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ENBRIDGE

April 25, 2007

VIA COURIER

State of Alaska
Senate Judiciary Committee
Alaska State Legislature
State Capitol Building, Room 417
Juneau, Alaska 99801

Attention: The Honorable Senator Hollis French, Chairman

Dear Sir:

Re: Speaking Notes from April 13, 2007 Testimony on Alaska Gas Pipeline Project

Enbridge Inc. wishes to thank you for the opportunity to present its testimony by conference call to the Senate Judiciary Committee on April 13, 2007 on the subject of Canadian rights-of-way in the context of the proposed development and construction of the Alaska Gas Pipeline Project. As you are aware, Enbridge is most interested in seeing this important project progress.

As you kindly offered at the end of my testimony, I am taking this opportunity to provide my speaking notes from the call. These notes outline the views of Enbridge respecting the right-of-way and regulatory regime in Canada under which such a natural gas pipeline would be required to proceed. They have been typed and acronyms defined so that they are more readable.

I have also taken the opportunity to attach for your information an Enbridge paper that provides our views on a number of matters in regards to the Northern Pipeline Act.

Again, Enbridge very much appreciates the opportunity to share its views on these matters with the State of Alaska and we would be pleased to provide any further assistance as may be required.

Yours truly,

Rob Carpenter
Senior Legal Counsel
Gas Strategy and Corporate Development
Enbridge Inc.
Encl.

Canadian Right-of-Way Issues

Speaking notes of Robert F. Carpenter
Prepared for testimony provided to Senate Judiciary Committee
State of Alaska
13 April 2007

* Discuss difference between Northern Pipeline Act ("NPA") right-of-way process and a National Energy Board ("NEB") process

  - fact is, there isn't much difference

  - proceeding under either the NPA or the NEB would require similar steps for right-of-way ("ROW") acquisition for the Canadian portion of the pipeline

  - ROW needs to be acquired in three jurisdictions – Yukon Territory, Province of British Columbia and Province of Alberta

  - in B.C., right-of-way acquisition under either the NPA and NEB would start from very much the same point in terms of process

    - TransCanada ("TC") does hold map notations in B.C. and Alberta, but these are not interests in land and allow no automatic right to be converted into a ROW

  - In the Yukon, TC does hold a federal ROW; however, that ROW currently only allows for investigatory activities such as geological investigations and surveying, it does not allow for construction. Construction cannot occur without prior written consent of the Canadian federal cabinet Minister who is designated for that purpose by the Canadian cabinet
    - Approval by Minister allows construction
    - it is unlikely that the Minister would provide consent to construction activities before all the requirements of the NPA had been met.

      e.g.
      1. NPA Part III (17) – requires TC to provide proof that they have obtained all necessary regulatory approvals.

         - These approvals would include application for many permits and approvals in the Yukon, B.C. and Alberta, including (but not limited to) applications for land use permits, water use permits, fisheries authorizations, navigable waters authorizations and timber cutting permits
         - All of the types of applications listed above (and many that are not listed) would trigger provincial or federal environmental reviews, including a requirement for aboriginal consultation

2. Part III (13) – requires filing of contracts between shippers and pipeline (essentially, TARIFFS)

- in summary, ROW acquisition under either NEB or NPA would begin at the same starting point from a process perspective and would require the same permits and approvals
    - o proceeding under the NPA provides no advantage

* discuss NEB process

- there is nothing explicit in the NPA, the Certificates of Public Convenience and Necessity ("CPCNs") or the Yukon right-of-way agreement that states that whatever rights those documents may grant are exclusive

- there is nothing in the National Energy Board Act that prohibits the NEB from looking at a new application

- not claiming that the NEB process would be a piece of cake – would still require application for all the same permits and applications – would still require aboriginal consultation

- Enbridge estimates permitting process would take up to 21 months between application and approval. Timing is dependent upon how much work is done before the application is made.

- NEB process has worked well in the past for a number of projects, including the Alliance gas pipeline from B.C. to Chicago (of which Enbridge owns 50%)

- NEB process will be used for several new crude oil pipelines that Enbridge is pursuing, and a major crude oil pipeline called Keystone that TC is pursuing

- NEB process is well understood and supported by a variety of judicial decisions – less potential for challenge under an NEB process vs. the NPA

- building the Canadian portion of the Alaska pipeline is anticipated to be undertaken in a different manner than the process used for the Mackenzie Gas Pipeline ("MGP"). For example, it is unlikely there would be a separate joint review panel. Instead, it is expected that the NEB and CEAA processes would be jointly undertaken, providing for greater efficiency and clarity.

* potential challenges to NPA process

A. Aboriginal
    - Canadian laws have changed significantly since the NPA was enacted in 1978
    - Constitution Act (1982) recognized the existence of aboriginal rights

- since 1982, numerous court decisions have confirmed the requirement for extensive consultation with First Nations (regardless of whether treaty or non-treaty lands are being crossed)

B. Environmental
- environmental standards in Canada (federal, provincial and territorial) have changed substantially since the NPA was passed
- the environmental work done prior to the passage of the NPA would no longer be adequate (and was not believed adequate at the time)

C. Challenges to changes in the scope of the project
- NPA authorized a very specific pipe, as described in the Treaty
- the project is currently very different
  - whether one agrees that the NPA allows for flexibility for changing the scope of the project or not, the fact is that such changes would be yet another ground for challenging the CPCNs which were issued under the NPA

D. North American Free Trade Agreement ("NAFTA")
- the NPA was not grandfathered under NAFTA
- the Canadian preferences set out in the NPA and the CPCNs are inconsistent with Canada's free trade obligations under NAFTA
  - yet another ground for challenge

<u>The bottom line</u>: an advocate for an environmental group or a First Nation that didn't want this project built would likely prefer that it go ahead under the NPA as compared to the NEB. Proceeding under the NPA offers several strong arguments by which the project can be challenged.

- TC says there have been no successful challenges to the NPA – while technically this is correct, the examples they use to make this point are not comparable to building a major, high pressure gas pipeline from Alaska to Alberta

  - up to now, the NPA has been used to build and expand facilities only in well developed areas like Southern Alberta in situations where the facilities were needed to carry gas from the Western Canadian Sedimentary Basin to markets

  - the NPA has <u>never</u> been tested in a situation where it was being used to justify the construction of a major pipeline in a pristine, wilderness area with unsettled First Nations claims.

Alaska Natural Gas Pipeline

Enbridge Inc.'s views on issues regarding the Canadian portion of the Alaska Pipeline

Background Of The Northern Pipeline Act ("NPA")

In the mid-1970's the United States and Canada suffered from significant energy shortages and security concerns. The two countries agreed that greater energy supply and security could be achieved through the development and construction of a pipeline that would transport natural gas from Alaska's North Slope through Canada to the lower 48 states. This agreement was embodied in an exchange of diplomatic letters between Canada and the United States (collectively, the "Treaty"), which set out the size and pressure of the pipeline, the fiscal regime that was to apply and the route along which the pipeline was to be built.

In 1978 the Government of Canada passed the NPA in order to facilitate the planning and construction of the pipeline that Canada and the United States had agreed to in the Treaty; in fact, the Treaty is included as Annex I to the NPA.

In Enbridge's view, the NPA is specific to the pipeline contemplated in the agreement between Canada and the U.S. set out in the Treaty; indeed, the definition of "pipeline" in the NPA means "the pipeline for the transmission of natural gas from Alaska across Canada along the route set out in Annex I [the Treaty] to the Agreement..." Accordingly, the definition of "pipeline" in the NPA cannot be separated from the pipeline referred to in the Canada-U.S. agreement. They are one and the same.

It is important to recognize that this is all that the NPA does. It is not an omnibus statute dealing with the development of northern pipelines generally or even a general statute dealing with the transportation of Alaskan gas through Canada. Equally importantly, the NPA does not make any changes to the powers of Canada's National Energy Board ("NEB") to consider alternative international pipelines from Alaska into or through Canada.

In 1978, in contemplation of the construction of "the pipeline", several Certificates of Public Convenience and Necessity ("CPCNs") were issued pursuant to the NPA. Under the terms of the Treaty the pipeline was to be finished by 1983. However, because of changing economic circumstances, only the "Pre-build" portions of the project defined in the Treaty were built.

No Party Has Exclusive Rights To Build A Pipeline In Canada To Transport Alaskan Gas

There is no reference in the NPA (or in any other piece of Canadian legislation that we are aware of) that prohibits the development of an alternative pipeline to ship Alaskan gas through Canada.

Enbridge does not dispute that the rights granted under the NPA are exclusive, but those rights do not preclude progressing another project under the National Energy Board / Canadian Environmental Assessment Act.

The NPA Is Project Specific

The NPA was passed in order to give effect to the Treaty. The Treaty contemplates a very specific pipeline project, right down to specifying the fiscal regime, the route to be followed and the operating pressures and the diameter of pipe to be used. Reference to the pipeline specified in the Treaty is then used in the NPA to define the term "pipeline" for the purposes of the NPA. In Enbridge's view, the CPCNs are not a general authorization for the construction of "a" pipeline

from Alaska through Canada - the CPCNs are at most a partial authorization for the construction of the pipeline specified in the Treaty.

The project currently envisioned is not the pipeline specified in the Treaty. For example, the Treaty specifies a pipeline with an initial capacity of 2.4 bcfd, while current proposals contemplate an initial capacity of about 4.5 bcfd. The Treaty specifies 54" diameter pipe while current proposals contemplate 48" or 52" diameter pipe. The Treaty specifies 1120 psi pressure. Current proposals contemplate 2500 psi. In addition current proposals contemplate a different termination point and include liquids in the gas stream. In short, the current proposal is significantly different than the pipeline approved in the CPCNs.

Absent formal amendments, it is questionable whether variations could occur under the Treaty. History supports this view. For example in 1978 the Governments of Canada and the United States believed it necessary to execute an amendment to the Treaty when they decided to change the pipe diameter from 56" to 54".

In addition it should be noted that historically the NPA has not covered all necessary facilities. For example, the NPA did not apply to the decompression / recompression facility that was installed in the late 1990's at Empress Alberta, as part of the Pre-build system. That facility was approved under the NEB process.

CPCNs

While there is no "sunset clause" or expiry date in the NPA, it should be noted that such legislation in Canada rarely includes expiry dates.

CPCNs can lapse if not exercised in a timely fashion, or if other factors have intervened.

In this particular case:

(i) The CPCNs are subject to conditions, including Schedule III of the NPA

Construction of the project cannot start tomorrow. Under Schedule III of the NPA, a number of conditions need to be satisfied before the CPCNs can be relied upon.

One of the conditions (s.13) of Schedule III requires the filing of contracts between producers and shippers and between shippers and the company [the holder of the CPCNs]. This makes shipper support critical to the holder of the CPCNs.

The conditions in Schedule III also include the requirement to apply for and receive all necessary regulatory approvals required for the work (s.17). Such approvals would include, for example, land use permits, water use permits, fisheries authorizations, navigable waters authorizations and timber cutting permits in the Yukon, British Columbia and Alberta.

The Northern Pipeline Agency, which administers the NPA, does not issue these necessary regulatory approvals; they are issued under any number of other Canadian Acts, including the Canadian Environmental Assessment Act and the Yukon Environmental and Socio-economic Assessment Act. Under the NPA, each approval would require its own panel. Unlike a modern NEB process, the NPA offers no opportunity to coordinate federal and provincial environmental reviews and does not include the statutory advantages of modern regulatory schemes. The NPA and the Northern Pipeline Agency have no authority to override provincial jurisdiction in environmental matters.

(ii) The CPCNs were granted in an era of limited environmental review

The environmental review that was completed when the CPCNs were originally granted would not, in Enbridge's view, meet current standards for environmental reviews. Indeed, when the original environmental review was done it was completed under an Environmental Assessment Review Panel ("EARP"), a process that has since been replaced by processes under the Canadian Environmental Assessment Act. At the time, the EARP panel recommended rejection of certain routes and concluded that it did not have enough information on which to make a decision. As Enbridge understands it, it was only when the federal government finally overrode the panel and ordered it to reconsider its rejection of certain routes that approval was achieved.

Stricter standards are in place today.

(iii) The CPCNs were granted prior to Canadian courts establishing rules requiring consultation with First Nations whenever activities take place in their traditional or treaty lands.

Canada's recognition and protection of the rights of its aboriginal people has changed. From the early 1980's a series of court decisions have recognized and upheld the constitutional rights of Canada's First Nations to be consulted in a comprehensive manner whenever development activities are proposed within their traditional lands or treaty areas.

(iv) The NPA and the CPCNs are inconsistent with modern international trade agreements

The NPA pre-dates the North American Free Trade Agreement ("NAFTA") and was not exempted from the application of NAFTA when NAFTA was brought into force in 1994.

Schedule III of the NPA, which sets out the conditions which must be met prior to being able to rely on the CPCNs, requires (in Article 10) that Canadian content be maximized as far as practicable and that maximum advantage be taken of opportunities provided by the pipeline to establish and expand suppliers in Canada that can make a long term contribution to the Canadian industrial base. A report must be submitted specifying how the requirement will be complied with. This requirement is not discretionary, but mandatory.

Enbridge is advised that preferential requirements for Canadian products and services are contrary to NAFTA. In addition, Enbridge understands that the Canadian content preferences specified under the NPA could violate Canada's World Trade Organization obligations under Article III of the General Agreement on Tariffs and Trade ("GATT").

The pipeline will be the largest infrastructure project in North America. Accordingly, the economic stakes for suppliers are huge. If one were to accept the position that the NPA provides an exclusive opportunity to the holder of the CPCNs that is not available to other NAFTA Investors, it could be argued that the NPA violates the provisions under Article 1102 of NAFTA. This opens the door for claims by other NAFTA investors.

Enbridge believes the Canadian Government would need to seek an exemption from the United States for the NPA to avoid the potential for litigation under NAFTA, but disputes under GATT may be unavoidable.

Rights-of-way ("ROW")

In B.C. and Alberta, right-of-way acquisition under either the NPA or an NEB process would start from the same point in the process. While there are existing map notations in B.C. and Alberta, map notations are not interests in land and allow no automatic right to be converted into a ROW.

To Enbridge's knowledge, the only ROW which exists is in the Yukon. That ROW only allows for investigatory activities such as geological investigations and surveying; it does not allow for construction. Construction cannot occur without prior written consent of the Canadian Federal Cabinet Minister designated for that purpose by the Canadian cabinet. It is unlikely that the Minister would approve construction prior to all the requirements set out in Part III of the NPA being met.

MEMORANDUM **STATE OF ALASKA**

ALASKA OIL AND GAS CONSERVATION COMMISSION

TO: Chair John K. Norman
Commissioner Daniel Seamount
Commissioner Cathy P. Foerster

DATE: February 28, 2007

FROM: Jane Williamson
Sr. Reservoir Engineer

SUBJECT: Prudhoe Major Gas Sales Study

Blaskovich Services, Inc. (BSI) and Commission staff recently completed a study of the impact of a future Major Gas Sale (MGS) on oil and gas recovery from the Prudhoe Oil Pool. The following is provided as a summary of major findings and conclusions from this study.

Foreward – Historical Review and Study Purpose

In 1977, the Commission set the maximum allowable Prudhoe Oil Pool annual gas offtake rate at 2.7 billion standard cubic feet per day (BSCF/D), which contemplated an annual average gas pipeline delivery sales rate of 2.0 BSCF/D. This allowable, set out in Rule 9 of Conservation Order 341D, was approved without benefit of production history. The Commission recognized that the rates may be changed as production data and additional reservoir data became available.

Over the past five years, there has been significant activity concerning a potential major gas sale. BPXA, Exxon-Mobil, and ConocoPhillips commissioned a $125 million dollar study to determine the conceptual feasibility of a gas pipeline. The tentative plan resulting from this study was for a 4.3 BSCF/D pipeline, with capacity to expand to 5.6 BSCF/D. The Prudhoe Bay Unit, Prudhoe Oil Pool is the only North Slope developed field with significant gas reserves (estimated at more than 24 trillion cubic feet (TCF)) and is of primary importance for any decision concerning the pipeline. Pt. Thomson, with over 8 TCF of gas and several hundred million barrels of gas condensate and oil, was assumed to also provide a supply of gas for the pipeline. The companies and the State of Alaska have devoted significant resources to negotiate fiscal terms to build the pipeline. Based on these efforts, the Commission became concerned that no application for modification to the Prudhoe gas offtake rule had been submitted.

As a result of a Commission inquiry and several public hearings, the Commission published a report on December 5, 2005 concluding that there was a need to comprehensively revisit the question of the appropriate gas offtake limits in light of several decades of reservoir development and information that has become available since 1977. Because delay in the Commission's decision-making could disrupt the timetable for a potential gas pipeline project, the Commission adopted a proactive approach to ensure there would be an adequate factual basis for its eventual decision on

allowable gas offtake. The Prudhoe Working Interest Owners (WIO) and the Commission therefore agreed to principles allowing the Commission consultants and staff to access their reservoir simulation and other relevant engineering studies for the purpose of analyzing gas offtake rates and gas sales startup timing for the Prudhoe Oil Pool. Blaskovich Services, Inc. (BSI) was commissioned to provide reservoir engineering consultation in this study.

This work-study officially began in late January 2006. A brief summary follows:

Summary of 2006 Commission Audit Results

The Prudhoe WIO full field reservoir simulator was used as the primary tool in this evaluation. In addition to runs made assuming no gas sales, simulation runs were made at various gas sales rates (1.0-5.6 BSCF/D) and gas sales startup dates (2015, 2019, and 2024). Some simulation cases were run to test the impact of other factors such as changes in waterflood operation, fuel usage, CO_2 offtake, and some drilling/workover variations. We also evaluated the effect of varying assumptions for end of the field life (EOFL).

Throughout our analysis, we searched for major factors that would affect the trends in total hydrocarbon recovery as a function of gas offtake rates and timing. We were not searching for "the" optimum development strategy. We did not value one type of energy resource (e.g., liquids or gas) over another, but equated them using their relative energy content in units of barrels of oil equivalent (BOE). Based on our analysis of currently available data, we have reached the following major conclusions.

- A major gas sale at Prudhoe represents approximately an additional 4 billion BOE recovery.

- The latest WIO model needs improvements in its ability to predict future field performance. Model errors are increasing with time. Nevertheless, it is the best tool currently available. It should be suitable for comparing directional trends in energy recovery during a gas sale.

- Increased oil capture prior to gas sales can increase hydrocarbon recovery and result in recovery trends that are less sensitive to either gas offtake rates or gas sales startup dates. This was the only mitigation option evaluated that significantly improved trends in BOE recovery.

- End of field life (EOFL) is a major source of uncertainty in determining the gas sale strategies that will maximize energy recovery.

    - Comparison of model reserves predictions at the same date for EOFL tended to favor an earlier, higher rate gas sale. We found the time limit EOFL approach to be inappropriate because ending energy production rates could be vastly different between the high rate, early startup case and the low rate, delayed startup case.

- Model results based on equivalent EOFL rate limits consistently show that total energy recovery is substantially decreased with an earlier, higher rate gas sale. We believe that rate limits are more reasonable than time limits for comparison of gas sales model predictions. However, exclusive use of rate limits is flawed because the risks of wells and field infrastructure failures with age are ignored.

- Well, facilities and infrastructure failures can significantly increase the risk of lost hydrocarbons. The longer that gas sale is delayed, the greater the risk of well and facilities failure resulting in premature field shutdown. Furthermore, near term failures will defer production and may result in more reserves loss with early gas sales. Diligent efforts to maintain, repair, and replace aging wells and facilities will help to mitigate risks and maximize recovery under any sales scenario.

Recommendations

The Commission has not received a request for a new gas offtake rule. At this time, we cannot recommend a specific gas offtake rate and sales startup timing. The Prudhoe WIO model evaluations and studies that have been shared with us are not sufficient to justify an allowable above that specified in Rule 9, CO 341D. An early, high rate gas sale could result in the loss of a substantial volume of hydrocarbons. However, even greater volumes may be at risk if gas sales are indefinitely delayed and Prudhoe wells and infrastructure fail before these reserves can be recovered.

We are concerned that Rule 9 does not specifically require a plan for such a major change in the Prudhoe Oil Pool depletion strategy. The ultimate impact of gas sales on hydrocarbon recovery cannot be appraised in the absence of a proposed development plan that identifies the start date, sales rate and liquid loss mitigation efforts. Although the start-up for gas sales is a minimum of 8 years away, many decisions that affect the project will be made earlier. Depletion planning should be required prior to commitments to sell gas so that the Commission is adequately informed and assured that other factors do not exist that would justify or require action by the Commission.

Regardless of the timing of their submittal, the Prudhoe WIOs need to develop near-term strategies to prepare the field for gas sales with focus on methods to increase the capture of oil prior to gas sales and to ensure facility and well downtime is minimized. On a regular basis, the Commission needs to be kept informed of the progress of the depletion planning efforts, including review of study plans, reservoir study results and other relevant information that may impact the Commission's ultimate decisions concerning gas sales offtake. The exchange of information in the past year was very successful and a similar mechanism of exchange should be considered during the depletion planning stage.

We wholeheartedly appreciate the cooperation of the Working Interest Owners over the past year, particularly that of the BP technical representatives who worked with us in this endeavor.

This report reflects the evaluation and opinions only of the authors and does not necessarily reflect those of the Prudhoe Owners or other Commission staff.

Role of the Alaska Oil and Gas Conservation Commission in Establishing Allowable Gas Offtake Rate for Prudhoe Bay

The State of Alaska and other interested parties are engaged in determining how best to bring North Slope gas to market. The Alaska Oil and gas Conservation Commission ("AOGCC") has a very important role in this process – to protect the public's interest by preventing waste and insuring greater ultimate recovery of both oil and gas. To fulfill this role, the AOGCC will decide what gas production rates should be allowed from Prudhoe Bay and other North Slope oil fields. Considering only the laws of science, these decisions are very simple; to prevent waste and insure a greater ultimate hydrocarbon recovery, produce all of the oil in a reservoir first and then "blow down" its gas cap only when there is no commercially recoverable oil left. The AOGCC recognizes, however, that many other factors will – and should – be considered in exercising its regulatory powers.

Before considering other factors, it is essential first to understand the science. Extracting gas from an oil field like Prudhoe Bay triggers a series of events. First, the pressure in the gas cap decreases and becomes lower than the pressure in the oil-bearing part of the reservoir. As driven by the laws of physics, the reservoir then works to get back to equilibrium, i.e., the same pressure throughout. To do this, some oil, which is at a higher pressure, moves up into the lower pressure gas cap and the pressure in the oil-bearing part of the reservoir drops. This process continues as the pressure throughout the reservoir equalizes at a lower pressure than before. And as more gas is withdrawn, the process repeats, causing more oil to move into the gas cap and also causing the reservoir pressure to decrease further.

Both the movement of oil into the gas cap and the decrease in reservoir pressure jeopardize oil reserves.

Let's look at movement of oil into the gas cap first. Think about what happens when you drain the oil from your car or when you pour cooking oil into a measuring cup. When you empty the container, some of the oil sticks to it and will not come off. That is what happens to oil when it moves into the gas cap, a part of the reservoir that has never contained oil but has always only held gas. However, because that container is porous rock rather than glass or plastic, the amount of oil that sticks is much greater. The previously "dry" reservoir rock becomes coated with oil. Although some of this oil can be produced, a substantial portion (in some fields over 20 to 30 per cent) sticks to the rock and will never come out. In short, producing gas without replacing the gas cap fluids will cause some oil to stick to the reservoir rock and result in a decrease of ultimate recovery of oil.

Now let's look at decreasing reservoir pressure. Think about an aerosol container. It starts out with high pressure inside; if you puncture it, it will explode. As you use it, more and more of the fluids – both the active product and the carrier gas -- are released and the pressure decreases until, eventually, you push the button and nothing happens. When you shake it, you might be able to hear that there is still hair spray or some other product inside, but you can no longer get it out. At this point the pressure has decreased so that you could even puncture the container and nothing would happen. Similarly, in an oil reservoir, the reservoir pressure provides the energy that allows the oil to flow through the reservoir and up the well bore. As fluids are produced, the

pressure decreases and the reservoir loses this energy. Eventually, as more and more gas is produced and the pressure continues to drop, there is insufficient energy to drive the oil from the reservoir. Typically operators of oil reservoirs maintain reservoir pressure and energy by re-injecting produced gas and injecting water to replace produced oil. They continue this process until they have recovered all the oil. Then, when no commercially recoverable oil is at risk, they "blow down" the gas cap. They do this because producing gas from an oil reservoir and not replacing it will result in a decrease of reservoir energy and, therefore, a decrease in oil recovery.

Another bad thing happens when the reservoir pressure decreases; some oil changes from liquid to gas. The remaining oil becomes thicker. Think about soup cooking; as water evaporates, the remaining liquid becomes thicker. In an oil field this thickening makes it harder for the oil to flow and, thus, decreases oil recovery. We all know that it is much easier to suck water up a straw than it is molasses.

In summary, looking simply at the reservoir engineering science, producing gas from an oil reservoir while there is still commercial oil remaining to be produced WILL cause a portion of the oil resources to be lost and, thus, the gas cap in an oil reservoir should only be "blown down" when no more commercially recoverable oil remains.

The explanation above assumes that all of the gas can be recovered after all of the oil has been produced, and for most Lower 48 scenarios this is a reasonable assumption. However, for the North Slope, there will be a trade-off between leaving oil in the ground and leaving gas stranded, and this trade-off will be influenced by several factors.

For example, the remaining useful life and increasing operating cost of the aging North Slope infrastructure will impact this balance between losing oil and stranding gas. Much of the North Slope infrastructure that was put in place thirty years ago for oil production will still be necessary for gas production. As this infrastructure ages, two things happen: 1) the cost to operate the equipment increases, and 2) components break and must be repaired or replaced. The later in time the gas is produced the higher the costs will be to operate, repair and replace equipment and, thus, the sooner the gas will become uneconomical to produce and the more gas will be left stranded.

The minimum rate at which TAPS can operate will also impact the balance between losing oil and stranding gas. Although the gas will have its own line which will operate independently of TAPS, continued operation of the TAPS line will impact the economic life of the gas production because, as long as TAPS is operating, many of the operating, repair and replacement costs will be shared by both the oil and gas production, thus extending the time before either becomes uneconomical.

These and other factors will complicate the gas off take rate and timing decisions for North Slope fields. The AOGCC is charged with preventing waste and insuring the greater ultimate recovery by making sure that the operators act in accordance with good oilfield engineering practices. In executing this responsibility, the AOGCC must be cognizant of the balance between oil recovery optimization and gas recovery optimization. This will be no trivial task.

Prudhoe Oil Pool
Gas Offtake Reservoir Study

Public Summary

February 28, 2007

Presentation Summary

- Commission authority
- Historical perspective
- Reservoir concerns related to gas sales
- Study purpose and available information
- Observations
- Recommendations

AOGCC Major Gas Sales Reservoir Study Disclaimer

Evaluation and opinions reflect those of only BSI and AOGCC staff who worked directly on the project. These opinions do not necessarily reflect those of the WIO, Commissioners or other AOGCC staff

Prudhoe Gas Offtake Allowable Commission Authority

- Commission Duties (related to MGS decisions)
  - prevent physical waste of resource
  - promote greater ultimate recovery
- Authorities
  - require/approve development plans
  - set allowable offtake

Prudhoe Gas Offtake Allowable Historical

- Pool Rules CO 341D, Rule 9 (1977)
  - Offtake allowable set at 2.7 BCFD
  - Envisioned ≈ 2.0 BCFD Pipeline Delivery
- Currently produced gas re-injected

Why do we care about gas offtake?

- Gas extraction lowers reservoir pressure
  - Decreases energy required for oil production
  - Oil recovery suffers; gas production benefits
- How is ultimate total hydrocarbon recovery affected by gas sales offtake?

Prudhoe Gas Offtake Allowable Recent Activities

- 2002 WIO study
  - Tentative P/L design of 4.3 BCFD
  - Prudhoe major source for P/L (+24 TCF)
- Pipeline fiscal discussions/negotiations
- No Application for Rule 9 Amendment
- AOGCC 2005 inquiry
  - Concluded comprehensive revisit of Rule 9 needed
  - Proactive Approach
  - "Principles" for access to WIO reservoir studies

Prudhoe Gas Offtake Study

- Study begun January 2006
  - Engineering Consultant Blaskovich Services Inc. (BSI)
  - WIO provided Data Room with necessary information and studies
- WIO Full Field Reservoir Simulator Primary Tool
  - Access/Electronic copies of reservoir simulation results
  - Additional simulation runs on request
- Good Cooperation from WIO staff, management

Study Approach

- Simulation runs variables
  - Gas Startup Times (2015-2024) Offtake Rates (1-5.6 BCFD)
  - Other field operating strategies
- Compared on basis of total energy content
  - Units of Barrel Oil Equivalent (BOE)
- Concentrated on trends in recovery, not absolutes
  - Not looking for "the" optimum development strategy

Conclusions

- Major Gas Sales adds ≈ 4 Billion BOE (+/- 24 TCF)
  - 11.4 BSTB Oil/Condensate/NGLs produced to date
  - 1977 projections of less than 9 Billion Barrel Oil
    - Initial projections assumed 1982 Gas Sales
    - End of Field life estimated 2003

Conclusions - Model

- WIO model best currently available
  - Years in development
  - Should be good for evaluation of directional trends
  - Some improvements needed in predictive mode

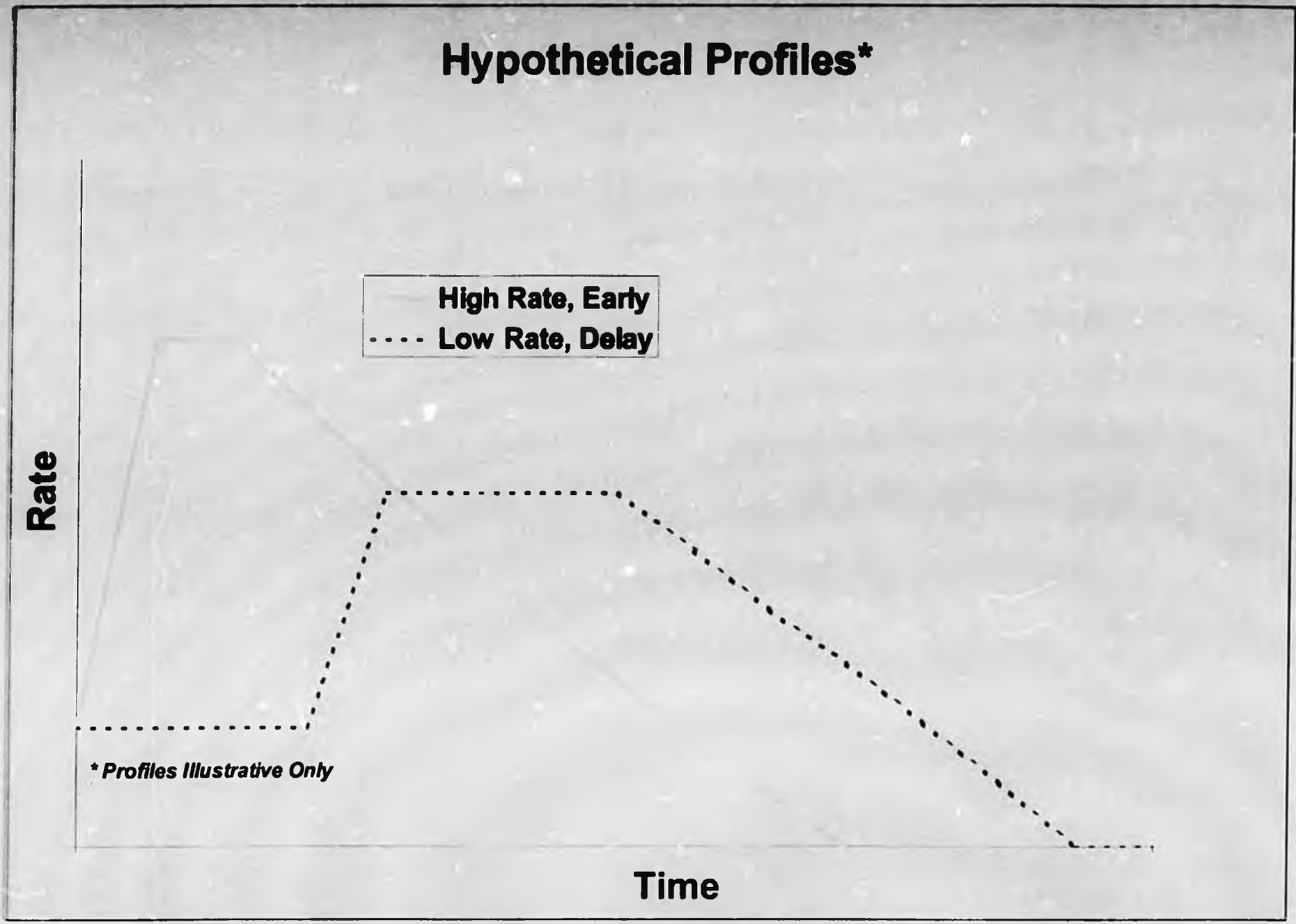
Conclusions

- ***Increased oil capture prior to Gas Sales***
  Improved recovery trends
  - Most encouraging strategy
  - Recovery trends less sensitive to gas offtake or S/U Rate
    - Allows for more flexibility

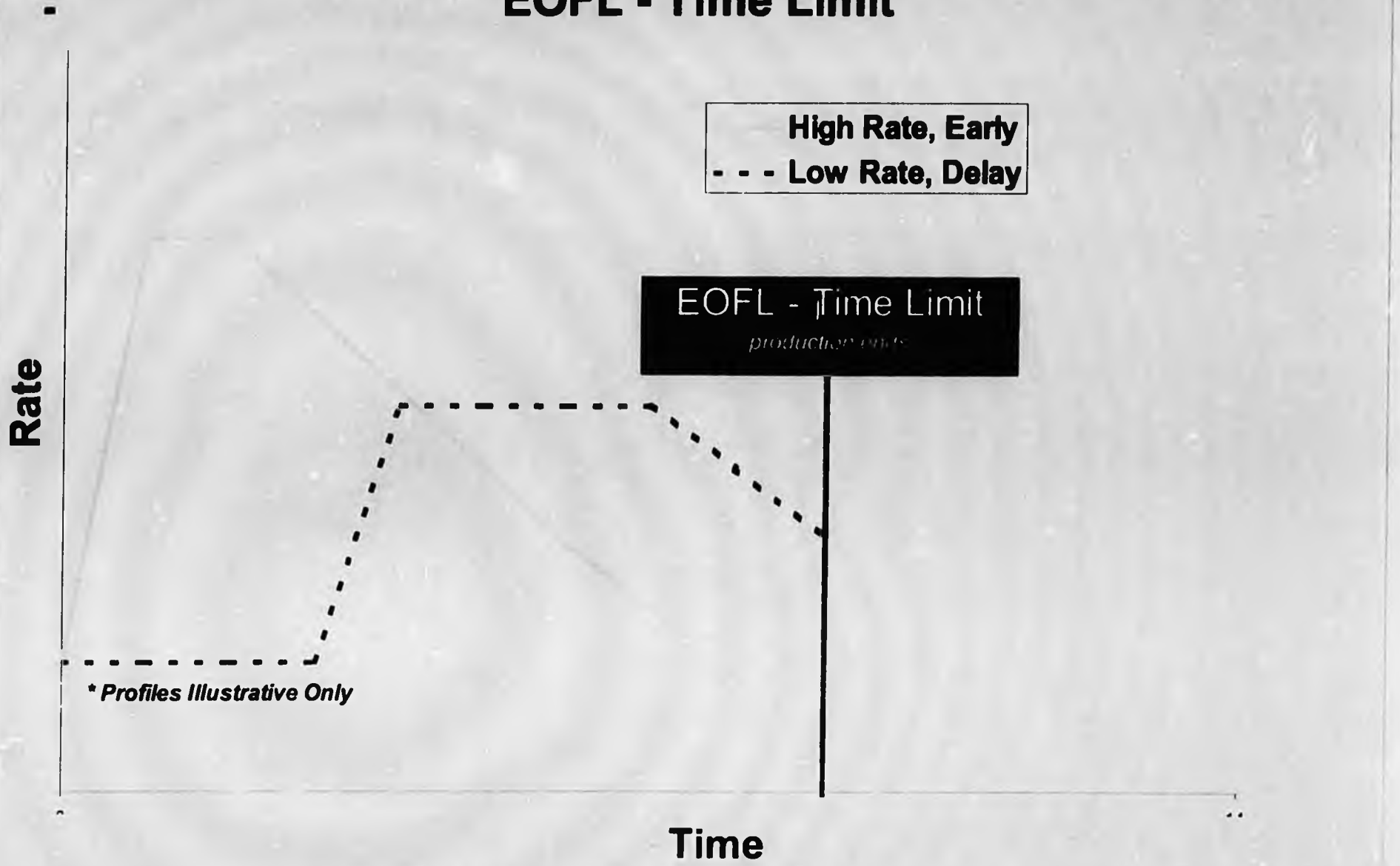
End of Field Life (EOFL)

- End of Field Life (EOFL) is when costs exceed revenue from continued production.
  - Reserves are evaluated at an assumed EOFL
  - Unknown – but important to compare all cases at same assumed EOFL
- Major effect upon predicted recovery outcomes
- Date Limit favors earlier, higher rate MGS
- Rate Limit favors later, lower rate MGS

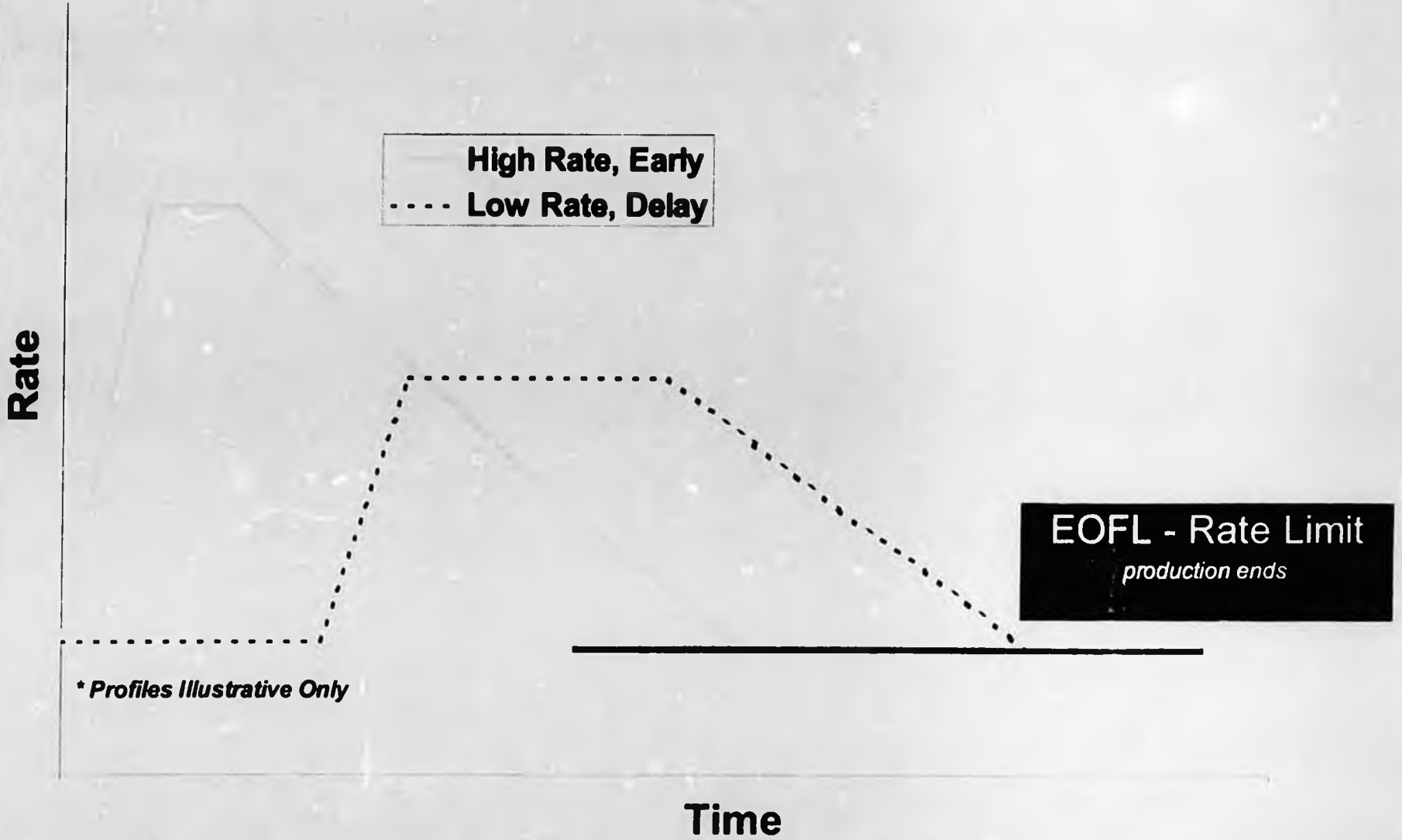
Hypothetical Profiles*



Hypothetical Profiles*
EOFL - Time Limit



Hypothetical Profiles*
EOFL - Rate Limit



EOFL Summary

- Time limits do not treat production (revenue) fairly.
- Rate limits do not treat future risk (costs) fairly.
- We believe rate limits are more correct but we need to consider risk with age.
- Use rate limits and risk analysis

Field Well/Infrastructure Failures

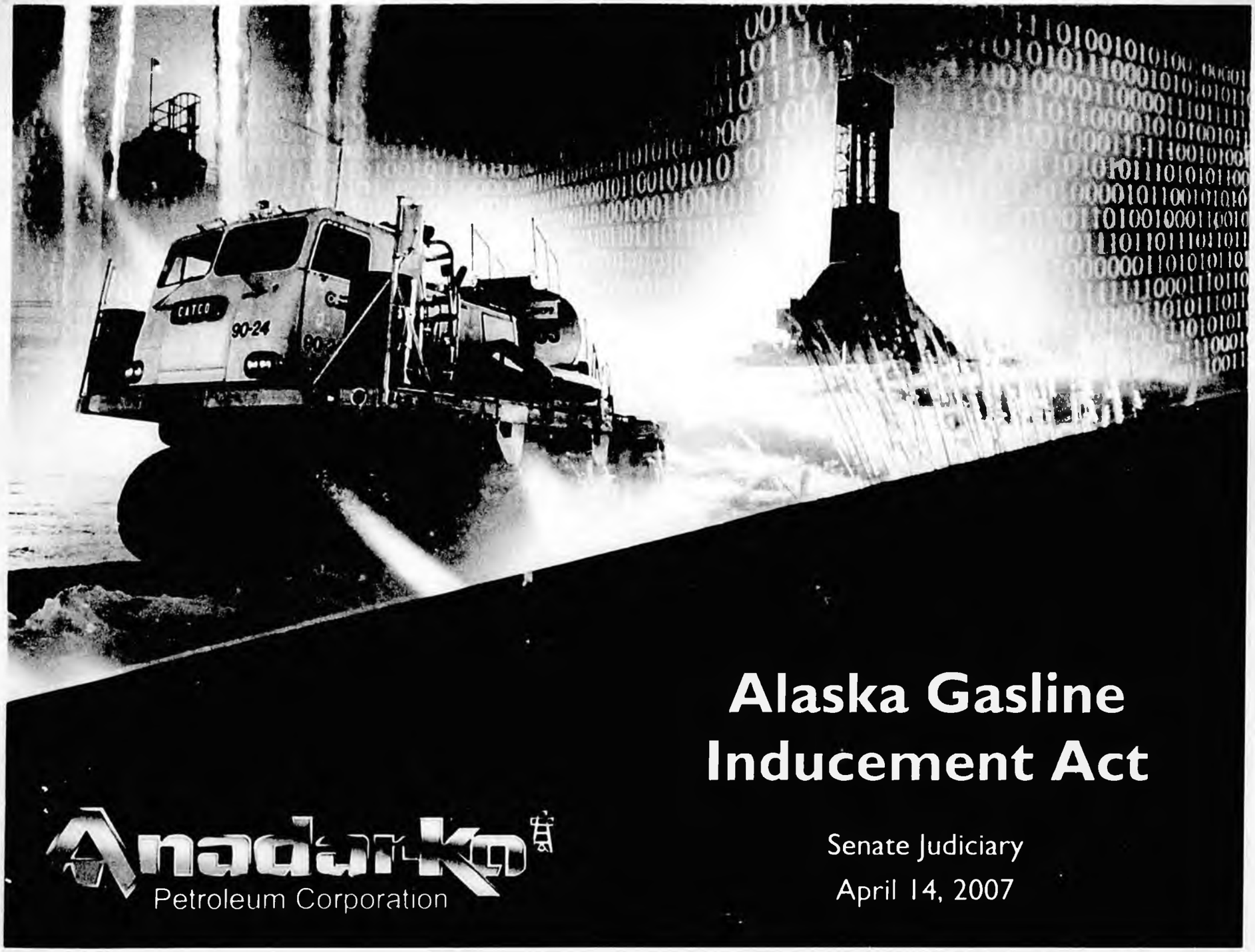
- Failures increase reserves risk
  - If MGS delayed
    - Higher risk with age– impact field life
  - Near Term failures
    - Deferred oil production prior to MGS risks reserves

Recommendations
MGS Offtake

- There is insufficient evidence at this time to recommend increasing Rule 9 Offtake
  - No request for modification of Rule 9
- Depletion planning should be required prior to commitments to sell gas

Recommendations
Pre-MGS Strategies/Plans

- Regardless of timing of request for modification near term strategies needed to prepare for MGS
  - Increase oil capture prior to MGS
  - Minimize well and facility downtime
- Mechanism needed for exchanging information during the depletion planning stage



Alaska Gasline Inducement Act

Anadarko Petroleum Corporation

Senate Judiciary

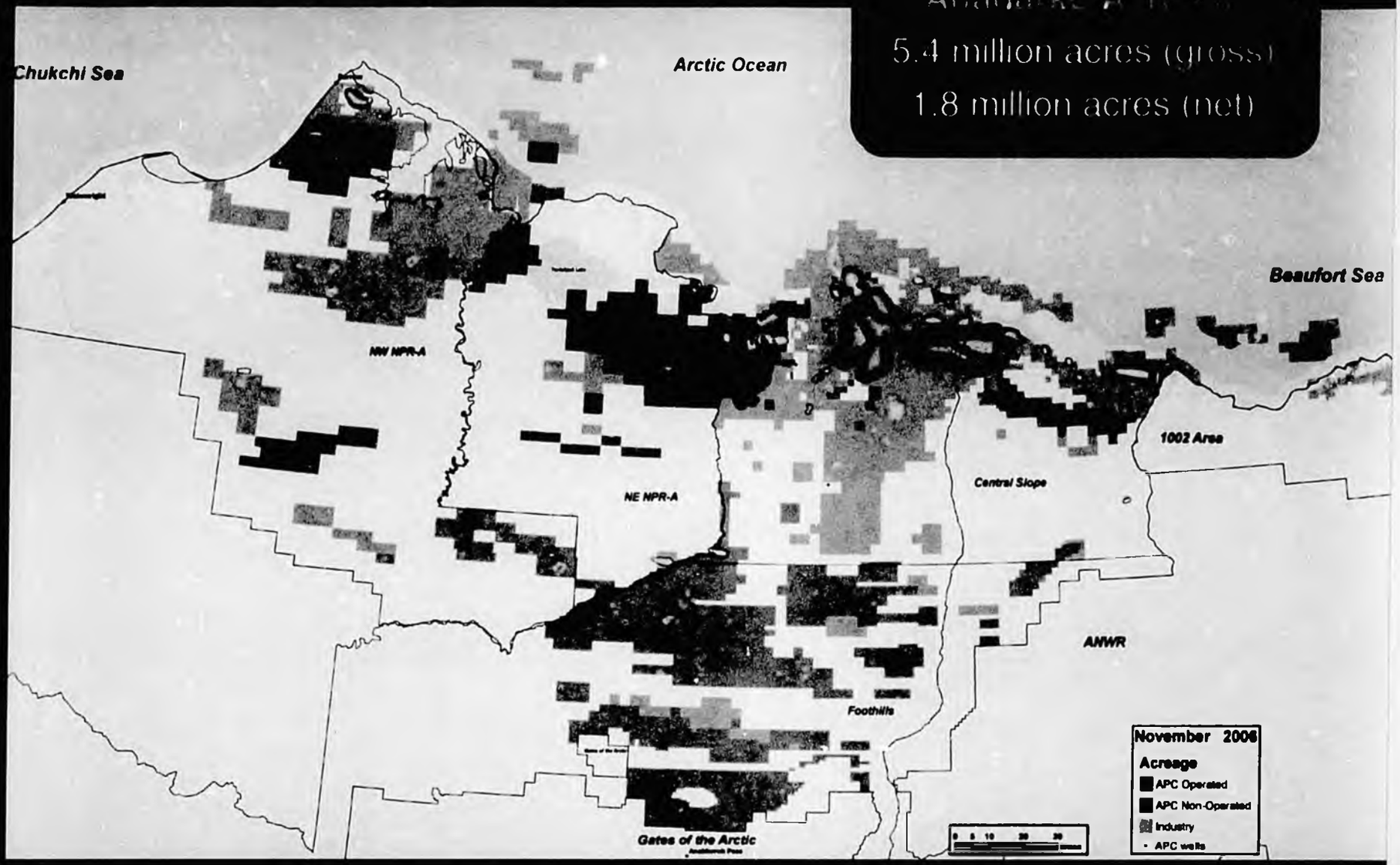
April 14, 2007

Anadarko's Investment in Alaska-Land

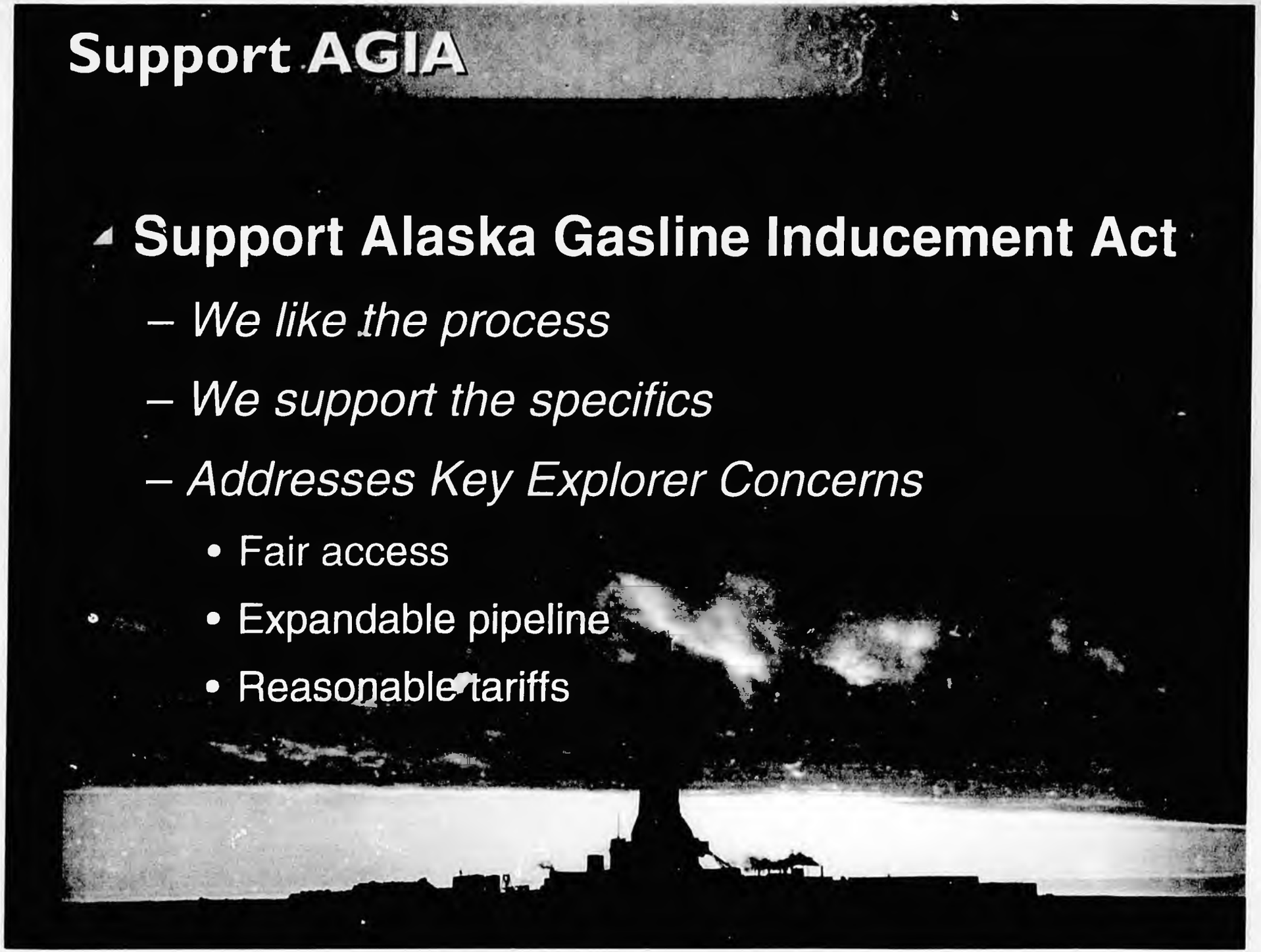
Anadarko Acreage

5.4 million acres (gross)

1.8 million acres (net)



Support AGIA



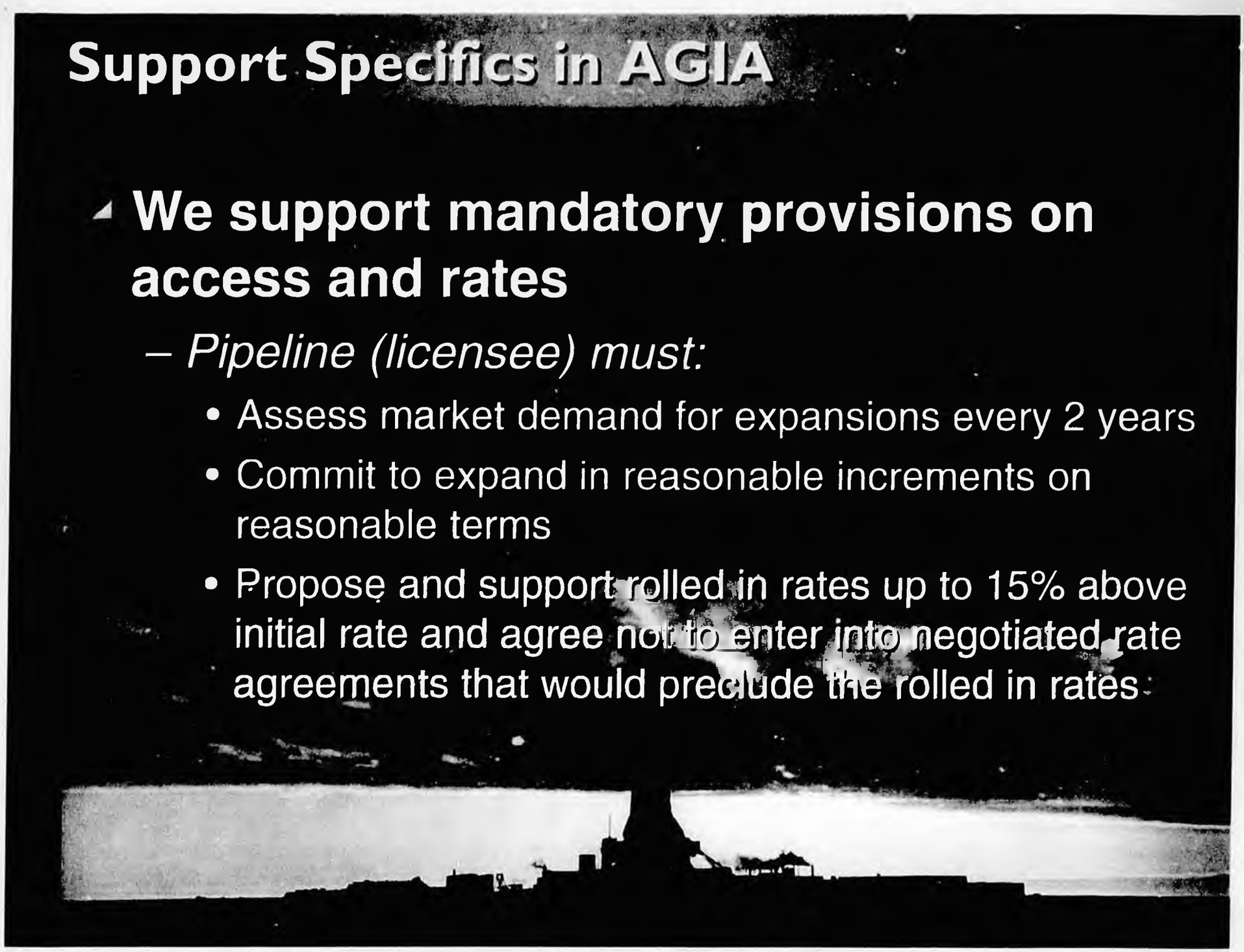
- **Support Alaska Gasline Inducement Act**
  - *We like the process*
  - *We support the specifics*
  - *Addresses Key Explorer Concerns*
    - Fair access
    - Expandable pipeline
    - Reasonable tariffs

Support AGIA Process

- **We like the process**
  - *Three opportunities for input and for key policy makers to consider issues before a deal is done*
    - Initial legislation
    - Public comment on submitted applications
    - Legislative review of selected application
  - *Creates competitive process*
  - *Lays out "must haves" that the state will require of any applicant*

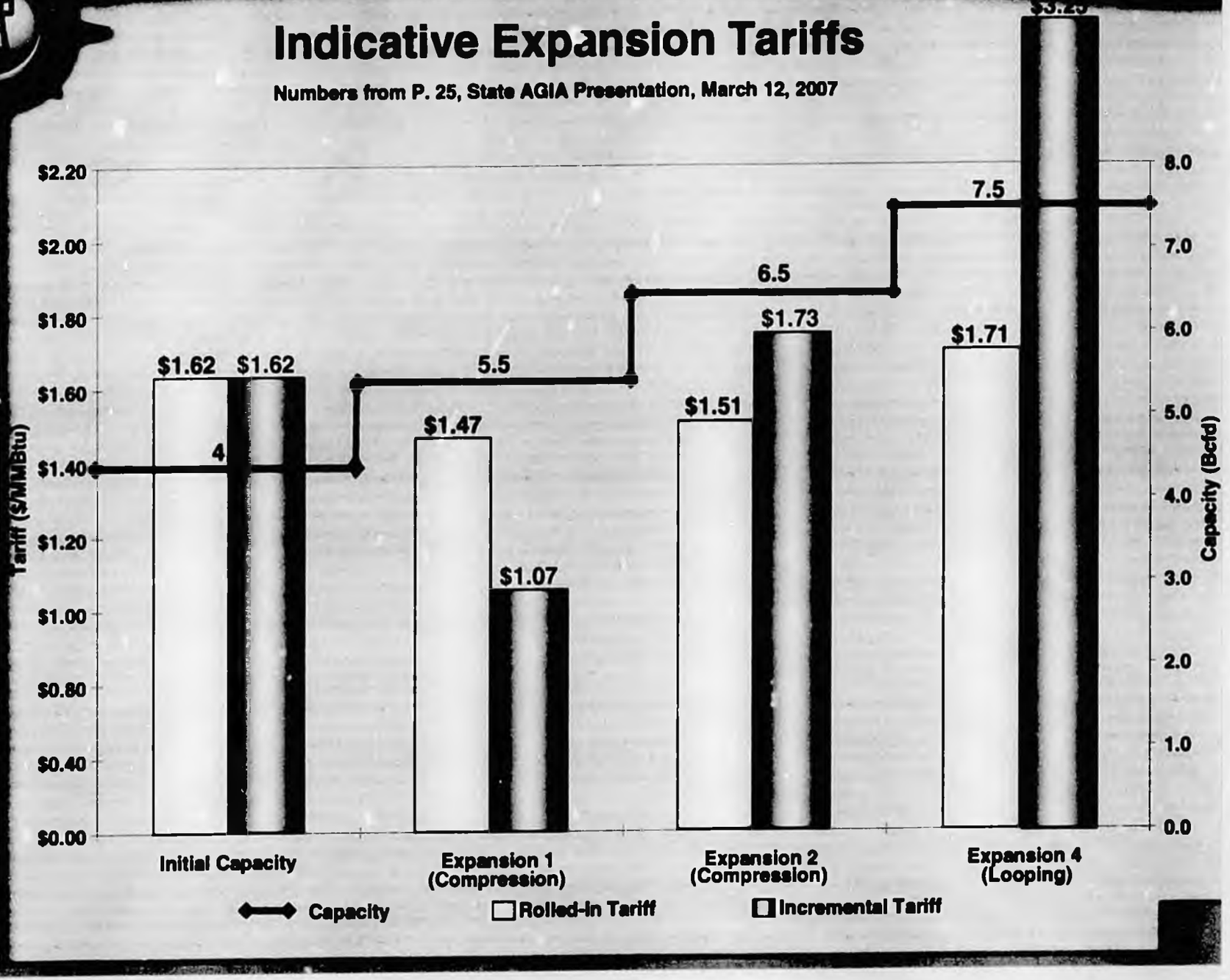
Support Specifics in AGIA

- **We support mandatory provisions on access and rates**
  - *Pipeline (licensee) must:*
    - Assess market demand for expansions every 2 years
    - Commit to expand in reasonable increments on reasonable terms
    - Propose and support rolled in rates up to 15% above initial rate and agree not to enter into negotiated rate agreements that would preclude the rolled in rates



Indicative Expansion Tariffs

Numbers from P. 25, State AGIA Presentation, March 12, 2007



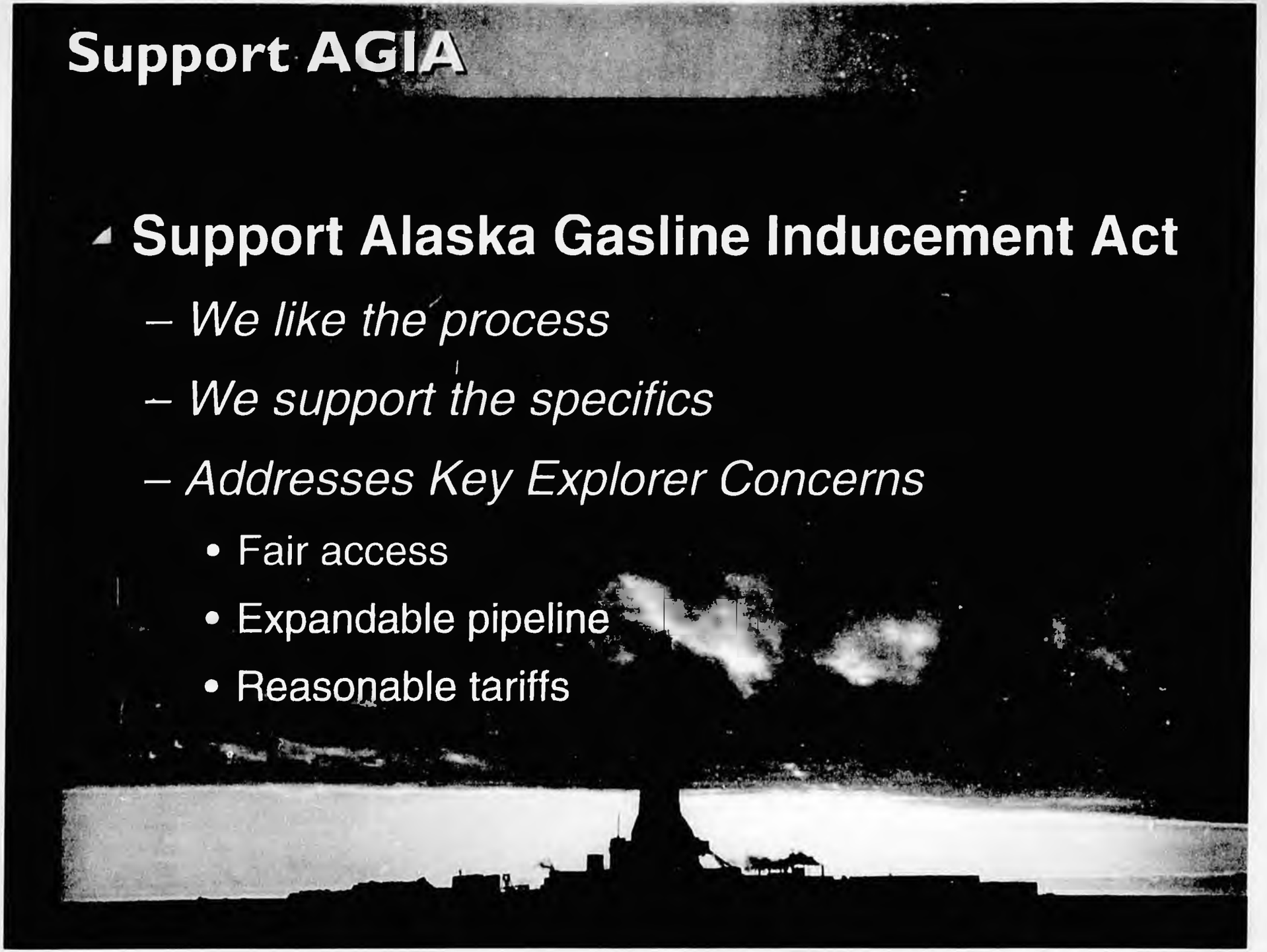
AGIA helps mitigate challenge of FERC rules

- Producers in court challenging FERC authority to ensure adequate pipeline capacity and low cost expansions
- Producers attempting to invalidate Sections 157.36 & 157.37
- 18 C.F.R. 157 Subpart B

- Section 157.36 Open seasons for expansions.
- Any open season for capacity exceeding the initial capacity of an Alaska natural gas transportation project must provide the opportunity for the transportation of gas other than Prudhoe Bay or Point Thomson production. In considering a proposed voluntary expansion of an Alaska natural gas pipeline project, the Commission will consider the extent to which the expansion will be utilized by shippers other than those who are the initial shippers on the project and, in order to promote competition and open access to the project, may require design changes to ensure that some portion of the expansion capacity be allocated to new shippers willing to sign long-term firm transportation contracts, including shippers seeking to transport natural gas from areas other than Prudhoe Bay and Point Thomson.

- Section 157.37 Project design.
- In reviewing any application for an Alaska natural gas pipeline project, the Commission will consider the extent to which a proposed project has been designed to accommodate the needs of shippers who have made conforming bids during an open season, as well as the extent to which the project can accommodate low-cost expansion, and may require changes in project design necessary to promote competition and offer a reasonable opportunity for access to the project.

Support AGIA



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CATCO
90-24
Bringing Excellence
to the Surface
Anadarko
Petroleum Corporation

Alaska Natural Gas Pipeline Project

Testimony on AGIA

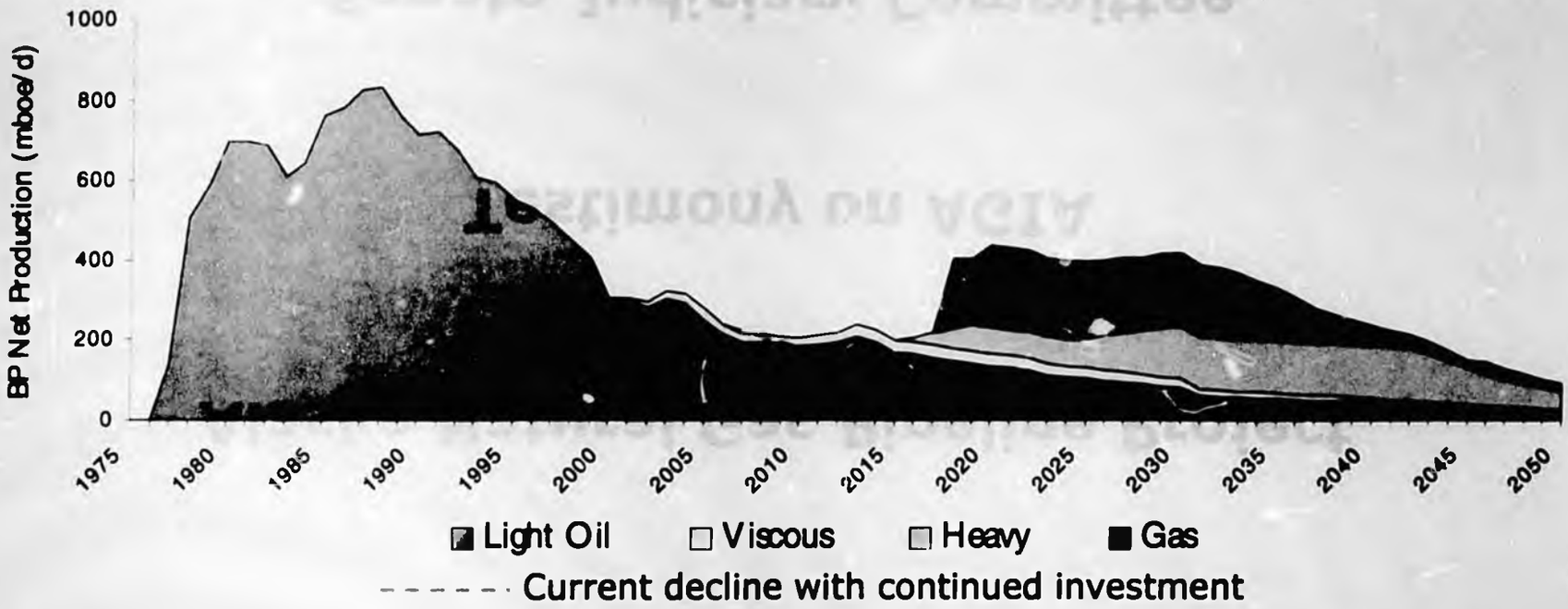
Senate Judiciary Committee

April 14, 2007

bp

BP's Vision for Alaska

- BP has a long history in Alaska....
- .....and we look forward to a 50-year future
- That future is only possible with a gas pipeline



BP Key Messages

- BP wants and needs a successful gas pipeline
- BP supports Gov. Palin's desire to get Alaska's gas to market
- AGIA can help deliver a successful gasline project provided key issues are addressed
  - Encourage best solution by offering objectives, rather than requirements
  - Don't require initial shippers to subsidize others
  - Encourage competition by allowing the market to determine the "winner"
  - Resource rules should be clearly defined and not be subject to change

What A Successful Gasline Means

- ***Jobs*** for Alaskans
- Additional ***revenue*** for future generations

- Increased ***economic activity***
- ***New businesses*** created

AGIA can help deliver a successful gas pipeline if we....

Use Objectives instead of Prescriptive Requirements

- Prescribing <u>solutions</u> will not result in the best project
  - A better project will result from allowing the market to respond to the State's objectives

- Subsidization is contrary to FERC regulation

  "It is consistent with our guiding principle...to adopt rolled-in rate treatment up to the point that would cause there to be a subsidy of expansion shippers by initial shippers, if any subsidy were to be found." [FERC Order 2005, para. 125]

- Agree that evaluation should be done in an open and transparent way