

AK LEGISLATURE SPECIAL COMMITTEE FILES SCOMM 148 3229

geopressed brines, natural gas hydrates, or oil and natural gas that may be present in insufficient quantities or quality (low permeability "tight" reservoirs) to be produced by conventional recovery techniques. In some instances the boundary between these resources is somewhat indistinct; however, we have not included in this assessment any significant volume of unconventional resources.

Estimates of undiscovered recoverable resources are presented in two categories, undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR). In addition, the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference for analyzing the estimates of UTRR. The UERR results are presented as price-supply curves which show the relationship of price to economically recoverable resource.

Methodology

This assessment incorporated a comprehensive play-based (see list of terms) approach toward the analysis of hydrocarbon potential. A major strength of this method is that it has a strong relationship between information derived from oil and gas exploration activities and the geologic model developed by the assessment team. An extensive effort was involved in developing play models, delineating the geographic limits of each play, and compiling data on critical geologic and reservoir engineering parameters. These parameters were crucial input in the determination of the total quantities of recoverable resources in each play.

Due to the inherent uncertainties associated with an assessment of undiscovered resources, probabilistic techniques were employed and the results reported as a range of values corresponding to different probabilities of occurrence. For plays in frontier areas with sparse data, analogs were developed using subjective probabilities to cover the range of uncertainties. Most plays in the Alaska, Atlantic and some in the Pacific OCS were assessed this way. For mature areas with significant amounts of data, such as the Gulf of Mexico and southern California, plays were analyzed using a method based on statistical parameters of discovered pools and historical trends.

Assessment Results

The MMS completed an assessment of the undiscovered technically recoverable oil and natural gas resources of the OCS, which reflects data and information available as of January 1, 2003. This assessment was the culmination of a multi-year effort that included data and information not available at the time of the previous assessment (MMS, 2001), incorporated advances in petroleum exploration and development technologies, and employed new methods of resource assessment.

UTRR estimates are presented at 95th and 5th percentile levels, as well as the mean estimate. This range of estimates corresponds to a 95-percent probability (a 19 in 20 chance) and a 5-percent probability (a 1 in 20 chance) of there being more than those amounts present, respectively. The 95- and 5-percent probabilities are considered reasonable minimum and maximum values, and the mean is the average or expected value. Results for individual plays, basins, and planning areas will be presented in subsequent regional reports.

Estimates of UTRR for the entire OCS range from 66.6 Bbo at the F₉₅ fractile to 115.1 Bbo at the F₅ fractile with a mean of 85.9 Bbo (figure 2 and table 1). Similarly, gas estimates range from 326.4 to 565.9 Tcf with a mean of 419.9 Tcf. On a barrel of oil-equivalence (BOE) basis 54 percent of the potential is located within the Gulf of Mexico. The Alaska OCS ranks second with 31 percent. The Pacific is third among the regions

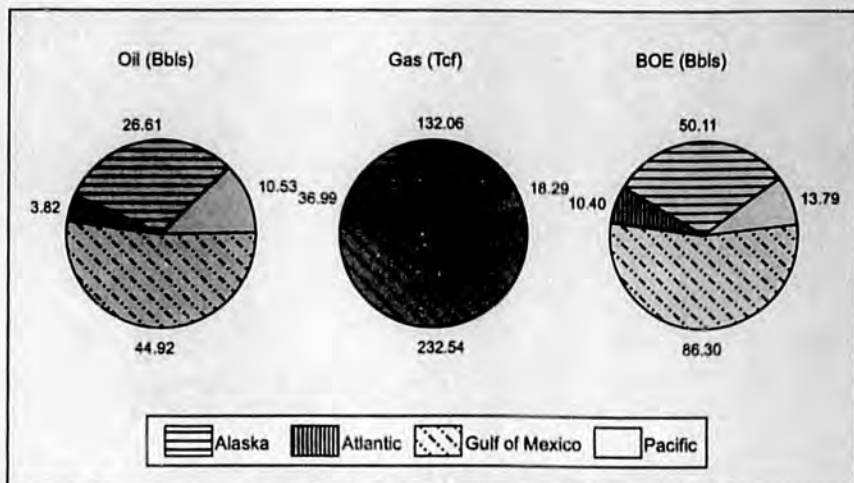


Figure 2. Undiscovered Technically Recoverable Resources by type and region.

in terms of oil potential and fourth with respect to gas. The Atlantic region, on the other hand, ranks third when considering gas potential and fourth in terms of oil.

Technological advances in hydrocarbon exploration and development are sure to occur in the future, yet the nature of advancement is extremely hard to predict and its impact difficult to estimate. However, past experience indicates most technological breakthroughs occur during high-cost scenarios and impact exploration and development by lowering the cost and sometimes by improving the chance of success. For the purpose of this assessment, recent technological advances in gathering, processing, and interpreting seismic data contributed to the identification and mapping of geological plays and development of geologic parameters used to model the plays. Similarly, recent technological advances in offshore drilling and development operations were incorporated through the assumptions associated with the costs of these activities.

However, no attempt was made to determine an empirical relationship between the future technological advancements and the estimated undiscovered resources. MMS believes that future technological advances will significantly affect the

Table 1. Undiscovered Technically Recoverable Resources of the OCS

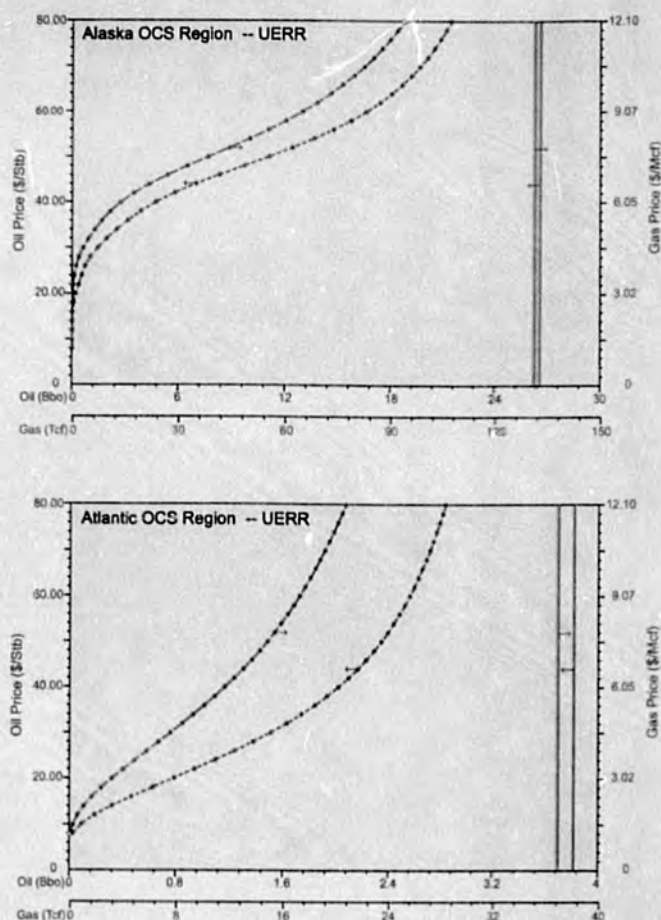
(Bbo, billion barrels of oil, Tcf, trillion cubic of gas. F95 indicates a 95 percent chance of at least the amount listed, F5 indicates a 5 percent chance of at least the amount listed. Only mean values are additive.)

Region	Oil (Bbo)			Natural Gas (Tcf)			BOE (Bbo)		
	95%	Mean	5%	95%	Mean	5%	95%	Mean	5%
Alaska OCS	8.66	26.61	55.14	48.28	132.06	279.62	17.25	50.11	104.89
Atlantic OCS	1.12	3.82	7.57	14.30	36.99	66.46	3.67	10.40	19.39
Gulf of Mexico OCS	41.21	44.92	49.11	218.83	232.54	249.08	80.15	86.30	93.43
Pacific OCS	7.55	10.53	13.94	13.28	18.29	24.12	9.91	13.79	18.24
Total U.S. OCS	66.60	85.88	115.13	326.40	419.88	565.87	124.68	160.60	215.82

portion of the undiscovered resources represented by estimates of UTRR, resulting in an increased percentage being classified as economically recoverable resources.

Estimates of UERR are presented as price-supply curves for the entire OCS as well as individual regions (figure 3). A price-supply curve shows the relationship of price to economically recoverable resource volumes (i.e., a horizontal line from the price axis to the curve yields the quantity of economically recoverable resources at the selected price). The price-supply curve for each region shows two curves and two price scales, one for oil and one for gas. The curves represent mean values at any specific price. They are not independent of each other; that is, one specific oil price cannot be used to obtain an oil resource and a separate gas price used to get a gas resource. The gas price is dependent on the oil price and must be used in conjunction with the oil price on the opposite axis to calculate resources. The reason for this condition is that oil and gas frequently occur together and the individual pool economics are calculated using the coupled pricing. A different gas price associated with the oil price would result in a different resource number than that shown on the curve.

The two vertical lines (green for oil and red for natural gas) indicate the mean estimates of UTRR. At high prices, the economically recoverable resource volumes approach the conventionally recoverable volumes. These curves represent resources available with sufficient exploration and development efforts and do not imply an immediate response to price changes.



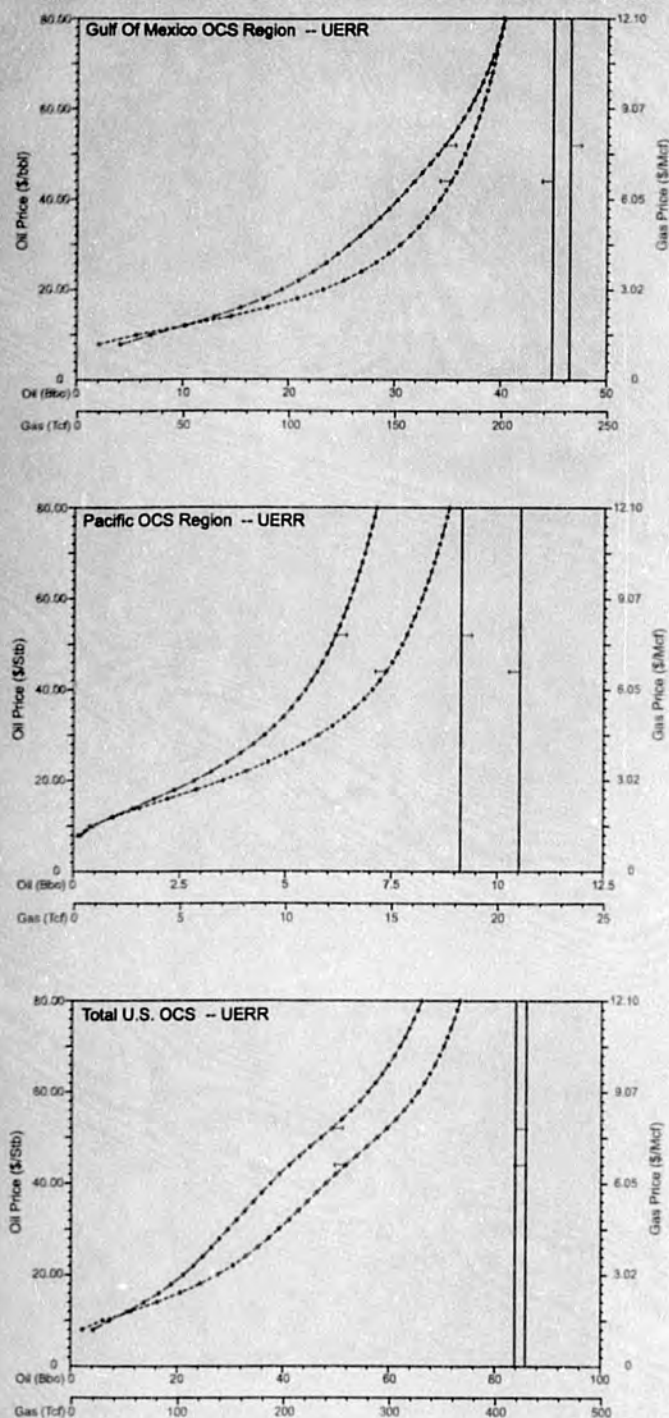


Figure 3. Price Supply Curves for Federal OCS Regions and Total Federal OCS.

Estimates of the quantities of historical production, reserves, and future reserves appreciation are presented to provide a frame of reference for analyzing the estimates of UTRR. The total endowment is the sum of historic production, reserves, future reserves appreciation, and UTRR. Mean estimates of the total endowment for the entire OCS are 115.4 Bbo and 633.6 Tcf (228.2 BBOE). The total endowment distribution by resource category can be seen in figure 4 and table 2. More

than 18 percent of the total endowment in terms of the mean estimate of BOE has already been produced. An additional 11 percent is contained within the various reserves categories, the source of near and midterm production. After more than 50 years of OCS exploration and development, 70 percent of the mean BOE total endowment is still represented by undiscovered resources.

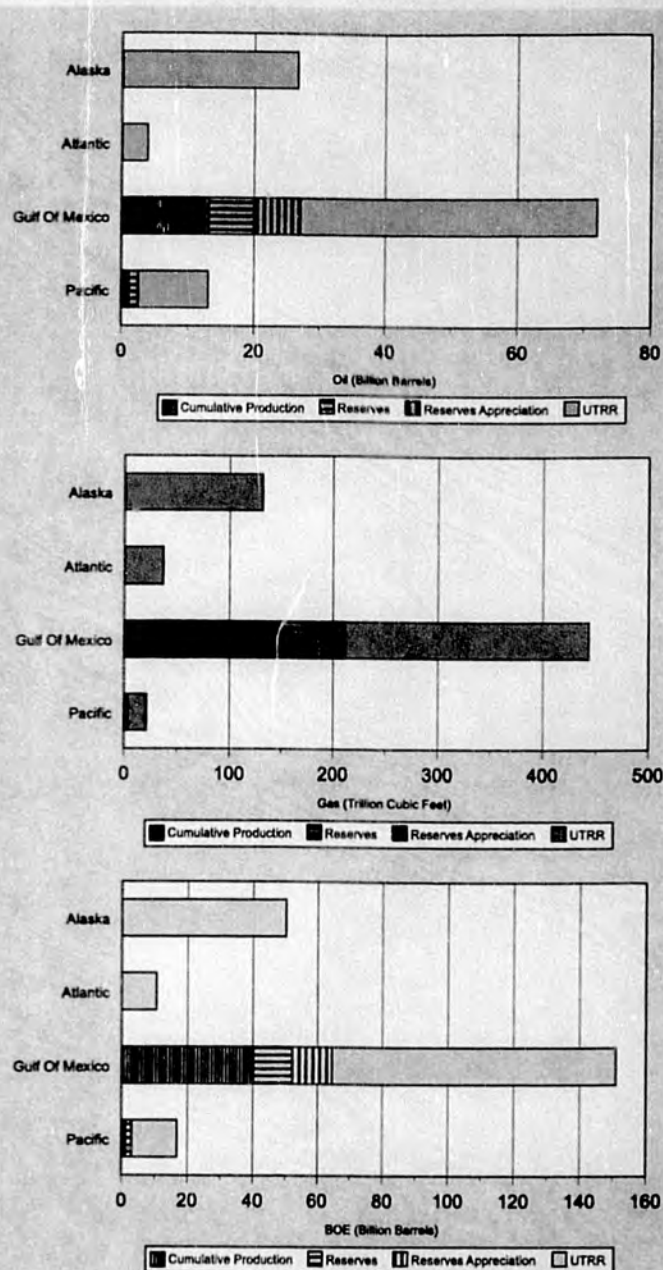


Figure 4. Distribution of total hydrocarbon endowment by type, region and resource category.

Table 2. Distribution of total hydrocarbon endowment by type, region and resource category.

Resource Category		Alaska	Atlantic	Gulf of Mexico	Pacific	Total OCS
Cumulative Production	Oil (Bbo)	.01	0	13.05	1.06	14.12
	Gas (Tcf)	0	0	152.25	1.32	153.57
	BOE (Bbo)	.01	0	40.14	1.29	41.45
Reserves	Oil (Bbo)	.03	0	7.06	1.46	8.55
	Gas (Tcf)	0	0	27.70	1.56	29.26
	BOE (Bbo)	.03	0	11.98	1.74	13.76
Reserves Appreciation	Oil (Bbo)	-	-	6.88	-	6.88
	Gas (Tcf)	-	-	30.91	-	30.91
	BOE (Bbo)	-	-	12.38	-	12.38
UTRR (Mean)	Oil (Bbo)	26.61	3.82	44.92	10.53	85.88
	Gas (Tcf)	132.06	36.99	232.54	18.29	419.88
	BOE (Bbo)	50.11	10.40	86.30	13.79	160.60
Total Endowment	Oil (Bbo)	26.65	3.82	71.91	13.05	115.43
	Gas (Tcf)	132.06	36.99	443.40	21.17	633.62
	BOE (Bbo)	50.15	10.40	150.81	16.82	228.18

Comparison with Previous Assessments

A general comparison of 1996, 2001, and 2006 assessment UTRR results is shown in figure 5. At the mean level, the estimates of UTRR for the entire OCS represent an increase compared to the previous (2001) assessment of 10.9 Bbo and 57.7 Tcfg or about 15 percent for oil and gas. The vast majority of this increase occurred in the Gulf of Mexico, where estimates of UTRR range from 41.2 to 49.1 Bbo and 218.8 to 249.1 Tcfg with a mean of 44.9 Bbo and 232.5 Tcfg respectively. Significant increases in the estimates for the deepwater areas were the major contributor to the overall growth in the estimates of UTRR for oil. The majority of the increase in the estimate of UTRR from gas was related to deep gas plays located beneath the shallow water shelf of the Gulf of Mexico. This increase in UTRR was also accompanied by approximately 4.5 Bbo and 14 Tcfg that were discovered in fields such as Thunder Horse and Holstein, whose resources were moved to the reserve category during this time period.

In the Pacific Region, the mean estimate for UTRR of 10.5 Bbo and 18.3 Tcfg represented a slight decrease for both oil and natural gas. The Atlantic estimate of UTRR ranges from 1.1 to 7.6 Bbo and 14.3 to 66.5 Tcfg with a mean of 3.8 Bbo and 37.0 Tcfg. The estimates represent a 66 percent increase in oil resources and a 33 percent increase in gas resources in the Atlantic OCS, when compared with the MMS 2001 assessment. The last remaining leases in the Atlantic OCS, on the Manteo Prospect, expired in 2002 without a well being drilled. However, significant new analog information was available as the result of recent exploration in the Scotian Shelf offshore Canada and the West African Continental Slope offshore Mauritania. Applying these new exploration ideas to

the older Atlantic play models led to adjustments to risks in previously defined plays and the identification of additional new plays.

Estimates of UTRR on the Alaska OCS changed only slightly compared to the previous assessment. The mean oil estimate

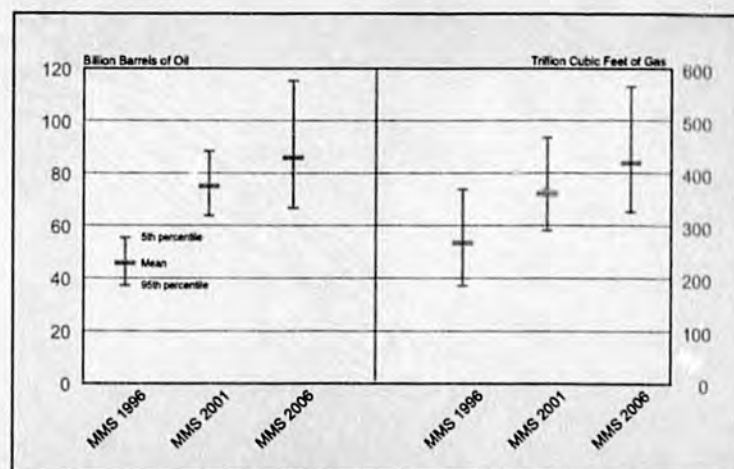


Figure 5. Comparison of UTRR from MMS 1996, 2001, 2006 assessments.

increased by 1.7 Bbo, while the mean natural gas estimate declined by 6.7 Tcf. The first Alaskan OCS production occurred in 2001 from the joint state/Federal Northstar unit in the Beaufort Sea.

Fifty-four percent of the mean estimate of UTRR on a BOE basis was projected to be present in the Gulf of Mexico OCS. The Alaska, Pacific and Atlantic OCS comprise 31, 9 and 6 percent respectively of the total UTRR.

List of Terms

Cumulative production: The sum of all produced volumes of oil and gas prior to a specified point in time.

Pool: A discovered or undiscovered accumulation of hydrocarbons, typically within a single stratigraphic interval.

Play: A group of pools that share a common history of hydrocarbon generation, migration, reservoir development, and entrapment.

Probability: A means of expressing an outcome on a numerical scale that ranges from impossibility to absolute certainty; the chance that a specified event will occur.

Prospect: A geologic feature having the potential for trapping and accumulating hydrocarbons; a pool or potential field.

Reserves: The quantities of hydrocarbon resources anticipated to be recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty.

Reserves appreciation: The observed incremental increase through time in the estimates of reserves (proved and unproved) of an oil and/or natural gas field as a consequence of extension, revision, improved recovery, and the addition of new reservoirs.

Resources: Concentrations in the earth's crust of naturally occurring liquid or gaseous hydrocarbons that can conceivably be discovered and recovered.

Undiscovered resources: Resources postulated, on the basis of geologic knowledge and theory, to exist outside of known fields or accumulations.

Undiscovered technically recoverable resources (UTRR): Oil and Gas that may be produced as a consequence of natural pressure, artificial lift, pressure maintenance, or other secondary recovery methods, but without any consideration of economic viability. They are primarily located outside of known fields.

Undiscovered economically recoverable resources (UERR): The portion of the undiscovered conventionally recoverable resources that is economically recoverable under imposed economic and technologic conditions.

Selected References

Minerals Management Service. 1996: An assessment of the undiscovered hydrocarbon potential of the Nation's outer continental shelf. OCS Report MMS 96-0034, 40 p.

———. 2001: Outer Continental Shelf Petroleum Assessment, 2000, 12 p.

Society of Petroleum Engineers and World Petroleum Congress. 1997: Petroleum Reserves Definitions, p. 4-7.

For Further Information

Supporting geological studies, previous assessment results, and methodologies used by MMS for resource assessment can be found on MMS's web site, www.mms.gov/offshore.

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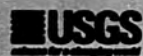
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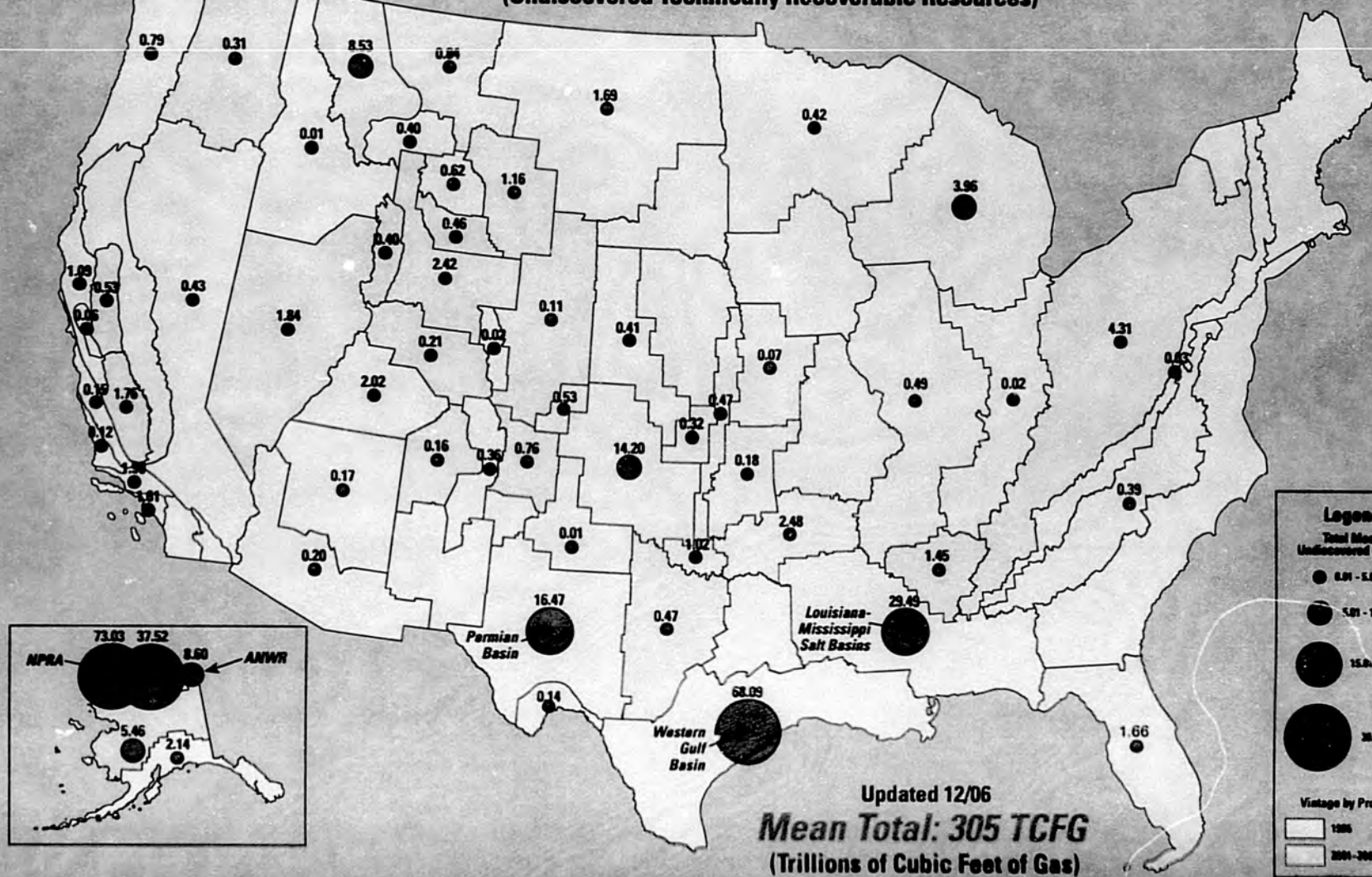
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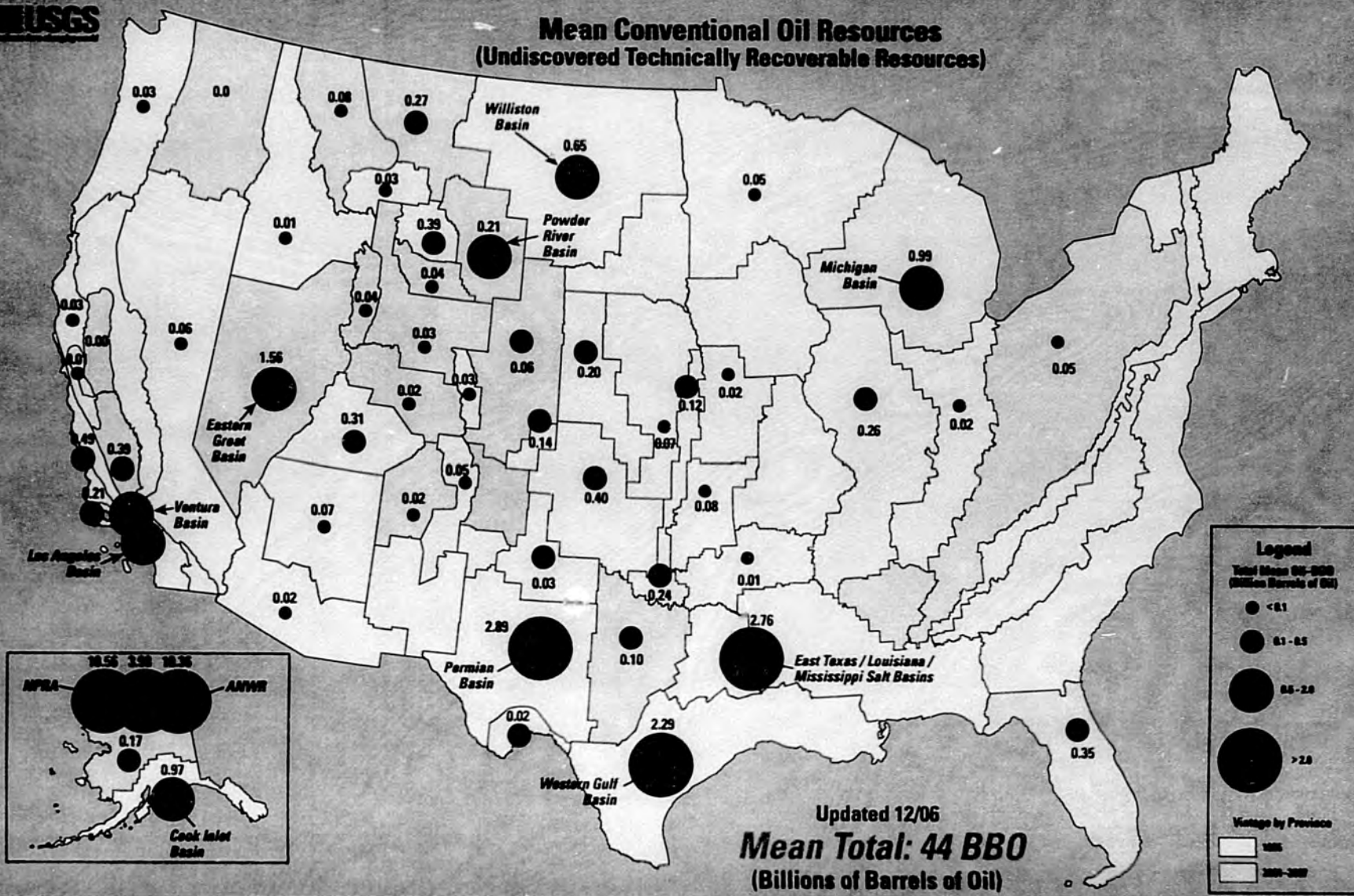
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Mean Undiscovered Conventional Gas Resources (Undiscovered Technically Recoverable Resources)



**Mean Conventional Oil Resources
(Undiscovered Technically Recoverable Resources)**



USGS NATIONAL ASSESSMENT OF OIL AND GAS RESOURCES UPDATE (December, 2006)
CONVENTIONAL OIL AND GAS RESOURCES

Province Number and Name	Vintage	Conventional Oil (billions of barrels)			Conventional Gas ¹ (trillions of cubic feet)			Natural Gas Liquids (billions of barrels)		
		F95	F05	Mean	F95	F05	Mean	F95	F05	Mean
1a North Slope ANWR	1998	5.72	15.95	10.36			8.60			0.32
1b North Slope NPRA	2002	6.67	15.01	10.56			73.03			1.42
1c North Slope Middle-ground Area	2005	2.56	5.85	3.98	26.62	50.90	37.52	0.33	0.66	0.48
2 Central Alaska	2004	0.00	0.59	0.17	0.00	14.63	5.46	0.00	0.35	0.01
3 Southern Alaska	1995	0.19	2.20	0.97	0.68	4.34	2.14	0.00	0.00	0.00
4 Western Oregon-Wash.	1995	0.00	0.12	0.03	0.10	1.94	0.79	0.00	0.01	0.01
5 Eastern Oregon-Wash.	2006	0.00	0.00	0.00	0.00	0.86	0.31	0.00	0.01	0.01
7 Northern Coastal	1995	0.01	0.09	0.03	0.35	2.33	1.09	0.00	0.01	0.01
8 Sonoma-Livermore	1995	0.00	0.06	0.01	0.00	0.42	0.06	0.00	0.00	0.00
9 Sacramento Basin	2007	0.00	0.00	0.00	0.14	1.07	0.53	0.05	0.77	0.26
10 San Joaquin Basin	2004	0.08	0.85	0.39	0.32	4.33	1.76	0.01	0.22	0.09
11 Central Coastal	1995	0.10	1.17	0.49	0.03	0.37	0.15	0.01	0.01	0.01
12 Santa Maria Basin	1995	0.02	0.60	0.21	0.01	0.35	0.12	0.01	0.03	0.01
13 Ventura Basin	1995	0.28	2.27	1.06	0.66	3.66	1.90	0.02	0.12	0.06
14 Los Angeles Basin	1995	0.41	1.78	0.88	0.61	3.08	1.61	0.02	0.11	0.06
17 Idaho-Snake River Downwarp	1995	0.00	0.01	0.01	0.00	0.09	0.01	0.00	0.00	0.00
18 Western Great Basin	1995	0.00	0.37	0.06	0.00	2.49	0.43	0.00	0.01	0.00
19 Eastern Great Basin	2005	0.24	3.80	1.56	0.19	4.98	1.84	0.01	0.23	0.08
20 Uinta-Piceance Basin	2002	0.00	0.04	0.02	0.07	0.44	0.21	0.00	0.01	0.00
21 Paradox Basin	1995	0.11	0.61	0.31	0.93	3.48	2.02	0.03	0.17	0.09
22 San Juan Basin	2002	0.00	0.04	0.02	0.06	0.31	0.16	0.00	0.01	0.00
23 Albuquerque-Sante Fe Rift	1995	0.00	0.15	0.05	0.00	1.29	0.36	0.00	0.06	0.02
24 Northern Arizona	1995	0.00	0.32	0.07	0.00	0.96	0.17	0.00	0.08	0.01
25 S. Ariz.-S.W. New Mexico	1995	0.00	0.06	0.02	0.01	0.53	0.20	0.01	0.05	0.02
26 South-Central New Mexico	1995	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27 Montana Thrust Belt	2002	0.01	0.19	0.08	1.10	20.67	8.53	0.03	0.59	0.23
28 Central Montana	1995	0.13	0.42	0.27	0.40	1.37	0.84	0.01	0.01	0.01
29 Southwest Montana	1995	0.00	0.13	0.03	0.12	0.76	0.40	0.01	0.01	0.01
31 Williston Basin	1995	0.25	1.17	0.65	0.89	2.61	1.69	0.07	0.22	0.14
33 Powder River Basin	2007	0.06	0.43	0.21	0.23	2.63	1.16	0.02	0.25	0.11
34 Big Horn Basin	1995	0.08	0.87	0.39	0.24	1.19	0.62	0.01	0.02	0.01
35 Wind River Basin	2005	0.01	0.09	0.04	0.11	0.97	0.46	0.00	0.00	0.00
36 Wyoming Thrust Belt	2003	0.01	0.08	0.04	0.01	0.82	0.40	0.01	0.09	0.04
37 Southwestern Wyoming	2002	0.01	0.07	0.03	0.61	5.38	2.42	0.02	0.17	0.07
38 Park Basins	1995	0.01	0.11	0.03	0.01	0.07	0.02	0.00	0.01	0.00
39 Denver Basin	2003	0.01	0.16	0.06	0.02	0.31	0.11	0.00	0.02	0.01
40 Las Animas Arch	1995	0.04	0.28	0.14	0.20	1.07	0.53	0.01	0.03	0.01
41 Raton Basin-Sierra Grande Uplift	2004	0.00	0.00	0.00	0.21	1.28	0.76	0.01	0.05	0.03
43 Palo Duro Basin	1995	0.01	0.07	0.03	0.01	0.01	0.01	0.00	0.00	0.00
44 Permian Basin	1995	1.59	4.52	2.89	10.56	23.32	16.47	0.40	0.88	0.61
45 Bend Arch-Fl. Worth Basin	2003	0.03	0.18	0.10	0.15	0.87	0.47	0.00	0.05	0.02
46 Marathon Thrust Belt	1995	0.01	0.04	0.02	0.06	0.28	0.14	0.01	0.02	0.01
47 Western Gulf	1995	0.73	4.56	2.29	44.11	96.18	68.09	1.04	2.20	1.57
49 East Texas Basin/LA-MS Salt Basins	1995	0.88	5.39	2.76	18.81	42.34	29.49	0.57	2.10	1.21
50 Florida Peninsula	2001	0.04	0.85	0.35	0.00	4.25	1.66	0.00	0.05	0.06
51 Superior	1995	0.00	0.44	0.05	0.00	2.95	0.42	0.00	0.01	0.01
53 Cambridge Arch-Central Kansas	1995	0.04	0.43	0.20	0.08	1.04	0.41	0.01	0.04	0.02
55 Nemaha Uplift	1995	0.03	0.29	0.12	0.17	0.96	0.47	0.01	0.06	0.03
56 Forest City Basin	1995	0.00	0.06	0.02	0.00	0.19	0.07	0.00	0.01	0.01
58 Anadarko Basin	1995	0.21	0.66	0.40	8.72	21.27	14.20	0.13	0.28	0.19
59 Sedgwick Basin/Salina Basin	1995	0.02	0.12	0.07	0.14	0.51	0.32	0.01	0.03	0.02
60 Cherokee Platform	1995	0.02	0.17	0.08	0.07	0.34	0.18	0.01	0.02	0.01
61 Southern Oklahoma	1995	0.05	0.57	0.24	0.47	1.79	1.02	0.01	0.05	0.02
62 Arkoma Basin	1995	0.00	0.07	0.01	1.17	4.22	2.48	0.04	0.13	0.08
63 Michigan Basin	2004	0.29	1.88	0.99	1.16	7.73	3.96	0.06	0.45	0.22
64 Illinois Basin	1995	0.05	0.57	0.26	0.01	3.24	0.49	0.00	0.00	0.00
65 Black Warrior Basin	2002	0.00	0.01	0.00	0.02	3.34	1.45	0.00	0.02	0.01
66 Cincinnati Arch	1995	0.01	0.04	0.02	0.01	0.04	0.02	0.00	0.01	0.01
67 Appalachian Basin	2002	0.01	0.10	0.05	1.26	8.28	4.31	0.01	0.80	0.04
68 Blue Ridge Thrust Belt	1995	0.00	0.00	0.00	0.00	0.15	0.03	0.00	0.00	0.00
69 Piedmont	1995	0.00	0.00	0.00	0.00	1.19	0.39	0.00	0.00	0.00
TOTALS				44.28			304.96			7.79

¹includes non-associated and associated-dissolved gas resources

DNR	Oil MBO		Gas TCF	
	Produced	Remaining	Produced	Remaining
Cook Inlet	1.3	0.1	7.3	1.7
PBU & Sats	11.5	2.7		23.0
GPMA	0.7	0.3		1.5
KRU	2.2	1.3		1.2
Milne	0.3	0.3		
Collville River (Alpine)	0.2	0.5		0.4
Badami	0.0	0.0		0.0
Northstar	0.1	0.1		0.5
Duck Island (Endicott)	0.5	0.1		0.8
Point Thomson	0.0	0.3		8.0
Other (Liberty)	0.0	0.4		0.0
	16.7	6.0		37.0

Undiscovered Technically Recoverable Resource Offshore (MMS)

	Liquids GBOE	Gas TCF
Beafor Sea	8.2	27.6
Chukchi Sea (Northwestern)	15.4	76.8
Cook Inlet	1.0	1.2
Gulf of Alaska	0.6	4.7
Hope Basin	0.2	3.8
Kodiak Shelf	0.0	1.8
North Aleutian Basin	0.8	8.6
Shumagin Shelf	0.0	0.5
St. George Basin	0.2	2.8
	26.4	127.8

Undiscovered Technically Recoverable Resource Onshore (USGS)

	Liquids GBOE	Gas TCF	NGL GBOE
North Slope ANWR	10.4	8.6	0.3
North Slope NPRA	10.6	73.0	1.4
North Slope Middle-ground Area	4.0	37.5	0.5
Central Alaska	0.2	5.5	0.0
Southern Alaska	1.0	2.1	0.0

TESTIMONY OF CRAIG HAYMES
ON PROPOSED HB 2001
TO THE ALASKA HOUSE SPECIAL COMMITTEE ON OIL & GAS
OCTOBER 23, 2007

INTRODUCTION

Mr. Chairman, members of the committee:

Good morning. For the record, my name is Craig Haymes. I am the Production Manager for ExxonMobil in Alaska, a position I have held since January 2007. I have the pleasure of living in Anchorage with my family. Prior to January this year I was involved with Arctic oil and gas projects on the East coast of Canada for almost five years.

I want to thank the committee for the opportunity to express ExxonMobil's views today regarding the Administration's proposed tax increase.

Let me state upfront, ExxonMobil believes the current PPT tax rate and the increase proposed by the Administration will have a negative impact on resource investments in Alaska. ExxonMobil does not support the proposed tax increase by the Administration.

We believe that Alaska needs to focus on a long-term resource development policy. The policy should encourage increasing investment that is needed to maximize the development of Alaska's resources. Alaska is rich in undiscovered resource potential, yet oil production continues to decline from mature basins. Oil production today is one

third of the peak of over 2 million barrels per day in 1988. Alaska faces a significant challenge. We have a common goal to maximize economic resource development and need to work together; Government, industry, and the people of Alaska, to enhance the development of Alaska's rich resources and the future.

EXXONMOBIL IN ALASKA

ExxonMobil invests all over the world to meet the growing need for energy. Over the last 20 years we have invested close to \$280 billion dollars to search for new supplies of energy, build new production facilities, expand refinery capacity and deploy new, environmentally sound technologies.

ExxonMobil believes technology innovation is the key to meeting the world and Alaska's energy challenges. Technology is the lifeblood of our industry. ExxonMobil currently spends close to \$1 billion per year on research and technology. We have consistently applied our technology in Alaska to unlock and develop resources. We have significant arctic experience around the world.

Some examples of technology applications that we have contributed to Alaska are

- The installation of the ice resistant Granite Point platform in Cook Inlet, which is still producing oil.
- Significant research and engineering for the Prudhoe Bay completion designs for permafrost
- The installation of the first Concrete Island Drilling System (CIDS) to drill exploration wells in ice covered waters in the Alaska Beaufort Sea.

- The first full-field 3-D simulation model of Prudhoe Bay, leading to many enhanced oil recovery and development drilling programs that are still being pursued today.

The application of technology will continue to be a key to the future of Alaska's resource developments.

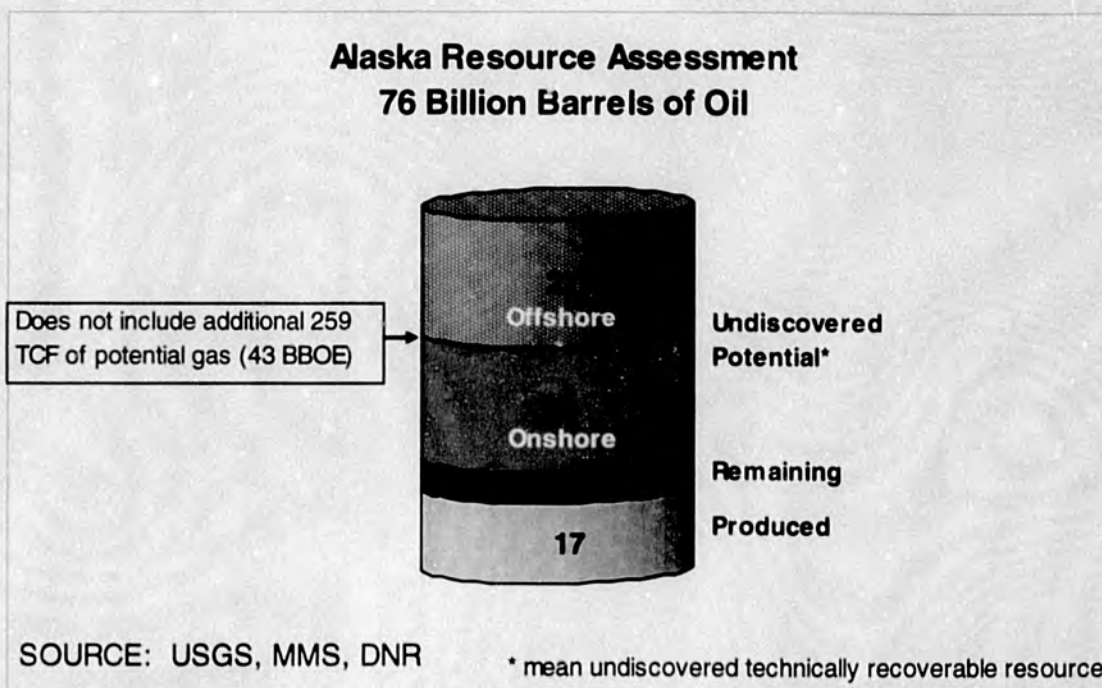
ExxonMobil has had a presence in Alaska for over 50 years and has been a key player in Alaska's oil industry development, spending and investing over \$20 billion dollars. We hold the largest working interest at Prudhoe Bay (36.4%) and our current working interest share of oil production in the state is approximately 150,000 barrels per day. We are also the largest owner of discovered Alaska gas resource.

We are currently active with our co-owners at Prudhoe Bay, Kuparuk, Duck Island, Granite Point and Point Thomson. Over the last two years we have participated in the drilling of over 70% of the wells on the North Slope - over 130 wells were drilled at Prudhoe Bay alone - this drilling will add 50,000 B/D of oil production in 2007, an important contribution to help mitigate production decline.

We are proud of the role that our company has played in Alaska, which we believe has benefited both the State and the industry, and we look forward to working with Alaska for many years to come.

ALASKA RESOURCE POTENTIAL IS SIGNIFICANT

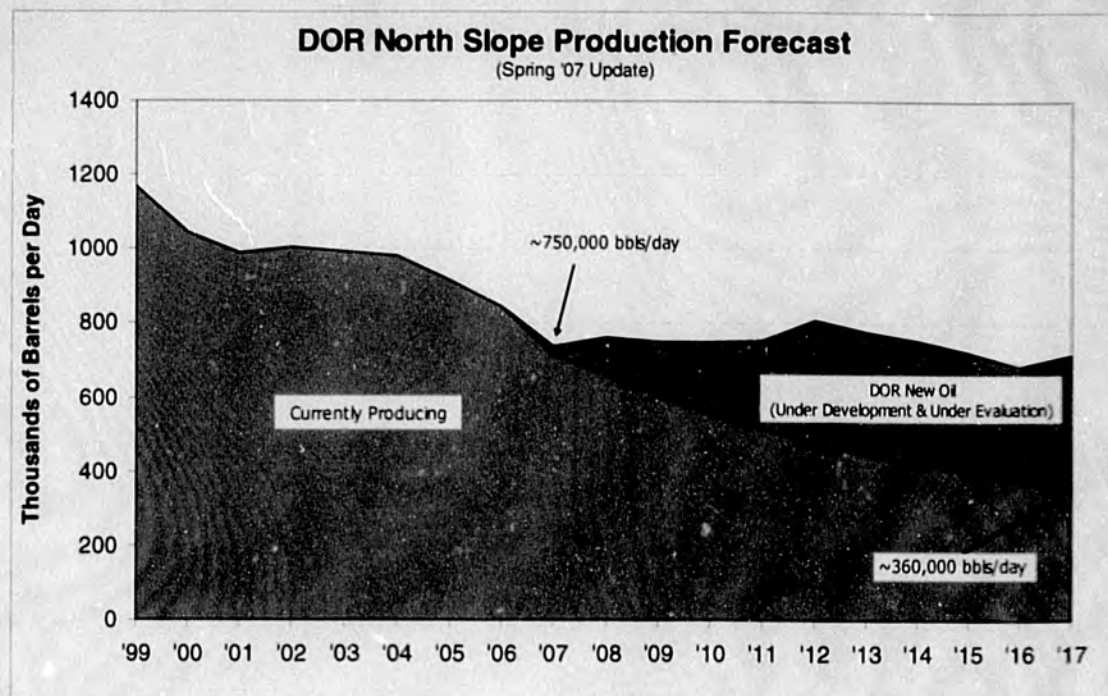
I would like to take a few moments to discuss Alaska's resource opportunities. Alaska has significant oil and gas resources. According to the US Geological Survey and the US Minerals Management Service, Alaska's undiscovered technically recoverable resources are 53 billion barrels of oil. This is in addition to the Department of Natural Resources estimate for known remaining oil resources of 6 billion barrels. To date Alaska has produced close to 17 billion barrels of oil - this is a world class result – but is less than one fourth of the potential total of 76 billion barrels. That is, Alaska still has the potential to produce another 59 billion barrels of oil. The gas resource potential almost doubles this undiscovered potential on an oil equivalent basis.



Whilst Alaska's resource potential is high, the Oil and Gas Journal and Energy Information Administration report that its world ranking of proved reserves has declined from 14th in 1977 to a position closer to 30th today.

ALASKA's FUTURE OIL PRODUCTION

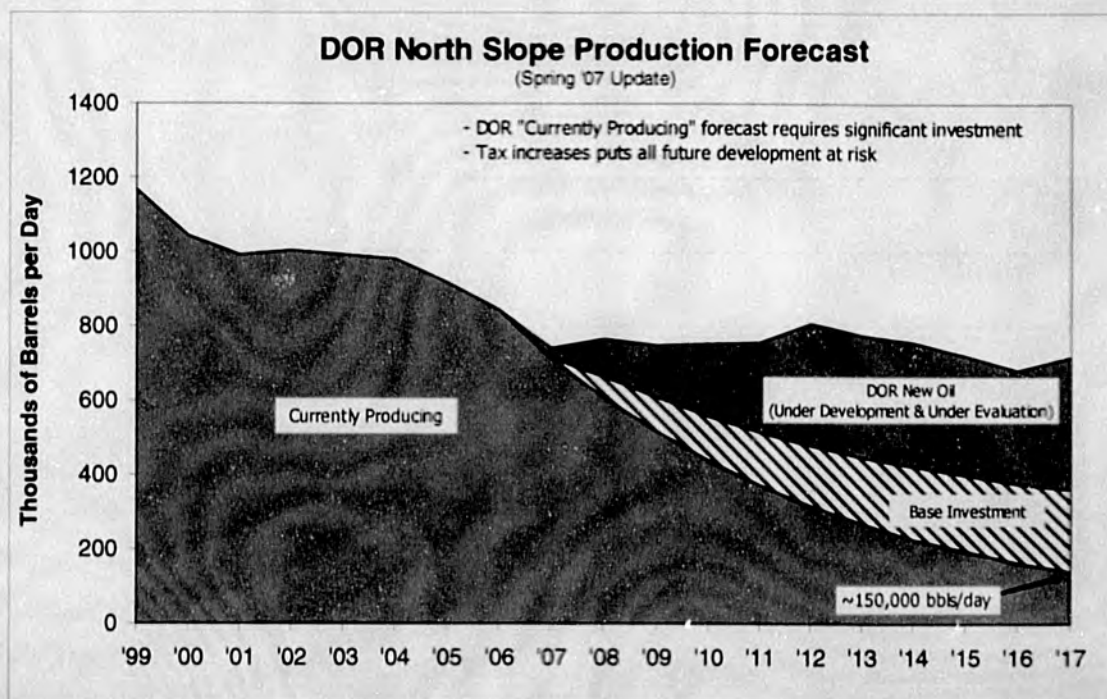
Today Alaska is producing approximately 750,000 barrels of oil per day from the North Slope, one third of its peak production. The Department of Revenue's production outlook, from their Spring Revenue Sources Book, shows that they estimate a 9% annual decline in Alaska's current base production. As the chart illustrates, at this decline rate, over the next ten years Alaska's current base production, shown in green, will drop to around 360,000 barrels per day. That is a production level of less than half of today's.



The Department of Revenue also forecasts that this base production decline will be partially mitigated with the development and production of oil in categories called "Under Development and Under Evaluation", shown in blue on the chart. These categories include future investments, such as development drilling, satellite developments, and enhanced oil recovery from existing fields. Based on this forecast, over 50% of the

projected oil production in 10 years will come from new investments. Let me say that again, 50% of future oil production in 10 years is not even developed or producing today. Considering that most new projects take at least 5-7 years to bring to production on the North Slope, investment decisions for these activities, particularly in the near term, will be critical to underpin the future of Alaska's oil production.

As I mentioned earlier, the Department of Revenue forecast is based on a 9% annual decline in Alaska's current base production. However, this decline assumes that production enhancement investments at the core Prudhoe Bay, Kuparuk and Alpine areas continue. The Department of Revenue forecast, as shown, does not highlight that this activity requires investment decisions that are no different from the "Under Development and Under Evaluation" categories. As such, a more accurate representation of the future oil production and investment levels required to achieve the Department of Revenue forecast is illustrated in the following chart.



As this chart shows, Alaska's oil production from the North Slope could be as low as 150,000 barrels per day within 10 years, (assuming 15% decline, which is typical for large oil fields such as Prudhoe Bay), without ongoing and increasing investment. Based on this forecast, within 10 years, 75% of production will come from new investments.

Conservatively, we estimate that at least \$30-40 billion of investment is required within the next 10 years to achieve the Department of Revenue forecast. This does not include the billions of dollars of additional operating expenditures that would be required to support the developments once they are producing. This is a significant level of future investment and spending.

The high tax rate in PPT and the proposed tax increase put this investment at significant risk. Alaska needs to encourage the increasing investments required, not only in exploration activities, but also in the ongoing development of existing and new fields.

ALASKA IS A HIGH COST REGION

Complicating the significant future investments required to mitigate Alaska's production decline is its high costs. Alaska has unique challenges resulting in a high cost environment for exploration and development and very mature producing fields with growing unit costs. Many factors contribute to Alaska's higher costs including:

- Severe arctic conditions, placing limitations on when drilling and other operations can be undertaken
- A sensitive environment, requiring significant and due diligence measures to protect it
- Remote location of the resource and distance to market
- Current restrictions for future exploration opportunities

All combine to create a unique and high cost environment for Alaska.

ALASKA'S SO-CALLED LEGACY FIELDS

The two largest oil fields in Alaska - Prudhoe Bay and Kuparuk, have been producing since 1977 and 1981, respectively. Today these two fields account for over 70% of the State's North Slope oil production. Assuming that exploration and investment activity continues in these fields, they could remain at this level of production contribution for the next decade.

These so called legacy fields require continuous investment to keep the oil flowing and the facilities operating at capacity. This is the same for any oil field in the world. During the production phase there are many changes in operating parameters, such as reservoir pressure changes, oil, gas and water production changes, changes in operating conditions, and ongoing technical challenges. In order to keep the oil flowing, these changes require additional investments, such as the addition of water and gas injection and gas compression facilities, which are historical significant investments at Prudhoe Bay.

Currently, the owners spend over \$2 billion dollars to optimize and enhance production from Prudhoe Bay and Kuparuk. These spending levels are in addition to the capital investments pursuing new wells, projects, and enhanced oil recovery opportunities. These operating expenditures are essential to mitigate production decline at these significant fields, which are critical to the future of Alaska's North Slope oil production.

Many of today's exploration and development activities are occurring in and around Prudhoe Bay and Kuparuk.

As an example, since the year 2000 there have been multiple Prudhoe Bay satellite fields developed - Aurora, Borealis, Midnight Sun, Polaris, and Orion - which are currently contributing over 40,000 B/D of oil production. These developments would not have been possible without the infrastructure and facility sharing of Prudhoe Bay, which reduced the development and operating costs of these satellites. As satellite fields are developed it reduces exploration and development costs for future new projects, as the infrastructure on the North Slope expands.

If the major Prudhoe Bay and Kuparuk developments did not exist these satellite fields would not have been economic to develop.

As another example, for the past seven years over 900 new wells have been drilled in Prudhoe Bay and Kuparuk. The drilling of these new wells has slowed the overall production decline from 12-15% to an estimated 6-9%. Almost 40% of Prudhoe Bay's production today is from these new wells.

For the past two years, development drilling at Prudhoe Bay has achieved the equivalent of the important Oooguruk development. This example highlights the importance of exploring for and developing new oil in and around the Prudhoe Bay and Kuparuk fields - all are important to the economic benefit and future of Alaska.

Let me re-emphasize that Prudhoe Bay and Kuparuk have the potential to continue to be critical contributors to Alaska's oil production. They have the potential to remain key hubs and enablers for exploration and development of heavy or viscous oil, light oil and gas. Encouraging increasing investment at these key fields is as important as encouraging investment in exploration and development of new fields. Without these two hubs, Alaska will be severely challenged to realize the full potential of its resources.

Progressing a tax policy that singles out and penalizes these fields will discourage investment not only at these fields but will also impact future investment attractiveness to explore and develop other Alaska oil and gas resources.

PROPOSED TAX INCREASE MORE COMPLICATED

In analyzing the Administration's tax proposal, we found that virtually all of the provisions are simply tax rate increases or further increases in complexity.

As an example, under the Administrations proposed tax increase the two so-called Legacy Fields, Prudhoe Bay and Kuparuk, would have a separate 10% gross minimum tax and be segregated from each other and all other North Slope fields. This gross tax would be in addition to the base royalty payments. With this minimum gross tax the State would be insulated from price and cost risks, whilst retaining the upside potential from the progressivity element. The Administration is simply proposing to increase its take while shifting the development risks to the producers. Essentially, at low price, producers are penalized.

Companies are willing to accept the risks of long-term, capital intensive investments when there is a corresponding opportunity for upside potential and a sharing of risk should prices fall. Under the Administration's proposed tax increase, investors will need to assume a higher economic risk when making funding decisions for future investments and spending.

The Administration has also proposed that all revenues and expenses for the Legacy Fields will have to be accounted for separately, with separate taxes paid for each unit and their satellites. This would include Alaska's heavy or viscous oil reserves produced from those Legacy Fields - a resource that already has significant economic and technical hurdles to overcome. No other fields, units or regions within the state would be subjected to these administrative burdens.

The ring-fencing of the Prudhoe Bay and Kuparuk Units makes the tax proposal more complex than the existing PPT.

EXXONMOBIL POSITON ON THE ENACTED PPT

I believe it is important that I clarify ExxonMobil's position on the current PPT.

ExxonMobil did not support the PPT that was enacted last year. As we testified last year, we supported the concept of a net based tax but stated that the proposed 20% tax rate, in the original PPT bill, would not encourage the full development of Alaska's resources. We agreed with the 20% tax rate in order to support the progression of a gas pipeline project.

The PPT that was ultimately enacted increased the already high 20% base tax rate to 22.5% with progressivity - more than doubling industry's taxation. Alaska's current PPT tax rate is too high. When combined with the gross royalties and the high development and operating costs, it makes Alaska one of the most expensive regions to invest.

There has been a lot of discussion recently on PPT revenues and forecasts, which has been used in part to support the Administrations proposal to increase taxes. PPT has only been in existence for slightly more than one year. The Department of Revenue has not completed its PPT regulations or started any PPT audit. ExxonMobil, like a number of the other producers, met with the Department of Revenue several months ago to discuss ways to help the State better forecast its expected PPT revenues and we are willing to continue those efforts. We are also willing to work with DOR auditors to improve their understanding of joint interest billings.

FISCAL PREDICTABILITY IS IMPORTANT

I would now like to address another important element of the business environment - fiscal predictability. ExxonMobil, and I believe the industry, values a predictable fiscal environment in which to make long term investment decisions. Our investments are capital intensive and are evaluated over timeframes of decades. Any change in the fiscal regime has a direct impact on how we view predictability of the Alaskan fiscal environment, which in turn directly impacts how we evaluate on a risk basis future investment decisions. Let me reemphasize this point. Because of the nature and magnitude of the risks associated with any oil or gas investment, coupled with the amount of time required to recoup that investment, fiscal terms that are predictable are key to any investment decision.

The Administrations proposed tax increase would represent the third significant change to Alaska's fiscal terms in the past three years. Changing the fiscal environment for capital intensive projects, that take many years to generate a return, can only reduce the attractiveness of future investments. Each time taxes are raised, the attractiveness of any prospective well or project diminish and the likelihood of it not being funded increases. For every well or project not progressed, additional production and State revenues are lost. As mentioned earlier, to mitigate oil production decline Alaska needs to increase investment. The Administration's proposed tax increase will reduce investment.

ExxonMobil expects to be involved in Alaska for many years to come. The policies established today and in the future will impact the attractiveness of future potential projects and the future of Alaska.

ALASKA NEEDS A LONG-TERM RESOURCE DEVELOPMENT POLICY

As I mentioned earlier, Alaska has significant resource potential, but with many unique cost challenges. It will take significant resources, technology, investment and teamwork from everyone to realize the full potential. Alaska and industry collaboratively need to create a resource development policy that encourages investment for long-term production and growth. This is a complex issue and needs significant time and effort from all parties. It is beneficial to look at what others have done.

The Canadian province of Alberta has enormous unconventional crude oil resources. Alberta's oil sands represent the potential of over 170 billion barrels of crude, and, like Alaska's resources, are located in higher cost, remote arctic regions that require significant investments to develop.

Alberta adopted a resource development policy approach, designed to increase industry investment and production. Their approach has proven successful due to a number of key factors:

- Collaborative pursuit of resource development objectives
- Development of technologies jointly with industry to reduce costs, increase oil recovery, and upgrade viscous oil to marketable products
- Creation of a level playing field for all projects
- Sharing risks with the investors by maintaining a lower gross revenue based tax, that is, lowering royalties significantly
- Providing long term fiscal predictability

Alberta's success suggests that Alaska should seriously consider what other regions are doing to encourage investment.

A long-term sustainable resource development policy is required to enable Alaska to maximize its oil and gas resource. There are many factors that need to be considered.

It is a complex issue. I hope that key points addressed in my testimony are considered:

- Alaska has significant resource potential, but it is in a high cost environment
- Oil production is already one third of its peak, yet we have only produced one fourth of the oil resource potential
- In 10 years, 75% of Alaska's future oil production needs over \$30-40 billion of new investments - investments that are needed sooner than 10 years.
- Prudhoe Bay and Kuparuk are the "hub" of the North Slope, they
 - Represent 70% of North Slope oil production for the next 10+ years
 - Can be the backbone for future exploration and economic developments, whether it is existing production, future light oil, heavy oil, or gas
 - Need increasing investments to achieve their potential
- Development drilling at Prudhoe Bay and Kuparuk over the last 2 years has added 50,000 B/D of new oil production in 2007

We propose a collaborative approach to develop a sustainable long term resource policy that will encourage the needed increasing investments and build the future of Alaska for many generations to come. ExxonMobil looks forward to working with the Administration, the legislators, industry and the people of Alaska in the future pursuit and development of its oil and gas resources.

To encourage full development of Alaska's resources, the PPT tax rate needs to be lowered, and should not include a gross revenue based component. Increasing investment fuels the economy.

Thank you again Mister Chairman for the opportunity to testify today.

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TESTIMONY OF THE
ALASKA OIL AND GAS ASSOCIATION
TO THE HOUSE SPECIAL COMMITTEE ON OIL & GAS
ON HOUSE BILL 2001

October 23, 2007

Mr. Chairman and Members of the Committee. Thank you for the opportunity to testify before you today on House Bill 2001.

My name is Marilyn Crockett and I am the Executive Director of the Alaska Oil and Gas Association ("AOGA"). AOGA is the trade association for the oil and gas industry in Alaska. Our 17 members account for the majority of oil and gas exploration, development, production, transportation, refining and marketing activities in the state. In addition to Alaska's instate refiners, Agrium and Alyeska, our membership includes companies new to Alaska hoping for the opportunity to explore, companies which are exploring today but do not yet have production (but hope to in the future) and those companies which are producing today.

One of the important functions the Association performs is to provide a forum for member companies to consider regulatory and legislative proposals, and to reach agreement on an industry position on those proposals. To establish an AOGA position, a 5/6 vote of the members is required. What this means, of course, is that when AOGA voices that position, regulators and legislators can be assured that that position is the position of the overwhelming majority of Alaska's oil and gas industry.

But on tax issues, AOGA members have taken this approval process to the highest level. AOGA positions on tax-related issues require 100% consensus of the AOGA Members. Let me be clear: my testimony today reflects the full consensus of the members of the AOGA Tax Committee, with no dissent.

The focus of our testimony today will be on the practical impact of declining production levels on industry operations and the State of Alaska. And while we are not in a position at this early date in this Special Session to provide you with a complete analysis of the many components of HB 2001, we will describe for you but a few of the troubling aspects of this legislation. The AOGA Tax Committee is in the midst of a comprehensive review of the legislation and will be in a position at a future date to characterize those concerns.

Here we are in Juneau for the fourth time in the past two years to deliberate whether one of the State's taxes on oil and gas should be changed, and if so, what it should be changed to.

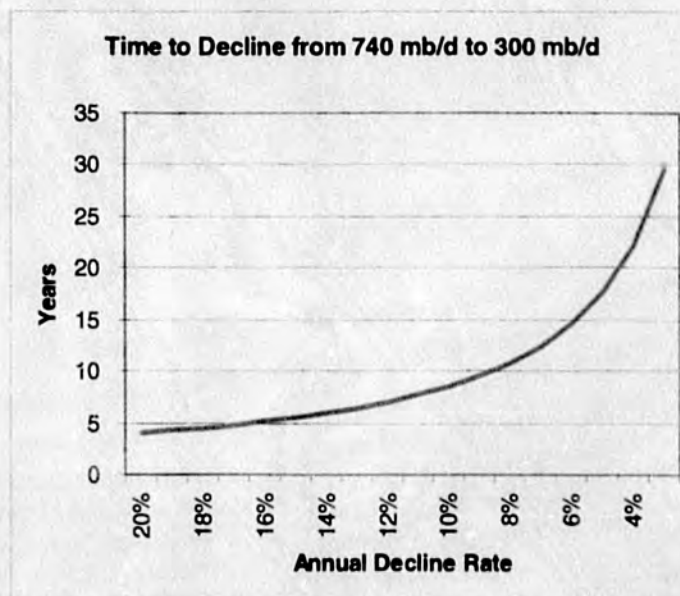
Last year the Legislature passed the Petroleum Production Tax, or PPT. Now, less than a year later, the Administration is telling you that the PPT is broken. They say it's too complicated to forecast, it isn't bringing in the revenue that was forecast last year, and they don't have enough capable auditors to enforce it.

In discussing the merits of HB 2001 versus PPT and the Administration's concerns, we must always keep in mind the real-world situation that Alaska faces. The greatest challenge that confronts this generation of Alaskans and the next is the ongoing decline of oil production, which has been, is today, and promises to remain the cornerstone of the finances of state government.

Production decline is eroding this cornerstone. It is a historical fact that even with the massive investments being made, North Slope production declined an average of 6.2% a year from FY 1997 to FY 2007, and Cook Inlet oil production declined at 8.0% a year.¹ Without those investments, decline would have been 15%.

With respect to the future of the North Slope, there is going to be a major challenge when ANS production gets down to about 300,000 barrels a day. According to Alyeska Pipeline Service Company, which operates the trans-Alaska oil pipeline (TAPS), the minimum mechanical capacity of the new electronic pumps that are being installed is about 300,000 barrels a day.

Here is a graph showing how long we have before ANS production reaches this 300,000 barrel-a-day mechanical threshold, depending on what the rate of decline is. If decline continues at the



historical rate of 6%, ANS will decline to 300,000 barrels a day in about 15 years, or FY 2022.

On the other hand, if decline can be held to 3% or less as DOR assumes, then we would have 30 years or so before we hit the mechanical threshold.

Let me stress that this graph is not a prediction. It merely plots the results of the mathematical calculations² of how long it would take to get to 300,000 barrels a day from the level of 740,000 barrels a day in FY 2007, depending on what decline rate you choose. What it does show is how important the rate of production decline is for Alaska's future. The difference between a 6% decline rate and 3% doesn't sound like much, but as you can see from the graph, that difference determines whether the 300,000 barrier is reached around FY 2022 or FY 2037. If you have a child in junior high school, this represents the difference between that child being able to grow up and have a career on the North Slope, and not having this opportunity.

Investment in new production is the only way to slow the decline enough to give the children of this state a future with the North Slope similar to what we have enjoyed. That's why new investment is such a crucial question facing the State, both in the context of the proposed tax proposal and in other areas that affect the business climate here.

There are three categories of investment that can slow the rate of decline on the North Slope, or at least keep it from getting any worse. These are, first, investment in exploration to discover new fields; second, investment in existing fields to prevent their decline from accelerating; and third, investment in innovation, technology, and new infrastructure to allow development of the vast but challenging resource of heavy and viscous oil that has already been discovered.

A great deal of the testimony to the Legislature, and a lot of the questions being asked, have focused on the fiscal terms of the "government take" for exploring in Alaska and the competitiveness of these terms relative to the terms in regimes elsewhere in the world. This kind of "who takes more" analysis is faulty for two fundamental reasons.

First, it assumes that the geologic prospects for making a commercial discovery in Alaska are comparable to those other regimes. This assumption is unsound. The North Slope has three major areas of significant oil and gas potential: the state lands in the central North Slope between the Colville and Canning rivers, the federal land in the National Petroleum Reserve - Alaska to the west of the state lands, and the coastal plain of ANWR to the east of the state lands. The exploration potential of the state lands is limited today primarily to the discovery of new satellite fields, as opposed to fields large enough to stand on their own economically. Exploration is still active in NPR-A and by no means over, but the courts have recently blocked federal leasing of the geologically promising lands around Teshekpuk Lake. And even if the Ninth Circuit decides to let that leasing go forward, the pro-leasing Bush Administration has less than 14 months left in office in which to hold the lease sale. Elsewhere in NPR-A, the relinquishment earlier this fall of some 300,000 acres of lands reflects disappointing results from leaseholder exploration efforts there. As for ANWR, despite Republican majorities in both houses of Congress and a pro-development president in the White House, the coastal plain is still closed.

And this brings me to the second reason why it is unwise to focus too much on investment in exploration as the solution to production decline. Exploration is a risky business, and there is no assurance that spending money to test a particular prospect will ever yield a dime of payback. Even when exploration succeeds in discovering a commercially viable field, it will take years from the time of its discovery until the time production from it begins. But the challenge of declining production confronts Alaska today — not eight, ten or a dozen years from now. By its nature, investing in exploration can make a significant contribution toward solving the challenge of declining production in the longer term, but not the shorter term when results are urgently needed.

Investment in heavy and viscous oil development is also a solution in the mid to long term. The first well ever drilled to test production from the Ugnu Formation was only drilled earlier this year in the Milne Point Unit, and it is still being tested and evaluated to gain a better understanding of the physical characteristics of the Ugnu oil. There are plans to use the results of these tests and evaluations to plan and develop a pilot project for producing Ugnu oil. Until then, West Sak will continue to be the only commercial heavy/viscous opportunity.

This gets us to investment in currently producing fields. Fortunately, there are investments that can be made, and are being made, in these fields to slow their decline. In the short term, this is in-fill drilling — that is, drilling new wells into the portions of a reservoir that are between the wells that have already been drilled. This accelerates the drainage of oil from the rock that currently lies in between existing wells. In-fill drilling last year contributed some 70,000 barrels a day to production from the Prudhoe Bay field. To put this into perspective, a 70,000 barrel per day field would be the 4th largest stand-alone field on the North Slope today.

There are also major investments being made, and yet to be made, in “renewal” of the surface facilities for existing fields. For instance, the gathering centers and flow stations for the Prudhoe Bay field have been in service for over 30 years now. For them the situation is not all that different from what yours would be if you bought a minivan van years ago when your children were young, and now that the kids are all grown up and it's just you and your spouse who are driving it, it's time to replace that minivan with a new vehicle that suits your needs better. If Prudhoe Bay and the other producing fields are to continue producing in the decades to come, their original production facilities will need to be overhauled or replaced. Also, as increasing amounts of heavy and viscous oil come into production, even relatively new facilities that were designed for comparatively light “conventional” oil will probably need to be modified, refitted or replaced in order to minimize operating problems in handling that heavy/viscous oil. Regardless of the stimulus or purpose for making them, renewal investments in production infrastructure present a very similar cash-flow pattern as there is for investments in the original infrastructure to develop a field. And consequently, an incentive that is effective for the initial development infrastructure is equally effective for renewal as well.

So, this is the harsh reality in which we — government, industry, the present generation of Alaskans, and the next one — find ourselves. For all of us, decline is the great challenge that

we must grapple with. It already threatens us now, and if unaddressed, will only get worse. Massive new investments for additional oil production are the only way to deal with this menace, and there are three areas of investment that can be made to deal with it: exploration, heavy and viscous oil development, and slowing decline of existing fields. The first two are of greatest benefit for the long term, and the other one is of great benefit for the near term. We need all three kinds of investment and don't have the luxury of ignoring one or two of them. I have explained our collective situation in such detail so we can each see for ourselves why declining production is the great issue of the day for Alaska.

Turning now to the relative merits of HB 2001 versus PPT, AOGA submits there are several self-evident principles of taxation that should be used to test those merits. First, a tax must be "fit for purpose" — that is, it must do the things it is intended to do, and it should do them well. Second, the administration and enforcement of a tax should be as efficient as possible, consistent with ensuring compliance by taxpayers. Third, for a taxpayer who wants to calculate and pay the correct amount of tax when it comes due, it must be possible to do so.

Regarding the first test — achieving what the tax is supposed to achieve — most new taxes have as their primary or only purpose the new revenues that they will bring in for the government. In the case of PPT, however, things were not so simple. In part its purpose certainly was revenue-related, because most legislators viewed the prior ELF-based production tax as outdated and unduly generous to producers in terms of the reduction in tax rate that the ELF caused. But, as Pedro van Meurs explained repeatedly in his testimony last year and again at the beginning of this special session, the PPT was also designed to provide incentives for investing in production and in that way answering the threat of declining production.

With respect to the revenue side, no one disputes that PPT has brought the State more tax revenue since April last year than ELF would have. According to DOR, the increase was more than \$800 million in the last nine months of 2006,³ and at that rate it would have been over a billion dollars in additional production tax revenue for a full year. DOR also said at the time that the March 31st payments were about \$137 million less than the \$950 million that it had estimated, and in due course I'll come back to the questions of forecasting the PPT and higher-than-forecasted lease expenditures. For now, my point is that PPT has certainly outperformed the old ELF tax, which is just what it is supposed to do.

As a consequence of the fact that field costs are higher than DOR predicted last year, this Administration criticizes PPT for failing to generate all the tax revenues that the fiscal note for HB 3001 predicted. It has even been suggested that Alaskans were somehow promised that PPT would generate \$800 million more this year than is now being projected, and that it is therefore necessary to raise the tax rate in order to make good on that promise.

That whole line of reasoning is flawed. First of all, DOR is complaining that they can't forecast PPT accurately because it has so many variables that affect the results. However, if they can't forecast it accurately, then why should so much reliance be placed on its current forecast

that shows the prior forecast was off by \$800 million? If the first forecast was poor, what has changed to make this latest one so good?

As I explained just a while ago, the purpose of PPT was more than just the tax revenues it would generate. It was to create incentives for attracting the massive new investments that will be needed in order to meet the threat posed by declining production. The system of tax credits under PPT provides significant incentives for investing in capital assets to explore for, develop, and produce more oil and gas.

- Current capital expenditures generate a 20% tax credit in addition to being immediately deductible as lease expenditures. For the kinds of economic analysis that reflect the time-value of money, these front-end benefits have the greatest possible positive effects on the results of the analysis.
- The incentive to invest sooner rather than later is materially increased by the fact that the "transitional investment expenditure" or "TIE" credit for pre-PPT capital investments can only be taken to the extent those prior expenditures are matched two for one by new capital expenditures, and taxpayers have only until the end of 2013 to use up their "TIE" credits.⁴
- The 20% tax credit for a carried-forward annual loss particularly benefits explorers and those who are bringing new fields into production for the first time in Alaska and don't have production yet that they can deduct their costs against.
- The "section 024(c) credit" of up to \$12 million a year for producers with less than 100,000 barrels a day of production is an incentive for independents and other smaller players to come to Alaska for oil and gas.
- The \$6 million annual credit under AS 43.55.024(c) is an incentive for exploration and development in the areas of Alaska outside the North Slope and Cook Inlet basin.

Have these incentives under PPT worked? The preliminary results so far say yes. DOR's August 3rd report on PPT states that capital investments for FY 2008 are 80% greater than previously estimated, despite the fact that operating expenditures are up by 101% over the prior projections.⁵ Of course, it will take time before companies can fully respond to these incentives, and it will take even more time to tell whether the new investments to increase oil production succeed in actually getting more production. But so far things appear to be moving in the right direction.

There is the question of whether the inability of explorers and almost-producers to sell their credit certificates near face value has been a material problem. As the Executive Director of AOGA, I can assure you there is no one among AOGA's membership who thinks any problem in selling the certificates has been serious enough to justify amending the PPT.

Now, moving on to HB 2001, how well does it stack up under the standard of being fit for purpose? Certainly, it would generate even more tax revenue than the PPT will, at least in

the short term. But it is premised on the totally mistaken notion that increasing what the government takes from the economic "pie" will encourage greater investment, or at least not decrease it from what it would be anyway. No one has ever taxed economic growth and development into existence. HB 2001 will not do so, either.

The second standard for evaluating HB 2001 versus PPT is that the administration and enforcement of the tax must be as efficient as possible, consistent with ensuring compliance by taxpayers. Here, the two chief objections to PPT have been, first, that it is all but impossible to forecast the revenues from it with the accuracy needed for state budget purposes, and second, that the audit challenges of PPT leave DOR's auditors hopelessly outgunned.⁶ So the questions that need to be answered are, how much merit do these criticisms have, and how would HB 2001 address these concerns?

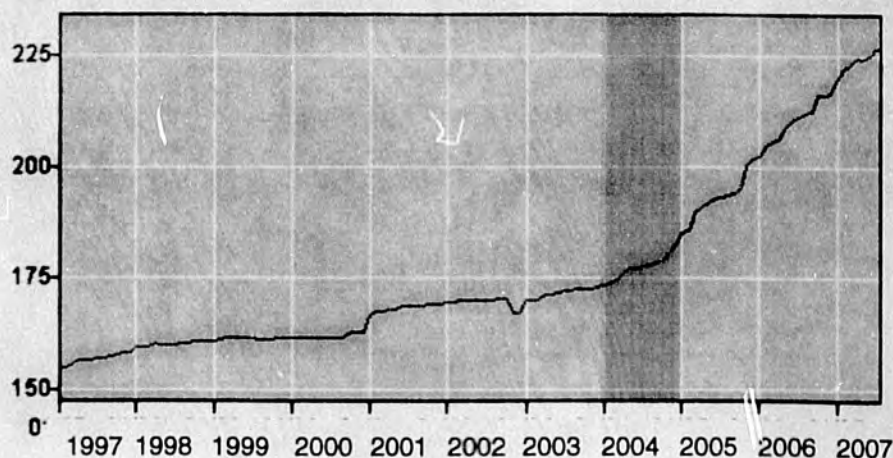
Regarding forecasts for PPT, DOR cites two major concerns about the forecasts. One is that, "[w]hile costs would be expected to increase, the dramatic difference between what was predicted [in the prior Administration's fiscal note for HB 3001] and what has actually been experienced brings into question whether the legislature made its decisions based upon appropriate information."⁷ The other is that DOR needs cost information about current and planned spending from the operators, producers and explorers, and this allegedly has not been forthcoming from them.

Let us consider this "dramatic difference" between the projected expenditures behind the fiscal note last year, and what those expenditures have actually been. When the DOR staff in the prior Administration sought information about expenditures, they chose not to rely on the representations about 2006 costs that individual companies gave the Legislature in public testimony at that time.⁸ Instead, they looked at what they believed to be more reliable information contained in the most recent partnership tax returns that had been filed with the IRS for fields on the North Slope.

Federal partnership returns are not due to be filed with the IRS until October of the following year, so even as late as August 2006 when the Legislature passed HB 3001, the most recent returns available were those for 2004. Here is a chart showing the Producer Price Index

Oil and Gas Field Machinery and Equipment PPI

Source: U.S. Department of Labor



for oil and gas field machinery and equipment during the last decade. The highlighted bar in the graph marks 2004, and you can see right away why a fiscal note based on the most recently filed federal tax returns, for 2004, would be way off the mark in predicting what the field costs would be in 2006 and '07.

There was nothing sinister about what that Administration did. The companies said the 2006 costs were high, but the latest tax returns at that time indicated the costs were significantly less, with a fairly lengthy track record of gradual increases. DOR went with the reported information on the tax returns. I suspect the DOR staff in the present Administration would do the same in those circumstances. In any event, this is not a reason for casting PPT aside.

The other criticism that DOR makes of PPT is that producers and other taxpayers are not providing DOR with the information it needs in order to be able to forecast PPT revenues with sufficient accuracy. Obviously, AOGA is not privy to what these taxpayers are reporting to DOR as they make their monthly installment payments and their annual true-up payment on March 31st.

DOR's second chief objection to the administrability and enforceability of PPT is that the audit challenges of PPT leave its auditors hopelessly outgunned. It is not for us to comment about the proposal to put auditors in the "exempt" service.

But there is a dimension to PPT audits, however, that we can and should address. This has to do with what the source or starting point for determining how much a producer's deductible lease expenditures are. The PPT statutes currently allow DOR a choice between starting from the joint-interest billings and invoices that operators bill to the other participants in

an oil and gas field or venture,⁹ or starting from a comprehensive set of accounting rules and principles that DOR writes up.¹⁰ Which choice DOR chooses will determine nothing less than the very success or failure of PPT as a tax — and for HB 2001 as well, if it is enacted. It is like having a tax based on your federal taxable income, and choosing between your federal tax return (as audited by IRS) as the starting point, or starting with the Internal Revenue Code and leaving it up to you and DOR's auditors alike to find what the right answer is under the Code. It is like having a tax based on your financial book income, and choosing between your audited financial statements filed with the SEC as the starting point, or starting with Generally Accepted Accounting Principles and leaving it up to you and DOR's auditors alike to find what the right answer is under GAAP.

From the taxpayer's perspective, this means a near certainty of continual assessments year after year for additional tax, interest, and perhaps penalties, and depending on how litigious a company may feel, it may mean a long series of lawsuits and appeals as well.

From the State's perspective, these same troubles for the taxpayer will mean that the incentives for investment under PPT, or HB 2001, will be seriously eroded. The greater the uncertainty about how much tax a company owes, the greater the likelihood that the incentives will turn out be less than their face value. A taxpayer's only recourse in this situation will be to discount the face-value of those incentives significantly, perhaps completely, in running the economic analysis about making an investment or not. As a consequence, the effectiveness of those incentives will be less than it should be, and Alaska will fail to realize the full amount of new production that it needs to meet the challenge of decline.

The other choice that DOR could make is to start with what an operator bills to the other participants in an oil and gas operation. Note that I said "start" with those billings — not "end." Anything in those billings that is nondeductible under AS 43.55.165(e) would have to be backed out. The central concept of lease expenditures in AS 43.55.165(a) is that they must be "direct" and "ordinary and necessary" costs of exploration, development, or production. It would be most surprising if there are anything in those billings that goes outside this standard.

How can Alaska be sure of this? Because the participants in an oil and gas operation do not give the operator a license to waste their money. I have heard a great deal of concern expressed during these hearings about how the companies might somehow try to "game the system" in order to reduce the tax they will pay the State. While so many are so worried about efforts by the companies not to overpay the State, why would most of these same people think the companies are somehow more willing to overpay the operator than the State? Clearly they don't want to overpay either one. If anything, since the operator usually is a direct competitor, they probably don't want to overpay it even more than they don't want to overpay the State. In other words, if an operator is exploring a geologic prospect, the non-operating participants don't want to pay any costs that are not for the exploration of that prospect. Similarly, if the operator is operating a producing field, they don't want to pay any costs that aren't for the operation of that field. It is reasonable to rely, in the first instance, on the non-operators' self-interests to

police and limit what the operator can spend their money on, and they will do that policing by auditing the operator's invoices to them.

In the context of PPT, DOR should "audit the audits" to verify that the non-operators do indeed audit an operator's invoices on a regular basis, and that those audits are rigorous and at arm's length. But once these things have been confirmed by DOR in its verification of the non-operators' audits, there is little point for DOR to spend the time and effort to re-plow the field that the companies' audits have already plowed.

Daniel Johnston, a consultant hired during last year's debate on PPT, gave an informal presentation to members of the Legislature on Friday, Oct. 19, 2007. During that meeting, he praised the expertise of joint interest auditors and the ability for the state to utilize unit accounting. He went on to say that it would be "extremely insightful for the state to get unit accounting". Mr. Johnston observed that state auditors can be "vicious", but that joint interest auditors are "even more vicious".

Of course, for operations where there is only one participant or where there are no audits of the operator's invoices, this approach will be inapplicable. But there are still things DOR could do to build off the billing systems where there are such audits and extend them to these other fields. However, DOR has not yet adopted the "Phase II" regulations to implement and apply its existing statutory authority to authorize or require taxpayers to follow this approach.

A very dismaying thing about HB 2001 is that Section 64 would repeal DOR's explicit statutory authority under AS 43.55.165(c) and (d) to require or authorize the use of operators' joint-interest billings as the starting point for computing the amount of a producer's deductible lease expenditures for that unit or field, while Section 71(b) would make that repeal retroactive to April 1, 2006.

We believe that this repeal will mean DOR cannot authorize or require a producer to start with an operator's joint-interest billings, even when DOR wants to allow or require their use. Since these repeals are in the proposed legislation that has been introduced, we expect that DOR, in response to us, will testify that somehow they will still be able to require or authorize the use of operator billings even if these present statutory provisions are repealed. However, if you enact a law specifically saying DOR may do something and later on you repeal that law, doesn't that repeal mean DOR can't do it anymore? We think so. But even if you are persuaded by DOR that we're wrong on this point, why should you repeal those statutes and take the chance that the courts won't agree? You could probably repeal AS 43.55.165(d) and keep subsection (c) on the books without taking much risk, because the text of (d) is very repetitive of that in (c). But repealing them both is taking a needless chance.

The reason I've spent so much time about the use of joint-interest billings as the starting point for determining a producer's lease expenditures is this: Consider the situation that a non-operating participant faces. All the information it has about what's being spent for the operation

is what it gets from its billings from the operator, plus whatever it may learn by auditing those invoices. But if such a non-operator cannot start from those invoices, how can it figure out what to report as the lease expenditures for that operation? All the books and records of the expenditures are with the operator, and if the non-operator hasn't yet audited the operator, it will have no idea what those books and records show. It is infeasible for a non-operator to be auditing the operator month by month, yet the non-operator will somehow have to be reporting and paying installments month by month throughout the year. Even by the March 31 true-up the following year, it is unlikely that any audit of the operator's books and records will have been begun by that date, much less completed. The penalty for mis-estimating the installment payments is principally in the difference between the rate of interest on overpaid installments and underpaid ones. But the March 31 true-up is very serious business. Interest at an APR not less than 11% compounded quarterly begins to accrue, and penalties of up to 30% for negligence and failure-to-pay¹¹ can be assessed, on the amount of any underpayment continuing after that true-up date. If a non-operator cannot rely on its billings from the operator as the starting point for these purposes, what is it supposed to use?¹²

If, as we fear, the repeals of AS 43.55.165(c) and (d) under the proposed bill will indeed take away DOR's discretion to allow or require the use of operators' joint-interest billings, then HB 2001 will completely fail the third standard by which a tax is measured — that it must be possible for a taxpayer to get the tax right when it is due, when the taxpayer wants to do so. This will be impossible for non-operators under the proposed legislation. Even PPT will fail if the "Phase II" regulations do not reasonably implement DOR's present authority under AS 43.55.165(c) and (d) regarding the use of operator billings.

Before I close, there are a few confusing things in the HB 2001 I would like to address.

The first of these is Section 1, declaring that subsection (b) in the new production-tax statute of limitations being enacted is intended to "confirm by clarification the long-standing interpretation of AS 43.05.260 by the Department of Revenue relating to limitation of assessments for the production tax on oil and gas and conservation surcharges on oil." Does anyone here know why this is in the bill? AS 43.05.260 is the existing statute of limitations for auditing all state taxes under AS 43, and what is it about this present limitations statute that is being "confirm[ed]" by the new AS 43.55.075(b)?

If you read this new section 075(b) — which begins on page 35 line 30 and runs through line 15 on page 36 of the bill — you see there are two parts to the subsection. One part is the first two sentences, which address the effects for tax purposes of judicial or administrative decisions that retroactively change parameters for calculating the tax. The other part is the last sentence, including paragraphs (1) and (2), and requires producers to report such decisions to DOR within 60 days and to file amended returns within 120 days.

The curious thing is that the existing statute of limitations (AS 43.05.260) — the interpretation of which is to be "confirmed" — has nothing in it pertaining to either of these

subjects. Here is the text of AS 43.05.260 and you can see this for yourselves. Subsection (a)

Sec. 43.05.260. Limitation on assessment. (a) Except as provided in (c) of this section and AS 43.20.200 (b), the amount of a tax imposed by this title must be assessed within three years after the return was filed, whether or not a return was filed on or after the date prescribed by law. If the tax is not assessed before the expiration of the three-year period, proceedings may not be instituted in court for the collection of the tax.

(b) For purposes of this section, a return filed before the last day prescribed by law or regulation is considered as filed on the last day.

(c) The following exceptions apply to the limitation period in (a) of this section:

(1) in the case of a false or fraudulent return with the intent to evade tax, the tax may be assessed, or a proceeding in court for collection of the tax may be begun without assessment, at any time;

(2) in the case of a failure to file a return, the tax may be assessed, or a proceeding in court for the collection of the tax may be begun without assessment, at any time;

(3) if, before the expiration of the time prescribed in this section for the assessment of a tax imposed by this title, both the department and the taxpayer have consented in writing to the assessment after the expiration of the time, the tax may be assessed at any time before the expiration of the period agreed upon; however, the period agreed upon may be extended by a subsequent agreement in writing made before the expiration of the period previously agreed upon.

sets three years as the period for DOR to audit and assess any additional tax that may be due, and it bars suits to collect any additional tax if that tax is not assessed within the three-year period. Subsection (b) says that, if a taxpayer files its tax return early before it is due, the three-year period starts running from the due date instead of the actual filing date. Subsection (c) creates three exceptions to the rule under subsection (a), which appear as paragraphs (1) – (3) of subsection (c): namely, for false or fraudulent returns to evade tax, for a failure to file any return at all, and for extensions of the three-year period that are mutually agreed upon in writing by DOR and the taxpayer.

Which of these provisions has anything to do with tax effects of retroactive decisions? Which has anything to do with having to report such decisions to DOR and filing amended tax returns? It is not immediately clear to us what either of these topics in the new statute of limitations has to do with interpreting any of the provisions in existing statute of limitations I've just reviewed with you. So what's going on with Bill Section 1?

We believe Section 1 is a stealthy attempt to legislate an outcome to matters that are already being litigated in the due course of administrative and judicial proceedings. In 1999 DOR amended one of its production tax regulations, 15 AAC 55.200, so that it reads remarkably like AS 43.55.075(b) being enacted in this bill. Here you have the regulation and the proposed

15 AAC 55.200. Retroactive adjustments. If retroactive adjustments in costs of transportation, sales price, prevailing value, or consideration for quality differentials relating to the commingling of oils or of oil and NGLs result from decisions of regulatory agencies, courts, or any other preemptive authority, those adjustments have a corresponding effect, either an increase or decrease as applicable, on the gross value at point of production as determined under this chapter, and the producer shall, on or before the third monthly payment due date specified in AS 43.55.020(a) after any adjustment, file amended returns covering the entire period of an adjustment unless the producer has obtained a stay on that filing or payment, regardless of the pendency of appeals of those decisions. [emphasis added]

(b) A decision of a regulatory agency, court, or other body with authority to resolve disputes that results in a retroactive change to a lease expenditure, to an adjustment to a lease expenditure, to costs of transportation, to sales price, to prevailing value, or to consideration of quality differentials relating to the commingling of oils has a corresponding effect, either an increase or decrease, as applicable, on the production tax value of oil or gas or the amount or availability of a tax credit as determined under this chapter. For purposes of this section, a change to a lease expenditure includes a change in the categorization of a lease expenditure as a qualified capital expenditure or as not a qualified capital expenditure. The producer shall (1) within 60 days after the change, notify the department in writing; and (2) within 120 after the change, file amended returns covering all periods affected by the Change, unless the department agrees otherwise or a stay is in place that affects the filing or payment, regardless of the pendency of appeals of the decision. [emphasis added]

new AS 43.55.075(b) side by side, with identical or parallel language in them being underlined. As you can see, the regulation deals with “decisions of regulatory agencies, courts, or any other preemptive authority” while the proposed new statute addresses any “decision of a regulatory agency, court, or other body with authority to resolve disputes[.]” The regulation deals with “retroactive adjustments in costs of transportation, sales price, prevailing value, or consideration for quality differentials relating to the commingling of oils or of oil and NGLs” while the proposed statute addresses “a retroactive change” to the very same things,¹³ plus any change to “a lease expenditure[.]” Both state that retroactive changes in the parameters for calculating the taxable value have “a corresponding effect, either an increase or decrease,¹⁴ as applicable on” that taxable value.

Now, the “interpretation” that comes into play here has to do with the question of when interest begins accruing on a tax increase or decrease that results from one of these retroactive decisions — does it begin to accrue as of the date of that decision? Or does it begin to accrue all

the way back to the original payment due date? When DOR adopted the amendment to the regulation in 1999, the director of the Tax Division at that time told AOGA members that DOR was interpreting that amendment to mean interest would start to accrue as of the original payment due date for the tax, not as of the date of the retroactive decision.

We believe it is this "interpretation" of its own regulation, which is in the process of being appealed in due course, that the Administration intends to have "confirm[ed]" under Section 1 of HB 2001 as the proper interpretation of the pre-PPT statute of limitations. The question for you is, do you really want to confirm this?

Confirming it would set a destabilizing precedent, because it will mean that the laws can effectively be rewritten to deal with subjects that they did not originally deal with, and this can be done clandestinely by "confirming" some purported "interpretation" of it. For one thing, it would be an attempt by the Executive and Legislative branches to determine the outcome of matters that are already before or headed to the Judicial Branch in due course. Can the Legislature intervene in Judicial matters under the Separation of Powers Doctrine, and even if it can, should it attempt to do so here? Second, what does it say to potential investors in this state about our sense of justice, Due Process, and fair play?

Now, if the Administration appears before you or any other committee of this Legislature and disavows any and all intention to do such a thing, I would encourage you to ask them to clearly explain what they did intend to achieve with Section 1, so that it will be part of the legislative history of this bill. Then, if it becomes law, the legislative history will be there to establish that the "interpretation" which we fear is not the Legislature's intent, nor the Administration's.

A second confusing thing in HB 2001 relates to the new statute of limitations being proposed for production tax only. Why does the limitations period need be six years instead of three, when the three-year period can be extended and re-extended any number of times as appropriate? If the state auditors are anything like me and everyone I know, their work will expand to fill the time allowed — giving them six years to get their audits done will mean they'll take six years to audit even when they could otherwise be done more quickly. Unfortunately, the longer the audit runs, the greater the amount of interest there will be that accrues on any underpayment claimed in the audit. After three years, interest represents 38¢ for each dollar of additional tax claimed, assuming interest is not above its 11% APR floor rate. But after six years the accrued interest is 92¢ for each dollar of additional tax. By raising the stakes so substantially for each audit claim that is raised, the longer limitations period will make it easier to justify litigating claims.

The purpose of a statute of limitations is to bar claims when they start to become so old that the records, documents, and recollections of witnesses may well be lost or not readily available by the time those claims are finally raised. The present statute of limitations has worked for all the other taxes under Title 43, including the present worldwide corporate income

tax for oil and gas taxpayers, the domestic or "water's edge" income tax for other corporations, even the former separate-accounting income tax. It is worth noting that separate-accounting involved not only determining net income from all of a taxpayer's interests in oil and gas fields and prospects, but also its income from interests in oil or gas pipelines as well.¹⁵ While PPT and IIB 2001 are not simple taxes, separate-accounting was probably even more challenging to administer and audit. If Alaska didn't need a longer statute of limitations for separate-accounting, we don't see why one is needed now.

In conclusion, HB 2001 fails two of the three standards for evaluating a tax, while PPT passes two of them and would pass the third one as well if DOR adopts the appropriate regulations. HB 2001 in the short term will generate more tax revenue for the State than PPT; however, it will achieve this at the cost of reducing the incentives for new investments, and worsening the overall tax climate for making them here. HB 2001 fails the test of being administrable as efficiently as possible, consistent with ensuring taxpayer compliance. This failure will primarily be due to repealing DOR's existing statutory discretion to allow, as appropriate, joint-interest partners do the auditing of the operator's billings to them. Instead DOR auditors could have to re-invent the wheel for themselves in each audit. HB 2001 also fails the test that a taxpayer who wants to pay the correct amount of tax when it comes due must be able to do so. This will be impossible for every company that owns an interest in a lease or property that it does not operate. This in turn will effectively destroy the value of the remaining tax incentives under this bill that potential investors will perceive. If they cannot tell what they owe, they surely cannot put a reliable figure to the value of the incentives under the tax.

All of this brings us back to the fundamental issue facing Alaska today...the decline of Alaska production. Today Alaska's production has fallen from its peak of 2.1 million barrels a day down to the 700,000 range. This means that the trans Alaska pipeline is 2/3 empty. I would remind you of my chart earlier that showed the purely mathematical results about how long we have before hitting the 300,000 barrel-a-day TAPS mechanical threshold, depending on what rate of decline you assume will turn out to come true.

And it's important to remember that today's 6% decline rate would be on the order of 15-16% were it not for the substantial investments which continue to be made by operators in existing fields. Further, Alaska is fortunate to have on the nearby horizon Pioneer's Oooguruk project, scheduled to go into production in 2008.

The importance of future investment is further emphasized when one looks at the Department of Revenue's forecast of future production levels. In three short years, DOR projects that production will come from projects requiring significant new investment. Draw that timeline out to 2017—ten years from now—and you discover that half of Alaska's production will come from new production—production which will only come from investments yet to be made.

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The most important policy question is whether HB 2001 provides a framework for encouraging this additional new investment. AOGA's 17 member companies unanimously agree that PPT does accomplish that goal, and as such, should not be changed at this time.

ENDNOTES

¹ When production declines at $X\%$ a year, this means the production rate after one year (P_1) is $(1 - X\%)$ of the initial production rate (P_0), or $P_1 = P_0 \times (1 - X\%)$. After the second year the production rate (P_2) is $(1 - X\%)$ of the rate after one year of production, or $P_2 = P_1 \times (1 - X\%) = [P_0 \times (1 - X\%)] \times (1 - X\%)$, which can be simplified as $P_2 = P_0 \times (1 - X\%)^2$. After 10 years of decline, the rate P_{10} is $P_0 \times (1 - X\%)^{10}$. North Slope production was 1,404 million barrels a day in FY 1997 and 740 thousand barrels a day in FY 2007, while Cook Inlet produced 37 thousand barrels a day in '97 and 16 thousand barrels a day in '07. See DOR, *Revenue Sources Book Spring 2007*, pp. 97-98. So for North Slope production,

$$1,404,000 \times (1 - X\%)^{10} = 740,000.$$

Dividing both sides of this equation by 1,404,000 gives:

$$(1 - X\%)^{10} = 740,000/1,404,000 = 0.5271.$$

One can solve for $(1 - X\%)$ by taking the 10th root of both sides of this latter equation:

$$\sqrt[10]{(1 - X\%)^{10}} = \sqrt[10]{0.5271}, \text{ or}$$

$$(1 - X\%) = 0.9380.$$

In other words, on average the production rate each year was 93.80% of the rate for the prior year, which means the rate of decline averaged 6.20% a year. The same calculation for Cook Inlet, using 37,000 and 16,000 barrels a day instead of 1,404,000 and 740,000 respectively, yields an average annual decline rate of 8.0 percent.

² Here is the math: From the analysis in Endnote 1 above, we know that for a given decline rate R , the volume of production after N years of decline is $P \times (1 - R)^N$. So for each decline rate in the table, you use that as the value of R in the formula, and then you solve for X as the value of N that gives 300,000 barrels a day as the rate. The equation for this is:

$$740,000 \times (1 - R)^X = 300,000.$$

When you take the logarithm of both sides of this equation, you get the following equation:

$$\log[740,000 \times (1 - R)^X] = \log[300,000].$$

The reason for using logarithms is that they have the property that the logarithm of two numbers being multiplied together equals the sum of the logarithms for each of them, while the logarithm of a number raised to an exponent X equals X times the logarithm of that number. Using this gives the following restatement of the prior equation:

$$\log[740,000] + X \times \log[(1 - R)] = \log[300,000].$$

Subtracting $\log[740,000]$ from both sides of the last equation yields the following:

$$X \times \log[(1 - R)] = \log[300,000] - \log[740,000]. \quad [\text{continued on next page}]$$

Now you can solve for X by dividing both sides of the last equation by $\log[(1 - R)]$, which yields:

$$X = \frac{\log[300,000] - \log[740,000]}{\log[(1 - R)]}.$$

By plugging the decline rate of your choice into this last equation as the value of R , the value of X can be calculated by simple arithmetic. This straightforward calculation has been done for each of the decline rates shown in the graph.

³ DOR Press Release, "New Production Tax Nets Increased Revenues For Alaska" (April 3, 2007).

⁴ For producers who begin producing in Alaska on or after April 1, 2006, they have six years from the year of that first production in which to use up their "TIE" credits. The rule still applies during those six years that it takes \$2 of new capital investment in order to get a credit for \$1 of the "TIE" investment from the years before their production begins.

⁵ See DOR, *Petroleum Profits [sic] Tax (PPT) Implementation Status Report* (August 3, 2007), p. 3.

⁶ See DOR, *Petroleum Profits [sic] Tax (PPT) Implementation Status Report* (August 3, 2007): "The Department has been severely hampered in its ability to provide the administration and the legislature with accurate revenue forecasts" *Id.*, p. 4. "The complexity of auditing production tax has increased several fold under the PPT, and the PPT increased the number of determinations an auditor must make." *Id.*, p. 5.

⁷ *Id.*, p. 5.

⁸ See, e.g., Alaska State Legislature, House Finance Committee, *Minutes* (March 29, 2006), p. 15:

Representative Holm ... asked about the rate of return at \$60 per barrel. Mr. [Angus] Walker [Commercial Vice President of BP Exploration (Alaska) Inc.] said BP is excited about current prices. BP does not make a profit until oil is above \$22.50 a barrel.

At a \$22.50 West Coast price, BP's implicit upstream field expenditures were about \$11.95 a barrel, as opposed to the \$7.27 per barrel in the fiscal note for HB 3001.

\$22.50	ANS price on West Coast
1.76	Marine transportation to West Coast
4.38	TAPS
0.67	North Slope pipelines, quality bank, etc.
\$15.69	Average North Slope wellhead value
1.96	State royalty (1/8)
\$13.73	Taxable value
1.09	Production tax (15% base rate $\times$ ELF of 0.529)
0.69	Property tax (\$/bbl average)
\$11.95	Implicit expenditures/bbl.

SOURCE: DOR, *Revenue Sources Book Fall 2006*, p. 33 Fig. 4-6 (average ANS ELF); p. 39 Fig. 4-9 (marine, TAPS, and Slope pipelines/quality bank); p. 40 Fig 4-11 (ANS production); p. 42 Fig. 4-12 (property tax; \$60 million for tax on TAPS is deducted from total for North Slope Borough, Fairbanks, Valdez and Unorganized Borough). All data are for FY 2006.

⁹ The authority for DOR to take this approach is in AS 43.55.165(c) and (d). Subsection (c) states in pertinent part: "if the department finds that the pertinent provisions of a unit operating agreement or similar operating agreement are substantially consistent with the department's ... standards under (a) of this section concerning whether costs are lease expenditures, the department may authorize or require a producer ... to treat as ... lease expenditures ... the costs, other than items listed in (e) of this section, that are incurred by the operator ... and ... billable to the producer by the operator in accordance with the terms of the [operating] agreement[.]" Subsection (d) has very similar language.

¹⁰ The authority for DOR to take this approach is in AS 43.55.165(a), which states in pertinent part: "In determining whether costs are lease expenditures, the department shall consider, among other factors, (1) the typical industry practices and standards in the state that determine the costs, other than items listed in (c) of this section, that an operator is allowed to bill a working interest owner that is not the operator, under unit operating agreements or similar operating agreements ... and (2) the standards adopted by the Department of Natural Resources that determine the costs, other than items listed in (e) of this section, that a lessee is allowed to deduct from revenue in calculating net profits under [net profit share] lease[.]"

¹¹ The penalty for an underpayment due to negligence is 5% of the amount of the underpayment. AS 43.05.220(b). The failure-to-pay penalty for an underpayment is 5% of the underpayment for each month or partial month that the underpayment continues after payment was due, up to a maximum of 25 percent. AS 43.05.220(a). By regulation, DOR has adopted the policy that the imposition of a negligence penalty automatically triggers the imposition of a failure-to-pay penalty as well. 15 AAC 05.210(g).

¹² It follows that, if a non-operator can rely on the operator's joint-interest billings as the starting point for the non-operator's own lease expenditures for that operation, then the operator should similarly be able to use its proportionate share of the same total billable costs as the starting point for its lease expenditures for that operation. There is no reason to discriminate between them.

¹³ The regulation addresses "quality differentials relating to the commingling of oils or of oil and NGLs" (emphasis added) while the proposed statute lacks the emphasized phrase. The PPT legislation last year changed the definitions of "oil" and "gas" so that "oil" includes "NGLs" and consequently emphasized language in the regulation is encompassed now by the phrase "commingling of oils" in the proposed statute.

¹⁴ The regulation lacks the comma that appears here in the proposed statute.

¹⁵ See former AS 43.21.020 (production income) and 43.21.030 (pipeline income).



ACES

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House Oil & Gas
October 23, 2007

APC Operational Overview

Rockies

- Large acreage holdings

International

- World class targets
- Focused exploration

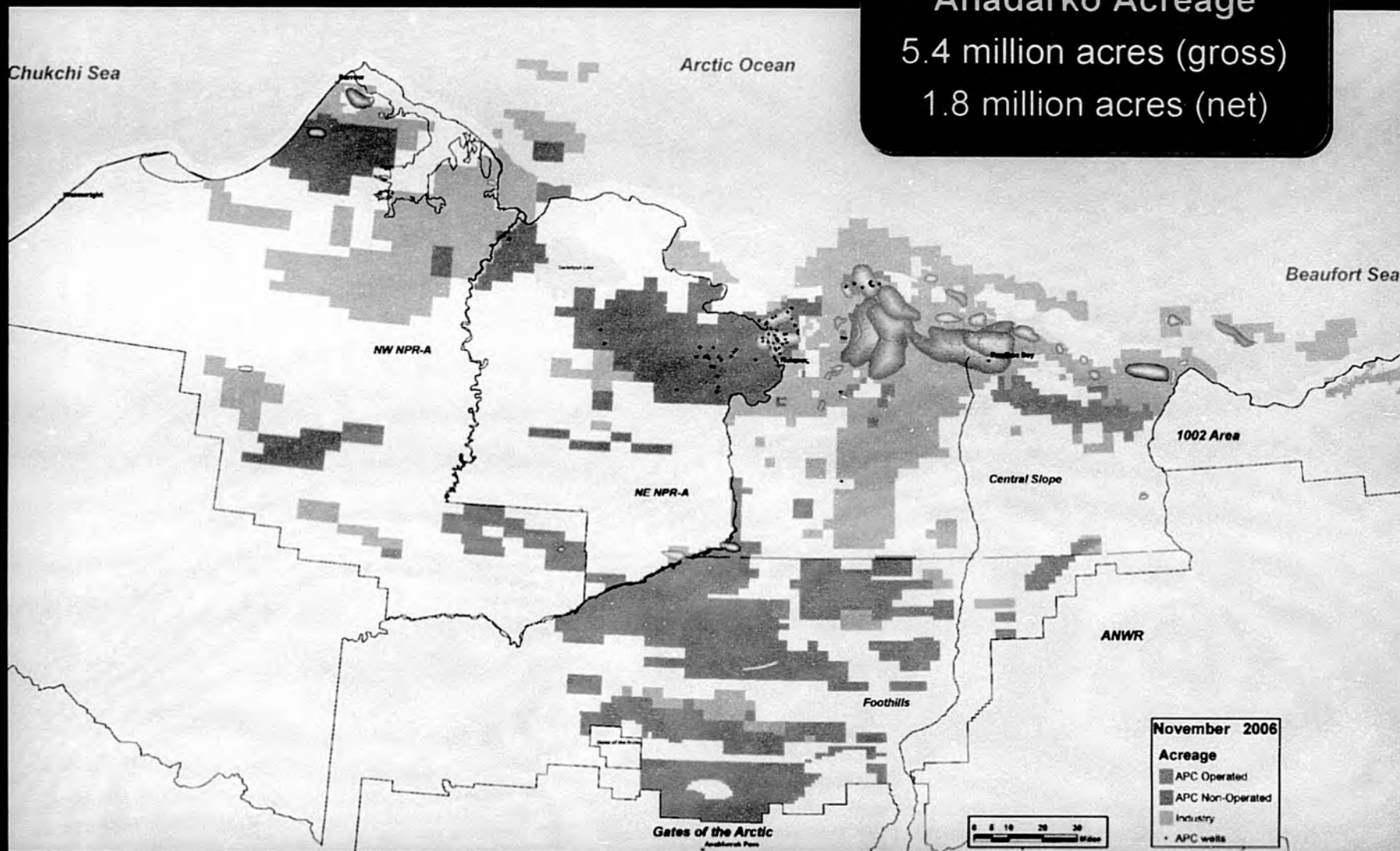


Gulf of Mexico Deepwater

- Significant Acreage position

-  Exploration Areas
-  Producing Areas

Anadarko Acreage
5.4 million acres (gross)
1.8 million acres (net)



Alaska Opportunities

- ▲ **World class petroleum basin**
- ▲ **Significant remaining resource potential**
- ▲ **Legacy type prospectivity (i.e. Anchor Fields)**
- ▲ **New entrants/partnering opportunities**
- ▲ **APC possesses tangible competitive advantages**

Alaska Challenges

- ▲ **Maturing basin/materiality/smaller prospects**
- ▲ **High costs**
- ▲ **Lack of infrastructure and competition**
- ▲ **Extremely long lead-time exploration**
- ▲ **Seasonal drilling & regulatory timing requirements**
- ▲ **Distance from market**
- ▲ **Lack of gas transportation**

Our View of PPT & Recap of 2006 Testimony

- ▲ **Significant tax increase at existing fields**
 - *Can be offset by increased exploration & development investment*
- ▲ **Improvement in exploration economics versus elf system encourages new investment**
 - *Credits help reduce high costs & improve NPV*
 - *25 – 20 worse than old elf system*
- ▲ **On balance supportive of PPT system**

Support Net Profits Approach

- ▲ **Appreciate Administration work to evaluate gross vs. net and conclusion to stick with net**
- ▲ **Net considers varying economics & costs**
 - *Tax paid on net income after costs*
 - *Accounts for costs and levels playing field*
 - *Still doesn't account for risk*
- ▲ **Gross collects on income regardless of profit**
 - *Gross tax with proper incentives harder to develop equitably and still complicated to administer*
- ▲ **Royalty acts like a gross tax**

Our View of ACES- Negatives Outweigh Positives

Support some parts of ACES

- Expand time to qualify for Exploration Incentive Credits (offset by new exclusions and requirements)
- Modify Net Loss carry forward to create level playing field
- Goal of increased transparency & state auditor capability

Stability

- Concern that PPT/ACES will be revisited again in next few years to deal with gas
 - Gas definitely needs to be addressed, but will reopen everything again

The significant tax increases would decrease exploration & development economics and far outweigh any positives in the bill

- Tax rate increase
- Tax escalator changes increase costs
- Transition Investment Expenditure Credits Elimination
 - Fairness and Investment Impact



Administration Field Economics Estimates

Table below from Sept 4, 2007 Administration Presentation

Project Net Present Value of Cash Flows (10% Discount Rate)				
\$40 Test Price (\$ Millions)				
	Status Quo PPT	ACES Plan	16% Gross Tax No Capital Credits	19% Gross Tax With Capital Credits
Field/Project A	178	128	-35	27
Field/Project B	72	48	-22	9
Field/Project C	59	27	-53	-22
Field/Project D	-64	-90	-398	-282
<i>Production Tax Revenues</i>				
<i>FY2008 @ \$60 oil price</i>	\$1.3B	\$2.0B	\$2.1B	\$2.0B

- Project Economics decrease by 33% to 54%
- What geologic & commercial risks were assigned?
- Where are dry holes & failed projects accounted for?

Summary

- ▶ **Significant tax increases outweigh any potential benefits**

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October 24, 2007

Profit Declines Sharply at BP

By STEPHEN LABATON and LOWELL BERGMAN

WASHINGTON, Oct. 23 — The British energy company BP, tarnished by a string of costly legal problems, is preparing to settle accusations that it was criminally indifferent to worker safety and that it manipulated energy prices, government officials and lawyers involved in the separate cases said on Tuesday.

The officials said that the Justice Department would announce as early as this week that BP had agreed to a settlement to end criminal investigations stemming from an explosion at a giant BP oil refinery in Texas City, Tex., two years ago.

The accident, at the nation's third-largest refinery, killed 15 workers and injured 180 others. It was the nation's deadliest industrial accident since 1990, and one of the worst in modern times.

BP is also preparing to settle accusations that its energy trading unit was involved in manipulating prices in the propane market three years ago.

The expected settlement in the refinery case signals the government's willingness to take a hard line in forcing companies to redress environmental and worker safety problems. Officials said that the Texas City case would not resolve accusations against BP executives who may have failed to take steps to make the refinery safer and that those investigations would continue.

The paradox for BP, once the oil industry's highflier, is that it has long promoted itself as an environmentally friendly company that takes its civic responsibilities seriously.

The industrial accidents and trading problems have tarnished that image and led to a management reshuffling and organizational shake-up at the highest levels, including the naming of a chief executive, Tony Hayward, last spring.

Mr. Hayward succeeded John Browne, a media-shrewd executive who resigned after losing a legal battle with a London tabloid. Mr. Browne acknowledged making an untruthful statement in court about the circumstances under which he had met a younger man with whom he had had a relationship.

In recent days, BP announced yet another series of executive appointments as it struggled to turn itself around and as Mr. Hayward sought to address morale problems and make a clean break from the past.

But the difficulties, particularly in the United States, have taken a toll. Despite the sharp spike in crude oil prices in recent months, BP said on Tuesday that its net income for the third quarter declined by 29 percent from the period last year. The company reported quarterly profit of \$4.41 billion, or 23 cents a share, on revenue of \$72.7 billion.

The results beat analysts' expectations, which were lowered when Mr. Hayward wrote in a document leaked in September that operational performance in the third quarter was "dreadful."

BP still faces huge expenses for the accident in Texas City. More than 1,000 civil lawsuits have been filed, and the company has set aside \$1.6 billion for compensation claims. It also has committed to spending \$1 billion to fix problems at the plant.

BP's shares closed on Tuesday at \$75.44, up \$1.56.

The refinery case could be the latest in a string of victories by a small unit of the Justice Department, the environmental crimes and natural resources division.

Last month, a federal appeals court in California ruled in favor of the division when it reinstated criminal charges against W. R. Grace and seven executives over widespread asbestos contamination at a vermiculite ore mine near Libby, Mont. Before that, the division won convictions against executives of companies owned by the McWane Corporation of Birmingham, Ala.

This year, a federal safety panel found that the Texas refinery accident was caused by deficiencies "at all levels" of the company and was a result of aggressive cost-cutting. The panel, the Chemical Safety and Hazard Investigation Board, also concluded that company officials had ignored warning signs of a possible disaster.

At the time of the explosion, the plant in Texas City had a capacity of about 10 million gallons a day, or 2.5 percent of the gasoline sold daily in the nation. It employed 1,800 workers and 800 contractors on a 1,200-acre site about 30 miles southeast of Houston. Since the accident, the refinery has been producing at about half its capacity. That decline has played a role in the erosion in BP's earnings.

The propane pricing settlement would resolve a complaint filed last year by the Commodity Futures Trading Commission that accused BP of inflating heating and cooking costs in 2004 for millions of Americans by manipulating the price of propane gas.

Spokesmen at BP, the Justice Department and the futures trading commission declined to comment about the planned settlement announcements.

The Wall Street Journal reported on its Web site on Tuesday that the propane pricing settlement would involve a \$303 million payment and changes to trading operations. As part of that settlement, and to defer criminal prosecution, BP is expected to put its energy trading operations under the supervision of a government-appointed compliance monitor.

Stephen Labaton reported from Washington and Lowell Bergman from Berkeley, Calif. Julia Werdigier contributed reporting from London.

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What price stability?

If Alaska gives up billions in oil taxes, what is the payoff?

(Published: October 23, 2007)

The message that expert oil economists have given Alaska legislators in the special session is clear:

Alaska is in the middle of the pack when it comes to favorable oil tax rates. With oil prices pushing past \$80 a barrel, many other jurisdictions are looking at claiming a greater share of windfall profits from oil production. The consultants agree: Alaska has room to get more revenue with its oil production tax and still be competitive with other stable, western governments with similar oil prospects.

Alaska's government share has been lower than Norway's for some time. Alaska has been higher than Alberta and the United Kingdom, but the UK raised taxes and Alberta is trying to get up to something approaching Alaska's current level. Among Alaska's peers, only the offshore Gulf of Mexico is more attractive than Alaska, and that's because there are no state taxes on production in federal waters. Alaska is well below places like Angola, where drilling is feverish, even though the marginal tax rate on oil profits can exceed 90 percent.

THE COST OF TAX STABILITY

The only expert who urged lawmakers not to seek any more of that oil money was Pedro Van Meurs. His advice was a mixed message. He said Alaska could have gotten a lot more money when the Legislature passed the new petroleum production tax (PPT), but now he thinks tax stability is more important than getting more revenue. In effect, he said, Alaska made a mistake not getting a lot more money with PPT, but having made that mistake, Alaska should just live with it.

Following Van Meurs' advice would be an expensive proposition. Gov. Sarah Palin is seeking about \$600 million a year more with her changes to PPT. Some fiscal hawks think Alaska left far more than \$1 billion a year on the table with PPT.

So when Van Meurs, the industry and its allies urge Alaska to stick with PPT, they are saying that tax stability is worth at least \$600 million a year to the state treasury.

What do we get for our investment of at least \$600 million a year?

We don't know, and oil companies won't tell us. Their investment plans are confidential. And they have a huge self-interest in talking Alaska out of any oil tax increase. We have no way of knowing whether the oil companies are just bluffing, or whether a tax increase will in fact delay or kill Alaska projects. The call for tax "stability" is the ultimate "trust us" deal.

WHAT ALASKA GIVES UP

Meanwhile, Alaskans know what we don't get.

We don't get at least \$600 million a year. If Alaska banked that money at 8 percent a year, we'd have another \$4.7 billion after just five years. That's less time than it would take to discover and produce one of the new oil fields we're trying to encourage with tax "stability."

Properly invested, the state's extra \$4.7 billion could produce \$235 million a year forever. Over just 15 years, the state would have boosted revenue by a total of \$7 billion from following the governor's plan and investing the proceeds.

To match up, investing in oil tax "stability" would have to produce an extra 390 million barrels of oil over the next 15 years (assuming the state earns \$18 per barrel of oil, as it did this past fiscal year.) That's equivalent to bringing on line a 100,000-barrel-a-day oil field within just five years. Since the big discoveries at Prudhoe Bay and Kuparuk, Alaska has only had one new field of that size.

Suppose lawmakers decided to go further and raise taxes \$1 billion a year. In that case, to yield the state an equal payoff, the industry would have to show that tax stability, all by itself, will produce another 650 million barrels. That would require bringing on-line 178,000 barrels a day of new oil production within just five years -- a 25 percent increase over today's levels.

If Alaska grants five more years of tax stability, can the oil industry guarantee it will produce at least 390 million extra barrels of oil over the next 15 years?

If the answer is yes, show Alaskans the numbers.

If the answer is no, the investment that the industry wants Alaska to make in "stable" taxes is a bad deal for Alaska.

BOTTOM LINE: Alaska is being asked to invest billions of dollars in "tax stability" for the oil industry. Mere rhetoric and slogans aren't enough to justify such a huge investment.

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House Oil & Gas Committee HB 2001 Details

Presentation by Dan E. Dickinson, CPA
For Legislative Budget & Audit Committee
October 23, 2007