PETROLEUM AND MINERAL ROYALTIES IN SOUTH AUSTRALIA*

By R.A. Laws**

INTRODUCTION

With only minor exceptions, minerals and petroleum *insitu* are the property of the Crown. Minerals beyond the three nautical-mile limit and underlying Commonwealth land are the property of the Commonwealth while within this limit they are the property of the relevant State or Territory.

Royalties are owing to the Crown following the recovery of petroleum and minerals at which point ownership is transferred to the person who undertakes the recovery. Royalties can therefore be clearly distinguished from tax, as they are the price paid for the transfer of ownership. In recent years the Commonwealth has led an active debate centred on this question of price — what is the appropriate rate of return to the community which should apply from granting access to publicly-owned resources?

It is therefore timely to review the current royalty situation in South Australia and to canvass possible future developments. Royalties paid since 1980/81 are listed in Table. 1.

Table 1
ROYALTIES PAID IN SOUTH AUSTRALIA
($million in $'s of the Year)

	Petroleum	Minerals (including coal)	Total
1980/81	4.621	1.914	6.535
1981/82	5.738	2.273	8.031
1982/83	6.500	2.072	8.572
1983/84	11.073	2.324	13.397
1984/85	24.319	2.483	26.802
1985/86	54.520	2.773	57.293
1986/87	29.250	3.342	32.642
1987/88	31.324	3.370	35.054
1988/89	28.170	5.710	33.880
1989/90	33.322	9.618	42.940
1990/91	68.200(est)*	10.800(est)	79.000(est)*

* Includes one-off benefit due to change from 6 monthly to monthly payments for Petroleum Royalty of $13 million.

* This paper was presented to the Joint Northern/South Australian State Branches' Conference, Alice Springs, May, 1991.

** Director, Ore & Gas Division, SA Dept. of Mines & Energy.

HISTORY

It was not until 1889 that minerals on new land purchases were vested in the Crown in South Australia. From the founding of the colony until this date, mineral rights had been attached to ownership of the land. Between 1846 and 1848 an attempt had been made to collect a royalty of 1/15 of the value of metalliferous minerals produced from new-lands sold, but this proved less than popular and collection difficult.

In 1940, all petroleum was declared to be the property of the Crown and in 1971 minerals followed suit with proclamation of the Mining Act. Any person who could establish prior ownership to minerals could apply for the grant of a 'private mine' and claim the consequent royalties. Approximately 200 private mines are currently in existence.

MINERAL ROYALTIES

MINING ACT, 1971

The principal royalty provisions of the Mining Act are summarised in Appendix I. The Act provides that royalties are levied at a rate of 2.5 per cent (or in the case of extractive minerals, 5 per cent) of an assessment made by the Minister of the value of the minerals delivered to the nearest port. No royalty is charged on opal, mainly due to the considerable practical difficulty and complexity which would be attached to its assessment and collection.

On either a weight or volume basis, the bulk of minerals produced in South Australia are extractives, which comprise those used for aggregate, ballast, road making, bricks etc, but do not include those commodities when used for a 'prescribed' purpose such as chemical manufacture, fertilizer, lime and glass manufacture, etc, on which the normal 2.5 per cent *ad valorem* royalty applies.

The currently assessed value of non-metallic minerals is summarised in Table 2. Royalties on metallic minerals are calculated on a case-by-case basis, by reference to the selling price, netted back to an ex-mine value of production, appropriately adjusted if necessary for transport charges to the nearest port.

Royalties are not levied on the production from private mines except when this involves extractive minerals, where the normal 5 per cent royalty applies. The currently-assessed value of extractive minerals is $2/tonne, giving a royalty of 10c/tonne. All of the royalties from extractive minerals (currently amounting to about $1 million/year) are paid into the Extractive Areas Rehabilitation Fund which is used for the rehabilitation of abandoned mines and quarries.

MINERAL ROYALTIES NOT UNDER MINING ACT

Royalties on iron ore production by BHP, and of production at Olympic Dam and Leigh Creek are not governed by the Mining Act. Royalty on iron ore mined by BHP in the Middleback Ranges is calculated under the BHP Indenture Act, 1958 and is based on the price of pig-iron, FOB Port Adelaide. Pig-iron is no longer exported, but the in-

Table 2
SA ROYALTIES — NON-METALLIC MINERALS
(value assessed by Minister)

	Assessed Value ($/tonne)	SA Royalty Paid ($/tonne)	SA Production 1989/90 (tonnes* × 1000)	Royalties Paid Interstate ($/tonne unless indicated otherwise)					
				WA	Qld	NSW	Vic	Tas	NT
Barite	$24.00 $14.00	0.60 1st grade 0.35 2nd grade	12	5% FOR or FOB	0.50	0.50	2.75% ex-mine	0.50	1.25% ex-mine
Dolomite	$10.00 $ 5.00	0.25 1st grade 0.125 2nd grade	991	0.30	0.25	0.50	”	0.50	”
Gypsum	$ 8.00 $ 4.00	0.20 1st grade 0.10 2nd grade	400	0.30	0.35	0.35	0.30	0.30	”
Jade	$5,000 $1,000	$125.00 $25.00	0.014						
Kaolin	$ 8.00 $ 4.00	0.20 1st grade 0.10 2nd grade	6	5% FOR OR FOB	0.50	0.50	2.75% ex-mine	0.50	”
Limesand	$ 4.00	0.10	18	0.30 to 0.50	0.30	0.35	2.75% ex-mine	0.25	”
Limestone	$ 4.00	0.10	1834						
Magnesite	$ 8.00	0.20	1	5% FOR or FOB	0.50	0.70	2.75% ex-mine	0.50	”
Micaceous Haematite	$14.00	0.35	—	5% FOR or FOB	0.35	4% ex-mine			
Phosphate	$ 4.00	0.10	5		5% ex-mine				
Rock Silica	$ 4.00	0.10	38	0.50	0.50	0.45	0.60	5% of profit	
Silica Sand	$ 2.00	0.10	74	0.30	0.50	0.25	2.75% ex-mine		
Salt	$ 8.00	0.20	1006	0.24	1.00	4% ex-mine	2.75% ex-mine		
Talc	$22.00 $10.00	0.50 1st grade 0.25 2nd grade	14	0.5	5% ex-mine	0.85	”		
Extractives**	$ 2.00	0.10		0.50		0.25	0.62	0.50	”

* includes production from private mines
** includes ornamental building stones

denture provides for the royalty to be calculated on a formula as if it were. As a result, a royalty on high grade iron ore of $1.10/tonne currently applies.

For the giant Olympic Dam copper/uranium/gold deposit owned by WMC and BHP, royalties are levied under the Roxby Downs (Indenture Ratification) Act 1982 (SA). This Act provides for a royalty of 2.5 per cent of the ex-mine value of production during the early years of operation, rising to 3.5 per cent five years after an agreed commencement date. As considerable processing occurs at Olympic Dam (it is the only mine in the world to produce refined copper on site), the ex-mine value is greater than normally would be the case. The Act also provides for a profit related royalty on any surplus in excess of a threshold value, calculated on a sliding scale which commences at zero when the annual rate of return on investment is 120 per cent of the ten year bond rate, increasing to 15 per cent when the rate of return is 240 per cent or more of the bond rate. The 1 per cent in *ad valorem* royalty is alowable as a deduction from the profit related royalty payment.

Coal is mined at Leigh Creek by the Electricity Trust of South Australia under leases issued under the Electricity Trust of South Australia Act, 1946 (SA) and is not subject to the Mining Act. By agreement, a royalty is levied of 2.5 per cent of the cost of the coal delivered to the power stations at Port Augusta.

OFFSHORE MINERAL ROYALTIES

Legislation governing offshore mining in Commonwealth waters (beyond the three nautical mile limit) is governed by the Minerals (Submerged Lands) Act, 1981 (Cth) which was not proclaimed until 1990.[1] Mirror legislation to apply within the Territorial Seas will be introduced by the States after further amendments are made to the Commonwealth legislation. No agreement has been reached on the issue of the royalty regime to apply.

PETROLEUM ROYALTIES

COOPER BASIN (RATIFICATION) ACT, 1975 (SA)

Royalties on the majority of petroleum production from the Cooper Basin are paid under the Indenture of the Cooper Basin (Ratification) Act, 1975 (the Indenture) and not under the Petroleum Act. Three small fields have been discovered outside of the Indenture Area (which occupies approximately 30 per cent of the Cooper Basin Producers' exploration licences) to which the royalty provisions of the Petroleum Act apply.

Until 1991, the Indenture provided that:

- Royalty was paid at six-monthly intervals at a rate of 10 per cent of the wellhead value of the petroleum, taken to be the selling value, less certain deductions.

1. See generally J D Stewart, 'Offshore Minerals Act' (1991) 10 *AMPLA Bulletin'* 90.

- The deductions comprised operating costs (including offsite overheads) and capital costs related to field and Moomba facilities depreciated over 15 years on a credit foncier basis at an interest rate equivalent to 120 per cent of the long term government bond rate (LTGBR). Capital costs for the liquids pipeline and Port Bonython were calculated on a credit foncier basis over 15 years at an interest rate of 18 per cent, but with the deduction continuing until destruction, disposal or cessation of use of the facility.
- There was provision for the State to open negotiations for a new royalty to apply from 1 January 1988 on petroleum liquids providing there had been a significant increase in royalty or related charges interstate since 1 January 1982.
- In the event royalty negotiations failed (there was an agreed range of factors to be taken into account during these negotiations), the State had the right to increase the royalty rate on petroleum liquids to a maximum of 12.5 per cent from 1 January 1988 with no limit on the gas royalty rate (other than it be as provided in the Petroleum Act).
- Royalty on gas reverted to the Petroleum Act provisions on 1 January 1988 and on petroleum liquids on 1 January 1993 (this issue was an important point of disagreement with the Cooper Basin Producers).

Royalty negotiations were not initiated until mid- 1989, to avoid conflict with new gas sales contracts finalised earlier in the year. During the negotiations, the central thrust of the State's position was that South Australia should not receive less royalty than would apply under equivalent regimes in other States. Using a comprehensive economic model of the Cooper Basin built up from data supplied in previous royalty and exploration expenditure returns, the Department of Mines and Energy (DME) prepared forecasts of future royalties payable under the range of Australian wellhead regimes set out on Table 3.

These forecasts showed that from a basic 10 per cent wellhead royalty rate, the State would receive only 4.6 per cent of the net present value of future Cooper Basin sales revenues, compared to 6.8 per cent under the Queensland regime (Table 4).

Agreement was finally reached early in 1991 with 10 of the 11 Producers for a new royalty regime to apply throughout their Cooper Basin licences, ie. for both the Indenture and non-Indenture areas. The dissenting Producer was Delhi Petroleum Pty Ltd. The new regime, which will ensure South Australia achieves parity with other States, was effected by an amendment to the Indenture in March 1991. The new regime provides:

- that it will operate from 1 January 1991 to 31 December 2000.
- a 10 per cent wellhead royalty rate;
- the royalty paid monthly on the basis of actual selling value less estimated deductions reconciled annually;
- all operating costs to be deductible from the selling value but with offsite overheads limited to direct labour;
- a reduction in the undepreciated capital as at 1 January 1991 from $1200 million (approx) to $800 million, to be depreciated over 10 years on a straight line basis with no interest;

Table 3
AUSTRALIAN ROYALTY REGIMES

The table below sets out the comparison of how various Australian wellhead royalty regimes would be applied to the SA Cooper Basin project. Where available, the regime selected is that which has been applied to a significant project in each State, or in the case of WA, a scheme that would probably be applied to a significant new onshore development.

	Royalty Rate (%)	Upstream Method	Capex Period (years)	Deprec Interest (%)	Down-stream Method	Capex Period (years)	Deprec Interest (%)	Debt/ Equity Ratio (%)
SA	10	CF	15	LTGBR×1.2	CF	15	18	N/A
Qld	10	SL	10	0	CF	10	LTGBR+4%	N/A
NT	10	SL	10	0	SL	10	0	N/A
Vic (off)	12	SL	20	8.5	SL	20	8.5	100
WA	12.5	SL	10	LTGBR	SL	10	LTGBR	60
Vic (on)	10	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Notes LGBBR = Long Term Government Bond Rate
CF = credit foncier
SL = straight line
Offshore Victorian royalty rate averages 12.2% (for the above table, 12% was used). The credit foncier depreciation on downstream capex for SA continues for the life of the project. Upstream capex denotes all capital expenditure from wellhead to Moomba plant outlet. Downstream capex denotes all capital expenditure on the liquids pipeline and Port Bonython. The Victorian onshore royalty is calculated as gross selling value rather than wellhead value.

Table 4
AUSTRALIAN ROYALTY REGIMES APPLIED TO THE COOPER BASIN PROJECT
Royalty Expressed as a Per Cent of a Gross Revenue

Royalty Regime	Total Project	Future Project
South Australia	4.6%	4.6%
Queensland	6.2%	6.7%
Northern Territory	6.5%	6.8%
Victoria Offshore	7.0%	7.2%
Western Australia	7.3%	8.2%
Victorian Onshore	10.0%	10.0%

Note: The per cent of gross revenue is the royalty expressed as the NPV of the royalty received over the life of project in 1989 at the LTGBR (assumed to be 10%), divided by the NPV of the gross revenue received over this period. Assumes future gas exploration successfully supplies 70 PJ/yr to 2020 and no future oil discoveries. Based on pre-Iraq crisis oil price projections.
Total Project denotes the period 1/1/64 to 31/12/23.
Future Project denotes the period 1/1/89 to 31/12/23.
NPV = net present value.
LTGBR = long term government bond rate.

- future capital expenditure to be deductible on a straight line basis over 10 years (or a lesser period if justified) with an interest rate of 50 per cent of the LTGBR on a declining balance basis;
- a limitation on deduction of leasing costs;
- deductibility of non producing well and downstream rehabilitation costs (these concessions facilitate enhanced oil recovery schemes and rehabilitation of the sites of abandoned production facilities).

It is estimated that the new regime will result in a 50 per cent increase in royalties providing oil prices remain relatively stable.

PETROLEUM ACT, 1940 (SA)

The royalty provisions of the Petroleum Act 1940 and Regulations are set out in Appendix 2. A wellhead royalty rate of 10 per cent applies and is 'calculated by subtracting from the amount that the petroleum might reasonably be expected to realise upon sale to a bona fide purchaser all expenses actually incurred or to be incurred by the licensee in treating, processing or refining the petroleum prior to delivery in conveying the petroleum to the point of delivery to the purchaser.'[2] Royalty is not payable on petroleum returned to a subsurface reservoir, used by the licensee in his operations, or destroyed or dissipated in accordance with sound production practices.

There is no provision for agreement on wellhead value between the Minister and the licensees. In fact, s. 35(7) provides that the Minister 'shall determine the wellhead value'. As a consequence, DME has prepared guidelines to assist companies in preparing royalty information in order for the Minister to make his determination. These guidelines are set out in Appendix 3 and are very similar in many respects to the Indenture provisions now applying in the Cooper Basin. They are intended to apply, with such minor modifications as are necessary for local conditions, to all other petroleum produced in South Australia.

Carbon dioxide is also covered by the Petroleum Act and the Caroline CO_2 field near Mount Gambier has been in production since 1968 (Cooper Basin production did not commence until 1969). A royalty of 2.5 per cent of the wellhead value has applied to date but negotiations for a new regime have been foreshadowed.

Commonwealth crude oil excise continues to apply onshore, although it will be replaced by Resource Rent Tax (RRT) offshore. The Commonwealth has sought to encourage the States to apply RRT type principals onshore (ie. royalty levied on profits or 'rent' rather than on production) via principals set out in the Resource Rent Royalty (RRR) Bill was intorduced into Parliament in 1987. Western Australia agreed to introduce RRR to replace royalty and excise on the Barrow Island oilfield where the disallowance of excise as a deduction in calculating wellhead value risked making production uneconomic.

Currently, no onshore oilfield exceeds the size (30 million barrels) or rate threshold to trigger excise. If such discoveries were to be made the

2. Petroleum Act, 1940 (SA), s. 35(6).

Commonwealth could be expected to seek a rent-based system to replace State wellhead royalty and Commonwealth excise.

PETROLEUM (SUBMERGED LANDS) ACT, 1982 (SA)

The Petroleum (Submerged Lands) Act, 1982 operates within South Australia's Territorial Sea, which covers an area extending three nautical miles seaward from the mean low water mark (except in certain bays and reefs which are considered to be historic or internal waters of the State).

This Act is, by agreement, virtually a mirror image of the Commonwealth Petroleum Submerged Lands Act 1967. The royalty provisions provide for a wellhead royalty of 10 per cent for a primary licence and from 11 to 12.5 per cent for a secondary licence. The method of calculation of wellhead royalty is similar to the Petroleum Act, 1940 except that there is provision for the wellhead value to be agreed with the licensee.

Crude oil excise continues to apply in the Territorial Sea and the Commonwealth is pressuring the States to replace their wellhead royalty and Commonwealth excise with RRT, but there has been little progress to date and the States are occasionally reminded of the Commonwealth's right to claim title to subsurface rights seaward of the low water mark.

PETROLEUM (SUBMERGED LANDS) ACT, 1967 (CTH)

The current royalty provisions of the Commonwealth Petroleum (Submerged Lands) Act 1967 are as those applying in the Territorial Sea.

The Commonwealth announced in 1985 that all new discoveries under their legislation will be subject to Resource Rent Tax and, in 1990, that RRT will replace both royalty and excise for all existing petroleum production except for two areas on the West Australian North West Shelf. RRT is a 'rent' based system, with 'rent' in this context meaning the revenue remaining after all costs are paid, including the required rate of return needed to maintain investment in the industry. The enabling legislation is yet to be introduced into Parliament.

RRT is levied at a rate of 40 per cent once the rate of return of a licensee exceeds a 'threshold rate' of LTGBR plus 15 percentage points for exploration expenditure and five percentage points for development expenditure. RRT payments are deductible for company tax purposes.

The offshore Australia-wide deductibility of exploration expenditure was an important concession won by the industry in 1990. The price they paid was a reduction from LTGBR plus 15 percentage points, to LTGBR plus five percentage points on the threshold rate for development expenditure. As onshore exploration costs are not similarly deductible, RRT distorts exploration decisions by favouring offshore exploration investment. Another important feature is that RRT is a levy on all petroleum produced but largely replaces excise which only affected crude oil. The flow-on impact to natural gas prices has yet to be realised.

Under the terms of a Commonwealth/State agreement, each State received between 60 per cent and 68 per cent of royalties from production in that State's adjacent offshore area. Under RRT, however, there has been no agreement as to the State's share. Economic modelling has been carried out to compare the revenue streams likely to be sourced from a range of projects under the royalty/excise regime with the new RRT arrangements. These calculations indicated a State share of about 35 per cent of RRT revenue would be appropriate. Since the modelling exercise was completed in 1989, changes to the RRT regime were made and negotiations have not recommenced.

AUSTRALIAN ROYALTIES IN PERSPECTIVE

It is difficult to compare royalty levels in South Australia with those applying in other countries. For example, between a system applying in Australia where the resource is owned by the State and Texas where the resource is owned by a company or individual. The royalty due to the State and the royalty due to the individual are both imposts on the petroleum industry and have to be taken into account. In particular, a comparison of government 'take' in Australia and Texas would not be useful. It is interesting to note that where the market place sets the royalty level, as in Texas, rates of 16.67 per cent and over are commonplace, compared to Australian States where 12.5 per cent is the maximum.

Kemp studied the peroleum taxation regimes in 13 countries.[3] Computer models were developed and the behaviours of each system was studied for a range of field sizes, costs and prices (depletion allowances, exploration costs write-off etc taken into account).

A comparison is set out in Table 5 of a summary of Kemp's calculations for three field sizes (50, 100 and 250 million barrels) for various countries using a 10 per cent discount rate above the rate of inflation, a 'moderate' cost of development (US $6/bbl) and US $27/bbl constant for oil (note that the study predates the oil price crash). The percentage of 'rent' which is collected by government (including company tax) is as shown in Table 5.

For onshore Australian fields of less than 30 million barrels, the percentage take would be no more than 50 per cent (comparable with an estimate given by Kemp for West Texas where the chance of finding a 30 million barrel field is slight). For the maximum onshore new oil excise/royalty of 35 per cent, the percentage of 'rent' taken by the Commonwealth and State governments is about equivalent to Alberta.

On available evidence, Australian petroleum resource taxation systems might be considered to be less onerous than many applying in other countries.

FUTURE DIRECTIONS

The Commonwealth have repeatedly urged the adoption of rent based royalties for both petroleum and minerals and the recent Industry

3. A Kemp, *Petroleum Rent Collection Around the World* (1987) (Institute for Research on Public Policy: Nova Scotia).

Table 5
COMPARISON OF ROYALTY INTERNATIONALLY
(total percentage "take")

	50 million bbls field	100 million bbls field	250 million bbls field
Australia (1)	50–60	60–70	60–70
Australia (2)	80–90	60–70	70–80
Australia — onshore (3)	50–60	60–70	70–80
UK	30–40	40–50	60
Alberta (3)	ND	85–90	ND
USA	80–90	60	60–70
Malaysia	>100	>100	>100
Indonesia	>100	>100	>100
China	80–90	90–100	90–100
Norway	ND	ND	90–100

ND = No data
(1) Development cost US $6/bbl assumed by Kemp for Australia.
(2) Development cost US $9/bbl.
(3) Assumed US $3.00/bbl onshore development cost. All other examples are offshore.
Includes company tax

Commission Report on Mining and Mineral Processing in Australia gave strong support to this concept. A Sub-committee of the Australian Minerals and Energy Council (with membership from all States, Territories and the Commonwealth) is engaged in a review of onshore mineral royalty regimes.

Critics of wellhead and *ad valorem* royalties have pointed to the plethora of systems and approaches across the various jurisdictions in Australia. Such royalties are criticised as being economically inefficient as they are either not sensitive to profits (for example when royalty is levied on a volume basis) or only partly sensitive (for example the wellhead royalty system which allows post wellhead costs to be deducted from the selling value). There is said to be a risk that royalties could prevent marginal projects from proceeding, which would not be the case under a sound profit based system where there is only a tax on profits in excess of those needed to keep the industry viable.

South Australia has not been convinced by the Commonwealth's arguments for a number of reasons including the following:

- The level of royalty in South Australia is so low as to have very little impact on project profitability (and in any event for minerals, the Minister has the ability to reduce royalty if he is convinced this is necessary to ensure project viability). However, if *ad valorem* royalty rates were raised to say 25 per cent there is little argument that many projects would be significantly affected.
- As minerals are the property of the Crown, resource projects should pay a direct return to the community. Under rent based systems, there are many projects which would never pay any RRT. For example, if

RRT applied to the Cooper Basin in South Australia, the State would still be awaiting the first royalty cheque, 22 years after the commencement of production!

- Cash flows from rent-based systems are difficult to predict with confidence and are complex to administer.
- Rent-related levies are easier to avoid or minimise compared with those levied on production.
- Rent-related royalties will act as an encouragement to over-capitalization.
- Existing royalty arrangements assure a return to the community from the commencement of production. Rent-based systems defer the return until later in a project life (if at all). Industry has pointed to the danger of 'sovereign' risk when projects generate large cash flows but do not pay any royalty because of high initial investment. Community pressure and government monetary needs may lead to a 'rule changing' in these circumstances.
- *Ad valorem* royalties are readily understood by industry and are often used in commercial agreements between companies.
- There is particular difficulty in the determination of the appropriate rate-of-return above which rent-based royalties are paid. The basic principle is not to kill the goose and ensure that industry as a whole receives a sufficient return to remain viable, and even to grow and prosper. Economic theories on methods of calculating the appropriate rate-of-return are less than robust. In any event, each company has a different structure, stock market valuation and source of funds, which are bases for calculating their desired minimum rate-of-return. A single threshold rate (ie. rate-of-return) for all industry threatens to benefit some and penalize others.
- To be efficient Australia-wide, there needs to be transferability of failed exploration costs. It is difficult to imagine the States accepting failed exploration from elsewhere in Australia as being deductible from royalties on local projects.
- Flew commented that RRT-type royalties, tax increases in efficiency at both the royalty and income tax stage.[4] The most competent producers would suffer the highest tax, acting as a disincentive to efficiency compared with flat-rate royalties.
- Under the RRT system the cost of rehabilitation, offshore platform removal etc are deductible. As a result, a repayment of RRT may be made to a producer towards the end of a project when cash flows become negative. This is unlikely to be received with enthusiasm by State governments.

The objective of resource taxation should be to ensure that the petroleum and mining industries prosper under a stable, equitable and internationally competitive regime which is non-distortionary on exploration and investment decisions. The regime must also ensure that an appropriate and direct return is received by the community from each

4. R J Flew, *Resource Rent Royalties: Proceedings of National Agricultural and Resources Outlook Conference 1991* (1991).

development in recognition of the Crown's ownership of petroleum and mineral resources.

Thus, a hybrid system comprising an *ad valorem* or wellhead royalty plus a rent-based system which is activated when a project makes a return above a specified 'threshold' rate is favoured. Such a system applies to Olympic Dam and consideration will be given to its wider application on review of the Petroleum and Mining Acts. Such a system has the advantage of ensuring a timely return to the community as well as a flow-on of benefits from highly profitable projects.

APPENDIX 1

MINING ACT, 1971 (SA)
PRINCIPAL ROYALTY PROVISIONS

16.(1) Notwithstanding the provisions of any other Act or law, or of any land grant or other instrument, the property in all minerals is vested in the Crown.

(2) This section shall apply in respect of all mineral lands and in respect of all other lands (including reserved lands) in the State.

17.(1) Subject to this section, royalty shall be payable to the Minister on all minerals recovered from mineral lands and —

(a) sold or intended for sale;

or

(b) utilized or to be utilized for any commercial or industrial purpose.

(2) The amount of the royalty shall be two and one half per centum, or in the case of extractive minerals, five per centum, of the value of the minerals as assessed for the determination of royalty.

(3) The Minister shall assess the value of minerals for the determination of royalty.

(4) The assessed value shall be such as, in the opinion of the Minister, fairly represents the amount that could reasonably be expected to be realized upon sale of the minerals assuming that any processing that would normally be carried out by the mining operator were in fact carried out by him or at his expense and the minerals were delivered to a purchaser at the expense of the mining operator at the nearest port within the State.

(5) The Minister shall cause a copy of his assessment of the value of any minerals to be served —

(a) upon the holder of the lease in respect of the mine from which the minerals were recovered;

or

(b) in the case of a private mine, upon the proprietor of the private mine.

(6) The person upon whom a copy of an assessment is served under subsection (5) of this section may within sixty days after the date of service appeal against the assessment to the Land and Valuation court.

(7) Upon the hearing of any such appeal the Land and Valuation Court may vary the assessment of the Minister to such extent as it thinks fit.

(8) The Minister may with the concurrence of the person liable to pay royalty determine that royalty shall be payable according to the weight or volume of minerals recovered and royalty shall thereupon be payable by that person in accordance with that determination.

(9) Royalty may be recovered by the Minister as a debt due to him in any court of competent jurisdiction.

(10) Royalty shall not be payable on precious stones.

(11) The Minister may, upon the application of a person liable to pay royalty, having regard to the effect that payment of royalty as required by this section would be likely to have on the viability or profitability of mining operations or related processing operations carried on by that person, waive payment of royalty, or reduce the rate at which royalty is payable, on minerals recovered in the course of those operations.

18. The property in minerals shall pass to the person by whom the minerals are lawfully mined upon, and in consideration of, payment of royalty or if royalty is not payable in respect of the minerals, upon recovery of the minerals.

19.(9) Royalty is, subject to and in accordance with the provisions of this Act, payable upon extractive minerals recovered from a private mine but is not payable upon any other minerals so recovered.

(12) While a mine continues as a private mine under this Act, the property in any minerals recovered from the mine shall —

(a) in the case of all minerals except extractive minerals pass to the proprietor of the mine upon recovery of the minerals;
or

(b) in the case of extractive minerals pass to the proprietor of the mine upon, and in consideration of, payment of royalty.

and any contract, agreement, assignment, mortgage, charge or other instrument in operation immediately before the commencement of this Act and relating to proprietary rights in the minerals shall, subject to its terms, apply to the minerals so recovered upon the passing of property in those minerals in accordance with this subsection.

APPENDIX 2

PETROLEUM ACT, 1940 (SA) ROYALTY PROVISIONS

4.(1) Notwithstanding anything to the contrary in any Act or in any land grant, certificate of title, lease, agreement, or other instrument of title, but subject to the proviso contained in this subsection, all petroleum existing in its natural condition at or below the surface of any land whether alienated from the Crown or not and if alienated, whether the alienation took place before or after the passing of this Act, is hereby declared to be the property of the Crown: Provided that the rights and title of the Crown under this section shall be subject to —

(a) any right or title lawfully granted to or vested in any person pursuant to this Act:

(b) any express grant of any right or title to petroleum made by the Crown after the commencement of this Act:

(2) Upon the extraction or effluxion of petroleum from a natural reservoir in which it has been contained, the petroleum shall become a property of the person by whom it has been extracted or released but the property in any petroleum that is returned or reverts to a natural reservoir, shall revert to the Crown.

35.(1) Subject to subsection (2) of this section, a licensee who holds a petroleum production licence shall pay to the Minister a royalty of ten per centum of the value at the well-head of all petroleum recovered from the land comprised in the licence.

(2) Royalty shall not be payable in respect of —

(a) any petroleum that is returned to the pool or is destroyed or dissipated in accordance with sound petroleum production practices;
or

(b) any petroleum used by the licensee in the course of operations for the recovery of petroleum and for any purposes incidental thereto (including the heating and lighting of any houses or buildings upon the petroleum field used by the employees of the licensee).

(3) An annual fee paid by a licensee under Section 34 of this Act in respect of a particular year may be set off against royalty payable by the licensee upon petroleum recovered during that year if the petroleum is recovered from an area comprised in the licence in respect of which the fee was paid, or from a contiguous area comprised in a licence held by the same licensee.

(4) The licensee shall in each month furnish the Minister with a statement in a form approved by the Minister in relation to the last preceding month of the quantity of petroleum recovered, the quantity of any petroleum or derivatives therefrom which has or have been sold and the amount realized upon such sale and with such other information as the Minister may by notice in writing served personally or by post upon the licensee require.

(5) The licensee shall at the request of the Director of Mines or of any person authorized by him to make the request on his behalf produce to the Director or to the person authorized as aforesaid all books, accounts and other records in his possession or power relating to transactions or dealings with petroleum recovered by the licensee and shall permit the Director or the person authorized as aforesaid to inspect and make copies of those books, accounts and records.

(6) For the purposes of this section the value at the well-head of petroleum shall be an amount calculated by subtracting from the amount that the petroleum might reasonably be expected to realize upon sale to a bona fide purchaser all expenses actually incurred or to be incurred by the licensee in treating, processing or refining the petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser.

(7) The Minister shall in accordance with subsection (6) of this section determine the value at the well-head of petroleum produced by the licensee and a value so determined shall in any proceedings before a court or other tribunal be taken as the value at the well-head of the petroleum, unless the contrary is proved.

3.(1a) The provisions of this Act with the exception of subsection (1) of Section 35 of this Act shall apply to and in relation to any naturally occurring subterranean accumulation of any of or any mixture of the following:

(a) hydrogen sulphide;
(b) nitrogen;
(c) helium;
(d) carbon dioxide;
and
(e) any other substance that the Governor declares by proclamation (which he is hereby empowered to do) to be a substance to and in relation to which this Act applies.

in all respects as if the word 'petroleum' denoted or included such substances.

(1b) The Minister may determine the rate at which royalty shall be paid upon any of the substances in subsection (1a) of this section mentioned or any substance declared by proclamation thereunder to be a substance to and in relation to which this Act applies, and such a determination shall, subject to the right of the Minister to vary or revoke the determination, have the force and effect of a provision of this Act.

ROYALTY PROVISIONS OF PETROLEUM REGULATIONS, 1989

14.(1) A royalty payable to the Minister under Section 35 of the Act will be due and payable not later than one month after the end of the relevant royalty calculation period.

(2) A royalty calculation period, in respect of a particular licence, is a period determined by the Minister after consultation with the relevant licensee.

APPENDIX 3

PETROLEUM ACT, 1940 (SA) *GUIDELINES FOR PAYMENT OF ROYALTY AND PROVISION OF INFORMATION*

(1) *Payment of Royalty*
The Licensees shall pay royalty in respect of all petroleum recovered from Petroleum Production Licence xx other than petroleum described in Section 35(2) of the Petroleum Act, 1940 ('The Act').

(2) *Calculation of Royalty*
The Licensees shall pay royalty at a rate of ten (10) percentum of the value at the wellhead of the petroleum, which shall be an amount calculated by taking the amount the petroleum might reasonably be expected to obtain upon sale to a *bona fide* purchaser ('*bona fide* sales value') (as defined in clause (3)(a)(i)) and subtracting therefrom all expenses actually incurred or to be incurred by the licensees in treating, processing or refining the petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser, which expenses shall be the following sums:

(a) a sum calculated by writing off on a straight line basis together with interest on the written down value at the rate provided in clause (3)(c), over a period of ten (10) years commencing from the month the expense was incurred (or such lesser period as may be determined as being the life of the field) the actual capital expenditure incurred by the licensees or some one or more of them in respect of all plant used for the purposes of treating, processing or refining of the petroleum prior to delivery (but not upstream of the wellhead) or in conveying the petroleum to the point of delivery to the purchaser provided however that if any item of such plant is sold prior to being fully depreciated, the amount obtained upon such sale shall be deducted from the written down value of such item for the purposes of calculating the deduction, but not so as to reduce the written down value below zero;

(b) a sum being expenditure actually incurred by the Operator in respect of persons not employed on site in Petroleum Production Licence xx but whose employment functions directly relate to treating, processing or refining of the petroleum prior to delivery (but not upstream of the wellhead) or in conveying the petroleum to the point of delivery to the purchaser;

(c) a sum being expenditure (other than expenditure upstream of the wellhead) actually incurred by the Licensees or some one or more of them in respect of operating costs related to treating, processing or refining of the petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser, including but not limited to the amount of any licence fees payable in respect of any pipeline licence, provided however that:

(i) the amount of such deduction will be reduced by the amount obtained upon the sale of any item of plant which has not been depreciated or which has been fully depreciated, but not so as to reduce the deduction below zero,

(ii) if any such expenditure is incurred pursuant to any agreement which is not *bona fide* or arms length, such expenditure (or part thereof) shall not be deducted, and

(iii) any expenditure allowed as a deduction under clause 2(c) shall not include any expenditure provided for in clause (2)(a) or (2)(b) or (2)(d),

(d) a sum being expenditure (other than expenditure upstream of the well-head) actually incurred by the Licensees or some one or more of them pursuant to a *bona fide* arms length agreement to lease any plant used for the purposes of treating, processing or refining of the petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser provided however that any such expenditure in any one calendar year which is in excess of:

(A) in the calendar year xxxx — the sum of $xxxx; or

(B) in all subsequent calendar years, the sum of $xxxx increased by the same percentage as the percentage increase in the Consumer Price Index (All Groups) for the City of Adelaide ('CPI') from the CPI in the calendar year xxxx to the CPI in the relevant year shall not be deductible,

(e) a sum being the actual expenditure (other than expenditure upstream of the wellhead) incurred by the Licensees or some one or more of them in rehabilitating the ground surface and site of plant and the actual expenditure incurred in dismantling removing or abandoning of such plant less any salvage obtained thereon where such plant is used for the purposes of treating processing or refining of the petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser and the actual expenditure incurred in rehabilitating the ground surface and site of a well of the type described in clause (3)(b) and the actual expenditure incurred in abandoning such well but not including any costs incurred as a result of the loss of control of any well.

(3) *Further provisions regarding calculation of Royalty*

(a) For the purposes of clause (2):

(i) in each month the *bona fide* sales value of the petroleum means the value of the actual sales in respect of the petroleum described in clause (1) in that month provided however that if any petroleum is not supplied to a *bona fide* sales value arms length purchaser, not sold for full market value, or returned to the pool, destroyed, dissipated or used by the licensees not in accordance with Section 35(2) of the Act, the gross sales value of such petroleum shall be the amount which would have been received in respect of such petroleum from a *bona fide* arms length purchaser for full market value;

(ii) the term 'plant' includes but is not limited to:

(A) any machinery, equipment, vehicle, implement, tool, article, vessel, pit, building, structure, improvement or other such property used in, or in connection with, treating processing or refining of the petroleum prior to the delivery or in conveying the petroleum to the point of delivery to the purchaser: or

(B) any pipeline;

and

(iii) 'wellhead' means the casing head and includes any casing hanger or spool, or tubing hanger, and any flow control equipment up to and including the wing valves.

(b) *Non Producing Wells*

The capital expenditure referred to in clause (2)(a) may include the actual capital expenditure incurred by the Licensees or some one or more of them in respect of wells used solely for the purpose of assisting or enhancing the recovery of the petroleum from other wells or for the purposes of storing the petroleum or for the recovery or disposal of water used in connection with treating processing or refining of the petroleum prior to delivery or for any similar purpose other than the production of the petroleum and may also include the actual capital expenditure incurred by the Licensees or some one or more of them in converting a well used for the production of the petroleum to a well used for such other purposes.

(c) *Interest Rate*

For the purpose of clause (2)(a) the interest rate shall be one half of the long term Australian Government Bond Rate for bonds of a 10 year term as published at the end of the month in which the capital expenditure was made. If no such rate is in existence or published at the end of such period then the interest rate for the purposes of clause (2)(a) shall be one half of the average of the long term Australian Government Bond Rate for bonds of a 10 year term prevailing during the period of 5 years preceding the date on which such rate ceased to exist or be published.

(d) *Apportionment of Expenses*

Where an item of plant is used partly for the purposes of treating, processing or refining of petroleum prior to delivery or in conveying petroleum to the point of delivery to the purchaser, and partly for some other purpose, the amount of the deduction (whether for capital or operating expenditure) which shall be allowed shall not include the proportion of the actual capital or operating expenditure applicable to that other purpose.

(e) *Sale of Plant*

Notwithstanding the provisions of clause (2), if an item of plant is sold by a Licensee ('the first Licensee') to another Licensee, or to a company that becomes a successor or assign of the first Licensee ('the second Licensee'), the second Licensee may only depreciate the plant to the extent to which the first Licensee was, immediately before the time of sale, entitled to depreciate the plant.

(f) *Take or Pay*

For the purposes of this clause and of calculating the gross sales value of the petroleum, where the Licensees or anyone or more of them enter into an agreement commonly known as a take or pay agreement, any payment received by the Licensees or any one or more of them in respect of petroleum which has been paid for but not been taken shall be treated as part of the gross sales value of the petroleum at the time of receipt of payment by such Licensee or Licensees and not any other time.

(g) *Tolling*

(i) If the Licensees or any one or more of them receive any revenue from the use of any plant downstream of the wellhead used for treating processing or refining petroleum sourced from anywhere within the area from time to time comprised in Petroleum Exploration Licences xx or any Petroleum Production Licence issued from an area which was comprised in Petroleum Exploration Licences xx immediately prior to the time such Petroleum Production Licence was issued, or in conveying such petroleum to the point of delivery to the purchaser such revenue shall be deemed to be part of the bona fide sales value of the petroleum to the intent that royalty shall be payable thereon.

(ii) Any sums, being sums deemed under clause (3)(g)(i) to be part of the bona fide value of the petroleum, paid by the Licensee or any one or more of them in respect of the use of such plant for treating processing or refining such petroleum or in conveying such petroleum to the point of delivery to the purchaser shall be deemed to be an expense under clause (2)(c).

(iii) If any such plant is used for treating processing or refining of petroleum sourced from outside of the areas referred to in clause (3)(g)(i) or in conveying such petroleum to the point of delivery to the purchaser any amounts which may be claimed as deductions under this clause (whether such deductions be by way of operating expenditure or capital expenditure) in respect of such plant shall be reduced by the proportion which would be obtained by the method of apportioning costs used by the Licensees to ascertain the tolling fee, but any revenue received by the Licensees or any one or more of them for the use of such plant for the treating processing or refining of such petroleum prior to delivery or in conveying the petroleum to the point of delivery to the purchaser shall not be deemed to be part of the gross sales value of the petroleum.

(4) *Royalty Returns*

(a) Not later than thirty (30) days after the conclusion of each calendar month the party appointed from time to time as Operator will calculate and notify to the Minister the royalty, calculated by taking the bona fide sales value of the petroleum sold in that month, and deducting therefrom the most recent estimated monthly expenditure provided under clause (4)(c), payable by each Licensee. The Operator shall with each such notification provide the Minister with a statement, in a form approved by the Minister, advising of the quantity of the petroleum sold and the amount realised upon such sale during the last preceding month, together with such other information as the Minister may require.

(b) The Licensees shall not later than thirty (30) days after the conclusion of each calendar month pay to the Minister the amount of royalty specified in the notice referred to in clause (4)(a) as payable.

(c) On or before each 15th April (in respect of the next succeeding twelve (12) month period commencing 1st July) and on or before each 15th October (in respect of the next succeeding twelve (12) month period commencing 1st January) the Operator shall bona fide estimate the bona fide sales value of the petroleum, the allowable deductions and hence calculate the estimated royalty payable for the next succeeding twelve (12) month period and shall provide the Minister with such estimates, together with the apportionment thereof on a monthly basis.

(d) Not later than thirty (30) days after the completion of each twelve month period concluding on each 30th June the Operator shall reconcile the estimated expenditure with the actual expenditure and reconcile all calculations of royalties and shall provide the Minister within the said period of 30 days with copies of such reconciliations, together with a notice advising the Minister of any additional royalty calculated in accordance with the reconciliations as payable by each Licensee. If any such reconciliation shows that the total of the amounts of royalty paid during the last preceding 12 months was in excess of the amount of royalty which should have been paid for that period, the difference may be set off against royalty payable in the next succeeding months provided however that any expenditure allowed as a deduction under clause (2)(b) to clause (2)(e) inclusive shall not be carried forward for a period of greater than 12 months from the month of expenditure.

(e) Each Licensee shall not later than thirty (30) days after the completion of each twelve month period concluding on each 30th June pay to the Minister the additional royalty calculated in accordance with the reconciliation referred to in clause 4(d) as payable by the Licensee.

(f) The Licensees shall at their cost cause the royalty calculation reconciliations submitted by the Operator to be audited by the auditor appointed by the Operator to audit its own accounts (provided that such auditor must be a duly registered auditor in Australia) and the Operator shall forward a copy of the auditor's report in respect of a particular reconciliation within 3 months of the receipt of such reconciliation by the Minister, such report to be accompanied by a certificate by the auditor that the reconciliation is in accordance with these guidelines.

(g) The Minister shall annually determine the value at the wellhead of the petroleum produced by the Licensees and may require the Licensees to pay within 30 days of the date of notice of such determination the additional royalty determined by the Minister as payable.