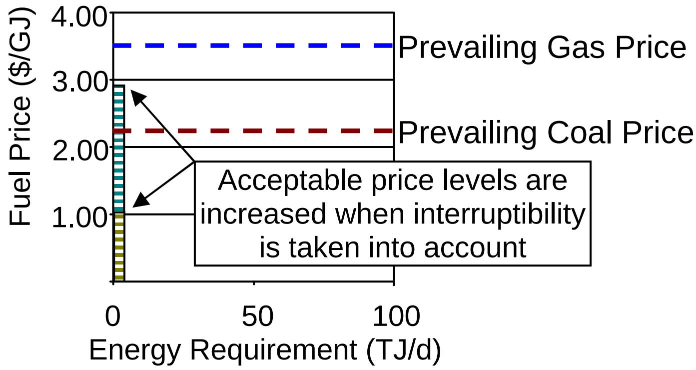

Figure 5.7: Achievable V's Target Energy Prices – Silicon Smelter

g) Fused Alumina and Ferro-silicon

As for silicon metal production, electricity pricing is a major determinant of the viability of electric arc furnace processes in the study region, including the production of fused alumina or ferro-silicon.

The potential exists for electricity to be generated at price levels that will facilitate the viability of these projects. This potential will be enhanced to the extent that the loads in question are interruptible.

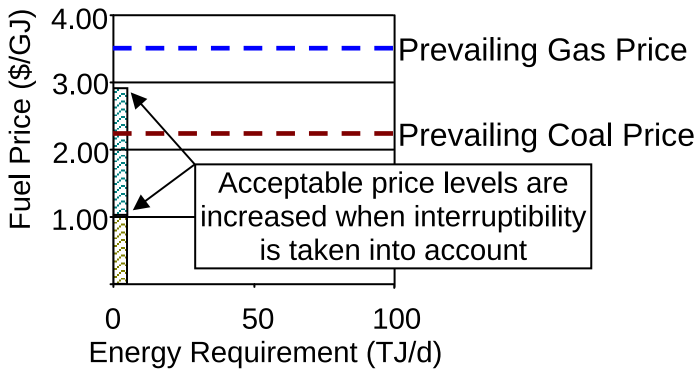

Figure 5.8: Achievable V's Target Energy Prices - Electric Arc Processes

h) Titanium Pigment

Expansions of titanium pigment production are viable at present levels of coal and gas price, as illustrated in Figure 5.9.

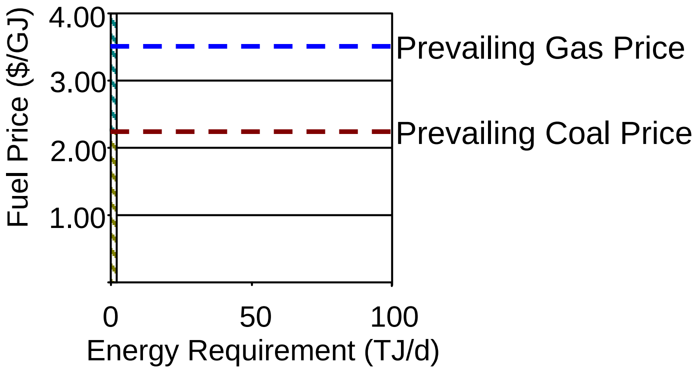

Figure 5.9: Achievable V's Target Energy Prices - Titanium Pigment

i) Metallurgical Pig-iron

The development of a DRI/HBI pig-iron production plant, using coal from a new coal mine development in the Eneabba area, is prospectively viable. This is illustrated in Figure 5.10.

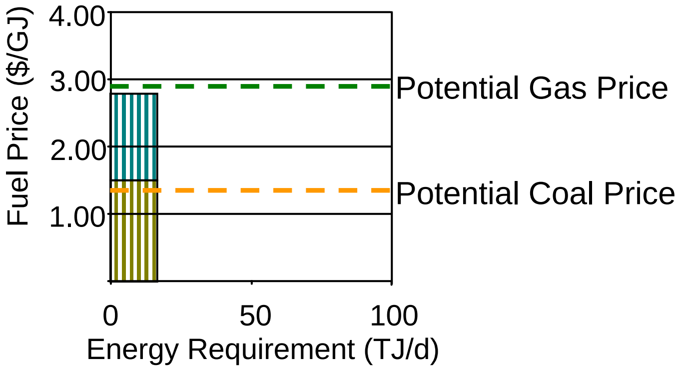

Figure 5.10: Achievable V's Target Energy Prices - Pig-iron

A coal based pig-iron plant would also have the capacity to produce electricity at prices that would contribute to the economic viability of other regional minerals developments, such as the production of magnetite. This is illustrated in Figure 5.11, which shows the inputs and outputs of a nominal 0.5 Mtpa pig-iron facility.

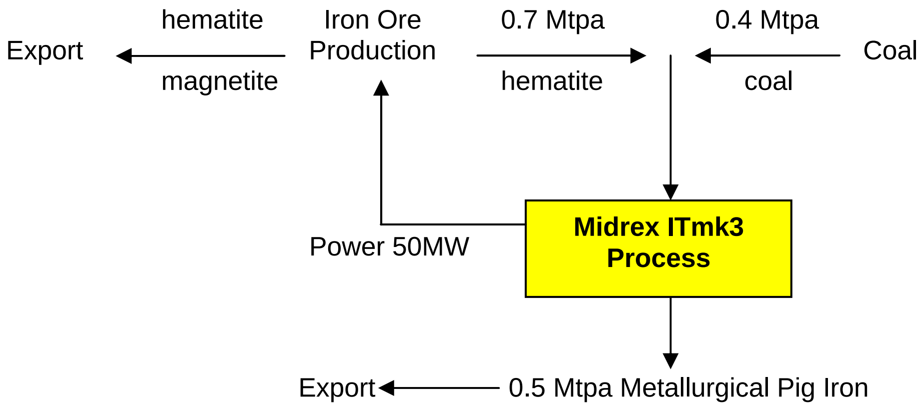

Figure 5.11: Input-Output Diagram for Coal Based Pig-iron Production

j) Aluminium Smelter

For electricity to be available at a price level that allows an aluminium smelter to be considered for development in the south west coast region it will be necessary for either:

- coal to be available at not more than (and preferably less than) $1.00/GJ, which is unlikely to be achievable; or
- gas and gas transportation will need to be available for an aggregate cost of less than nominally $2.50/GJ, and a high level of electricity generation efficiency will need to be achieved. Within the limits of accuracy of the cost estimates developed for this Study, the potential could exist for these requirements to be achieved.

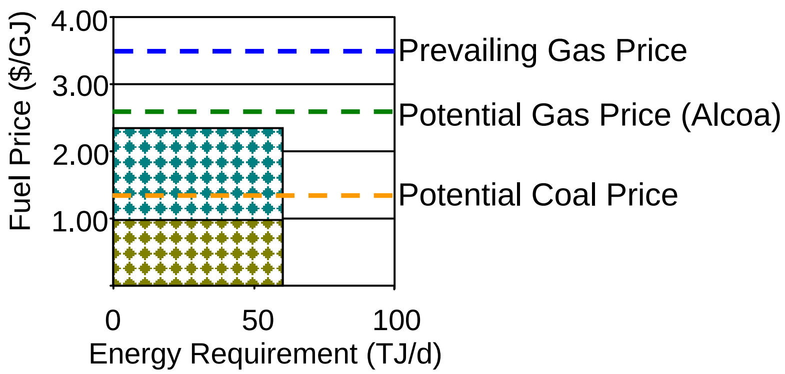

Figure 5.12: Achievable V's Target Energy Prices - Aluminium

From this analysis it is evident that the potential exists for many of the identified mineral development opportunities to achieve viability on the basis of energy prices that are prevailing or achievable. Prospective energy sources to achieve these target prices are summarised in Table 5.1.

<table>
<tr><th rowspan="3">Project</th><th colspan="6">Prospective Energy Source</th></tr>
<tr><th rowspan="2">Eneabba Coal</th><th rowspan="2">Collie Coal</th><th rowspan="2">Gas</th><th colspan="3">Electricity</th></tr>
<tr><th>Alcoa (Gas)</th><th>Western Power</th><th>Other</th></tr>
<tr><td>Alumina expansions</td><td></td><td>✓</td><td>✓</td><td></td><td></td><td></td></tr>
<tr><td>Nickel Smelter Expansion</td><td></td><td></td><td>✓</td><td></td><td colspan="2">✓</td></tr>
<tr><td>Iron Ore Production</td><td colspan="3">**F**</td><td></td><td colspan="2">✓</td></tr>
<tr><td>HIsmelt (displace imported coal)</td><td></td><td>✓*</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Synthetic Rutile Growth</td><td></td><td>✓*</td><td></td><td></td><td></td><td></td></tr>
<tr><td>Silicon Smelter</td><td></td><td colspan="2">**F**</td><td></td><td colspan="2">✓</td></tr>
<tr><td>Iron Ore Pellet Plant</td><td></td><td></td><td></td><td></td><td colspan="2">✓</td></tr>
<tr><td>DRI / HBI Pig Iron Plant</td><td>✓</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>Aluminium Smelter</td><td></td><td></td><td colspan="2">#</td><td></td><td></td></tr>
<tr><td>Ferro Silicon</td><td></td><td colspan="2">**F**</td><td></td><td colspan="2">✓</td></tr>
</table>

Table 5.1: Energy Sources for Minerals Developments

Legend to Table:

✓ indicates that the potential exists for these opportunities to achieve viability at prevailing or achievable levels of fuel and/or electricity prices.

✓* indicates that viability is subject to technical factors.

F indicates primary fuel for generation of electricity at required target price.

# indicates the opportunity may (with favourable outcomes) exist for this opportunity to achieve viability.

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6 ECONOMIC IMPACTS OF DEVELOPMENT SCENARIOS

6.1 Introduction

As a complement to the review of energy for minerals development in the south west coast region, the economic impacts of a range of minerals development opportunities were analysed. The analysis was undertaken on behalf of Sleeman Consulting by the Centre of Policy Studies ('CoPS') at the Monash University using MMRF-Green, a multi-sector dynamic model of Australia's six States and two Territories. For modelling purposes a Base Case and two development scenarios were formulated

CoPS' report on the economic modelling exercise is provided in Appendix 6.

6.2 Modelling Scenarios

The identified south west coast region minerals development opportunities are presented in Table 6.1 which groups the respective development opportunities according to whether or not their viability is dependent upon energy prices. Opportunities treated as not being sensitive to energy price levels include:

- those that are considered to be viable at prevailing energy price levels, even though their viability could be compromised if prices increase (for example, alumina production); and
- those for which factors other than energy price levels are the determinants of viability (for example, titanium metal production based upon new technology that is significantly less energy intensive than the current process).

The development opportunities have also been categorised according to the certainty of the project. Projects that have already been announced (or which are likely to be announced at a suitable juncture) are shaded blue in the table. These projects are likely to proceed at prevailing price levels (ie, regardless of initiatives that might arise from this Study). Projects of a brownfields nature are shaded amber and projects of a greenfields nature are shaded green. The remaining (unshaded) projects represent opportunities that were identified in Section 3 but which were not considered to have significant potential for development in the study region. They are included in Table 6.1 for completeness only.

	Product	Comment	Development Opportunities
Viability Not Dependent upon Energy Prices	Alumina	Demonstrated viability in southwest.	Expansions likely.
	Gold	No present production.	Possible reopening of Boddington.
	Iron Ore (Hematite)	Present production 1.6 Mtpa.	Demand strong. Expansions likely.
	Synthetic Rutile	Present production 700 ktpa.	Possible increased production though use of briquettes or char.
	Zirconia	Current small operations, low production levels	Expansion is dependent upon factors other than energy prices.
	Kaolin, Silica sand, Gallium, Garnet, Talc		
	Titanium metal	No present production.	Contingent upon commercialisation of new production technology.
	Titanium dioxide pigment	Present production around 200 ktpa.	Prospects may arise for expansion.
	Pig Iron (HIsmelt)	800 ktpa production to commence shortly, using imported coal.	Likely Expansion to 1.6 Mtpa.
			Opportunity for Collie coal to displace imported coal
	Mineral Sands	Ilmenite, rutile, zircon and leucoxene produced in southwest.	Expansions unlikely in view of resource constraints.
	Tantalum, Spodumene	Existing operations at Greenbushes.	Tantalum mine likely to be developed underground.
	Nickel	Refining of matte to produce 70 ktpa of metal takes place at Kwinana.	Progressive expansion of Kwinana refining capacity is likely.
Viability Dependent upon Energy Prices			Future scope for price dependent development of additional smelting capacity may emerge.
	Aluminium	No production at present.	Smelter development viability depends upon energy prices.
	Ferro Silicon		Development potential exists
	Ferro Nickel		Development potential higher elsewhere.
	Fused materials	Fused alumina and fused zirconia produced at Kwinana.	Prospects could arise for expansion of existing operations or for production of fused silica.
	Iron Ore (Magnetite)	No production at present.	Potential exists for integrated development of these opportunities.
	Iron Ore (Pellet plant)		
	Pig Iron (DRI / HBI)		
	Silicon Metal	Existing 32 ktpa production.	Markets strong. Expansion likely.

Table 6.1: Minerals Development Opportunities

For modelling purposes three scenarios, as described below and summarised in Table 6.2, were formulated.

6.2.1 Base Case Scenario

The Base Case was a projection for the Australian and state economies, compiled from business-as-usual assumptions for minerals development, but specifically including those developments considered highly likely to proceed (ie, shaded blue in Table 6.1).

6.2.2 Development Scenario 1

Scenario 1 incorporates (in addition to Base Load developments) the 'brownfield' developments identified in Table 6.1, namely:

- the use of coal char produced from Collie coal to displace imported coal that would otherwise be used in the existing and expanded HIsmelt facility;
- the use of briquettes, manufactured from Collie coal, to achieve increased levels of production from the synthetic rutile operations of the study region; and
- expansion of the Kemerton silicon smelter on the basis of electricity prices considered to be achievable (having regard for the interruptible nature of the silicon smelter load).

6.2.3 Development Scenario 2

Scenario 2, the highest growth scenario, incorporates the 'greenfields' developments identified in Table 6.1. Inherent in Scenario 2 are:

- the development of the Eneabba coal resource, to allow value-added processing of iron ore produced in and to the north of the study region;
- the development of a ferro-silicon plant; and
- the use of Gorgon gas as a basis for generation of electricity for use in an aluminium smelter. In this regard, Scenario 2 involves a symbiotic relationship between:
  - the domestic phase of the Gorgon project (which will require a sizeable foundation load to achieve commerciality);
  - the aluminium smelter development (which requires significant quantities of gas); and

- expansion of the Dampier to Bunbury gas pipeline (for which economies of scale are predicted to be realisable as capacity expansions proceed).

Scenario 2 also incorporates a modest, general lowering of gas transportation prices reflecting a flow-through of benefits as pipeline expansion economies are realised.

6.3 The Modelling Process

6.3.1 Simulation Design

The economic impacts of the three scenarios, covering new investments scheduled to take place between 2005 and 2010, were modelled to determine changes in key economic indicators over the period 2005 to 2020. The effects of Scenarios 1 and 2 were measured as deviations between the values of variables in these scenarios and their value in the Base Case scenario.

6.3.2 Exogenous Shocks

The modelling process involved the imposition of exogenous shocks that represented the annual changes in production and investment expenditure associated with the projects underlying scenarios 1 and 2. The exogenous input is summarised in Table 6.3.

New project investment begins in 2005 with the brownfields expansion of synthetic rutile production and the early construction of the coal char plant. The peak investment years are 2008 to 2010 during which most of the construction of the pig iron plant and aluminium smelter occurs. No new investment has been included after 2010. Production from the new projects begins in 2006, and gradually ramps up to a value of about $200 million in 2009.

Production from new projects jumps in 2010 when the aluminium smelter commences operation. Further increases in aluminium production and the start-up of the pig iron plants leads to annual production valued at over $2,000 million by 2013. The value of the production is maintained at its 2013 value through to the end of the simulation period (ie, 2020).

Nearly all of the new production is exported. The exception is production from the coal char plant, valued at $30 million per annum, which is destined for the local HIsmelt plant.

Case / Description	Developments included	Load Increase
Base Case 'Business as usual' scenario but inclusive of specific developments that are considered likely regardless of energy price initiatives.	Alumina production expansions [from 11 to 14.5 Mtpa by 2010]	100 TJ/d gas
	Kwinana nickel refinery growth [from 70 to 95 ktpa by 2010]	5 MW
	Increased iron ore (Mid West hematite) production [from 1.6 to 5.2 Mtpa by 2006]	10 MW
	HIsmelt expansion [doubling of size in 2008]	0.5 Mtpa imported coal
Scenario 1 Higher growth scenario, equivalent to Base Case plus <u>brownfields</u> expansions	Increased (20%) synthetic rutile production, associated with use of coal briquettes.	-
	Supply of coal char to HIsmelt to displace imported coal	0.8 – 1.6 Mtpa coal
	Silicon Smelter expansions	50 MW (2007) 50 MW (2011)
Scenario 2 Higher growth scenario equivalent to Scenario 1 plus <u>greenfields</u> developments plus a general but modest (5%) lowering of gas prices.	Mid West pig iron production (coal based) [1.5 Mtpa] plus increased magnetite production	10MW 800 kt coal
	Aluminium smelter [2 potlines]	1120 MW
	Ferro silicon production [50 ktpa in 2008]	45 MW

Table 6.2: Modelling Scenarios

	2005	2006	2007	2008	2009	2010	2011	2012	2013	ongoing
Scenario 1 projects										
Investment										
1 a)Synthetic rutile	10.0									
1 b)Coal char for HIsmelt		50.0	50.0							
1 c) Silicon smelter	35.0	40.0			35.0	40.0				
Total	45.0	90.0	50.0	0.0	35.0	40.0	0.0	0.0	0.0	0.0
Production										
1 a) Synthetic rutile		40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0	40.0
1 b) Coal char for HIsmelt			15.0	30.0	30.0	30.0	30.0	30.0	30.0	30.0
1 c) Silicon smelter			38.9	58.3	77.8	77.8	116.7	136.1	155.6	155.6
Total	0.0	40.0	93.9	128.3	147.8	147.8	186.7	206.1	225.6	225.6
Additional projects in Scenario 2										
Investment										
2 a) Mid West pig iron				400.0	650.0	695.0				
2 b) Aluminium smelter			700.0	1200.0	1200.0	700.0				
2 c) Ferro silicon		40.0	40.0		40.0	40.0				
Total	0.0	40.0	740.0	1600.0	1890.0	1435.0	0.0	0.0	0.0	0.0
Production										
2 a) Mid West pig iron							339.2	413.0	450.9	450.9
2 b) Aluminium smelter						400.0	1000.0	1300.0	1350.0	1350.0
2 c) Ferro silicon				25.0	50.0	60.0	85.0	110.0	120.0	120.0
Total	0.0	0.0	0.0	25.0	50.0	460.0	1424.2	1823.0	1920.0	1920.9
All projects aggregate										
Investment	45.0	130.0	790.0	1600.0	1925.0	1475.0	0.0	0.0	0.0	0.0
Production	0.0	40.0	93.9	153.3	197.8	607.8	1610.7	2029.1	2146.5	

Table 6.3: Exogenous Shocks to Production and Investment
($million, constant price, deviations from Base Case values)

6.3.3 Other assumptions

Other assumptions applied in relation to the labour market, public expenditure, taxes and government budget balances, private consumption and investment, rates of return on capital and production technologies are detailed in Appendix 6.

Present value calculations have been carried out using a discount rate of 5%, consistent with that used in other similar exercises carried out by the State, for the period 2005 to 2020.

6.4 Estimated Economic Impacts

6.4.1 Scenario 1

a) Key Indicators

The impact on gross domestic, gross state and gross regional products that is forecast to result from development of the scenario 1 projects is set out in Table 6.4.

Impact $M (2001 prices)	2005	2010	2015	2020	PV
Real GDP Australia	9.0	101.3	134.4	143.6	1,221
Real GSP W.A.	24.5	269.2	313.0	329.2	2,673

Table 6.4: Scenario 1 Gross Product Impacts

The stimulus to the state economy that flows from the scenario 1 projects is $24.5 million in 2005, rising to $329.2 million by 2020. This represents a present value increase to the state economy of $2,673 million over the period 2005 to 2020 generated by upfront investments of only $260 million.

The impact on the state's economy is significantly higher than the overall increase in GDP for Australia, which is estimated at $1,221 million in present value terms over the same period. This is the result crowding out[146] of other export and import sectors.

b) Direct Employment

Development of the scenario 1 projects will stimulate employment, as shown in Table 6.5.

[146] The additional minerals exports from the study region '*crowd-out*' other export and import-competing sectors. The mechanism by which this occurs is real exchange rate adjustment. Additional minerals exports strengthen the real exchange rate, reducing the competitiveness of Australia's other traded-goods industries. Thus other export industries lose market share on foreign markets and import-competing industries lose out to foreign goods on local markets

Employment Increase	2005	2010	2015	2020
Western Australia	300	1,300	1,000	900

Table 6.5: Scenario 1 Employment Impacts

Approximately 900 long-term jobs would be created of which around 200 are in the South West region[147]. Since the projects included in scenario 1 are brownfields in nature, direct employment associated with their development is low at 100 new jobs. The remaining 800 long-term jobs are in related industries. Employment levels including construction and operations peak at 1,400 in 2009.

c) Consumption

Real consumption in Western Australia is strongly stimulated through the study period 2005 to 2020. The longer-term annual increase in real consumption is $179 million, or 0.3%. This is seen as a reliable guide to the impact on the welfare of the incumbent population. Thus, even though the projects have a significant degree of foreign ownership they result in a significant increase in the welfare of the local population.

d) Tax Revenue

Development of the scenario 1 projects will lead to increased tax revenue being collected by Western Australia. The increase is $2.1 million in 2005, rising to $22.6 million by 2020, as shown in Table 6.6. This represents a present value increase of $191 million over the period 2005 to 2020.

Increase ($M)	2005	2010	2015	2020	PV
GST	1.5	13.5	13.7	14.4	-
Other tax revenue	0.6	6.7	7.8	8.2	-
Total	2.1	20.2	21.5	22.6	191

Table 6.6: Scenario 1 State Tax Impact

Company and labour tax on a national basis will increase by $2.9 million in 2005, rising to $18.0 million by 2020, as shown in Table 6.7. This represents a present value increase of $146 million over the period 2005 to 2020.

[147] The South West region referred to here is the South West statistical land division rather than the south west coast study region.

Increase ($M)	2005	2010	2015	2020	PV
Company Tax	1.1	12.2	16.1	17.2	-
Labour Tax	1.8	1.8	0.5	0.8	-
Total	2.9	14.0	16.6	18.0	146

Table 6.7: Scenario 1 National Tax Impact

6.4.2 Scenario 2

a) Key Indicators

The impact on gross domestic, gross state and gross regional products that is forecast to result from development of the scenario 2 projects[148] is set out in Table 6.8.

Impact $M (2001 prices)	2005	2010	2015	2020	PV
Real GDP Australia	11.3	527.7	980.8	960.7	6,764
Real GSP W.A.	33.6	1,672.0	2,395.1	2,625.6	17,676

Table 6.8: Scenario 2 Gross Product Impacts

The level of stimulus to the State economy that is predicted to result from scenario 2 is $33.6 million in 2005, rising to $2,626 million by 2020. This represents a 2.18% increase in GSP. The present value of the increases in GSP between 2005 and 2020 is approximately $17,676 million compared to an upfront investment of $5,965 million. On a marginal basis, the net impact of scenario 2 over scenario 1 is around $15,000 million in present value terms.

b) Direct Employment

Development of the scenario 2 projects will stimulate employment, as shown in Table 6.9.

Employment Increase	2005	2010	2015	2020
Western Australia	400	12,200	9,100	9,100

Table 6.9: Scenario 2 Employment Impacts

Approximately 9,000 new full and part-time jobs would be created in Western Australia, with employment peaking at 13,700 during the height of the

[148] It is important to note that scenario 2 includes the projects of scenario 1.

construction phase. Of these jobs, some 3,900 would be in the South West region[149].

c) Consumption

Over the long-term real consumption in Western Australia would rise by $1,434 million, or 2.39% relative to the Base Case, if the scenario 2 projects were to proceed.

d) Tax Revenue

Development of the scenario 2 projects will lead to increased tax revenue being collected by Western Australia. The increase is $3.0 million in 2005, rising to $180.3 million by 2020, as shown in Table 6.10. This represents a present value increase of $1,282 million over the period 2005 to 2020.

Increase ($M)	2005	2010	2015	2020	PV
GST	2.2	92.7	104.6	114.7	-
Other tax revenue	0.8	41.8	59.9	65.6	-
Total	3.0	134.5	164.5	180.3	1,282

Table 6.10: Scenario 2 State Tax Impact

Company and labour tax on a national basis will increase by $3.6 million in 2005, rising to $124.3 million by 2020, as shown in Table 6.11. This represents a present value increase of $984 million over the period 2005 to 2020.

Increase ($M)	2005	2010	2015	2020	PV
Company Tax	1.4	63.3	117.7	115.3	-
Labour Tax	2.2	32.8	5.8	9.0	-
Total	3.6	96.1	123.5	124.3	984

Table 6.11: Scenario 2 National Tax Impact

6.5 Project by Project Summary

The economic modelling process also provided an indication of the economic impacts of individual projects. A summary of this information is provided in Table 6.12. Detailed information may be found in Appendix 6.

[149] The South West region referred to here is the South West statistical land division rather than the south west coast study region.

	Projects Included	Present Value of Increase ($ million 2001 basis, @ 5%)			Long-term, Full-time Employment Increase
		GDP	GSP	Real Cons.	
Scenario 1	Synthetic rutile exp.	339	594	368	100
	HIsmelt - Collie coal use	147	813	520	200
	Silicon smelter exp.	632	1,264	659	500
	Subtotal	128	711	516	900
Scenario 2	Mid West pig-iron	773	2,934	1,951	1,600
	Aluminium smelter	4,563	10,440	5,598	4,900
	Ferro-silicon	128	711	516	600
	Total	6,764	17,676	10,503	9,100

Table 6.12: Modelling Scenarios and Results
(subtotals are subject to rounding errors; totals for Scenario 2 include impact of gas price change)

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7 INFRASTRUCTURE, ENVIRONMENTAL AND OTHER

7.1 Key Observations

a) Infrastructure Concerns

The major sector of the study region where infrastructure limitations are threatening to constrain growth is the Mid West. Currently several small companies are negotiating with a range of infrastructure suppliers. Co-ordination of matters at State Government level would help to ensure mineral development is not constrained. The Great Southern is also lacking in appropriate infrastructure required to support significant industry development. A study is required to ensure any investment in this region is targeted correctly and aligned with prospective industrial growth.

b) Security of Energy Supply

Towards ensuring security of electricity supply, Western Power has put in place a range of measures, including committing to new peaking power stations and is well advanced in development of arrangements for base load power plant.

The recently completed sale of the Dampier to Bunbury gas pipeline to a consortium led by Diversified Utility and Energy Trusts (‘DUET’), augurs well for expansion of the capacity of the pipeline to meet market requirements for pipeline capacity. However capacity may still be a constraint during peak load periods over the next five years.

c) Uncertainty Regarding Greenhouse Gas Actions

The nature of future actions in relation to climate change and greenhouse gas emissions is uncertain. There is a risk that future global warming mitigation measures could have an impact upon the economics of new minerals developments. Consistency of national and international approaches would help to avoid distortion of investment decisions.

d) Mechanisms to Reduce Greenhouse Gas Emissions Should be Explored

To minimise the cost of compliance with possible future greenhouse abatement measures, a strategy of preparedness as promoted by the Australian Government is wise.

e) Geosequestration Opportunities are of Interest

In particular, opportunities for geosequestration of carbon dioxide are worthy of further investigation.

7.2 Introduction

The objective of this section of the report is to highlight areas where action is required to ensure infrastructure and environmental concerns and other issues do not adversely impact on development of the resource potential of the study region.

Comments in relation to the industrial and social infrastructure of each of the key sub-regions of the study region are set out in Sections 7.3 to 7.6, while environmental and other issues are reviewed in subsequent sections.

7.3 Mid West Sub-Region

The Mid West sub-region ('Mid West') is that part of the study region depicted in Figure 7.1.

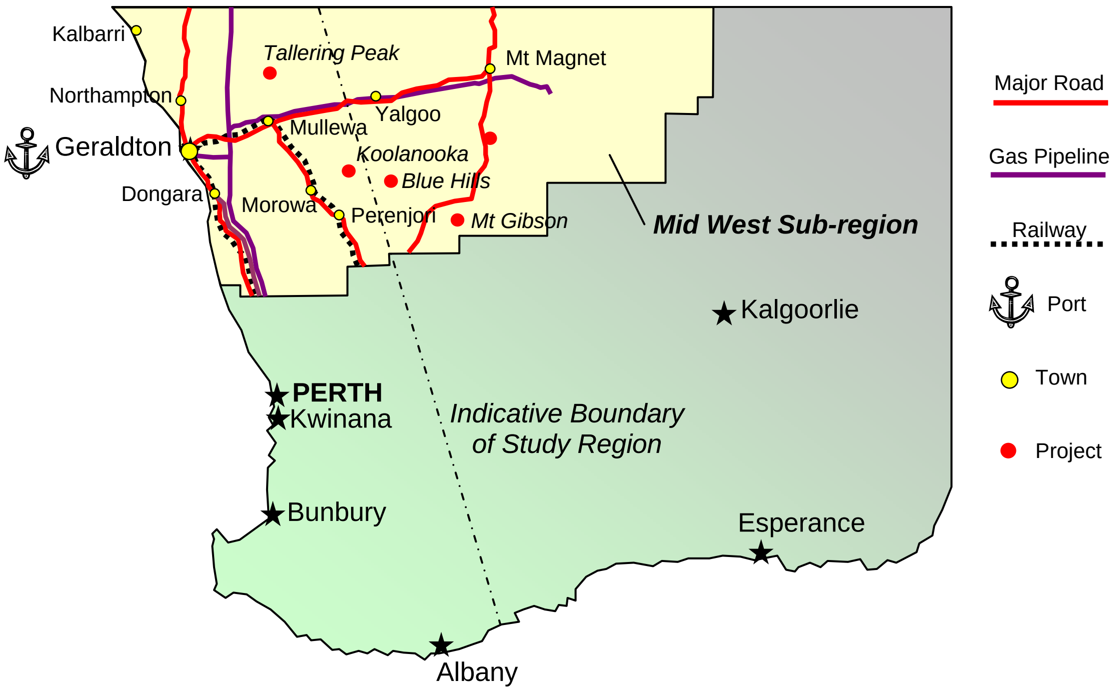

Figure 7.1: Mid West Location and Infrastructure

There are significant infrastructure challenges to be faced in the Mid West if the efficient and effective development of the iron ore deposits of the region is to be supported.

7.3.1 Rail

In a recent report to the Stock Exchange, Mt Gibson stated that Westnet, the owner of rail infrastructure in the Mid West, had advised Mt Gibson that it could only handle 2.3 Mtpa of iron ore on the existing Perenjori, Mullewa, and

Geraldton system without major capital expenditure on track upgrade. This has resulted in a decision by Mt Gibson to concentrate on expansion of Tallering Peak to 2.3 Mtpa whilst delaying development of the Mt Gibson mine by 12 months.

Similarly Mid West has recently announced that rail capacity limitations will result in it concentrating on export of 1.1 Mtpa from the Koolanooka mine while working with Westnet to expand the rail system to a standard capable of supporting magnetite production.

With hematite production from Mt Gibson and Mid West predicted to reach 5.2 Mtpa by 2006 plus planned development by both companies of magnetite production totalling 5 to 9 Mtpa in the 2006 to 2010 period, and other potential developments by Gindalbie, substantial investment is likely to be required in order for the rail infrastructure to achieve the necessary capacity.

7.3.2 Energy

Western Power provides electricity to the Mid West region by dual 132 kV lines. Geraldton, Chapman Valley, Golden Grove, Three Springs and Eneabba each have 132 kV zone substations. Electricity is then distributed by 33 kV lines to Dongara, Kalbarri, Northampton, Mullewa, Narngulu and Nabawa and throughout the Geraldton-Greenough area.

Electricity supplies are supplemented as necessary by 21 MW and 112 MW gas power stations located at Utakarra (Geraldton) and Mungarra (60 kilometres south east of Geraldton) respectively. Mining customers are expected to meet the full cost of upgrading electricity supplies through non-refundable capital contributions.

Development of the magnetite resources of the study region will necessitate upgrading of localised power generation or transmission lines.

The area of the Mid West that is covered by the study region is serviced by both the Parmelia Pipeline and the Dampier to Bunbury Natural Gas Pipeline.

As discussed in Sections 3 and 4 of this Report, there is potential to develop additional power generation in the Mid West area based on local coal or gas, or alternatively gas recovered from a pig iron plant.

7.3.3 Water

As for electricity, additional infrastructure will be needed to provide the water requirements of the magnetite operations as they develop. Water will need to be piped into the area and discussions are understood to have been held between the Shire of Morawa, Mt Gibson, Midwest and Gindalbie in regard to developing shared water and gas pipelines to service the requirements of both the Morawa area and the miners.

7.3.4 Port

The Port of Geraldton has six land backed berths with mineral products currently being loaded through berth 4 and, after installation of another ship loader is completed, through berth 6. The $103 million Port Enhancement Project has been successfully completed with the port now able to handle ships up to 55,000 tonnes.

In its June 2004 report to the Stock Exchange, Mt Gibson indicated that port related constraints had been resulting in shipping delays but that problems were expected to be alleviated by introduction of the new loader. However, this may only be a short-term fix. Assuming rail upgrades take place, export tonnages will increase steadily over the next 5 to 6 years reaching 5.2 Mt by 2006 with the potential to exceed 10 Mt by 2010.

While export in 55,000 tonne vessels may suit customers currently being serviced by Mt Gibson, this limitation raises two potential concerns:

- It places significant restrictions on the customers that can be serviced as many of the larger iron and steel producers in the Asia Region require delivery in Cape size vessels (>80,000 t). As the Chinese Government has a policy to rationalise its iron and steel industry over the next decade, this problem will be exacerbated as the smaller producers are closed down and replaced by modern high capacity plants. Restrictions in the ability to service these major companies could compromise development of iron ore production in the region.

- The number of vessel movements will clearly increase in line with export demand with the potential to eventually exceed port capacity. At 5.0 Mtpa this represents in excess of 100 vessel movements per annum and at 10.0 Mtpa in excess of 200 vessel movements. These will virtually double the current vessel movements in the port which were 234 in 2002/03.

7.3.5 Heavy Industrial Estate

While a significant number of studies have been carried out in regard to development of a new industrial estate in the Mid West, to date no decision has been made to proceed. This indecision has the potential to deter heavy industrial development.

7.3.6 Social Infrastructure

The development of the iron ore mines in the Morawa (population 964), and Perenjori (population 590) areas has the potential to increase the population of these towns by as much as 30% to 50%, placing significant pressure on the facilities within the towns.

7.3.7 Summary

There are a broad range of infrastructure concerns in the Mid West portion of the study region which need to be addressed in a co-ordinated manner.

Government investment in deepening of the port of Geraldton and upgrading export facilities is an excellent first step but needs to be complemented by continued development of transport, energy, water and social infrastructure.

Similarly the region cannot attract heavy industrial projects until it has established industrial estates with appropriate infrastructure and services in place.

7.4 Great Southern Sub-region

The Great Southern sub-region ('Great Southern') is that part of the study region depicted in Figure 7.2.

Southdown Magnetite is the only major power sensitive mineral project that may be developed within the Great Southern over the next ten years. This project, together with the rapidly developing timber industry and its associated potential for value added processing, will require upgrading of infrastructure if development is not to be restricted.

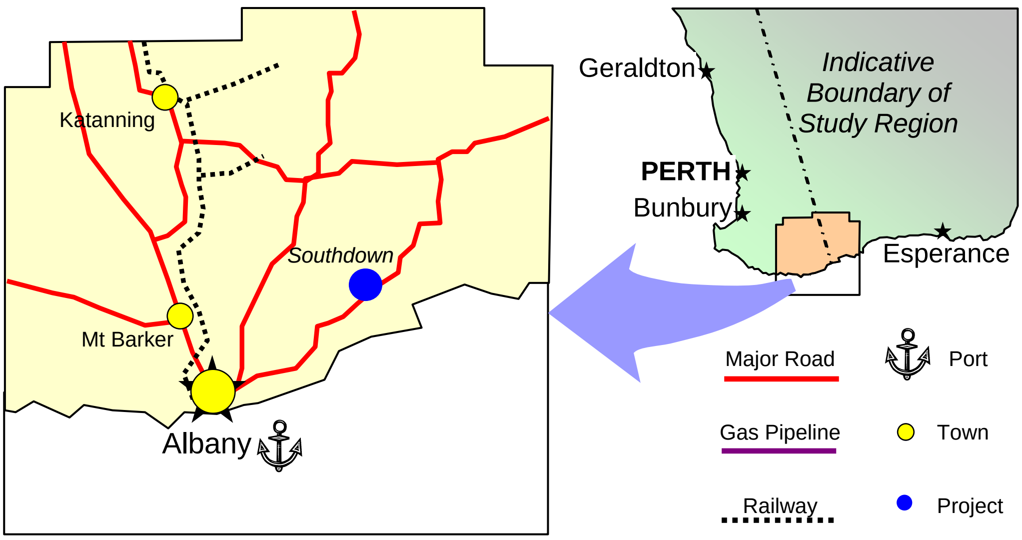

Figure 7.2 Great Southern Location and Infrastructure

7.4.1 Transport

- Rail

The rail service connects the grain regions in the area's hinterland with the port of Albany. It may also have the capacity to service the timber industry although this is mainly expected to be transported by road to wood chipping facilities, and from there by either rail or road to the port.

- Road

The region has a well developed road system which is capable of transporting products from Southdown and also meeting the demands of the region's other industries.

7.4.2 Energy

WPC supplies the region's electricity from the SWIS and there is a fully operational 22 MW wind farm in Albany. Albany also has an LPG gas supply network but is not serviced by gas pipeline infrastructure.

This restricted power availability on the southern extremity of the SWIS may limit the scope for large industry to secure electricity at price levels that are competitive with other locations

7.4.3 Water

Annual water use in the region is currently relatively low at 10 GL. This is projected by the Water Corporation to increase to 32.6 GL by 2020, largely through increased demand to service the wood and paper products industry and expansion of irrigated horticulture activities.

A recent survey by the Waters and Rivers Commission of supply sources in the Great Southern has indicated that, while sufficient water production capacity can be identified, it is mostly from small sources with high development costs or from large sources that are distant from demand centres. In addition, two of the largest sources are of marginal salinity.

Consequently further work is required to determine how water will be sourced to service the projected growth in the area and particularly the development of the timber industry and the Southdown magnetite project.

7.4.4 Port

The Port of Albany serviced one hundred and four vessels with a total trade of 1.9 Mt in 2003, with the majority of exports being associated with the grain and timber industries.

Loading capacity of the Albany port is approximately 47,000 tonnes with average turnaround time is 81 hours per vessel.

In order to service a magnetite mine it would be necessary to increase the capacity of ships that the port can handle to Panamax class (60,000 to 75,000 t) and increase loading capacity to 2,000 plus tonnes/hour.

This would require a significant dredging program of the berths, channel and channel access. Dredging distance would be 9 kilometres to a depth of 14 metres and would be complicated by the unexploded ordinance at the bottom of the harbour.

Magnetite from Southdown would need to be pumped in a pipeline to the port as delivery by truck would have an unacceptable impact on the town of Albany.

7.4.5 Industrial Land

The region has several industrial estates that have been established by the various Shires but there has been little success in attracting industry to these estates.

7.4.6 Social Infrastructure

Albany has the infrastructure to support a significant population growth while several other towns in the region have experienced negative or static growth over the past decade and, as such, might welcome new industrial developments that would reverse this trend.

7.4.7 Summary

The Great Southern will continue to struggle to attract industry. In order to support the ongoing development of the timber industry and facilitate development of greenfields projects such as Southdown, significant planning supported by targeted investment into infrastructure is required.

7.5 South West Region

The South West sub-region (‘South West’) is that part of the study region depicted in Figure 7.3. As a major minerals production and export province, the South West has developed a sound basic infrastructure to support the resource, agricultural and timber sectors of the economy.

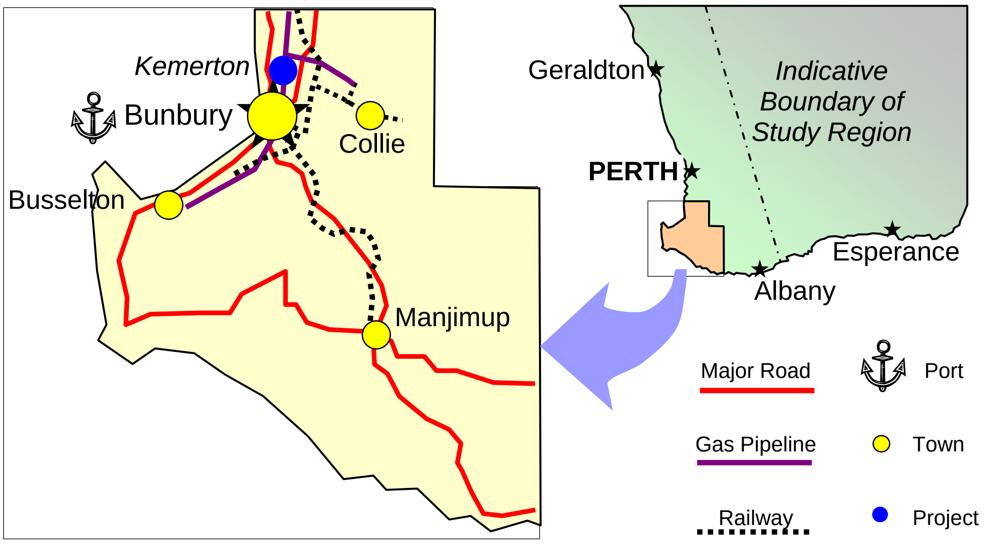

Figure 7.3: South West Region Location and Infrastructure

7.5.1 Rail

The South West Regional rail depot is centred at Picton near Bunbury and the narrow gauge rail network radiates out from there in five main directions:

- north to Perth via Brunswick Junction and Harvey;
- east to Collie via Brunswick Junction;
- south to Boyanup with lines to Manjimup and Capel;
- north-east to the Port of Bunbury, and
- west to the Bunbury passenger terminal.

Major factors that need to be considered in regard to ensuring the rail system meets industry demands include:

- the potential to service Kemerton directly by rail in order to alleviate the necessity to unload trains at Picton and backload material to the consumers;
- the need to expand rail capacity between Brunswick Junction and the Port of Bunbury in order to cater for the increased tonnages projected by the Alumina producers; and
- the introduction of dual gauge (standard and narrow) to the region would allow cargo to be imported/exported to the eastern states without the need for transfer in Perth.

DoIR is currently carrying out a study on the rail system which is understood to be addressing these factors.

7.5.2 Energy

The South West portion of the study region is well serviced in terms of electricity infrastructure with the State's major generation capacity at Collie, supplemented by co-generation facilities at Worsley and a new peaking power station being developed at Kemerton.

The Dampier to Bunbury Natural Gas Pipeline services the region with the main line finishing at Clifton Park and laterals servicing major consumers such as the Worsley Alumina Refinery, and the Capel mineral sands producers. Gas is also supplied to Busselton. There are currently significant constraints on gas transmission capacity south of Kwinana and increased compression and/or additional pipelines are required to meet current and future demand.

Successful development of the Whicher Range or Vasse coal seam methane resources, or discovery of new gas resources, could enhance the availability and reduce the cost of gas within the South West.

7.5.3 Water

The Water and Rivers Commission is responsible for planning to meet future water requirements. Water allocation licences are presently held by three water distribution utilities and by large private users.

While water quality is considered to be adequate for industrial needs, there are still challenges to be met in regards to distribution of and access to water supplies. For example, Kemerton long term water supplies have still to be finalised.

7.5.4 Port

The Port of Bunbury handled a total trade of 12 Mt in 2003 with 323 vessel movements. Over 80% of this was associated with export or import traffic servicing the mining industry.

The port has a long-term development plan for the inner harbour basin, which will accommodate all services when the outer harbour is closed. The inner harbour currently has five berths with a long-term development plan that allows for development of a further six. All berths have excellent land backed facilities, and the port is well serviced by both road and rail.

A major target of both the Bunbury Port Authority and the South West Development Commission is the development of Bunbury as a container port to reduce regional transportation costs.

7.5.5 Heavy Industrial Estates

The Kemerton Industrial Park is a dedicated heavy industrial estate situated 17 kilometres north-east of the Port of Bunbury. Power and gas is available and it is located in reasonable proximity to urban areas supplying access to an established and skilled workforce.

The Blue Water Industrial Estate with an associated 200 MW coal fired power station is also proposed for development at Collie with the potential to service heavy industry requiring access to a significant energy source.

7.5.6 Social Infrastructure

The region is well serviced with several major towns in addition to Bunbury providing attractive locations for placement of industrial workforces.

7.5.7 Summary

While the region is well serviced with infrastructure, continued forward planning is required to ensure that rail capacity and water availability meet industry requirements and do not constrain development.

Availability of maintenance personnel to support major shutdowns, residue disposal sites for mineral processing and development of a container port at Bunbury are key factors that industry has indicated need to be addressed.

7.6 Perth Metropolitan and Peel Region

The major mineral processing plants in this sub- region are located at Kwinana and Pinjarra. Infrastructure in the region is generally of a high standard with the necessary capacity to meet industry requirements and future growth.

However the following concerns have been raised by industry during this Study:

- Continuity of water supply, both on regional sites where groundwater sub-districts are coming under pressure and in the Kwinana Industrial area, needs to be ensured. The development of water recycling and desalination plants in the Kwinana area is leading to concerns regarding potential increases in the cost of water.
- There is a need for expenditure by Fremantle Port Authority to ensure that aging loading and unloading facilities meet both industrial demand and environmental standards. This is seen as particularly important by Kwinana's industry and was highlighted as a concern in the Kwinana Industrial Area Economic Impact Study.
- The cost impost, where new services are developed for an area of land far larger than that required by a developing industry, can be a deterrent to development.

- Interruptions to the operation of and delays in expanding, the Dampier to Bunbury Natural Gas pipeline give rise to concerns regarding security of gas and electricity supplies.

7.7 Infrastructure Issues

Clearly there are significant "black holes" in the infrastructure of the Mid West and Great Southern that need to be addressed. The paucity of infrastructure in these regions is already negatively impacting on resource development and has the potential to stagnate growth unless addressed effectively.

For established producers there is a need to ensure that the cost of infrastructure and utilities remains competitive on an international basis. Inefficiencies in these areas when passed on to consumers can threaten international competitiveness and result in Western Australia becoming less attractive as a location for expansion or establishment of new projects.

Conversely the availability of world class infrastructure and utilities would enhance the State's reputation as an internationally competitive location in which to invest. However any investment in infrastructure must be carefully co-ordinated by the State Government to ensure it is developed in areas of either current demand or of maximum impact to attract industrial development.

The expansion of the DBNGP is seen by industry as a critical requirement.

7.8 Environmental Issues

7.8.1 Greenhouse Gas Emissions and Global Warming

a) Background

The greenhouse effect[150] is a natural phenomenon without which the earth's atmospheric temperature would be sub-zero. There is however concern that human activity (particularly the use of fossil fuels) is leading to increases in the concentration of greenhouse gases[151] in the atmosphere which, in turn, could lead to increased atmospheric temperatures (i.e., global warming) with consequences for the climate and weather patterns.

Table 7.1 provides information on changes in atmospheric concentrations of greenhouse gases that have been caused by human activity.

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[150] Visible (short wavelength) light reaching the earth from the sun passes through the earth's atmosphere and is absorbed by, and therefore heats, the earth's surface. Heat from the surface of the earth is re-radiated as longer wavelength infrared light. Some of the infrared re-radiation is absorbed by greenhouse gases in, and therefore leads to warming of, the earth's atmosphere.

[151] The most abundant greenhouse gas is water vapour (which contributes about 75% of the greenhouse effect). The next most abundant is carbon dioxide.

Concentrations (parts per billion, by volume)	Carbon dioxide	Methane	Nitrous oxide	CFC-11
Current concentration	370,000	1720	312	0.26
Pre-industrial concentration	288,000	850	285	0.00
Increase %pa	0.4	note	0.25	note
Global Warming Impact[152]	1	21	310	3400

Table 7.1: Atmospheric Concentrations of Greenhouse Gases[153]

The concentration of CFC-11 is now declining and the rise in methane concentrations appears to have stopped[154].

While the relative contribution of greenhouse gases to global warming varies (for example, methane has 21 times the impact of carbon dioxide) the increased concentrations of carbon dioxide are, in view of their magnitude, of principal concern in the global warming debate. Accordingly, Government policies aimed at dealing with global warming concerns have a focus on initiatives that will lead to reduction in emissions of carbon dioxide, the bulk of which is associated with the burning of fossil fuels.

b) Carbon Dioxide Emissions

Reflecting its higher carbon density, the combustion of coal leads to greater levels of carbon dioxide emission than the combustion of gas. The difference is increased when the efficiency of fuel use for electricity generation is taken into account. To make a definitive comparison of relative emissions of gas and coal a life-cycle comparison[155] could be undertaken. Such a comparison is not warranted for this Report as it would not alter the conclusions and observations made.

c) Government Initiatives

Governments have addressed global warming concerns in varying ways.

At an international level, the United Nations Framework Convention on Climate Change provides a forum for dealing with climate change issues. The Kyoto protocol, which sets out differentiated emission reduction targets for member

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[152] The global warming impact is an indication of the contribution (relative to carbon dioxide) that molecules of a gas may make to the greenhouse effect.

[153] Information from: ‘The Greenhouse Effect (Information Sheet)’, CSIRO Australia, 16 May 2002.

[154] CSIRO Australia announced on 25 November 2003 that atmospheric methane concentrations, as measured at Cape Grim, Tasmania, had not exhibited any rise over the preceeding four years (compared with a rise of 15% over the 20 years preceding that).

[155] Taking into account emissions associated with upstream coal and gas production or processing activities and making allowance for any losses of gas from the gas system.

countries, was established at a ‘Conference between the Parties’ in late 1998. For Australia (which has not ratified the protocol) greenhouse gas emissions were to be limited to 2% above 1990 levels.

At a national level, the Australian Government has implemented measures to contribute to achievement of the Kyoto protocol, including:

- the introduction of the MRET scheme, which is discussed in Section 4.4.3; and

- as part of the ‘Securing Australia’s Energy Future’ initiatives, the establishment of a $500 million Low-Emission Technology Development Fund to support industry-led projects to demonstrate low-emission technologies (such as geosequestration, which is discussed further in section 7.7.2). Some Australian States have also implemented measures, such as those set out below, aimed at reducing greenhouse gas emissions.

- The NSW Government has implemented a Greenhouse Gas Abatement Scheme that requires electricity retailers in NSW to contribute to a progressive lowering of greenhouse gas emissions expressed on a per capital basis. Unlike the MRET scheme, the NSW Government scheme also encourages non-renewable initiatives (such as improved efficiency of existing generating stations). The penalty for failure to meet prescribed targets is $10.50 per tonne of excess carbon dioxide.

- The Queensland Government has introduced a ‘13% gas scheme’ focussed on increasing the proportion of the state’s electricity that is generated from gas. The penalty for failure to achieve the prescribed percentage is 1.1 c/kWh (indexed).

d) Future Concerns

The key environmental concern faced by proponents of new energy or minerals developments is uncertainty regarding the shape of future international, national and state actions on climate change[156].

There is also concern that the Environmental Protection Authority’s indicated requirements for coal users to meet emission standards that are far stricter than in other States and countries, will, if enforced, place a severe economic impost on both industry and the community more generally.

Consistency of approach is essential in order that investment decisions will not be influenced by jurisdictional differences in environmental costs.

[156] This concern is recognised by the Australian Government. See page 131 of ‘Securing Australia’s Energy Future’, 4th dot point, which recommends a strategy of preparedness aimed at reducing the costs of complying with a future greenhouse constraint.

For example, if a carbon tax of $20 per tonne of carbon in a fuel (which is equivalent to $5.45 per tonne of CO_2 emitted) is introduced the impacts on energy costs would be indicatively as illustrated in Table 7.2

	Cost Increase	
	Fuel	Electricity
Collie Coal	$10.40/t ($0.51/GJ)	0.5 c/kWh
Gas	$0.28/GJ	0.2 c/kWh

Table 7.2: Illustrative Impact of Carbon Tax

7.8.2 Low Emission Technologies

With a view to encouraging development of technologies that will reduce possible future costs of compliance with greenhouse constraints or imposts, the Australian Government has established a $500 million Low-Emission Technology Development Fund to support industry-led projects to demonstrate low-emission technologies.

Major emission reductions from fossil fuel, particularly coal, use might be achievable through initiatives including, but not limited to, those set out below.

- Advances in power-station efficiency

Integrated Gasification Combined Cycle coal based technologies are being explored. Efficiency improvements and reduced nitrous and sulphur oxide emissions are achievable, but further review of this technology is not considered to be warranted for this report.

- Linking coal and renewable energy technologies

Co-firing of biomass with coal in a conventional power station could increase the efficiency of biomass use and decrease taxable carbon dioxide emissions. Similarly, solar-thermal systems can be integrated with a coal fired power station for feed-water preheating and steam raising. Initiatives of this nature are being pursued at the Liddell power station in NSW.

- Geosequestration of carbon dioxide

Geosequestration involves the capture of carbon dioxide created as part of electricity generation or other industrial processes and storage of it deep underground, in either depleted petroleum reservoirs or saline aquifers.

A particular challenge to be resolved is the economic capture of carbon dioxide, which represents about 14% of the flue gas (i.e., gas stream after combustion) for a coal fired power station.

The opportunity could exist for geosequestration of carbon dioxide at locations in the southern coast region. Of particular interest are:

- the now substantially depleted Dongara gas reservoir, where carbon dioxide from power station or processing activities in the Eneabba-Geraldton region might be sequestered with possible beneficial impacts upon the future recoverability of oil from the reservoir (as is done in some West Texas oilfields); and

- Collie Basin opportunities.

Initiatives of this type are worthy of further investigation, particularly if support should prove to be available from the Low-Emission Technology Development Fund. If suitable sequestration sites can be identified, there would also be merit in investigating prospects for development of a ‘common-user’ facility as a basis for securing the state’s long term competitiveness in light of possible future environmental cost impositions.

7.9 Other Issues

7.9.1 Government Approval Systems

Significant concern was expressed by a number of companies regarding what was believed to be the excessive time required to obtain State Government approvals and particularly the environmental approvals process.

This was seen as a key constraint for future projects. While industry accepted that environmental standards need to be high, it believes that the approval process is unacceptably slow, costly and time-consuming and that this situation is continuing to worsen.

Application of the findings of the Keating Report is supported by industry. However, there is concern that the State Government’s moves to implement the findings are inadequate.

7.9.2 Security of Electricity Supply

Several industries that are reliant on the SWIS for power supply expressed concern that security of supply may not be adequate during peak periods over the next two to three years, based on anticipated growth in electricity demand.

The long lead time for development of coal-fired generation and the lack of capacity in the DBNGP are challenges in terms of expanding the State’s generating capacity.

In recognition of these concerns, Western Power and others have put in place a range of measures that will reduce the likelihood of power supply problems during peak demand periods[157]. In addition to Western Power's 240 MW Cockburn plant, which has been operating for 12 months, new plant is scheduled to come on line as set out in Table 7.3.

Start-up date	Owner	Nameplate Capacity
July 2005	Alinta	160 MW Pinjarra 1
October 2005	Transfield	320 MW Kemerton peaking station
October 2007	To be advised[158]	420 MW reserve capacity
2008		300 to 330 MW base load station

Table 7.3: Near-term Power Generation Developments

In addition the recently completed sale of the Dampier to Bunbury gas pipeline to a consortium led by DUET, and involving Alinta and Alcoa, promises some certainty for the expedient expansion of the pipeline.

7.9.3 Pulp and Paper Mill Opportunities

There has been considerable interest in development of a paper pulp mill in the south west coast region with the Collie and Albany areas being identified as possible locations. Whilst not minerals related, a development of this nature may assist in achieving, or alternatively benefit from the availability of a pool of energy at prices below prevailing market levels.

Two alternative pulp mill technologies, as outlined below, are available.

- A chemi-mechanical process, which achieves around 80% yield from input timber, produces pulp best suited to manufacture of materials such as newsprint, packaging and tissues. A chemi-mechanical facility would require around 75 MW of electricity and 7 Glpa of water.

- The 'KRAFT' process achieves a yield of only around 50% but product quality is higher. With the KRAFT process, high organics liquor is burnt to produce electricity which means the net requirement for electricity import is only around 15MW. The capital cost of this technology is, however, about double that of the chemi-mechanical process and the water requirement is up to 25 Glpa.

It is understood[159] that, although electricity transmission system and other infrastructure upgrades could be required to support the development of a pulp mill, energy prices are not the primary obstacle to development of a pulp mill in

[157] Comprehensive details of planned and announced electricity generation initiatives can be found in the publication titled 'Generation Status Review 2004' prepared by Western Power.
[158] Public procurement processes are underway to select proponents for these facilities.
[159] Advice from Western Australian Department of Industry and Resources.

the south west coast region. Rather, the reliability of timber supply needs to be established.

7.9.4 Excise On Liquid Fuels

The focus of this Report is on primary energy and electricity requirements for mining and mineral processing activities, rather than on fuel requirements for mobile plant (as may be used in mining or transportation activities). It is noted however that the fuel excise reforms announced [160] by the Australian Government, and to be phased in from July 2006, will have some desirable impact, particularly on the cost of road transport of materials.

[160] The review of the fuel excise regime was announced as part of the White Paper on Energy titled 'Securing Australia's Energy Future'. The reforms include removal of excise from fuel used on-road in vehicles of GVM greater than 4.5 tonnes and confirmation of the excise exempt status of fuel used off-road or in mine-site power stations.

8 CONCLUSIONS AND RECOMMENDATIONS

8.1 Key Findings

8.1.1 Minerals Opportunities

The south west coast region of Western Australia is a significant mineral province, with in excess of $660 billion of mineral resources, equivalent to 10% of the state's mineral wealth, available for production. While bauxite and coal predominate in terms of resource value, opportunities exist for production of other minerals and, more significantly, for expansion or development of downstream, value-added processing. Key opportunities are outlined below.

a) The Collie coal producers are currently working on schemes to upgrade Collie coal to meet specific market requirements. Griffin Coal has developed a briquetting process using CSIRO binderless technology and Premier plans to develop a pilot plant to produce coal char. Target markets for these products are:

- Synthetic rutile production, where the reduced moisture content of briquettes and / or char has the potential to increase kiln production by 20%;
- HIsmelt's pig iron plant, where the reduced volatile level in char could result in it being suitable for use to displace imported Queensland coal; and
- As a reductant in production of silicon, ferro-silicon and other ferro-alloys.

It is possible that upgrading of Collie coal, to reduce its susceptibility to spontaneous combustion, could also facilitate pursuit of export opportunities.

b) There is strong international demand for silicon and the prospect exists for expansion of production from Simcoa's silicon smelter at Kemerton. While access to markets is the key determinant in the expansion decision, energy price levels are also important. The cost of electricity represents around one-third of the costs of producing silicon.

It is estimated that electricity prices below 4.0 c/kWh will be required for an expansion of silicon production in the south west coast region to be attractive. Silicon production requires up to 25 MW of electricity for a 20 ktpa furnace.

c) Although there has been ongoing but historically unsuccessful investigation of prospects for development of an aluminium smelter within the south west coast region of Western Australia, ongoing review of this opportunity is warranted in view of the following market factors.

- International demand for aluminium is buoyant, and considerable additional smelting capacity will be required over coming years. Development of an aluminium smelter in the south west coast region would build upon the region's well-established and competitive alumina industry base, and would deliver significant commercial and employment benefits to the state; and

- The availability of low-cost hydro-electricity is limited and high-value alternatives (such as LNG production) are emerging for Middle East gas sources that might otherwise have been available for generation of the large quantities of electricity required for an aluminium smelter.

For an aluminium smelter to approach viability in the south west coast region, electricity will need to be available at a price of the order of (and preferably below) 2.6 c/kWh. An aluminium smelter with two pot-lines, producing 700 ktpa of aluminium would require around 1,100 MW of electricity.

d) The potential may exist for ferro-metal production in the south west coast region, with ferro-silicon being of most interest in the short to medium term. The viability of ferro-metal production would be dependent upon electricity being available at prices below 4.0 c/kWh. A 50,000 tpa ferro-silicon plant would require around 45 MW of electricity.

e) Several companies are undertaking feasibility studies for production of magnetite which will be exported either as a concentrate or in pellet form. While energy is an important factor in both these processes, discussions with the companies indicated they will proceed at current 6-7 c/kWh electricity prices.

f) Value-added processing of iron ore, to produce metallurgical pig-iron, is of potential interest and could help to alleviate infrastructure capacity constraints as iron ore export tonnages rise. Various technologies (both gas and coal based) are available for pig-iron production. Energy prices will need to be below $2.80/GJ for gas or $1.50/GJ for coal in order for such projects to be internationally competitive. In order of magnitude terms, the energy requirement is around 10 GJ per tonne of pig-iron.

The international competitiveness of minerals projects within the south west coast region has, historically, been enhanced through:

- the high quality of the minerals resources upon which the projects are based;

- access to a technologically advanced and highly productive workforce;
- the region's proximity to Asian markets; and
- the availability of locally produced coal and plentiful supplies of competitively priced natural gas.

Against this backdrop the competitiveness of existing minerals industries of the south west coast region is reasonably secure. There are good prospects for ongoing expansion of alumina, iron ore and refined nickel production to match growth in international demand.

8.1.2 Energy Supply Prospects

Prospects exist for energy to be sourced in quantities and at prices that might facilitate development of the minerals projects outlined above. Observations of particular relevance are set out below.

a) The coal reserves of the Collie Basin, from which all Western Australian coal production is presently sourced, are sufficient to support significantly expanded rates of production. Simultaneously there is considerable scope for improvement in coal prices, both through competitive pressures and as increased production allows economies of scale to be realised. Western Power Corporation, the state's major user of coal, is presently reviewing its ongoing coal purchase arrangements (bringing competitive pressures to bear) while the supply of coal to meet expanded market requirements would contribute to the achievement of lower production costs. The mining companies active in the Collie Basin (i.e., Griffin and Premier) are also pursuing initiatives, such as the manufacture of coal char and coal briquettes, aimed at opening up both domestic and export market opportunities.

   On the basis of Australian coal industry indicative information, it is estimated that coal prices of the order of $30 to $35 per tonne ($1.50/GJ to $1.75/GJ), and potentially lower, may be achievable.

b) Substantial reserves of coal that will be mineable by open-cut methods also exist to the north of Perth. Development of these reserves will be of particular interest to meet the energy requirements of iron-ore processing projects in the Mid West region, thereby avoiding the considerable cost of transportation of coal from Collie. It is estimated that coal may be available from Aviva Corporation's proposed Eneabba coal mine at prices of the order of $23 per tonne ($1.35/GJ). This is subject to production levels being around 1.5 Mtpa, which would be sufficient to allow good utilisation of mining equipment. At a production level of 0.5 Mtpa, coal prices might rise to between $27.50 and $35 per tonne ($1.60/GJ to $2.05/GJ).

c) Western Australia, including the south west coast region, presently enjoys an abundant supply of natural gas. However, continued development of both gas reserves and gas pipeline infrastructure will be necessary in order for the medium to long-term requirements of the south west coast region to be met. The principal prospective sources of gas for use in the region are the Perth and Carnarvon Basins.

d) The Perth Basin is relatively lightly explored and prospects are considered to be good for discovery of new reserves of gas. Gas discovered within the Perth Basin has an inherent cost advantage, given its location close to established south west coast markets, and is therefore well placed to compete for a share of that market. However, it is unlikely that gas from the Perth Basin would be priced to stimulate market growth unless quantities discovered are well in excess of that which can be placed in the existing market. Indicatively, this would require the proving up of well in excess of 2 EJ of gas (four times the original reserves in the Dongara reservoir).

e) The Carnarvon Basin is the backbone of the Western Australian gas industry. It contains proven reserves of gas that are easily sufficient to meet both long-term Western Australian and prospective LNG export requirements. Ongoing development of gas reservoirs will be required to ensure gas is available in quantities to meet medium to longer term south west coast market requirements. Should there be tightening of supply there could be upward pressure on domestic gas prices as more remote gas reservoirs are developed and in view of trade-offs between domestic and LNG market opportunities.

In the near to medium term the potential may exist for gas to be procured from the proposed Gorgon project, or possibly the North West Shelf project, on terms that will facilitate the development of large, base-load minerals developments. The Gorgon project will have reserves of gas available in excess of likely LNG sales commitments. The sale of gas to a substantive, domestic market opportunity should be attractive relative to the value of longer-term LNG sales forgone at a gas price of the order of $1.85/GJ (excluding transport costs).

f) In addition to the cost of gas procurement, the availability and cost of transporting gas to the south west coast region needs to be considered. At present there is no capacity available in the DBNGP for delivery of gas and, if the gas requirements of prospective new minerals developments are to be supplied by gas from the Carnarvon Basin, the capacity of the DBNGP will have to be either expanded or duplicated.

Published tariffs for use of the DBNGP are presently around $1.06/GJ at a 100% load factor although, through expansion or duplication of the pipeline, lower tariff outcomes should be realisable. Whether or not the benefit of lower tariffs flows through to delivered gas prices may depend upon regulatory outcomes (under the National Third Party Access Code for Natural Gas Pipelines) and individual contract arrangements.

With favourable outcomes, delivered gas prices of the order of $2.60/GJ might be achievable in the south west coast region.

g) Electricity for new minerals developments could be sourced in a number of ways. For base load, interruptible applications, Western Power Corporation is likely to be well placed to supply electricity on competitive terms. Electricity tariffs in the range 3.0 to 3.5 c/kWh, excluding electricity transmission costs, might be achievable for large, steady loads.

For larger loads, on-site (or close to site) generation of electricity is likely to lead to the least cost outcome. This is because the cost of transporting fuel (ie, gas or coal) appears to be lower than the cost of electricity transmission, even before the cost of associated services (such as spinning reserve) is taken into account. Electricity costs in the range 4.0 c/kWh (+/- 0.3 c/kWh), exclusive of transmission costs, are estimated to be widely achievable. Through initiatives such as cogeneration, it is possible that electricity might be generated at considerably lower levels of cost (around 3.0 c/kWh). Alcoa may be well placed to achieve such an outcome.

h) Environmental factors, such as the introduction of a carbon tax, could have a marked impact upon the cost of coal or gas and, hence, electricity. For example, a carbon tax of $10 per tonne of carbon (equivalent to $2.70 per tonne of carbon dioxide) would increase the cost of coal by around $0.25/GJ, the cost of gas by around $0.14/GJ and the cost of electricity by 0.1 c/kWh (gas based) to 0.25 c/kWh (coal based).

i) While renewable energy sources will undoubtedly have an increasingly important role to play in the supply of future energy and electricity requirements, it is not yet possible to source renewable energy at prices that will facilitate the development of the identified minerals opportunities developments. In addition, renewable electricity sources typically suffer from the need for and the costs of back-up supply from conventional generation sources. Of the potential renewable electricity sources, geothermal (hot-dry-rock) applications appear to have reasonable potential, particularly if carbon related taxes are introduced. The performance of the Cooper Basin hot-dry-rock demonstration project will therefore be of particular interest.

8.1.3 Other Considerations

The prospect that energy might be procured at prices to meet the estimated threshold requirements of the minerals development opportunities is unlikely, by itself, to ensure that any particular development will proceed. All prospective developments are sensitive to a range of factors other than energy prices including, for example:

- market factors;
- world competitive capital costs:
- the availability, security and cost of utilities and raw material;
- access to appropriate infrastructure, particularly efficient rail and port facilities;
- ongoing access to a productive, cost competitive workforce;
- successful development of facilitating technologies, such as the use of coal char to displace imported coal; and
- extraneous factors over which Western Australian project proponents have no influence, such as the provision of incentives for development in other, competing locations.

Table 8.1 provides a subjective assessment of the potential for infrastructure related issues to have an impact upon the viability of minerals development opportunities within various sub-regions of the south west coast region.

Sub-region	Infrastructure Category					
	Port	Rail, Road	Elect	Water	Land	Social
Mid West	✗✗	✗✗✗	✗✗	✗✗	✗✗	✗✗
Perth and Southwest	✗	✗	✓	✗	✗	✓
Great Southern	✗✗	✗	✗✗	✗	✗	✓

Table 8.1: Perceived Subjective Impact of Infrastructure Issues
(✓ indicates satisfactory; ✗ indicates issues to be addressed)

Overall, the Mid West region (ie, to the north of Perth) is perceived to have a range of broad infrastructure issues that will need to be addressed in a coordinated manner in order that development prospects will not be compromised. In particular, transport, energy, water and social infrastructure needs to be in place to support industry development.

While prospects for minerals developments in the Great Southern region are limited, there is likely to be a need for targeted investment to support prospective developments (such as the Southdown iron ore project) as well as developments in other industries, such as agriculture and timber.

In the Perth and Southwest regions infrastructure is generally of a good standard with capacity to meet industry requirements and future growth. However, continued forward planning will be desirable to ensure that rail capacity and water availability meet industry requirements and do not constrain development. The availability of residue disposal sites and the development of a container port at Bunbury are other infrastructure factors that industry has indicated need to be addressed.

In addition industry has indicated significant concern in regard to the length of time required to obtain Government approvals for new projects. Lead times of 2 to 3 years are not uncommon and this delay in bringing projects on-line could reduce the attractiveness of pursuing development opportunities in the south west coast region.

8.1.4 Development Benefits

If the identified minerals development opportunities are realised, significant benefits will accrue to Western Australia. The magnitude of the potential benefits has been estimated using computable equilibrium modelling techniques, and selected key impacts are presented in Table 8.2.

If all identified projects proceed, Western Australia's GSP could be increased by more than $2 billion per annum, State revenue increased by $160 million per annum and 16,200 new jobs created.

The opportunities that are considered most likely to be realised are those that are essentially brownfields in nature (ie, expansions or developments of existing operations), that is:

- expansion of synthetic rutile production (through use of coal briquettes);
- displacement of imported coal from HIsmelt, through use of coal char; and
- expansion of silicon metal production.

It is perceived that greenfields development opportunities, as listed below, will require more favourable energy cost outcomes.

- production of magnetite, magnetite pellets and pig-iron, most likely using coal from new mining development at Eneabba;
- production of ferro-silicon; and
- production of aluminium, using electricity generated on-site and/or in association with alumina production activities.

Project	Indicative medium term annual impact			
	GSP increase	Consumption increase	Employment increase	WA tax revenue increase
Expanded synthetic rutile production	$60m	$36m	200	$4.6m
Displacement of imported coal from HIsmelt	$80m	$50m	200	$5.9m
Silicon metal expansion	$175m	$80m	500	$12m
Subtotal Brownfields	**$315m**	**$166m**	**900**	**$22.5m**
Pig-iron production	$360m	$225m	1,600	$28.6m
Ferro-silicon production	$100m	$70m	600	$9.3m
Aluminium production	$1,500m	$725m	5,000	$100m
Subtotal Greenfields	**$1,960m**	**$1,020m**	**7,200**	**$137.9m**
TOTAL	***$2,275m***	***$1,186m***	***16,200*** [note]	***$160.4m***

Table 8.2: Indicative Annual Impact of Identified Projects

Note: This figure represents a notional aggregate of the peak full-time and part-time employment during project construction based upon construction employment effects being double the medium to long term direct and indirect employment impact. The economic impact analysis presented in Appendix 6 takes account of the anticipated timing of the tabulated projects plus the impact of other factors and identifies a peak employment impact of 13,700 in 2009.

8.2 Issues Requiring Attention

In the course of this Study a number of issues have been identified that require attention if the identified development opportunities and the benefits that flow from them are to be realised. The identified issues are set out below. For ease of reference the issues have been grouped by subject area. Recommendations for dealing with or addressing the issues are presented in Section 8.3.

8.2.1 Availability and Price of Energy

a) Coal

Issue 1: Provided coal is available at prices of the order of $1.50/GJ, prospects for coal-based production of pig-iron in the Geraldton region are good. Development of the coal reserves of the northern Perth Basin will be instrumental to achievement of this outcome, and should be actively promoted.

Issue 2: It is desirable that opportunities for rationalisation or expansion of Collie coal production activities, so as to achieve improved economies of scale, be pursued.

Issue 3: Successful demonstration of the technical and commercial viability of briquette and coal-char production, and of their suitability for use in synthetic rutile production and/or the HIsmelt process will allow significant benefits to be realised including improved economies of coal production.

b) Gas

Issue 4: Capacity constraints in the Dampier to Bunbury Natural Gas Pipeline need to be addressed. Economies that are expected to be achievable as the pipeline is expanded need to flow through to delivered gas prices.

Issue 5: The availability of gas from Perth Basin reserves will contribute to competitive gas market outcomes. It is desirable that Perth Basin exploration activities be promoted. It is also important that:

- mechanisms to allow utilisation of gas from small reserves (the economics of which may be challenging) be identified and implemented;

- techniques for production of gas from tight formations be commercialised; and

- unduly onerous technical regulatory requirements (that increase gas production costs) be avoided.

Issue 6: Ongoing development of Carnarvon Basin gas reserves will be important to ensure the continued, competitive availability of gas to meet domestic requirements. The approach taken in approving development of the Gorgon project (ie, reservation of a quantity of gas for domestic applications) is a useful precedent for future developments. In the case of greenfields developments, such as the proposed Gorgon project, a sufficient foundation load will be required to underwrite investment in infrastructure to supply the domestic market.

c) Electricity

Issue 7: Prospects are good for continued access to competitively priced gas and coal. However, reform of the electricity sector is required to allow effective competition in the electricity sector.

Issue 8: For development of an aluminium smelter to achieve viability, electricity will need to be available for around 2.6 c/kWhr. To achieve this will require both a high level of electricity generation efficiency and delivered gas prices below $2.50/GJ (which, in turn, requires a lowering of both the cost of gas and the cost of transportation through the DBNGP).

d) Renewable Energy

Issue 9: Renewable energy sources are not presently competitive with traditional, fossil-fuel based electricity generation and cannot deliver electricity tariffs that will promote new minerals related developments. However, geothermal (hot dry rock) technologies show promise and there may be merit in investigating opportunities for application of the technology in the south west coast region.

8.2.2 Environmental Considerations

Issue 10: State Government policy incorporates, among other things, the promotion of fuel diversity, with coal and gas to have equal opportunities for use. Within this policy framework, the Environmental Protection Authority ('EPA') is responsible for assessing and making recommendations on environmental matters without regard for other issues (such as social or economic factors), which can be taken into account by the Minister for the Environment.

A clear and non-discriminatory policy framework on greenhouse gas emissions from energy use needs to be developed by Government and relevant agencies. The policy should have regard for social and economic imperatives so as to be consistent with the fuel diversity policy and State Sustainability Strategy. The opportunity for public consultation should be afforded.

Issue 11: Greenhouse gas related imposts on the use of fossil fuels will, if applied, increase the cost of energy and electricity. A consistent approach to these matters, both within Australia and internationally, is required in order that the competitiveness of the south west coast region is not compromised relative to other Australian or overseas locations.

Issue 12: The Australian Government's aim to promote development of technologies that will reduce possible future costs of compliance with greenhouse constraints or imposts is logical. In this context, initiatives appropriate to the south west coast region, including potential sequestration opportunities, need to be pursued. Opportunities may also exist for the State Government and industry to work with the Australian Government with funding through the $500 million Low-Emission Technology Development Fund.

8.2.3 Non-energy Issues

a) Technical and Productivity Improvements

Issue 13: Although the competitiveness of existing minerals production and processing operations in the south west coast region is reasonably secure, changing economic circumstances (eg, exchange rates) and the potential for cost or efficiency improvements to be achieved in competing locations could adversely impact the international competitiveness of local producers. Consequently it is critical that ongoing attention is paid to the level of all costs of operating within the south west coast region.

b) Infrastructure

Issue 14: If the significant potential for iron-ore based developments in the Mid West region is to be realised a range of infrastructure constraints must be addressed. Since iron-ore based developments will be progressive (ie, initial growth of hematite exports followed by magnetite mine development and subsequently, pellet and pig-iron production) a coordinated approach should be adopted in resolving these issues in order to meet long-term demands.

Immediate upgrading of rail systems is necessary and, as export tonnages increase, deep-water port facilities will be required. In addition, industrial land with access to the deep-water port facilities needs to be developed and water, electricity and social infrastructure constraints addressed.

Issue 15: Infrastructure issues in the South West and Great Southern regions will need to be addressed. In the South West Region it is likely that rail capacity between Brunswick and Bunbury Port will not be adequate to meet transportation requirements as expansions of alumina production take place. In addition, extension of rail infrastructure to Kemerton and the establishment of container facilities at the Bunbury Port would contribute to the economics of silicon and titanium pigment production in the south west.

In the Great Southern Region, transportation and electricity infrastructure constraints will have an impact upon the Southdowns iron-ore project and upon developments in other industries (for example, the development of a paper pulp mill).

c) Downstream Processing

Issue 16: To realise the potential for development of an aluminium smelter in the south west coast region will require a number of energy related and other outcomes to be achieved. The beneficial impacts of a smelter development (eg, an average $1.2 billion per annum increase in GSP and additional State tax revenue of $1.2 billion over the period to 2020) provide a strong incentive to promote these outcomes.

Issue 17: The advantages of the south west coast region with its world competitive titanium pigment plants and technologically competent workforce can be promoted in support of the location's selection for development of a titanium metal pilot plant to commercialise new production technologies.

d) Project Approvals

Issue 18: There are significant concerns about the time being taken by State Government departments to process approvals required for new minerals projects and for expansions of existing projects. The proposed establishment of a coordinated approvals process, in line with the recommendations of the Keating Report, will assist in dealing with this problem but it is unlikely (in view of resourcing and empowerment issues) that the proposed approach will be adequate.

It is critical that the Government process, while ensuring appropriate standards are maintained, is carried out within timelines that do not place unacceptable time and cost imposts on industry.

e) Resource Depletion

Issue 19: As the identified mineral sand resources of the south west coast region are depleted there may be a requirement for development of mines in areas that are increasingly sensitive from a social and environmental perspective. There may be an eventual need for import of ilmenite for use in synthetic rutile production.

8.3 Recommendations

Table 8.3 sets out recommendations for dealing with or addressing the issues identified during the course of this Study. Implementation of these recommendations will remove impediments and open up the potential to facilitate further development of the minerals opportunities of the south west coast region, resulting in significant employment and financial benefits for the region, the State and Australia.

	Recommendation	Issues Addressed	Responsibility	Due
Recommendations Relating to Availability and Price of Energy				
1	Development of a northern Perth Basin coal mine as a source of energy supply to facilitate iron-ore processing initiatives should be promoted. The Department of Industry and Resources ('DoIR') should provide active facilitation and support for industry participants.	1, 13	Industry DoIR	ongoing ongoing
2	Cooperative initiatives (eg, joint venture approach) that may allow improved economies of coal production should be investigated.	2	Industry	2005
3	The Collie coal companies should complete their programmes of research into and commercialisation of coal briquette and coal char production. Gasification related technological developments should be monitored.	2, 3	Industry	ongoing
4	The capacity of the Dampier to Bunbury Natural Gas Pipeline should be expanded and any resulting economy of scale benefits that are realised should flow through to gas transportation tariffs.	4, 8	Industry	ongoing
5	Perth Basin exploration prospects should be further promoted.	5	DoIR	ongoing
6	To assist in promotion of Perth Basin exploration, the Geological Survey Division of DoIR should undertake research that will allow a better understanding of exploration prospects or that will contribute to identification and commercialisation of techniques for production of gas from tight formations.	5	DoIR	ongoing
7	Mechanisms to avoid stranding or flaring of small or associated gas resources should be actively pursued. This could include, for example, the use of CNG technologies.	5	Industry	ongoing
8	An audit of technical regulatory requirements (relating to gas production activities) should be undertaken, with input from industry stakeholders, to ensure Western Australian requirements are not unnecessarily onerous.	5	DoIR with Industry	2005

Table 8.3: Recommendations, Including Responsibilities and Timing

	Recommendation	Issues Addressed	Responsibility	Due
9	Ongoing development of the gas resources of the Carnarvon Basin, including for supply of gas for domestic purposes, should be promoted.	6, 8	DoIR Industry	ongoing
10	Development of gas reserves to ensure there is competition for supply of gas to meet present and future domestic market requirements should be actively encouraged. This could involve working with industry stakeholders to identify foundation loads that will allow timely development of new gas projects.	6, 8, 13, 16	DoIR and Office of Energy	ongoing
11	DoIR, in conjunction with the Department of Treasury and Finance (‘DTF’), should establish a working group with industry stakeholders to identify and remove barriers to development of an aluminium smelter within the south west coast region.	6, 8, 16	DoIR DTF	2005
12	Development of the Western Australian electricity market, to facilitate and promote competition between generators of electricity, should be continued	7	Office of Energy	ongoing
13	Potential sites in the south west coast region, if any, that are suited for use of hot dry rock electricity generation technologies should be identified by the Geological Survey Division and data made available for consideration by prospective project developers.	9	DoIR	2005
Recommendations Relating to Environmental Considerations				
14	A clear statement of policy regarding carbon dioxide emissions should be developed and promulgated by the Western Australian State Government and applied in a consistent manner.	10, 11	DoIR Office of Energy	asap
15	A consistent Australian and international approach to greenhouse gas issues and imposts is required.	11	Office of Energy Australian Greenhouse Office	ongoing
16	Prospective geosequestration sites within the south west coast region should be identified by the Geological Survey Division of DoIR.	12	DoIR	2005

Table 8.3: Recommendations, Including Responsibilities and Timing (continued)

	Recommendation	Issues Addressed	Responsibility	Due
17	The technical and commercial viability of establishing a ‘common-user’ carbon dioxide sequestration facility to service the needs of industry in the south west coast region should be investigated.	12	DoIR	2005
18	Opportunities for low emissions research (including geosequestration) should be identified and research programmes involving industry or other stakeholders developed to take advantage, if possible, of the Australian Government’s low emissions research program.	12	DoIR and Industry	2005, then ongoing
Recommendations Relating to Non-Energy Issues				
19	Opportunities for ongoing productivity improvement need to be identified and pursued to ensure the international competitiveness of industry in the south west coast region is maintained.	13	Industry	Ongoing
20	Consideration should be given to assisting industry by identifying issues of general concern and, as appropriate, promoting research through Cooperative Research initiatives (such as the A J Parker Centre for Hydrometallurgy, the WA Energy Research Alliance or the Australian Resources Research Centre).	13	DoIR	Ongoing
21	Consideration should be given to carrying out a ‘skills inventory’ to identify skills requirements and availability in the medium to longer term and to promote training and education programmes to meet identified shortfalls. DoIR should facilitate this process with input from relevant Departments and industry.	13	DoIR	2005
22	A solution for the Mid West infrastructure constraints needs to be identified and implemented immediately in order to ensure proposed iron ore developments in the region are not further impeded. In order to achieve this, a working group including DoIR, the Department for Planning and Infrastructure (‘DPI’), industry and the major infrastructure providers needs to be established to facilitate necessary solutions.	13, 14	DPI, DoIR	2005

Table 8.3: Recommendations, Including Responsibilities and Timing (continued)

	Recommendation	Issues Addressed	Responsibility	Due
23	DoIR and DPI, in conjunction with the Mid West Development Commission should undertake a focussed review of medium and long-term infrastructure requirements with input from industry stakeholders to develop plans and strategies to ensure infrastructure is developed in line with industry requirements. The review should address transportation and port infrastructure as well as water, electricity, the availability of industrial land, and social infrastructure requirements and should include input from industry stakeholders.	13, 14	DPI, DoIR and Mid West Development Commission	2005-2006
24	Consideration should be given, if necessary, to the use of innovative infrastructure financing arrangements.	14	DoIR and State Treasury	as required
25	DoIR, with the Department of Planning and Infrastructure and with input from key stakeholders in the minerals and other industries, should carry out a comprehensive study to identify long term infrastructure requirements in the Southwest and Great Southern regions. Coordinated strategies should be developed to ensure infrastructure is in place as required to support regional development.	15	DoIR	2005
26	DoIR in conjunction with the Great Southern Development Commission should carry out a study to determine the region's competitive position in regard to industrial and commercial development and determine how this potential should be promoted.	15	DoIR, Great Southern Development Commission	2005
27	The benefits that may be realised through development of an aluminium smelter are significant and, accordingly, appropriate project facilitation should be provided.	16	DoIR State Treasury	as required
28	DoIR should promote the development of a pilot plant to demonstrate new titanium metal production technologies. DoIR should be aware of companies involved in this avenue of pursuit in order to successfully promote the south west coast region.	17	DoIR	near term

Table 8.3: Recommendations, Including Responsibilities and Timing (continued)

	Recommendation	Issues Addressed	Responsibility	Due
29	A more rigorous, fully resourced and empowered approach is required to implement the recommendations of the Keating Report to ensure Government approvals processes are not an obstacle to project developments or expansions. The State Government must clearly understand industries' concerns in regard to the approvals processes and implement an integrated approvals system consistent with "world best practice".	18	DoIR, CME	2005
30	DoIR should coordinate matters relating to development of mines in sensitive areas. This will involve working with industry and communities to identify and address issues at an early stage so that there can be a logical and timely progression of mine development.	19	DoIR	ongoing

Table 8.3: Recommendations, Including Responsibilities and Timing (continued)