ALASKA LEGISLATURE SPECIAL COMMITTEE/SUBJECT FILES 8672

2927 SCOMM 128: HOUSE SPEC.COMM. ON OIL AND GAS, 2001-02

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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 B / 4.8 MTPA = $260.4 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 million x 4) + $1.25 B = $1.95 B / 4.8 MTPA = $406.3 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 Billion + $0.25 Billion = $ 2.2 Billion / 4.8 MTPA = $458.3 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 Contact (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.

7) Competing LNG Projects

What projects are potential competitors for the LNG market in East Asia?

Noted below are the potential East Asian LNG projects that were listed in a February House Oil and Gas Committee hearing as potentially competing with ANS LNG. This is our current understanding of primary ownership in these projects:

Australia NWS
Shell, BP, Chevron, BHPP, Woodside, Mitsui/Mitsubishi
Malaysia Tiga III
Petronas (majority), State of Sarawak, Shell, Nippon/Mitsubishi
Tangguh (Irian Jaya)
Pertamina (majority), Oxy, BP, British Gas, Nippon/Mitsubishi, Kanematsu, Nissho Iwai and Genting
Qatargas
QatarGPC (majority), TotalFinaElf, Exxon/Mobil, Mitsui, and Marubeni
Rasgas
QatarGPC (majority), Exxon/Mobil, Itrochu and Nissho Iwai
Bayu-Undan / Sunrise
Phillips, Kerr McGee, Inpex Sanos, ENI, Woodside, Shell and Osaka Gas
Indonesia I
Pertamina (majority), TotalFinaElf and Unocal
Yemen
Yemen Gas Company, TotalFinaElf, Hunt, Exxon/Mobil, SK Corp and Hyundai
Gorgon
Texaco, Chevron, Exxon/Mobil, Shell
Sakhalin I
Exxon/Mobil, Sodeco, Russian Companies
Sakhalin II
Shell, Mitsui and Mitsubishi

Comparatively, how competitive are these projects, including Alaska?

The table of capital unit costs, discussed in detail previously (Attachment 10), indicates that the ANS LNG 8 million metric tons per year (MTPA) Project and the Backbone 9.3 MTPA LNG Project are in the $600 to $800 million range per MTPA for the treating, pipeline, compression, LNG plant and marine terminals (excluding ships). Various other projects such as Ras Laffan, Trinadad, Oman, Tangguh, Malaysia III and industry rule of thumb from public articles suggest that cost competitive LNG projects should be in the $200 to $250 million per MTPA range.

The major difference for Alaska is a unique, 800 mile, buried, arctic pipeline that constitutes about $300 million per MTPA for an 8 MTPA project ($2.4 Billion divided by 8). While there are advantages to Alaska's cold climate in terms of system performance, this pipeline is unique compared to other competing LNG projects. Because of its length, the need and cost to bury it in an arctic and permafrost environment, and the remoteness of the pipeline, it does not lend itself to low cost construction. It also presents elements of construction completion cost uncertainty that must be carefully considered.

While it may be argued that some upstream development cost should be included in comparing other projects, most such upstream development cost is often offset by revenues generated from liquid condensate and domestic gas sales. While there may be some upstream LNG development costs associated with various other LNG projects, these costs are more likely to be in the hundreds of million dollars and not near the $2.4 billion for the 800 mile, ANS pipeline.

East Asian LNG is fiercely competitive. While E. Asian LNG demand is expected to grow by 20 to 40 MTPA by 2010, there are already over 60 – 75 MTPA of potential LNG projects vying for that demand. An overview of the East Asian LNG market is given in Attachment 11.

Doesn't the East Asian LNG market present a better opportunity for ANS gas than the North American market, because of the substantial demand and the fact that LNG is usually sold under long term contract?

Phillips believes that the best, initial market opportunity for ANS gas commercialization is in the L-48/Canada. There are several reasons for this. First, as shown in Attachment 12, the demand for new gas through 2010 is expected to be 6 to 7 times higher in North American than in East Asia. From another perspective, a L-48 pipeline project (sized at 2.5 to 4.0 billion standard cubic foot per day (bcfd)) would be about 5 – 8% of North American new gas demand and a Market Entry Project for LNG (sized about 1.0 bcfd) would be about 10– 15 % of East Asian new gas demand. Therefore, market entry by a larger project is more feasible in North America as compared to entry by even a smaller LNG project in a substantially oversupplied East Asian market. Indeed, the Phillips/El Paso announcement discussed in Section 6 reinforces this current reality. Finally, the long term LNG contracts typical in East Asia do not in and of themselves guarantee that ANS gas would realize sustained, higher prices that in the North American market.

8) Cook Inlet Gas Supplies and Plans for the Kenai LNG Facility

Is the Cook Inlet "running out of natural gas"?

There is no doubt that the existing, known reserves in the basin are finite and that these reserves will eventually be exhausted by ongoing demand. However, as discussed below, it is inaccurate to conclude from this that natural gas is "running out" in the foreseeable future. This question must be viewed in the context of "normal" gas production, rather than from the context that Cook Inlet has historically had: abundant reserves and limited market potential. With this view, Phillips believes that, unless the Cook Inlet is vastly different from most other resource basins, it is expected that, as reserves decline, prices will rise above historic stranded gas levels, and exploration and development activity will increase and new reserves will be discovered and developed.

Typically, in the oil and gas business, a new resource basin is opened when a major accumulation is discovered. For example, the discovery of Prudhoe Bay, then the largest oil field in the Western Hemisphere, spurred the opening of the North Slope for ongoing development. Since then, there have been continuous discoveries and development, even though they have not matched the size of Prudhoe. In Phillips' case, we expect to stabilize our net ANS oil production through at least the end of the decade through discovery and development of what are expected to be smaller accumulations.

Similarly, in Cook Inlet, deep oil exploration efforts in the 1960's, in easily identifiable structures, yielded relatively significant gas finds. These reserves were developed over time in support of local domestic and commercial use, electrical generation, fertilizer production and LNG exports to East Asia. No second phase of drilling for gas has occurred until recently.

In hydrocarbon basins, there is a commonly-used indicator of how long the reserves will theoretically last. This indicator is the total proved reserves divided by the (then) annual production rate or "R to P" ratio. This ratio has the units of years, but it is recognized as only a "snap shot" of the current situation.

We now know that by 1970, gas reserves in Cook Inlet stood at about 8 trillion cubic feet (TCF) and production was about 145 billion cubic feet per year: thus the R to P ratio was just about 55 years. As would be expected with such a high ratio, there was little incentive to explore for gas, since it could be a long time before revenues would be realized for the additional, discovered gas.

Over time, the known Cook Inlet reserves have been slowly consumed. Today, reserves are about 2.7 TCF (cited in the application to Amend Authorization to Export Liquefied Natural Gas, Department of Energy, Office of Fossil Energy), consumption is about 215 bcf/yr and the R to P ratio is just under 13 years. Theoretically, this would suggest that developed reserves will be exhausted in 2014 and at first blush, the situation might seem to be a matter of concern.

But, in reality, it is a very normal situation in the natural resource industry. For example, the R to P ratio of the L-48 United States is about 7 years and it has roughly been 7-10 years, with a slight decline, for the last 20 years. New resources have been added at about the same level as consumption. Further, the Cook Inlet figure is based upon today's consumption rate: the Kenai LNG plant has an export license through 2009 and it is commonly understood that the Urea plant's viability is dependent upon a long term supply of low cost gas. For illustration, it is assumed that continued operation of the Kenai plant and other industrial uses after 2009 (about 61% of demand) will have to be based upon new reserves. In that case, the currently known Cook Inlet reserves are projected to serve the remaining demands (e.g. power generation and home heating) through about 2018. Note that this somewhat simplistic view is on an annual average basis and does not account for seasonal deliverability, which is addressed below.

Phillips believes that Cook Inlet is entering a period of new exploration and discovery. In recent months, we have seen public announcements showing that gas activity has begun to pick up. Phillips has had recent success in finding gas in the Moquawkie well with Anadarko. We also note the public announcement that Nikolai Creek No. 3 has been successfully recompleted and that Northstar Energy Group proposes a well to tap the North Fork gas field. Rig activity is publicly reported at West McArthur River, Redoubt Shoal and the Kenai Gas field.

Beyond this anecdotal information, there are many reasons for prudent optimism. First, for the first time in 30 years, a producer that finds gas might actually be able to begin selling it soon after the field is hooked up. Second, the historically low Cook Inlet gas prices are beginning to rise to a level high enough to make the inherent risks of exploration and the high costs of development worth pursuing. Third, seismic technology has progressed and should significantly improve exploration chance factors. Fourth, there are a number players, some new, in the picture. Besides the historical players such as Unocal, Marathon, Chevron and Phillips, companies such as Northstar Energy, Forrest Oil, Anadarko, Aurora, and Crosstimbers are investing in the inlet. Clearly the more players, the more likely that wells will be drilled and discoveries made.

Finally, returning to the concept of the Cook Inlet as a resource basin, there is typically a cycle when a number of discoveries are made based upon a particular geologic concept, often followed by a period of few discoveries. Almost invariably, there is then a new concept or a new technology that leads to a new round of discoveries. As mentioned earlier, the North Slope seems to be in just such a new discovery phase. Although it may seem counter intuitive, the Cook Inlet is just starting to come out of its first phase of discoveries. Applications of new technology and new ideas about play types are just beginning to appear. The next five to ten years are likely to tell us much about the potential of the basin.

What can the State do to help facilitate secure Cook Inlet gas supplies?

Clearly, more frequent and wider lease sales and expedited permitting is an excellent policy. The Cook Inlet region, like the North Slope, has historically been considered so attractive for oil and gas development that state statute prohibits exploration licensing in preference to traditional lease sales. Reconsideration of this and other acreage prohibitions may be worthy of review. In addition, State support of increased federal lease sales in the potentially gas prospective lower Cook Inlet would also be appropriate.

In summary, to say that the Cook Inlet is "running out of gas", is to ignore the role that exploration is very likely to play in Cook Inlet in the next five to ten years.

But isn't there a seasonal deliverability problem in the Cook Inlet?

Gas demand in the Cook Inlet is very seasonal. For a period of a few days to perhaps several weeks in the winter, consumption peaks perhaps 30 – 40 % higher than that for the rest of the year. However, meeting these peak demands is not so much a function of reserves as a function of the capacity of wells and facilities. To meet the peak winter demand, investments must be made that are underutilized at other times of the year. Peaking gas investments may take the form of additional compression, additional wells, gas storage in reservoirs or additional LNG storage. In addition, the robust initial rate typical of new discoveries could help supply peaking gas requirements. Phillips believes that this tension of not over-investing, yet still meeting peak demands is something that the marketplace can and will ultimately solve through a variety of strategies. Further, Phillips is committed to ensuring that our industrial use does not impact the needs of the community during critical periods.

How can Phillips justify continued LNG exports that will eventually exhaust Cook Inlet resources and what are Phillips plans for its Kenai LNG plant post 2009?

Currently, Phillips has about 1 TCF of proven gas reserves in the Cook Inlet, of which about 1/3 are uncommitted. Phillips produces about 73 bscf/yr, which goes to fulfilling a variety of demands both industrial and local. The Kenai LNG plant, which is jointly owned and supplied by Phillips and Marathon consumes about 77 bscf/yr. Phillips'70% share of that demand is about 54 bscf/yr.

On April 2, 1999, Phillips and Marathon were granted a renewal of the export license for the Kenai LNG plant for the period 4/2004 to 3/2009. For that renewal, a thorough analysis of reserve adequacy was conducted and substantial hearings were held. The results of that process demonstrated that reserve capacity was sufficient for LNG exports to continue through 2009. It was also found that export was consistent with the public interest and would not result in local/regional gas supply shortfall on an annual basis.

The Kenai LNG plant is in very good condition and Phillips hopes to operate it well past 2009. However, the plant is a relatively large gas consumer in the Cook Inlet. As such, Phillips does not expect to justify extending its current export license beyond 2009 based solely on proven reserves known today. In fact, Phillips is internally assessing and developing its strategic options. As always, when Phillips has meaningful information on this matter, it will communicate it publicly.

9) Consideration of Wellhead Sales to Third Parties

Is Phillips willing to sell ANS gas at the "wellhead"?

Yes, Phillips has been and continues to be willing to consider any commercially-sound proposal and to meet with parties seeking to purchase ANS gas. However, Phillips has its own commercialization efforts and is not dependent upon third party wellhead sales to achieve ANS gas commercialization.

Through its ARCO Alaska heritage, Phillips has long stated that it will entertain wellhead sales. In the late 1980's, we in fact, announced that wellhead sales would be our preferred commercialization option, rather than investing in gas transportation facilities. In the mid-1990's we again began to explore commercialization options involving "downstream" investment. However, we have not foreclosed wellhead sales since that time.

In 1998, Phillips/ARCO formed the Alaska North Slope LNG Project, also known as the Sponsor Group. The Sponsor Group includes participants who do not own ANS gas resources. Therefore, the commercial structure envisioned by this group is to buy gas at the wellhead from the Producers and to sell LNG in East Asia. By definition, this implies that Phillips stands ready to sell gas if an LNG project can be commercially viable.

Finally, Phillips is a signatory to the Charter for Development of the Alaska North Slope, executed on March 15, 2001. In that, Phillips agrees to "negotiate in good faith to make available to third parties at a commercially reasonable fair market price or transportation charge that is mutually agreeable to BP and ARCO, the third party and the State, Alaska North Slope natural gas in sufficient quantities to support a qualified treatment and transmission project to domestic and/or international markets." The agreement also has provisions: to define a qualified treatment and transmission project, to require reasonable efforts for approvals, to specify the gas delivery point, to specify the requirements for fair consideration of various alternatives; to not foreclose Phillips from proceeding with its own projects; to provide for a termination date; and to provide enforcement of the agreement.

In the Charter, Phillips also agrees to biannual reports of contacts with potential projects. The initial contact report cited the names of contacts, including Yukon Pacific Corporation, Gas Pipeline Port Authority and Arctic Resources Company.

Why doesn't Phillips post a "wellhead price" for third parties to acquire its ANS Gas?

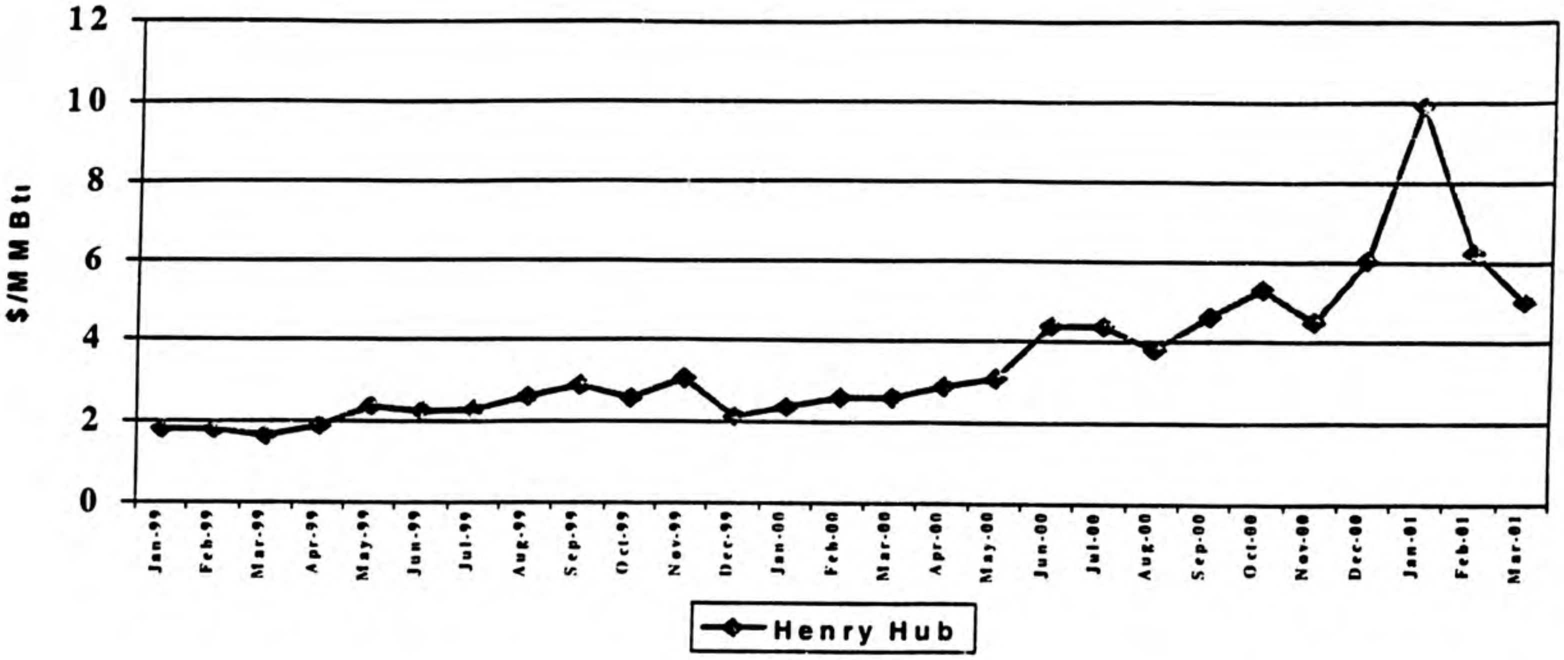
Since there are no existing facilities for Alaskan gas to reach the market, it is not appropriate nor in the state's interest, from a royalty and tax viewpoint, to post a single wellhead price that is applicable for an unspecified period of time. Ultimately, ANS gas pricing will be tied to the market or markets that it actually serves and will reflect the costs of reaching that market(s). A "posted price", has the possibility of establishing an artificial "ceiling" which could limit the state and producers enduring realization of revenues.

The concept of "posting" wellhead prices applies when there is a mature and active, ongoing market, with many buyers, many sellers, extensive existing facilities, defined points of trade, clear timeframes and an active "paper market" such as that described for the L-48 in Section 1. In contrast, the initial ANS gas commercialization step will be characterized by high costs and risks and limited participants. For this step to be viable, the commercial arrangements will have to be carefully developed, such that risks are appropriately mitigated.

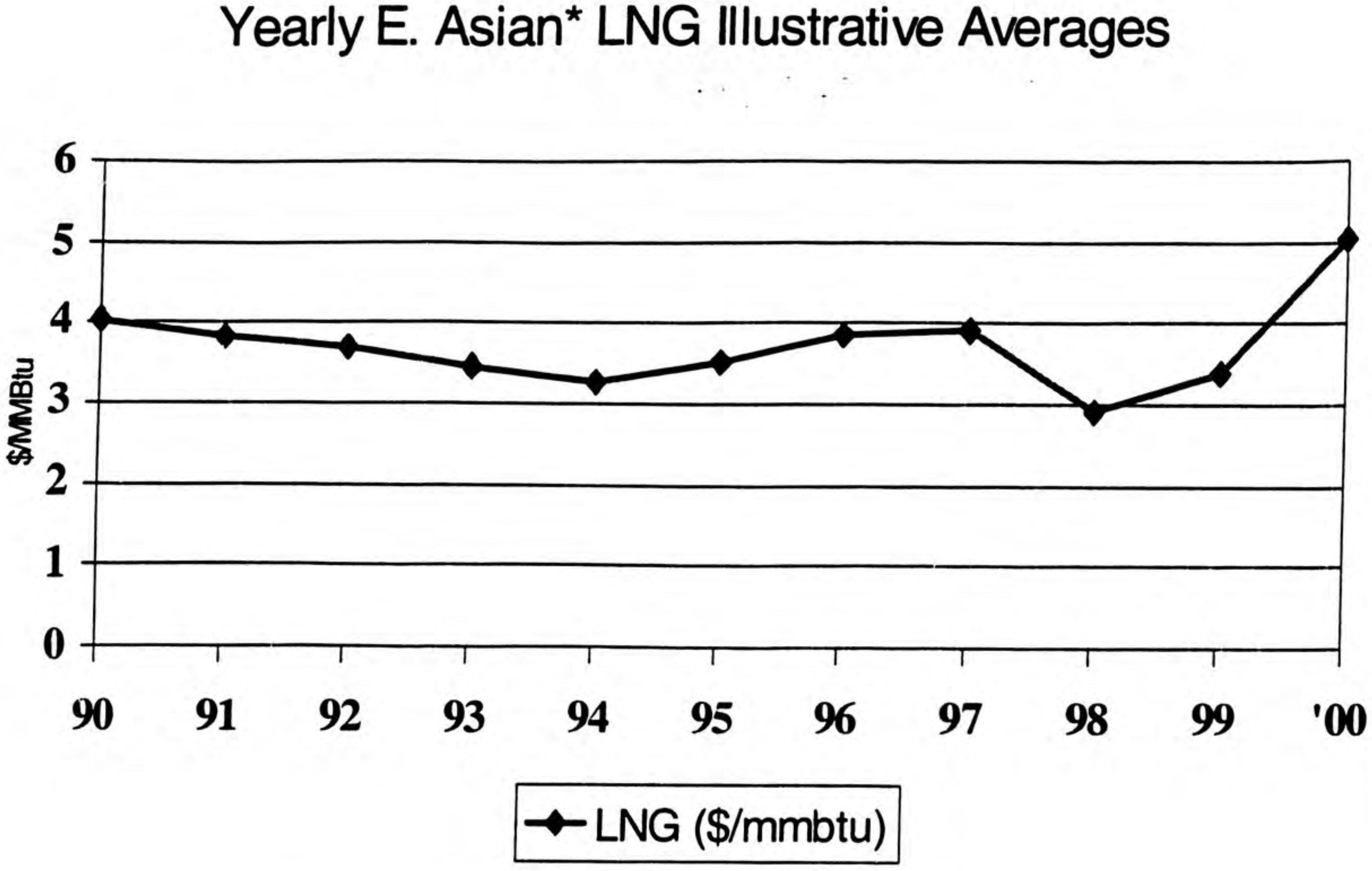
Again, Phillips stands ready to consider any commercially sound proposal and to meet with third parties seriously and in good faith seeking to purchase ANS gas.

<u>Attachment 1</u>

Historic Henry Hub Prices



Attachment 2

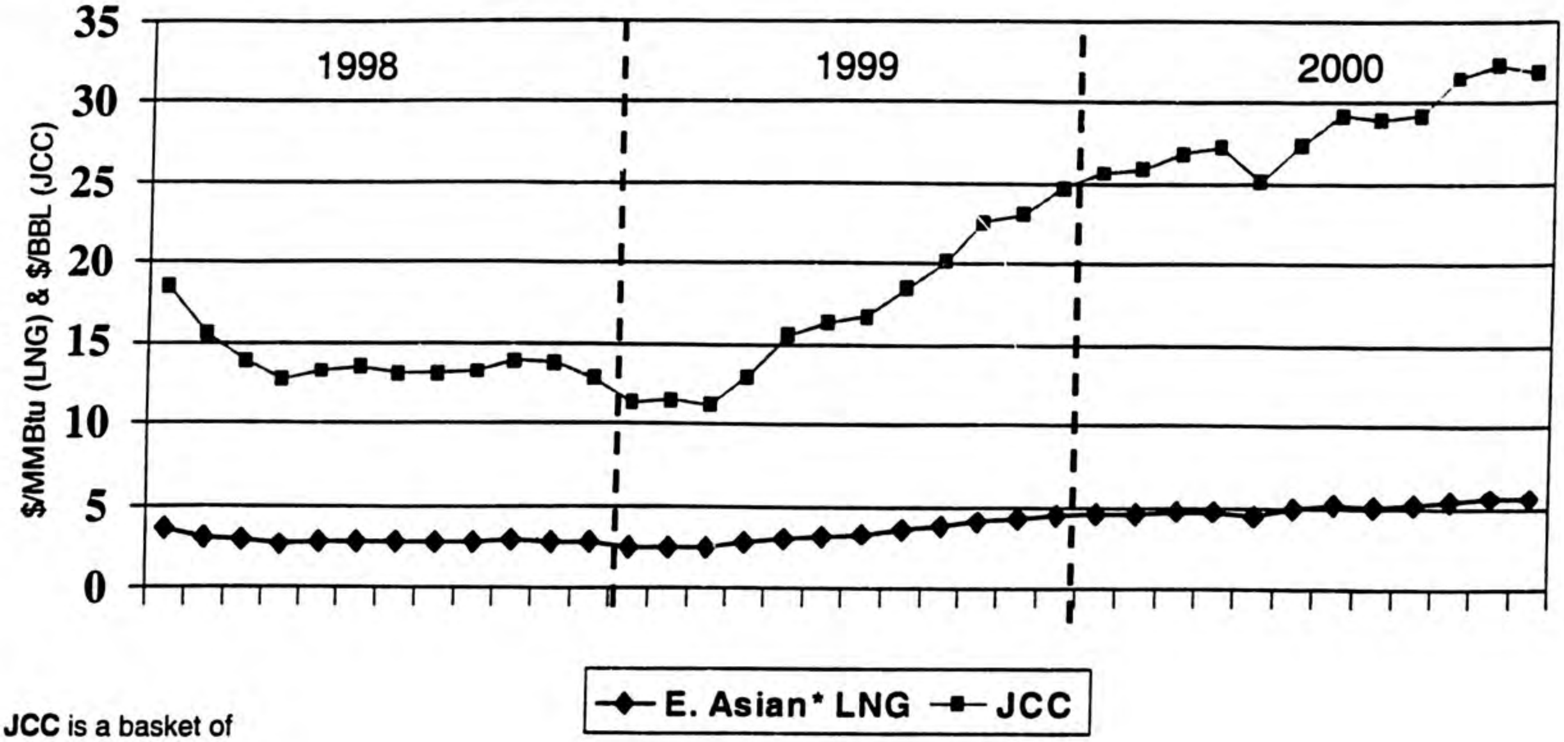


*** Example JCC formula as:** *LNG = .1485 x JCC + .83*

(No 'S' curve adjustment)

Attachment 3

Monthly JCC and Estimated E. Asian LNG Prices



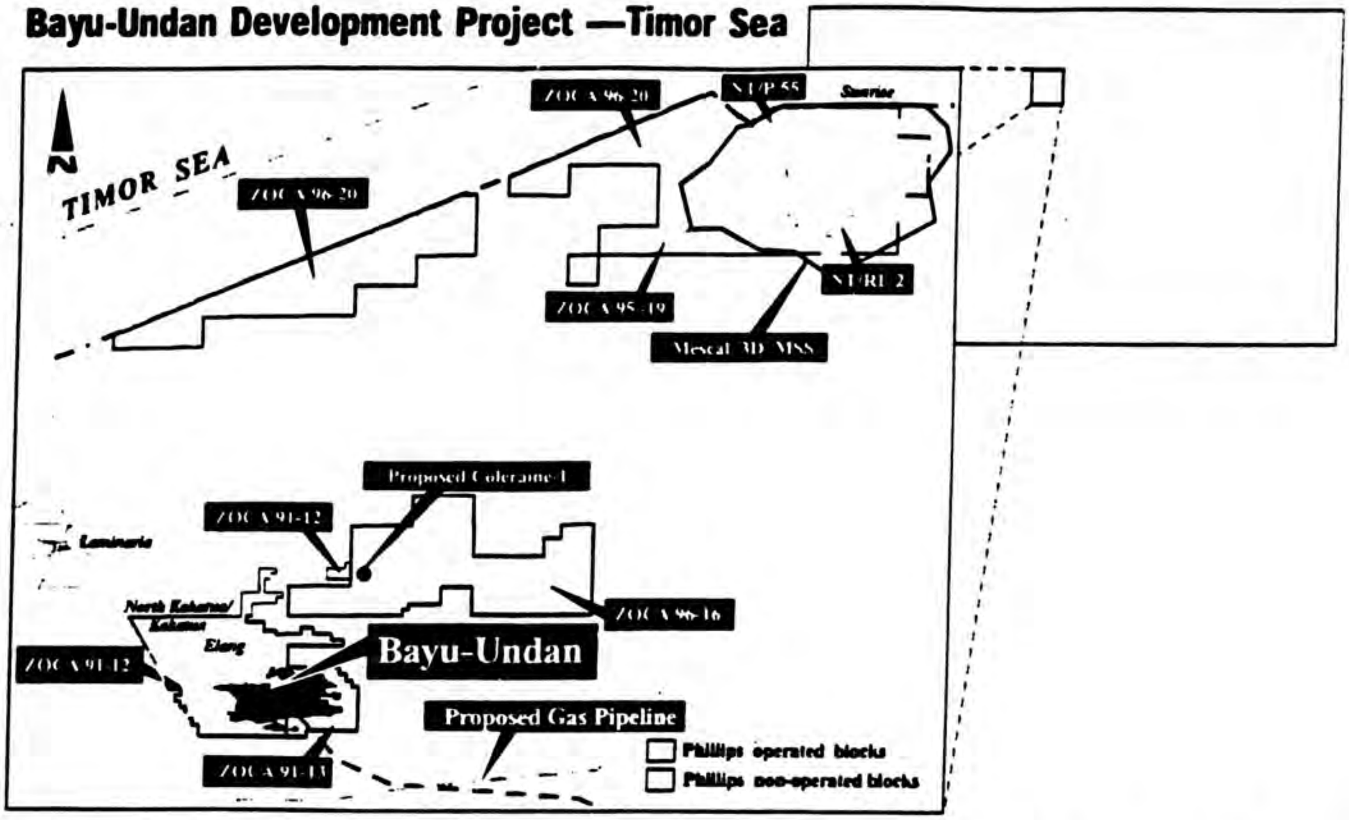
JCC is a basket of world crude oil prices into Tokyo

* **Example JCC formula as:** *LNG = .1485 x JCC + .83*
(No 'S' curve adjustment)

Attachment 4

Overview of Bayu-Undan Development Project –Timor Sea
(page 18 from Phillips 2000 Information for Analysts)

Bayu-Undan Development Project —Timor Sea



Timor Sea

Bayu-Undan Development
Phillips 50.3% (Operator)
In 1995, Phillips discovered the Bayu-Undan gas condensate field in the Timor Sea Zone of Cooperation (ZOCA). Nine successful appraisal wells have been drilled, confirming the presence of a world-class gas and gas condensate field. The field is estimated to hold 400 million barrels of petroleum liquids and 3.4 TCF of natural gas.

The field is being developed in two phases. The first phase is a $1.4 billion gas-recycle project. Phillips has completed over 40 percent of the engineering design work on the offshore facilities. The project is expected to begin producing and processing the gas, separating and selling the liquids, and reinjecting the gas back into the reservoir in late 2003. Full commercial production is expected to begin in the first quarter 2004 at approximately 50,000 net BLPD.

The second phase will be a gas project and will proceed as gas markets are developed. Phillips is negotiating an agreement to build a subsea pipeline from the Bayu-Undan project to Darwin, Australia. All potential gas markets, including LNG and domestic Australian markets, are being pursued.

The field, in 240 feet of water, lies some 300 miles northwest of Darwin, Australia.

Elang/Kakatua/Kakatua North
ZOCA 91-12
Phillips 42.4% (Operator)
In the first quarter of 2000, Phillips and its co-venturers completed a successful well intervention program at the company's Elang/Kakatua/Kakatua North field. As a result, the remaining estimated economic field life has been extended to mid-2001. The field is currently producing 5.7 net MBOPD.

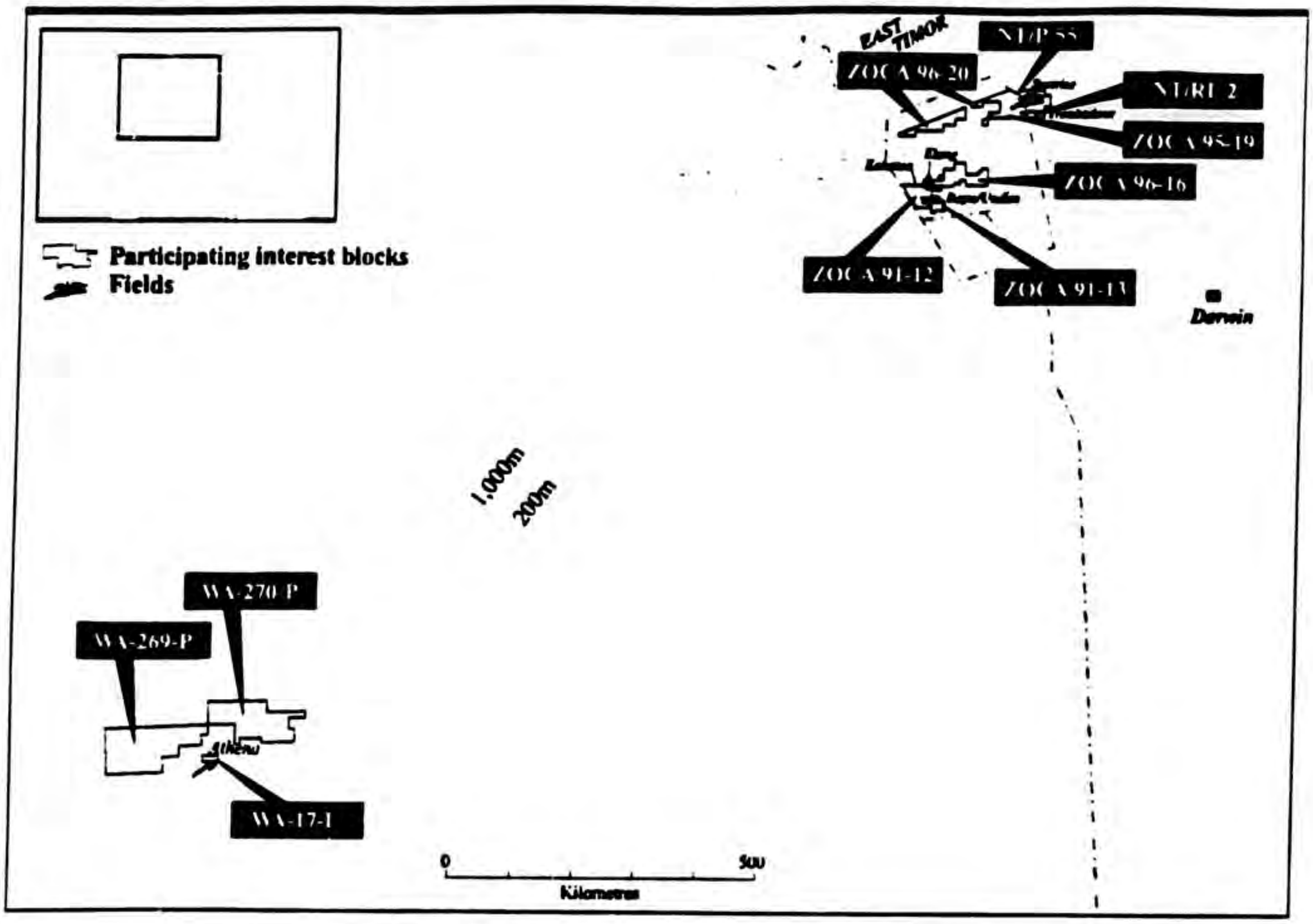
Australia

WA-17-L
Phillips 50%
Following a successful appraisal well on the Athena prospect, this portion of the WA-248-P exploration permit was converted to a production license area. Athena (which tested at rates of 47 MMCFD and 2,100 BOPD) is on the north flank of the Perseus field, and unitization efforts are under way *(See Northwest Australia and Timor Sea map on page 10.)*

Attachment 5

Overview of Northwest Australia and Timor Sea
(page 10 from Phillips 2000 Information for Analysts)

Northwest Australia and Timor Sea



Timor Sea

Bonaparte Basin, Zone of Cooperation, Timor Sea

ZOCA 91-12 and 91-13
Bayu-Undan, Elang areas: *The contract areas are located in the Zone of Cooperation between Australia and East Timor. (See Key Production Areas, Bayu-Undan Development Project map on page 18.)*

ZOCA 95-19
Permit Area NT/P55
Phillips 33.3%

Permit Area NT/RL-2
Phillips 8.3%
A 3-D seismic program is being acquired over the Sunrise/Troubadour gas fields area.

ZOCA 96-16
Phillips 66% (Operator)
Phillips entered into an agreement to earn interest and become operator by paying 94.2 percent of the Coleraine-1X exploration well, scheduled to be drilled in the latter part of 2000.

ZOCA 96-20
Phillips 33.3%

Western Australia

WA-17-L
Phillips 40%
Following the successful drilling of the Athena A-1X well in 1997, that portion of Permit WA-248-P containing the Athena gas accumulation was converted into a production license (WA-17-L) and Phillips withdrew from the balance of the permit.

WA-269-P and WA-270-P
Phillips 40%
The Titania well was drilled in 2000 as one of the four remaining commitment wells on these permits. The well was unsuccessful.

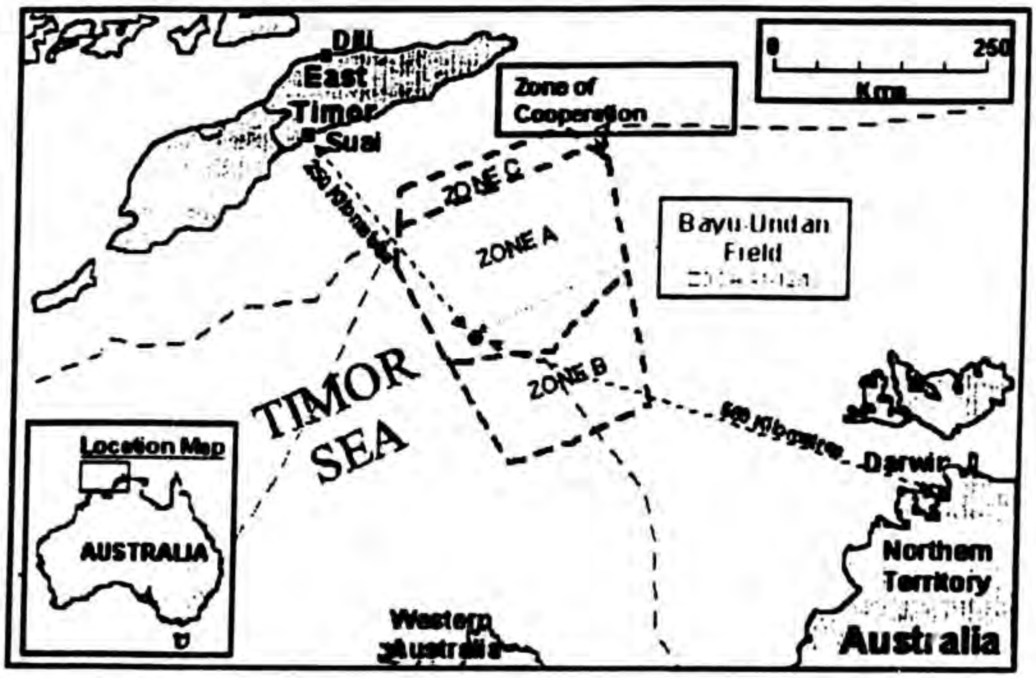
Attachment 6

Overview of Bayu-Undan Development Project
(Introduction, pages 1-6, bayuundan.phillips66.com)

Introduction

The Bayu- Undan development is a world- class project. The project involves two phased developments of the field's natural gas and gas liquids resources. Following the co- venturer companies approval of the first phase of development in October 1999, an initial expenditure of approximately $US 1.4 billion on the liquids stripping/lean gas recycle phase makes it the largest investment proposed to date in the Timor Sea. The field life is estimated to be 25 years, with first liquids production planned to commence in late 2003.

The Bayu-Undan field is located in the central Timor Sea about 500 kilometres north west of Darwin Australia and about 250 kilometres south of Suai in East Timor.



The field straddles two production sharing contract (PSC) areas (91-12 and 91-13) in Area A of the Timor Gap Zone of Cooperation (ZOCA). The Bayu-Undan field is a single gas/condensate resource with recoverable reserves of approximately 400 million barrels of liquids (condensate and LPG) and 3.4 tcf of gas.

A second phase downstream development to commercialise the field's valuable gas reserves is also planned and concepts for this are the subject of separate studies and approvals by the co-venture companies and government authorities.

Field Administration, Operator & Participants

The Zone of Cooperation Area A (ZOCA) is administered by the Timor Gap Joint Authority (Joint Authority), comprising representatives appointed from the contracting nations administering Area A. The Joint Authority is responsible to a joint Ministerial Council, comprising an equal number of ministers from each contracting nation, under the requirements of the current Timor Gap Treaty.

The Bayu- Undan development will be undertaken under the terms of the PSCs and applicable regulation and by the following Unit Participants:

ZOCA 91-12 Unit Participants
Phillips Petroleum (91-12) Pty Ltd: ACN 064 963 346
(Operator)

Santos (ZOCA 91-12) Pty Ltd: ACN 056 937 752
Inpex Sahul, Ltd: ARBN 059 844 781
Petroz (Timor Sea) Pty Ltd: ACN 053 697 794
Emet Pty Ltd: ACN 050 134
907

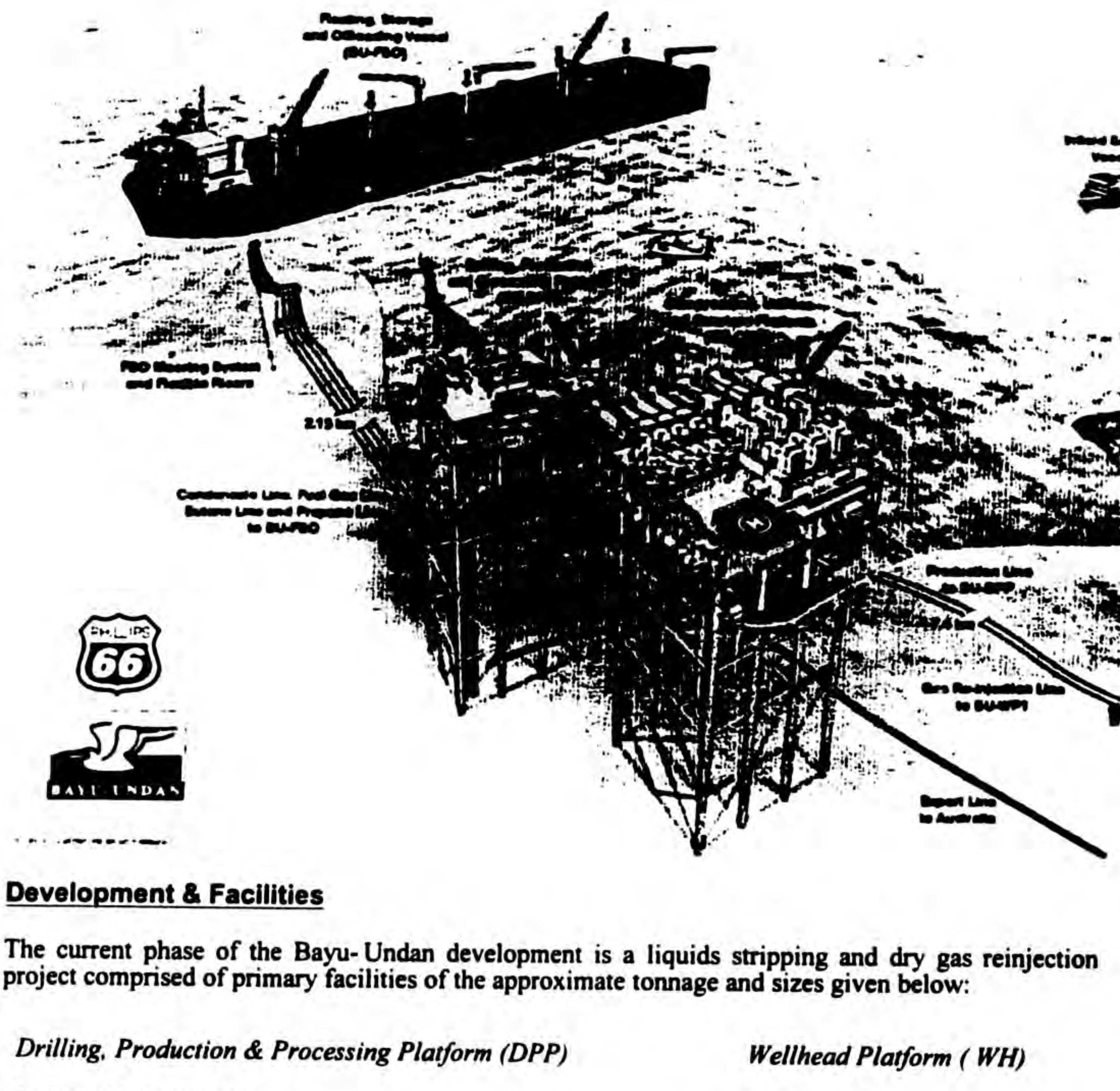
ZOCA 91-13 Unit Participants
Phillips Petroleum Company ZOC: ARBN 0
(Operator)

Kerr-McGee (ZOC) Energy Ptd Ltd: ACN 05
Agip Australia 91-13 Ltd: ARBN 054 729 930
Phillips Petroleum Timor Sea Pty Ltd: ACN 00

The Unit Participants signed a Unit Operating Agreement on 14 July 1999 and have appointed Phillips Petroleum (91-12) Pty Ltd as the Unit Operator. The Unit Participants have also approved a Unitization Agreement as stipulated under terms of the Petroleum Mining Code relating to petroleum operations in Area A, which has been approved by the Joint Authority.

Project Management

The field was discovered in early 1995 following the successful completion of the Bayu-1 located in ZOCA 91-13. Subsequent wells drilled in ZOCA 91-12 and ZOCA 91-13 confirmed the size and potential of the field. Preliminary engineering studies for the liquids stripping / gas recycle phase of development were completed in late 1998, and a detailed cost estimate was prepared for the Unit Participants. Co-venturer approval of this phase of the development was received in October 1999. After evaluation of competitive tenders, Unit Participants selected TIGA, an alliance between Fluor Daniel and Worley, to serve as the engineering and procurement contractor for the detailed design work. The contractor will work in an Integrated Team with the Unit Operator's personnel on this phase and will be located in Perth, Western Australia. The Unit Operator's team will be supplemented by specialist contract personnel as appropriate - see the Employment Page for further details on personnel requirements.



Development & Facilities

The current phase of the Bayu- Undan development is a liquids stripping and dry gas reinjection project comprised of primary facilities of the approximate tonnage and sizes given below:

Drilling, Production & Processing Platform (DPP)

Jacket - 10,664 tonnes

Deck – 14,000 tonnes

Compression, Utilities & Quarters Platform (CUQ)

Jacket – 10,380 tonnes

Deck - 11,500 tonnes

Wellhead Platform (WH)

Jacket - 1,390 tonnes

Deck - 1,550 tonnes

Floating Storage & Offloading F

820k barrels (130,000M^3) of Con

2 x 300k barrels (47,500 M^3) of Propane/Butane

248m long x 54m wide

The purpose- built FSO, which will be manufactured by Samsung Heavy Industries will be permanently positioned offshore in the field. All liquid products will be sold directly to world markets and exported from the offshore facilities in the field on buyer-chartered condensate and LPG offtake tankers.

The field, which measures approximately 25 km by 15 km, will require approximately 26 wells over its life to produce the reserves; approximately 16 of these wells will need to be completed by startup.

Major Milestones

- Commencement of detailed design-Q4 1999
- Award major equipment orders- Q2 2000
- Award Hook-up and Commissioning contract-Q2 2000
- Award major fabrication contracts -Q2 2000
- First Production-Q4 2003

Status of the Zone of Cooperation

As a consequence of a referendum conducted on 30 August 1999 in East Timor, the United Nations Transitional Administration in East Timor ("UNTAET") was established to oversee East Timor's transition to independence. Effective on 25 October 1999, UNTAET is endowed with the overall responsibility for the administration of East Timor, including those maritime zones which comprise the current Area A of the Zone of Cooperation.

UNTAET, on behalf of East Timor, and the Commonwealth of Australia are currently negotiating key transition agreements for the conduct of ongoing operations in Area A. The purpose of these agreements is to maintain the current legal, fiscal and administrative regime applicable to petroleum operations in Area A. Phillips, as Unit Operator, has been assured by senior leadership within the National Council for Timorese Resistance ("CNRT") of their support for continued development of petroleum resources within this area.

The Bayu-Undan Unit Participants look forward to a close and productive relationship with the East Timorese during the current transitional period and throughout the life of the development.

Project Conditions

The Project is subject to tight economic and schedule conditions that must be met in order to achieve timely execution and completion. This will require the support of the various government authorities and all suppliers and contractors to achieve the demanding targets which will ensure the development proceeds expeditiously.

The Project will seek to place business with those suppliers and contractors that can offer reliability and quality at a competitive cost.

The Project is firmly committed to the highest ethical standards and will deal in a fair, impartial and non- discriminatory manner with all parties. The Project respects the confidentiality of sensitive information and will expect the same standards from vendors. All project activities will be undertaken within the constraints of the regulatory framework.

Project contracts and procurement activities will be carried out in compliance with the Joint

Authority regulations, which require the Project to:

- Subject tenders to Joint Authority approval.
- Use competitive tendering as the preferred method of vendor selection.
- Give preference to goods and services that are produced in the contracting states, provided they are offered on competitive terms and conditions compared with those from other countries.

Safety, health and environment considerations will be a major part of the selection process for contractors. Close attention will be given to monitoring performance of all parties involved in the project to meet high standards in caring for people and the environment.

Key Vendor Requirements

- Successful vendors are likely to be those who are competitive, reliable and responsive to the needs of the Project.
- Successful vendors will be expected to provide comprehensive operational support after the project phase.
- Vendors must be able to compete on a lowest total cost basis (including life cycle cost) rather than on price alone.
- Engineering, Operations and Procurement are actively working together to efficiently expedite the Project. Vendors will not secure an advantage by solely dealing with one group.
- The Project has a preference towards harmonious working relationships with its vendors.
- The Project advises bidders to submit their best price first time around, as this will be the prime (and possibly only) opportunity to make an offer. Negotiations are not routine Phillips practice and bidders should not assume that a negotiation will occur as a matter of course. Should bidders choose to ignore this advice and add any margin to their offers in expectation of a negotiation then they run the significant risk of being beaten by a bidder that provides their best offer from the outset. Bidders expecting a negotiation may not even get to the table to discuss their offer.

Attachment 7

Bayu-Undan: Catalyst for a New Energy Province
By James J. Mulva
June 26, 2000
(philnet.ppco.com/newsroom/)

Bayu-Undan: Catalyst for a New Energy Province

James J. Mulva
Chairman and Chief Executive Officer
Phillips Petroleum Company
South East Asia Australia Offshore Conference 2000
Darwin, Australia
June 26, 2000

I appreciate this opportunity to join you for SEAAOC 2000.

It is good to be back at the top end of Australia. Darwin is an extraordinary city, with a colorful history, a rich culture and a promising future as the onshore hub for Timor Sea gas.

For more than 30 years, the petroleum industry has been looking for ways to tap the Timor Sea's vast natural gas resources. Today, we are close to achieving that goal. By the end of the decade, the Timor Sea will be an important, new regional energy province, providing benefits to both Australia and East Timor.

Within the next few years, Phillips and its co-venturers will build infrastructure that will carry abundant, clean-burning Timor Sea gas to the Northern Territory and to major population centers throughout Australia. The gas will not only help meet domestic energy needs, but will also provide feedstock for products that can be marketed throughout all of Australia and Asia.

The deep Timor Trench makes it impossible to transport gas to East Timor; but even so, this newly independent nation will prosper greatly as the Timor Sea is developed. The revenue that will flow into the country will enable its citizens to build a strong, sustainable economy; develop new employment opportunities, and improve their overall quality of life.

The Timor Sea holds great promise for the region; and for companies like Phillips, which are pioneering the development of its natural gas resources. We have a long history as a major producer, processor and supplier of natural gas; and we hold patents for some of the most advanced gas processing technologies in the world.

Working with our partners, we are making investments that will unlock the potential of the Timor Sea. Bayu-Undan is the cornerstone of our effort.

Bayu-Undan is the world-class gas and gas condensate field that Phillips and its co-venturers discovered some five years ago. It lies 500 kilometers northwest of Darwin and about 250 kilometers south of East Timor. It is located in the Timor Gap Zone of Cooperation and straddles two production-sharing contract areas. The field is estimated to hold almost three and a half trillion cubic feet of natural gas and 400 million barrels of condensate and liquefied petroleum gas.

Creating the Catalyst for Future Development

Bayu-Undan will be the region's first major gas development. It will be as significant to the future of the Timor Sea as Phillips' Ekofisk field was to the North Sea.

We discovered Ekofisk in 1969. Like Bayu-Undan, it was the first major discovery in a high-potential, centrally located region. The Ekofisk discovery was the catalyst for Phillips to invest in a pioneering development program more than 200 miles off the coast of Norway. For other companies, it was the catalyst to step up exploration in the North Sea, using our infrastructure to develop new discoveries.

The Ekofisk field established the North Sea as a major energy province and helped build a world-class service and supply industry. If we move together cooperatively – as developers, governments, suppliers and customers – Bayu-Undan will do the same for the Timor Sea.

Today, I have been asked to talk about Bayu-Undan and Phillips' plans for developing it. I welcome your invitation; because just as Bayu-Undan is important to the future of the Timor Sea, so is it important to the future of Phillips Petroleum Company.

Bayu-Undan not only gives Phillips a strategic position in a major new energy province, but it also plays a key role in an overall strategy we have put in place to grow our company and make it more competitive.

Nine months ago, we told the financial community that we were taking Phillips in a new direction, one far different from that of our peers. What we outlined was a strategy to grow all four of our business lines, up and down the integration chain.

Over the past few years, we had seen several companies give up the benefits of integration to focus on one or two businesses. At the same time, we had seen others merge to form mega-companies, or be absorbed into these super-large enterprises.

Given our size and position in the industry, we believed there was another way to grow and remain competitive. Our approach was to put our midstream and downstream businesses into larger, stronger, self-funding joint ventures and invest more heavily upstream -- in projects like Bayu-Undan, where we could use our technical and project-execution skills to achieve higher financial returns and deliver greater shareholder value.

The course we are taking enables us to maintain the benefits of being a fully integrated petroleum company, yet grow large enough to compete with the very largest companies across all business lines.

This morning I want to talk briefly about the progress we've made in carrying out our strategy for growth, then focus on Bayu-Undan. I will tell you where it fits in our overall growth plans, and the vision we have for making it a long-term, legacy asset for Phillips and the people of this region.

Creating Significant Growth

We announced our strategy for growth last September. Since then, we have made three important transactions that have already increased our asset base by about 50 percent.

The first was the joint venture of our midstream company with Duke Energy. This created one of the largest gas gathering and processing companies in the United States.

Now, we are moving ahead with our second joint venture. We are working with Chevron to create a company that will be one of the largest and most competitive producers of chemicals and plastics in the world. We expect to complete this transaction within the next week or two.

Our third transaction is by far the largest and most significant in our company's history. It is our $7 billion purchase of ARCO Alaska. We completed this acquisition in April. It immediately boosted our worldwide production by almost 75 percent; it more than doubled our reserves, bringing our reserve base close to the size of Texaco; and it added more than one million high-potential exploratory acres to our portfolio.

The deals we have done have enabled us to grow significantly in a very short time. At the end of 1999, we had an asset base of $15 billion. This year, our net asset base will be almost $23 billion.

Pursuing New Growth Opportunities

This is growth in the here and now. Mid-term and long-term, we are pursuing a number of other prospects that will sustain the momentum.

Downstream, we have a third joint venture planned for our refining, marketing and transportation operations. This will occur in a year or so, after we have completed two projects that will enhance the value of this business.

Upstream, we have an aggressive exploration and production (E&P) program under way, which will enable us to continue growing our production and reserves. Going forward, E&P is where we see the greatest opportunities to deliver shareholder value, and where we have the resources -- human, technological and financial -- to remain a strong competitor.

As we grow our E&P business, our strategy is to build legacy assets -- high-quality oil and gas developments that have a long producing life and provide strong financial returns. These are assets like Ekofisk, Alaska and Bayu-Undan.

On the exploration side, we are focusing our search on a few, select, high-potential areas. They include Alaska, the deep-water Gulf of Mexico, Canada, the North Sea, the Atlantic Margin and the Caspian Sea.

We are also drilling in less explored areas, such as Oman and South Africa; and we are looking at investment opportunities in the Middle East, primarily Saudi Arabia and Kuwait.

On the production side, we are developing three major projects, which combined will contribute more than a billion barrels of oil equivalent to our reserve base.

One is the Bohai Bay discovery offshore China, which we will bring into production late next year. Bohai

Bay contains at least 500 million barrels of crude oil; we believe another 300 million barrels could potentially be recovered.

Next year, we also expect new production from the Hamaca heavy oil project in Venezuela. Hamaca is located in the Orinoco Oil Belt, an area that is believed to hold some 31 billion barrels of oil, of which about two billion barrels can be recovered with conventional technology.

Recovering Liquids from Bayu-Undan

And finally, there is Bayu-Undan, our world-class discovery in the Timor Sea. Bayu-Undan is a classic legacy asset, with a good mix of near-term and mid-term development opportunities for both liquids and natural gas.

In February, the Joint Authority for the Timor Gap Zone of Cooperation approved a development plan for a $1.4-billion gas recycle project. This is the largest approved investment to date in the Timor Sea.

The project is designed to recover liquids and recycle produced natural gas back into the reservoir. The development plan calls for building two bridge-linked gas production and processing facilities and a separate unmanned wellhead platform.

The liquids will be delivered to a floating storage and offloading vessel. Separate shuttle tankers will transport product to Asian markets.

To date, we have completed about one-third of the engineering design work for the offshore facilities.

We recently awarded the contract for the storage and offloading vessel to Samsung Heavy Industries. In the next few months, we expect to award the other major fabrication and equipment contracts.

To bring Bayu-Undan into full production, we will initially need to drill 16 wells, 10 producing wells and six injection wells. We will begin drilling them in 2002 and add wells as the field matures.

We expect Bayu-Undan to be in full production in early 2004 and to peak the following year at around 100,000 barrels of liquids a day.

Monetizing the Gas

The first phase of the Bayu-Undan development is to produce the field's petroleum liquids. The second phase of the project will deliver gas to onshore markets and possibly to a liquefied natural gas (LNG) processing facility in Darwin.

Phillips developed the world's most advanced LNG technology, and we have been supplying product to Japan for more than 30 years from our facility in Kenai, Alaska. We would like to do a similar LNG project here if Asian markets can be developed.

As we look at the overall development of Bayu-Undan, the gas-recycle project is possible on a standalone basis. However, natural gas represents 60 percent of the resource base and is valuable in its own right. Phillips and the Joint Authority want to develop the liquids and gas simultaneously, and we are moving closer to that goal.

Producing the gas and liquids together not only would greatly enhance the value of our project, but it would also put the infrastructure in place to economically develop other Timor Sea gas reserves.

There is sufficient demand in Australia to justify a gas-development project. By the end of the decade, the country's traditional onshore gas supplies -- those that can compete with offshore sources -- will be rapidly depleting. Bayu-Undan and other parts of the central Timor Sea will provide a new supply source and keep gas prices competitive.

We have looked at a number of options for monetizing Bayu-Undan gas -- options that have low technical risk and provide maximum flexibility as new gas markets evolve. All require constructing a 500-kilometer subsea pipeline to Darwin.

With an offshore pipeline in place, we could then facilitate the development of a national onshore pipeline system -- one that would transport gas to customers here in the Northern Territory, as well as other parts of Australia.

We are now working with two large companies to develop the pipeline infrastructure. For the subsea portion, I can confirm that we are in the final stage of exclusive negotiations with Multiplex Construction to build a primary trunk line from Bayu-Undan to Darwin.

Multiplex has the demonstrated capability to manage large projects and has aligned itself with an experienced, well-known group of sub-contractors who can assure the successful completion of a turnkey pipeline project. We believe our negotiations with Multiplex will lead to an agreement and expect to announce a project soon.

Onshore, we have formed an alliance with Epic Energy to identify potential markets outside the Northern Territory. To date, Epic has identified some 2,800 kilometers of new pipeline infrastructure in the eastern half of the country. This new system will connect to the company's existing assets in Queensland and

South Australia. This will help establish a national distribution network that can economically supply gas to the population centers of south and eastern Australia.

We are also pursuing markets in other parts of Australia where Timor Sea gas can effectively compete. We will announce these projects as they are approved. Because of confidentiality agreements, it is our policy to issue joint announcements only after all parties have agreed to a project.

Given the advanced status of our Bayu-Undan liquids project, as well as our work with Multiplex and Epic, customers can be assured that Phillips and its co-venturers will supply gas on schedule and at a competitive price.

The infrastructure we will build -- both offshore and onshore -- will ensure the timely development of Bayu-Undan; but just as importantly, it will be the catalyst for other companies to increase their investments in the region and develop additional markets for Timor Sea gas. Looking ahead, it is conceivable that our subsea pipeline could be expanded to include other fields, such as Greater Sunrise, Evans Shoal and Petrel-Tern, as well as new discoveries east and west of the Zone of Cooperation. This would increase the value of Timor Sea gas to all stakeholders.

Overcoming the Challenges

The Timor Sea offers enormous opportunities to contracting nations and producers alike, but it also presents some challenges. As we go forward, there are several issues of particular significance that must be addressed.

One is the intense competition for long-term gas markets. For the Timor Sea to be a successful, commercial development, all of us must work cooperatively to deliver low-cost gas supplies. The global competition for gas markets is intense. Unless Timor Sea gas can be delivered at a competitive price, other projects will capture these markets.

A second issue is the need for a secure and stable legal, fiscal and administrative regime. Phillips and its co-venturers will invest almost one and a half billion dollars for the gas recycle project alone. The gas development will require an even greater investment. Projects of this magnitude can only go forward in a business environment that's fair, transparent and bound to contractual commitments.

These issues are not unique to Bayu-Undan; they affect other developments in the Zone of Cooperation. How they are resolved depends in large measure on the efforts of Australia, East Timor and the United Nations to negotiate the Timor Gap Treaty.

The current terms of the treaty provide a clear fiscal regime for oil development within the Zone of Cooperation, but not for gas development. To date, there has been no agreement on how or where gas will be valued. As a result, contracting states cannot calculate their share of revenue from gas sales. This is unsettling to producers and potential customers, and could delay gas development.

Earlier this year, the parties agreed to continue the terms of the treaty during East Timor's transition to an independent nation. Phillips applauds this decision.

Now, there are indications that East Timor and the United Nations are in negotiations with Australia on a new treaty, one that may not be ratified until East Timor's government is in place sometime between mid-year 2001 to late 2002. We would like to see the parties reach an agreement in principle on the gas issue well before then.

We are encouraged that Australia and East Timor have expressed a desire to see gas developed as quickly and efficiently as possible and equally encouraged by their assurances that a new treaty will not impair the investments of companies operating in the Zone of Cooperation.

Both countries have made it clear that they understand the economic benefits of simultaneously developing the region's liquids and gas resources and the importance of a gas fiscals agreement in reaching that goal.

They have also indicated a desire to provide a stable business environment that will encourage additional investments in the Timor Sea.

All of this is cause for optimism.

For more than 30 years, producers and contracting nations alike have searched for ways to tap the rich potential of the Timor Sea. Today, we have that opportunity; but only if we maintain a spirit of mutual trust and cooperation and move quickly to address the issues that could impede our efforts.

Helping Build an Emerging Economy

For Phillips, one of the most gratifying aspects of Bayu-Undan is the opportunity to contribute to the economic development of a new nation. The people of East Timor have experienced great hardship and are now working to establish a stable, independent government.

Bayu-Undan will contribute significantly to the effort. Our gas-recycle project will likely be the country's largest source of revenue for a number of years; our gas project will benefit them for decades. As we establish Phillips' presence in the region, we will make every effort to be a good citizen and contribute to the quality of life.

Already, we are working on several educational and training initiatives, which will prepare the people of East Timor for jobs in the petroleum industry. The long-term nature of most developments in the Zone of Cooperation means there will be significant employment opportunities.

We are also working with East Timor and the U.N. transitional team to develop a taxation system for the country, one that will encourage additional investments in the Zone of Cooperation.

And we are helping the country restore its agricultural and educational base. We recently donated 13 trucks -- one for each province -- to support agricultural efforts, and a four-wheel-drive vehicle that serves as a mobile medical clinic in the Suai area. With our co-venture companies, we have also provided school supplies to rebuild the educational system in Dili.

As we develop Bayu-Undan, we will continue to look for other opportunities to help the people of East Timor build their economy and raise their standard of living.

Building a New Legacy

Before I close, let me emphasize once again Phillips' commitment to Bayu-Undan and the Timor Sea.

We see Bayu-Undan as a long-term, legacy asset -- one that will help Phillips grow and compete against the largest companies in the industry, and one that will benefit the economies of both Australia and East Timor.

There are challenges ahead, both commercial and political; but we are optimistic they can be overcome, especially if we work cooperatively.

The Timor Sea is uniquely positioned to become a major, regional energy province. Bayu-Undan will be the catalyst that makes it happen.

Thirty years ago, Phillips and its co-venturers helped turn the North Sea into one of the world's premier energy-producing regions. We are now prepared to do the same in the Timor Sea.

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Attachment 8

Overview of Bayu-Undan Development Project
(Engineering and Design, pages 1-3, bayuundan.phillips66.com)

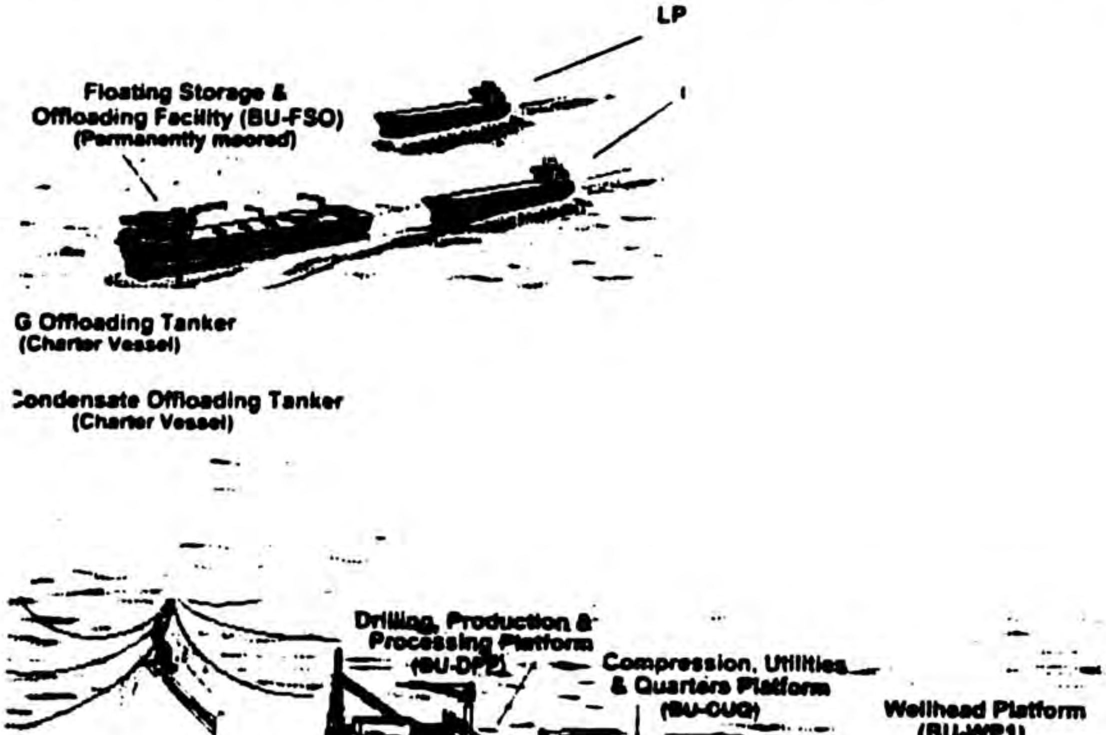
ENGINEERING AND DESIGN

OVERVIEW

The Bayu-Undan surface facilities include:

- A Central Production and Processing Complex (CPP) comprising two platforms: the Drilling, Production and Processing platform (BU-DPP), Utilities and Quarters platform (BU-CUQ).
- An unmanned Wellhead Platform (BU-WP1)
- A Floating Storage and Offloading Facility (BU-FSO)

The field will be developed with two drilling centres: the BU-DPP and the BU-WP1. These facilities are designed for drilling using a jack-up rig in cantilever mode. Wellstream fluids will be exported from the BU-WP1 for processing on the CPP. Sales-quality condensate, propane and butane will be produced on the CPP, then exported to and stored on the BU-FSO. The Lean Gas will be re-injected.



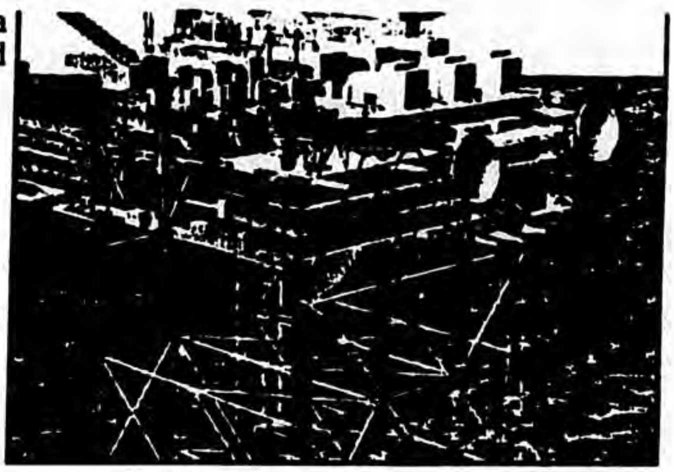
Bayu-Undan Upstream Development Concept (Artist impression)

THE FACILITIES

BU-CUQ

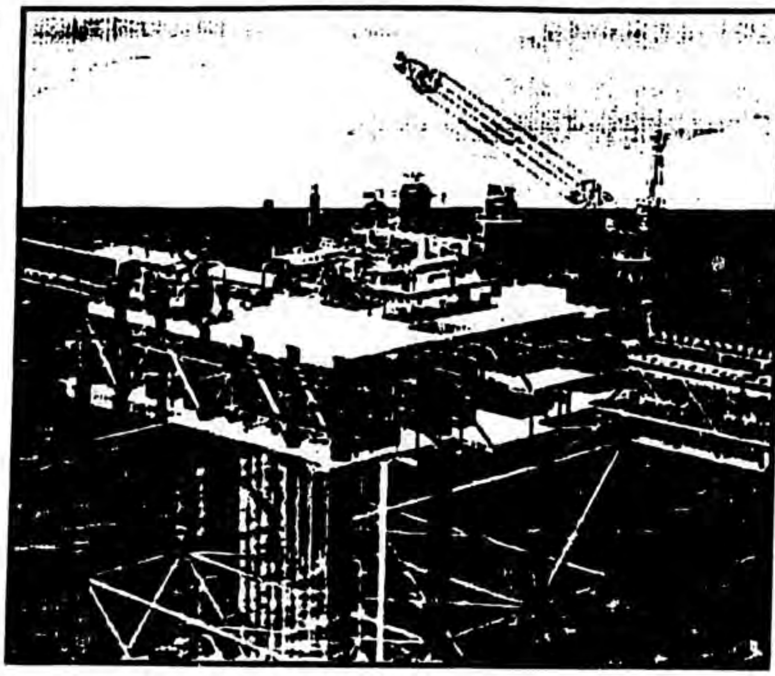
The BU-CUQ deck is a three-level integrated deck (11.5m deck separation) approximately 64m by

54m. The deck will be installed over the jacket via a "float-over" installation method and is bridge-linked to the BU-DPP.



Other features include:

- a fully integrated, three-level living quarters building and associated helideck
- two crane pedestals
- Power Generation and Waste Heat Recovery Units
- Re-Injection Compressors



BU-DPP

The BU-DPP platform is bridge-linked to the BU-CUQ platform.

The BU-DPP deck is a three-level integrated deck of similar dimensions to the BU-CUQ. It will also be installed using a "floatover" method.

The DPP Platform contains most of the process equipment for dehydration and fractionation of the wellstream fluids.

BU-WP1

The Wellhead Platform

The BU-WP1 is an unmanned platform and the topsides consist of a single, integrated module with two primary deck levels (dimensions 17.7m by 24.2m).

A pedestal crane is located at the south-east corner and has a design capacity of approximately 28 tonnes to handle wireline and workover equipment.

A helideck is located five metres above main deck with the south west corner of the platform.

A dayroom will provide for meal breaks and also act as emergency shelter for anyone who may become stranded on the platform overnight.

SUBSTRUCTURES

The substructures for the CUQ and DPP are designed, using high strength steel, to withstand extreme cyclone and earthquake events as well as accidental boat collisions. Each substructure is eight legged, approximately 90 metres high, weighs approximately 6,500 tonne and has four vertical sides, with plan dimensions of 48.0 metres wide by 50.0 metres long.

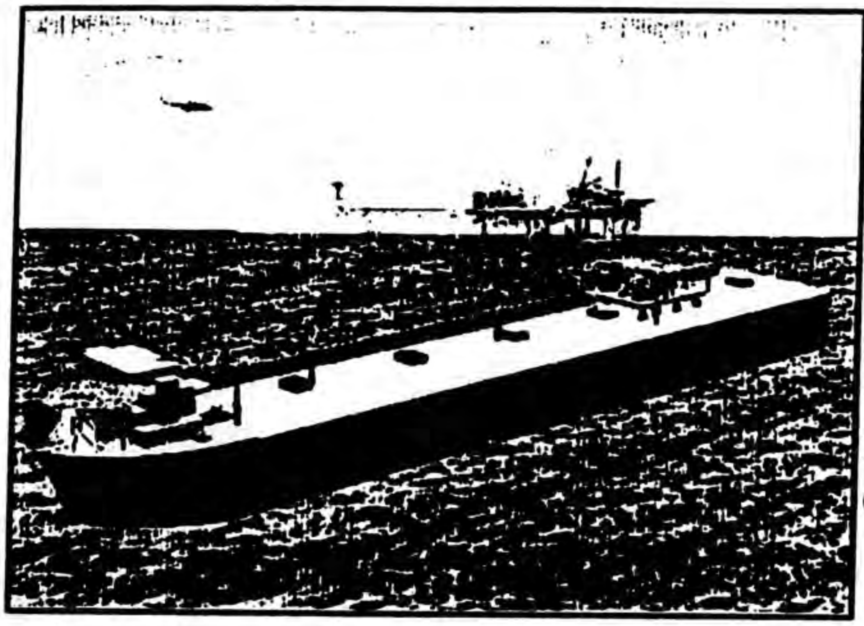
The key feature of the jackets is an open slot at the top to accommodate the barge for mating the topsides with the jacket, using the floatover technique. The BU-DPP accommodates sixteen well slots and supports the risers for the pipelines to and from the BU-WP1 and to the BU-FSO.

Flare

The flare bridge is 155 metres long, supported by a tripod substructure and is triangular in cross section. It provides personnel access to the flare tip and carries the High Pressure (HP), Low Pressure (LP) flare and atmospheric vent lines.

FLOATING STORAGE AND OFFLOADING (FSO)

The BU-FSO is located approximately two kilometres from the CPP flare tip and is a permanently turret-moored facility linked by pipeline from the CPP. It receives sales-specification propane, butane and condensate at ambient temperature, as well as fuel gas for power generation. The BU-FSO topsides include a LPG refrigeration plant. A reliquefaction plant handles the boil-off from the propane and butane storage tanks. Condensate offloading will be to a shuttle tanker in a tandem arrangement. Propane and butane offloading will be by means of a side –to-side arrangement.



Approximate facility dimensions will be:

Length overall 270m

Breadth moulded 51m

Depth moulded 34m

Displacement 200,000 tonnes

Storage capacity :

Propane 47,500 m^3

Butane 47,500 m^3

Condensate 130,000m^3

Attachment 9

Phillips and El Paso Plan to Deliver Australian LNG
to California and Mexico in 2005
03/08/2001
(philnet.ppco.com/newsroom)

03/08/01

Phillips and El Paso Plan to Deliver Australian LNG to California and Mexico in 2005

BARTLESVILLE, Okla. --- Phillips Petroleum Company [NYSE:P] is stepping up its efforts to bring Timor Sea gas to market ahead of schedule through a letter of intent with El Paso Corporation [NYSE:EPG] which contemplates development of a major liquefied natural gas (LNG) project that would deliver approximately 4.8 million tons per year of LNG to growing gas markets in Southern California and Mexico's Baja California peninsula.

Subsidiaries of the two companies have signed a letter of intent (LOI) for the long-term purchase by El Paso of LNG from a plant to be built by Phillips near Darwin, Australia. A definitive agreement, expected to be finalized by mid-year, provides for LNG sales to El Paso beginning in 2005. The LNG would be shipped to North America, where it would be re-gasified and sold as approximately 680 million cubic feet per day of natural gas. This would foster electric power, commercial and industrial development in Mexico's Baja California peninsula and provide a new source of natural gas supplies in growing Southern California markets. El Paso would be responsible for marketing the natural gas.

Phillips and El Paso also are working jointly to develop LNG shipping and a new LNG receiving terminal on the West Coast of North America that will receive, store and re-gasify the LNG. The companies are working with Mexican and U.S. authorities to establish the site of the new terminal and acquire regulatory permits. The new terminal will be scheduled to begin providing service in 2005. The companies would use existing pipelines to transport the natural gas from the terminal to customers.

The Darwin LNG facility, which is planned to be built using Phillips' Optimized Cascade LNG Process, will be supplied with gas from the Greater Sunrise fields in the Timor Sea. These fields contain gas reserves of approximately 9 trillion cubic feet.

This project, along with Phillips' cooperative development agreements with Shell and Woodside, will enable the company to commercialize net hydrocarbon reserves of up to an additional 760 million barrels of oil equivalent from Bayu-Undan and the Greater Sunrise fields. This is in addition to 186 million barrels of net condensate reserves already under development at Bayu-Undan.

The LOI follows the increase of Phillips' interest in the Greater Sunrise fields to 30 percent and finalization with Shell and Woodside of principles for cooperative development of gas resources in the Timor Sea. Gas production from the Woodside-operated Greater Sunrise fields could begin as early as mid-2006. Gas required to satisfy Greater Sunrise deliveries prior to this time will be made available from Phillips-owned equity reserves in Bayu-Undan and possibly other participants in the Bayu-Undan project.

"This LOI with El Paso, combined with the cooperative arrangements with Shell and Woodside, validates Phillips' vision for Timor Sea gas developments and increases the value to all stakeholders in these resources," said Bill Parker, Phillips executive vice president, worldwide production and operations. "With future gas sales to this LNG project – and to domestic customers in Australia's Northern Territory and elsewhere – the Timor Sea will become a new center of production for Phillips, commercializing significant quantities of gas and condensate reserves. Further, these developments serve to better balance the company's

production of oil and natural gas, and build on Phillips' strategy to grow its exploration and production asset portfolio."

Phillips' Optimized Cascade LNG Process is used at a company-operated LNG plant in Kenai, Alaska. In addition, Phillips has interests in LNG shipping and licenses its proprietary LNG manufacturing technology to other users worldwide.

Phillips is an integrated petroleum company with interests around the world. Headquartered in Bartlesville, Okla., the company has 12,400 employees and $20.5 billion of assets, and had $21.2 billion of revenues in 2000.

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CONTACT: Kristi DesJarlais

CAUTIONARY STATEMENT FOR THE PURPOSE OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

Certain statements contained in this press release are "forward-looking statements" within the meaning of The Private Securities Litigation Reform Act of 1995. Such forward-looking statements involve known and unknown risk and uncertainty. The factors identified in this cautionary statement are important factors (but not necessarily all important factors) that could cause actual results to differ materially from those expressed in any forward-looking statement. Factors which could cause the result to differ from those expected or believed to be achieved or accomplished are: preparation and approval of plans and definitive agreements for the development by the co-venturers in the Bayu-Undan and Greater Sunrise projects and the governments of Australia and East Timor; availability of drilling and production equipment and skilled workers; approvals by federal and state governments in Mexico and the United States of regulatory and other matters; the construction of a new LNG terminal; the price of LNG; and success in securing sufficient gas customers. In any forward-looking statement in which the company expresses an expectation or belief as to future results, such expectations or belief is expressed in good faith and believed to have a reasonable basis, but there can be no assurance that the statement or expectation or belief will result or be achieved or accomplished. Additional information concerning factors that could cause actual results to differ materially are contained in the company's reports filed with the Securities and Exchange Commission (SEC). Copies of the company's filings with the SEC are available at the following Web site http://www.phillips66.com.

Attachment 10

Example LNG Project Cost Comparisons

From Public Sources

Ex-Production Development Costs* and Ex-Shipping

Potential ANS LNG Projects	Estimated CAPEX (US$Billion)	MTA	$Million per MTA
ANS LNG Nikiski	$4.9	8.0	**$610**
Backbone (ANS)	$7.3	9.2	**$790**
Example other LNG Projects			
Qatar Ras Laffan (grass roots)	$1.7	5.2	$330 *O&GJ April 27, 1998*
Trinidad (grass roots)	$0.95	3.2	$300 *Energy Day*, June 1999
Oman (grass roots)	$2.0	6.6	$300 *Oman LNG Journal*, January 2001
E. Timor (grass roots)	$1.25**	4.8	$260 *Dow Jones Newswire, March 9, 2001*
Tangguh (grass roots)	$1.5	6.0	$250 *FT International Gas Report*, April 28, 2000
Malaysia III (expansion)	$1.5	7.6	$200 *WGI*, January 27, 2000
Industry Convention (rule of thumb)			***$250*** *O&GJ December 13, 1999*

ANS PROJECTS INCLUDES A *DEDICATED* - 800 MILE PIPELINE that OTHER PROJECTS DON'T HAVE
($2.4 B / 8 = $300)

****Public information on development costs is limited but is more significantly related to oil production***

MTA = Million metric tons per annum

***** Article quotes LNG Plant estimate at $2.5 billion in Australian dollars (~$0.50)***

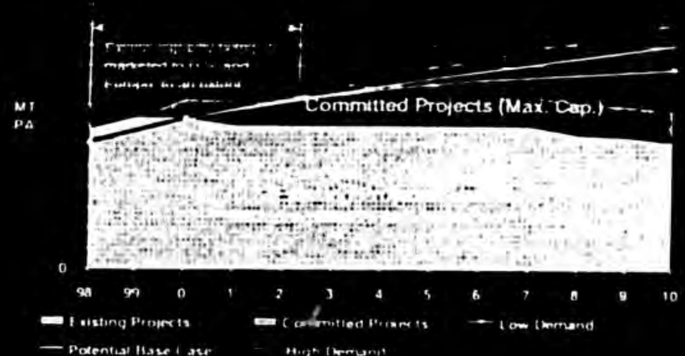
Attachment 11

LNG Market View
Alaska North Slope LNG Project
Presented to Senate Resources Committee
03/07/2001

Market Competition
Potential Asian LNG Projects

Country	Earliest Date of 1st Delivery	Customers	Nominal Capacity MTPA
Australia NWS	~2003+	Asian Markets	7.5
Malaysia Tiga (III)	~2003+	Asian Markets	7.6
Tangguh (Irian Jaya)	2003+	Asian Markets	6
Qatargas/Rasgas	~2002+	Asian Markets	7.5
Bayu	~2003+	Asian Markets	3
Indonesia "I"	~2004+	Asian Markets	3
Yemen	~2004+	Asian Markets	5
Sub Total			39.6

Total Asia-Pacific Supply/Demand Outlook
Includes Emerging Markets (India, China, etc.)



LNG Market View --
Fiercely Competitive

Market Competition
Potential Asian LNG Projects (cont'd)

Country	Earliest Date of 1st Delivery	Customers	Nominal Capacity MTPA
Gorgon	2004/5	Asian Markets	7.6
Sakhalin II	2005/6	Asian Markets	6
Alaska NS	2007+	Asian Markets	8 - 14.7
Indonesia Natuna	NA	Asian Markets	0
Sakhalin I	2007+	Japan/Asia	7
Sub Total			28.6 - 35.3
Total			~68 - 75

Smaller market entry improves probability

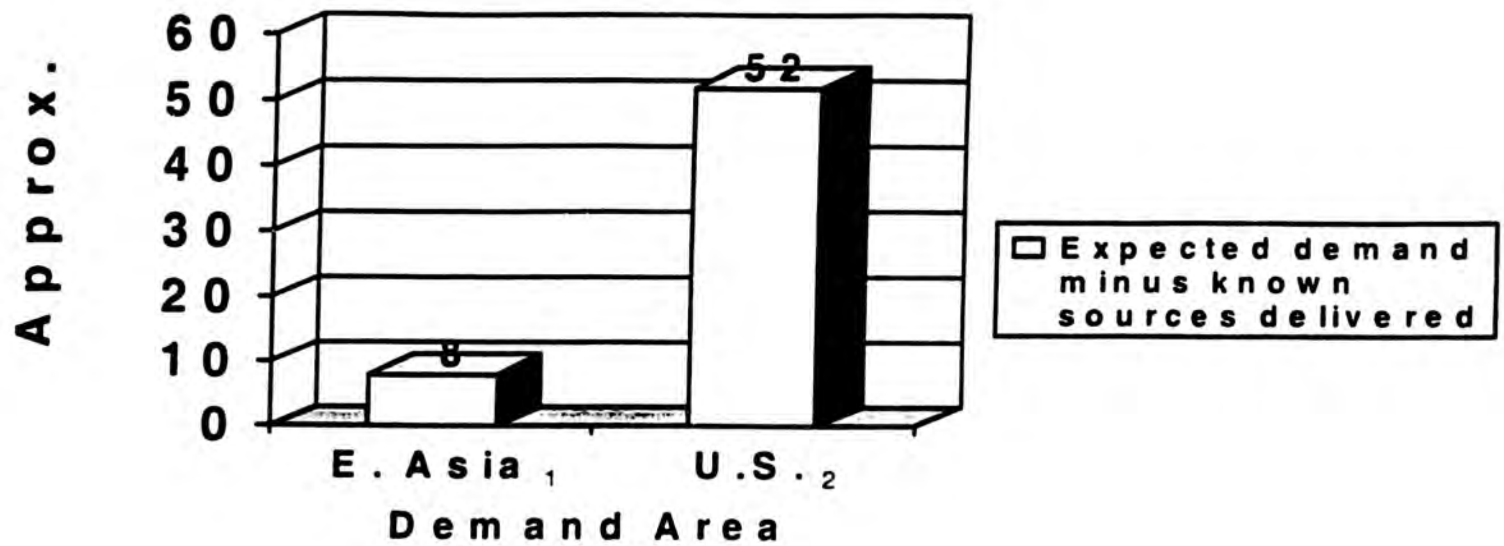
- **60-75 MTPA of potential projects**
  - **Pursuing 20 - 40 MTPA of 2010 growth**
- Problematic trends
  - Downward price pressure
  - Shorter contracts & spot deliveries

Attachment 12

U.S/East Asian New Gas Demand
Alaska North Slope LNG Project
Presented to Senate Resources Committee
03/07/2001

ANS LNG MUST ALSO COMPETE
WITH U.S. GAS DEMAND

2010 New Source Needs



1 - High case LNG demand forecast of Tokyo Gas presented to 2001 HOAG
Year 2010 high demand of 135+ MTA (~19 Bcfd) minus ~80 Mta (11 Bcfd)
2 - National Petroleum Council, 12/99
2010 demand of 76 Bcfd minus 24 Bcfd of existing production

SCOMM

128:14

Alaska Oil and Gas Activities

Division of Oil and Gas
January 2002

Alaska Department of
Natural
Resources

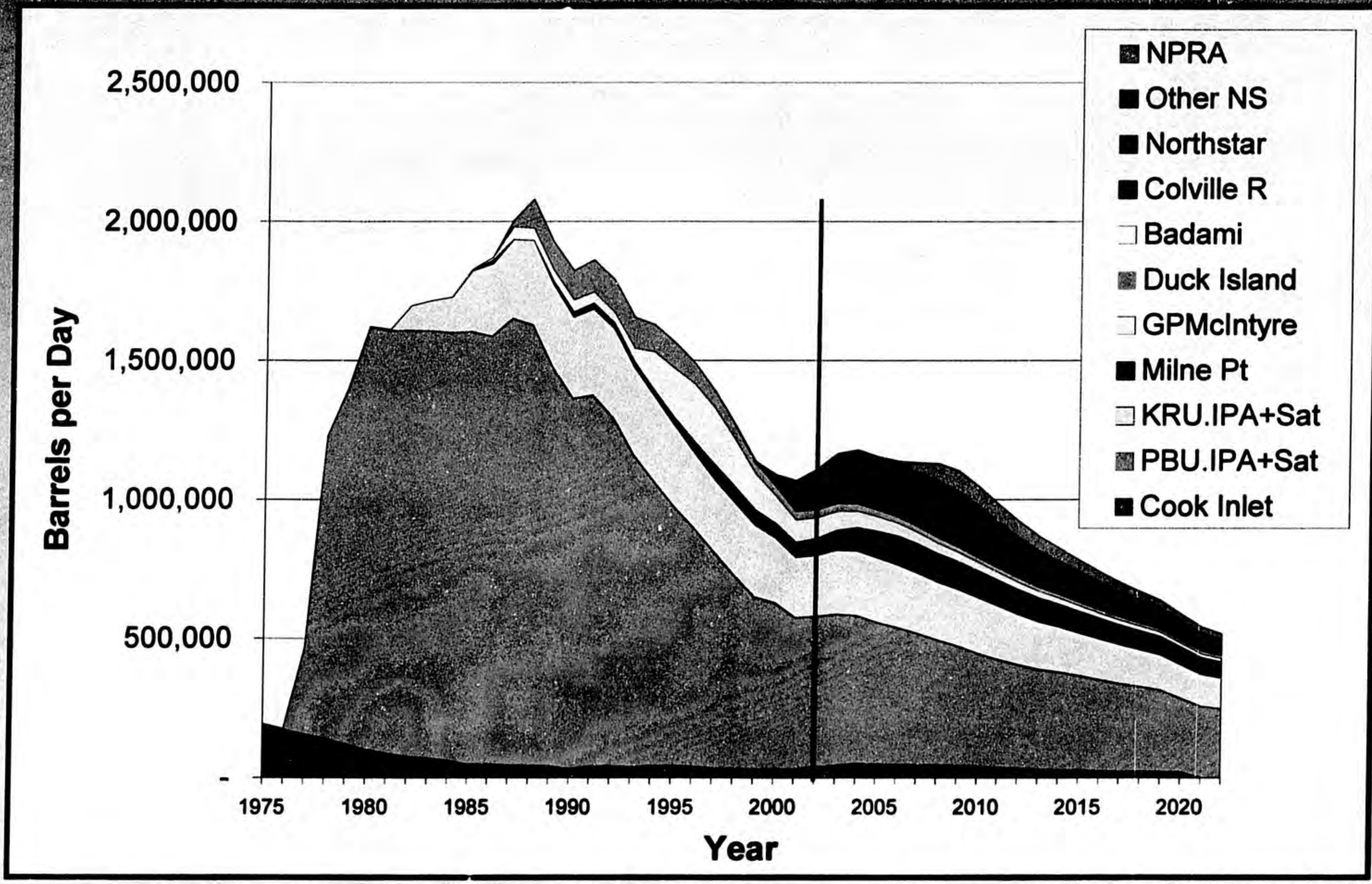
http://www.dog.dnr.state.ak.us/oil/products/products.htm

Alaska Reserves and Production

- **36% of total U.S. oil reserves.**
- 8.0 billion barrels of oil
- **17% of total U.S. gas reserves**
- 35 trillion cubic feet of gas
- **20% of total U.S. oil production**
- 1.04 million barrels of oil per day

Sources: Alaska data are from Department of Natural Resources, Division of Oil and Gas, 2001 Annual Report
U.S. data are from U.S. Crude Oil, Natural Gas, and NGL Reserves, 2000 Annual Report, U.S.D.O.E.-E.I.A.

wdv/tjr 01/2002



Barrels per Day
2,500,000
2,000,000
1,500,000
1,000,000
500,000
-
1975
1980
1985
1990
1995
2000
2005
2010
2015
2020
Year
NPRA
Other NS
Northstar
Colville R
Badami
Duck Island
GPMcIntyre
Milne Pt
KRU.IPA+Sat
PBU.IPA+Sat
Cook Inlet

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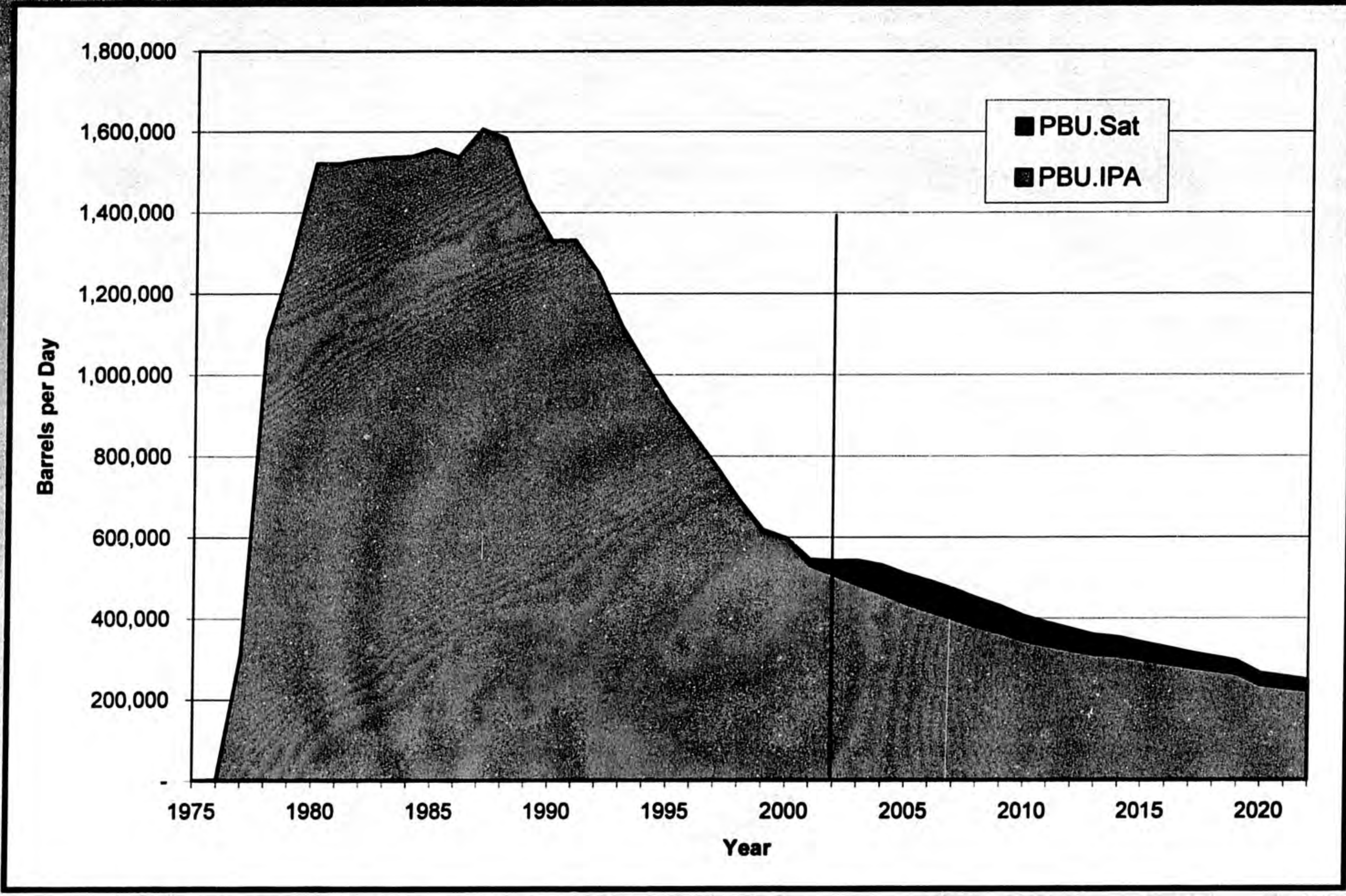
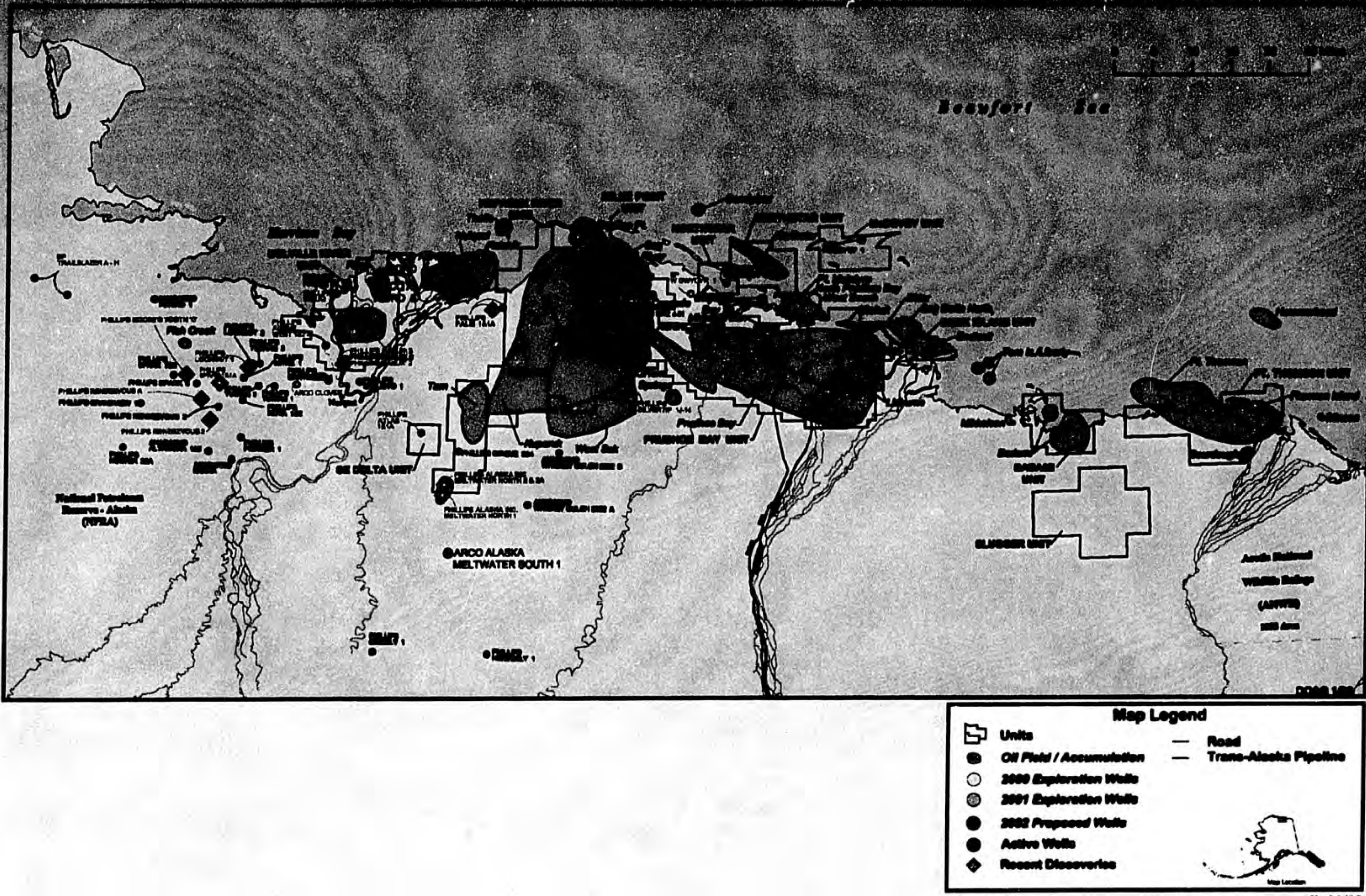

PBU.Sat
PBU.IPA
Barrels per Day
1,800,000
1,600,000
1,400,000
1,200,000
1,000,000
800,000
600,000
400,000
200,000
-
1975
1980
1985
1990
1995
2000
2005
2010
2015
2020
Year

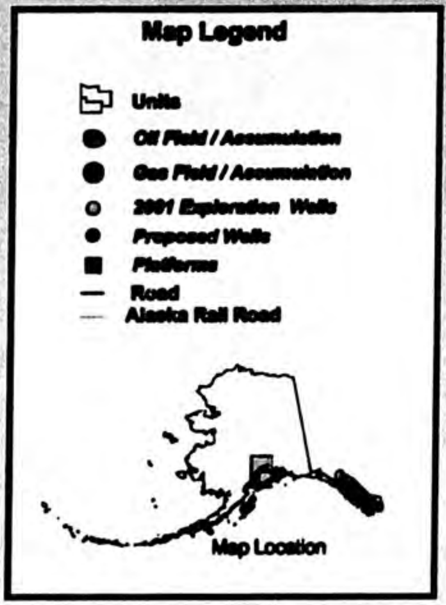
wen 01/02

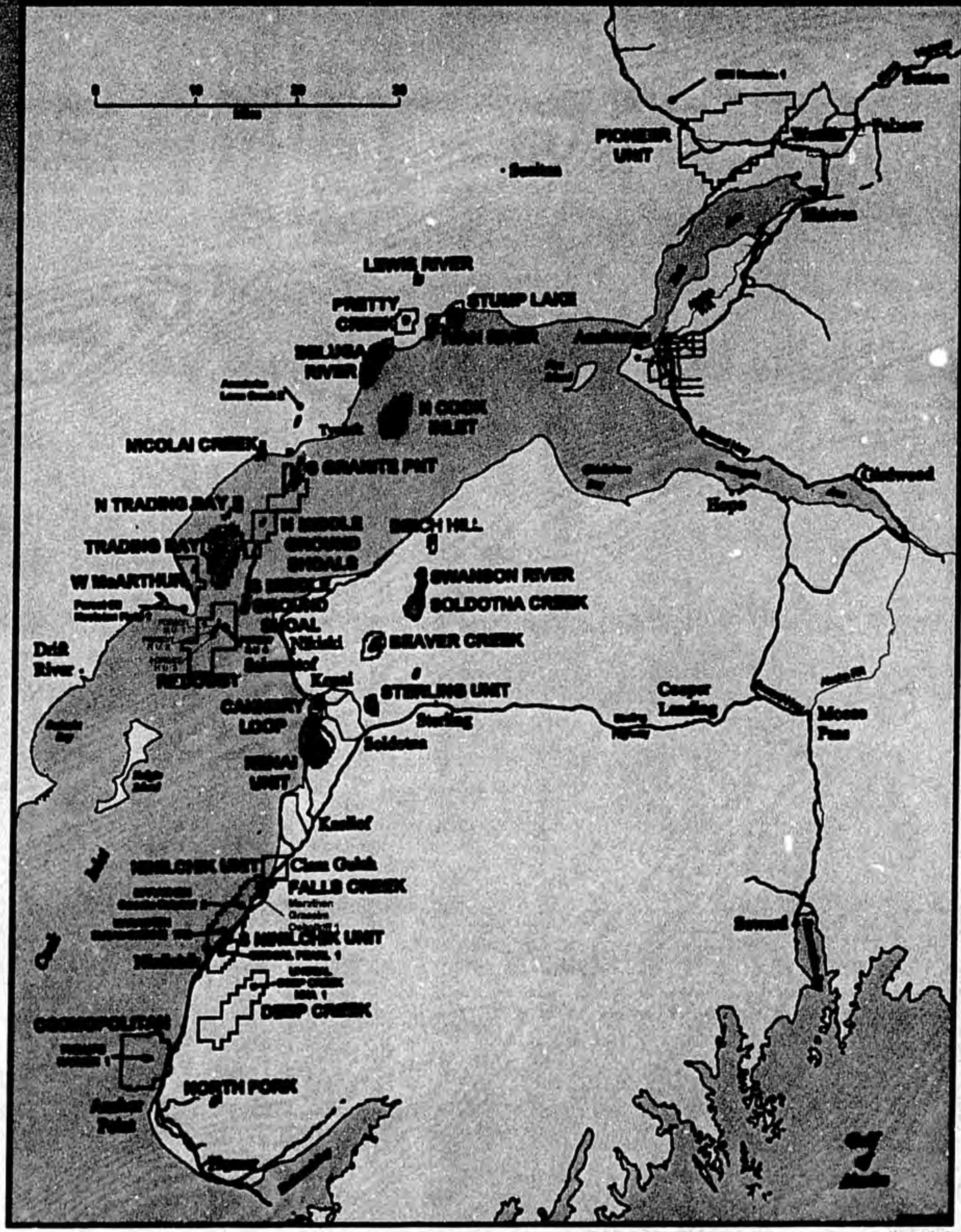
2002



plb 01/02

Cook Inlet Oil & Gas Activity January 2002





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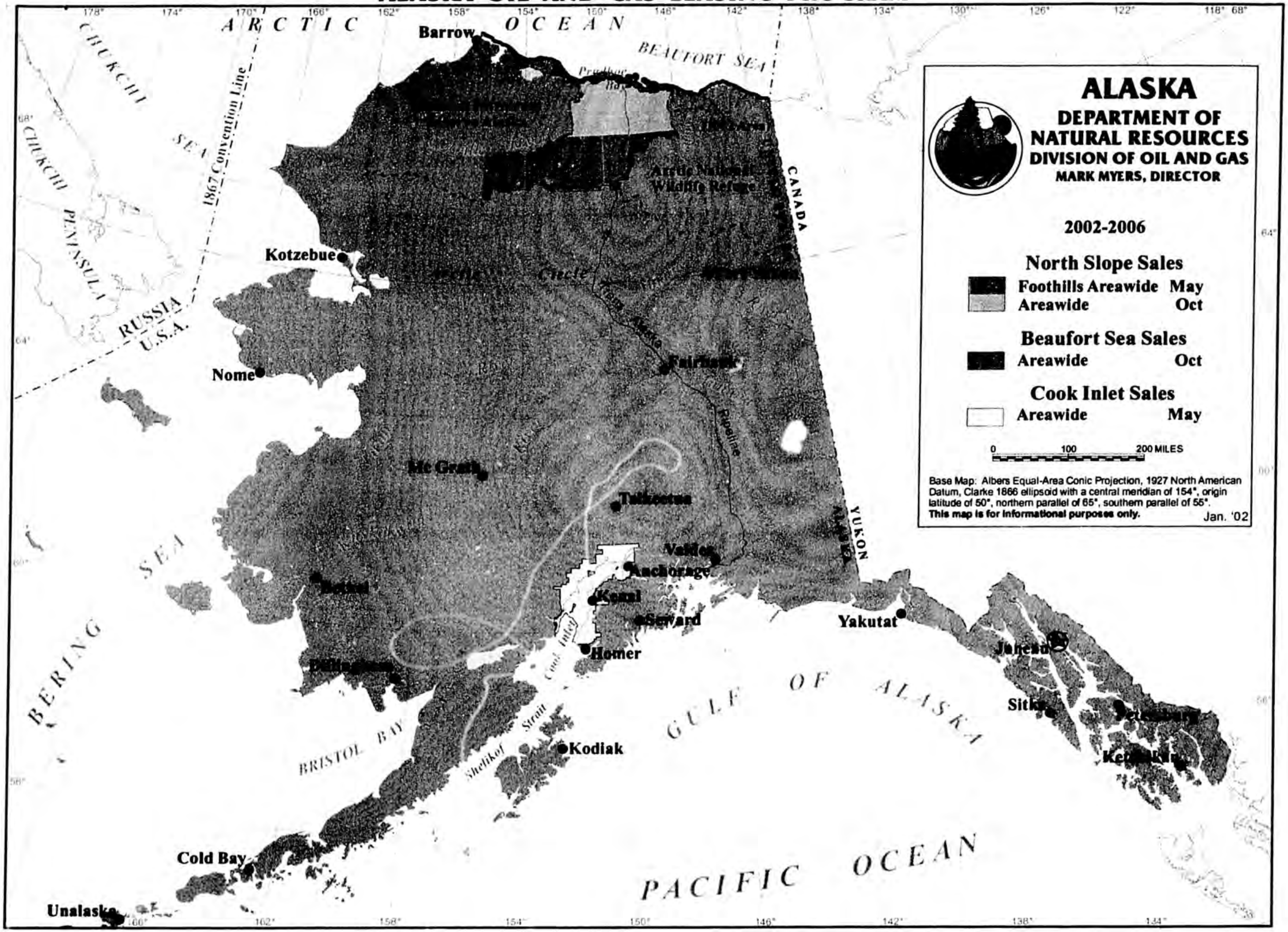
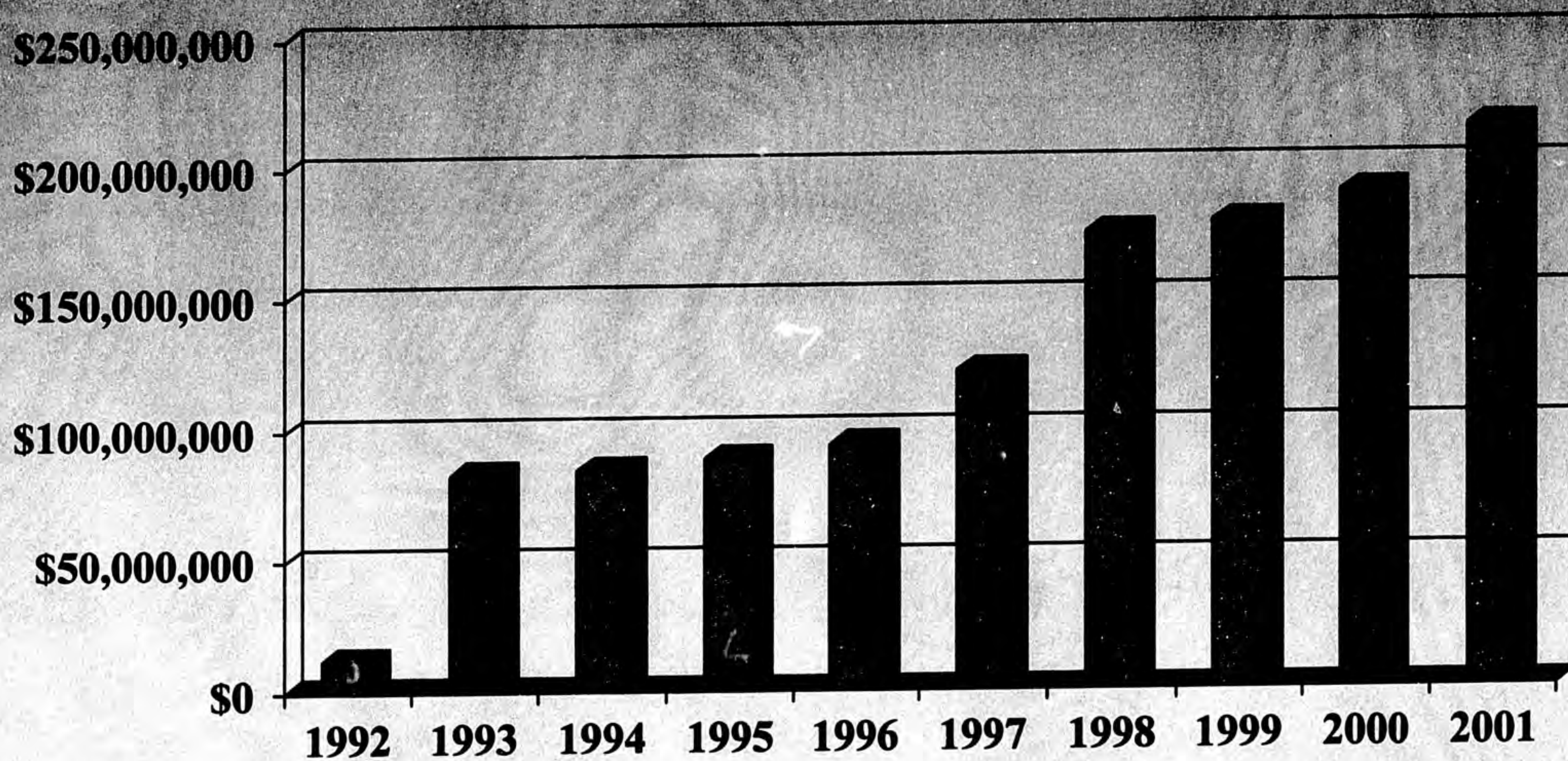
ALASKA OIL AND GAS LEASING PROGRAM



Cumulative Bonus Bids

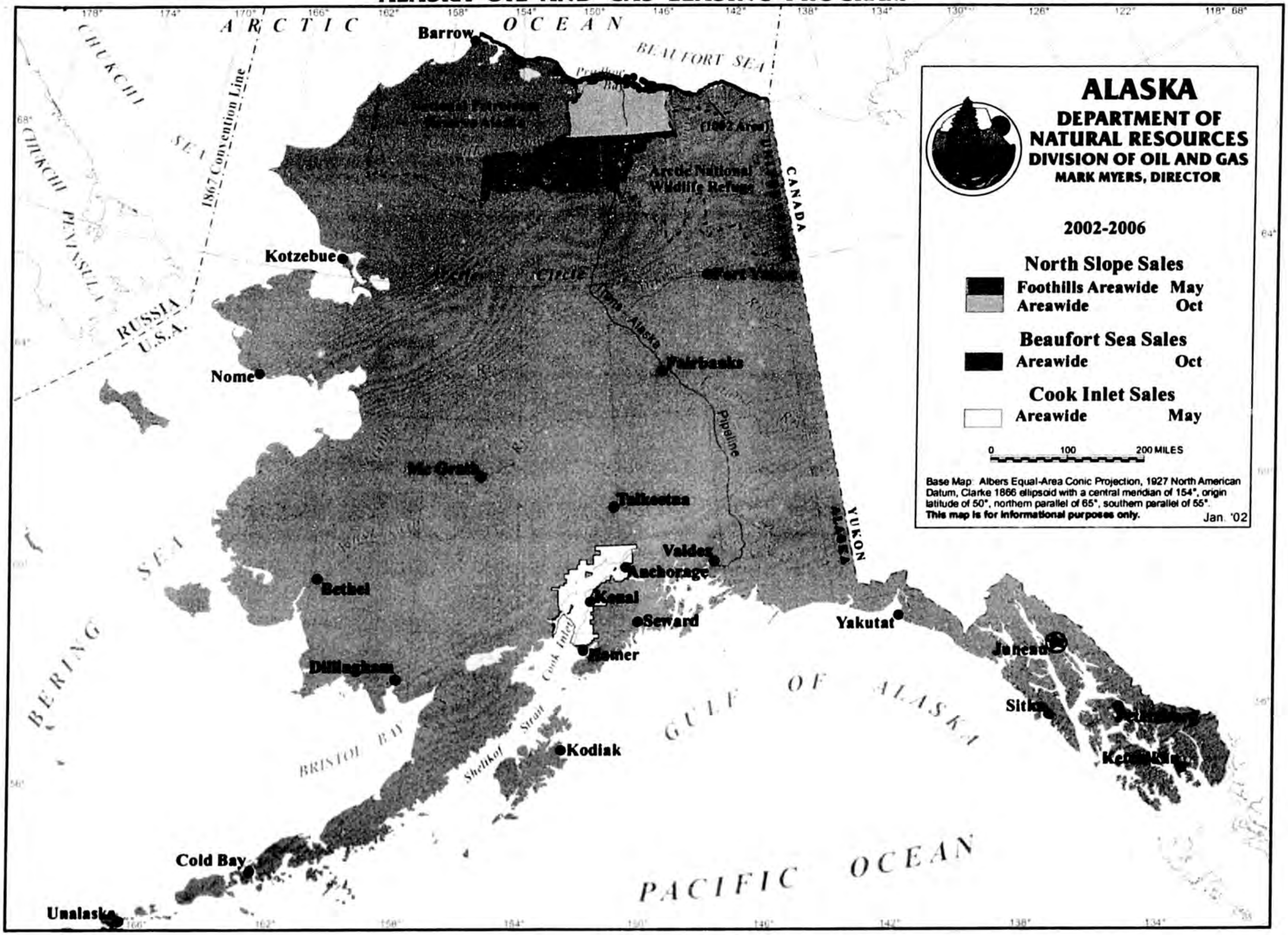


jjh 11/01

CORRECTION

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

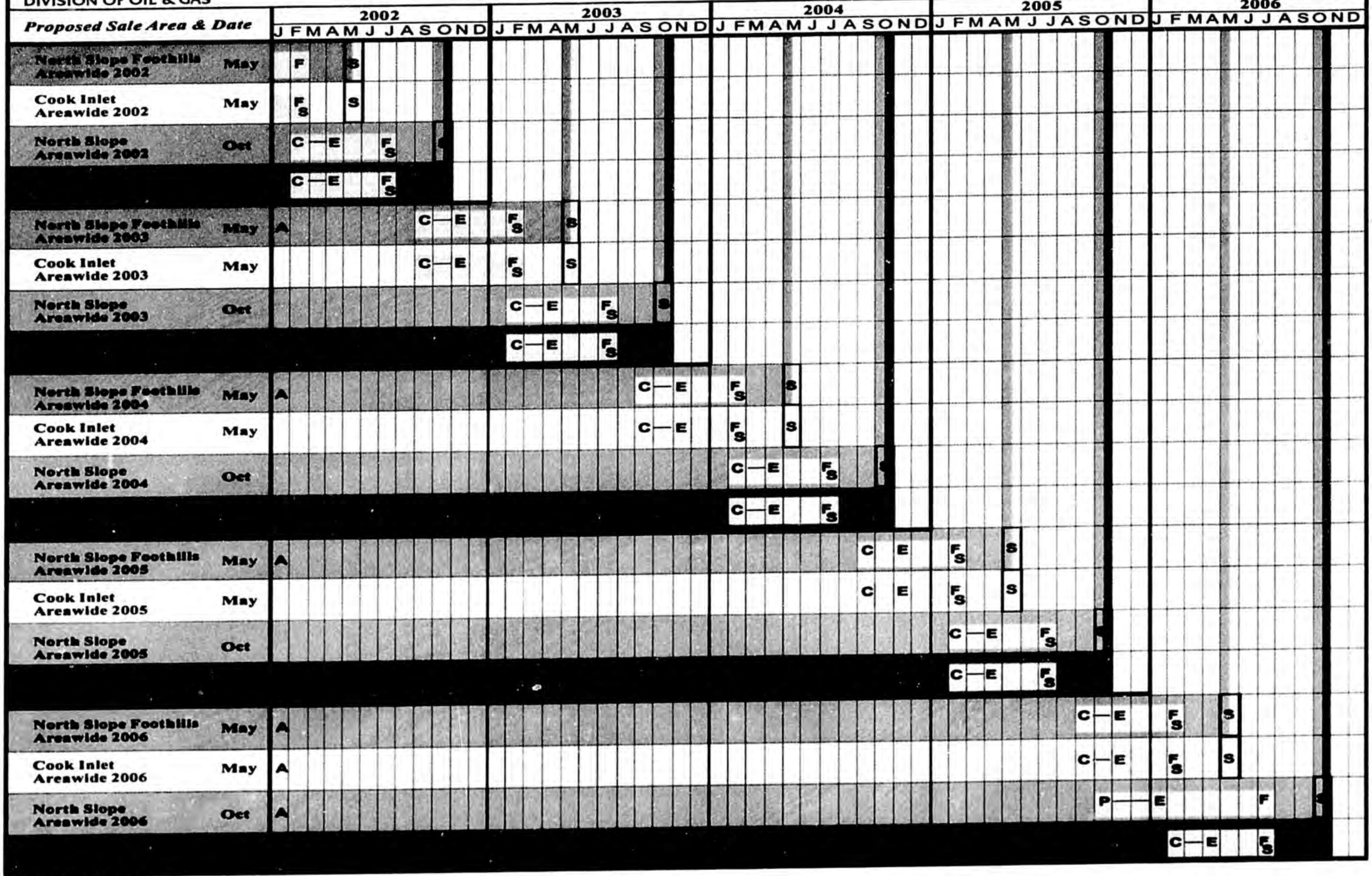
ALASKA OIL AND GAS LEASING PROGRAM



ALASKA
DEPARTMENT OF
NATURAL RESOURCES
DIVISION OF OIL & GAS

FIVE-YEAR OIL AND GAS LEASING PROGRAM
PUBLIC NOTIFICATION SCHEDULE

January
2002



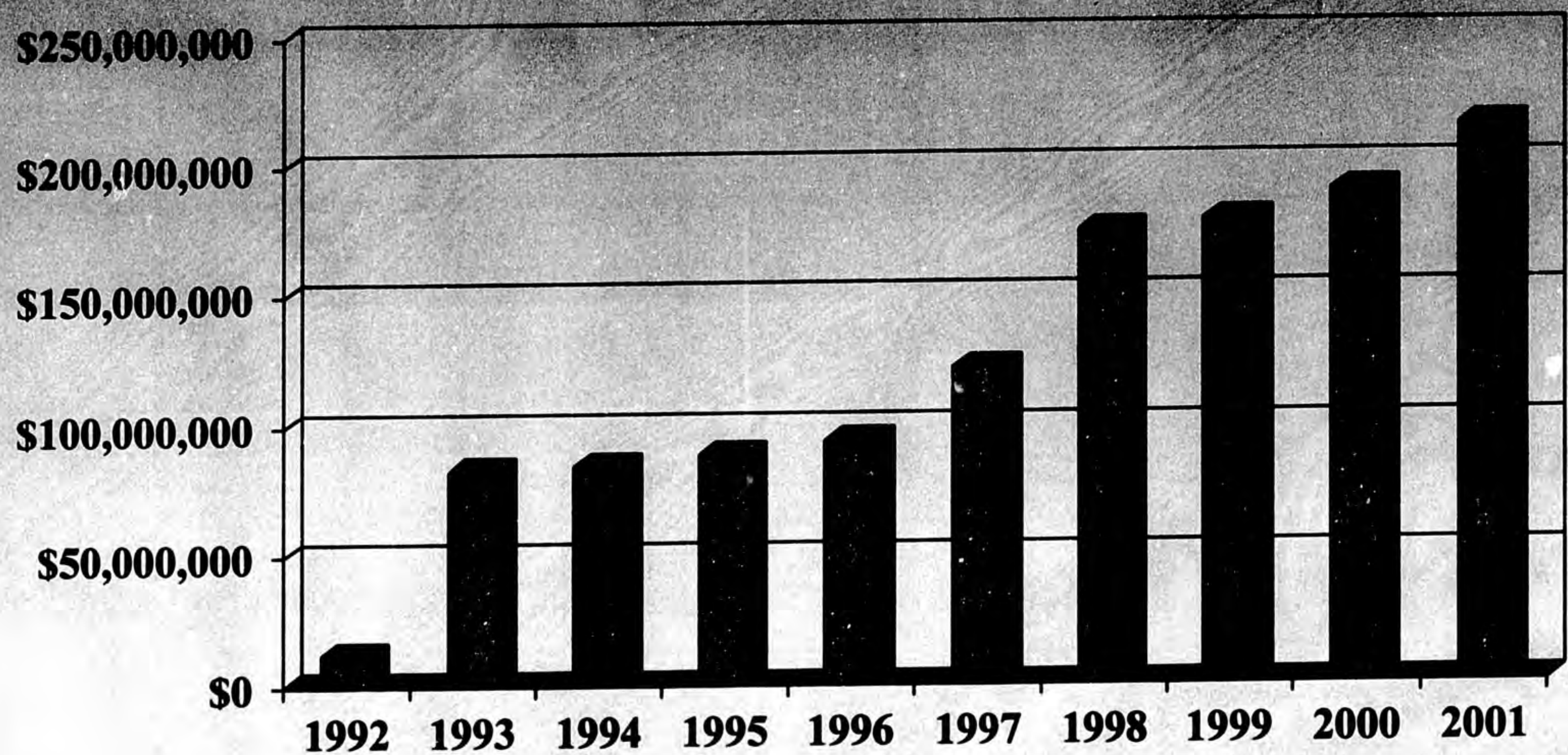
A = Sale Added to Schedule.
C = Call for Comments:
Request for New Information Made Available Since Last Finding.
E = End of Comment Period.
P = Preliminary Best Interest Finding / ACMP Consistency Analysis.

F = Final Finding and Notice of Sale and Terms.
F_S = Supplement to Final Finding and/or Notice of Sale and Terms.
S = Sale.

Public Process

Visit our Website at "www.dog.dnr.state.ak.us/oil"

Cumulative Bonus Bids



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2001 Areawide Lease Sales

Total Acres Leased = 1.6 Million
Total Bonus Bids = $24.5 Million

North Slope Foothills

- Area's First Lease Sale
- Largest State Sale Ever
- 8 Bidding Groups
- 978,560 Acres Leased
- $10.7 Million in Bonus Bids

North Slope

- 16 Bidding Groups (Shell returns after 13 yrs)
- 469,760 Acres Leased
- $7.4 Million in Bonus Bids

Cook Inlet*

- 6 Bidding Groups
- 102,523 Acres Leased
- $928,085 in Bonus Bids

(* Final Results)

Beaufort Sea

- 7 Bidding Groups
- 60,800 Acres Leased
- $5.4 Million in Bonus Bids

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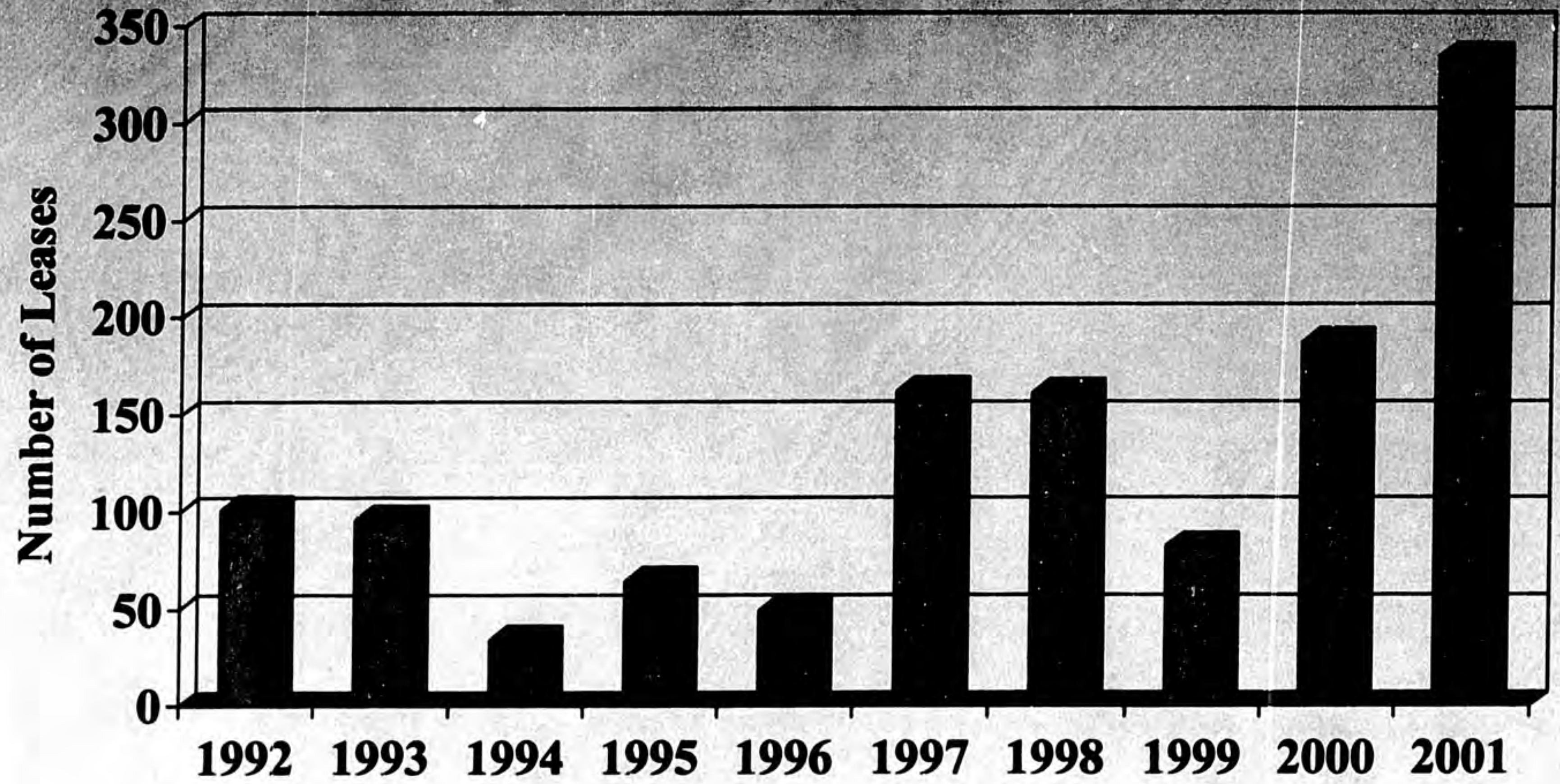
Oil and Gas Leases Sold



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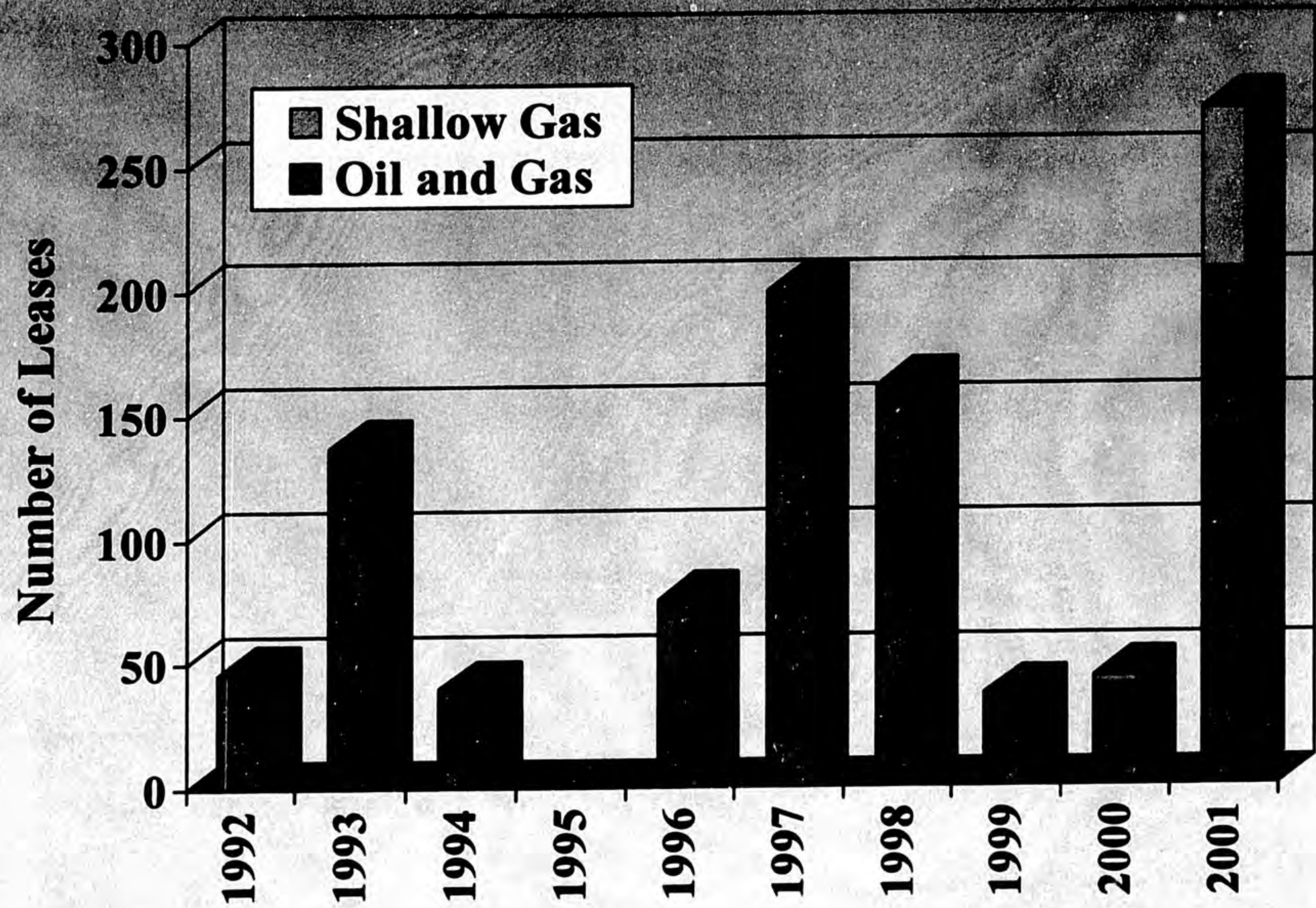
Leases Issued



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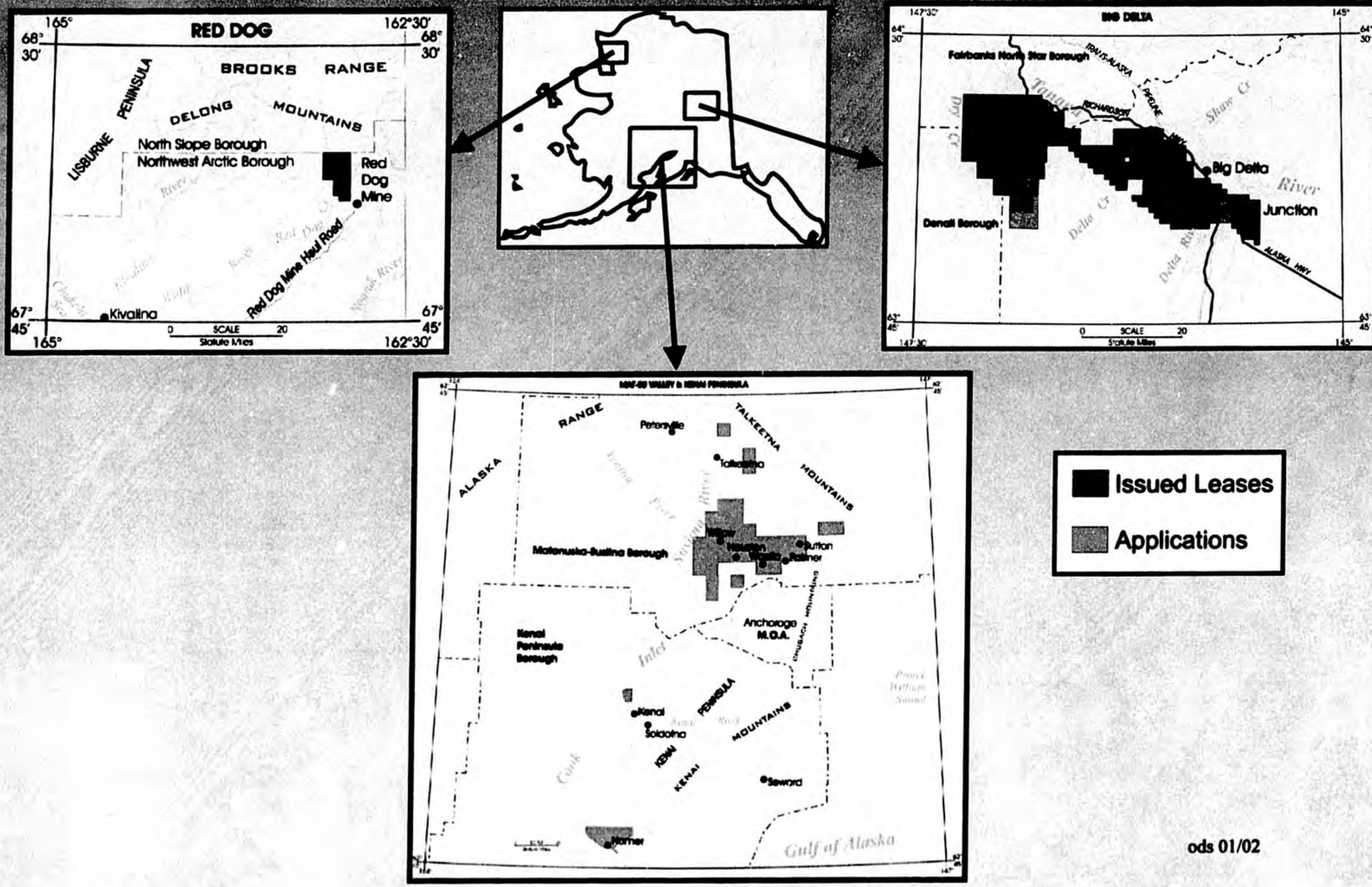
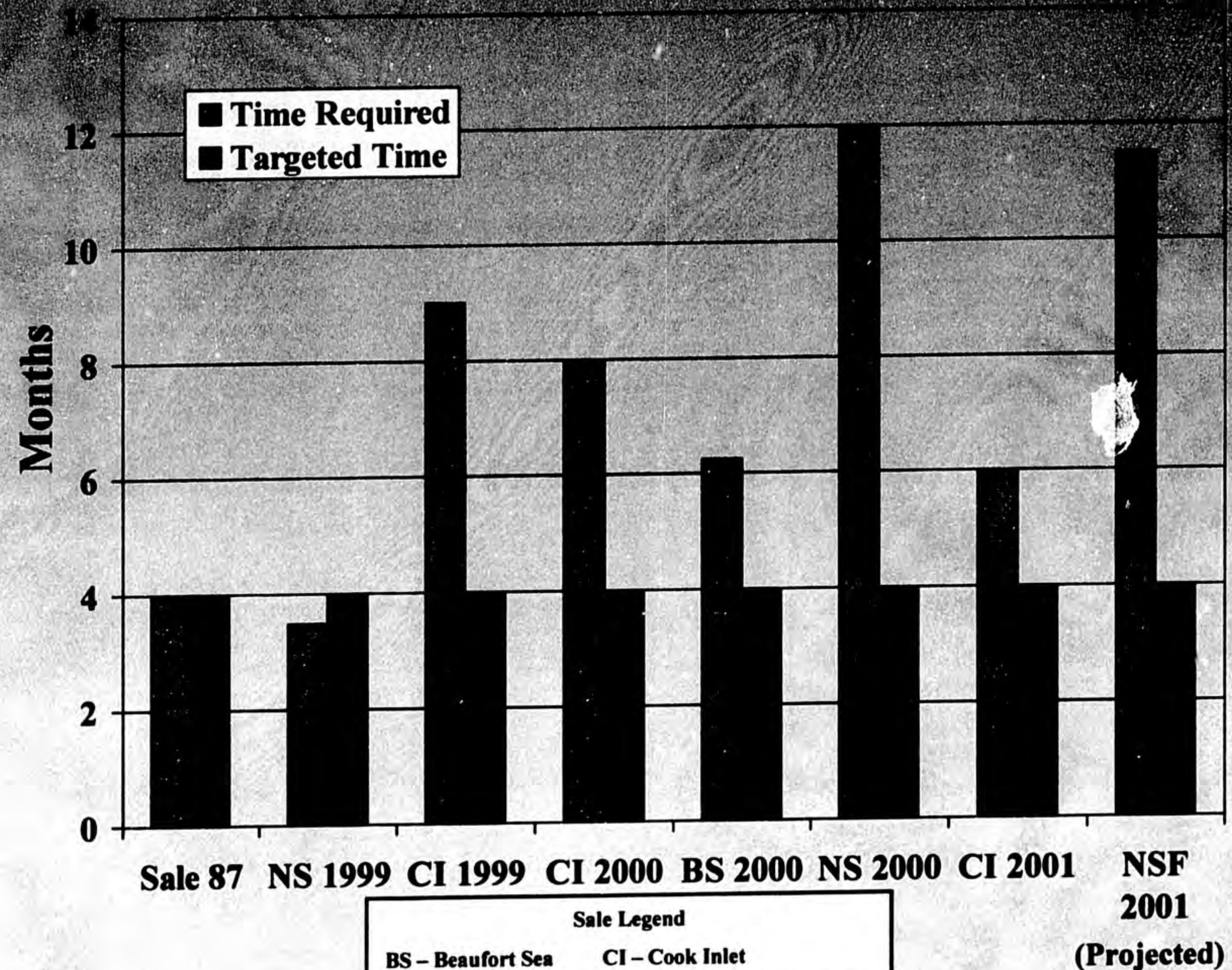
Shallow Natural Gas Leasing



Time Required to Issue



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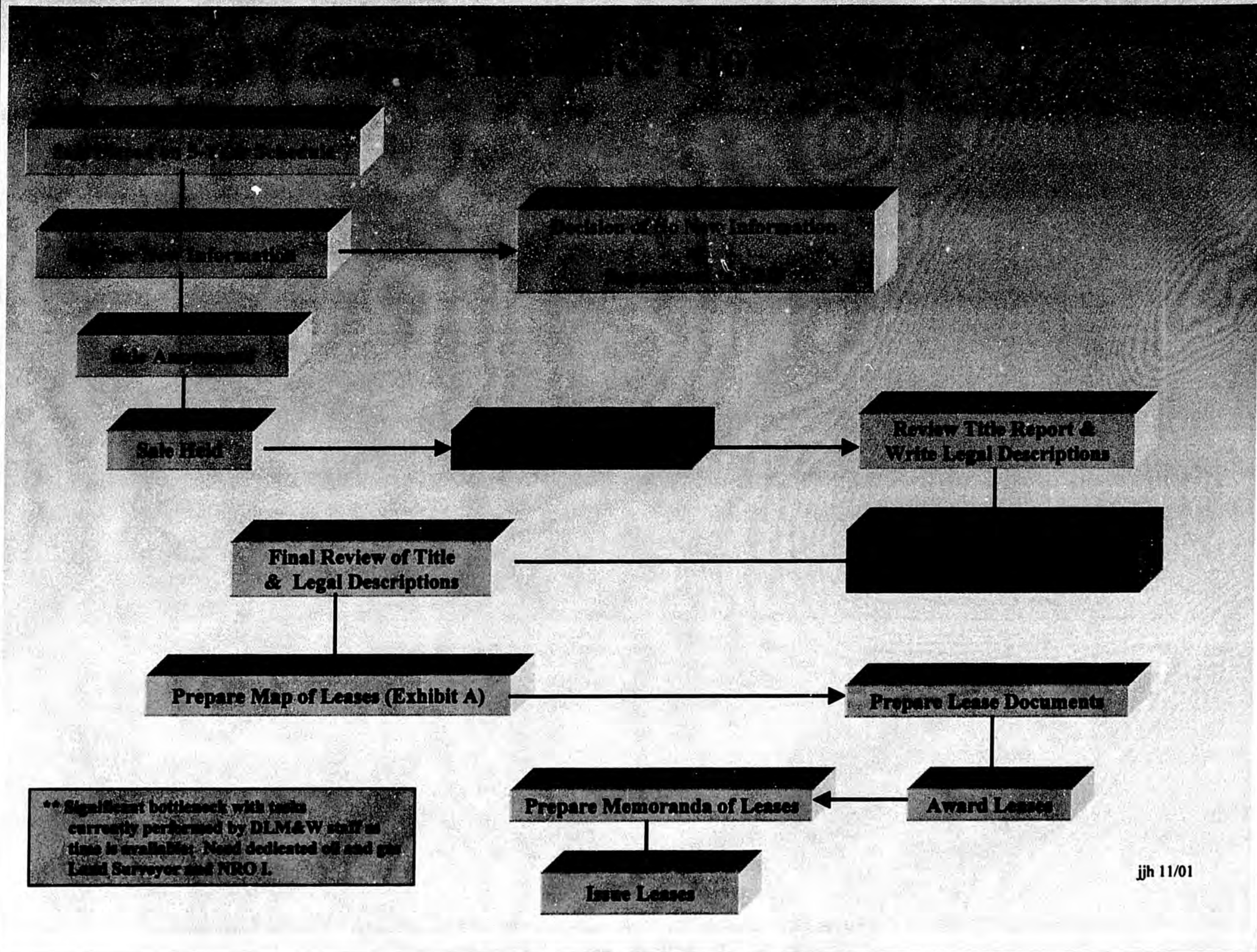
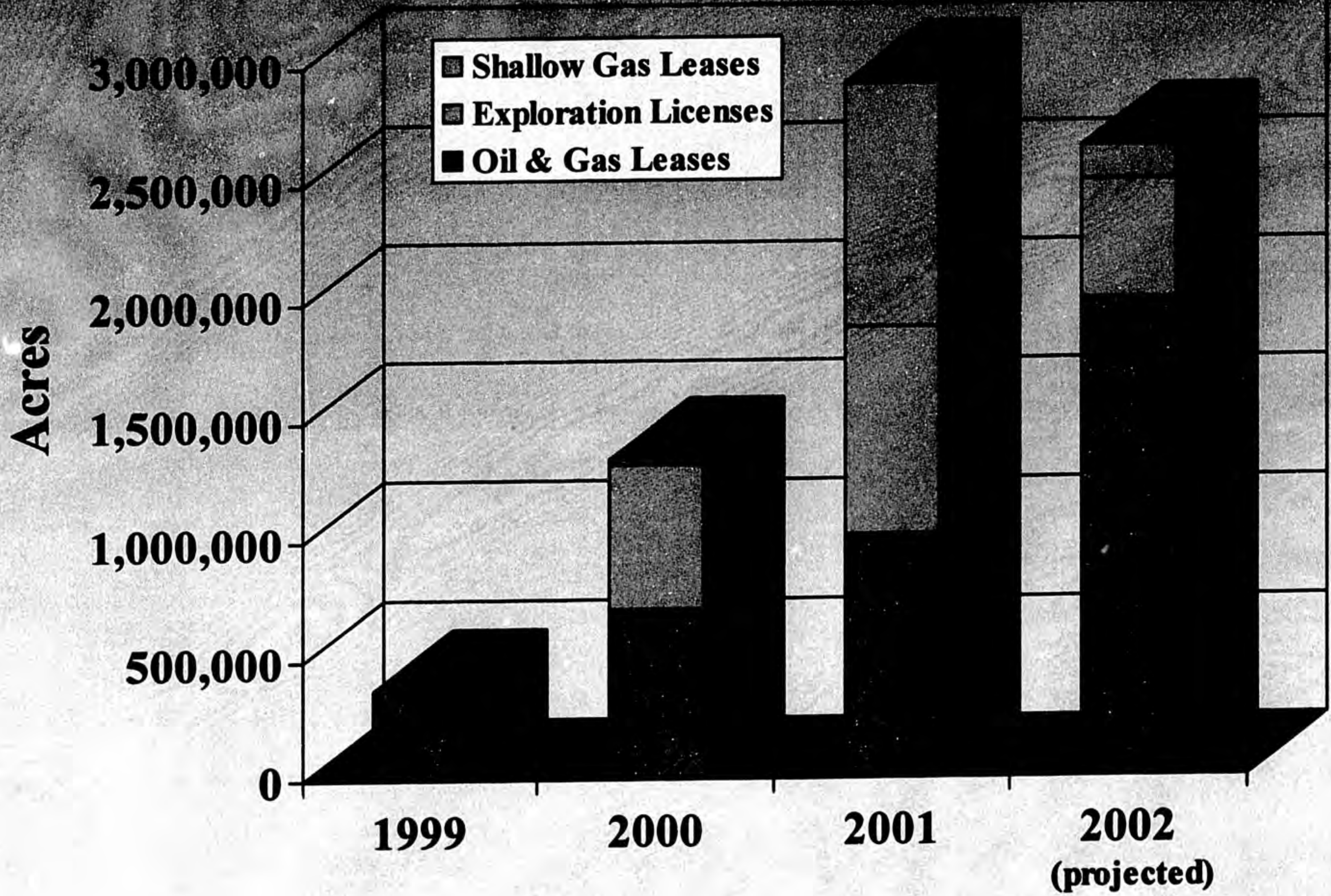


Sale Held
Review Title Report & Write Legal Descriptions
Final Review of Title & Legal Descriptions
Prepare Map of Leases (Exhibit A)
Prepare Lease Documents
Award Leases
Prepare Memoranda of Leases
Issue Leases
** Significant bottleneck with tasks currently performed by DLM&W staff as time is available. Need dedicated oil and gas Land Surveyor and NRO I.
jjh 11/01

Title Work



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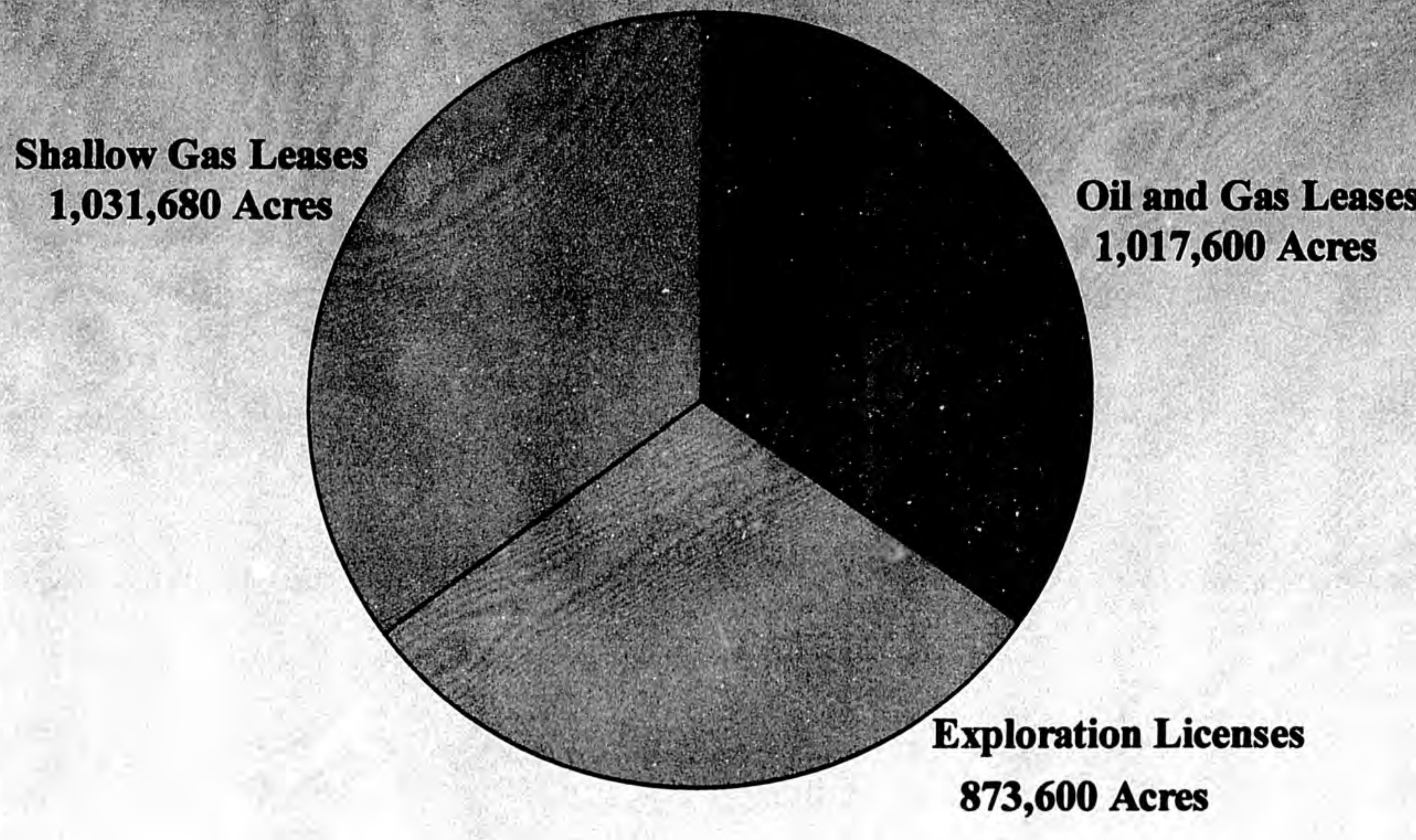
[illegible] Shallow [illegible]
Programs Dramatically Increase Division Workload

2001 Title Work

2,922,880 Acres



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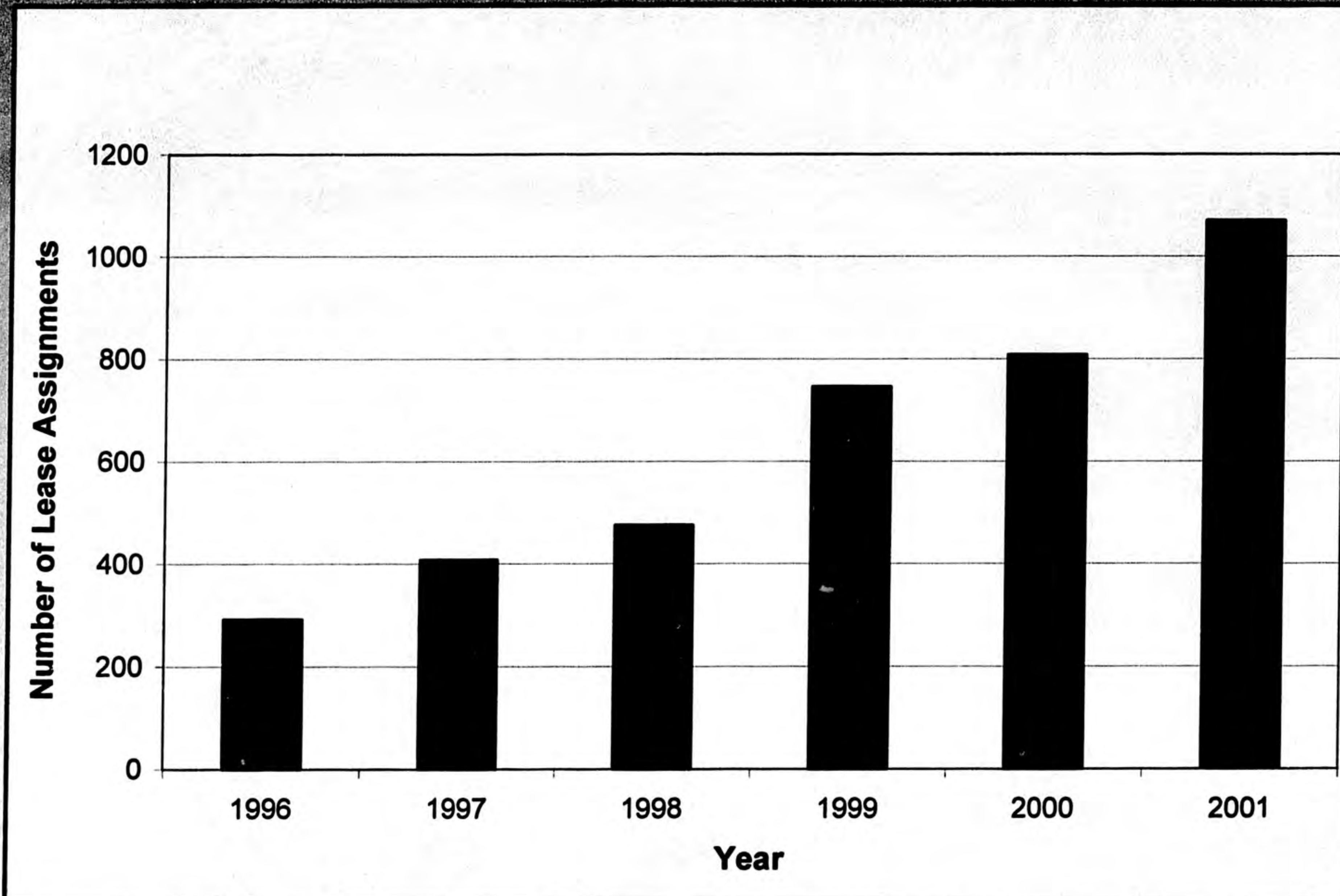
Number of Lease Assignments
0
200
400
600
800
1000
1200
1996
1997
1998
1999
2000
2001
Year

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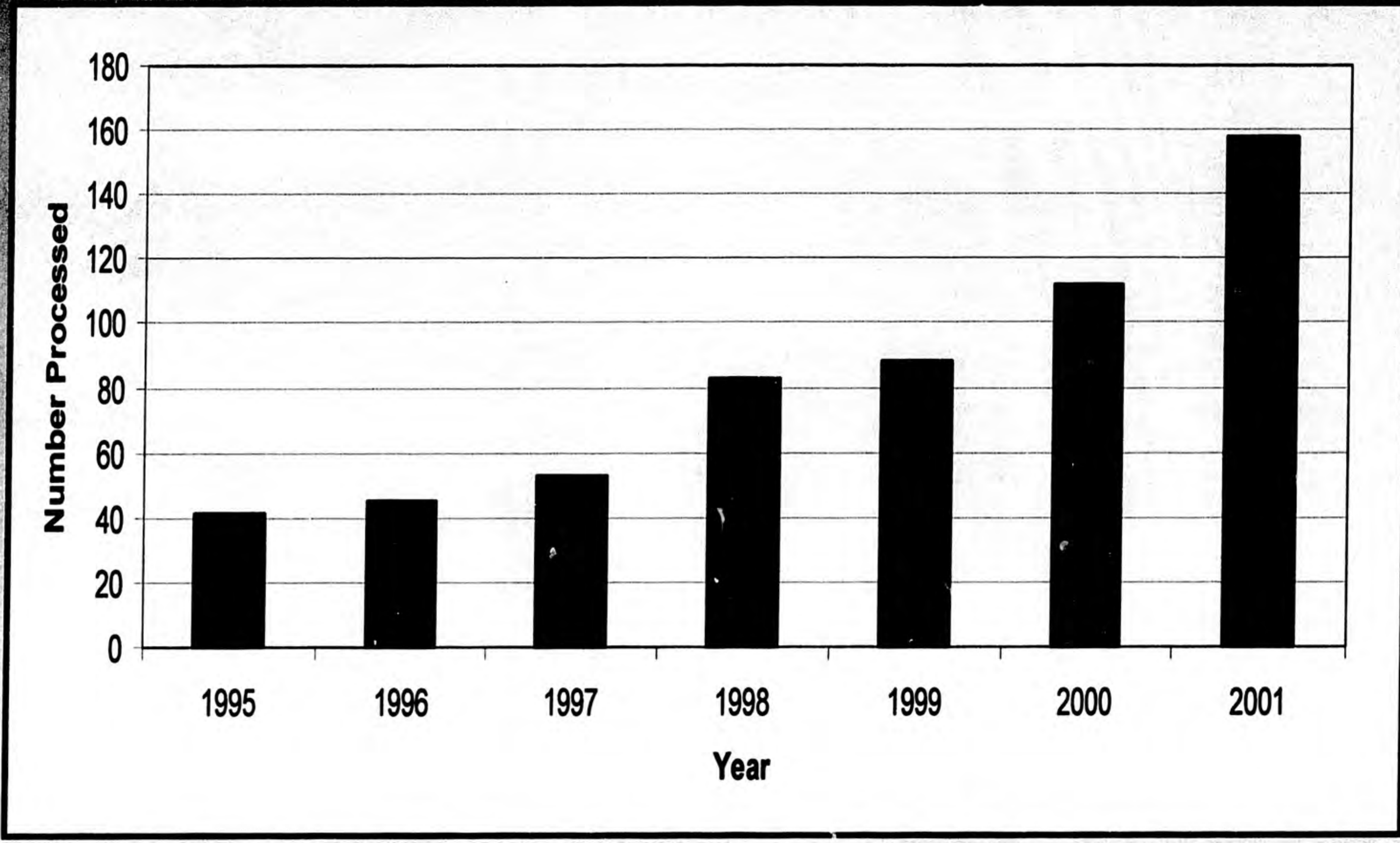

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Actions include Units and Participating Areas formed, expanded, contracted, and terminated; Unit decisions appealed; Unit Plans of Exploration and Development reviewed and approved.

What are the Common
Lease/Unit Administrative Actions?

Unit - Units are groups of leases; units are established to efficiently explore and develop the leases covering one or more potential hydrocarbon accumulations

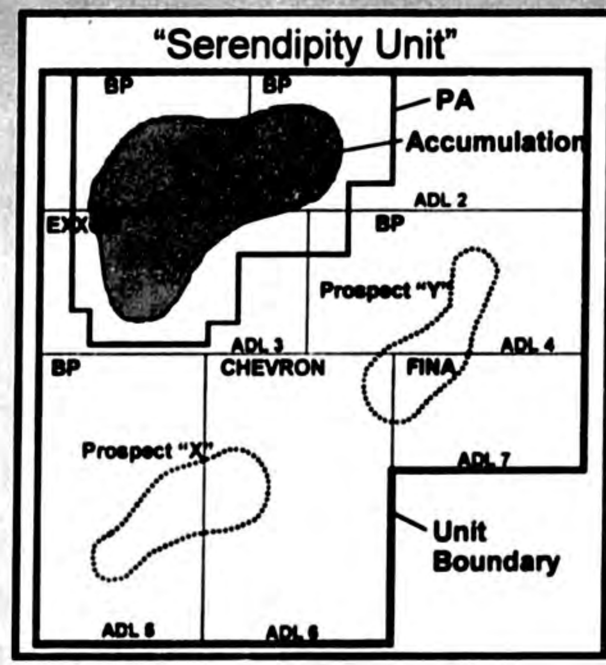
Participating Area (PA) - That portion of leases in a unit which cover a known or estimated accumulation and to which production is allocated via a unit agreement

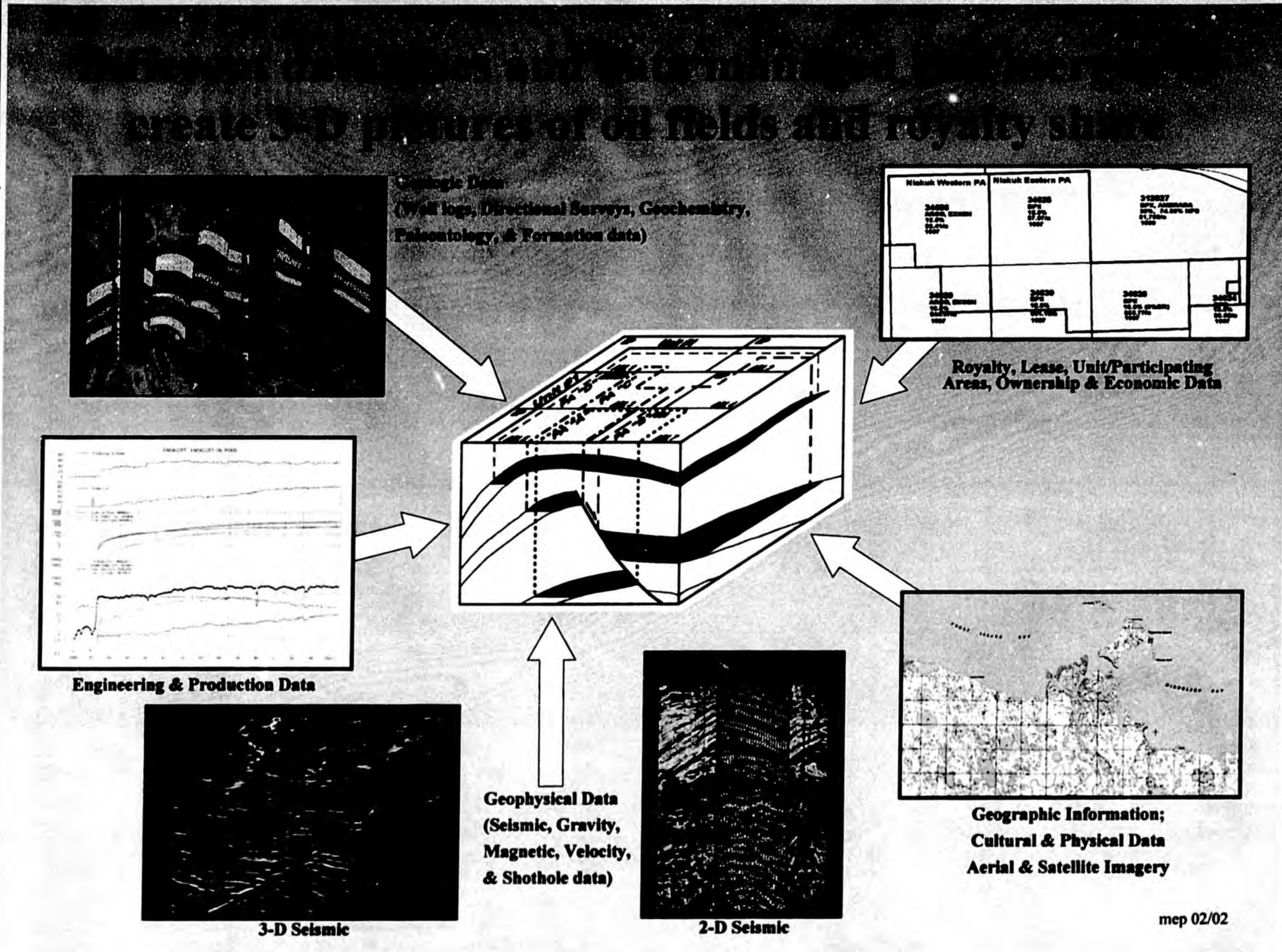
Units Actions:

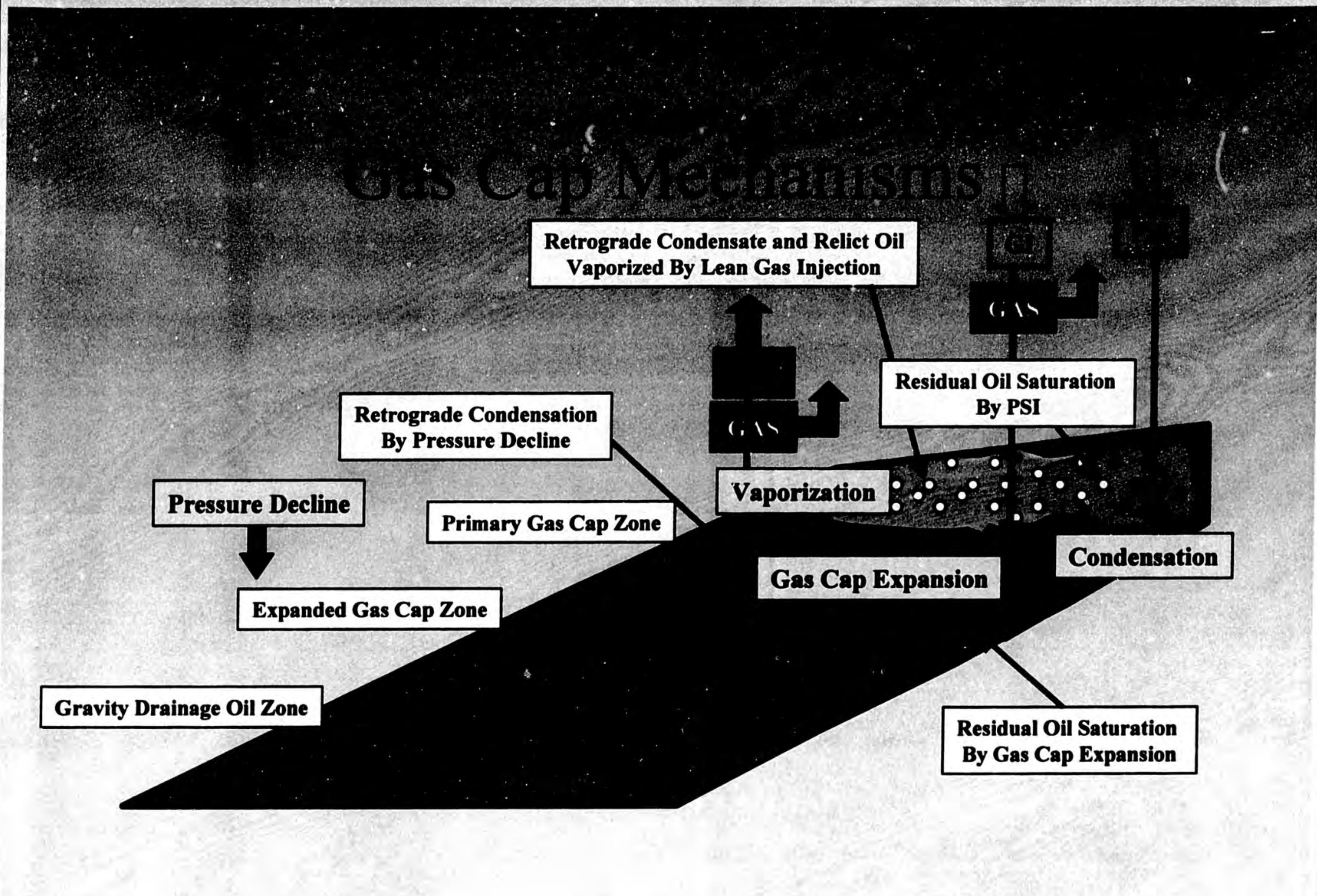
- Initial Formation
- Technical Evaluations - Reservoir Extent, Paying Quantities
- Negotiations - Unit Agreement
- Work Commitments
- Expansions
- Contractions
- Annual Plan of Exploration or Development

Participating Areas:

- Initial Formation
- Technical Evaluations - Commerciality
- Tract Allocation Factors
- Field Costs/Processing Costs
- Gas and Gas Liquids
- Fluid Commingling
- Facility Sharing
- Well Test Allocation
- Expansions
- Contractions
- Annual Plan of Development




create 3-D pictures of oil fields and royalty share
Geologic Data
(Well logs, Directional Surveys, Geochemistry,
Paleontology, & Formation data)
Niakuk Western PA
Niakuk Eastern PA
Royalty, Lease, Unit/Participating
Areas, Ownership & Economic Data
Engineering & Production Data
Geophysical Data
(Seismic, Gravity,
Magnetic, Velocity,
& Shothole data)
Geographic Information;
Cultural & Physical Data
Aerial & Satellite Imagery
3-D Seismic
2-D Seismic
mep 02/02



Gas Cap Mechanisms
Retrograde Condensate and Relict Oil
Vaporized By Lean Gas Injection
GAS
Residual Oil Saturation
By PSI
Retrograde Condensation
By Pressure Decline
Pressure Decline
Vaporization
Primary Gas Cap Zone
Condensation
Gas Cap Expansion
Expanded Gas Cap Zone
Gravity Drainage Oil Zone
Residual Oil Saturation
By Gas Cap Expansion

Figure 4

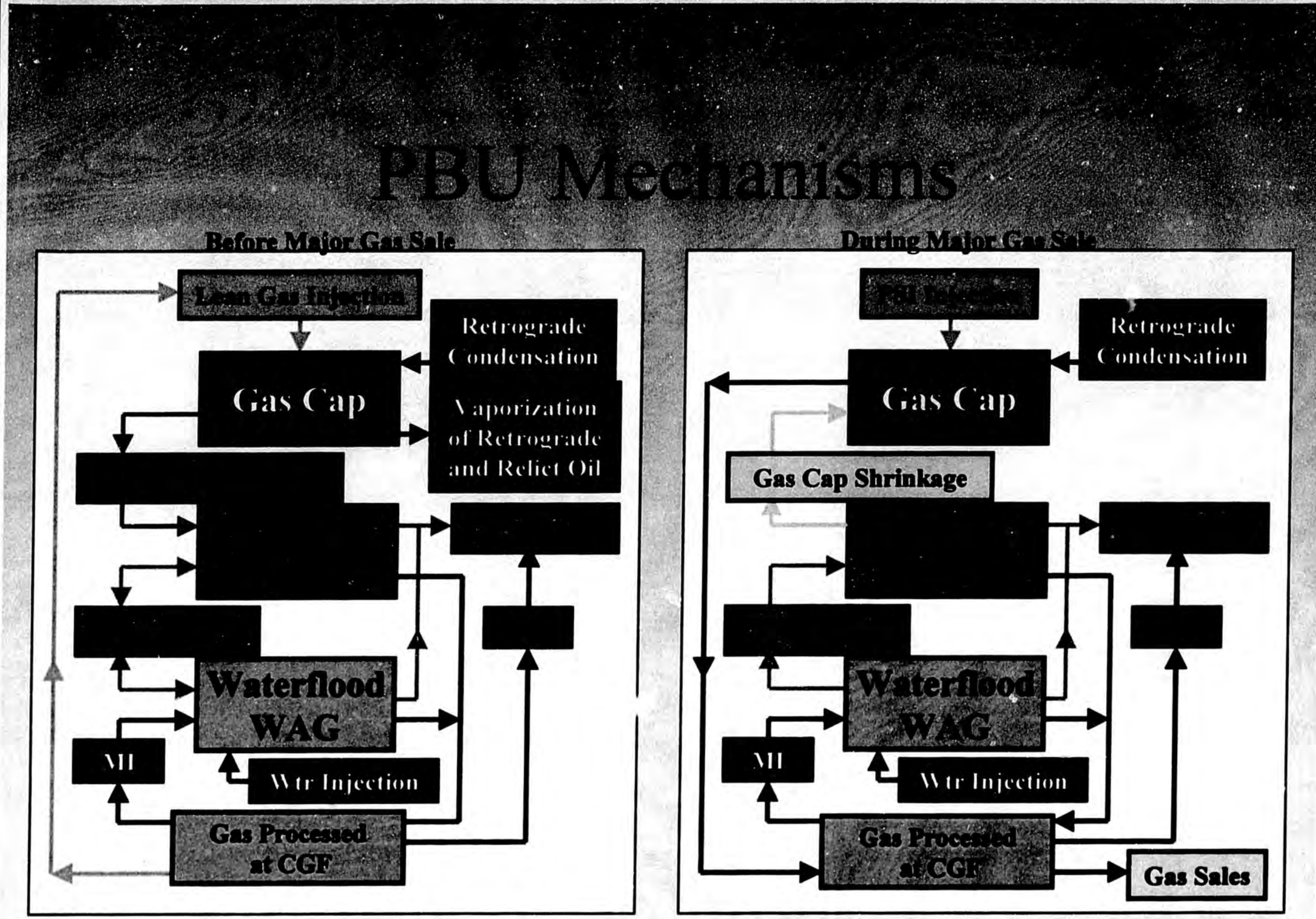
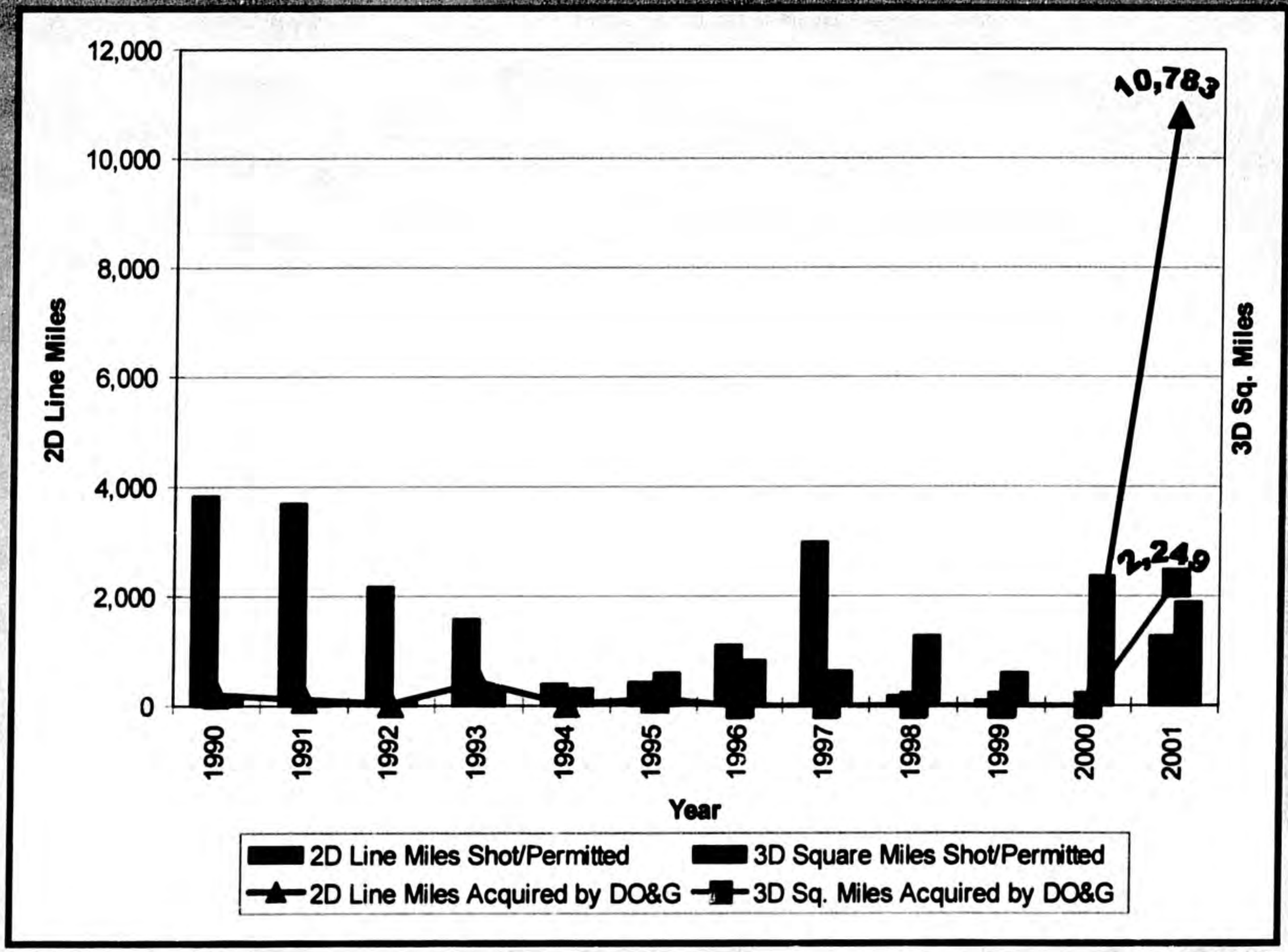

PBU Mechanisms
Before Major Gas Sale
Lean Gas Injection
Retrograde Condensation
Gas Cap
Vaporization of Retrograde and Relict Oil
Waterflood WAG
MI
Wtr Injection
Gas Processed at CGF
During Major Gas Sale
Retrograde Condensation
Gas Cap
Gas Cap Shrinkage
Waterflood WAG
MI
Wtr Injection
Gas Processed at CGF
Gas Sales

Figure 10

Seismic Data Status

1990 - 2001



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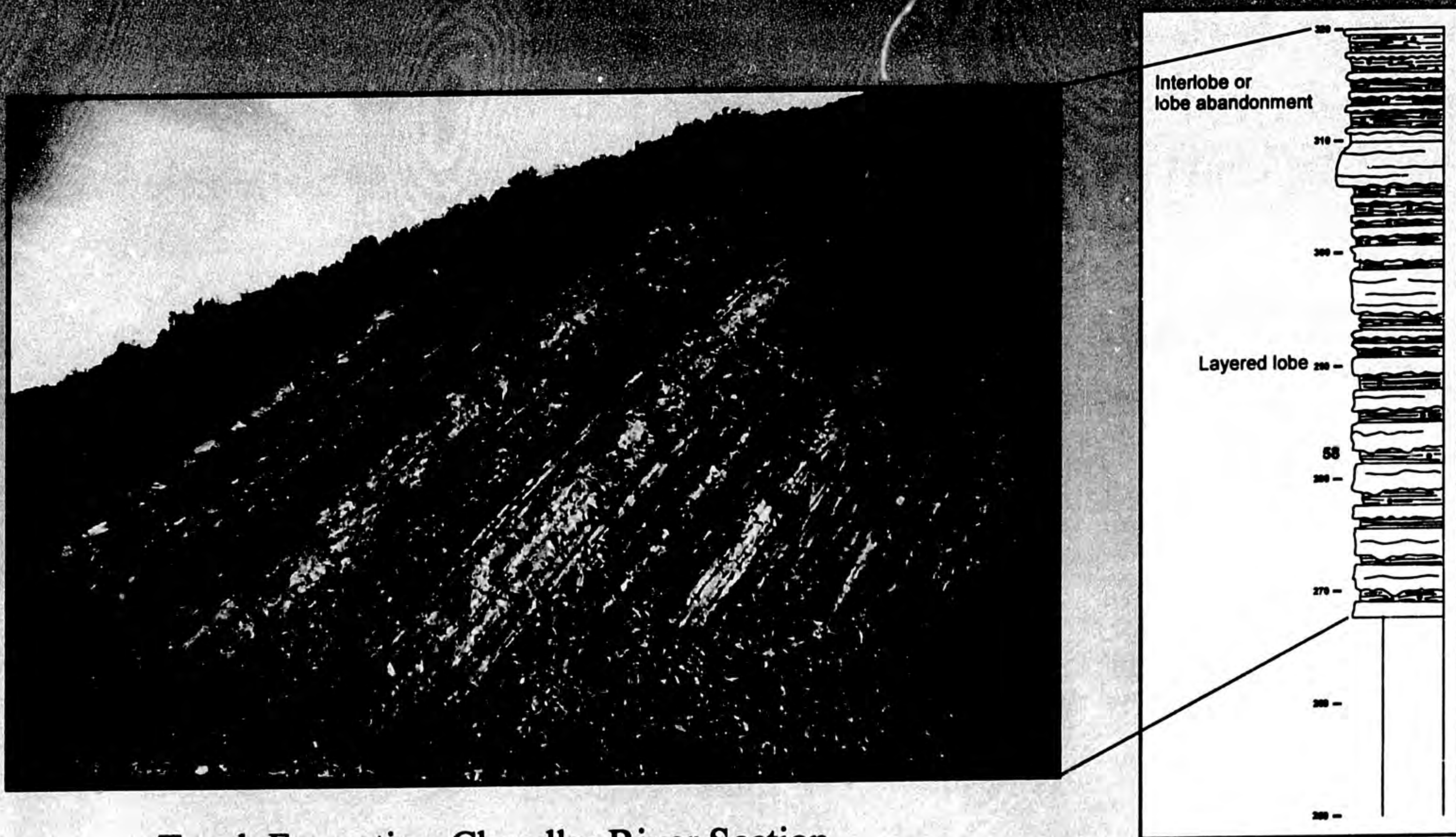
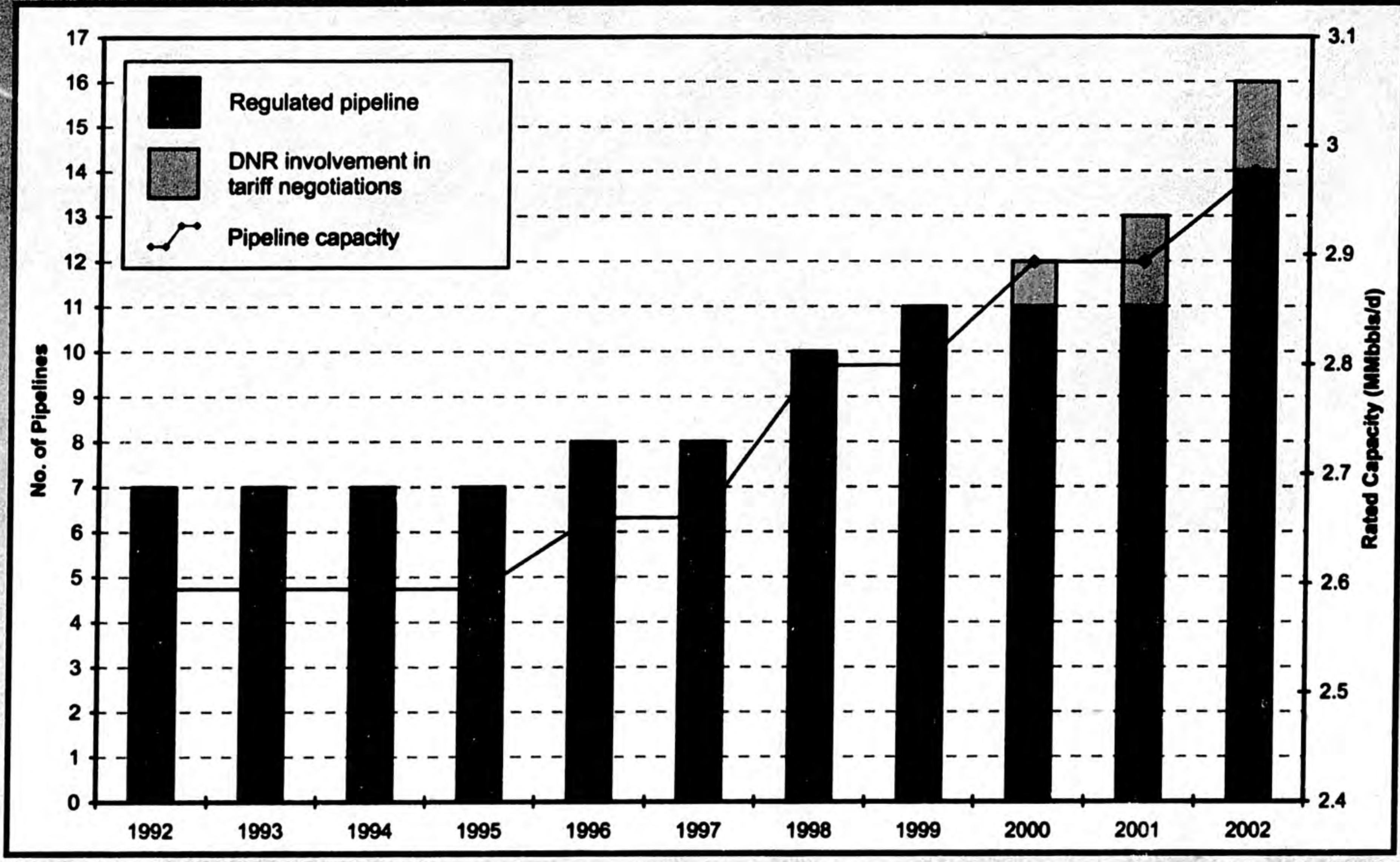
Modified from Phillips Alaska

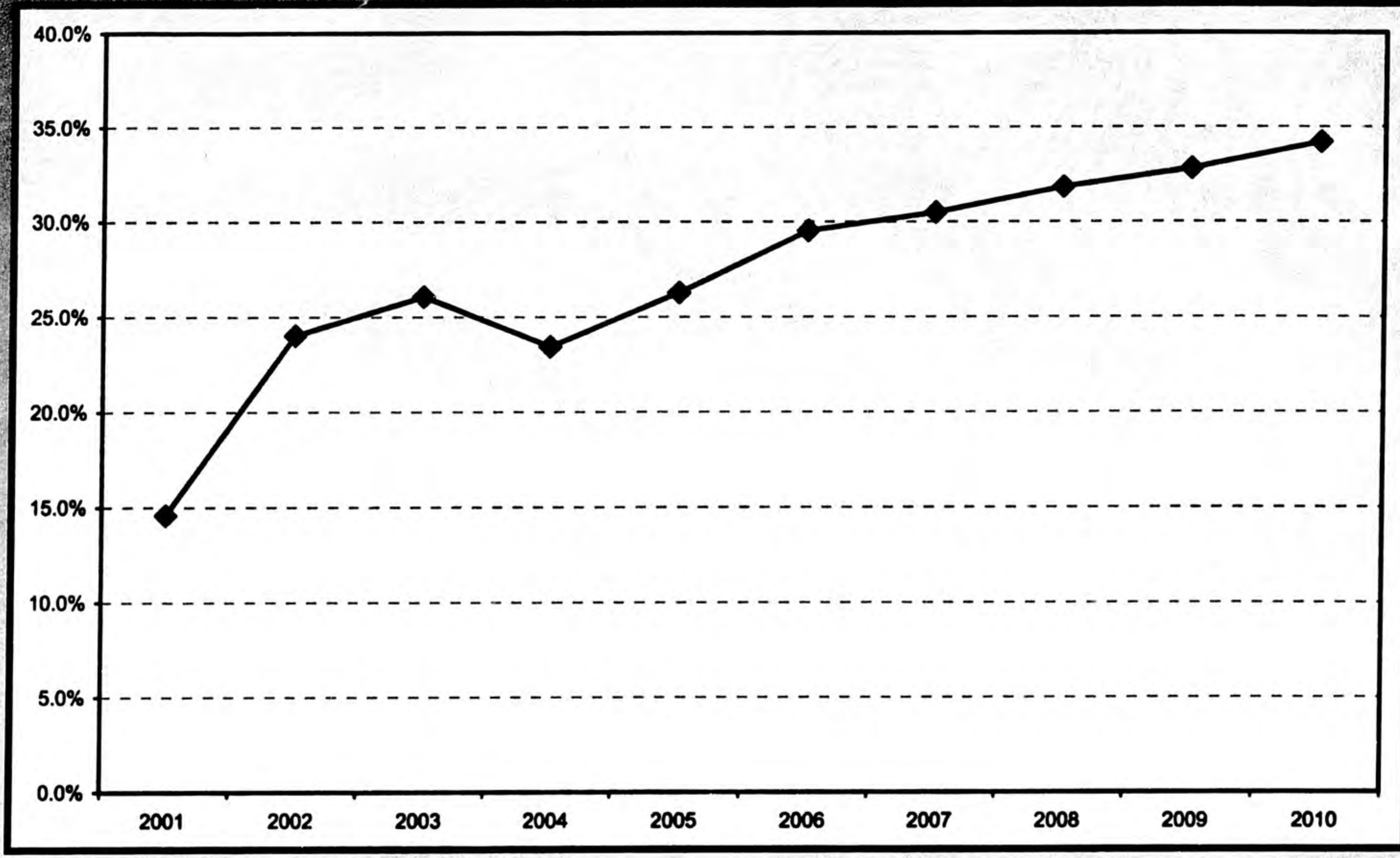


Torok Formation-Chandler River Section



Source: Division of Oil and Gas, January 2002

krb 1/02

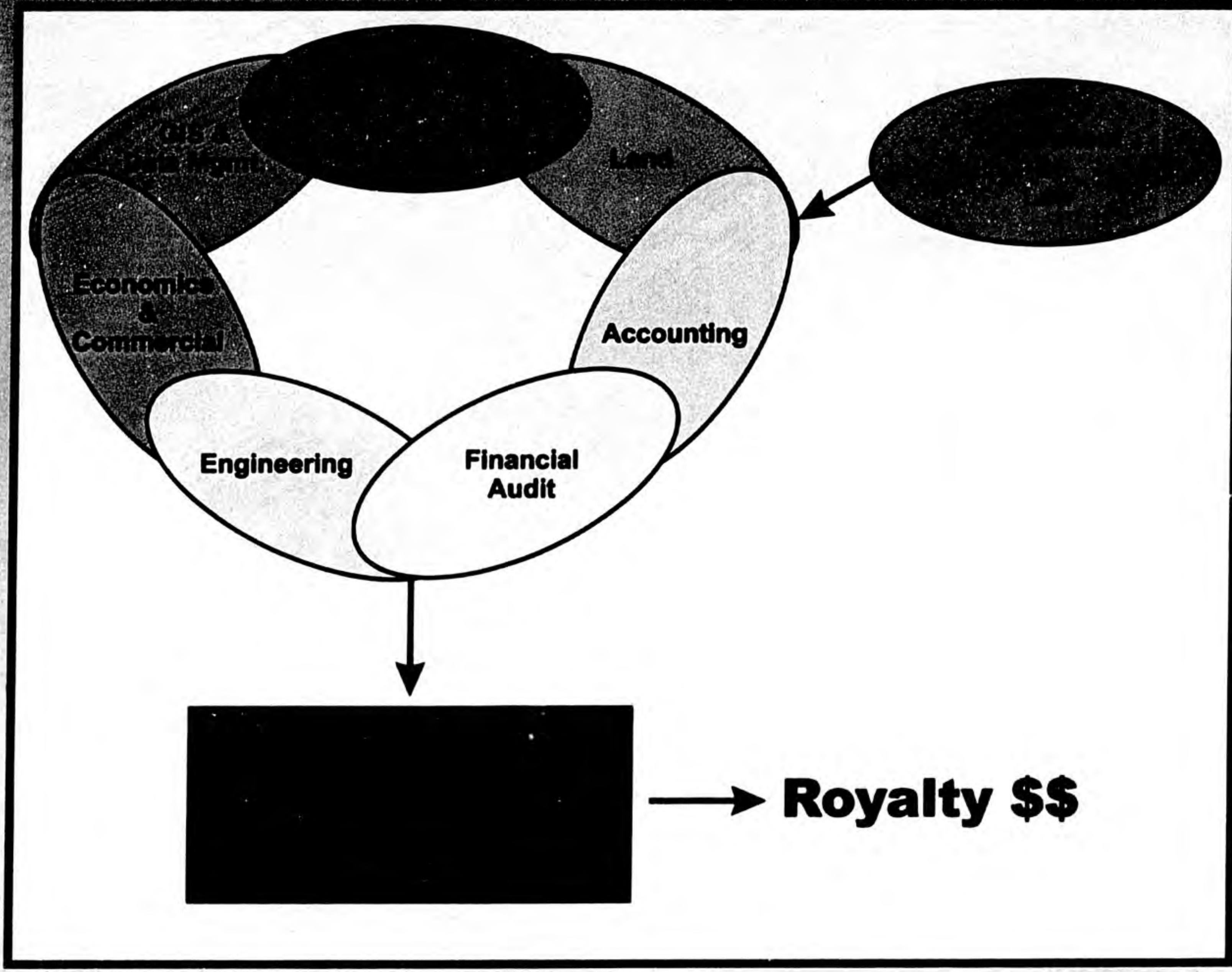


Source: DOR, Revenue Sources Book, Fall 2001

krb 1/02


USGS
ANWR 1002 Area
Wells, Discoveries, & Seismic Data
Hammerhead 1985
Kuvlum 1993
Point Thomson
1977-79
Flaxman Island 1975
Corona 1986
Stinson 1990
Sourdough
1994
Warthog
1997
Belcher 1989
70 15'
KIC 1986
Aurora 1988
Kavik
1969
146°00'
70 00'
144°00'
69°45'
142°00'
Exploration Wells:
Discoveries:
Oil
Public Domain
Gas & Condensate
Tight Hole
Gas
ANWR
1002 Area
0
mi
25
0
km
50
2-D Seismic Grid
1984-1985 Vintage

Bottom Line



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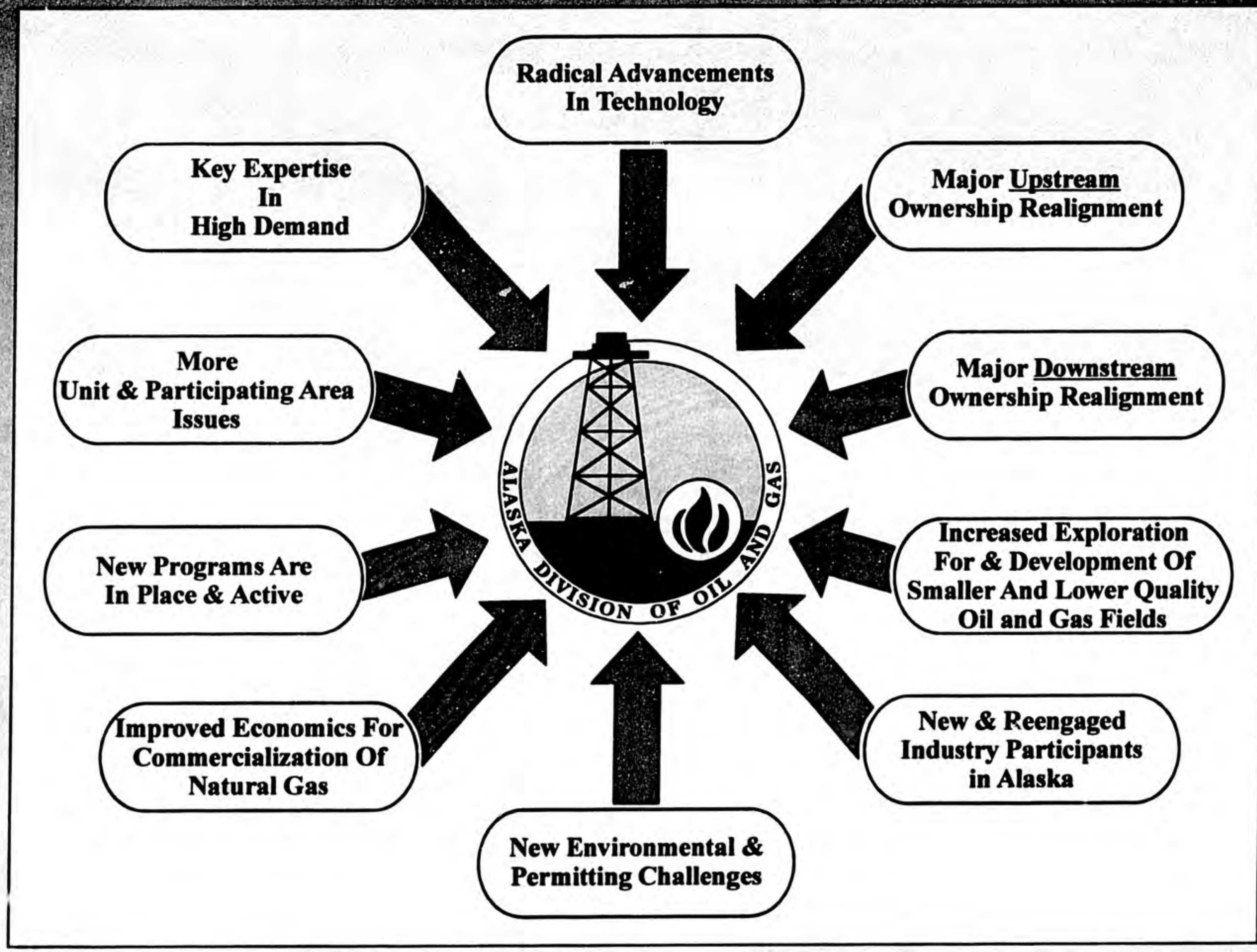
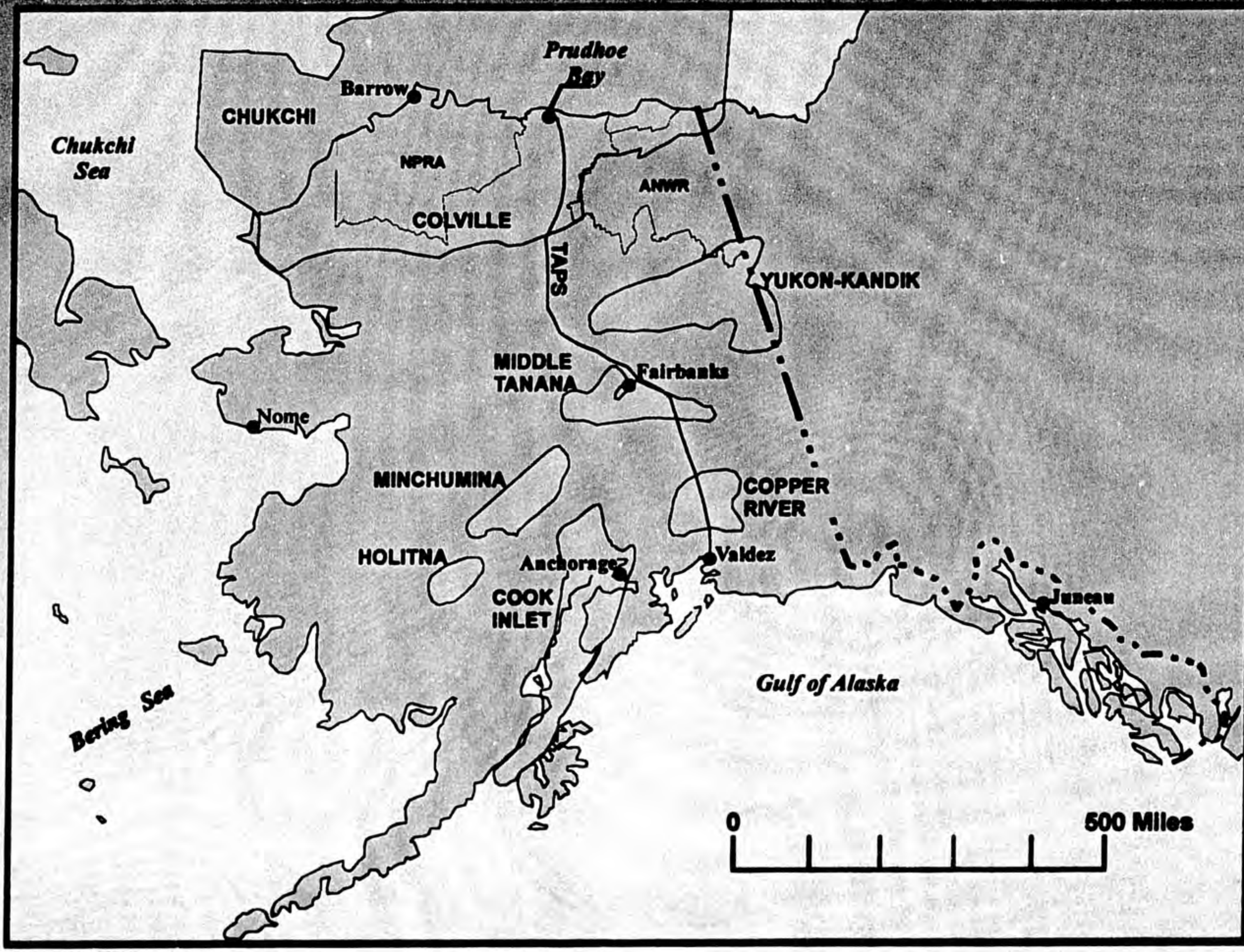
REQUIRE [illegible] of the Division of [illegible]




Prudhoe
Bay
Barrow
CHUKCHI
Chukchi
Sea
NPRA
ANWR
COLVILLE
TAPS
YUKON-KANDIK
MIDDLE
TANANA
Fairbanks
Nome
MINCHUMINA
COPPER
RIVER
HOLITNA
Anchorage
Valdez
COOK
INLET
Juneau
Gulf of Alaska
Bering Sea
0
500 Miles