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Australia Blocks Shell-Woodside Deal

By THE ASSOCIATED PRESS

Filed at 8:04 a.m. ET

CANBERRA, Australia (AP) -- Bowing to political pressure, the government Monday rejected oil giant Royal Dutch/Shell Group's \$5.1 billion hostile takeover of Woodside Petroleum, Australia's largest oil and natural gas producer, saying it was against the country's interests.

The move stunned the business sector, which had widely expected the conservative government to approve the takeover. Some Australian businesses denounced the decision, saying it would discourage foreign investment, and the Australian dollar fell in reaction.

"I have decided the Shell proposal is contrary to the national interest," Treasurer Peter Costello said in a statement.

The government is under intense pressure to limit foreign purchases of Australian companies. Many Australians fear the country's economy is being taken over by foreign multinationals that are not concerned about protecting local workers and assets.

The government's economic reforms to spur competition and attract foreign investment are unpopular, especially among key supporters such as small businesses and farmers. Facing likely defeat in elections later this year, the government's decision Monday appeared aimed at trying to maintain its political support. The decision was warmly welcomed by its own lawmakers.

Shell reacted with disappointment, insisting the takeover would have been in Australia's interests.

"It is disturbing that the intensive campaign to position the merger as against the national interest has succeeded in depriving Woodside shareholders of the benefits of the merger proposal," Shell Australia chairman Peter Duncan told reporters.

Costello said the government would consider any new bid from Shell, which already owns 34 percent of Woodside shares.

At the heart of Shell's bid was control of the multibillion-dollar North West Shelf liquefied natural gas project in Western Australia, one of the nation's largest fuel resources.

"Woodside is the operator of the project and it is in the national interest of Australia that the project be developed to its full capacity and that Australia's export sales from the North West Shelf are maximized," Costello said.

The government has the power to prohibit a foreign takeover if the move is deemed to be against the national interest.

"I've determined that this is one of those rare occasions on which that power should be operated," Costello said. "I believe it is in the national interest of Australia that that resource be developed to its full," he said.

The Woodside board had urged shareholders to reject the offer, arguing it undervalued the company.

In a statement, Woodside called the government's decision "informed and clear" and said that it planned to meet with Shell "to discuss ways to take the company forward for the benefit of all shareholders."

The long-awaited decision was seen as unfriendly to foreign investment by money markets, which dumped almost 1.5 U.S. cents from the value of the Australian dollar to 50.42 cents. Further losses were expected with currency traders saying the decision sent a negative signal to foreign investors.

Shares of Woodside fell 1.47 Australian dollars, or 10.5 percent, to 12.49 Australian dollars (\$6.30) on the news.

Shell said the decision would not effect its commitment to Australia or Woodside.

The Australian Gold Council, which represents the country's producers, said the decision was a blow for Australian industries that rely on international investment.

"It will send a negative message to international capital markets that don't fully appreciate Australia's domestic political environment," AGC chief executive Greg Barns said.

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6) Foreign laws and concessions (Phillips Timor Sea activities)

What is Phillips' general approach to developing multiple, potentially competing projects around the world?

Phillips is in the business of exploring for, developing, producing and marketing hydrocarbon resources. The development strategies and tactics in this endeavor are as numerous and varied as are the resources and their locales. However, there are two aspects common to all. First, our efforts involve high front end risk because discoveries are relatively unlikely and require large capital outlays. Second, there is an ongoing need to use innovative approaches to shorten the time between first discovery and the realization of revenues. Phillips' activities on both the Alaska and Timor Sea legacy assets exemplify this.

Over 30 years ago, Phillips pursued and developed a new option for its Cook Inlet gas and created what is now known as the East Asian LNG market. Unlike many later LNG projects, the Kenai project did not have condensate available to it for early revenues. In addition, buyers had to develop the facilities to receive and utilize LNG. While the project required pioneering innovation to develop, Phillips has also demonstrated an impressive record of safety and reliability over the past 30+ years.

Today, Phillips has many gas developments ongoing around the world. Simply stated, a diverse portfolio of projects is essential to the success of our company. We've taken significant risks and invested significant capital in each one and we need to commercialize each opportunity as quickly as possible. At times, multiple Phillips projects may be entering the same markets. We believe that this is healthy, because the competitive spirit just makes our projects stronger in the long term. Phillips works hard to ensure that each of its projects succeeds. Phillips does not have a strategy to "warehouse" gas.

Following its discovery in 1995, Phillips has aggressively pursued development of its Timor Sea resources. Plans for field development yielding liquid condensate reserves are being executed. Phillips has also actively pursued gas development, both by increasing its equity interest and by pursuing diverse markets. Because of its need for additional gas resources, the L-48 market is now a primary target as indicated by the recent Phillips/El Paso announcement, discussed below.

Following the acquisition of ARCO Alaska in 2000, Phillips immediately stepped up an already aggressive gas commercialization program by proactively pursuing the L-48 market option via its participation in the North American Natural Gas Pipeline Group. We believe strongly that there is sufficient demand in this market to accommodate both ANS gas as well as Timor Sea gas and gas from many other sources. Further, our development of LNG receiving facilities on the West Coast may further provide opportunities for Alaskan LNG if and when that option becomes cost competitive. We

believe that it is strategic for an Alaskan gas owner to have ownership in West Coast receiving facilities.

What are the characteristics of the Timor Sea development including the latest Baja announcement?

Attachments 4, 5 and 6 show the location of the Timor fields off of the Northwest Coast of Australia, west of the city of Darwin. As another point of reference, the fields are southeast of East Timor, Indonesia.

In 1995, Phillips discovered the Bayu-Undan condensate/gas field. This field is located in the Zone of Cooperation between Australia and Indonesia. Nine appraisal wells have been drilled, confirming the presence of a world-class gas and gas condensate field. The field is located some 300 miles Northwest of Darwin in 240 feet of water. Phillips is the operator. Additional information can be accessed at: <http://phillips66.com/newsroom/>.

The Bayu-Undan field is being developed in two phases which will involve a total of about 26 wells. The first phase is a gas-recycle project to recover condensate, with an expected startup date of 2003 and full commercial production to begin in 2004. A schematic of the platforms and ship for this development is shown in Attachments 6 and 8 (more detail on this can be accessed at <http://bayuundan.phillips66.com/>).

This first phase will allow Phillips to realize revenues as soon as practicable. The second phase will be a gas project and will proceed as gas markets are developed. This phase will involve a subsea pipeline to Darwin, also shown in that schematic. All potential gas markets, including LNG and domestic Australian markets are being pursued.

What has been the chronology of the Phillips' announcements concerning Timor Sea?

On April 13, 1999, Phillips announced the acquisition of Broken Hill Proprietary Co.'s interest in the Bayu-Undan field. This resulted in a booking of about 98 million boe of reserves. This raised Phillips interest to 50.3%. The sale package also included permits for other static gas resources in the Timor Sea area.

On October 26, 1999, Phillips announced that the condensate development at Bayu-Undan will proceed, with first production expected by late 2003 or early 2004. The project is estimated to cost about \$1.4 billion. Phillips also announced continuing progress towards the establishment of gas markets for Bayu-Undan gas resources.

On November 23, 1999, Phillips announced that it and Epic Energy had entered into an alliance to conduct market development activities to commercialize Timor Sea gas throughout Australia. This domestic market focus is in the Northern Territory, Queensland and the southeastern states. Phillips also indicated that it had made significant progress in identifying near-term gas markets in the Northern Territory. Epic Energy is Australia's largest natural gas transmission company.

On June 26, 2000, Phillips Chairman, Jim Mulva, delivered a speech to the South East Asia Australia Offshore Conference 2000 summarizing Phillips activities relative to Timor Sea resources and demonstrating Phillips proactive approach to developing its legacy assets. See Attachment 7.

On November 11, 2000, Phillips and Woodside announced that they had reached in-principle an agreement to pursue cooperative development of their Timor Sea gas resources. Woodside has an equity interest and is operator of the Greater Sunrise venture, the location of which is shown in Attachment 5. This announcement reinforced the emphasis on domestic Australian markets as well as methanol and LNG. Phillips also said that it would buy additional equity from Woodside to achieve a 30% interest in the Greater Sunrise project.

On February 22, 2001, Phillips announced an agreement with Woodside and Shell for Timor Sea Cooperation. Phillips agreed to bring its interest to 30% in the Greater Sunrise field. Phillips also agreed with Shell to purchase 25% interest in the Evans Shoal field. The three parties also announced that they had finalized principles for cooperative development of Timor Sea gas resources, including Bayu-Undan and Greater Sunrise.

The principles cover supply of gas and marketing of LNG, pipeline infrastructure and field optimization. Gas production is to begin from Bayu-Undan in 2004 for domestic Australia markets (and possibly to fulfill early Sunrise commitments) and from Greater Sunrise in 2006 for a diverse customer base, including an LNG plant at Darwin and a Methanex-owned methanol venture.

The following table summarizes the key items relating to Phillips interest in the Timor Sea resources. In total, Phillips currently owns about 6.5 TCF of known Timor Sea Gas resources.

	Bayu-Undan	Greater Sunrise	Evans Shoal
Operator	Phillips	Woodside	Shell
Phillips Equity, %	58.5%	30%	25%(pend)
Total Liq., MMBOE	400	321	nil
Total Gas, TCF	3.4	9.6	6.6
Phillips Gas, TCF	2.0	2.8	1.7
First gas	2004	2006	?

The current ownership of the Bayu-Undan field is:

Phillips	58.5%
Santos	11.8%
Inpex	11.7%
Kerr-McGee	11.2%
British Borneo	6.7%

The current ownership of the Greater Sunrise field is:

Woodside	33.44%
Phillips	30.00%
Shell	26.56%
Osaka Gas	10.00%

The Evans Shoal field is located to the east of the Sunrise and Bayu-Undan fields and development plans are more prospective.

What about the recent announcement for Timor LNG to the West Coast of North American in 2005?

On March 8, 2001, Phillips and El Paso announced a letter of intent which contemplates development of a project to deliver LNG to growing gas markets in California and Mexico's Baja California peninsula. The Phillips press release is given in Attachments 9. Additional information concerning the Woodside estimates referenced below can be accessed from Reuter News Service (Friday, March 9 - "Woodside Timor Sea fields poised for LNG) and Dow Jones Newswires (Friday March 9, - "Interview: Woodside Eyes Early Share of a A2\$B/yr LNG sales).

Aren't the costs of Timor LNG roughly equivalent to ANS LNG?

Attachment 10 summarizes unit capital costs on several projects, which is a key indicator of competitiveness. ANS LNG costs are not roughly or otherwise equivalent to E. Timor capital costs for LNG. At \$6.8 Billion (\$4.9 Billion without ships) for 8 MTPA, the Alaska North Slope LNG Project unit capital cost is currently over \$600 million per MTPA. Thus, by this one measure alone, an Alaskan LNG project needs more improvement to be cost competitive with other new, grass roots projects that are being developed in the \$200 - \$300 million per MTPA range.

Proprietary cost estimates have not yet been publicly disclosed and will ultimately require partner concurrence to be released. The Timor Sea to Baja or the U.S. west coast LNG Project can be expected to be significantly more competitive than the ANS LNG Project on this unit cost basis, since an 800 mile pipeline adds about \$300 million per MTPA to the Alaska LNG project.

Field development costs for E. Timor are primarily for the benefit of condensate recovery and anticipated domestic natural gas delivery to Australia, but some comparison scenarios from published data can be developed. The March 9, 2001, Dow Jones Newswire article cites a Woodside estimate for an E. Timor LNG Plant at roughly U.S. \$1.25 billion. Using 4.8 MTPA, that computes to a unit capital cost of around \$260 million per MTPA versus ANS LNG's \$610 million per MTPA. $((\$1.25 \text{ B} / 4.8 \text{ MTPA} = \$260.4 \text{ million})$

It could be argued that there are also more ships involved in shipping E. Timor gas to Baja than from Alaska. The cost of ships is not included in unit capital costs given in Attachment 10. However, if we add an incremental 4 ships for Timor LNG (compared to Alaskan LNG) at an estimated cost of \$175 million per ship, for illustrative purposes, the unit capital cost is \$405 per MTPA, still well below the \$600 million per MTPA ANS number. Again, these shipping assumptions are hypotheticals, in addition to the Woodside LNG cost projection. $((\$175 \text{ million} \times 4) + \$1.25 \text{ B} = \$1.95 \text{ B} / 4.8 \text{ MTPA} = \$406.3 \text{ million})$

Finally, previously published reports indicate that the offshore pipeline is anticipated to be built to supply domestic gas to Australia with or without an LNG project. However, we can take the extreme position and allocate, say, half of the Woodside estimated ~US\$500 million of that offshore pipeline to the LNG plant. With the LNG plant and additional ship cost above, E. Timor cost per MTPA at about \$460 million would still be less than the \$600 million per MTPA of the ANS LNG project when burdening the calculation with this pipeline cost. $(\$1.95 \text{ Billion} + \$0.25 \text{ Billion} = \$2.2 \text{ Billion} / 4.8 \text{ MTPA} = \$458.3 \text{ million})$

Is there some penalty clause in the Timor agreement that has motivated Phillips to commercialize Timor gas ahead of AK gas?

No, as indicated above, Phillips' motivation for developing its Timor Sea resources is driven by economics, not by punitive provisions or economic disincentives. To summarize, Phillips realizes its interest in Bayu-Undan through a Production Sharing Contract (PSC) with the Timor Gas Joint Authority. The Timor Gap (being that offshore area between Australia and the island of East Timor, Indonesia where they could not agree on the international boundaries) was developed as a 'Zone of Cooperation' through the Joint Authority. As such, the two contracting countries (Australia and Indonesia) adopted a hybrid of their two petroleum regimes. This hybrid is a completely different system from Alaska's bonus-bid leasing system. Phillips, similar to its partners, is essentially a contractor to the Authority. Among the partners, Phillips is also designated as the operator. The PSC forms the basis for a mutually agreed to work program which the contractors are then obliged to perform. The PSC entitles Phillips to a share of the production. The following expands on these summary points. Further general information can be accessed at bayuundan.phillips66.com.

PSC's entered into within the Zone of Cooperation are substantially on similar terms and follow a basic model form attached to the Treaty. As with most contracts that can be terminated for breach, Section 13 of the PSC refers to article 48 of the Petroleum Mining Code. Article 48 generally provides that where the Contractor has not complied with any provision of the Treaty, the Joint Authority must give 30 days notice of its intention to

recommend termination. The Ministerial Council (comprised of a minister from each country – effectively the head of the Joint Authority) cannot agree to termination until the contractor has had an opportunity to respond. Thus, even where there may have been an event that may potentially justify termination, rather than being punitive, steps are in place to allow a response and corrective action prior to any contract termination.

The PSC sets forth the mechanism for allocating production and its provisions for liquids and gas are different. To some extent this reflects the reality that field development is primarily underpinned by liquids recovery. The PSC requires that a first tranche of liquids to be split between the Authority and the contractors. Then, liquids are next allocated to the contractors to cover 125% of field development costs and operating costs. Liquids beyond that level, as well as gas, are shared 50/50 between the Authority and the contractors. Phillips is subject to the normal taxes of the relevant country, but there are no additional royalties, rent or the like which are levied on the recovered liquids and gas. There are no incentive taxes.

However, the Timor Sea Treaty's absence of disincentives notwithstanding, punitive provisions in agreements or treaties rarely motivate us to develop resources under concessions or agreements. Strong resource bases and robust economics encourage us to develop while marginal, high-risk, economics, which can be caused in part by onerous tax or other fiscal disincentives or instabilities, inhibit development.

Shouldn't AK gas be better positioned for Baja than Timor?

Though developed independently and begun prior to Phillips ownership of substantial Alaska North Slope reserves, the Timor project would have been considered by the marketplace before the ANS LNG Project regardless of development timing and regardless of ownership. As indicated earlier, this is because of Timor's economic viability and competitiveness relative to other world-class LNG projects versus ANS LNG's cost of development, primarily due to the requirement for an 800 mile, buried Arctic pipeline to ice-free, tide water.

What does this say about Alaska's ability to compete in the E. Asian marketplace?

The Alaska North Slope LNG Project sponsor group determined in its early analysis that 1) the E. Asian market is fiercely competitive and, 2) that market entry before the end of the decade for any new green field project would be very difficult. The projects with current inroads into the E. Asian marketplace are existing, incremental LNG project expansions such as Australia's NW Shelf with relatively low, incremental unit capital costs.

For various reasons, the Phillips Timor Sea LNG project team determined that its best near term opportunity to enter the market would be in the Western U.S. and/or Mexico over East Asia. Clearly, the near term E. Asian market does not sufficiently support an E. Timor project in the near term. Rather, the investors were economically and market

driven to engage a lower 48 market that is 6,900 nautical miles away from E. Timor rather than E. Asia at only 3,000 nautical miles away.

If and when ANS LNG becomes economically viable and cost competitive with other new, green field projects or other alternatives for North Slope gas, Phillips would expect to expeditiously advance it within the gas/LNG market dynamics. The best possibility for an ANS LNG project may be in synergy with a L-48 pipeline to maximize cost sharing potential.

Phillips ownership and strategy for Timor Sea LNG (Bayu-Undan and Sunrise) was developed over the last 6+ years (since about 1995). This development strategy pre-dates Phillips acquisition of ARCO Alaska, Inc. and subsequent ownership of substantial Alaska North Slope gas reserves that were purchased this last year (April, 2000).

Even before its acquisition of these significant volumes of North Slope gas, Phillips joined (as a charter member) and actively participated in the Alaska North Slope LNG Project Sponsor Group. This \$12-15 million LNG development project began in October of 1998 and is ongoing today as a concerted effort to commercialize North Slope gas. The Sponsor Group continues to try to develop an economic or cost competitive LNG project.

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1989 the State has kept its fiscal regime stable, although there are occasional proposals to change the taxes or enact new ones.

21. *State whether BP's concessions or interests in Indonesian natural gas projects are subject to any provisions of Indonesian law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production.*

The concessions in Indonesia call for the companies, who are contractors to the state oil company Pertamina, to pursue specific programs of exploration for oil and gas, and often it is the diligence with which a company promises to explore for oil and gas that determines who is awarded a particular concession. Once oil or gas is found, the concessions contemplate that it will be brought into production within a reasonable time. From the time of discovery to the time in which a Plan of Development is sanctioned, certain provisions are imposed that include acreage relinquishments and spending commitments. There is no requirement to develop a discovery while it is uneconomic to do so. Typically, the concession-holder is required to pay a fixed sum of money to the government each year, similar to lease rentals in Alaska, as the price to continue holding a concession with sub-economic discoveries until they become economic and go into production. Once a development is on production and delivery contracts are in place, the contractors act on a best endeavours basis with no penalty clauses for failing to meet contract rates.

22. *Please set forth information obtained and/or developed by BP pertaining to Indonesian rebel, separatist and terrorists groups and organizations.*

It would be inappropriate to respond to this question.

23. *Please set forth the three highest non-spot LNG prices, which have come to BP's attention directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan. If BP contends its LNG pricing is confidential and/or proprietary, then provide any price data BP has obtained or developed from third party sources or indices that are not subject to contractual confidentiality provisions.*

Two potential sources of LNG prices are *LNG in World Markets* and *World Gas Intelligence*.

The highest LNG prices, from the last three years, BP found by referencing *LNG in World Markets* were all from LNG supplied by Indonesia during October 2000. The three highest LNG prices and the countries of delivery are as follows:

Korea \$6.06/mmbtu
Taiwan \$6.04/mmbtu
Japan \$5.89/mmbtu

For comparison, the average Brent crude oil price during the same month was \$30.91/bbl.

24. *Please describe in detail all efforts, initiatives and undertakings by or on behalf of BP to offer ANS natural gas for sale to unrelated third parties from the inception of Prudhoe Bay production to the present.*

BP has been selling natural gas from the Prudhoe Bay field to third parties for over fifteen years. It has been, and will continue to be, in BP's best interest to give full consideration to any commercially viable opportunity to sell gas from the North Slope of Alaska as well as to work with all third parties who demonstrate the ability to add value to any ANS gas commercialization scheme. As mentioned in the

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Gas Transportation System, or equivalent pipeline system along the Alcan Highway route.

The viability of a project depends on a number of factors, including the overall economics and risks associated with a project. Market conditions are a key determinant in whether a project is viable and when it could be built. Specific pricing terms would be negotiated by individual companies through private and confidential negotiations.

17. EM has made substantial capital commitments to LNG projects in Yemen, Qatar, Natuna, and Sakhalin, apparently targeting sales to Asian markets. Please set forth in detail EM's rationale and analysis supporting capital expenditures to commercialize natural gas reserves in foreign countries rather than ANS natural gas reserves.

ExxonMobil continues to pursue commercialization of all of its worldwide gas resources by progressing all potentially viable projects. Each project has its own characteristics that impact its feasibility. ExxonMobil has spent over \$110M on specific efforts seeking a means of commercializing Alaska North Slope gas.

18. Please describe and compare the political and business conditions in Yemen, Qatar, Natuna, and Sakhalin with the political and business conditions in Alaska, particularly focussing on the political stability of the differing regimes.

It is inappropriate for ExxonMobil to comment on the political regimes and conditions in these countries.

19. State whether EM's concessions or interests in Yemen, Qatar, Natuna, and Sakhalin natural gas projects are subject to any provisions of law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production.

The terms of our agreements with other governments contain confidentiality provisions that limit our ability to discuss them.

20. Please set forth information obtained and/or developed by EM pertaining to rebel, separatist and terrorist groups and organizations operating in the vicinity of the Yemen, Qatar, Natuna, and Sakhalin natural gas fields and developments.

It is inappropriate for ExxonMobil to comment on rebel, separatist, or terrorist activities in other countries. Each potential project has many different characteristics that impact the overall risks and commercial viability of the project. Ultimately for a project to be built the project investors, those that finance the project, and those buying the product from the project must be convinced that the risks are acceptable, the project is competitive with other sources of supply and provides a reasonable return to investors.

21. Please set forth the three highest non-spot LNG prices, which have come to EM's attention directly or indirectly in the last three years, and which may have been

appropriate recommendations for the valuation of the state's royalty gas. The Lower 48 market is complex and rapidly changing. Customers (local distribution companies, power utilities, and industrial end-users) meet gas producers and merchant marketers of gas throughout the U.S. in an active marketplace. Prices are relatively transparent. New gas supplies, whether shipped by pipeline into California and the Midwest or delivered as LNG to the West Coast, have access to the entire Lower 48 market, either physically, through the existing pipeline network, or virtually, through exchanges or swaps.

5. Please identify potential customers for sales of ANS natural gas in Mexico.

See 2 above.

6. Please identify potential customers for sales of ANS natural gas in the Midwest region of the United States.

See 4 above.

7. Please identify potential customers for sales of ANS natural gas in Canada.

See 1 above.

8. Please set forth the minimum sales price per million BTU or thousand cubic feet at a specified delivery point which must be sustainable, specifying the relevant period of time and the required volumes, to support capital construction of the Alaska Natural Gas Transportation System or equivalent pipeline systems along the Alcan Highway route.

See 4 above.

9. Are you aware of any provisions or law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production? In the United States? In the world?

Our own leases provide for a term—usually seven to ten years—when the lease expires if the lessee has not found oil or gas, or included the lease in a unit. Holders of state leases with shut-in oil and gas wells can be ordered to develop and produce the lease. The Charter for Development, section I.J., compels BP and ARCO (Phillips Alaska) to provide ANS gas reserves in sufficient quantities to any qualified "treatment and transmission project" that is willing to pay a fair market price for the gas. BP and Phillips have an obligation to negotiate in good faith with the sponsors of any such project through December 31, 2003. We are not aware of any specific laws noted in this question.

10. Please set forth the three highest non-spot LNG prices, which have come to your attention, directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan.

Answer:

Please see answer to question #1.

7. Please identify potential customers for sales of ANS natural gas in Canada.

Answer:

Please see answer to question #1.

8. Please set forth the minimum sales price per million BTU or thousand cubic feet at a specified delivery point which must be sustainable, specifying the relevant period of time and the required volumes, to support capital construction of the Alaska Natural Gas Transportation System or equivalent pipeline system along the Alcan Highway route.

Answer:

Pipeline economics are not part of the AOGCC's regulatory jurisdiction and information related to this issue is not regularly provided to us.

9. Are you aware of any provisions or law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production? In the United States? In the world?

Answer:

This question involves lease obligations and relations between lessor and lessee. These subjects are not regulated by the AOGCC.

10. Please set forth the three highest non-spot LNG prices, which have come to your attention, directly or indirectly in the last three years, and which may have been obtained from customers located in Taiwan, South Korea and/or Japan.

Answer:

Please see answer to #1

NATURAL GAS UTILIZATION STUDY: OFFSHORE NEWFOUNDLAND

1998

Prepared for:

Atlantic Canada Opportunities Agency
and
Newfoundland Ocean Industries Association

Prepared by:

Imperial Venture Corp
St. John's, Newfoundland
Canada

2. BACKGROUND

2.1 Purpose and Scope

The purpose of the study is to quantify the gas resources of Newfoundland, identify production and transportation options and lay out the Terms of Reference for a follow-up study. The present study (Phase I) is characterized as a scoping study while Phase II will be comprehensive examination of critical issues. The ultimate objective is to create a development strategy for Newfoundland industry.

This report was commissioned by the Newfoundland Ocean Industries Association (NOIA) and the Atlantic Canada Opportunities Agency (ACOA). The Terms of Reference were developed by NOIA and ACOA who also provided supervision of the study through a Steering Committee. The Departments of Industry, Trade and Technology and Mines and Energy of the Newfoundland and Labrador Government were also represented on the Steering Committee.

The study was carried out by an alliance of independent consultants under the lead of the principal contractor, Imperial Venture Corp of St. John's, Newfoundland. The study team and their principal areas of expertise are as follows:

Steven M. Millan, P.Geol. - *Project Leader, Resource Assessments*

Gus Cammaert, Ph.D, P.Eng. - *Development and Transportation Options*

Lorne Spracklin, M.A. - *Project Economics*

Pedro van Meurs, Ph.D - *Global Economics, Fiscal Regimes*

The level of effort for the study was approximately \$25,000 and it was conducted over a period of approximately eight weeks in May and June 1998.

Information for the study was derived mainly from public domain sources augmented, where appropriate, from the consultants' databases. Proprietary cash-flow (van Meurs) and cost models (Cammaert) were used for analysis.

The report is organized into the following main sections:

- **Summary and Conclusion**
- **Background**
- **Resource Endowment**
- **Production Systems**
- **Transportation Systems**
- **Preliminary Project Economics**
- **Phase II - Terms of Reference**

As a result, some governments have started to respond to the fact that gas is an energy source with very different characteristics from oil. Accordingly, fiscal systems are now being developed for gas which are different from oil. Most gas terms involve a lower governmental take than for oil.

The strongest case of a country adopting a concerted policy of offering substantially more favorable terms for gas than for oil is Indonesia. Indonesia accepts a government take which ranges from 30% to 17% lower than for oil. Given that gas development in Indonesia has a low netback to the producer, the policy appears entirely rational. Indonesia also has an aggressive policy of promoting the export of LNG.

Within Canada, Manitoba is the only province which offers a substantial incentive for natural gas by fixing the royalty level at 12.5% as compared to the marginal oil royalty rate of 24.75%. This results in a drop of 15% in government take.

Next in line is Australia whose onshore State regimes exhibit a government take which is roughly 14% lower for gas than for oil. This is because the commonwealth excise tax which applies to cumulative oil production above 30 MMbbl does not apply to natural gas, LNG or LPG.

The same fiscal regime which applies to both France and St. Pierre and Miquelon offers a government take which is also just under 14% lower for gas than for oil. This is partially accomplished by a royalty free gas production of up to 29 MMcf/d with a royalty of only 5% in excess of this amount, as opposed to a sliding scale oil royalty whose marginal rate is 12%.

Trinidad & Tobago is another country which has adopted a clear policy and implementation plan of encouraging natural gas development over the past decade. As the Supplemental Petroleum Tax and the Petroleum Levy do not apply to natural gas, the government take in the case of a natural gas development is almost 14% lower than for oil. ***The success of this strategy was recently witnessed by a Newfoundland trade mission to that country in April of this year.***

This trend is increasing and recently a number of other potential LNG exporting countries have taken steps to introduce significant incentives for gas development. These countries include Qatar, Yemen, and Papua-New Guinea. In addition, Iran has recently concluded a contract with the oil company Total under terms that greatly stimulate gas development.

The fact that both Qatar (with 300 Tcf of gas reserves) and Iran (with 812 Tcf of gas reserves) are taking aggressive steps to make their gas resources economically attractive, indicates that even the huge gas reserves in the Middle East may become increasingly part of a new worldwide pattern of gas-gas competition.

An interesting case for Newfoundland is that Alaska recently passed a new law which dramatically changes the fiscal terms applicable to gas for LNG exports. This now may become the basis for an Arco-led consortium for the production of Prudhoe Bay gas for exports.

It is important to realize, therefore, that it is unlikely that gas development will come about in Newfoundland unless the Province joins the worldwide trend of offering fiscal terms for gas which are substantially more attractive than for oil. The assessment of the Province's competitive position will require the analysis of a variety of factors affecting the value of the resource to prospective developers and resource owners. A key factor is the fiscal regime.

2.3 Regulatory Setting

Management of the offshore hydrocarbon reserves rests with the Canada Newfoundland Offshore Petroleum Board (CNOPB) which administers mirror legislation of the Governments of Canada and the Government of Newfoundland and Labrador. Onshore resources fall under Provincial jurisdiction. In both cases, Legislation covering such major aspects as land tenure, fiscal take, exploration and production operations, are in place. In general, oil developments were contemplated in the drafting of the various pieces of Legislation and usually natural gas is included under the definition of petroleum. Generic royalty regimes have been announced for both the onshore and offshore areas. These regimes have not yet been put into regulations. Whether these systems will apply to oil only or extend to gas is unclear.

As discussed elsewhere, gas specific legislation is advisable where there are clear differences in the development characteristics of oil and gas. Within a competitive investment setting, having an explicit competitive regime for natural gas would be expected to encourage exploration and development by improving potential rewards and providing a firm foundation of established legislation in the assessment of risk factors by the private sector.

Northern Territory, Australia: Petroleum Act

Licenses for Petroleum Retrieval:

- 1) **Exploration License:** A license for exploration is issued for a period of 1½ years (Sec.22).
- 2) **Retention License:** After the exploration license has expired, if significant quantities of petroleum have not been found, a retention license may be issued for anywhere from 2-5 years (Sec. 34). However, if at any time, the minister finds that production of the petroleum held within the exploration blocks is economically viable, both in size and marketability, he may order that production begin (Sec. 43, 44).
- 3) **Production License:** An initial production license is issued for a period of five years, that initial license, however, may be extended for up to 25 years, subject to the will of the minister. If, at any time, the minister does not feel that the petroleum resource is being properly produced (according to the Petroleum Act), he may withdraw the license* (Sec. 50 and conversation with Dept of Mining and Petroleum Production, Northern Territory, Australia).

Additional notes:

Any survey or core sample may not be disposed of, held, or kept confidential by the producer (Sec. 60).

Core Samples: Any core sample taken must be presented to the minister within 28 days of the time that it is taken. The sample will then be made public with an announcement in the *Gazette*.

Surveys: Any survey taken must be presented to the minister and his staff within one calendar year of its completion. The minister may then decide to make the survey public based upon information provided by the producer of the survey and the requestor of the survey. If it is decided that the survey need remain confidential, then it shall only be made available to the members of the territorial and parliamentary government and no to the general public.

- There has never been an instance, in the Northern Territories, when a petroleum producer failed or refused to produce an economically viable field.

(1) Subject to section 18(3), a person may object to the granting of a permit by lodging with the Minister, within the time referred to in section 18(1)(e), a written notice of his objection setting out the grounds on which the objection is made.

(2) The Minister shall give an applicant notice of the content of objections received under this section and specify a date, not being earlier than 28 days after the date of the notice, by which the applicant may lodge a reply or other comment in relation to the objections.

20. GRANT OF PERMIT

(1) After the date specified in a notice under section 19(2), the Minister shall consider -

(a) the application;

(b) the objections, if any;

(c) the replies or other comments of the applicant, if any; and

(d) any other information supplied to him under a request made under section 16(2) or other matter which, in the opinion of the Minister, is relevant to the application,

and shall determine to grant the permit in respect of some or all of the blocks to which the application relates or refuse to grant it.

(2) Where the Minister determines under subsection (1) to grant a permit, he shall give notice to the applicant of -

(a) the conditions subject to which he is prepared to grant it; and

(b) the date, not being earlier than 28 days after the date of the notice, after which the application shall lapse unless the Minister has received from the applicant an acceptance of the conditions specified in the notice.

(3) Subject to subsection (4), where the Minister receives from an applicant within the time specified a written acceptance of the conditions specified in a notice under subsection (2), he shall grant to the applicant a permit subject to those conditions.

(4) The Minister may not grant a permit in relation to an area which is the subject of another permit or a licence.

21. REFUSAL OF PERMIT

Where the Minister determines not to grant a permit, he shall, as soon as practicable after he has so determined, serve notice of his determination on the applicant.

22. TERM OF PERMIT

(1) Subject to sections 28(3), 30(3), 73 and 74, a permit remains in force for the period specified in the application, being a period of not less than 2 years or more than 5 years, commencing on the day on which

it was granted or last renewed.

(2) The Minister may not renew a permit more than twice.

23. APPLICATION FOR RENEWAL OF PERMIT

(1) Subject to section 24, a permittee may apply to the Minister to renew his permit in relation to the blocks specified in the application.

(2) For the purposes of subsection (1), an application for the renewal of a permit shall be -

- (a) in an approved form;
- (b) made in an approved manner; and
- (c) accompanied by the prescribed fee.

(3) In relation to an application for a renewal of a permit, the Minister -

- (a) shall, where the application is received not earlier than 6 months before, but not later than 3 months before, the expiration of the permit;
 - (b) may, where the application is received later than 3 months before the expiration of the permit; and
 - (c) shall not, where the application is received after the expiration of the permit,
- accept the application.

24. APPLICATION FOR RENEWAL OF PERMIT TO BE IN RELATION TO REDUCED AREA

(1) Subject to subsection (3), the number of blocks in relation to which an application for the renewal of a permit may be made shall not exceed -

- (a) where the number of blocks in respect of which the permit is in force is a number that is divisible by 2 without remainder - one-half of that number; or
- (b) where the number of blocks in respect of which the permit is in force is a number that is not divisible by 2 without remainder - one-half of the number arrived at by increasing the number of blocks by one.

(2) In an application for the renewal of a permit -

- (a) the blocks specified in the application shall constitute a single area, or a number of discrete areas each comprised of 2 or more blocks; and
- (b) each block, in a discrete area referred to in paragraph (a), shall have a side in common with at least one other block in the area.

(3) Subject to subsection (4), where the number of blocks in respect of which an application for the renewal of a permit may be made is 12 or more, each area constituted by blocks in respect of which the application is made shall be constituted by not less than 12 blocks.

- ### 34. GRANT OF RETENTION LICENCE

- ### 35. PERMIT NOT AFFECTED

(a) an application for a retention licence; or

(b) the determination of the Minister not to grant a retention licence.

Subject to sections 43(3), 73 and 74, a retention licence remains in force for a period of 5 years commencing on the date on which it was granted or last renewed.

43. NOTICE TO APPLY FOR PRODUCTION LICENCE

- (1) Subject to subsection (5), where the Minister is satisfied that commercial production of **petroleum** should commence in a retention licence area, he may, by notice served on the retention licensee, require him to show cause why he should not apply for a production licence in relation to the blocks where the commercially exploitable accumulation of **petroleum** occurs and specify a date, being not earlier than 6 months after the date of the notice, by which the licensee should show cause.
- (2) Where a retention licensee has been served with a notice under subsection (1) and he fails to show cause to the satisfaction of the Minister, within the time specified in the notice, the Minister may, by notice served on the retention licensee, direct him to apply for a production licence and specify a date, being not earlier than 3 months after the date of the notice, by which the licensee should apply for the production licence.
- (3) Where, under subsection (2), a retention licensee has been directed to apply for a production licence before a date specified in the direction and the licensee has failed to so apply, the Minister may, by notice served on the licensee, cancel his licence.
- (4) The Minister may, by notice served on a retention licensee, vary the date in a notice under subsection (1) or (2) so as to allow a longer period for the retention licensee to show cause or apply for a production licence.
- (5) The Minister may not exercise his powers under this section if the blocks where the commercially exploitable accumulation of **petroleum** occurs are, in whole or part, Aboriginal land and no agreement in relation to the production of **petroleum in that area has been reached under the Land Rights Act** between the retention licensee and the Land Council or as otherwise permitted under that **Act**.

Division 4 - Production Licences

44. APPLICANT

A person who is -

- (a) a permittee; or
- (b) a retention licensee,

may apply for a production licence in relation to the whole or part of his permit or licence area.

45. APPLICATION FOR PRODUCTION LICENCE

- (1) Subject to this **Act**, a permittee or licensee may apply for a production licence by lodging with the Minister -
- (a) a statement containing the name and address of the applicant and an address for service within the Territory;
 - (b) a statement containing the designated number of each block the subject of the application;

- (c) a map clearly delineating the application area and the boundaries of the existing permit or retention licence area in which the application is comprised;
- (d) a proposed technical works programme specifying the proposals for exploration, appraisal and production of ~~petroleum~~ from within the proposed licence area;
- (e) evidence of the technical and financial capacity of the applicant to carry out the proposed technical works programme and to comply with this ~~Act~~;
- (f) proposals for the protection of the environment, including proposed measures to be undertaken by the applicant for the rehabilitation of the licence area or other affected areas;
- (g) where the application is made by 2 or more persons, the proposed sharing arrangements between the applicants;
- (h) a statutory declaration stating the applicant's interest, if any, in or in relation to each permit or licence applied for or granted under, or in force by virtue of, this ~~Act or the repealed Act~~;
- (j) the prescribed application fee; and
- (k) such other information in support of his application as the applicant thinks fit.

(2) Where the Minister has received an application for a production licence, he may, by notice served on the applicant, request further information in relation to the applicant or his application.

(3) A permittee or licensee may apply for one or more production licences.

46. SIZE OF PRODUCTION LICENCE

(1) A person shall not apply for a production licence in respect of an area which is constituted by more than 12 blocks.

(2) A person shall not apply for a production licence in respect of an area which is constituted by more than one block unless the blocks form a discrete area which conforms to an approved shape.

(3) The Minister may grant a production licence in respect of -

- (a) an area of less than one block; or
- (b) blocks which form more than one discrete area,

where he is of the opinion that circumstances justify his doing so or it is in the public interest to do so.

47. GRANT OF PRODUCTION LICENCE

(1) Where the Minister -

- (a) has received an application under section 45;
- (b) is satisfied that the applicant has complied with the requirements of this ~~Act~~ relating to an

(b) by notice served on the licensee, inform him as to the conditions to which the licence on its being granted, is to be subject and the amount of security to be lodged.

(8) An applicant who has been served with a notice under subsection (7)(b) may, within 28 days after the date of service of the notice on him, by notice served on the Minister, request the Minister to grant to him the licence subject to the conditions specified in the notice under subsection (7)(b).

(9) Where an applicant has served a notice under subsection (8), within the period referred to in that subsection, the Minister shall grant to him the licence subject to the conditions specified in the notice under subsection (7)(b).

(10) Where an applicant who may request, under subsection (5) or (8), that the Minister grant a licence to him, fails to make the request, his application for a licence lapses at the expiration of the period during which the request may be made.

48. REFUSAL OF PRODUCTION LICENCE

(1) Where the Minister determines to refuse to grant a production licence he shall, as soon as practicable after he has so determined, serve notice of his determination on the applicant, setting out the reasons for his determination.

(2) The Minister may not determine to refuse to grant a licence, unless he has -

(a) by notice served on the applicant, given not less than 28 days notice of his intention to refuse to grant the licence;

(b) in the notice, specified -

(i) the reasons for his intended refusal; and

(ii) a date on or before which the applicant may, by notice served on the Minister, submit any matters he wishes the Minister to consider; and

(c) taken into account any matters so submitted to him on or before the specified date by the applicant.

49. PERMIT OR LICENCE NOT AFFECTED

The term and area of a permit or retention licence are not affected by -

(a) an application for a production licence; or

(b) the determination of the Minister not to grant a production licence.

50. TERM OF PRODUCTION LICENCE

Subject to sections 73 and 74, a production licence remains in force for a period of 25 years commencing on the date on which it was granted or, in respect of the renewal of a production licence, the date on which it was last renewed, notwithstanding that it is renewed before the date on which it would otherwise have expired.



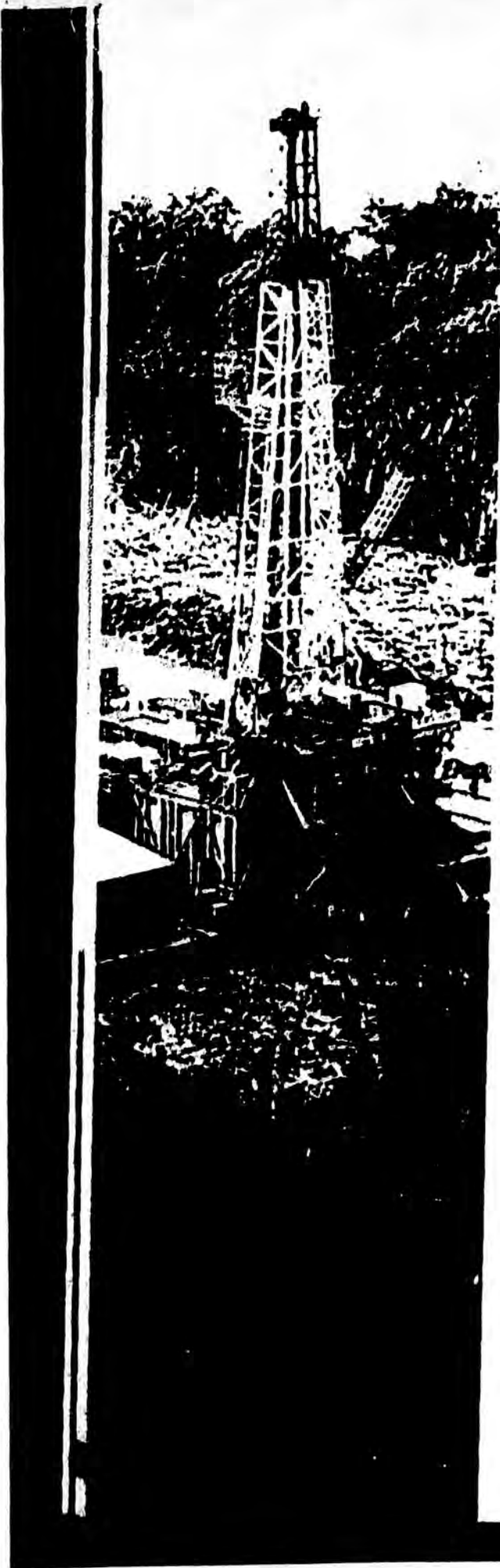
The Indonesia

Production Sharing Contract



Production Sharing Contract

Basic Term



- PERTAMINA is responsible for the management of the operations, but the contractor bears all risks and is responsible for the preparation and execution of work program.
- The term of the contract is 30 years, including 6 to 10 years exploration period. If a commercial petroleum discovery is not made by the end of the exploration period, the contract shall be automatically terminated.
- * The contractor is free to export its entitlement under the cost recovery and production split subject to fulfill its domestic supply obligation.
- Allowable costs, as defined on the basis of an accounting procedure, are recoverable from available production without volume restrictions.
- The sharing is made on production, not on profit. Government / PERTAMINA and Contractor share will be split after deduction of cost recovery and tax.
- Contractor and PERTAMINA shall be entitled to first take (First Tranche Petroleum - FTP) and receive each year a quantity of petroleum from the annual production before deduction of cost through the cost recovery mechanism. The FTP is further shared between PERTAMINA and Contractor in accordance with the applied sharing split.
- PERTAMINA shall have the right to demand from Contractor that a ten percent (10%) undivided interest in the total rights and obligations to itself or a limited liability company to be designated by PERTAMINA.

745-3300

**COMPARATIVE STUDY
OF FISCAL REGIMES
FOR LNG PROJECTS**

by
**Dr. Pedro van Meurs
&
Andrew Seck**

DRAFT ONLY
20 November 1996

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7.2.2 Land and System

Article 33 of the 1945 Constitution stipulates that land and water and all natural richness contained therein shall be controlled by the State to be utilized for the maximum benefit of the people.

7.2.2.1 Land Allocation Procedures

Acreeage is awarded under direct negotiations.

7.2.2.2 Block Size

304 sq. km (1993 ARCO PSC).

7.2.3 Exploration and Production Periods and Phases

30 year duration with an initial exploration period of 6 years which may be extended for another 4 years (1993 ARCO PSC).

7.2.4 Relinquishments

*

In the case of the 1993 ARCO PSC for the Wiriagar Block which only covered 304 sq. km, the Contractor is relieved of the relinquishment obligation.

7.2.5 Work Obligation

7.2.5.1 Work Program and Financial Obligations

Contractor to spend US \$3.5 million in year 1, US \$1.5 million in year 2, US \$1.5 million in year 3, US \$3.5 million in year 4, US \$1.5 million in year 5, US \$3.5 million in year 6, US \$1.5 million in year 7, US \$1.5 million in year 8, US \$1.5 million in year 9 and US \$1.5 million in year 10 for an aggregate total of US \$21 million (1993 ARCO PSC).

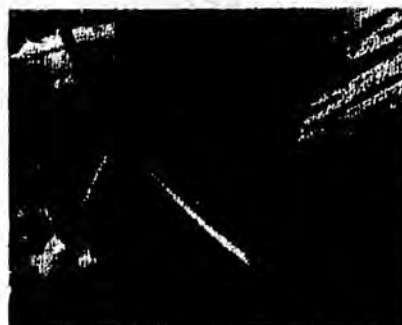
7.2.5.2 Guarantees and Non-Performance Provisions

Contract shall be terminated in its entirety by a 90 days notice if a major breach of the Contract is committed by the other Party

7.2.6 Fiscal Framework

7.2.6.1 Negotiation of Terms

Terms more or less fixed, details negotiable.

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Four types of contract in the exploration and production of oil and natural gas in Indonesia are: PSC, JOA/JOB, EOR, and TAC.

In Indonesia, nearly all of the oil and gas operations are operated by foreign companies

under Production Sharing Contract (PSC), which allow the Contractor's profit after tax and cost recovery about 15-35% on oil and 30-40% on gas. The production sharing contract now covers about 90% of the contracted petroleum acreage, thereby representing the dominant share of all the petroleum activities in the country.

In Indonesia, the cooperation between PERTAMINA and foreign contractors in the petroleum sector through the form of the PSC has proven to be highly successful.

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Flow of Contract Arrangement

● Production Sharing Contract (PSC)

Cooperative agreement in the sector of oil and natural gas between PERTAMINA and foreign capital investors, in which:

- PERTAMINA is responsible for the management.
- Related foreign oil company is a Contractor who is responsible to PERTAMINA.
- The sharing is made on production, not on profit.
- Title to the Contractor's portion of crude oil and gas (cost entitlement oil/gas) shall passed to the Contractor at the point of export or point of delivery.
- The contract application is under the laws, decrees, regulations, decisions, etc. of the Republic of Indonesia.

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● Joint Operating Agreement (JOA), Joint Operating Body (JOB)

- o PERTAMINA holds 50% participating interest.
- o The participating interest of the Contractors is subject to the same terms and split as used in the current PSCs.
- o PERTAMINA is the operator assisted by the Contractor in the form of a Joint Operating Body (JOB).
- o JOB is responsible to, and is supervised by a Joint Operating Committee (JOC).
- o PERTAMINA and the Contractors form the members of the JOC.
- o JOC approves Work Program and Budget and holds the policies.
- o Contractors carry PERTAMINA in financing exploration ventures and advanced development project.
- o The Sunk Cost of PERTAMINA is recoverable and an uplift of 50% is applicable.

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● Enhanced Oil Recovery (EOR)

- o The scope of project: pilot phase in water injection, fluid handling and facilities treating, drilling/workover of injection and production wells, injection system, flowlines to the connecting flange of the manifold inlet at gathering stations of PERTAMINA.
- o Primary production is determined for each production zone and is agreed prior to contract signing.
- o EOR cost and incremental oil produced are governed by the same terms as in JOA, except that a 65% cost recovery ceiling is applied.
- o Cost incurred by PERTAMINA down stream activities is chargeable to the EOR operation on pro-rata basis.
- o The initial two-year contract is allowed for the pilot phase, after which, the full EOR project will commence.

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● Technical Assistance Contract (TAC)

- o Shareable crude is crude other than the primary crude.
- o Cost of equipment and services for the primary crude

- will be defined part of operating cost.
- o Maximum operating cost is 65% of total shareable lifting cost.
- o An obligation of DMO contribution at 15% of the export price is taken from the share of the Contractor.
- o After Cost Recovery, the share of PERTAMINA will be 85% and the share of the Contractor will be 15%.

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The policy is summarised as follows:

To assure availability of energy for domestic use at affordable prices
 To make energy available for export
 To conserve oil consumption
 To develop new and renewable energy resources
 To protect the environment

In essence, the energy policy is aimed at balancing the

required energy resources to fulfill domestic demand and to obtain foreign exchange through export. Further, development of the nation's energy reserves, in order of priority, should start from renewable and non-tradeable energies such as hydropower and geothermal, followed by coal with its relatively low export value. Consideration then goes to energy resources which can be exported with a high value, such as natural gas.

According to the energy policy, oil should be utilised only if there is no alternative energy for the end user.

Implementation of the energy policy can be summarised into three measures:

- Intensification: increasing and expanding surveys for the exploration of energy resources
- Diversification: developing and using non-oil energy resources as far as possible
- Conservation: economizing energy use by using it efficiently

For economic and technological reasons however, fossil fuels (oil, gas, coal) still maintain the majority share in global energy consumption. Oil is the fuel of today and natural gas is described as the 'fuel of the future'.

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☒ Petroleum Incentive Package**Second Incentive Package, February 1989**

Element	Description
Split for Marginal Fields and for Tertiary EOR	Conventional areas 80% : 20% Frontier areas 75% : 25%
Split for Pre-Tertiary and Deep Sea Production	Incremental split as for frontier production (see First Incentive Package)
Investment Credit for Deep Sea Areas	For oil = 110% For Gas = 55%
Extension to the 6 years Exploration Period	1 x 4 years
Gas Pricing	Oriented towards field development economics
Access to Data	Not restricted to areas open for bidding
Field Data Acquisition	Will be conducted by PERTAMINA and will be available to contractors



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Fourth Incentive Package, 1993

Element	Description
After Tax Split for Oil	65% : 35%
After Tax Split for Gas	60% : 40%
DMO Oil Fee	25% of export price (after first five years)
FTP for Oil and Gas	15%

Explanation of the 1993 Petroleum Incentive Package

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1993 Incentive Package Table and Explanation

Table

Element	Precious Incentive Packages (1988, 1989, 1992)	1993 Incentive Package
After tax split for oil	Frontier : 80% / 20% Water depth of more than 1500 meters: 75% / 25%	65 % : 35%
After tax split for gas	Frontier: 60% / 40% Water depth of more than 1500 meters: 55% / 45%	60% : 40%
DMO oil fee	Petroleum: 15% of export price (after first five years)	25% of export price (after first five years)
FTP for oil & gas	20%	15%

Explanation

1. Objective

The purpose of the 1993 Petroleum Incentive Package is to encourage the petroleum exploration & production in the eastern and western parts of Indonesia that have similar geological and geographic conditions.

2. Applied Areas the Package

a. Eastern Indonesia areas are:

- east of 200 meters isobath starting from the offshore Kalimantan in Makassar Strait to the offshore Bali in Lombok Strait and an Area in the South east of Bali to the east of 155°30'00" longitude
- all Tertiary and Pre-Tertiary basins, except producing fields of Tertiary reservoir in the Bintuni, Salawati and Seram Basins

b. Western Indonesia areas are:

- west of Sumatra and south of Java offshore areas
- any other offshore areas in excess of 200 meters water depth
- Intramontane areas of Sumatra that are geologically located outside of the known existing basins (i.e.: North Sumatra, Central Sumatra and South Sumatra basins) and physiographically located in hilly areas of the volcanic back bone of Sumatra
- Basins in Melawi and Ketungau in West Kalimantan

3. Application

- a. the 1993 Incentive Package is an integrated package, that is, the package should be applied as a whole.
- b. Contractors who signed the working contract before January the 1st, 1994 have the option to apply either the 1993 Incentive Package relevant to the frontier terms.
- c. The application of two different fiscal terms is considered in the case where the new field development is located on two different areas that have different concepts.

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- **General Conditions**
- **Fiscal Conditions**
- **Tax Regime**

● General Conditions

Oil and gas in Indonesia are considered as a very vital commodity; all oil and gas minerals existing within the territory are national riches and controlled by the State. The authority to mine is delegated to PERTAMINA.

The general conditions of the Indonesian PSC is as follow:

1. PERTAMINA is responsible for the management of the operations.
2. Government must have a guarantee of the minimum income for each field development.
 - a. Oil field development - 85% (including Contractor Income tax) of First Tranche Petroleum 20% and 15% (for frontier area)
 - b. Gas field development - 70% for (including Contractor Income tax) of First Tranche Petroleum 20% and 15% (for frontier area)
3. In order to accelerate the exploration and development of the potential oil and gas resources, partners or investors shall have the financial ability, technical competence and professional skills necessary to carry out the operations.

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● Fiscal Conditions

The status of acquisition cost, the principle of cost recognition and the operating cost components are important issues to oil and gas investors. Fiscal conditions of the Indonesian PSC are based on:

1. In the stage of working area acquisition, the investor have to pay signature, compensation and production bonuses, not included in operating costs, but tax deductible.
2. Yearly operating costs and working area ring fencing
3. The unrecovered excess shall be recovered in succeeding years
4. Interest expense that approved by PERTAMINA shall include Operating Cost
5. Operating Cost
 - a. Non Capital - Current Year Operating Cost
 - b. Capital - Current Year Depreciation
 - c. Non Drilling Exploration - Direct Non Capital
 - d. Drilling (Exploratory, Delineation, Development, Workover)
 - i. Success Intangible Drilling Cost - direct Non Capital & Tangible Drilling Cost - Capital
 - ii. Dryhole Intangible and Tangible Drilling Cost - direct Non Capital
6. Depreciation
 - a. Asset placed in to service
 - b. Full year depreciation
 - c. Average asset use life 5 years with depreciation factor 25%
 - d. End year of the use life direct fully recovered
7. Profit Oil or Gas Split
 - a. Standard or conventional oil field - 85% for PERTAMINA, 15% for the Contractor (after income tax)
 - b. Marginal oil field (2 years for the first

- production working areas less than 10 MBOPD) 80% for PERTAMINA, 20% for the Contractor (after Income tax)
- c. Gas field - 70% for PERTAMINA, 30% for the Contractor (after Income tax)

8. Domestic Market Obligation (DMO)

After commercial production commences, Contractor agrees to sell and deliver a portion of the share of crude oil to fulfill towards the supply of the domestic market in Indonesia. Fee DMO oil for 5 calendar year production is market price and after 25% from market price.

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● **Tax Regimes**

1. Production Sharing Contractor has an economic interest in the development of oil and gas reserves.
2. Working area ring fencing consolidation.
3. Contractor subjected the Indonesian income tax with tax rate of 44%.
4. Contractor assumes and discharges all Indonesian taxes including transfer tax, value added tax, import and export duties, exaction's in respect of property, capital, net worth, operations, remittances or transactions including any tax or levy on/or in connection with operations.
5. Value added tax to be reimbursed by PERTAMINA after production commence.

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- production working areas less than 10 MBOPD) 80% for PERTAMINA, 20% for the Contractor (after income tax)
- c. Gas field - 70% for PERTAMINA, 30% for the Contractor (after income tax)

8. Domestic Market Obligation (DMO)

After commercial production commences, Contractor agrees to sell and deliver a portion of the share of crude oil to fulfill towards the supply of the domestic market in Indonesia. Fee DMO oil for 5 calendar year production is market price and after 25% from market price.

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● **Tax Regimes**

1. Production Sharing Contractor has an economic interest in the development of oil and gas reserves.
2. Working area ring fencing consolidation.
3. Contractor subjected the Indonesian income tax with tax rate of 44%.
4. Contractor assumes and discharges all Indonesian taxes including transfer tax, value added tax, import and export duties, exaction's in respect of property, capital, net worth, operations, remittances or transactions including any tax or levy on/or in connection with operations.
5. Value added tax to be reimbursed by PERTAMINA after production commence.

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LEGISLATIVE RESEARCH REPORT

MARCH 14, 2001



REPORT NUMBER 01.147

TAXES ON NATURAL GAS RESERVES

PREPARED FOR REPRESENTATIVE SCOTT OGAN

BY CHERIE NIENHUIS, LEGISLATIVE ANALYST

You asked us to determine which other states or countries, if any, tax natural gas reserves. You also requested that we identify natural gas development *disincentives* you believe were instrumental in encouraging development of Australia's natural gas reserves.

We made extensive contacts with national and international experts in the fields of energy, natural gas and oil, and in taxation. We could not locate a state or country that levies a tax on undeveloped natural gas reserves.¹ Most individuals with whom we spoke indicated that tax *incentives* are the norm around the world for encouraging development of natural gas reserves—and that a tax on nonproducing reserve leaseholds would only exacerbate the economic feasibility problem that keeps producers from developing them. Following a short discussion on the fiscal regimes used by various countries, we summarize Australia's current gas development policy, and then lastly, we look at laws in other states regarding undeveloped mineral reserve taxation.

¹ We contacted the following individuals and/or organizations: National Conference of State Legislatures; Interstate Oil and Gas Compact Commission; American Petroleum Institute; International Association of Assessing Officers; Pritchard & Abbott, Inc. (a resource valuation firm); the National Energy Information Center Tax Department; the International Monetary Fund; the International Energy Agency; Cambridge Energy Research Associates; Robin Boadway, a much published Professor of Economic Theory at Queen's University at Kingston, Ontario; Commissioner Wilson Condon, Alaska Department of Revenue (DOR); Deputy Commissioner Larry Persily, DOR; Tom Williams, former Commissioner, DOR, who now works for British Petroleum; Bill Van Dyke, Petroleum Manager, Alaska Department of Natural Resources; Richard Brewer, State Petroleum Property Assessor, DOR; and Glen Gray, Project Analyst, Alaska Division of Governmental Coordination.

In addition, we consulted numerous Internet sites and publications. The publications include, but are not limited to the following: Pedro van Meurs, *Alaska North Slope LNG Project*, February 12, 1997; Robert L. Bradley Jr., *Oil, Gas and Government*, Vol. II, Cato Institute (1996); Georg Koopman, Klaus Matthies, and Beate Reesat, *Oil and the International Economy: Lessons from Two Price Shocks*, Transaction Publishers (1989); Robert Mabro, *Natural Gas: An International Perspective*, Oxford University Press (1986); Aaron Wildavsky and Ellen Tenenbaum, *The Politics of Mistrust: Estimating American Oil and Gas Resources*, Sage Publications (1981).

NATURAL GAS FISCAL REGIMES

As of January 1, 2000, approximately 89% of the world's known natural gas reserves were distributed among just 20 countries, with one-third of that supply attributed to the Russian Federation.² Of these 20 countries, the United States is ranked 6th, holding approximately 164 trillion cubic feet, or 3.2% of the world's reserves. According to the Energy Information Administration, natural gas is the fastest growing component of world energy consumption. In 1999, several major international pipeline projects were completed, including lines linking Asia, Europe and South America with nearby countries.³

We spoke with Marie Fagan, Associate Director of the Cambridge Energy Research Associates (CERA). Ms. Fagan is very knowledgeable in the topic of world oil and gas fiscal regimes. She told us that there are currently two major types of fiscal regimes used in oil and gas production operations: tax/royalty regimes (common in the U.S. and Great Britain) and production sharing agreements (commonly used to develop resources in higher risk areas or areas with significant start-up costs). Production sharing agreements are contracts between governments and resource developers that usually contain terms delaying revenue sharing in the first several years of operation while the company recoups initial investment costs.

In his testimony before the U.S. Senate Committee on Energy and Natural Resources in July 1997, Dr. Pedro van Meurs, an expert in fiscal policies relating to oil and gas resource development, supported Ms. Fagan's views.⁴ He said that countries generally fall into one of two fiscal policy groups when addressing the liquefied natural gas market: countries that levy taxes on natural gas as part of an overall tax system (such as the U.S., Canada, and Australia); and countries that negotiate their fiscal policies with the developers on an individual basis (such as Southeast Asian and Middle Eastern countries). Mr. van Meurs said that Asian and Middle Eastern countries almost "foot the bill" for development-related construction and provide long-term tax breaks, which, he claims, amount to "corporate welfare."⁵ Additionally, the style differs between leases offered by the two groups of fiscal policies. Whereas U.S. leases can last indefinitely, leases in the Middle East are very limited in duration, and companies therefore have an incentive to "get in, get the gas, and get out."⁶

AUSTRALIA'S DEVELOPMENT OF NATURAL GAS RESERVES

You expressed a special interest in what incentives or disincentives Australia uses to encourage development of their natural gas reserves. We searched numerous Internet sites to learn as much as we could about the country's fiscal policies. We also e-mailed several gas and oil

² See "Table 16: World Natural Gas Reserves by Country as of January 1, 2000," reproduced from "Worldwide Look at Reserves and Production," *Oil & Gas Journal*, Vol. 97, No. 51, pp. 91-93, at <http://www.eia.doe.gov/oiaf/ieo/ta16.html>, accessed 3/1/01, included as Attachment A.

³ See Energy Information Agency's "Natural Gas" information, p. 2, included as Attachment A.

⁴ Senate Hearing on the Natural Gas Industry, July 23, 1997, before the Senate Committee on Energy and Natural Resources, available at <http://stage.ehweb.org/hearings/natga.html>, accessed 3/8/01.

⁵ Senate Hearing on the Natural Gas Industry, July 23, 1997, p. 4.

⁶ Senate Hearing on the Natural Gas Industry, July 23, 1997, p. 4.

representatives in Australia, inquiring about the use of incentives and/or disincentives to spur development of their natural resources.

The Western Australia Minerals and Energy Department website describes the following three petroleum royalty systems the country uses:

- Well-head Royalties
- Resource Rent Royalties
- Resource Rent Tax

Although all three systems basically tax the value of petroleum produced, there is a noticeable difference between the deduction limits on oil projects as opposed to gas projects. According to the government's web page, deductible costs can be as much as 90% of the gross value of production for gas projects, whereas only 50% of costs may be deducted for oil projects.⁸ According to Ms. Fagan, CERA, it is not uncommon for countries to tax natural gas projects at a lower percentage than they tax oil projects.

The recent East Timor/Australia petroleum project was initiated under a three-party production sharing agreement between the developers, Australia, and Indonesia. An important aspect of the agreement is that developers will be able to recover all exploration and operating costs.⁹

All news releases and articles we located on the development of Australia's oil and gas indicated that the government provides *incentives* for development, not *disincentives* against not developing the resources. Additionally, e-mail contacts with Australian officials were fruitless in uncovering policies applied by state or federal governments for the purpose of compelling companies to develop natural resources. We did find a document that provides a framework of joint government and industry commitments to the future of the natural gas industry in the country, called the "LNG (liquefied natural gas) Action Agenda."¹⁰ This lengthy document may be accessed at: <http://www.isr.gov.au/resources/lng/>.

TAXATION OF UNMINED MINERALS IN OTHER STATES

Even though we were unable to identify any states that specifically tax natural gas reserves, we did find that in at least two states—Kentucky and Colorado—unmined minerals that are held separately from surface real property are assessed and taxed on their value, just as are other real properties.

Kentucky Revised Statutes § 132.820 mandates that "unmined coal, oil, and gas reserves and other mineral or energy resources shall in all cases be valued and assessed by the Revenue

⁷ A copy of the web page describing Australia's petroleum royalties is included as Attachment B.

⁸ See Attachment B, p. 1.

⁹ From Barrow's Inc. *World Fiscal Systems for Oil*, pp. 234-235, included as Attachment C. Because the publication is voluminous, the Australia portion of the book was faxed to us by Ms. Fagan at CERA.

¹⁰ See "Government and Producers Boost LNG Industry" Media Release, Senator Nick Minchin, Minister for Industry, Science and Resources, dated October 10, 2000, accessed 3/9/01 at <http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>, included as Attachment D.

Cabinet" and shall be subject to taxation on that value.¹¹ Colorado law also specifies that "nonproducing severed mineral interests are to be valued at twenty-nine percent of actual value in the same manner as other real property."¹²

We discussed Kentucky's taxation of nonproducing mines with David Gabbard, Branch Manager for Minerals Service Tax, Kentucky Revenue Cabinet.¹³ He told us that although unmined mineral interests had long been subject to property tax, the properties were previously granted a special classification, and taxed at such a low rate that it created a *de facto* exemption for the properties. In a class action lawsuit brought against the state of Kentucky Revenue Cabinet in 1988, the Kentucky Supreme Court ruled the classification unconstitutional, thereby requiring the state to tax these properties as they would other real properties in the state.¹⁴

Mr. Gabbard said that in 1989, the Revenue Cabinet began assessing coal properties in order to determine a fair market value for them for taxation purposes. Coal reserves are known to exist in 32 counties in the state of Kentucky, and valuing these properties has been an arduous task for the Cabinet. Yet, Mr. Gabbard explains, coal reserves are easier to quantify than gas and oil reserves, of which the state has very little. For that reason, no effort has been made to place a value on the unproduced reserves of oil and gas in Kentucky, and even though the law requires these resources be taxed, thus far, no taxes have been levied on them. Mr. Gabbard told us it probably would not be worth the Revenue Cabinet's time to try to value these scant reserves, and his department has not received complaints from interested parties that the limited petroleum reserves have not been taxed.

Additionally, Mr. Gabbard believes the tax imposed on unmined resources has had a negligible effect on development of them. The tax is so minimal—1% of the value of the property—that it is not much of a factor, although Mr. Gabbard thinks that a higher tax on more valuable reserves could prompt a positive response. Coal mining has decreased for other demand-related reasons, Mr. Gabbard said, and Kentucky simply does not have the vast quantities of undeveloped natural gas reserves that Alaska has.

I hope you find this information useful. Please do not hesitate to contact us if you have questions or need additional information.

¹¹ KRS § 132.820 is included as Attachment E.

¹² CRS § 39-1-104 (4).

¹³ Mr. Gabbard may be reached at (502) 564-8334.

¹⁴ *Gillis v. Yount*, 748 S.W.2d 357, (1988 KY) is included as Attachment F.

LIST OF ATTACHMENTS

Attachment A

"Table 16: World Natural Gas Reserves by Country as of January 1, 2000,"
from *Oil & Gas Journal*, Vol. 97, No. 51, pp. 91-93,
http://www.eia.doe.gov/oiaf/ieo/tabl_16.html;
and Energy Information Agency's "Natural Gas,"
http://www.eia.doe.gov/oiaf/ieo/nat_gas.html

Attachment B

Western Australia Department of Minerals and Energy
"Petroleum Royalties,"
<http://www.dme.wa.gov.au/insidedme/royalty/petsys.html>

Attachment C

Barrow's Inc., *World Fiscal Systems for Oil*,
pp. 234-235, "Australia"

Attachment D

"Government and Producers Boost LNG Industry"
Media Release, Senator Nick Minchin, Minister for Industry,
Science and Resources, October 10, 2000
<http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>

Attachment E

Kentucky Revised Statutes § 132.820, relating to the
Assessment and Taxation of Unmined Minerals and Energy Resources

Attachment F

Gillis v. Yount,
748 S.W.2d 357, (1988 KY)

Attachment A

"Table 16: World Natural Gas Reserves by Country as of January 1, 2000,"
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and Energy Information Agency's "Natural Gas,"
http://www.eia.doe.gov/oiaf/ieo/nat_gas.html

Table 16. World Natural Gas Reserves by Country as of January 1, 2000

Country	Reserves (Trillion Cubic Feet)	Percent of World Total
World	5,146	100.0
Top 20 Countries	4,571	88.8
Russian Federation	1,700	33.0
Iran	812	15.8
Qatar	300	5.8
United Arab Emirates	212	4.1
Saudi Arabia	204	4.0
United States	164	3.2
Algeria	160	3.1
Venezuela	143	2.8
Nigeria	124	2.4
Iraq	110	2.1
Turkmenistan	101	2.0
Malaysia	82	1.6
Indonesia	72	1.4
Uzbekistan	66	1.3
Kazakhstan	65	1.3
Canada	64	1.2
Netherlands	63	1.2
Kuwait	52	1.0
China	48	0.9
Mexico	30	0.6
Rest of World	575	11.0
Source: "Worldwide Look at Reserves and Production," <i>Oil & Gas Journal</i> , Vol. 97, No. 51 (December 20, 1999), pp. 91-93.		

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Natural Gas

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Natural gas is the fastest growing primary energy source in the IEO2000 forecast. The use of natural gas is projected to more than double between 1997 and 2020, providing a relatively clean fuel for efficient new gas turbine power plants.

World natural gas consumption continues to grow, increasing its market share of total primary energy consumption. In the *International Energy Outlook 2000* (IEO2000), natural gas remains the fastest growing component of world energy consumption. Over the IEO2000 forecast period from 1997 to 2020, gas use is projected to more than double in the reference case, reaching 167 trillion cubic feet in 2020 from the 1997 level of 82 trillion cubic feet (Figure 46). Over the 1997-2020 period, the role of natural gas in energy use is projected to increase in all regions except the Middle East and Africa, where its share remains relatively stable. The developing countries of Asia and of South and Central America will see the strongest growth rates in gas demand. Large incremental increases are also projected for industrialized countries, including the United States, and for the former Soviet Union (FSU).

Figure 46. World Natural Gas Consumption, 1970-2020
[Sources]

In the IEO2000 reference case, a slowly increasing share of world gas consumption is used in the electric power sector (rising from 29 percent in 1997 to 33 percent in 2020), and natural gas accounts for the largest increment in electricity generation (increasing by 33 quadrillion Btu). Not only do combined-cycle gas turbine power plants offer some of the highest commercially available plant efficiencies, but natural gas is also attractive for environmental reasons. When it is burned, natural gas releases less sulfur dioxide, less particulate matter, and less carbon dioxide than does oil or coal.

For the industrialized countries, natural gas—compared with other fuels—is expected to provide the greatest incremental increase in energy consumption among the major fuels and has the fastest average annual growth in the forecast (2.1 percent per year, compared with 1.0 percent for oil). The percentage of gas used for power generation also grows from 20 percent in 1997 to over 30 percent in 2020. In 1997, natural gas consumption in the developing countries was a smaller portion of total energy use (14 percent) than the world average (22 percent). From that starting point, gas consumption in developing countries grows at a faster rate in the reference case than any other fuel (an average of 5.6 percent per year, compared with 3.1 percent for both oil and coal). Increments in gas use in the developing countries are expected to supply both power generation and other uses, such as town gas and fuel for industry.

In Central and South America, the power sector currently

Global gas reserves have more than doubled over the past 20 years, outpacing the 62-percent growth in oil reserves over the same period. *Oil & Gas Journal* estimated proven world gas reserves as of January 1, 2000, at 5,146 trillion cubic feet, an increase of 1.5 trillion cubic feet over the previous year's estimate (see discussion on "Taking Stock: Reporting Reserves and Selected Natural Gas Finds of 1999").² Over the past 20 years, reserve estimates have grown rapidly in the FSU and in developing countries in the Middle East, South and Central America, and the Asia-Pacific region (Figure 47).

Figure 47. World Natural Gas Reserves by Region, 1975-2000 [Sources]

The largest incremental increases in reserves over the past year were nearly 4 trillion cubic feet for the Asia-Pacific region and more than 33 trillion cubic feet for Africa, mostly in Algeria and Egypt. Those reserve expansions were offset, however, by reported decreases in all other regions. Reserves in Mexico were reported to decline by more than 50 percent (from 63 to 30 trillion cubic feet), and reserves in the United States and Western Europe also declined by 3 and 2 trillion cubic feet, respectively. Gas reserves reported by *Oil & Gas Journal* are compiled from voluntary survey responses and do not always reflect most recent changes. Some significant gas discoveries made in 1999, for example in Asia and the Middle East, are not reflected in the most recent estimates.

In regional terms, world gas reserves are more widely distributed than oil reserves. The Middle East, which holds nearly 65 percent of global oil reserves, accounts for only 34 percent of gas reserves (Figure 48). Thus, some regions with limited oil reserves hold a greater portion of global gas

Figure 48. World Natural Gas Reserves by Region as of January 1, 2000 [Sources]

stocks. The FSU, in particular, accounts for around 6 percent of world oil reserves but nearly 40 percent of proven gas reserves, most of which (33 percent of world reserves) is located in the Russian Federation. The Russian reserves are the largest in the world, more than double the second-largest reserve volume in Iran. Gas reserves are also more widely distributed than oil reserves within the Middle East, where Qatar, Iraq, Saudi Arabia, and the United Arab Emirates all have significant gas volumes (Table 16).

Reserve-to-production (R/P) ratios exceed 100 years in the Middle East and Africa and are next highest in the FSU at 83.4 years. South and Central America also has a high ratio (71.5 years), but in North America and Europe R/P ratios are relatively low at 11.4 years and 18.3 years, respectively. The R/P average for natural gas in the world is 63.4 years, compared with 41 years for oil [1].

Table 16. World Natural Gas Reserves by Country as of January 1, 2000

Regional Activity

CORRECTION

**THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION**



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Department of Education & Early Development
State of Alaska

Natural Gas

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relies heavily on hydroelectric power, which accounts for about 12 percent of primary energy use (compared with a 2.5-percent share in the global energy mix in 1997). Because dependence on hydroelectric resources in the region has led to problems in maintaining electricity supply during times of drought, fuel diversification is now being pursued. In developing Asia, gas use is also desirable for environmental reasons and to diversify the energy mix away from heavy reliance on oil imports. The problem has been complicated, however, by greater distances between gas resources and market centers, leading to a combination of liquefied natural gas (LNG) and pipeline trade in the region.

There are also new efforts to develop natural gas use in the Middle East, although the projected growth rates and incremental increases there are smaller than in Asia or the Americas. Domestic resources may supply some of the increase in gas use in the Middle East (for example, in Saudi Arabia), but trade will also be important. In addition to Turkey and Israel, both Oman and the United Arab Emirates may become gas importers, using pipeline imports from Qatar to meet domestic demand while sustaining their own LNG export commitments.

Some important gas market developments in 1999 include:

- The completion of several major international pipelines and firming of plans for other new pipelines in Europe and South America. Steady growth in pipeline infrastructure is leading to increased trade, which can facilitate a more transparent (and mature) gas market. The 1999 completion of the Europipe II from Norway to Germany will lead to an expanded role for North Sea gas in Germany. On the southern side of Europe, Italy moved forward with plans to build a new pipeline for imports of Libyan gas. In South America, pipelines from Bolivia to Brazil and from Argentina to Chile (the GasAtacama and the Norandino) were completed in 1999.
- Completion in Asia of several major international pipelines and plans for additional lines. In Asia, the new pipeline from Myanmar to Thailand began building up deliveries to contracted volumes, more than a year behind schedule. Contracts were signed for two new pipelines that would carry Indonesian gas exports to Singapore, and plans moved forward for a pipeline from Papua New Guinea to Australia, with finalization of gas sales contracts.
- The completion of several LNG facilities. Three grassroots natural gas liquefaction facilities came on stream in 1999 in Trinidad and Tobago (Atlantic LNG), Nigeria (Bonny), and Qatar (Rasgas). An expansion, Indonesia's eighth train ("Train H") at its Bontang facility is also starting operations at the end of 1999 or early in 2000. Qatar has concluded agreements with India for the sale of 7.5 million metric tons of LNG with deliveries starting in 2003.

Reserves

Global gas reserves have more than doubled over the past 20 years, outpacing the 62-percent growth in oil reserves over the same period. *Oil & Gas Journal* estimated proven world gas reserves as of January 1, 2000, at 5,146 trillion cubic feet, an increase of 1.5 trillion cubic feet over the previous year's estimate (see discussion on "Taking Stock: Reporting Reserves and Selected Natural Gas Finds of 1999").² Over the past 20 years, reserve estimates have grown rapidly in the FSU and in developing countries in the Middle East, South and Central America, and the Asia-Pacific region (Figure 47).

Figure 47. World Natural Gas Reserves by Region, 1975-2000 [Sources]

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Table 16. World Natural Gas Reserves by Country as of January 1, 2000

Regional Activity

North America

In the *IEO2000* reference case, natural gas consumption is projected to grow by 1.6 percent per year between 1997 and 2020 in Canada and the United States and by 2.4 percent in Mexico. Fuel use for electric power generation is largely responsible for the increases in all three countries. In the United States alone, natural gas consumption for electricity generation (excluding cogenerators) is projected to grow from 3.4 trillion cubic feet in 1997 to 9.3 trillion cubic feet in 2020. In projections from EIA's *Annual Energy Outlook 2000* (*AEO2000*), nearly 90 percent of new electricity generating capacity between 1997 and 2020 is combined-cycle or combustion turbine technology fueled by natural gas or both oil and gas; and while increases are also expected in the other U.S. demand sectors, the growth in gas use in the electric utility sector is by far the most significant [2]. For Canada, the Canadian Energy Research Institute (CERI) estimates that gas demand for electricity generation could nearly triple in the next decade, assuming the continued restructuring of the electricity sector that is currently either underway or anticipated in many provinces.

In 1998, approximately 55 percent of Canada's natural gas production was exported to the United States, and Canadian gas accounted for about 14 percent of U.S. consumption. Canada's exports have been growing steadily in response to increasing demand in the United States, more than tripling since 1985. By 2005, *AEO2000* projects that Canada's share of end-use consumption in the U.S. gas market will increase to 18.4 percent.

Currently, significant pipeline construction both within Canada and between the United States and Canada is underway to accommodate U.S. import demand. By the end of 2000, five major new natural gas pipeline projects and an upgrade on a sixth (Alliance, Millennium, NOVA, Northern Border, TransCanada, and Maritimes Northeast) are expected to be complete, allowing a considerable increase in trade between the two countries [3]. Most of the construction will provide access to supplies in western Canada, and the Maritimes and Northeast project will transport supplies from Canada's offshore Atlantic Sable Island fields to markets in New England. Gas fields with more than 6 trillion cubic feet of combined reserves near Sable Island and at Terra Nova are under development, and Cambridge Energy Research Associates has indicated that natural gas reserves off Nova Scotia may be five times what has already been discovered, with approximately 53 trillion cubic feet possible [4].

Considerable pipeline construction is also under way in the United States. Several major projects will provide access to new sources of both supply and demand and increase capacity along corridors where utilization rates are high during peak periods. Recently completed projects include Interstate's Pony Express project, the Trailblazer system expansion, the Transwestern Pipeline expansion, and the El Paso Natural Gas system expansion. The first two provide access to Wyoming and Montana production regions, and the last two provide access to New Mexico's San Juan Basin. Further expansions are underway that will increase flows from these areas to markets on the east and west

coasts. U.S. pipeline capacity expansion is expected to slow after 2001, however, to less than 1 percent a year. Overall utilization of pipeline capacity is expected to increase significantly after 2001 as demand for natural gas to fuel electricity generation leads to increased flows during the summer months.

LNG imports are also becoming more economical for the United States. LNG imports are expected to increase more than fivefold between 1997 and 2020, from 0.08 trillion cubic feet per year to 0.39 trillion cubic feet per year. In the past, U.S. LNG imports have come predominantly from Algeria. New sources of supply include Australia, Trinidad and Tobago, and Qatar, and Abu Dhabi and Norway are potential sources.

Additions to U.S. LNG import capability include a 50-percent increase in offloading capacity at the Everett, Massachusetts, port facility; a projected reopening of the Southern Natural Gas Company LNG terminal at Elba Island, Georgia; and a potential reopening of Columbia LNG's Cove Point, Maryland, facility. Both Elba Island and Cove Point were closed over 15 years ago when LNG became too costly to compete with other sources of natural gas in the United States. Cove Point subsequently reopened in the early 1990s for peak-period service storage only. Preliminary approval to reopen Elba Island was granted by the Federal Energy Regulatory Commission (FERC) in December 1999, and Southern plans to begin importing up to 0.8 trillion cubic feet of LNG per year from Trinidad in 2002 [5]. Anticipating increased demand for LNG shipments, especially in the Northeast, Columbia LNG is hoping to recommission its Cove Point, Maryland, facility to provide LNG tanker unloading services. The terminal can deliver up to 1 billion cubic feet per day to Columbia's main system. If response is sufficient to a planned open season for customers to bid on capacity, as Columbia expects it to be, Cove Point will file with the FERC for authorization to recommission [6].

Although Mexico has considerable resources that could be developed, production is not expected to keep pace with rising internal demand, and Mexico is expected to remain a net importer of natural gas. As in the United States and Canada, most of the projected growth in demand is for electricity generation. A recent forecast by the Mexican government indicates that natural gas demand will grow by 9.2 percent a year between 1998 and 2007, with consumption for electricity generation increasing by 20 percent a year.

Another area of significant growth in Mexico's gas consumption is expected to be manufacturing and assembly plants located close to the U.S. border, where U.S. producers are in a much better position to satisfy the demand [7]. Although considerable investment is currently being made in the expansion of pipeline infrastructure, Mexico continues to have the problem, at least in the near term, of not being able to transport natural gas from southern producing regions to northern consuming regions in quantities sufficient to meet demand. AEO2000 projects U.S. exports to Mexico to grow from 0.05 trillion cubic feet in 1997 to 0.24 trillion cubic feet in 2020, in the wake of Mexico's

recent elimination of a 4-percent import tariff and an increase in pipeline capacity between the two countries.

Western Europe

Europe's gas reserves, which account for less than 5 percent of global resources, are located predominantly in the Netherlands, Norway, and the United Kingdom. Production in those three countries currently surpasses production in other regions with greater reserves, such as the Middle East. Nearly one-third of Europe's gas demand is met by supplies from outside the region, particularly pipeline imports from the FSU and Algeria, as well as LNG primarily from North Africa. Recent demand increases reflect rising gas use for power generation as well as in the industrial sector. Demand growth has been particularly strong in Greece, Portugal, Italy, Spain, Finland, Belgium, and Denmark. *IEO2000* projects growth in Western Europe's gas use averaging 2.9 percent per year, reaching 25.9 trillion cubic feet by 2020 (Figure 49).

Figure 49. Natural Gas Consumption in Western Europe, 1970-2020 [Sources]

European investments in infrastructure in 1998 included the completion of the Interconnector and at least four other significant pipeline projects, and 1999 saw the on-schedule completion and commissioning of the Europipe II. The 420-mile Europipe II, operated by Statoil, links Norway's west coast to Dornum in northwest Germany. With its commissioning, imports from Norway could supply up to 30 percent of Germany's natural gas use by 2010 [8]. In *IEO2000*, German gas consumption is expected to rise by an average of 2.9 percent per year, nearly doubling in 2020 from the 1997 level of 3.4 trillion cubic feet (Figure 50).

Figure 50. Natural Gas Consumption in Germany, 1970-2020 [Sources]

Elsewhere in Europe, pipeline projects such as a Swiss line scheduled for completion in October 1999 will improve and increase north-south gas flows. Future construction in Switzerland could eventually double capacity by 2003. A new leg of the Yamal-Europe pipeline was also completed in Germany in September. Financed by Wingas and Gazprom investment, the 209-mile section stretches from Frankfurt-on-Oder to Rueckersdorf, Thuringen, and will transport up to 990 billion cubic feet of gas per year to German and West European consumers [9]. Germany's Ruhrgas started construction of a 71-mile pipeline from Mittelbrunn in Saarland to Esch in Luxembourg. With deliveries scheduled to start mid-2000, the \$45 million project will transport 20 billion cubic feet of gas annually to a gas and steam power plant under a 15-year contract signed with Soteg [10].

In addition to the announced and planned mergers of such large international corporations as BP, Amoco, and ARCO and Mobil and Exxon, Europe also saw important mergers in 1999. TotalFina and Elf Aquitaine agreed in September to a friendly merger that would rival BP Amoco (which plans to merge with ARCO) in European gas production and

marketing. In October, however, the European Union announced an investigation into the merger, citing concerns about potential dominance in the liquid petroleum gas (LPG) market [11]. In Germany, Veba and Viag will merge to create a group with electricity, natural gas, and water businesses and with the stated goal of pursuing growth abroad through targeted acquisitions [12].

Strong gas market growth continues in Italy and Spain. Italy's Eni announced that final agreements were reached with Libya's National Oil Corporation (NOC) to import gas via a new undersea pipeline. Plans call for imports of some 280 billion cubic feet per year starting as soon as 2003, with Italy now in the stage of awarding contracts [13]. Regional approval has been given to Edison-Mobil plans for a new Italian LNG receiving terminal in the northern Adriatic Po Delta (Figure 51) to be built on an artificial island; approval by the national government is still required. The terminal could be operational as early as 2003, with Egypt as the potential supplier of LNG [14].

Figure 51. Italy's Natural Gas Infrastructure [Sources]

Spain has agreed to buy more LNG from Shell-led facilities in Nigeria, enabling Shell to go forward with expansion plans there. Spanish gas demand is expected to grow rapidly after 2000, when a series of gas-fired, combined-cycle power plants are due for commissioning [15]. Competition has been increasing in the Spanish gas and power markets with the government's announcement of new operators allowed in each market. Five more companies now able to trade in gas include Enagas, Gas de Asturias, Gas de Euskadi, Iberdrola, and BP Amoco [16]. In Portugal, plans continue to develop the country's first LNG receiving terminal, to be sited on the Atlantic coast near the Sines oil terminal. Transgas Atlantico is seeking a turnkey contractor for the project and has issued an invitation to tender. Construction could begin by the end of 2000.

Eastern Europe and the Former Soviet Union

In most of Eastern Europe, natural gas consumption continued to decline in 1998, although there were increases in some countries. The Russian Federation continued to dominate world trade movements of natural gas, exporting 4.2 trillion cubic feet to Europe and to other FSU countries. The only other exports of natural gas from the FSU were 63.5 billion cubic feet delivered to Iran from Turkmenistan [17].

Nonpayment for gas supplies continues to be an issue throughout the FSU, both within and between countries, and barter continues to be an accepted form of payment. Uzbekistan threatened to stop deliveries to Kyrgyzstan on November 15, 1999, if the mounting debt was not paid. Because of problems with Kyrgyzstan's hard currency, Uzbekistan had agreed to take partial payment for gas supplies in flour, but Kyrgyzstan had fallen considerably behind even in its "flour debt." As a result, the Uzbek gas transport company Uztransgaz indicated that it had no option but to cut off supplies [18]. Deliveries were temporarily halted

but resumed in mid-December after the payment of \$3 million, partly in cash and partly in goods. The gas currently being received is roughly half the amount received during 1998, and it is going mainly to homes in the northern part of the country [19].

Belarus, in debt to the Russian gas monopoly Gazprom, has major internal problems with consumers not paying their gas bills, which in turn make it difficult for the Belarusian government to pay Gazprom. The government gave internal consumers until January 1, 2000, to pay gas debts, and the state-owned gas transport company Beltranshaz proposed that partial payment of the debt to Gazprom be made in agricultural equipment [20].

The situation is similar in Ukraine, which owes Russia more than \$1 billion for natural gas purchases. Ukraine's internal nonpayment problem is significant, with consumers owing Naftogaz Ukrainy about \$3 billion. In an effort to secure payment from domestic customers, the government has been cracking down on nonpaying customers by curtailing supplies. A total of 13,700 were disconnected in 1998, including 3,650 industrial customers. After some initial problems involving cutoffs during the cold winter months, the government pledged to forbid cutoffs during the winter. Cutoffs resumed in the spring, however, and at the beginning of April 1999, 378 debtor firms were disconnected from natural gas supplies [21].

Ukraine has resorted to barter to satisfy its external debt, agreeing to deliver to Russia 11 bombers and 500 cruise missiles, valued at \$285 million, by the end of 1999 as partial payment of the debt owed to Gazprom. The first of the bombers, all of which were inherited after the breakup of the Soviet Union, were delivered to Russia in November 1999 [22]. Ukraine is also in debt to Turkmenistan for gas supplies delivered as far back as 1993, and Turkmenistan cut off supplies in June 1999. The debt has since been restructured, with payments to be completed in December 2001. In October 1999, the debt exceeded \$300 million [23].

Russia has also threatened to take action against Ukraine for reasons other than nonpayment. Ukraine is the main transit route for Russian gas to reach European markets, and Russia has long accused Ukraine of siphoning off gas during transit. Itera, the main supplier of Russian gas to Ukraine, threatened to stop supplying gas to Ukraine by October 1, 1999, pending payment of debt. Gas exports are a major source of revenue for Russia, and over 90 percent of gas exported by Russia passes through Ukraine. According to a Gazprom spokesman, since ceasing gas flow to Ukraine would entail giving up the European market, it is unlikely that gas shipments to and through Ukraine will cease anytime soon [24].

Although Russian natural gas trade with Europe is currently dependent on Ukraine, Russia expects new export routes to be developed in the next few years. The first section of the Yamal-Europe pipeline, through Belarus and Poland, went into operation in 1999, and a second parallel section is in the planning stages. The new pipeline allows Russia to eliminate Ukraine from its route to Western Europe, which currently

Poland's natural gas needs. As a move towards diversification, however, Poland signed a 5-year gas supply contract with Norway in December 1999 for supplies beginning in 2001. Talks to determine how the gas might be transported to Poland are only at an initial stage, however [30]. Poland is anticipating large increases in natural gas demand between now and 2020 and is dependent on imports to meet most of the new demand. Natural gas industry restructuring, which will facilitate gas purchases from countries such as Norway, Holland, and Germany, is in the works, with an anticipated start date sometime in 2001. Accompanying the restructuring is a move toward privatization, which the government expects to be completed in 2005.

In spite of the uncertainties and problems currently facing the EE/FSU, *IEO2000* projects significant future growth in the region's natural gas markets. Consumption in the FSU is projected to grow at a rate of 2.1 percent a year between 1997 and 2020, with the strongest growth at the end of the forecast period from 2015 to 2020. The projected increase in Eastern Europe is steadier but considerably higher, at an overall rate of 5.6 percent per year. Total EE/FSU consumption nearly doubles, from 22.3 trillion cubic feet in 1997 to 41.2 trillion cubic feet at the end of the forecast period. The considerable effort, both internally and via foreign investment, that is going into the development of the region's natural gas infrastructure will be a significant factor in increasing future production, consumption, and export capabilities for natural gas.

Central and South America

Central and South American gas markets are small in terms of total volumes handled, but they continue to show strong growth with active upstream and downstream development. Between 1990 and 1997, the region's gas consumption grew by an average of more than 5 percent per year. Estimated reserves in the region account for less than 5 percent of global gas reserves, but much of the area has been underexplored, and discoveries are accompanying recent exploration activity. Production, consumption, and trade are also limited. Production and consumption of natural gas in the region were at about 2.9 trillion cubic feet in 1997. In 1999, natural gas trade extended outside the region with initiation of LNG exports from Trinidad and Tobago. The only international pipelines in the region before 1999 operated from Bolivia to Argentina and from Argentina to Chile. The *IEO2000* reference case projects that the region's gas use, facilitated by additional pipelines, will grow to 15.3 trillion cubic feet by 2020, at an average annual growth rate of 7.5 percent (Figure 52).

Figure 52. Natural Gas Consumption in Central and South America, 1990-2020 [Sources]

On the production side, a new LNG facility in Trinidad and Tobago came on stream in 1999, loading the first Atlantic Basin export cargoes in April [31]. Starting in 2000, the U.S. LNG company Cabot will take 1.8 million metric tons of LNG per year from the facility, some of which will be delivered to Puerto Rico. A new receiving terminal now under

construction in Puerto Rico will enable increased use of gas in power generation. BP Amoco and Repsol are promoting plans to add two more LNG trains in Trinidad and Tobago, with Spain lined up as a buyer for at least some of the increased output and Cabot also expected to take more gas [32].

Much of the gas market growth in South America involves Brazil, a large country with large projected gas demand. In the *IEO2000* reference case, gas use in Brazil grows from 0.2 trillion cubic feet in 1997 to 2.5 trillion cubic feet in 2020. A new Bolivia-Brazil pipeline began operating in July 1999 after years of negotiation. Initially, the line was expected to begin carrying about 78 million cubic feet per day to Brazil, rising to 200 million cubic feet per day by the end of 1999 and then to 318 million cubic feet per day in 2000, when a take-or-pay contract begins. By 2006, volumes could exceed 1 billion cubic feet per day, worth about \$400 million per year. Import volumes at the end of 1999 were much lower, however, ranging only around 22 to 53 million cubic feet per day due to a significant rise in Brazilian gas prices. Prices are linked via formulae to fuel oil prices (which were rising) and were also affected by a 40-percent devaluation of the Brazilian real. Pipeline operators are estimating the associated financial loss at about \$500,000 per month [33].

A second line to Brazil is now under consideration following significant gas discoveries in Bolivia, but construction is not anticipated before 2001. In addition, an Enron project involving a 390-mile pipeline from Bolivia to Cuiaba in Brazil has received approval from the U.S. Overseas Private Investment Corporation (OPIC) for a \$200 million credit, despite objections from environmentalists. Protestors opposed the pipeline route through what may be the world's largest intact dry forest (called Chiquitana). Backers of the project have emphasized planned environmental mitigation measures (including a partial rerouting to avoid the most environmentally sensitive areas and a pledge of \$20 million over 15 years for conservation efforts) as well as benefits of new gas supplies replacing diesel use and local firewood demand. A 490-megawatt Cuiaba power plant and the pipeline together amount to a \$570 million effort involving Shell and Bolivian firm Transredes (50 percent owned by Enron and Shell) [34].

In addition, a pipeline to Brazil from Argentina is under construction to enable the first imports of Argentine gas. The 272-mile Transportadora de Gas del Mercosur, SA (TGM) pipeline from Parana in Entre Rios, Argentina, to Uruguaiana, Brazil, will connect to Argentina's existing domestic line, Transportadora de Gas del Norte (TGN). CMS Energy holds equity in both pipelines. TGM's other owners include Canada's TransCanada Pipelines, Argentina's CGC and Techint, and Malaysia's Petronas. The pipeline is scheduled for completion in 2000 and will initially transport about 100 million cubic feet per day, with capacity expandable up to 425 million cubic feet per day [35].

To address higher gas prices in Brazil and encourage gas-related investment, particularly in the power sector, the government announced that it may control prices in some regions. In southern, southeastern, and central western

states as well as the Brasilia Federal District, power projects signing 20-year contracts could have a price ceiling equivalent to \$2.26 per million Btu (in 1999 dollars). In Brazil's northeast, where gas will initially be domestically supplied, there is a proposed price ceiling for the first 5 years of \$1.94 per million Btu and \$2.26 for the remainder of the 20-year period. As many as 23 power plants with a combined capacity of 7,400 megawatts could benefit from the price control policy. The move is welcome by foreign investors and will facilitate project funding, because it fixes long-term contracts in dollars rather than the more volatile Brazilian real [36].

Elsewhere in South America, the GasAtacama pipeline began operating in mid-1999, sending gas from Argentina to Chile. It is the second pipeline linking the two countries, after TransCanada's GasAndes pipeline in central Chile, which started operation in 1997. The \$400 million GasAtacama line was built by CMS Energy and Chilean generator Endesa in a project that includes a \$350 million, 370-megawatt power plant. A parallel and rival line, Norandino, backed by Belgian Tractabel and Southern Energy, began operation at the end of 1999. The 585-mile GasAtacama has a capacity of 300 million cubic feet per day but will operate significantly below that at first. Because the project's associated long-term electricity sales contract with Chilean Emel and its distribution companies (via the Nopel power plant) does not begin until 2002, it will sell power on the spot market at first. A pipeline extension is being planned to reach other power plants [37].

A pipeline has also been proposed for transporting Colombian gas into Central America. Backed by local firm Promigas (operated by Enron) and supported by state oil company Ecopetrol, such a project could supply gas to Panama, Costa Rica, and Nicaragua. Conceived to find markets for Colombia's abundant known and potential reserves, the line could face a possible competing or complementing project from Mexico [38]. Venezuela has also expressed an interest in exporting gas to Central America and/or forming a strategic alliance with Ecopetrol [39].

In Peru, the government repeatedly postponed bidding deadlines in 1999 for the sale of the \$2 billion Camisea natural gas project. Although the delays purportedly were to give interested parties more time, they followed the resignation of energy and mines minister Daniel Hokama, as well as reports of disagreement within the government's Camisea committee. Potential investors have complained that the terms of the project are not sufficiently attractive and that gas prices should be set by the market, while the government has maintained that set prices are needed as incentive to potential power producers [40].

Venezuela's election of populist president Hugo Chavez has led to turmoil and power struggles for Petroleos de Venezuela (PDVSA), one of Latin America's biggest companies. The president of PDVSA, Roberto Mandini, has resigned, to be replaced by Hector Ciavaldini, who is said to back reforms promoted by Venezuelan President Chavez including a government effort to control the oil industry. PDVSA has been described as the economic backbone of

Venezuela, the largest producer and consumer of natural gas in South and Central America [41]. Reorganization at PDVSA includes the establishment of a Natural Gas Division, reflecting a government preference to emphasize gas resource development. Although PDVSA will no longer pursue plans with Shell for an offshore Cristobal Colon LNG project because of poor economics, it is still looking for potential LNG or pipeline projects to commercialize gas reserves. Several domestic pipeline projects will also be prioritized [42].

Asia

Gas market activity in Asia during 1999 reflected ongoing recovery in the region from the Asian financial and economic crisis. Demand growth recovered, most notably in South Korea and Thailand, and new projects moved forward. In the *IEO2000* reference case, the growth rate for natural gas use through 2020 in the whole of Asia (both industrialized and developing) averages 5.6 percent per year, increasing consumption to 31.5 trillion cubic feet from 8.9 trillion cubic feet in 1997. The projected demand growth in developing Asia is much higher than in the industrialized countries of the region (Figure 53).

Figure 53. Natural Gas Consumption in Asia by Region, 1980-2020 [Sources]

Industrialized Asia

For the countries of industrialized Asia, natural gas consumption is expected to rise from 3.2 trillion cubic feet in 1997 to 5.2 trillion cubic feet in 2020. Gas use in Japan, the world's largest consumer of LNG, accounts for 70 percent of the incremental increase over the period, increasing from 2.3 to 3.7 trillion cubic feet in the *IEO2000* reference case.

Although in the short run Japanese demand growth is affected by economic recession there, LNG imports to Japan are expected in the long run to grow slowly from their large base. The September 1999 occurrence of Japan's worst nuclear accident in history could ultimately affect gas use, which is consumed primarily in the electricity sector, competing with nuclear power.

As not only the largest but also the first LNG importer in Asia, Japan has several major contracts that end over the next 5 to 10 years. Whether or not Japanese utilities seek to renew those contracts and/or secure LNG from other suppliers could have a major impact on the gas industry in the region. In September 1999, Tokyo Electric (Tepco) and Tohoku reached an initial agreement with Indonesia's Pertamina to extend their purchase of Arun LNG for another 5 years from the 2005 conclusion of their current contract. Volumes would drop from 3.5 million metric tons per year in 1999 to 1 million metric tons per year (reflecting Japan's uncertain demand outlook and desire to diversify suppliers). In view of increasing competition among suppliers, the agreement is good news for Pertamina, although a firm contract must still be finalized [43]. Tokyo Electric and Tokyo Gas also have contracts with Malaysia that will expire before 2005.

Australia is not a large gas consumer (fifth largest in the Asian region in 1997), but it is an important LNG exporter using its sizable resources located in the northwest, far from domestic demand centers. In 1999, Texaco and Chevron announced the discovery of a new field holding several trillion cubic feet of gas near the existing Gorgon reserves offshore Western Australia (Figure 54). Although the Gorgon and nearby fields contain proven, probable, and possible reserves of 21.5 trillion cubic feet—enough to more than double Australia's current LNG exports—no buyer has yet signed a final sales contract, delaying development plans [44]. Australia is promoting its LNG in China (a future importer) and Taiwan, and a number of high-level government and private-sector meetings were held in 1999.

Figure 54. Australia's Natural Gas Pipelines [Sources]

At the same time, there are also plans for Australia to become a gas importer, via a pipeline planned from Papua New Guinea (PNG) to northeastern (Queensland) Australia. In July 1999, the \$3.5 billion dollar project involving Chevron received a boost with the finalization of sales contracts between upstream producers and Australian buyers. The Australian side of the pipeline will be built and owned by a joint venture between Australian Gas Light Company and Malaysia's Petronas. On the PNG side, owners of the gas assets are expected to set up an entity for pipeline construction, funding, and ownership [45].

Developing Asia

Developing Asia includes the two most populous countries in the world, China and India—emerging giants that are geographically large, have large economies, and are expected to have a tremendous impact on gas use in the region (see discussion on "Two Giants Emerge: natural Gas in China and India"). At the same time, China and India accounted for only about 15 percent of gas use in the region in 1997, and both use a much smaller proportion of gas in their total energy mix than the region as a whole.

For now, much of the gas market growth and significant infrastructure projects are taking place elsewhere in the region, largely, in Southeast Asia. At the beginning of 1999, Singapore agreed to import gas via pipeline from Indonesia's Natuna West field. A contract involving SembCorp Industries, Ltd. (a government-linked company in Singapore) calls for deliveries of 325 million cubic feet of gas per day over a 22-year period and links the price primarily to Singapore spot prices for high-sulfur fuel oil. The project has raised controversy in Indonesia, including allegations of corruption because of linkages to Mohamad "Bob" Hasan, a businessman and close friend of former president Suharto. A pipeline construction contract worth \$335 million was awarded to McDermott, and Hasan holds about 18 percent equity in McDermott Indonesia. In October, however, two independent audits reported that the contract was awarded fairly. The pipeline is under construction, with deliveries still scheduled to start in 2001 [46].

A second deal between Singapore and Indonesia, worth about \$7 billion and leading to further pipeline trade, was

also finalized in September 1999. The 20-year contract set to begin in 2002 calls for state-owned Singapore Power to buy from Pertamina initially 150 million cubic feet per day of gas, with volumes increasing up to 350 million cubic feet per day by 2008. Gas could be used increasingly in Singapore for power generation and petrochemicals [47].

Despite its political and economic upheaval, Indonesia is completing an eighth train at its Bontang LNG plant. Train H is set to begin exporting gas to Taiwan and South Korea by the end of 1999 or early 2000. Already the world's largest LNG exporter, Indonesia would also like to proceed with construction of a grassroots LNG plant, "Tangguh," in Wiriagar, Irian Jaya, using reserves discovered by British Gas and ARCO (which will merge with BP Amoco). To do so, Pertamina must find buyers for the LNG, which it is actively marketing to China in competition with Australian producers, among others [48]. In its domestic market, the Indonesian government will reduce natural gas prices from around \$2.50 per million Btu (U.S. dollars) to about \$1.50 per million Btu, in response to a dramatic plunge in gas use over the past 2 years, during which domestic contracts were priced in dollars and the Indonesian rupiah depreciated sharply against the U.S. dollar [49].

Elsewhere in Southeast Asia, production and delivery of contracted gas from the Yadana field in Myanmar (formerly Burma) was delayed until 2000 because of the postponed completion of Thailand's Ratchaburi power plant from its originally scheduled July 1998 startup. The Petroleum Authority of Thailand (PTT), which has a take-or-pay contract with the Yadana consortium, recently reached settlement to pay for some of the gas not taken. It was at first claiming "force majeure" following paralyzing events of the Asian financial and economic crisis [50]. Early estimates from PTT are that it will transmit 10 percent more gas in 1999 than the previous year, suggesting some recovery from the Asian crisis in the gas sector [51].

Completion of the Ratchaburi plant and recovery of Thai gas demand growth will also be important, because Malaysia and Thailand have reached agreement over the development of gas resources in their joint development area (JDA), with infrastructure construction to begin as early as 2000. Initially, project equity is split with 50 percent held by Petronas and 50 percent by PTT. Thailand may offer equity to foreign investors. In September 1999, Thai cabinet ministers approved a PTT investment plan for the project, which includes a pipeline and gas separation plant [52]. Malaysia could take all of the gas during the initial years of production if Thai demand cannot at first absorb the supply [53]. The first phase of the project (with targeted completion by 2002) calls for a 220-mile off/onshore pipeline from the JDA through the southern Thai town of Songkhla to the Malaysian province of Kedah. A second phase would involve a pipeline connecting JDA gas fields to the PTT grid in the Gulf of Thailand. Thai environmentalists quickly objected to the approval of investment plans before public hearings could be convened [54].

In 1998, Petronas of Malaysia signed eight oil and gas production sharing contracts (PSCs), the highest number in

10 years, reflecting the 1997 introduction of new revenue-over-cost formulae in PSCs [55]. Petronas also reached an agreement with Metropolis (wholly owned by Enron) to supply 2.6 million metric tons of LNG to India for a 20-year period starting in 2002. If a final contract is signed, it could be the first arrangement for delivery of Asian LNG into India [56].

India moved forward in 1999 with other plans to begin importing gas, which involve a host of projects and potential LNG terminals. In May, Enron's 624-megawatt Dabhol I power plant began operating, and the 1,624-megawatt Dabhol II reached financial closure [57]. Dabhol I is initially burning naphtha but will switch to LNG, and Dabhol II should use LNG at startup. Enron is making shipping arrangements for LNG imports, which are planned to start in 2002 (from Oman) and will eventually send fuel to the Dabhol power plants. Petronet is still pursuing plans for two initial LNG import terminals, and other terminals are also planned. In July, a 25-year agreement was signed with Rasgas for the purchase of 7.5 million metric tons of LNG per year, although a final contract must still be signed. The agreement calls for delivery of 5 million metric tons per year to a terminal at Dahej in Gujarat and 2.5 million metric tons per year to Cochin in Kerala [58]. Deliveries are scheduled to begin July 2003.

Gujarat Pipavav LNG, involving British Gas and Sea King Engineers, obtained agreement from India's National Thermal Power Corporation (NTPC) to take on a 26-percent equity stake in their project. British Gas and Sea King will then jointly hold a 50-percent share and offer the balance to public-sector gas users. As part of the agreement, an international tender will be issued to select an LNG supplier, although British Gas had earlier signed a memorandum of understanding with Yemen LNG. NTPC also continues to pursue an equity stake in Petronet and will eventually seek the best LNG price possible to fuel its power plants [59].

Another Indian LNG project in strong standing involves Total and Tata Electric Companies (TEC) at Trombay near Mumbai (formerly, Bombay). Equity in the project's joint subsidiary, Indigas, will be acquired by Gas Authority of India (GAIL). TEC and GAIL have agreed to initial purchases of 3 million metric tons of LNG imports per year. TEC will use the gas to fuel its Trombay power station, and GAIL will market gas to industries around Mumbai [60]. Plans for gas imports to India reflect expectations of rising consumption. In the IEO2000 reference case, gas use in India is projected to grow at an average annual rate of nearly 8 percent per year from 1997 to 2020, increasing sixfold (Figure 55).

Figure 55. Natural Gas Consumption in India, 1990-2020
[Sources]

China, also moving toward initiating LNG imports, has undertaken a feasibility study of importing LNG in Guangdong. Australia has remained visible as the potential supplier, with visits to southern China by Australia's Foreign Minister. The Chinese import project involves a consortium led by China National Offshore Oil Corporation (CNOOC), which is likely to retain a 36-percent equity share. CNOOC is

to invite bids from foreign companies, which will be allowed to acquire a 35-percent share [61]. In addition, Shell has reached a gas and power joint venture agreement with China National Petroleum Company (CNPC) for a \$3 billion project to construct pipelines and convert power plants and industrial facilities from coal to gas supplied from the Ordos Basin (Changbei field) [62].

In LNG-importing South Korea, monopoly importer Kogas faces deregulation and privatization. Presenting a restructuring plan in October 1999, the Commerce, Industry and Energy Ministry proposed spinning off and selling importing and wholesale units of Kogas as well as selling off its stakes in storage facilities and the main pipeline network by 2001 [63]. Taiwan, another LNG importer, was hit by a major earthquake in September 1999. Damage to the power grid could cause Taipower to take less LNG from Chinese Petroleum Corporation (CPC) in 2000 for power generation.

Middle East

As a region, the Middle East has the second largest natural gas reserves after the former Soviet Union. Reserves in the Middle East were estimated at 1,750 trillion cubic feet as of January 1, 2000. Iran, Qatar, and the United Arab Emirates (UAE) have the second, third, and fourth largest reserves in the world, respectively, following Russia. Middle East reserves, which expanded rapidly in the late 1980s and early 1990s, include the super-giant gas structure involving Qatar's North Field and Iran's South Pars. With its large reserves, the Middle East is a strong producer and growing exporter of natural gas, although domestic consumption to date has generally been quite low in the region. The *IEO2000* reference case projects a doubling of Middle East gas consumption between 1997 and 2020, rising from 6.0 to 12.0 trillion cubic feet (Figure 56).

Figure 56. Natural Gas Consumption in the Middle East, 1990-2020 [Sources]

Turkey, one of the fastest growing gas markets, suffered a major earthquake in August 1999 (and another in November), taking at least 16,000 lives and causing infrastructure damage, especially to an oil refinery, but not to gas pipelines. Fierce competition continued among gas projects proposing to supply the Turkish market. Russian Gazprom's Blue Stream project (involving a pipeline from Russia directly to Turkey under the Black Sea) signed a memorandum of understanding with Italy's Eni in February 1999 and then received a series of approvals in Russia. Construction of the pipeline could begin in 2000, according to project participants. The competing Trans-Caspian Pipeline proposal (which would export Turkmen gas to Turkey via the Caspian Sea) also received a boost when commercial agreements were signed in November in Istanbul with President Clinton attending [64].

In an effort to provide gas for domestic development in the south Persian Gulf region, the UAE Offsets Group (UOG) has begun promoting the "Dolphin" gas venture. The UAE and Oman have little gas for local demand, because resources are earmarked for export. Thus, a pipeline has

been proposed from Qatar's North Field to Abu Dhabi, Dubai, and Oman—with a proposed future extension on to Pakistan. UOG has signed a memorandum of understanding with Mobil Oil Qatar, Inc., for gas volumes in the range of 300 to 500 million cubic feet per day. Developers say construction could start in 2000, with deliveries by 2003 [65]. Elsewhere in the UAE, BC Gas of Canada began connecting gas consumers to a new domestic gas grid in Sharjah [66].

In Qatar, the Mobil-led RasGas LNG venture loaded its first cargo in August 1999. Korean owned and operated LNG carriers will ship the LNG to Korea under a 25-year contract. A second LNG train under construction is on schedule and expected to start up in the first half of 2000. In addition, further trains can be expected if a RasGas agreement is finalized with India for 7.5 million metric tons per year of LNG [67]. Qatar has also announced intentions to develop a commercial-scale gas-to-liquids (GTL) conversion project that would use its substantial domestic reserves for emerging GTL technologies (see discussion on "Gas-To-Liquids Technology: The Current Picture").

Elsewhere in the Middle East, Israel has announced that natural gas will power 25 percent of its electricity needs by 2005, but it is still seeking gas supplies. British Gas has discussed exploring for gas in Israel, and Egypt is also a possible source, although talks between the two countries stalled in 1999. Israel is prequalifying bidders for an upcoming tender on development of domestic gas infrastructure, which is due to be issued in the first quarter of 2000 [68]. A pipeline is currently under construction from Egypt to Jordan and on to the Palestinian Authority areas [69], and plans are nearing finalization for a pipeline from Syria to Lebanon that would supply Lebanon with 105 million cubic feet of gas per day. The pipeline would have two sections: a 75-mile stretch from the Syrian city of Homs to Deir Ammar in northern Lebanon and a 90-mile portion continuing to the southern Lebanese town of Zahrani. Conoco and Elf already signed a deal to process gas from the Syrian Deir al-Zur field [70].

Saudi Arabia is also seeking to increase domestic gas use and has undertaken a \$4 billion program to develop gas infrastructure and the non-associated gas reserves from the Khuff reservoir. The gas will go to the new Hawiyah gas processing plant (due on stream in 2001) and to power plants in Riyadh. Saudi Arabia's 204 trillion cubic feet of gas reserves are primarily associated gas, which was flared until the early 1980s. Gas is currently produced from about 10 of more than 80 known fields and is used in fertilizer and petrochemical plants at Jubail and Yanbu [71].

Africa

Gas reserves in Africa account for nearly 8 percent of global stocks. With new additions in Egypt and Nigeria, the region's reserves amount to 394 trillion cubic feet. Roughly 70 percent of Africa's domestic gas consumption and more than 80 percent of its production occurs in Algeria and Egypt. Algeria exports 70 percent of its domestic production via pipeline and LNG tanker. Within Africa, natural gas remains

the least utilized fossil fuel. Low growth in Africa's gas consumption (Figure 57) reflects a lack of economic growth in much of the region as a result of political instability, which has been particularly severe in sub-Saharan Africa. In Ghana and the Ivory Coast (in West Africa), economic growth has led to rising demand for energy and associated interest in natural gas development, particularly for electricity generation. Domestic use of natural gas in Africa is heavily for power generation, amounting to 40 percent of the region's gas demand [72].

Figure 57. Natural Gas Consumption in Africa, 1990-2020
[Sources]

In the *IEO2000* forecast, Africa's natural gas consumption continues to grow at a relatively slow pace. The average projected growth rate of 1.8 percent annually from 1997 to 2020 is the slowest among the developing regions, including the Middle East, developing Asia, and Central and South America. In the reference case, total gas use in Africa rises from 1.8 trillion cubic feet in 1997 to 2.8 trillion cubic feet in 2020.

In 1999, Nigeria's LNG (NLNG) export facility came on stream amid continued protests by local activists demanding jobs and cash payments. Protests that closed down the Bonny plant in September, just 2 weeks after production began, and again in late September and early October, ended after negotiations with government officials. NLNG was able to repair related damage and make its first delivery to France at the end of October [73]. In early 1999, Shell awarded a construction contract for a third Nigerian LNG train to a consortium involving Technip, Snamprogetti, MW Kellogg, and JGC Corp. More than 70 percent of the LNG from the expansion has already been sold to Spain's Enagas over a 21-year period [74]. Like Qatar, Nigeria has tentative plans for a GTL project (see box on pages 59-60), with South Africa's Sasol as a partner.

Plans to supply Nigerian gas to Ghana, primarily for power generation, also made progress in 1999. The West African Gas Pipeline (WAGP) joint venture agreement was signed in August by six energy companies, including Chevron, Shell, and the oil companies of Nigeria, Ghana, Benin, and Togo. The consortium seeks to build a \$400 million pipeline by 2002 that would send initially about 120 million cubic feet per day of now flared Nigerian gas to Ghana, Togo, and Benin [75]. In addition, Ghana has started up the second of two gas-fired power plants using offshore Ivorian gas [76]. There is also development of domestic resources for power generation in the Tano Fields Development and Power Project, involving a 100- to 140-megawatt power plant fueled by offshore gas [77].

Egypt, too, is moving toward expanding its domestic gas market, in part to switch from oil to gas and save oil for export. The state-owned Egyptian General Petroleum Company (EGPC) has amended agreements with BP Amoco and Eni, allowing production to expand at offshore gas fields (in the Ras el-Barr concession) in order to supply the domestic market. Investments of up to \$200 million will be used to expand production by up to 399 million cubic feet per

day by 2002. In addition, BP Amoco together with Burlington Resources has also signed a separate gas sales agreement with EGPC for gas off the coast of northern Sinai. Requiring a \$150 million investment, production from three fields in the area, which could reach 110 million cubic feet per day by 2004, will also be used for the domestic market [78]. EGPC will also form a joint venture with UK-based British Gas and Italy's Edison International to develop Egypt's largest gas field, Sacarab/Saffron, in the Nile Delta. Production of high-quality gas from the field is expected to start in 2003 and build quickly to deliveries of about 530 million cubic feet per day for a contract period of at least 17 years. The European Investment Bank (EIB) will advance a loan to Egyptian Natural Gas Company (Gasco) for the construction and operation of a pipeline to move gas from the Suez Canal region to a distribution plant north of Cairo, which will reinforce the domestic grid [79].

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Attachment B

Western Australia Department of Minerals and Energy
"Petroleum Royalties,"

<http://www.dme.wa.gov.au/insidedme/royalty/petsys.html>

WESTERN AUSTRALIA - MINERALS & ENERGY



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Petroleum Royalties

Royalty Systems

Generally, there are three systems used for the collection of petroleum royalties:

- well-head;
- resource rent royalty; and
- resource rent tax.

Well-head Royalty

The well-head value is derived by taking the gross value of petroleum recovered and deducting all costs incurred between a defined valve on the christmas tree and the point of sale. Deductible costs are normally confined to the processing, storage and transport of the petroleum recovered by the producer to the point of sale. All other costs, including costs associated with exploration, drilling, recovery and abandonment are not deductible.

The defined location of the well-head and the methodology for calculation of well-head value are usually included in a royalty schedule specific to each producer.

New petroleum projects landward of the outer limit of the Territorial Sea are subject to either the Petroleum (Submerged Lands) Act 1982 or Petroleum Act 1967, and in either case the well-head royalty regime have the following elements:

- royalty return - generally required to be submitted on a monthly basis;
- royalty rate - generally between 10.0% and 12.5%;
- gross value - value of petroleum recovered, generally the arms length sales value of petroleum recovered and the change in petroleum inventories;
- allowable deductions - post well-head costs; and
- deduction limit - 50% of gross value for oil projects and 90% of gross value for gas projects.

Petroleum Royalty Rates

Royalty rates between 10% and 12.5% of well-head value generally apply. The rate applied is dependant upon the type of licence from which the petroleum is

produced. Production from primary production licences attracts a rate of 10% while production from secondary licences attracts a rate of 12.5%. Primary licences are those initially issued to producers, while secondary licences are those subsequently issued to cover the width of the producing field.

Gross Value

Gross value is the value of petroleum recovered. It includes the value of arms length sales and the change in stocks of petroleum products.

Opening and closing stocks are valued according to the weighted average unit price of the past month's sales. Transactions denominated in foreign currency are converted to Australian Dollars based on Reserve Bank of Australia (RBA) mid-rates as published weekly by the RBA and daily in the *Australian Financial Review*.

Allowable Deductions

Three types of costs are allowed to be deducted against the gross value to determine well-head value:

- post well-head operating costs;
- depreciation on commissioned post well-head assets; and
- cost of borrowing on commissioned post well-head assets

Post well-head operating costs

Usually at the beginning of a project expected operating costs are itemised by a prospective producer. Post well-head percentages are then agreed between the State and for each operating cost item.

Depreciation on commissioned post well-head assets

Usually at the beginning of a project a depreciation calculation is negotiated between the State and producer and set out in an agreed schedule. A straight line depreciation calculation normally applies.

Cost of borrowing on commissioned post well-head assets

The well-head value system allows a producer to deduct from the gross value an amount in recognition of the cost of raising funds related to post well-head assets of the project. This amount is calculated from the time each post well-head assets is commissioned.

Not all costs of raising funds are allowed. A gearing allowance is determined at the beginning of the project, usually set at a maximum of 50% of the total cost of post well-head assets. The term or write-down period of the deduction is also determined at the beginning of a project and proxies the length of time it will take for the project owners to repay their borrowed funds. A standard interest rate is used instead of the actual interest rates paid for funds by individual project owners. The standard rate is usually the preceding month's 5 year term bond rate as published each month by the RBA.

Deduction Limits

Deductible costs can vary up to a limit of 50% of the gross value of production for oil projects or 90% of the gross value of production for gas projects for each royalty period. The choice of the deduction limit is determined by the 'predominant' nature of the project, and may change as a project shifts from a predominantly oil to a predominantly gas project. Any undeducted expenditure is carried forward to the next month.

Resource rent royalty

The Barrow Island Royalty Variation Agreement Act 1982 was agreed between the producer, the State and the Commonwealth as an incentive for the continued maintenance of the wells on Barrow Island to ensure optimal recovery of oil. The resource rent royalty (RRR) replaced the well-head royalty and excise system that had previously applied.

RRR is a royalty based on a percentage of net cash flow. The key aspects are as follows:

- all allowable expenditure, both current and capital, is written off when incurred. However exploration costs incurred more than a year prior to the application of the RRR are not allowable;
- any excess of costs over revenues are carried forward and compounded at a 'threshold' rate;
- any excess income over the threshold rate is charged to RRR at the rate of 40%;
- RRR is a primary tax before income tax, and is deductible against that tax; and
- the revenue is shared 75% to the Commonwealth, 25% to the State. The higher Commonwealth share reflects the far larger proportion of Commonwealth entitlements under the prior royalty and excise regime.

By agreement between the Commonwealth and the State, the State maintains full responsibility for the administration of the RRR regime.

Petroleum resource rent tax

The Commonwealth petroleum resource rent tax (PRRT) is a secondary tax on petroleum production based upon the cash flows of a given project. Royalties do not apply to fields chargeable to PRRT, but PRRT is deductible against income tax.

Home: Inside DME: Petroleum Royalty Systems

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Attachment C

**Barrow's Inc., *World Fiscal Systems for Oil*,
pp. 234-235, "Australia"**

AUSTRALIA**Environment:**

Safety and environmental protection will be dealt with through regulations which will set standards equivalent to those now applying offshore Australia.

Production Sharing:

The basic principle of the production sharing contract is that the Joint Authority owns all petroleum and, on behalf of the two countries, enters into contracts with companies to explore for and produce petroleum. In return, companies will receive a share of the petroleum produced.

The first step in the sharing process designates 10% of any production as "First Tranche Petroleum". This percentage will increase to 20% after the fifth year of production. The First Tranche Petroleum will be shared between the Joint Authority and the contractor in accordance with the sharing ratios given below. In effect this means that, for crude oil production, a royalty of between 5% and 7% will be paid to the Joint Authority during the first five years of production.

After the First Tranche Petroleum has been calculated, contractors will be allowed to recover Investment Credits for exploration and capital costs equal to the quantity of petroleum production equivalent to 127% of the exploration and capital costs incurred in each calendar year.

In addition, contractors will be able to immediately recover all exploration and operating costs, and depreciation of capital costs. Depreciation is calculated on a 20% straight line basis.

In any year in which production is insufficient to allow full recovery of investment credits and costs the remainder may be carried forward and recovered in future years.

After the recovery of Investment Credits and all costs, the remaining quantity of crude oil production is shared according to the following formula:

<u>Production Rate</u>	<u>Joint Authority Share</u>
0 - 50,000 bpd	50%
50,000 - 150,000 bpd	60%
150,000 bpd +	70%

AUSTRALIA

The Joint Authority will receive a 50% share of natural gas production irrespective of production rates, after recovery of Investment Credits and all costs.

Taxation:

Both countries will apply their tax legislation to Area A, but in such a way as to ensure that only 50% of income and 50% of expenditures will be taken into account by each country.

For individuals working in Area A, rules will apply so that residents of Australia will be subject to Australian taxes and residents of Indonesia to Indonesian taxes.

Employment:

Contractors to give preference in employment to nationals or permanent residents of Australia and Indonesia. The terms and conditions of that employment, including occupational health and safety, will be no less favorable than those applying to comparable categories of employment in both Australia and Indonesia.

Law:

Criminal law will be applied on the basis of the nationality or permanent residency of the person.

Customs Regime:

Under the provisions of the Treaty, Australia and Indonesia may apply their respective customs, migration and quarantine laws to individuals, equipment and goods entering their territories from Area A or leaving their territories for Area A.

Attachment D

"Government and Producers Boost LNG Industry"
Media Release, Senator Nick Minchin, Minister for Industry,
Science and Resources, October 10, 2000

<http://www.minister.industry.gov.au/minchin/releases/2000/october/cmr516%2D00.doc>

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GOVERNMENT AND PRODUCERS BOOST LNG INDUSTRY
10 October 2000



MEDIA RELEASE

SENATOR NICK MINCHIN

Minister for Industry, Science and Resources

10 October 2000 00/448

GOVERNMENT AND PRODUCERS BOOST LNG INDUSTRY

The Minister for Industry, Science and Resources, Senator Nick Minchin and the Chairman of the Australian Petroleum Production and Exploration Association (APPEA), Dr Agu Kantsler today launched a new policy framework to ensure Australia remains a competitive and reliable liquefied natural gas supplier.

*

"The *LNG Action Agenda* will provide a framework of joint Government and industry commitments for securing the future of the LNG industry," Senator Minchin said.

"These commitments are important, not only to traditional and prospective buyers of Australian LNG, but to investors who need to take a long-term position in the industry."

Dr Kantsler said the agenda outlines a shared vision for a strong, internationally competitive LNG industry.

"The industry is well on its way to achieving the vision. It also recognises LNG's role as a clean energy fuel," Dr Kanstler said.

The recent signing of Letters of Intent with Japanese energy companies for purchase of increased quantities of LNG points to increased buyer confidence in the Australian product.

The *LNG Action Agenda* is the joint effort of all key stakeholders - the Australian LNG industry and the Commonwealth, States and Northern Territory governments.

"This Action Agenda represents a significant milestone in the development of Australia's LNG industry," Senator Minchin said.

"Through the LNG Action Agenda the Government and industry

Attachment E

**Kentucky Revised Statutes § 132.820, relating to the
Assessment and Taxation of Unmined Minerals and Energy Resources**

CORRECTION

**THE FOLLOWING DOCUMENT(S)
HAVE BEEN REFILMED TO
ASSURE LEGIBILITY OR PAGINATION**



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GOVERNMENT AND PRODUCERS BOOST LNG INDUSTRY
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"Through the LNG Action Agenda the Government and industry

1 of 2 * The LNG Action Agenda may be accessed at: <http://www.isr.gov.au/resources/lng/>

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responded positively to a number of issues including:

- greenhouse gas emissions;
- taxation;
- customs and tariffs;
- Australian industry participation in LNG projects;
- Government approval processes;
- LNG marketing and promotion; and
- the Timor Gap Zone of Cooperation Treaty (ZOCA).

"The Government has made the commitment that future greenhouse gas policies and measures will promote cost effective actions so that Australian industry can remain competitive.

"Very importantly, the Government is saying that we will only implement a domestic emissions trading scheme if the Kyoto Protocol is ratified by Australia, has entered into force and there is an established international emissions trading regime.

"We've also said that we will avoid policies and measures that distort investment decisions between particular LNG projects and locations.

"We will avoid policies and measures that disadvantage those companies which have moved early in undertaking greenhouse emission abatement actions, or that discriminate against new industry entrants.

The Action Agenda announces the Government's in-principle agreement to establish a new By-law for major projects with an initial project capital expenditure of \$50 million or more, to enable duty free importation of capital equipment and components which are unavailable within Australia and integral to the project.

"With exports around \$2 billion per year - the LNG industry is a major contributor to our national and economic well being," Senator Minchin said.

"Australia's major LNG project, the \$12.1 billion North West Shelf (NWS) Project has increased GDP by 1.24%, provided Australian suppliers with \$10 billion in business since 1980 and has produced an extra 80,000 Australian jobs each year over its life.

"There are also plans for the \$2.5 billion development of the Sunrise and Troubadour fields and Methanex is looking at \$1.5 billion processing plant that would use the gas from the fields," Senator Minchin said.

A copy of the *LNG Action Agenda* can be accessed on the ISR web site at: <http://www.isr.gov.au/resources/lng/>

Attachment E

**Kentucky Revised Statutes § 132.820, relating to the
Assessment and Taxation of Unmined Minerals and Energy Resources**

Kentucky Revised Statutes

132.820 Assessment of unmined coal, oil, and gas reserves held separately from surface real property – Effect of appeal on payment of taxes.

- (1) The cabinet shall value and assess unmined coal, oil, and gas reserves, and any other mineral or energy resources which are owned, leased, or otherwise controlled separately from the surface real property at no more than fair market value in place, considering all relevant circumstances. Unmined coal, oil, and gas reserves and other mineral or energy resources shall in all cases be valued and assessed by the Revenue Cabinet as a distinct interest in real property, separate and apart from the surface real estate.
- (2) Each owner or lessee of property assessed under subsection (1) of this section shall annually, between January 1 and April 15, file a return with the cabinet in a form as the cabinet may prescribe. Other individuals or corporations having knowledge of the property defined in subsection (1) of this section gained through contracting, extracting, or similar means may also be required by the cabinet to file a return.
- (3) Any property subject to assessment by the cabinet under subsection (1) of this section which has not been listed for taxation, for any year in which it is taxable, by April 15 of that year shall be omitted property.
- (4) After the valuation of unmined minerals or other energy sources has been finally fixed by the cabinet, the cabinet shall certify to the county clerk of each county the amount liable for county, city, or district taxation. The report shall be filed by the county clerk in his office, and shall be certified by the county clerk to the proper collecting officer of the county, city, or taxing district for collection.
- (5) The notification, protest, and appeal of assessments under subsection (1) of this section shall be made pursuant to the provisions of KRS Chapter 131.
- (6) No appeal shall delay the collection or payment of taxes based upon the assessment in controversy. The taxpayer shall pay all state, county, and district taxes due on the valuation which the taxpayer claims as the true value as stated in the protest filed under KRS 131.110. When the valuation is finally determined upon appeal, the taxpayer shall be billed for any additional tax and interest at the tax interest rate as defined in KRS 131.010(6), from the date the tax would have become due if no appeal had been taken. The provisions of KRS 134.390 shall apply to the tax bill.
- (7) The collection of tax bills generated from the assessments made under subsection (1) of this section shall be made pursuant to the provisions of KRS Chapter 134.

Effective: July 15, 1998

History: Amended 1998 Ky. Acts ch. 391, sec. 3, effective July 15, 1998. -- Created 1994 Ky. Acts ch. 263, sec. 1, effective July 15, 1994.

Legislative Research Commission Note (7/14/00). 2000 Ky. Acts ch. 446 (Senate Bill 323), sec. 1, purports to amend this statute, and the General Assembly version of that bill was signed by both presiding officers and by the Governor. The Journals of the House of Representatives and Senate will reflect, however, that House Floor Amendment 1 was adopted by the House on March 27, 2000, but was not transmitted to the Senate for its concurrence when the bill was returned to that body. Thus, the bill signed did not pass both chambers of the General Assembly in the same form and did not become law. Ky. Const. secs. 46 and 88; see also Mason's Manual of Legislative Procedure sec. 737, at 508-509 (1989 ed.). Because the General