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ExxonMobil
Production

March 30, 2001

The Honorable Scott Ogan
Alaska State Legislature
State Capitol
Juneau, Alaska 99801-1182
Fax #: (907) 465-3265

Dear Representative Ogan:

Consistent with our March 13 discussion, the attached package contains our responses to the questions that you had submitted to me. I am faxing a copy of this package to you and will also be providing an original by mail.

Commercialization of North Slope gas is obviously very important to ExxonMobil as well as to the State of Alaska. I look forward to continuing to work with you and your committee.

Sincerely,



Robert D. Schilhab

Attachment

Responses to Questions from Alaska State Representative Scott Ogan

1. Please identify all persons participating in and/or assisting in preparing answers to these questions, including their full name, title, and a general description of their contribution to the effort.

As a matter of normal business practice and for security and confidentiality reasons, ExxonMobil does not release the names of individual employees. Questions on Alaska Gas Commercialization should continue to be directed to Robbie Schilhab, Manager, Alaska Gas Development.

2. Please set forth in detail all capital improvements designed, engineered or constructed by or on behalf of EM to facilitate sales of ANS natural gas to unrelated third parties from inception of Prudhoe Bay oil production to the present.

ExxonMobil has diligently pursued commercializing Alaska North Slope gas since start-up of the Prudhoe Bay field. Since 1977 we have spent over \$110 million on specific efforts directed toward gas sales.

From 1977-1991, our efforts primarily focused on a pipeline to the Lower-48 as part of the Alaska Natural Gas Transportation System (ANGTS) project. In spite of significant efforts by our company in conjunction with other companies, the North American gas market could not support the project. The demand for natural gas was insufficient to justify the large capital expenditures required.

In the early 1990's, we investigated the potential offered by using Liquefied Natural Gas (LNG) technology. This work did not indicate that a project could be economically viable in the foreseeable future.

More recently, we have been looking at the application of ExxonMobil's Gas-to-Liquids conversion technology in Alaska. Through the use of this technology, gas would be converted into high quality liquids, such as diesel and naphtha, and moved through the existing TAPS oil pipeline to Valdez. The products would be fractionated and shipped to customers in Alaska and around the world. ExxonMobil plans to continue its research efforts to further improve its gas-to-liquids technology and will continue to evaluate its application in Alaska.

Today, with the improving longer-term demand outlook for the North American gas market, we are working with BP and Phillips to evaluate and progress a pipeline project to serve Lower-48 gas markets. Details concerning this joint work effort were reviewed with the House Oil and Gas Committee on February 8, 2000.

3. Please describe in detail any and all efforts undertaken by or on behalf of EM to develop ANS natural gas reserves not associated with existing oil producing fields, including without limitation, Point Thomson.

ExxonMobil has, and is, assessing the possibility of sales from Point Thomson in conjunction with sales from Prudhoe Bay. More detail on our efforts to develop the Point Thomson resource is included in the Plans of Development (POD) that are on file with the DNR.

4. Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of EM to locate and develop domestic markets for ANS natural gas.

In the 1970's, Exxon worked extensively with a number of North American pipeline companies to develop the ANGTS pipeline to the Lower-48. In the late 1970's, Exxon signed sales contracts with several pipeline companies committing all of Exxon's gas that would be transported through the ANGTS pipeline. Those contracts subsequently were cancelled, as the North American gas market could not support the project. The demand for natural gas was insufficient to justify the large capital expenditures required.

We have been looking at the application of ExxonMobil's Gas-to-Liquids conversion technology in Alaska. Such technology would produce a high quality diesel product that could serve the West Coast diesel market.

Currently we are working with BP and Phillips to evaluate and progress a pipeline project to serve Lower-48 gas markets. We are working to develop a project that can provide gas to the Lower-48 that can compete with alternate sources of energy.

5. Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of EM to locate and develop international markets for ANS natural gas.

We have investigated the potential offered by using Liquefied Natural Gas (or LNG) technology. That work did not encourage us that such a project could be economically viable in the foreseeable future. We continue, however, to analyze these markets to understand potentially changing conditions.

6. Please identify (full name, title, address and telephone number) the officers and employees whose primary duties and responsibilities have included marketing and sales of ANS natural gas.

As a matter of normal business practice, ExxonMobil does not release the names of individual employees.

7. Please provide an organizational chart for the EM marketing department, identify the positions dedicated to marketing and sales of ANS natural gas, and indicate the persons currently holding such positions.

As a matter of normal business practice, ExxonMobil does not release its organization charts and the names of individual employees.

- 8-14. Please identify potential customers for international sales of ANS natural gas, sales of ANS natural gas in Asia, sales of natural gas in Canada, sales of ANS natural gas in Mexico, domestic sales of ANS gas, sales of ANS natural gas in California, and sales of natural gas in the mid-west region of the United States.

International customers include natural gas distributors, major industrial users, and major electrical power generators. More detail on potential customers in specific countries is available from comprehensive information published by the U.S. Department of Energy, the International Energy Agency, and the Canada National Energy Board on the following websites:

- <http://www.eia.doe.gov/emeu/cabs/contents.html>
- <http://www.iea.org/weo/index.htm>
- <http://www.energy.gov>
- <http://www.neb.gc.ca>

Natural gas in the U.S. is purchased by numerous local distribution companies and power companies, as well as industrial, commercial, and residential customers. More detail on regional markets and customers is available from comprehensive information published by the U.S. Department of Energy and the Federal Energy Regulatory Commission on the following websites:

- <http://www.eia.doe.gov/emeu/cabs/usa.html>
- http://www.ferc.fed.us/online/gas/Index_of_Customers
- <http://www.eia.doe.gov/emeu/states.html>

15. With respect to responses to questions 8-14, please describe with specificity all efforts, initiatives and programs undertaken by or on behalf of EM to market, sell, solicit bids to purchase (including public and obvious declarations of a willingness to sell significant quantities of ANS natural gas, whether conditioned or unconditioned, at clearly stated prices and terms) or otherwise to actively cultivate and encourage interest in and from potential developers of a project to transport and sell ANS gas to buyers or customers in any prospective market.

ExxonMobil continues to pursue all viable opportunities to commercialize its ANS gas resources and continues to meet with parties seeking to purchase ANS natural gas. For instance, in the late 1970's Exxon signed sales contracts with several pipeline companies committing all of Exxon's gas that would be transported through the ANGTS pipeline. Those contracts subsequently were cancelled, as the North American gas market could not support the project. The demand for natural gas was insufficient to provide a natural gas price that would justify the large capital expenditures required. ExxonMobil has maintained contact with the market and continued to pursue other potential opportunities to commercialize its gas, including LNG and GTL technologies.

16. 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.

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

obtained from customers located in Taiwan, South Korea and/or Japan. If EM contends its LNG pricing is confidential and/or proprietary, then provide any price data EM has obtained or developed from third party sources or indices that are not subject to contractual confidentiality provisions.

Data from the Japanese Government indicates that the monthly average price for LNG sold in Japan over the last 3 years ranged from a low of \$2.71 per million BTU to a high of \$5.11 per million BTU.

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

ExxonMobil continues to pursue all viable opportunities to commercialize its ANS gas resources and continues to meet with parties seeking to purchase ANS natural gas. For instance, in the late 1970's Exxon signed sales contracts with several pipeline companies committing all of Exxon's gas that would be transported through the ANGTS pipeline. Those contracts subsequently were cancelled, as the North American gas market could not support the project. The demand for natural gas was insufficient to provide a natural gas price that would justify the large capital expenditures required. ExxonMobil has maintained contact with the market and continued to pursue other potential opportunities to commercialize its gas, including use of LNG and GTL technologies.

23. Please provide an estimate of the estimated cost of permitting an overland gas pipeline from the ANS to the lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting the estimate.

We do not have such estimates. Permitting is one of the areas that the joint ExxonMobil/BP/Phillips team will be working on assuming a commercial project can be defined.

24. Please provide an estimate of the time necessary to permit an overland pipeline from the ANS to the lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting each estimate.

We do not have such estimates. Permitting is one of the areas that the joint ExxonMobil/BP/Phillips team will be working on assuming a commercial project can be defined.

25. Does EM believe that current lower 48 natural gas prices are sustainable, and if not, what average annual price does EM anticipate over the next five years? Ten years?

ExxonMobil does not release its proprietary price outlooks. However, public forecasts can be obtained from the U.S. Department of Energy or from a number of consultants.

26. Has EM abandoned the prospect of a large scale GTL project in Alaska?

No, ExxonMobil has not abandoned the prospect of a large scale GTL project in Alaska.

27. If EM contends it has not abandoned the prospect of a large scale GTL project in Alaska, please describe in detail all of the efforts currently being undertaken to bring such a project to fruition.

ExxonMobil continues to make significant investments in GTL research and will continue to evaluate its application to Alaska.

28. Has EM made a decision regarding the most cost-effective route for an overland pipeline from the ANS through Canada to the lower 48 states? If so, please describe the route and the economic assumptions underlying the cost analysis.

We have not selected a route. At this stage, it is important to consider the costs, benefits, and environmental impacts of all potential routes. By examining all options, we can help ensure that a project will provide the best value to leaseholders as well as the State of Alaska and its citizens. We are working to better understand which is the environmentally preferred route, considering length, footprint, local environmental sensitivities, and other factors. In addition, it is essential that an eventual project be economically viable and competitive with other potential gas supplies.

29. Governor Knowles has publicly set a goal to break ground for an ANS gas commercialization project in two years. Please comment on the feasibility of achieving this goal, and what contribution EM is willing to make thereto.

We are encouraged by the Governor's interest in aggressively pursuing an economically feasible gas pipeline project. However, ExxonMobil has not established a timeline for the project. ExxonMobil has joined with BP and Phillips in a work program to evaluate and progress a pipeline and timing will be one of the issues considered. Details concerning this joint work effort were reviewed with the House Oil and Gas Committee on February 8, 2000.

30. Assuming EM supports an overland pipeline to the lower 48, specifically the Alcan route, does EM intend to negotiate to acquire Foothills' pre-existing governmental approvals, or to commence an independent permitting effort?

The joint ExxonMobil, BP, Phillips team will be looking at the costs and benefits of several routes. No decisions have been made on how best to approach permitting.

31. Please set forth all of the perceived impediments to the so-called over-the-top route, submerged in the Beaufort sea, emerging on uplands in the Canadian Northwest Territory, and traversing the McKenzie Delta and valley regions. Include environmental and political impediments.

This is an area that the joint ExxonMobil, BP, Phillips work team will be evaluating.

32. Please list all of the contracts, excluding any confidential provisions, that EM has entered into or has interest in, since the inception of production from Prudhoe Bay, contemplating sales of LNG to Asian markets. Exclude sales involving Alaska LNG.

As a matter of normal business practice, ExxonMobil does not release information on its contracts.

33. Please describe all permit applications submitted to governmental agencies by or on behalf of EM directly in support of ANS natural gas commercialization project.

ExxonMobil worked with a number of other companies as part of the ANGTS project. As part of that project there were significant permitting activities. As a result of our work on LNG we were not encouraged that such a project could be economically viable in the foreseeable future, so we did not pursue permitting for an LNG project. In addition, our work on GTL did not mature to the point of filing permit applications.

34. EM, in conjunction with BP and Phillips, recently announced the formation of a group to study ANS natural gas commercialization alternatives. Please describe the alternatives the group intends to study, and among such alternatives, please identify those which have previously been studied by one or more of the group members.

ExxonMobil, Phillips and BP have agreed to a joint work program to evaluate and progress a pipeline project to serve Lower-48 gas markets. Details concerning this joint effort were reviewed with the House Oil and Gas Committee on February 8. ExxonMobil previously worked extensively on a pipeline as part of the ANGTS project. We cannot speak for what BP and Phillips have studied.

35. The study group referenced in question 34 is to receive \$75 million in first year funding. Please describe the rationale for this particular level of spending.

This is our current best estimate of the cost to complete the work program that was reviewed with the House Oil and Gas Committee on February 8.

36. What is the relationship between the mandate of the study group reference in question 34, and the Alaska Highway Natural Gas Policy Council the governor is proposing to fund during this legislative session?

The ExxonMobil, BP, Phillips joint work program to evaluate and progress a pipeline project is independent of the Council the governor is proposing to fund.

37. Has EM established a time-line for sales of ANS natural gas to unrelated third parties, and if so, what is the target date to accomplish such sales?

ExxonMobil has not established a timeline.

38. Please describe in detail any and all agreements, understandings, arrangements, whether verbal or in writing, tacit or express, between EM and any other Alaska producers, or TAPS owners, concerning, expressly or by implication, the commercialization of ANS natural gas. Include, without limitation, any such agreements, understandings, and arrangements relating, directly or indirectly, to the timing of any commercialization project and associated sales of ANS natural gas to unrelated third parties.

ExxonMobil, Phillips and BP have agreed to a joint work program to evaluate and progress a pipeline project to serve Lower-48 gas markets. Details concerning this joint effort were reviewed with the House Oil and Gas Committee on February 8.

39. Has EM ever, since the inception of Prudhoe Bay production, circulated or published among prospective ANS natural gas purchasers, a request for proposals or similar documents? If so, please provide details, including without limitation, the contents of the RFP or other solicitations, the date(s) circulated the recipients, and all responses.

ExxonMobil continues to pursue all viable opportunities to commercialize its ANS gas resources and continues to meet with parties seeking to purchase ANS natural gas. For instance, in the late 1970's Exxon signed sales contracts with several pipeline companies committing all of Exxon's gas that would be transported through the ANGTS pipeline. Those contracts subsequently were cancelled, as the North American gas market could not support the project. The demand for natural gas was insufficient to provide a natural gas price that would justify the large capital expenditures required. ExxonMobil has maintained contact with the market and continued to pursue other potential opportunities to commercialize its gas, including LNG and GTL technologies.

40. Until recently, several ANS producers, including EM, claimed that off unit sales of ANS natural gas prior to 2005 would result in unacceptable losses of oil production. Has EM's position on this issue changed, and if so, please explain the reason.

ExxonMobil has not claimed that sales of ANS natural gas prior to 2005 would result in unacceptable losses of oil production. ExxonMobil does not believe that reservoir impacts would have impeded construction of the ANGTS pipeline and commercialization of the gas in the early 1980's if market conditions had supported such a project.

41. To the best of EM's knowledge, do any of the agreements pertaining to the BP-Arco merger/acquisition, or the sale of ARCO's Alaska assets to Phillips, address, directly or indirectly the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.

ExxonMobil is not a party to these agreements so we have no direct knowledge. This question would best be directed to BP and Phillips.

42. Do any of the amendments or modifications to agreements pertaining, directly or indirectly, to North Slope oil and gas units, and relating to the transactions described in question 41, address the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.

No.

43. Assuming an adequate Asian market for ANS natural gas, has EM made any decision or judgement whatsoever regarding the regional siting of a LNG plant and shipping terminal in Alaska? If so, please describe the decision and judgement in detail.

ExxonMobil has not made any decision or judgement regarding the regional siting of a LNG plant and shipping terminal in Alaska.

44. Pt. Thomson is a gas condensate field. As operator of Pt. Thomson, is EM considering sale of gas from Pt. Thomson to a gas pipeline project as an option to installing high pressure gas reinjection facilities or other means of disposing of the gas? How are the production facilities proposed for Pt. Thomson influenced by the prospects of a major gas project?

ExxonMobil is considering gas sales via a pipeline as an alternative to, or in conjunction with, a gas cycling project. Our current engineering effort with the other Working Interest Owners of Pt. Thomson includes the work to identify the costs and facilities associated with these options.

45. Pt. Thomson ownership has changed in the last year. As operator of Pt. Thomson, please describe the current ownership of the Pt. Thomson unit. Are the ownership percentages expected to change once Pt. Thomson is actually unitized? If so, what are the anticipated ownership percentages?

Pt. Thomson is unitized and there is currently an application pending before the ADNRP to redefine the unit boundaries to include all of the Thomson gas reservoir within the Unit. Equity participation within the Unit will depend on the final outcome of this application and negotiations between the Owners. However, given the ownership of the leases that may be included in the Unit by the ADNRP, it is apparent that the major equity holders in the Unit will continue to be ExxonMobil, BP, Chevron, and Phillips with 21 additional Owners of smaller shares.

46. Does a gas balancing agreement or agreements exist with respect to any ANS natural gas reserves? If so, please summarize the relevant terms and conditions of the agreement(s). If not, then set forth the circumstances and conditions under which EM must obtain the concurrence and /or consent of one or more of the other ANS procedures to sell or otherwise transfer ANS natural gas off-unit.

Under the various North Slope operating agreements, each owner has the right to take and dispose of its share of gas. In the event of a gas sale, a gas balancing agreement would be necessary only if each owner does not have arrangements in place to dispose of its share of gas. There currently are no gas balancing agreements in place.

47. Since there have been fundamental changes of ownership and operator interests and responsibilities in several oil and gas units on the North Slope, particularly at Prudhoe Bay and Pt. Thomson, please provide a comprehensive detailed description and explanation of any and all such changes, whether completed in progress or contemplated. Include specific references to all agreements which require approval of the State of Alaska and the nature and status of those agreements, as well as a description, explanation and status report on all other agreements (specifically including Unit Operating Agreements) which are currently being negotiated, will be negotiated, or have been negotiated, and which do not require approval by the State of Alaska.

ExxonMobil has agreed to align interests with other owners in the Prudhoe Bay Unit and the Point Thomson Unit. At Prudhoe Bay, BP, Phillips Alaska and Forest Oil also have agreed to alignment. At Point Thomson, BP and Chevron have so agreed. At Prudhoe Bay, this alignment has led to the cross-assignment of leases to achieve a similar working interest for each owner in each lease. Such an assignment required approval from the Alaska Department of Natural Resources and has been received. This step has not yet been taken at Point Thomson. The Prudhoe Bay Unit owners also agreed to BP assuming operator responsibilities for the Eastern Operating Area formerly operated by ARCO. The ADNRC has approved that action.

48. Please describe, in detail, your company's plans for best efforts to contract with qualified Alaskan contractors and firms in the state for work to be performed on planned projects, including the fabrication and installation of required facilities. Include in your response your company's plans to develop training for Alaskans through labor apprentice programs, University of Alaska, vocational training through local school districts, or any other programs.

ExxonMobil recognizes that there are benefits to employing Alaska residents and contracting with Alaska businesses that are qualified and cost competitive. As part of our joint pipeline team activities, we continue to seek Alaskan businesses to compete for contracting opportunities. If a commercial pipeline project can be defined, we would expect to develop plans with the other project sponsors and the appropriate State entities, including local universities and

colleges, and others to help to develop the appropriate skills and training for the local work force.

K. Konrad –

Opening comments to HOG Committee, 23 April, 2001

Mr. Chairman. Members of the committee.

I would like to thank you for this opportunity to speak with you today. It has been a little over a year since I first appeared before this committee to speak about BP's plans for ANS gas commercialization.

At that time, I spoke about BP's view that the opportunities around ANS gas commercialization were brighter than ever.

I outlined our view that advancing technology and changing markets offered the exciting possibility of gas commercialization before the end of the decade. –

And I spoke about our plans to pursue these opportunities aggressively.

Specifically, I said:

We were forming a new business Unit in Alaska dedicated solely to ANS gas commercialization and were actively mobilizing technologists from around the world to support our activity.

We were finalizing plans to demonstrate leading edge GTL technology here in Alaska.

We were continuing our participation in the LNG sponsor group where Arco and others had focused their attention.

And we were embarking on a screening study to evaluate the possibility of transporting gas via pipeline to North American markets that appeared to us to be the most promising ANS gas commercialization alternative based on initial work we did in 1999.

Others were circumspect about this "new" (actually old) idea but we pursued it anyway.

Now, 14 months later I am pleased to say we achieved all we said we would and more.

We increased our participation in the LNG sponsor group to 26% to ensure adequate funding to continue into Phase II of the study. While we still view LNG as sub-economic, we felt strongly that work should continue to ensure no option was prematurely discarded and that potential synergies were evaluated.

We aligned our interests at Prudhoe Bay with our major partners and in the process significantly increased our gas ownership at Prudhoe Bay and at the same time also increased our ownership in the Pt Thomson gas condensate discovery.

We entered into an agreement with Anadarko and Alberta Energy to explore for gas across 2.2 million acres in the foothills of the Brooks Range.

We completed engineering and began construction of our 86 million dollar GTL demonstration plant in Nikiski, Alaska to demonstrate BP's proprietary GTL technology which is expected to reduce capital costs by 20% relative to existing industry norms. The project remains on schedule for 2002 start-up.

We formed and are leading a joint industry group seeking to develop new technology around CO₂ removal and sequestration.

And we completed a screening study that confirmed our belief that ANS gas commercialization via gas pipeline to North American markets held the most potential relative to other alternatives.

In August of last year, BP began to share our findings with our partners ExxonMobil and Phillips and invited them to join us in a study to further advance this exciting opportunity.

In December of last year, the three companies executed an agreement to jointly study this opportunity in more detail. As this committee is aware, the joint team now has over 90 professionals in place working on the project and 10 contract packages have been awarded to support this exciting and aggressive work program.

I am very pleased to point out that Alaskan firm's are very well represented in these important contracts.

So a very productive and exciting 14 months. Of course there is more to come.....

Irrespective of what I personally see as enormous progress, I am very aware that we have been less than successful in effectively communicating our efforts to this legislature. I can assure you that this is not our intent.

I am well aware that our work is important to Alaska and I am also well aware that there are many complex issues which are of interest to this committee and that this committee often receives seemingly conflicting information.

I am here today to do my best to help this committee understand BP's view around ANS gas commercialization.

On February 16, my office received a letter containing 49 questions from Representative Ogan with respect to ANS gas commercialization. I must admit, I found the structure and tone of the questions a bit surprising.

I spoke with Representative Ogan on March 7 to better understand his intent and out of that conversation gained a better

understanding of how we could address the questions in a meaningful way that would be helpful to the committee.

I followed up our conversation with a letter to representative Ogan on March 8 and on March 21st sent representative Ogan a response to the 49 questions. I met with representative Ogan on March 22nd to follow up.

I hope our answers have been helpful. I am here today to follow up further on any of the questions and to address any other questions or issues of interest to members of the committee.

Rather than me telling you what I think is important, I would offer instead that you ask me to address any and all issues you would like hear from me about

bp



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March 21, 2001

The Honorable Scott Ogan
Alaska State Representative
Chairman – House Special Committee on Oil & Gas
State Capital Room 108
Juneau, Alaska 99801

Dear Representative Ogan,

In advance of our meeting Thursday, enclosed is BP's response to the questions referenced in your letter dated February 16. We have sought to answer these questions in a manner consistent with what you and I discussed in our phone conversation a couple of weeks ago and I trust they will provide useful context for our forward discussions.

Look forward to seeing you Thursday.

Sincerely,

Ken Konrad
Sr. Vice President BP Exploration Alaska Inc.

BP Responses to Representative Scott Ogan

1. *Please identify all persons participating in and/or assisting in preparing answers to these questions, including their full name, title, and a general description of their contribution to the effort.*

The responses to these questions have been authorized and developed under the direction of Ken Konrad, BP's Business Unit Leader – Alaska Gas.

2. *Please describe in detail all efforts, initiatives and actions undertaken by BP to comply with natural gas provisions of the Charter entered into to facilitate the merger with ARCO and the related sale of Alaskan assets to Phillips.*

BP is actively engaged in efforts to further commercialize North Slope natural gas. These efforts include:

- the formation of the **BP Alaska Gas Business unit**;
- participation in the **Alaska North Slope LNG Project** (BP, Phillips, Marubeni, and Foothills Pipeline Company) which is assessing opportunities to commercialize ANS gas via an LNG development scheme;
- investing \$86 million to construct a **Gas to Liquids demonstration plant** in Nikiski, Alaska;
- the completion of a **BP natural gas pipeline screening study** in 2000, and
- the establishment of the **North American Natural Gas Pipeline Group** (BP, Phillips and ExxonMobil) which is assessing opportunities to commercialize ANS gas via a gas pipeline development scheme.

The above activity set resulted in approximately \$60 million dollars of spend by BP in the year 2000. Gas commercialization spending by BP is expected to further increase in 2001.

3. *Please set forth in detail all capital improvements designed, engineered or constructed by or on behalf of BP to facilitate sales of ANS natural gas to unrelated third parties from inception of Prudhoe Bay oil production to the present.*

The initial facilities at Prudhoe Bay, as well as capital improvements thereto, were designed, engineered and constructed as common facilities to serve both the Oil Rim Participating Area and the Gas Cap Participating Area. Examples of these facilities include, but are not limited to, the Central Compression Plant (CCP), the Central Gas Facility (CGF), oil and gas separation facilities, wells and flowlines. It was and still is anticipated that these shared facilities will facilitate sales of gas from Prudhoe Bay.

BP has not designed, engineered or constructed additional facilities to facilitate large scale sales of ANS natural gas. If a commercially viable gas sales project is identified, facilities specific to that project will be designed and constructed.

4. *Please describe in detail any and all efforts undertaken by or on behalf of BP to develop ANS natural gas reserves not associated with existing oil producing fields, including without limitation, Pt. Thomson.*

BP's gas commercialization efforts have been focused on known fields, many of which are currently associated with oil production. The estimated volume of known North Slope natural gas resource is

~35 trillion cubic feet, most of which comes from Prudhoe Bay and Pt. Thomson. Pt. Thomson development is integral to the large scale ANS gas commercialization options current being evaluated.

BP expects that if an economically viable project can be identified there will be an incentive to explore for and develop additional gas fields on the North Slope.

5. *Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of BP to locate and develop domestic markets for ANS natural gas.*

The North American gas market is the largest and most diverse in the world. Daily consumption is 67 billion cubic feet per day (bcfd) according to the Energy Information Administration (EIA) and is expected to expand by 19 bcfd over the coming ten years, driven significantly by growth in the electric power generation sector. To meet this demand growth North America will require additional natural gas volumes from a number of sources and Alaskan gas may be able to play a part in meeting this demand provided it has a competitive cost of supply.

BP is the largest producer of gas in North America, with production in excess of 4 bcfd, and is also a leading gas marketer with 9 bcfd in gas sales. Once Alaskan gas enters the North American gas grid, it will be marketed in a manner similar to BP's currently marketed volumes. BP's marketing efforts over the years provide BP with detailed and current knowledge of specific gas markets throughout North America that positions BP well to ensure end use markets are found for ANS gas. While BP's share of ANS gas production will be significant it will not require any fundamental changes to our overall North American gas marketing strategy, but will rather complement our existing business. ANS gas would be marketed across a diverse set of buyers, in line with the continued growth and development of the North American natural gas market. In addition to the domestic gas market, BP continues to study the domestic market demand for products generated from developing ANS gas via a GTL scheme.

Specific initiatives undertaken within the past two years to increase BP's marketing presence in particular North American gas markets include acquiring IGI Resources, based in Boise, and Progas, based in Calgary. Detailed information on our current efforts is competitive and cannot be disclosed.

6. *Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of BP to locate and develop international markets for ANS natural gas.*

BP is a significant supplier of gas to international markets, via pipeline delivered gas and LNG, and as such has regular contact with gas customers within these markets. BP has evaluated potential international market opportunities for ANS gas in conjunction with cost screening studies since the discovery of the Prudhoe Bay field. The focus of this work has been primarily on Pacific Rim LNG demand, notably Japan, Korea, and Taiwan. To date, we have not been able to identify an ANS LNG project that is commercially viable. BP's current involvement in the Alaska North Slope LNG Project represents a continuation of these efforts, which, as of yet, have not yet established an economically viable export project for ANS gas. BP continues to attempt to establish and expand LNG markets in Asia Pacific and is currently studying the feasibility of developing LNG terminals in China and India.

Potential customers for ANS gas might be identified in Canada related to the efforts of the North American Natural Gas Pipeline Group to develop a gas pipeline project. In addition, BP continues to study the international market demand for products generated from developing ANS gas via a GTL scheme.

7. *Please identify (full name, title, address and telephone number) the officers and employees whose primary duties and responsibilities have included marketing and sales of ANS natural gas.*

For BP, Ken Konrad has overall responsibility for Alaskan gas commercialization.

8. *Please provide an organizational chart for the BP marketing department, identify the positions dedicated to marketing and sales of ANS natural gas, and indicate the persons currently holding such positions.*

BP North America Gas & Power is an integrated marketing organization. The primary offices of BP North America Gas & Power are Houston and Calgary with regional offices throughout Canada and the United States. In general, BP's marketing activities are not segmented by specific supply source. BP's efforts to market ANS gas will be a well coordinated team effort.

BP does not, as a normal business practice, distribute organization charts.

9. *Please identify potential customers for international sales of ANS natural gas.*

For ANS gas transported as LNG, there would be a variety of potential customers (typically electric power utilities, gas distribution companies as well as large industrial companies). In Japan, Korea and Taiwan the process of deregulation is underway. This could create new buyers of LNG. For example, in Korea there are plans to split Korea Gas into three separate wholesale companies who will buy LNG and onsell it to city gas companies and power utilities. Theoretically, LNG customers could be anywhere in the world; however, geographic proximity would have bearing on a most likely customer base for ANS gas.

Companies that BP currently markets LNG to include:

The Tokyo Electric Power Company Inc.
Chubu Electric Power Company Inc.
The Kansai Electric Power Company Inc.
The Chugoku Electric Power Company Inc.
Kyushu Electric Power Company Inc.
Tokyo Gas Company Ltd.
Osaka Gas Company Ltd.
Toho Gas Company Ltd.

Other customers of LNG in Asia Pacific include:

Tohoku Electric
Korea Gas Corporation
Chinese Petroleum Company

For ANS gas transported via pipeline or GTL there would be a wide variety of potential Canadian customers. Large combination gas and power utilities as well as power generators in Canada are potential markets for ANS gas transported via pipeline.

10. *Please identify potential customers for domestic sales of ANS natural gas.*

The continental United States domestic gas market is a large competitive commodity market with many buyers and sellers. A majority of gas sold within this market is via gas supply contracts between individual buyers and sellers, but a greater volume of gas is being bought and sold via market hubs with no direct link between individual buyers and sellers. However, natural gas marketed by Canadian suppliers, both within Canada and to the United States, tend to be under long term contracts.

The industrial sector, which includes power generators, is the largest consumption group. The majority of the growth is anticipated to be within this sector, dominated by power generation customers. According to EIA data more than 90 per cent of new power generation projects that have been announced will be fueled by natural gas. In addition, there are thousands of distribution companies (LDCs), which provide natural gas to residential and commercial customers.

11. *Please identify potential customers for sales of ANS natural gas in Asia.*

Please see answer to question 9.

12. *Please identify potential customers for sales of ANS natural gas in California.*

Please see answer to question 10.

The situation in California that has developed over the past 6 months or so would suggest there could be a strong desire for additional gas supplies to the state. For example, PG&E Northwest recently closed an open season to expand its system by 200 mmcf to Malin (Oregon/California border). The capacity has been fully subscribed. Utilities and power generators are the most likely end users of gas within the state.

The state has more than 37,000 industrial consumers of natural gas. These include chemical facilities that use natural gas as a feedstock, refineries and power generators, including merchant power plants.

Local Distribution Companies (LDCs) in California sold gas to more than 9.7 million residential and commercial customers in 1999.

As reflected in the rest of the country, the significant growth market for natural gas in the state is expected to be power generation. Many of these power generation facilities are expected to use natural gas as their primary fuel.

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

Mexico is currently a small volume net importer of natural gas, but has significant undeveloped natural gas resources. The largest potential natural gas customer in Mexico, at present, is the state owned company Pemex. There are a number of merchant power plants, presently fewer than ten in Baja California, as well as a number of small LDCs who are potential buyers of natural gas. In addition, as highlighted in the March 8, 2001 announcement by El Paso Corporation, there is potential for a regasification facility to be constructed in Mexico's Baja California providing a point of import for ANS gas into Mexican and domestic West Coast gas markets.

14. *Please identify potential customers for sales of ANS natural gas in the mid-west region of the United States.*

Please see answer to question 10.

The Midwest region has more than 79,000 industrial consumers of natural gas. These include chemical facilities that use natural gas as a feedstock, refineries and power generators, including merchant power plants.

Local Distribution companies (LDCs) in the region sold gas to more than 13.7 million residential and commercial customers during 1999.

As reflected in the rest of the country, the significant growth market for natural gas in the state is expected to be power generation. Many of these power generation facilities are expected to use natural gas as their primary fuel.

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

Please see answer to question 9.

16. *With respect to responses to questions 8-14, please describe with specificity all efforts, initiatives and programs undertaken by or on behalf of BP to market, sell, solicit bids to purchase (including public and obvious declarations of a willingness to sell significant quantities of ANS natural gas, whether conditioned or unconditioned, at clearly stated prices and terms) or otherwise to actively cultivate and encourage interest in and from potential developers of a project to transport and sell ANS gas to buyers or customers in any prospective market.*

BP is, and has historically been, actively engaged in efforts to further commercialize North Slope natural gas. As stated in the response to question 2, BP's current efforts to commercialize ANS gas include the formation of the BP Alaska Gas Business unit, participation in the Alaska North Slope LNG Project, the establishment of the North American Natural Gas Pipeline Group, the completion of a BP natural gas pipeline screening study in 2000 and investing \$86 million to construct a Gas to Liquids demonstration plant in Nikiski, Alaska. Also, as highlighted in the responses to questions 5 and 6, BP has been and continues to take steps to develop additional opportunities both domestically and internationally to commercialize ANS gas. In the charter with the State of Alaska, BP clearly outlined with the State of Alaska terms under which BP would provide Prudhoe Bay gas to interested third parties.

17. *Please reference any and all studies, examinations, analyses, or similar efforts, regardless of their official internal characterization, as well as the results and conclusions generated or reached by each, undertaken by or on behalf of BP, or by a group in which BP participated directly or indirectly pertaining to actions and undertakings directed toward the commercialization of or decisions not to advance the commercialization of ANS natural gas.*

BP has engaged in many studies over the years related to large scale ANS gas commercialization, none of which have resulted in an economically viable project. The amount of money spent by industry since the discovery of the Prudhoe Bay field to commercialize ANS gas reaches into the hundreds of millions of dollars.

BP's current efforts to examine large scale ANS gas commercialization options include: active involvement in the North American Natural Gas Pipeline Group which is progressing the option of supplying ANS gas to North American gas markets via a gas pipeline, active involvement in the Alaska North Slope LNG Project which is progressing the option of supplying ANS gas to Asia Pacific markets via LNG and the construction of a GTL demonstration plant in Nikiski.

18. *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.*

With regards to further commercializing ANS gas, BP is focusing on developing a project that has a cost of supply that is competitive with other new supply sources for each relevant market. For the

North American gas markets new supply sources include, for example, existing basins, tight sands, deepwater Gulf of Mexico, Mackenzie Delta, Eastern Canada, coalbed methane and LNG. For the Asia Pacific gas markets new supply sources include numerous existing and developing regional LNG projects as well as gas from Russia. The market will determine price based on a variety of supply and demand interactions.

The challenge for Alaska in terms of gas pipeline or LNG cost of supply, given its distance to market, is transportation costs. If we are able to engineer and design a modern day system that results in low unit costs, BP is hopeful that Alaska gas can be competitive.

The driving factor in seeking to develop a low cost of supply project is to maximize gas netback prices at the field wellhead. A high wellhead price provides maximum benefits to Alaska. It maximizes royalty and severance tax revenues, and more significantly, creates an environment that encourages further exploration and development which in turn leads to more jobs within Alaska, more revenue for the state and ultimately the creation of a new gas industry. With an economic incentive to explore, more gas will be found and developed on the North Slope.

19. *Sir John Brown recently announced an additional capital commitment to the Irian Jaya LNG project of approximately \$2 billion, apparently targeting incremental increases in sales to Asian markets. Please set forth in detail BP's rationale and analysis supporting capital expenditures to commercialize natural gas reserves in foreign countries rather than ANS natural gas reserves.*

Regardless of their location in the world, all projects BP invests in must establish themselves as being economically sound. In general, an economically sound project must be able to deliver cost competitive supplies to their expected market. Historically, though there have been numerous efforts no industry participant or industry group has been able to demonstrate an ANS gas project that is capable of delivering cost competitive gas supplies to any market off the North Slope. However, BP is currently very active in attempting to establish an ANS gas project that is economically sound with our involvement in the North American Natural Gas Pipeline Group, the Alaska North Slope LNG Project and the BP GTL demonstration plant.

20. *Please describe and compare the political and business conditions in Irian Jaya with the political and business conditions in Alaska, particularly focusing on the political stability of the two regions.*

Irian Jaya comprises the western half of the island of New Guinea, and it has formally been the 26th province of Indonesia since 1969. After three decades of stability under the authoritarian rule of President Suharto, Indonesia has entered a period of political and social unrest following his overthrow in 1998. Political factions in the national government run not only along pro- and anti-Suharto lines, but also between and among a Christian minority and several strands within a Moslem majority that have various degrees of fundamentalist militancy. Despite the social, religious, ethnic, economic and political turmoil in Indonesia, the terms of the oil and gas concessions between the government and the industry remain stable, and there has been no significant effort to alter or repudiate those arrangements.

Alaska comprises the northwesternmost portion of the North American continent, and it has formally been the 49th state of the United States since 1959. The legal and political institutions in Alaska are clearly more stable than those in Irian Jaya today. However, there are three levels of government active in Alaska - federal, state and municipal - and their policies, objectives and regulations are not always consistent. The land claims of Alaska's indigenous peoples were extinguished by the Alaska Native Claims Settlement Act of 1971, and attempts to establish numerous sovereign enclaves of "Indian country" in Alaska were rebuffed by the U.S. Supreme Court in 1998. Although the "impairment of contracts" clauses of the state and federal constitutions barred the state government from changing the terms of its oil and gas leases unilaterally, it did rewrite the fiscal terms numerous times by enacting and amending state tax laws following the discovery of Prudhoe Bay. Since its last major tax change in

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

response to question 16, terms under which BP would provide Prudhoe Bay gas to third parties have been outlined in the charter with the State of Alaska.

BP's royalty reports to the State of Alaska Department of Natural Resources disclose sales of ANS natural gas to the following customers from 1984 through 2000:

<u>Dates</u>	<u>Customers</u>
1993-1995	Arctic Utilities Inc.
1999-2000	Badami
1989-2000	BP (Alaska) Pipeline Co.
1993-1995, 1997-2000	Endicott Pipeline Co.
1989-1995	Exxon Pipeline Co.
1993-2000	Lake Colleen Enterprises
1994-2000	Kodiak Oilfield Haulers
1986-1997	Kuparuk Industrial Center
1999-2000	Kuparuk Participating Area
1993-2000	Kuparuk Topping Plant
1988-1996	Kuparuk Transportation Co.
1995-2000	Milne Point Pipe Line
1994-2000	Nabors Alaska Drilling
1993-2000	Natchiq, Inc.
1989	Norgasco, Inc.
1994-1996	Northern Eclipse Inc.
2000	Northstar field
1994-1996	Peak Oilfield Service Co.
1984-1988	Phillips Alaska Pipeline Corp.
1993-2000	Piquini Management Corp.
1996-1999	Pt. McIntyre
1984-1988	Sohio Pipeline Co.

25. *Please provide an estimate of the cost of permitting an overland gas pipeline from the ANS to the Lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting the estimate.*

An estimate of the cost of permitting a gas pipeline will be developed by the North American Natural Gas Pipeline Group. However, it is clear that a gas pipeline to connect ANS gas to North American markets will require fundamental re-engineering, relative to the engineering completed for the ANGTS permits, to bring the pipeline design up-to-date with 21st century technology. This will likely include different: gas rates, pipeline diameter, pipeline materials, compressor station sites and design, construction methods, pipeline termination point and gas transportation routes from Canada to domestic gas markets. This review is being conducted for multiple routes to seek the combination of route and design which best serves the needs of a broad constituency of owners and stakeholders.

26. *Please provide an estimate of the time necessary to permit an overland pipeline from the ANS to the Lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting the estimate.*

The goal of the North American Natural Gas Pipeline Group, assuming an economic project is identified, is to file regulatory permit applications with the FERC and NEB as soon as the required content can be compiled. BP has stated an aspiration to complete this work by yearend 2001,

recognizing that this is a very aggressive target. The time required for regulatory review and approval is unknown, but BP will seek to balance the time spent preparing our applications with the time required to evaluate and process our applications, with the ultimate goal being the shortest possible time to the granting of permits.

27. *Please provide a timeline for the permitting, design, engineering, and construction of the Gas-To-Liquids pilot plant BP has proposed to develop on the Kenai Peninsula.*

The final permits for the BP GTL demonstration project were received on February 14, 2001 and construction began the week of February 19, 2001. BP expects construction to be complete, and first production to begin sometime during the second quarter of 2002.

28. *Why did BP move the proposed siting for the Alaskan pilot GTL plant from the North Slope to the Kenai Peninsula?*

The decision to build the demonstration plant on the Kenai Peninsula was based primarily on the following factors:

- construction and operating costs are lower on the Kenai Peninsula than on the North Slope;
- access to high quality local labor (BP has received many positive comments from individuals pleased that they will be able to work close to home) and existing infrastructure (utilities, natural gas, roads, etc.);
- easy accessibility for specialist visitors as well as technical and management staff based in Anchorage;
- enthusiastic support from the state, local governments and the community;
- greater flexibility to process, test and transport GTL syncrude into finished products, and
- greater flexibility for adding/testing new technologies in the future.

29. *Has BP made a decision regarding the most cost-effective route for an overland pipeline from the ANS through Canada to the Lower 48 states? If so, please describe the route and the economic assumptions underlying the cost analysis.*

No conclusions have yet been reached. Understanding the relative competitiveness between routes is a focus of the North American Natural Gas Pipeline Group.

30. *Governor Knowles has publicly set a goal to break ground for an ANS gas commercialization project in two years. Please comment on the feasibility of achieving this goal, and what contribution BP is willing to make hereto.*

BP is aligned with Governor Knowles in wanting to see an economically viable large scale ANS gas project aggressively pursued. Our first priority is to identify an economic project. BP has assembled a set of its best employees in Alaska in order to progress ANS gas commercialization opportunities. Once an economic project is identified, BP expects to progress as quickly as prudent with the ultimate project timing being developed as part of the North American Natural Gas Pipeline Group work program. We will continue to work with the Governor's Office to deliver our common goal of a commercially feasible large scale Arctic gas development to the State of Alaska.

31. *Assuming BP supports an overland pipeline to the Lower 48 (specifically the Alcan route), does BP intend to negotiate to acquire Foothills' pre-existing governmental approvals, or to commence an independent permitting effort?*

This will be determined as part of the North American Natural Gas Pipeline Group's work program. The work program is geared toward the identifying the best project designed and engineered to 21st century technology levels. Relative to historic efforts, a 21st century project will likely include changes in gas rates, pipeline diameter, pipeline materials, compressor station sites and design, construction methods, pipeline termination point and gas transportation from Canada to domestic gas markets.

After the best possible project is established, a regulatory process will be identified taking into consideration whether it is more prudent to pursue new permits under the Natural Gas Act or seek to revitalize historic efforts. The process which is most efficient will become the most promising way forward.

32. *Please set forth all of the perceived impediments to the so-called over-the-top route, submerged in the Beaufort Sea, emerging on uplands in the Canadian Northwest Territory, and traversing the McKenzie Delta and Valley regions. Include environmental and political impediments.*

Part of the work program of the North American Natural Gas Pipeline Group will be to assess these and other factors that must be considered for both routes. It is BP's intent to objectively compare the relative attributes for both routes against a number of criteria. These criteria include:

- economic viability is one, both or neither route(s) viable
- revenues (government and producer)
- jobs for Alaska (construction, operations and gas exploration/development related jobs);
- access to gas within Alaska for either route
- environmental impact;
- project timing, and
- construction and operating safety.

33. *Please list all of the contracts, excluding any confidential provisions, that BP has entered into or has an interest in, since the inception of production from Prudhoe Bay, contemplating sales of LNG to Asian markets. Exclude sales involving Alaska LNG.*

BP has an interest in the following active LNG Projects which provide LNG to Asian markets:

Australia North West Shelf project

BP share 16.67%

Start-up 1989

Current LNG volumes under contract - 7.3 million tonnes per annum (mmtpa)

Background The original LNG contracts were for 5.8 mmtpa. The volumes were increased in early 90s to 6.8mmtpa and then to 7.3 mmtpa. A fourth LNG train 4 will start-up in 3Q2004, but plateau production will not be reached until 2010 due to market constraints.

Abu Dhabi (ADGAS)

BP share 10%

Start-up 1977

Current LNG volumes under contract - 7.3 million tonnes per annum (mmtpa)

Background The original LNG contracts were for 2.06 mmtpa. An additional LNG train started in 1994 and contractual volumes were increased to 4.7mmtpa. LNG sales are expected to increase by 0.5mtpa starting in 4Q2001.

Indonesia (Bontang)

BP share ~12% in gas supplied to LNG facilities

Start-up 1977

Current LNG volumes under contract - 22 million tonnes per annum (mmtpa)

Background BP has no contracts to sell LNG from Indonesia (Bontang). All Indonesian LNG is marketed by the national oil company Pertamina. BP has a 50% share in VICO which supplies gas to the LNG plant.

BP's contracts are confidential.

34. *Please describe all permit applications submitted to governmental agencies by or on behalf of BP directly in support of an ANS natural gas commercialization project.*

No permit applications have been submitted by BP directly in support of the current large scale ANS gas commercialization project focus. The North American Natural Gas Pipeline Group is currently defining and developing the appropriate permit applications in support of a gas pipeline project.

The Alaska North Slope LNG Sponsor Group is assessing appropriate permitting requirements in support of an LNG project.

35. *BP in conjunction with Phillips and Exxon-Mobil, recently announced the formation of a group to study ANS natural gas commercialization alternatives. Please describe the alternatives the group intends to study, and among such alternatives, please identify those which have previously been studied by one or more of the group members.*

The North American Natural Gas Pipeline Group is a joint project team formed by BP, Phillips and ExxonMobil. The focus of the group is the large scale commercialization of ANS gas via a gas pipeline from the North Slope to North American gas markets in Canada and the continental United States. Two general routes being evaluated by the joint team to transport ANS gas from the North Slope to Alberta, Canada: a northern route traveling east from the North Slope to the Mackenzie Delta in Canada and then south to Alberta and a southern route traveling south from the North Slope along TAPS to a point near Delta Junction and then following the Alcan highway to Alberta. Several options, including new-build and expansion options, will be evaluated to transport ANS gas from Alberta, Canada, to North American gas markets. The concept of transporting gas via pipeline from ANS to North American gas markets has previously been studied by BP.

36. *The study group referenced in Question 35 is to receive \$75 million in the first year funding. Please describe the rationale for this particular level of spending.*

This is an estimate and a more detailed budgeting is underway. The level of spend is to cover study group staff costs, technical feasibility and definition studies, environmental studies and regulatory application preparation.

37. *What is the relationship between the mandate of the study group referenced in Question 35, and the Alaska Gas Natural Gas Policy Council the governor is proposing to fund during this legislative session?*

There is no formal relationship between the North American Natural Gas Pipeline Group and the Alaska Highway Natural Gas Policy Council. The Project Group plans to consult with a wide range of stakeholders, potentially including the Council.

- 38. *Has BP established a timeline for sales of ANS natural gas to unrelated third parties, and if so, what is the target date to accomplish such sales?***

BP has not established a timeline for sales of ANS gas to third parties. BP is openly communicating our work activities and near term aspiration of regulatory filings by yearend 2001 which provides relevant context for third parties interested in purchasing ANS gas. Third parties can approach BP, or any gas producer on the North Slope, at any time to discuss the sale and purchase of gas from the North Slope of Alaska.

- 39. *Please describe in detail any and all agreements, understandings, arrangements, whether verbal or in writing, tacit or express, between BP and any other Alaska producers, or TAPS owners, concerning, directly or indirectly, the commercialization of ANS natural gas. Include, without limitation, any such agreements, understandings, and arrangements relating, directly or indirectly, to the timing of any commercialization project and associated sales of ANS natural gas to unrelated third parties.***

BP, ExxonMobil and Phillips Alaska have recently entered into an agreement for a joint work program (the North American Natural Gas Pipeline Group) to evaluate the costs and benefits of a possible natural gas pipeline to deliver natural gas from Alaska's North Slope to Canada and the Lower 48 states as referenced in Question 35.

Alaska producers have also entered into various Unit Agreements with the State of Alaska and Unit Operating Agreements with other producers, which agreements could be said to indirectly concern the commercialization of ANS natural gas. All of these agreements are on file with the Department of Natural Resources Division of Oil and Gas. None specifically addresses the timing of a gas commercialization project or possible sales to third parties.

- 40. *Has BP ever, since the inception of Prudhoe Bay production, circulated or published among prospective ANS natural gas purchasers, a request for proposals or similar documents? If so, please provide details, including without limitation, the contents of the RFP or other solicitations, the date(s) circulated, the recipients, and all responses.***

BP has and continues to speak on a regular basis with a wide range of companies and groups who have an interest in ANS gas. However, BP is not aware of any requests for proposals circulated or published among prospective ANS natural gas purchasers.

- 41. *Until recently several ANS producers, including BP, claimed that off unit sales of ANS natural gas prior to 2005 would result in unacceptable losses of oil production. Has BP's position on this issue changed, and if so, please explain the reason.***

Due to the time period required for designing, permitting and constructing facilities BP does not expect large scale ANS gas sales utilizing Prudhoe Bay gas to occur prior to 2005. BP's target for first gas sales is 2007 which itself is an aggressive target.

With regards to the impact on Prudhoe Bay oil production, as a general principle reinjection of produced gas to maintain reservoir pressure will help sustain oil production. However, as the Prudhoe Bay field continues to mature, the benefit of reinjecting produced gas to maintain reservoir pressure decreases. Prior to proceeding with a large scale ANS gas sales, reservoir studies will be undertaken to fully evaluate any potential oil production impacts. We expect that with additional investment any potential for oil losses from the Prudhoe Bay reservoir can be minimized or eliminated.

42. *Do any of the agreements pertaining to the BP-ARCO merger/acquisition, or the sale of ARCO's Alaska assets to Phillips, address, directly or indirectly, the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.*

No.

43. *Do any of the amendments or modifications to agreements pertaining, directly or indirectly, to North Slope oil and gas units, and relating to the transactions described in question 42, address, expressly or by implication, the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.*

The Prudhoe Bay Unit alignment agreement executed by some of the Prudhoe Bay Unit owners does not address commercialization of ANS natural gas and/or sales to unrelated third parties. To the extent the alignment agreement aligns ownership interests in the Prudhoe Bay Oil Rim and Gas Cap, it could be said to facilitate, by implication, commercialization of Prudhoe Bay Unit gas.

44. *Assuming an adequate Asian market for ANS natural gas, has BP made any decision or judgment whatsoever regarding the regional siting of a LNG plant and shipping terminal in Alaska? If so, please describe the decision and judgment in detail.*

No decision has been taken. The Alaska North Slope LNG Sponsor Group is investigating potential sites in both Anderson Bay and Nikiski.

45. *Various gas pipeline project proposals (and Governor Knowles' Charter with BP regarding the ARCO/BP/Phillips merger/transaction) have referred to spiking of NGL (ethane, propane and butane) to increase project revenues. A substantial quantity of these NGLs reside in the miscible injectant that is currently used for the Prudhoe Bay enhances oil recovery project. As operator of the Prudhoe Bay field, what is BP's best estimate regarding the date at which the EOR project will terminate and the NGL in the miscible injectant will be available to spike gas for introduction to a pipeline project?*

BP does not believe the Charter addresses the spiking of NGLs (ethane, propane and butane) to increase project revenues.

BP, as an equity interest owner, and the other Prudhoe Bay owners review, on an ongoing basis, the performance and optimization of the Prudhoe Bay EOR Project. Because it is an ongoing review process, no decision has been taken as to when the Prudhoe Bay EOR Project might end. Gas commercialization will be a factor in optimizing the disposition of some or all miscible injectant. It is possible that some of the miscible injectant components could be exported from the North Slope while still maintaining an EOR project.

46. *Production from Prudhoe Bay is limited by the capacity to handle the gas that is produced concurrent with the oil. The Gas Handling Expansions (GHX-1 and GHX-2) were installed, among other reasons, to increase the gas handling capacity and obtain the resulting increase in oil production. It appears that a delivery of 2-4 bscfd of gas to a pipeline project offers an opportunity for the PBU to increase field gas off-take without having to spend money to dispose of the gas (such as injection compression installed for GHX-2). As operator of the Prudhoe Bay field and as a participant in the BP/ExxonMobil/Phillips group studying gas commercialization, is BP, directly or indirectly, investigating the possibility of increasing field gas off-take from Prudhoe Bay? If so,*

what is BP's estimate regarding the percent increase in oil production from Prudhoe Bay that could be achieved?

BP, as an equity interest owner, and other Prudhoe Bay owners are analyzing the possible optimization of Prudhoe Bay infrastructure in relation to large scale ANS gas commercialization. This includes the possible uses of the central gas facility, the central compression plant, the gathering centers and flow stations and the construction of a gas treatment plant. Specific to a gas pipeline development scheme, there is a possibility that the gas handling capacity of existing facilities can be utilized to compress part or all the sales gas prior to its delivery to the pipeline and to remove and reinject CO₂ separated from the sales gas. In addition, as the Prudhoe Bay field continues to mature and the field's producing gas-oil ratio continues to increase, the relative economics of gas handling expansion are significantly reduced. The Prudhoe Bay owners will be evaluating this component of the optimization.

- 47. Does a gas balancing agreement or agreements exist with respect to any ANS natural gas reserves? If so, please summarize the relevant terms and conditions of the agreement(s). If not, then set forth the circumstances and conditions under which BP must obtain the concurrence and/or consent of one or more of the other ANS producers to sell or otherwise transfer ANS natural gas off-unit.***

There currently are no gas balancing agreements in place for the Prudhoe Bay or Point Thomson Units. However, it is common within the oil & gas industry for balancing agreements to be put in place once a specific commercialization option has been identified.

- 48. Since there have been fundamental changes of ownership and operator interests and responsibilities in several oil and gas units on the North Slope, particularly at Prudhoe Bay and Pt. Thomson, please provide a comprehensive, detailed description and explanation of any and all such specific references to all agreements which require approval of the State of Alaska and the nature and status of those agreements, as well as a description, explanation and status report on all other agreements (specifically including Unit Operating Agreements) that are currently being negotiated, will be negotiated, or have been negotiated, and that do not require approval of the State of Alaska.***

In 2000, BP, ExxonMobil, Phillips and Forest Oil agreed to align their interests in the Prudhoe Bay Unit. The Prudhoe Bay Unit not only includes the Prudhoe Bay Oil Rim and Gas Cap, but also all of the Prudhoe Bay Satellites as well as the Greater Point McIntyre Area. The relative aligned interests are: BP (26.7%), ExxonMobil's (36.8%), Phillips (36.5%) and Forest Oil (0.02%). At Pt. Thomson, BP, ExxonMobil and Chevron have agreed to align their interests.

BP does not have records which disclose all of the fundamental changes of ownership and operator interests in the several oil and gas units on the North Slope; however, such changes should be reflected in the lease assignment records of the Division of Oil and Gas and in the change of operator records of the Alaska Oil and Gas Conservation Commission and the Division of Oil and Gas.

Assignments of oil and gas leases require approval by the Alaska Department of Natural Resources. Amendments of Unit Agreements require approval by the Alaska Department of Natural Resources, who is a party to such agreements. Amendments of Unit Operating Agreements do not require approval by the State of Alaska but are filed with the Alaska Department of Natural Resources. Negotiations for amendment of the Prudhoe Bay Unit Operating Agreement will be undertaken following complete alignment of the Prudhoe owners.

- 49. Please describe, in detail, your company's plans for best efforts to contract with qualified Alaskan contractors and firms in this state for work to be performed on planned projects, including the fabrication and installation of required facilities. Include in your response your company's plans to***

develop training for Alaskans through labor apprentice programs, University of Alaska, vocational training through local school districts, or any other programs.

Alaska Hire, buy and build is of great importance to Alaska, and to BP, as referenced in the Charter with the State of Alaska. Each year, BP submits a public report on Alaska Hire to the governor, detailing our activities in this area. BP is actively engaged in a variety of training and development programs for Alaskans. BP's procurement policy supports Alaska spend goals through a concerted effort to include Alaskan firms on all bid lists provided the firms are pre-qualified on both technical capability and safety record.

BP has been a leader in creating, utilizing and promoting in-state training programs at the University of Alaska, technical certification and K-12 school levels. Specific examples that will be continued include our active role in the Alaska Process Industry Careers Consortium (APICC) which has created a new two year Associates Degree program with the University of Alaska in three campuses (Kenai, Anchorage, Fairbanks) to train process operators that will work not only on the gas line, but will also help to renew our aging workforce in existing facilities. The overall effort included the identification of a significant gap in terms of skilled workers, development of cross-industry skill standards, and development of a common curriculum. Over 150 students are currently enrolled and over 100 are expected to start again in the fall. BP sponsors at least 10 scholarships and summer internships each year in association with this program and is planning to hire a number of operators from the first graduating class this year and each year thereafter. BP's leadership in this program has now created a following by other partners such as Phillips, Alyeska, Williams and Unocal, who have contributed to the development of the curriculum and this summer are also offering internships to Process Technology students.

BP is working closely with APICC to move forward in a similar way for construction training, based on existing construction worker and skill shortages. BP and APICC have engaged construction training entities and construction contractors throughout the state in an effort to raise the visibility and quality of exiting training programs to attract more workers, and also to define what additional training might be needed if there isn't enough currently going on. This evolving partnership is in the process of being formalized by a Memorandum of Understanding with APICC, Alaska Works, Alaska General Contractors, Alaska Building Contractors and hopefully many individual member companies. Significant attention will be given to marketing and awareness campaigns of the training and jobs opportunities, as well as to establishing and endorsing clear skill standards for training. A significant effort is both underway and expected to grow in the K-12 schools, particularly in rural Alaska. The medium term impact this will have for a gas project is that students coming through vocational training in high schools will be guided along Career Pathways and into appropriate apprenticeship and post-secondary training schools. By acting now and by working together, industry, education and government have the ability to increase numbers and skills of the the in-state construction workforce -not just for a potential gas project, but also to fill current gaps and those on the horizon due to the aging of the current workforce.

Other efforts BP will maintain and enhance include our Native and rural outreach and training programs, such as Itqanaiyagvik. This broad "Career Pathway" program includes: ALVA, a high school bridging internships for engineering students in partnership with UAA, High School Job Shadow which has taken nearly one hundred youths from the North Slope Borough School District to Prudhoe Bay to see and experience the wide variety of jobs there, and a long-term sponsorship for welding and electrical trainees at Alaska Vocational Technical College and Illisagvik College. BP remains the largest sponsor of the Anchorage School District mentorship program, hosting between 8-18 high school students each year and sponsors a wide range of educational programs statewide that enhance our youth's understanding of science, technology and the associated jobs in our industry.

In terms of hiring within BP itself, we are proud to have one of the strongest Alaska Hire policies in the state, and as a result, to have seen an improvement of around 10% in our residency statistics over the past four years. We actively recruit statewide, in both urban and rural newspapers, on the web, through

in-state networking and of course, through the Alaska Job Center Network. We recruit on campus at UAA and UAF each year and have been successful in attracting excellent interns and graduate hires from both schools.

BP employees are active leaders in state workforce development and educational boards, policy groups and programs. As such, we are proud to have positively influenced and endorsed the development of things like the Alaska Business Education Compact, APICC, the Blueprint for Alaska's Vocational Education, Alaska School to Work and Career Pathway programs, and Employability Standards. Most recently, we are supporting the consideration of an Alaskan award and implementation of the Malcolm Baldrige Total Quality Standards framework as a means to increase the accountability and success of Alaska's educational system.

Phillips

1. Please identify all persons participating in and/or assisting in preparing answers to these questions, including their full name, title, and a general description of their contribution to the effort.
2. Please set forth in detail all capital improvements designed, engineered or constructed by or on behalf of PA to facilitate sales of ANS natural gas to unrelated third parties from inception of Prudhoe Bay oil production to the present.
3. Please describe in detail any and all efforts undertaken by or on behalf of PA to develop ANS natural gas reserves not associated with existing oil producing fields.
4. Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of PA to locate and develop domestic markets for ANS natural gas.
5. Please describe in detail all efforts and initiatives specifically undertaken by or on behalf of PA to locate and develop international markets for ANS natural gas.
6. Please identify (full name, title, address and telephone number) the officers and employees whose primary duties and responsibilities have included marketing and sales of ANS natural gas.
7. Please provide an organizational chart for the PA marketing department, identify the positions dedicated to marketing and sales of ANS natural gas, and indicate the persons currently holding such positions.
8. Please identify potential customers for international sales of ANS natural gas.
9. Please identify potential customers for domestic sales of ANS natural gas.
10. Please identify potential customers for sales of ANS natural gas in Asia.
11. Please identify potential customers for sales of ANS natural gas in California.
12. Please identify potential customers for sales of ANS natural gas in Mexico.

13. Please identify potential customers for sales of ANS natural gas in the mid-west region of the United States.
14. Please identify potential customers for sales of ANS natural gas in Canada.
15. With respect to responses to questions 8-14, please describe with specificity all efforts, initiatives and programs undertaken by or on behalf of PA to market, sell, solicit bids to purchase (including public and obvious declarations of a willingness to sell significant quantities of ANS natural gas, whether conditioned or unconditioned, at clearly stated prices and terms) or otherwise to actively cultivate and encourage interest in and from potential developers of a project to transport and sell ANS gas to buyers or customers in any prospective market.
16. 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.
17. PA has made substantial capital commitments to a proposed LNG project in the Timor Sea, apparently targeting sales to Asian markets. Please set forth in detail PA's rationale and analysis supporting capital expenditures to commercialize natural gas reserves in foreign countries rather than ANS natural gas reserves.
18. State whether PA's concessions or interests in the proposed Timor Sea natural gas project are subject to any provisions or law that penalize or jeopardize the concessionaire or interest holder for delays in bringing natural gas reserves into production.
19. Please set forth the three highest non-spot LNG prices, which have come to PA'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 PA contends its LNG pricing is confidential and/or proprietary, then provide any price data PA has obtained or developed from third party sources or indices that are not subject to contractual confidentiality provisions.
20. Please provide PA's best estimate of proven natural gas reserves in the Cook Inlet region of Alaska, projected rates of consumption, and the approximate time of anticipated shortages if additional reserves are not discovered in a timely manner.

21. Please describe in detail all efforts, initiatives and undertakings by or on behalf of PA to offer ANS natural gas for sale to unrelated third parties from the inception of Prudhoe Bay production to the present.
22. Please provide an estimate of the cost of permitting an overland gas pipeline from the ANS to the lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting the estimate.
23. Please provide an estimate of the time necessary to permit an overland pipeline from the ANS to the lower 48 under each of the currently proposed routes, assuming the applicant is unable or unwilling to obtain permits and related assets from Foothills and/or its affiliated companies. Provide a narrative explanation of the rationale and analysis supporting the estimate.
24. Does PA believe that current lower 48 natural gas prices are sustainable, and if not, what average annual price does PA anticipate over the next five years? Ten years?
25. South Central Alaska currently uses Cook Inlet natural gas for home and office heating and electrical generation. How does PA propose to replace Cook Inlet natural gas sources as they are depleted?
26. Has PA made a decision regarding the most cost-effective route for an overland pipeline from the ANS through Canada to the lower 48 states? If so, please describe the route and the economic assumptions underlying the cost analysis.
27. Governor Knowles has publicly set a goal to break ground for an ANS gas commercialization project in two years. Please comment on the feasibility of achieving this goal, and what contribution PA is willing to make hereto.
28. Assuming PA supports an overland pipeline to the lower 48 (specifically the Alcan route), does PA intend to negotiate to acquire Foothills' pre-existing governmental approvals, or to commence an independent permitting effort?
29. Please set forth all of the perceived impediments to the so-called over-the-top route, submerged in the Beaufort Sea, emerging on uplands in the

Canadian Northwest Territory, and traversing the McKenzie Delta and Valley regions. Include environmental and political impediments.

30. Please list all of the contracts, excluding any confidential provisions, that PA has entered into or has an interest in, since the inception of production from Prudhoe Bay, contemplating sales of LNG to Asian markets. Exclude sales involving Alaska LNG.
31. Please describe in detail all permit applications submitted to governmental agencies by or on behalf of PA directly in support of an ANS natural gas commercialization project.
32. PA, in conjunction with BP and Exxon-Mobil, recently announced the formation of a group to study ANS natural gas commercialization alternatives. Please describe the alternatives the group intends to study, and among such alternatives, please identify those which have previously been studied by one or more of the group members.
33. The study group referenced in question 32 is to receive \$75 million in the first year funding. Please describe the rationale for this particular level of spending.
34. What is the relationship between the mandate of the study group referenced in question 32, and the Alaska Highway Natural Gas Policy Council the governor is proposing to fund during this legislative session?
35. Has PA established a time-line for sales of ANS natural gas to unrelated third parties, and if so, what is the target date to accomplish such sales?
36. Please describe in detail any and all agreements, understandings, arrangements, whether verbal or in writing, tacit or express, between PA and any other Alaska producers, or TAPS owners, concerning, directly or indirectly, the commercialization of ANS natural gas. Include, without limitation, any such agreements, understandings, and arrangements relating, directly or indirectly, to the timing of any commercialization project and associated sales of ANS natural gas to unrelated third parties.
37. Has PA ever, since the inception of Prudhoe Bay production, circulated or published among prospective ANS natural gas purchasers, a request for proposals or similar documents? If so, please provide details, including without limitation, the contents of the RFP or other solicitations, the date(s) circulated, the recipients, and all responses.

38. Until recently several ANS producers, including PA, claimed that off unit sales of ANS natural gas prior to 2005 would result in unacceptable losses of oil production. Has PA's position on this issue changed, and if so, please explain the reason.
39. Do any of the agreements pertaining to the BP-ARCO merger/acquisition, or the sale of ARCO's Alaska assets to PA, address, directly or indirectly, the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.
40. Do any of the amendments or modifications to agreements pertaining, directly or indirectly, to North Slope oil and gas units, and relating to the transactions described in question 42, address the commercialization of ANS natural gas and/or sales to unrelated third parties? If so, please describe in detail the relevant provisions.
41. Assuming an adequate Asian market for ANS natural gas, has PA made any decision or judgment whatsoever regarding the regional siting of a LNG plant and shipping terminal in Alaska? If so, please describe the decision and judgment in detail.
42. The gas produced from Prudhoe Bay contains substantial amounts of carbon dioxide (about 12% CO₂). We understand that depending upon the gas project, most or all of the CO₂ will be removed from the gas on the North Slope prior to entering the pipeline (from 12% to 2% for lower 48 pipeline, from 12% down to "parts per million" for an LNG project). Can the CO₂ extracted from gas committed to gas pipeline project(s) be used for enhanced oil recovery projects? Which fields might be considered for a CO₂ rich miscible injectant? Specifically, can CO₂ be used to enhance oil recovery in West Sak?
43. There is a projected shortage of natural gas in Cook Inlet by 2010. If there is a gas shortage, gas for export via the Phillips Kenai LNG plant may be the first to be curtailed relative to gas to the fertilizer plant or gas for residential heating and power generation. Is PA concerned whether gas supplies in Cook Inlet are sufficient for PA's existing LNG plant, the fertilizer plant and use by Alaska citizens for the future? What new sources of natural gas does PA foresee being developed in Cook Inlet in order to avoid future gas shortfalls? Does PA intend to file for a DOE authorization to extend LNG exports past 209?
44. Does a gas balancing agreement or agreements exist with respect to any ANS natural gas reserves? If so, please summarize the relevant terms and conditions of the agreement(s). If not, then set forth the circumstances

and conditions under which PA must obtain the concurrence and/or consent of one or more of the other ANS producers to sell or otherwise transfer ANS natural gas off-unit.

45. Since there have been fundamental changes of ownership and operator interests and responsibilities in several oil and gas units on the North Slope, particularly at Prudhoe Bay and Pt. Thomson, please provide a comprehensive, detailed description and explanation of any and all such changes, whether completed, in progress or contemplated. Include specific references to all agreements which require approval of the State of Alaska and the nature and status of those agreements, as well as a description, explanation and status report on all other agreements (specifically including Unit Operating Agreements) that are currently being negotiated, will be negotiated, or have been negotiated, and that do not require approval of the State of Alaska.
46. Please describe, in detail, your company's plans for best efforts to contract with qualified Alaskan contractors and firms in this state for work to be performed on planned projects, including the fabrication and installation of required facilities. Include in your response your company's plans to develop training for Alaskans through labor apprentice programs, University of Alaska, vocational training through local school districts, or any other programs.



PHILLIPS Alaska, Inc.

A Subsidiary of PHILLIPS PETROLEUM COMPANY

Post Office Box 100360
Anchorage, AK 99510-0360
Joseph P. Marushack
Vice President
ANS Gas Commercialization

April 2, 2001

The Honorable Scott Ogan
State of Alaska
House of Representatives
Juneau, AK 99801

RE: Alaska North Slope Gas Commercialization Briefing Paper

Dear Representative Ogan

Enclosed for your information, please find two copies of the subject paper.

As set forth in my March 6, 2001 letter to you, we have structured this paper to address the key topics in which you expressed interest. Under each topic, we have used a general question and answer format to assist in quickly finding material. You will also note, as you go through the paper, that there are extensive references to public web resources. We are providing a separate hard copy of some of the key public market information from those sites and we also stand ready to assist you in retrieving additional material if need be.

I also want to take this opportunity to assure you that Phillips is committed to economically commercializing its ANS gas resources. It is a legacy asset and we are aggressively pursuing what we think is the most promising option: a gas pipeline to the L-48. We also continue to try to find a way to make LNG cost competitive.

We hope that this briefing paper will provide useful information to you as you consider public policy matters concerning Alaskan gas commercialization. If you have any questions or concerns, please do not hesitate to contact me directly at (907) 265-6517. If you are unable to reach me, please contact George Findling (907) 263-4174, or Jerry Gallagher or Beverly Ward in our Juneau office 586-3680.

Sincerely,

Joe Marushack
Vice President, ANS Gas Commercialization
Phillips Alaska, Inc.



PHILLIPS Alaska, Inc.
A Subsidiary of PHILLIPS PETROLEUM COMPANY

Alaska North Slope Gas Commercialization

Briefing Paper

Contact:

Joseph P. Marushack, Vice President
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907-265-6517
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Overview

Phillips is committed to economically commercializing the ANS gas resources it acquired just one year ago. This resource is one of the largest, undeveloped legacy assets in the Phillips portfolio. Since acquiring the Alaskan resource, Phillips stepped up an already active development program. It has focussed substantial human and capital resources on what appears to be a very promising option: gas pipeline delivery to the Lower-48/Canadian markets. Phillips also continues to lead in the effort to develop a cost competitive LNG project located on the South-central coast of Alaska. Phillips has a history of proactive and innovating approaches to commercializing such opportunities.

Phillips Alaska, Inc. has prepared this briefing paper in order to convey both information and our perspective on a variety of topics concerning ANS gas commercialization. These topics have arisen during public discussion in Alaska. Phillips hopes that readers will find this briefing paper a useful resource in beginning to better understand this often complex but important matter.

Phillips has endeavored to ensure, to the extent practicable, the accuracy of the information presented in this briefing paper. We have tried to strike a balance between providing useful and candid information, but without disclosing confidential information.

The paper sets forth information concerning nine topics, each in a separate section. For each topic, a broad question and answer format is used to help the reader focus on material that is of interest. A summary of each topic is presented below.

1) Market Overview

This topic addresses the two potential markets for ANS gas: a) L-48 Gas Markets and b) East Asian and North American LNG Markets. For both markets, a description of the commercial aspects of how gas/LNG is bought, sold and transported is given. An overview of market players is presented as well as web site addresses for those interested in obtaining further, detailed information.

Phillips has had a significant presence in both of these markets for many decades. We live these markets. Therefore, we are well connected to potential customers for ANS gas and well aware of market dynamics and trends. Phillips considers the marketing of ANS gas to be a process not an event. Successful marketing depends upon developing and maintaining of relationships, on building credibility, and on keeping buyers well informed of the choices that Phillips brings to them.

2) Focus of North American Natural Gas Pipeline Group

This topic addresses Phillips' efforts in trying to commercialize ANS gas via a gas pipeline to the L-48/Canada. Overall, Phillips has seen what we believe could be a

substantial shift in supply/demand in the L-48/Canadian markets and that there is opportunity for ANS gas to enter that market. This is the reason why this option is receiving most of Phillips' focus. Since the work effort just began in December, this topic primarily addresses work plans that will be pursued to develop the substance.

3) North Slope Agreements That Address Gas Sales

An overview of the role gas has played in North Slope agreements is presented under this topic. The focus is on the core agreement: the Prudhoe Bay Unit Operating Agreement, which has many specific provisions related to gas sales. In addition, there have been a variety of agreements, by various parties, whose specific purpose is to advance gas commercialization.

4) Gas Balancing

Under this topic, the basic elements of gas balancing are discussed and it is shown that the Prudhoe Bay Unit (PBU) Operating Agreement already addresses many of them. From Phillips' perspective, gas balancing is not a major issue that would negatively impact our ability to commercialize PBU gas, but it is nonetheless covered in this briefing paper.

5) LNG Sponsor Group Plans

This topic deals with the Sponsor Groups plans regarding the Stranded Gas Development Act. No decision about whether to apply for a fiscal contract under the Act will be made until the second quarter, 2001, after some necessary additional work is complete.

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

Under this topic, details are given concerning Phillips' ongoing activities in developing its interests in the Timor Sea off of the North West Coast of Australia. These offshore developments center around the recovery of reservoir liquids, which provide critical initial revenues. Phillips has also been leading the development of gas resources by focusing on both domestic Australian markets as well as LNG. Reflecting the reality of the fiercely competitive and potentially oversupplied East Asian Market, Phillips recently announced intent to develop the first LNG supply project serving the North American West Coast. This project may present an opportunity for Alaskan LNG in the long term.

7) Competing LNG Projects

Details about the ownership and costs of LNG projects that compete with Alaskan LNG are given under this topic. In previous public presentations, the Alaska North Slope LNG Project sponsor group, which Phillips leads, has presented information that demonstrates how the East Asian LNG market is likely to be in a state of substantial oversupply through the end of the decade. While this market is growing, it is expected that about 60 - 75 million metric tons per year (MTPA) of supply will be chasing about 20-40 MTPA

of demand. Further, Alaska is at a distinct competitive disadvantage to other expansion and grass roots LNG projects because of the costs and risks of an 800 mile, buried, arctic pipeline that would be required to get gas to ice free tide water.

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

The Cook Inlet gas supply/demand situation is reviewed, including seasonal deliverability. Phillips' expectation is that the Cook Inlet, like most other resource basins, will experience new discovery and development of additional reserves as current supplies are produced. Also, Phillips' goal is that its Kenai LNG plant operate well beyond 2009, but the gas reserves that will underpin that operation still have to be defined.

9) Consideration of Wellhead Sales to Third Parties

This topic addresses why 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. Also addressed under this topic is why the concept of posting a "wellhead price" is not meaningful.

1) Market Overview

What are the characteristics of the L-48 markets and players in that market?

The lower 48 gas market is complex. Ultimate consumers of gas include primarily the electric power generators, gas fired industrials of multiple disciplines and residential customers. Many industrial and most residential customers are serviced by local distribution companies (LDC's) that buy gas wholesale and distribute it retail. Some larger industrials and many of the gas-fired electric power generators make arrangements to purchase their own gas.

Gas producers, gas marketing companies and gas pipeline marketing affiliates do much of the wholesale buying and selling of gas at various points from the wellhead all the way to the various "burner-tip" markets identified above. Relatively few marketing companies, in deregulated LDC areas, by-pass the LDC and sell retail to the smaller industrials and selected residential customers.

Natural gas in the U.S. and Canada is also sold on the gas commodities market. While physical gas is required to complete the final transactions each month, 'paper transactions' to buy and sell gas on the NYMEX, other exchanges and the over-the-counter markets can be traded until the close of business for a particular gas contract month. These paper and physical transactions involve purchase and sale of gas commodity contracts as well as purchase and sale of commodity options.

From these transactions, 'price derivatives' can be developed to create ceiling and floor prices for gas transactions or to 'swap' fixed prices for index-related or 'floating' prices. Because of this liquidity in the natural gas commodity and physical market and because of the current demand and expected significant growth in gas demand over the next decade, U.S. and Canadian sales of natural gas have a multitude of flexible purchase and sale options and opportunities.

While a large percentage of gas can be and continues to be sold monthly and daily on the 'spot market', there is also a significant market for long term gas sales to marketing companies, other wholesalers and end users seeking long term supply. This long-term gas supply provides the 'base load' for servicing their industrial, power generation, LDC, residential sales customer and other burner-tip needs. This long-term supply provides the base load needed to arbitrage storage and transportation opportunities across the pipeline grid.

Further, gas-fired electric power producers and gas-fired industrials are also seeking longer term supplies to base load their portfolios as their demand continues to grow. According to the Energy Information Agency (EIA), *Natural Gas Monthly*, September 1999, about 50% of gas demand growth is expected from electric generation and about 25% of demand growth is expected from gas-fired industrial demand through the end of the decade.

Offers to purchase gas under 10 to 20+ year contracts at either negotiated fixed prices -- or prices with 'collars' (a floor price and a ceiling price) -- are commonly available for relatively small "packages" up to very large "packages" of gas (large usually measured in billions of standard cubic feet). Long-term gas contracts can also be structured based on an index or floating price if the gas supplier (or purchaser) so desires. This is possible due to the liquidity in the marketplace through the physical and gas derivatives market as well as the anticipated, substantial gas demand growth.

As reference, a plot of historic gas prices at the Henry Hub is given in Attachment 1.

While the list of U.S. and Canadian gas buyers and sellers is not endless, it is extensive. A list of over 60 Canadian Electric and Gas Utilities is enclosed. Information on the individual companies listed can be accessed at www.utilityconnection.com/page3x.html. A list of over 150 U.S. Investor Owned Electric Utilities is enclosed. Information on the individual companies can be accessed at www.utilityconnection.com/page2b.html

A list of over 180 U.S. Cooperative Electric Utilities can be accessed at www.utilityconnection.com/page2a.html. A list of over 240 U.S. Publicly Owned Electric and Gas Utilities can be accessed at www.utilityconnection.com/page2e.html. A list of over 150 U.S. Investor Owned Natural Gas Utilities can be accessed at www.utilityconnection.com/page2c.html. A list of 30 Energy Marketers can be accessed at www.utilityconnection.com/page2d.html. All of these lists and a ranking of U.S. Electric Utilities by fuel consumption as well as a ranking of U.S. Electric Non-utilities can be provided in hard copy upon request.

The 'mega marketers' or 'top tier players' in domestic natural gas include, but are not limited to:

- Gas Processing
 - Duke Energy Field Services
 - El Paso Natural Gas
 - Williams Energy
- Transmission
 - El Paso Natural Gas
 - Williams Energy
 - Duke Energy
 - Enron
 - Columbia
- Wholesale marketing
 - Enron
 - El Paso Natural Gas
 - Duke Energy
 - Dynegy
- Merchant power
 - Miront (aka: Southern)

- Edison
- Duke Energy
- El Paso Natural Gas
- PG&E

Note that Duke Energy Field Services for gas processing is a joint venture between Duke Energy and Phillips Petroleum Company, established in April, 2000.

Gas marketing is also a function of transportation and storage. There are over 80 interstate pipelines in the U.S. and Canada regulated by the Federal Energy Regulatory Commission (FERC) in the U.S. and by the National Energy Board and various provinces in Canada. There are over 20 major intrastate onshore pipelines and over 20 Gulf Coast offshore pipelines.

There are over 400 storage facilities in the U.S. alone. Those facilities, consisting of depleted production fields, aquifers, salt domes and domestic LNG storage hold over 8,300 Bcf of working gas and can deliver over 89 Bcf on a daily basis.

This storage is used by the various market players to provide seasonal peaking service, pipeline balancing and market arbitrage by loading in gas in lower-priced seasons and withdrawing it during potentially higher priced seasons. While interstate pipelines (~60%), LDC's (~33%) and independent operators (~7%) own and operate most of the U.S. gas storage, they are not necessarily the owners of the gas in storage.

Gas transportation is primarily held by shippers on either a firm basis or an interruptible basis. Firm transporters pay a reservation fee regardless of whether the full volume is shipped on the pipeline and also pay an additional fee based on the actual volume of gas transported. Interruptible customers are not subject to a reservation fee but are the first shippers pro-rated off of the pipeline in times of restricted capacity.

Transportation to the marketplace can be critical. A FERC list of firm shippers by pipeline can be accessed on the FERC's web site at www.ferc.fed.us or provided in hard copy upon request. While this list is quite extensive, it demonstrates the vast opportunity to do business with multiple shippers/marketers/consumers across the interstate pipeline grid.

What are the characteristics of the East Asian and North American LNG markets and the players?

Phillips started the East Asian trade some 30 years ago and continues to be active in that market. As we have stated, Phillips doesn't just visit the markets, we live there. We have offices in Japan, China and Taiwan. In particular, our Japan country representative has personal relationships developed over decades of working with LNG buyers and we treat our business relationships as valuable and confidential assets.

Current market conditions suggest that multiple markets in East Asia would be required to find a home for the initial 7-8 million metric tons per year (MTPA) of LNG envisioned for an Alaskan LNG project. Expansion projects such as Malaysia Tiga and Australia Northwest Shelf have reportedly struggled to develop multiple, small-volume markets in E. Asia for their ongoing expansion projects. Some of these markets are less than 1 MTPA each. Phillips determined that it was economically better served to pursue U.S./Mexican markets with its E. Timor LNG rather than seek markets in a fiercely competitive E. Asian marketplace at this time.

LNG is primarily purchased in E. Asia by well-established utilities in Japan, S. Korea and Taiwan. Emerging markets include China and India, which have to overcome ongoing concerns about both infrastructure and market stability.

Japan is the largest and most complex of the Pacific Rim LNG markets. Japan's largest electric utility purchases more LNG by itself than S. Korea and Taiwan combined. Several factors that are likely to have the greatest influence on future LNG demand growth in Japan include nuclear power generation growth, competition from coal-fired power generation and the ability of city gas companies to displace competing industrial fuels as well as the overall Japanese economy.

Electricity deregulation in Japan is in its early stages with significant policy issues yet to be defined. It is expected that the picture concerning the ultimate direction of deregulation and the effect it might have on LNG demand in Japan will not be clear for several years. It will be difficult to predict with any certainty what effect electricity deregulation initiatives in Japan will have on LNG demand potential.

However, LNG-fired power plants will likely remain the near-exclusive domain of the existing electric power companies and a few existing city gas companies that have current access to existing infrastructure. All Japanese electric power companies and city gas companies should be considered potential customers of ANS LNG.

More EIA information on Japan's energy needs and issues can be retrieved at www.eia.doe.gov/emeu/cabs/japan/html. That web site lists major electric power companies as: Chubu Electric, Chugoku Electric, Hokkaido Electric, Hokuriku Electric, Japan Atomic Power, Kansai Electric, Kyushu Electric, PNC, Shikoku Electric, Tohoku Electric, Tokyo Electric. Other potential energy contacts are listed on that web site that may be able to provide further information on potential Japanese customers.

Until recent years, S. Korea was the most rapidly growing market for LNG demand posting average annual growth rates upward of 25%. However, more recent economic crisis has resulted in the stagnation of the LNG demand growth. While there are other potential customers developing, currently, Korea Gas Corporation (KOGAS) is the sole importer of LNG into S. Korea.

Though there are plans for partial privatization of Taiwan, Chinese Petroleum Company (CPC) in the future and while others are progressing potential projects to construct an

additional LNG import terminal in the northern part of Taiwan. Chinese Petroleum Company (CPC) effectively has a current monopoly as the sole importer of LNG.

As reference, yearly East Asian LNG illustrative prices for 1990 to 2000 are shown in Attachment 2 and monthly Japan crude cocktail (JCC) and estimated East Asian LNG prices are shown in Attachment 3.

While there is talk of future LNG to E. Asia being fully based or partially tied to natural gas prices, those LNG markets are currently tied to crude oil for their pricing formula. Conversely, LNG delivered to the U.S. marketplace is currently tied to U.S. natural gas prices and the U.S./Canadian natural gas market dynamics previously discussed.

Looking toward the United States, according to the EIA, there are almost 100 peak shaving LNG storage sites in the U.S. with 83 on the East Coast and Midwest and about a dozen in the Western United States. Domestic pipeline gas is the primary source for this LNG. This storage constitutes over 90 Bcf of working gas capacity and over 11 Bcf of daily deliverability. This gas is used primarily as high cost and high priced, seasonal peaking and balancing.

While LNG imports are not expected to become a significant percentage of U.S. gas use in the near term, there are currently 4 LNG receiving terminals located in the U.S. at Everett, MA, Cove Point, MD, Elba Island, GA and Lake Charles, LA. While Cove Point and Elba Island are in the process of being reactivated from mothball status, at full capacity the EIA reports that there is about 19 Bcf of LNG storage and 3 Bcf of combined regas capability from the 4 facilities when in full operation.

Phillips and El Paso recently announced a letter of intent for an E. Timor LNG Project by Phillips and El Paso. If the deal is finalized, the resulting project is expected to land around 4.8 MTPA of LNG with about 680 MMcf of natural gas availability as early as 2005. Location of the regassification facility in either Baja California, Mexico or the U.S. West Coast is yet to be determined. If ANS LNG can overcome the cost of the 800-mile, buried, arctic pipeline and become cost competitive and otherwise economic compared to other ANS gas alternatives, the potential exists for expansion of this West Coast regassification facility for future ANS LNG supplies.

Another potentially useful overall information source on gas markets is www.gas.com.

2) Focus of North American Natural Gas Pipeline Group (NANGPG)

Why was the joint team formed?

In September 2000, the three major producers of Prudhoe Bay started discussions regarding the desire to look jointly at the possibility of developing a pipeline that would transport Alaska North Slope natural gas from the Alaskan North Slope to Canada and the lower forty-eight markets. Agreement was reached in December.

Up until that time there were various efforts being conducted regarding the commercialization of ANS gas. The LNG Sponsor Group was and is still trying to make LNG feasible. BP publicized its earlier effort on a pipeline to the lower forty-eight as well as committed to build a demonstration Gas to Liquids plant in Alaska. Some producers were considering the feasibility of locating a Gas to Liquids plant on the North Slope. In 2000, the industry, among others, had sponsored a study by Purvin & Gertz (P&G) regarding the feasibility of transporting Arctic gas to markets in the lower forty-eight. The P&G study concluded that transportation of ANS gas to the lower forty-eight markets might be problematic in the near term, and that a pipeline route following the "Northern Route" was more economical.

Phillips was participating in the LNG Sponsor group during this time, and, in April of 2000 we had just acquired the Alaskan assets of ARCO. During the BP/ARCO merger activities, ARCO Alaska, Inc. and Phillips did not pursue the L-48 pipeline option in any significant detail. The agreement to move forward is an indication of a common belief among the producers that the Lower-48 pipeline presents an opportunity that will best be addressed by combining the talents and resources of the major gas owners.

These strong natural gas markets as well as realignment of oil and gas interests in the Prudhoe Bay Unit set the stage for a pipeline project. In order for a project to move forward, parties need to be confident that the project will be feasible and economic. This requires an understanding of: the economic, regulatory, and socioeconomic issues; the trade off of potential oil loss and gas sales; the optimization of design and routing options; and the implications of First Nation issues and native rights. There are many other details that haven't been mentioned that will affect the project.

Phillips believes that a common view and understanding of the project fundamentals among the major owner producers of the gas will provide the highest probability of success in the implementation of a project of this magnitude. That is why the joint group has been formed.

What is the basis for the expenditure of \$75 million?

While the NANGPG Agreement was being negotiated by the three companies, personnel from each company worked together to develop a work scope and budget for the year

2001. The initial premise was to estimate the resources that would be required to file for permits to the National Energy Board (NEB) of Canada and the Federal Energy Regulatory Commission (FERC) for a pipeline from the North Slope to Alberta Canada and on into the lower forty-eight markets. The pipeline from the North Slope to Alberta would be evaluated along two routes to determine the economic feasibility of each route. Additional information necessary to make complete applications included the conceptual estimates for the gas treatment facilities, the NGL facilities and any connections that would be needed to facilitate the operation and financial success of the pipeline.

To file an application for permits, one needs to identify a route, and to have been in contact with the landowners along the right-of-way. It's required to demonstrate the supply of natural gas and the market demand for the gas. Extensive environmental assessments need to be made. The footprint of the project and also any possible future expansions must be identified. There is a need to provide assurance that the project will be financially viable. To prove financial viability one has to have established the tariff methodology. The system will be a non-discriminatory, contract carrier pipeline and potential customers are going to have input into the rate structure. These are just a few of the matters that need to be addressed prior filing for applications.

Adopting an aggressive target of December 2001 as a target for the filing of applications, the group evaluated the necessary resources in the commercial, environmental/regulatory, external affairs, and technical disciplines required to meet the target. Preliminary work plans and required resources were identified and then cost to complete those plans was estimated. Space to house the project was identified. In the Agreement, each company supplies a roughly equal number of people to the joint group. All costs for the project are shared equally among the three companies, and no one company has the lead in managing the project.

The joint group identified the need for third party resources and estimated those costs as well. It was agreed by the companies that the logistics of appointing staff and engaging contractors would tend to limit the expenditures in the first year of this project to approximately seventy five million dollars, though the actual amount that will ultimately be spent in 2001 could be higher.

One of the first objectives of the joint group in the first quarter of 2001 is to verify the preliminary budget and schedule with contractors. This activity should be completed soon. The budget for the year 2001 was the best estimate of the resources required to enable the joint group to file an application for permits with the NEB and FERC. The joint group hopes to be ready to file for permits along a single route from the North Slope to Alberta, and for one route from Alberta to markets such as Chicago.

3) North Slope Agreements That Address Gas Sales

Have North Slope agreements positively or negatively impacted the prospects for AAS gas sales?

The core agreement among the Working Interest Owners ("WIO") of the Prudhoe Bay Unit is the Prudhoe Bay Unit Operating Agreement ("PBUOA"), which was executed in 1977 prior to field start up. The PBUOA is a complex document for many reasons, including the size and remoteness of the field, the complex reservoir recovery mechanisms, the difference in timing of oil and gas recoveries, and the differences in ownership resulting from different original lease positions.

The WIO's have had great success in developing the Prudhoe Bay Unit. Indeed, whereas initial liquid hydrocarbon recoveries from the main Prudhoe reservoir were projected to be 9.6 billion barrels, more than 10 billion barrels have been recovered already and current estimates are that recoveries will exceed 13 billion barrels.

The WIO's have made these substantial increases in recoveries through huge investments and attendant amendments to the PBUOA and other agreements. For instance, starting in 1983, the WIO's entered into the first of a series of agreements that provided for the construction of the Central Gas Facility ("CGF"), which increased gas handling capacity, developed the capacity to manufacture and blend natural gas liquids ("NGL") into the crude oil delivered to TAPS, and provided for the manufacture of miscible injectant ("MI") for use in enhanced oil recovery operations. Subsequently, in 1988, 1990 and 1997, the WIO's repeatedly agreed to major expansions of the CGF, with concomitant increases in gas handling capacity, and NGL and MI production.

Other agreements have been reached by the WIO's to provide for exploration and development of the satellite fields within the Prudhoe Bay Unit (currently Lisburne, Pt. McIntyre, Niakuk, West Niakuk, West Beach, North Prudhoe Bay, Midnight Sun, and Aurora; with Polaris and Borealis now in process). Before each of these new fields could come on line, special operating agreement terms were required, as were terms for the sharing of equipment and services among the various participating areas, and various state approvals.

The PBUOA already establishes the right of the WIO's to take gas in kind. Indeed, gas has been taken in kind by various WIO's since start up in 1977. Prudhoe gas has been sold to the TAPS Owners to run the first four pump stations, sold to Norgasco for distribution and sale in Deadhorse, and more recently, used in production operations at NorthStar. Likewise, gas in the form of NGL's has been taken in kind, blended into the crude oil and sold since 1982 and additional NGL's have been taken in kind for use in EOR operations at Kuparuk since 1996. As necessary, agreements to address such matters as connection points, operational interfaces, and measurement have been entered into to facilitate these takings.

Finally, it is important to recognize that the PBUOA specifically provided for what is called "Major Gas Sale," which is essentially triggered by sales through a gas pipeline from the North Slope in excess of 1.75 BCFD. No PBUOA amendment or other WIO agreement since the original drafting of the document contradicts the basic premise of the PBUOA that such a sale will eventually occur. To be sure, Phillips Alaska anticipates that some further agreements will be negotiated in connection with a Major Gas Sale. However, consistent with the history of the Prudhoe Bay Unit, these will address specific issues particular to the project, as it becomes defined. Moreover, Phillips Alaska is not aware of any term of any agreement among the WIO's that would allow any WIO to block a Major Gas Sale.

But aren't there any agreements that specifically facilitate ANS Gas commercialization?

Since Prudhoe Bay field startup, the leaseholders and others evaluating and attempting to commercialize the gas have spent nearly \$1 billion. These efforts were conducted under specific, usually confidential agreements that are too numerous and wide ranging to cite. Two recent examples, however, are the Agreement for the Alaska North Slope LNG Project, executed in 1998 and the Agreement for the North American Natural Gas Pipeline Group executed in 2000, which lead to the formation of the joint producer group. We know of no agreements that prohibit gas sales.

4) Gas Balancing

Is a gas balancing agreement required for ANS gas sales?

This paper will describe the imbalances which may occur when gas is produced; will identify some typical causes and common remedies for such imbalances; and then address potential gas balancing issues specific to the Prudhoe Bay Unit.

Generally, a gas imbalance occurs where there are two or more owners with the right to a share of continuing gas production and at least one of those owners takes more than that owner's proportionate share of that production. Gas imbalances can be caused when one or more, but less than all of the owners entitled to a share of the production enter into marketing contracts, or when the separate marketing arrangements of individual owners provide for deliveries at different rates. Imbalances can also result when individual owner's anticipated marketing arrangements are disrupted or terminated by events such as a gas purchaser's default or bankruptcy, or by failures or operational problems encountered by a particular pipeline or other transportation system.

While there are some "form" gas balancing agreements available in the industry, it is normal to tailor such agreements to specific circumstances through negotiations among the producers. In those negotiations, the owners may address matters such as:

- 1) each working interest owner's ownership interest in the gas to be produced;
- 2) the right of each owner to take its share of gas production in-kind;
- 3) the right of the parties to take any gas production allocated to but not currently taken by other owners;
- 4) the scope to be used for gas allocation and balancing;
- 5) the responsibility of the operator to control production, to maintain accurate records of production, including over or under production by any party and to administer the parties' gas balancing agreements;
- 6) the basis for an under-produced party to subsequently make up imbalances, either volumetrically and/or by monetary settlement;
- 7) responsibility for the payment of royalties and production taxes; and
- 8) the sharing of any gas liquids recovered during gas production and processing operations.

Currently, there is no separate gas balancing agreement for the Prudhoe Bay Unit. However, the Prudhoe Bay Unit Operating Agreement ("PBUOA") already addresses many of the matters described above. For instance, interest ownership, gas allocations, gas accounting provisions, responsibility for production taxes and royalties, the sharing of gas liquids and operator responsibilities are established, albeit subject to the possibility of future refinement or amendment, as appropriate and mutually agreed. Moreover, each working interest owner currently has the right, but not the obligation, to take gas in kind. After a "Major Gas Sale" - which is effectively when 1.75 Bcf/d is exported from the

North Slope via pipeline - each working interest owner is required to take in kind or separately dispose of its allocated share of gas production each month.

This right and obligation to take Prudhoe Bay gas in kind is subject to certain limitations. For instance, it is subject to procedures that may be agreed to among the working interest owners and gas purchasers for deliveries to a gas pipeline, and it may also be subject to procedures for balancing deliveries that "shall be developed and approved" by the working interest owners. The PBUOA requires that any such procedures for balancing deliveries must provide means whereby each working interest owner receives its share of gas reserves in a "timely and equitable manner".

Thus, the PBUOA already addresses many of the elements of a gas balancing agreement, and provides standards that will facilitate gas sales, while protecting each working interest owner's interests. As a gas pipeline project is developed and becomes better defined, and before it is sanctioned, Phillips Alaska anticipates that any necessary agreements will be developed. In addition, Phillips Alaska recognizes that various governmental agencies have existing authority to influence or regulate gas offtake and balancing issues so as to assure that no undue impediments to gas commercialization arise and that the public interest is served.

Can one of the producers block gas commercialization through gas balancing?

While it is true that various agreements will be needed to move gas commercialization to reality, this would not be our view of the situation. Rather, Phillips believes that the current focus should be on developing a economically competitive project that will be robust in entering and staying in the market.

Can the state take its Prudhoe royalty gas independent of the producers?

No, not under the lease terms. The state is eligible to take its royalty share of gas when it is produced and sold from the Unit.

5) LNG Sponsor Group Plans

Does the LNG Sponsor Group intend to apply for a fiscal contract before the deadline?

While the ANS LNG Sponsor Group and the Alaska North Slope LNG Project qualify now under the Stranded Gas Development Act, the plan is to complete more Stage 2 work and then make a decision on whether to file as a qualified project in the second quarter of 2001.

The essentials of the Stranded Gas Development Act provide that the Department of Revenue Commissioner may negotiate terms for inclusion with qualified sponsors or sponsor groups. Since there is no guarantee of outcome to the qualified sponsor in this negotiation, satisfactory or project beneficial results cannot be considered a given. A qualified project is a proposal for new investment that 1) exports liquefied natural gas, 2) uses more than 0.5 Tcf in 20 years from commercial operations and 3) is capable of making gas available instate, within economic proximity of the project.

A qualified sponsor or sponsor group needs to meet the criteria of both 1 and 2 below:

Criteria I (one of)

- Intends to own an equity interest
- Intends to commit gas it owns
- Holds permits that departments determine are essential

Criteria II (one of)

- Owns a working interest in at least 10% of the stranded gas
- Has the right to purchase at least 10% of the stranded gas
- Has the right to acquire, control, or market at least 10% of the stranded gas
- Has a net worth of at least 33% of the project
- Has an unused credit line of at least 25% of the project

Again, the ANS LNG Project Sponsors qualify under both Criteria I and II. A proposed project should describe:

- Work accomplished to date
- Schedule of development activity
- Description of lease or property believed to contain stranded gas
- Methods and terms for 'local gas' and pipeline
- Detailed mitigation methods re: public services and negative impacts
- Detailed options for safe management and operation after construction
- Other information required by the Commissioner to show 2 requirements:
 - Diligence
 - Non-conflict with other lessees
 - Satisfactory instate gas plan

The ANS LNG Sponsor Group believes it can readily meet these requirements within the prescribed sequence under the Stranded Gas Development Act. Even if the ANS LNG

Project were cost competitive now, a more natural market driven schedule would be to file an application 2-3 years from today. However, since the statute requires applications by June 30, 2001, the ANS LNG Project believes it meets the requirements and the Sponsor Group will decide in the second quarter of this year whether to make an application.

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 Bayu 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.

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, Trinidad, 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 of 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

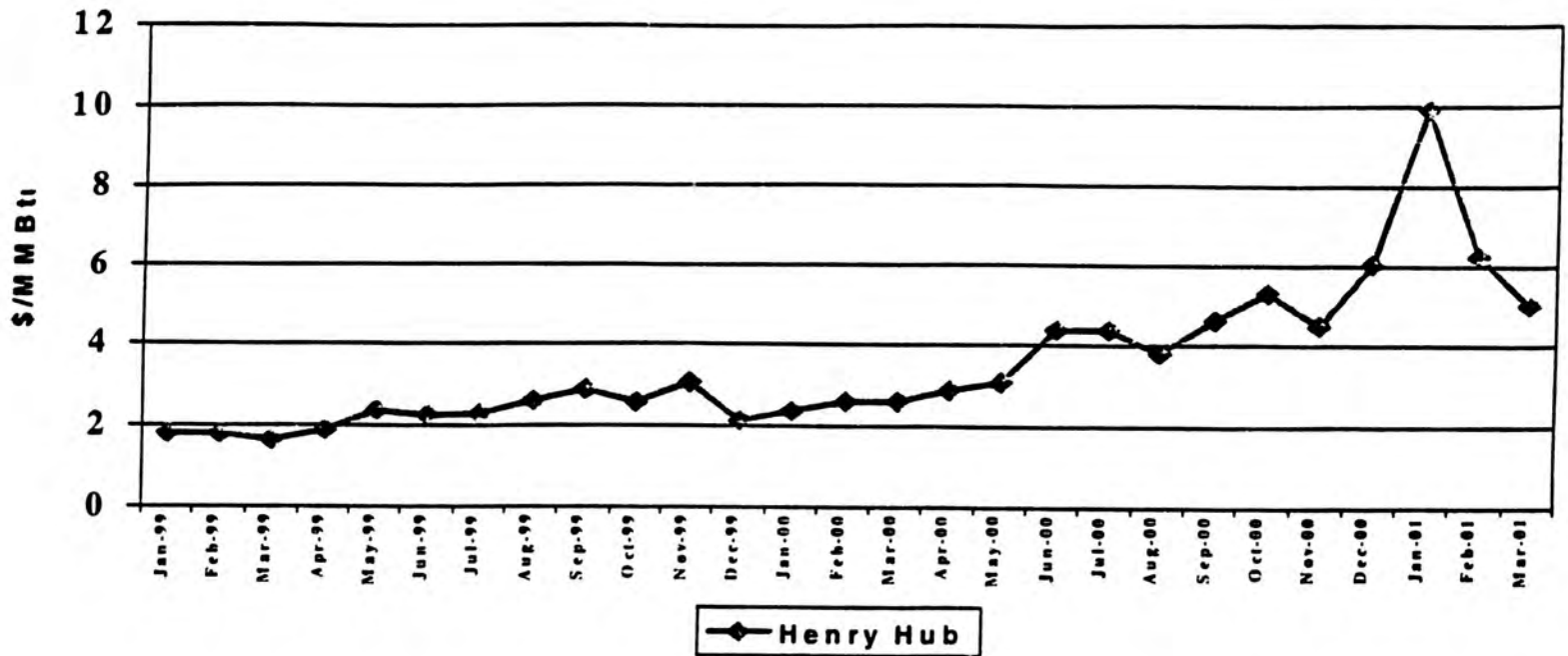
artificial "ceiling" which could limit the state and producers enduring realization of revenues.

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.

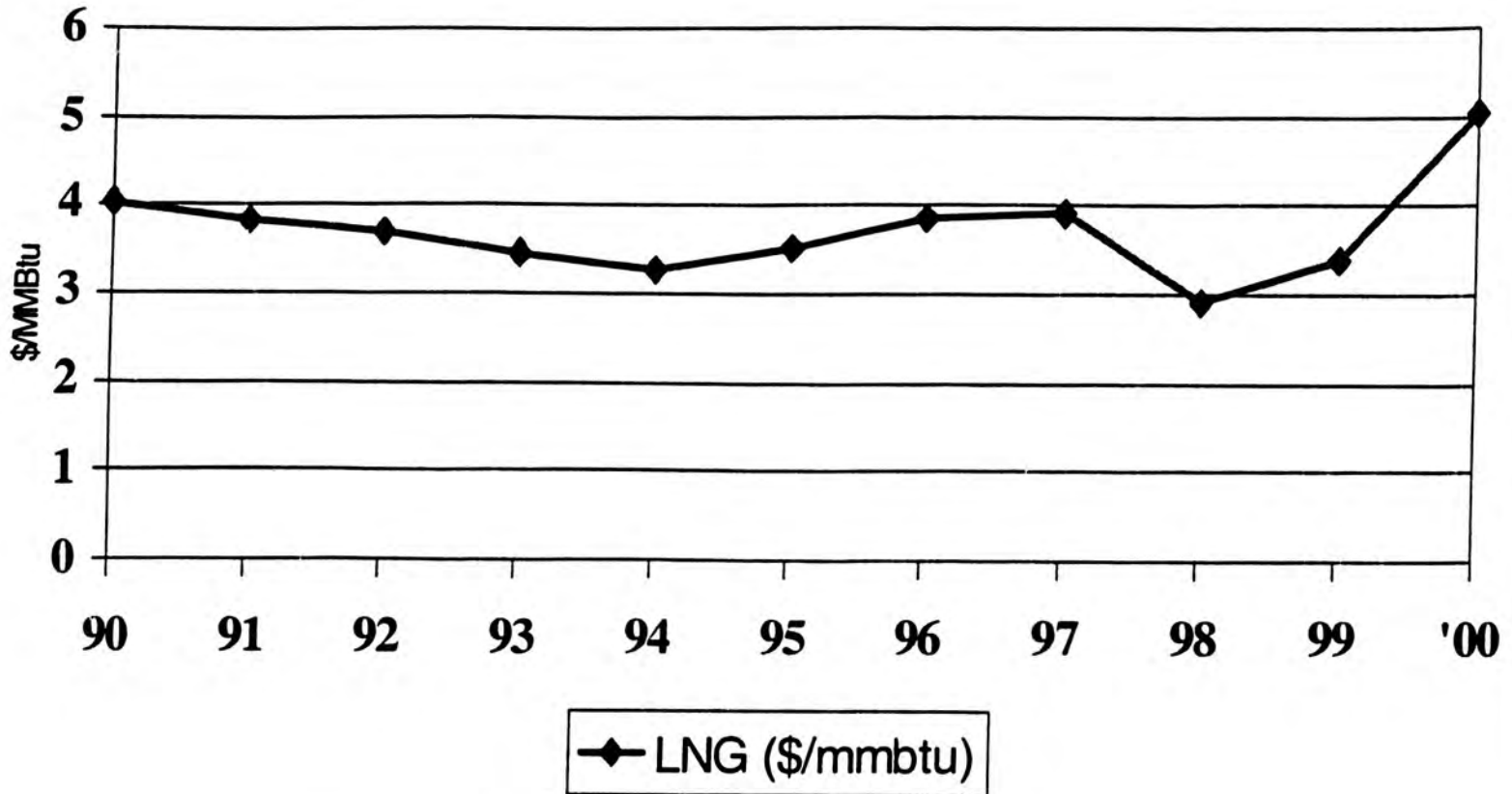
Attachment 1

Historic Henry Hub Prices



Attachment 2

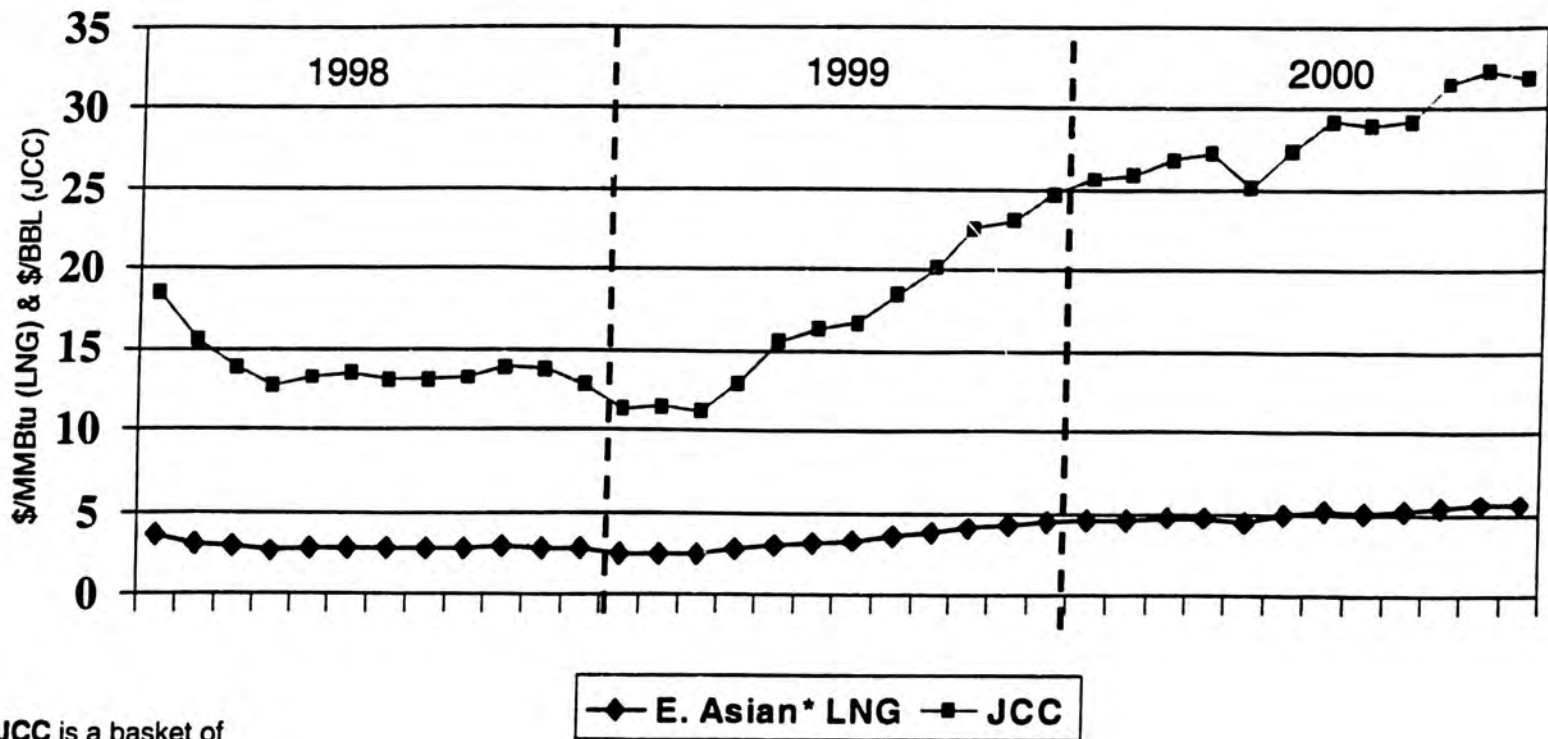
Yearly E. Asian* LNG Illustrative Averages



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

Attachment 3

Monthly JCC and Estimated E. Asian LNG Prices



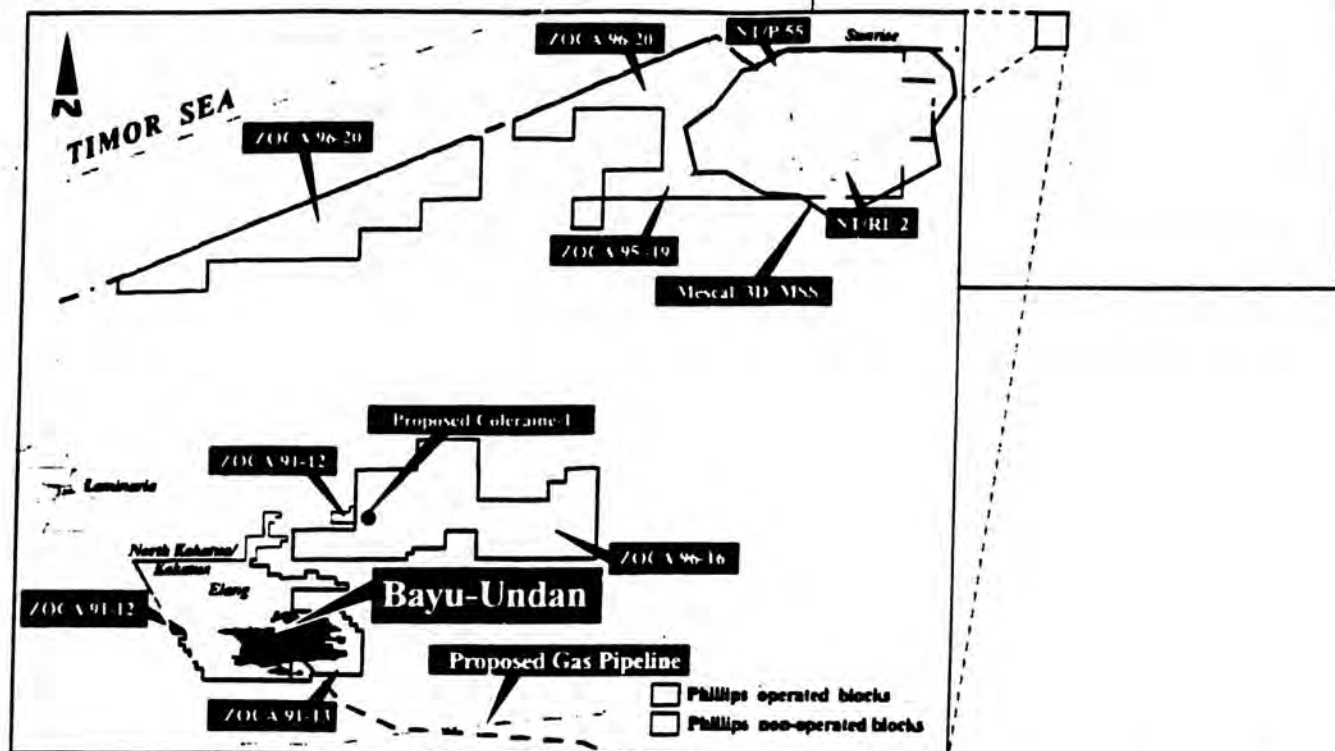
JCC is a basket of world crude oil prices into Tokyo

* Example JCC formula as: $LNG = .1485 \times JCC + .83$
(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

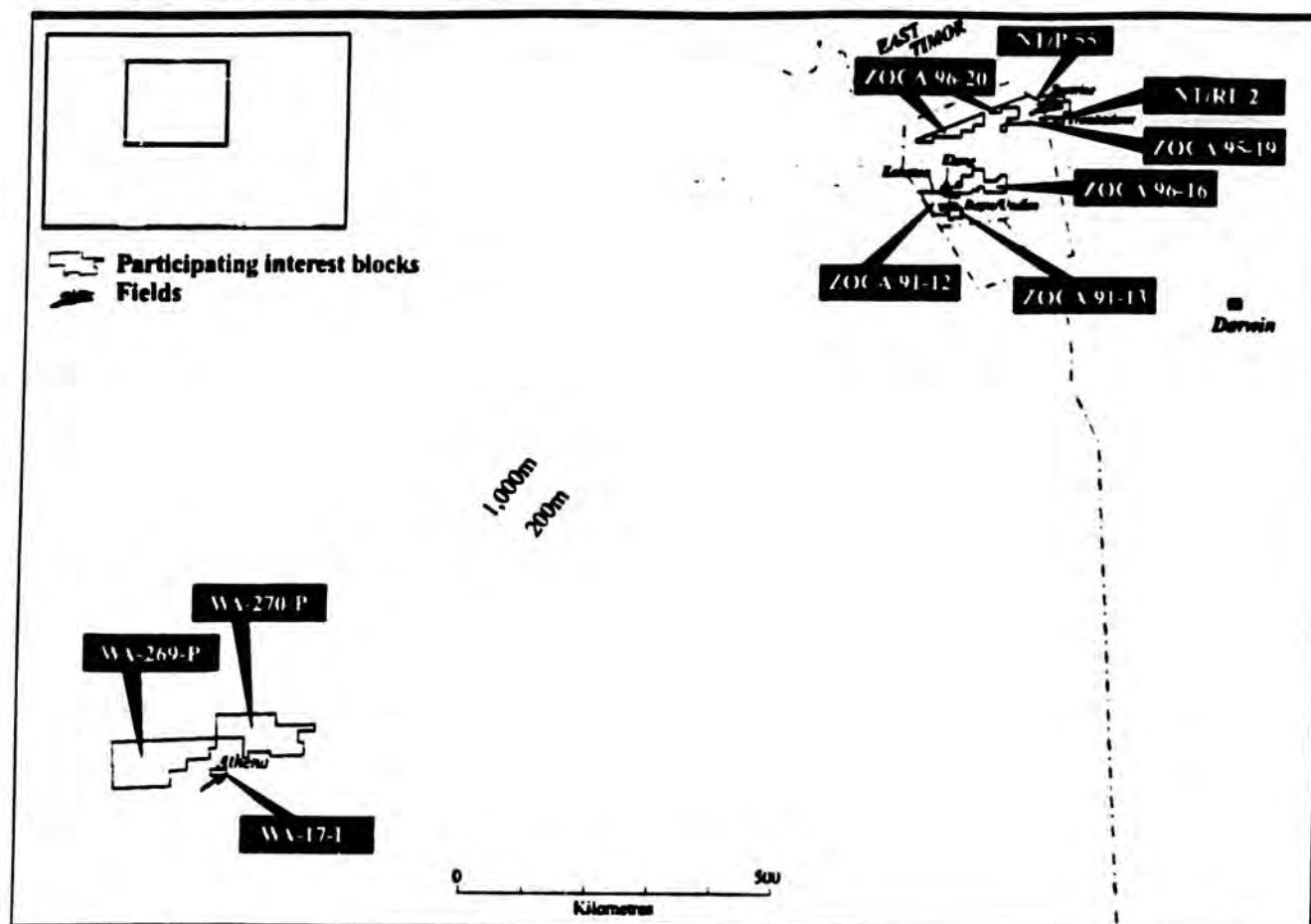
Phillips 50%

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.

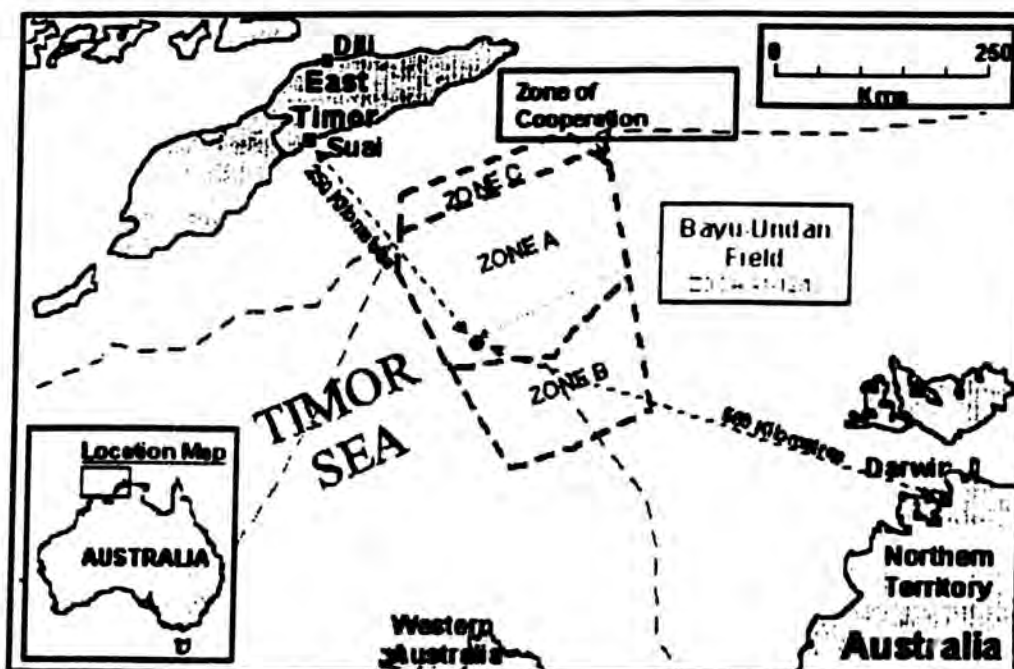
Attachment 6

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:
 (Operator)

ACN 064 963 346

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

ARBN 0

Santos (ZOCA 91-12) Pty Ltd:
Inpex Sahul, Ltd:
Petroz (Timor Sea) Pty Ltd:
Emet Pty Ltd:

ACN 056 937 752

ARBN 059 844 781

ACN 053 697 794

ACN 050 134

Kerr-McGee (ZOC) Energy Ptd Ltd:
Agip Australia 91-13 Ltd:
Phillips Petroleum Timor Sea Pty Ltd:

ACN 05

ARBN 054 729 930

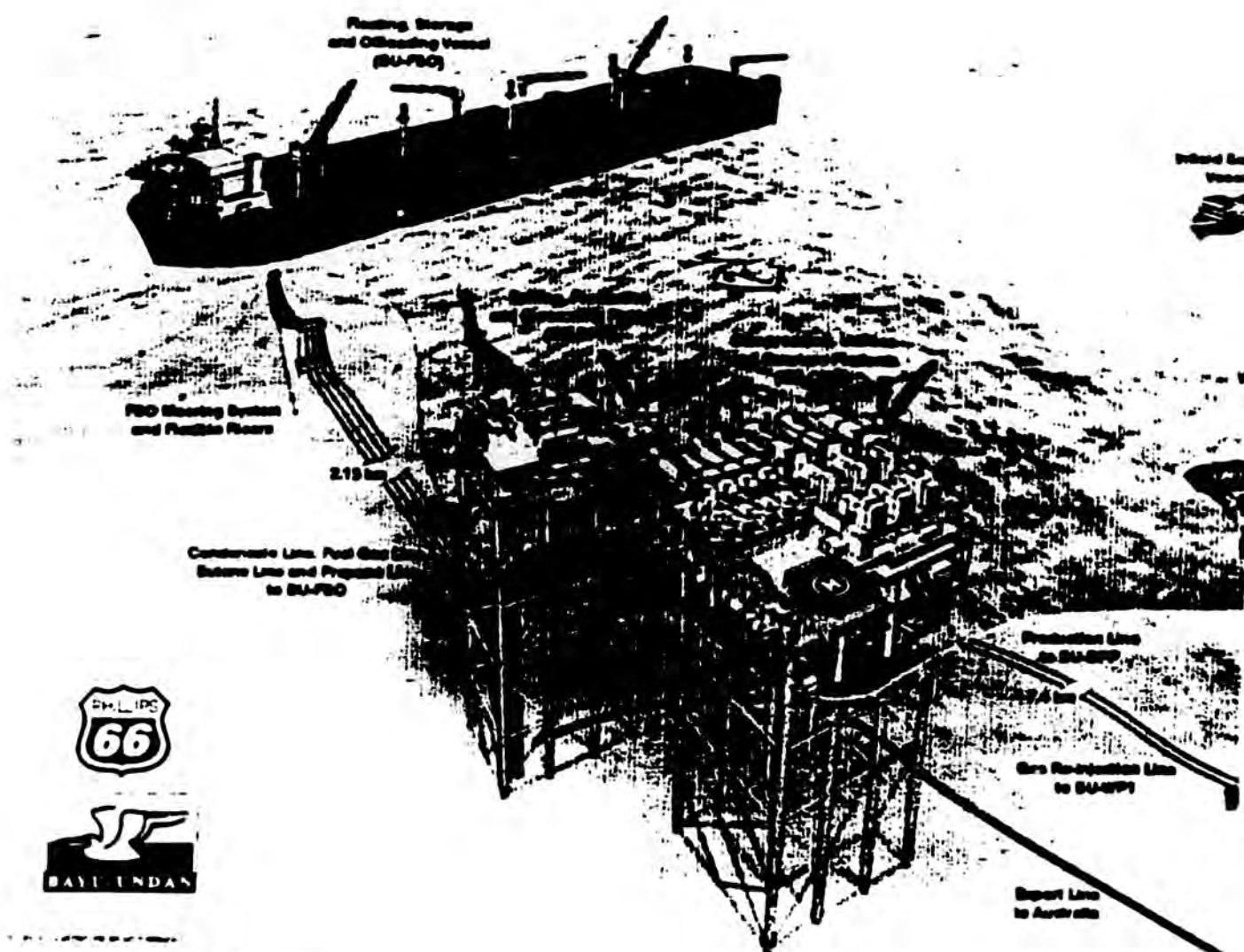
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907

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 (130,000M³) of Con

2 x 300k barrels (47,500 M³) 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.

CAUTIONARY STATEMENT FOR THE PURPOSES OF THE "SAFE HARBOR"

PROVISIONS OF THE U.S. PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

The contents of this website contain forward-looking statements made by, or on behalf of, Phillips and the other Unit Participants. Neither Phillips nor the other Unit Participants undertake to update or revise any of these forward-looking statements. These include, without limitation, statements relating to operations, plans, strategies, objectives, expectations and limitations. These statements are not guarantees of future performance or result. Rather, due to risks, uncertainties and other factors, actual results may differ materially from those expressed in any such forward-looking statement. The following are certain (but not necessarily all) important risk factors that could cause actual results to so differ:

Plans to drill wells and develop Bayu-Undan are subject to: the ability to obtain agreements or consents between or from co-venturers and governmental authorities; engaging drilling, construction and other contractors; geological, land or sea conditions; world prices for oil, natural gas and natural gas liquids; applicable law and regulatory requirements; and the availability of economical financing.

Estimates of proved reserves, raw natural gas supplies, and project cost estimates have been developed using the latest available information and data, and recognized techniques of estimating, including those prescribed by the U.S. Securities and Exchange Commission, generally accepted accounting principles and other applicable requirements.

Attachment 7

Bayu-Undan: Catalyst for a New Energy Province

By James J. Mulva

June 26, 2000

(philnet.pcco.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 fiscal 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)

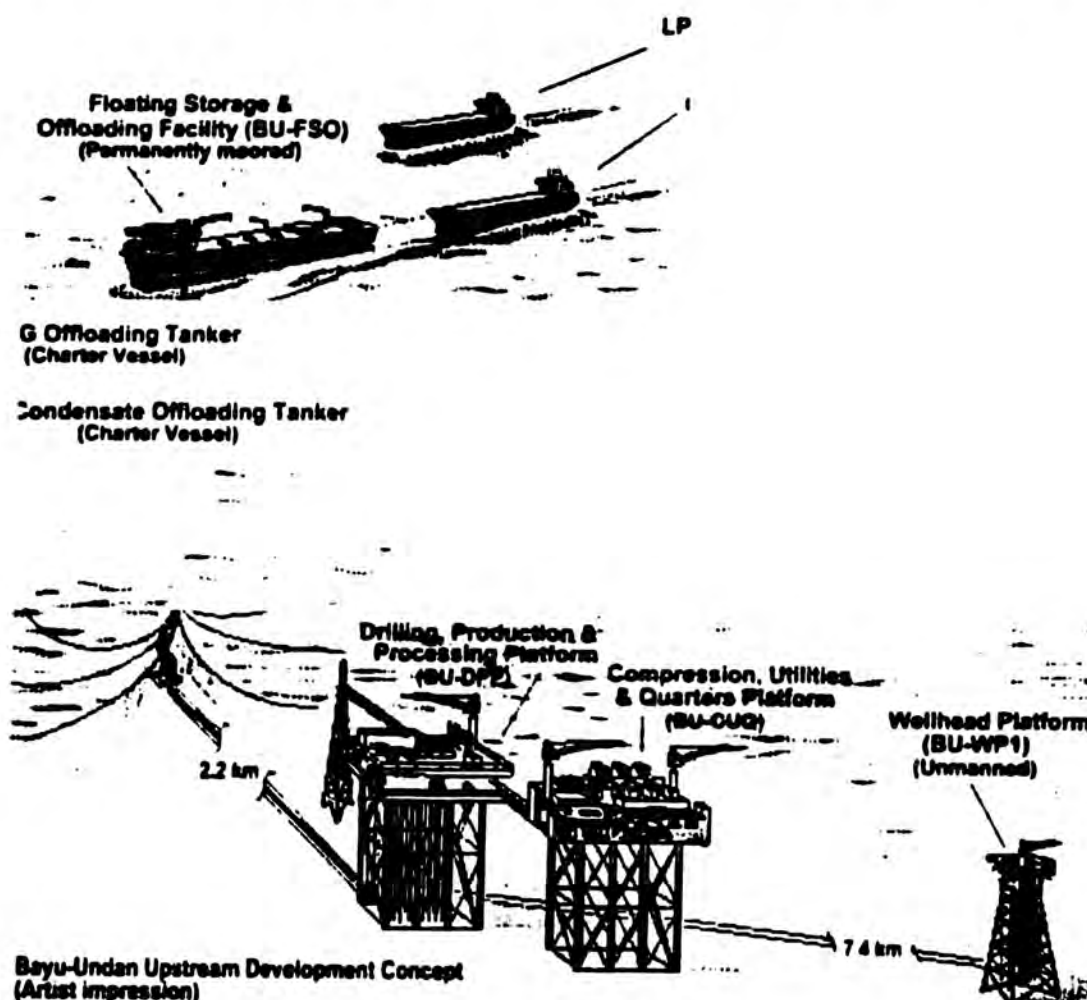
ENGINEERING AND DESIGN

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.



THE FACILITIES

BU-CUQ

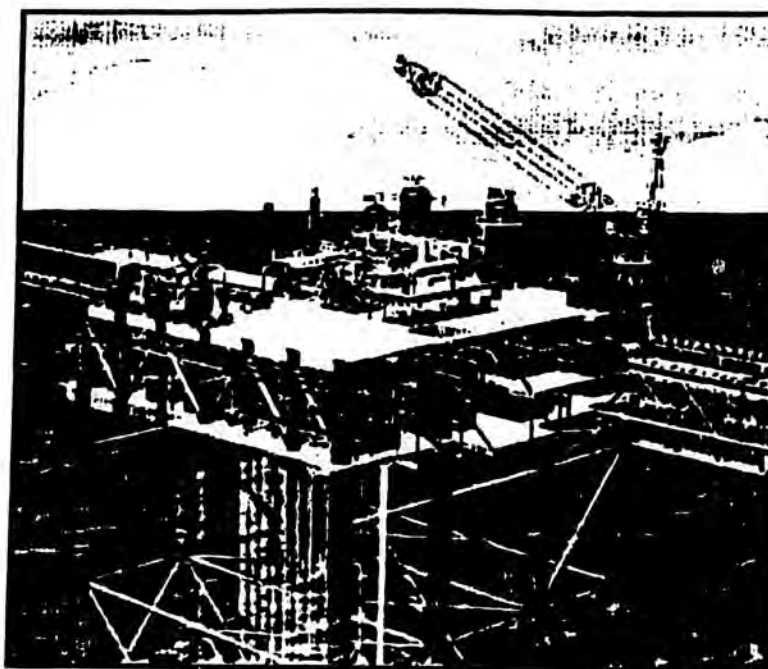
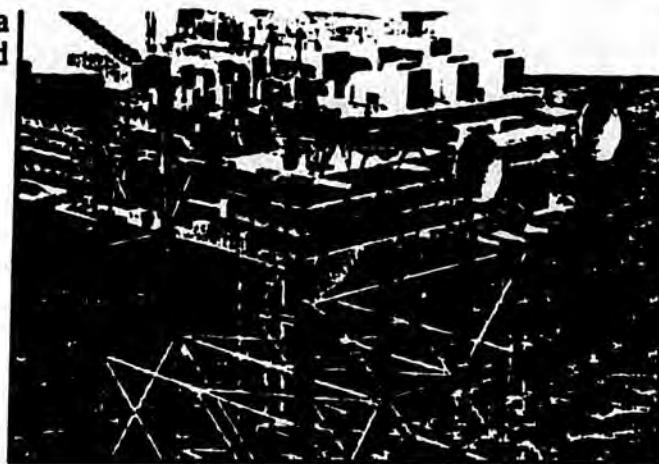
The BU-CUQ deck is a three-level integrated deck (11.5m deck separation) approximately 64m by



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.

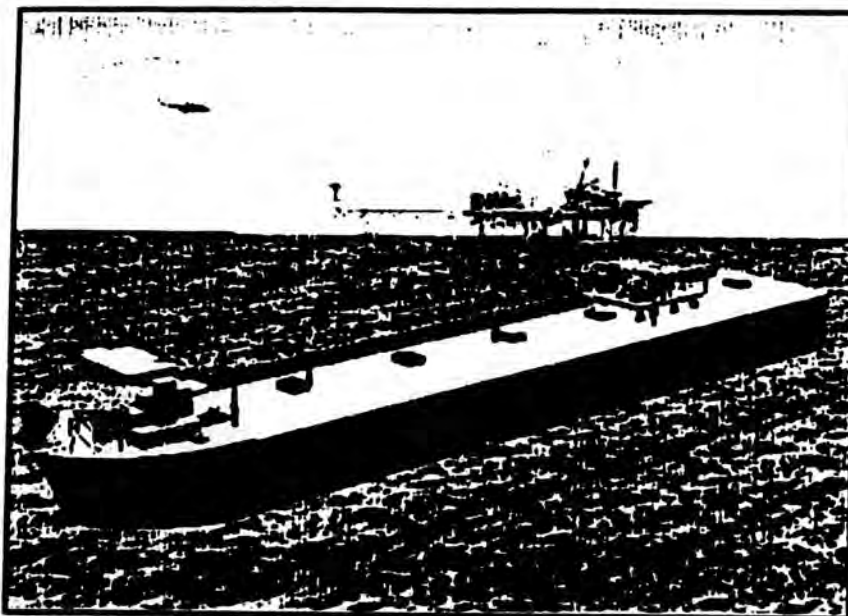
The key feature of the jackets is an open slot at the top to accommodate the barge for mating the topsides with the jacket, using the floatover technique. The BU-DPP accommodates sixteen well slots and supports the risers for the pipelines to and from the BU-WP1 and to the BU-FSO.

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 m³

Butane 47,500 m³

Condensate 130,000m³

Attachment 9

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

03/08/2001

(philnet.ppc.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>.

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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
Trinidad (grass roots)	\$0.95	3.2	\$300
Oman (grass roots)	\$2.0	6.6	\$300
E. Timor (grass roots)	\$1.25**	4.8	\$260
Tangguh (grass roots)	\$1.5	6.0	\$250
Malaysia III (expansion)	\$1.5	7.6	\$200
Industry Convention (rule of thumb)			\$250

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

O&GJ April 27, 1998

Energy Day, June 1999

Oman LNG Journal, January 2001

Dow Jones Newswire, March 9, 2001

FT International Gas Report, April 28, 2000

WGI, January 27, 2000

O&GJ December 13, 1999

*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 1 st Delivery	Customers	Nominal Capacity MTPA
Australia NWS	~2003+	Asian Markets	7.5
Malaysia Tiga (III)	~2003+	Asian Markets	7.6
Tangguh (Indon 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 1 st 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

Smaller market entry improves probability

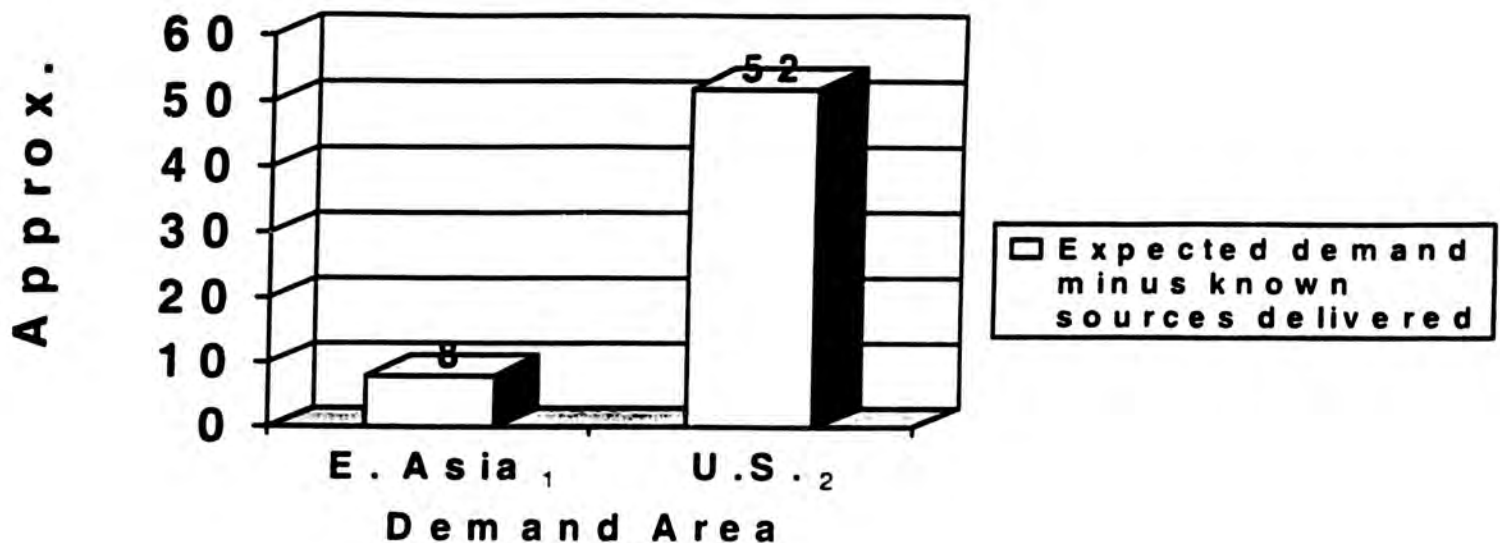
~68 - 75

- **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 Bcf/d) minus ~80 Mta (11 Bcf/d)
- 2 - National Petroleum Council, 12/99
2010 demand of 76 Bcf/d minus 24 Bcf/d of existing production