12008 SENATE RESOURCES

Section 21

AS 43.55.160(a)

. . . is the total of the
of . . . oil and gas . . .
from in the state, less
. . . . . as . . . and
. . . 1/72 of . . .

Section 21

AS 43.55.160(c)

. . . lease expenditures . . . are the costs of the point of production

. . ..that are the costs of oil or gas deposits located . . . in the state.

Section 21

AS 43.55.160(c) *(continued)*

In determining . . . [
] costs . . . the department shall give substantial weight . . . to typical . . . as to [billable] costs . . . under . . . and [
].

Section 21

AS 43.55.160(a)

. . . is the total of the

of . . . oil and gas . . .

in the state, less

from

. . .

. . . as

. . . and

. . . 1/72 of . . .

Section 21

AS 43.55.160(e)

[Lease expenditures must be by the producer for (1) another's use of a production facility; (2) reimbursement, e.g. field costs paid by state, that offset lease expenditures; and (3) sale of assets acquired through lease expenditures or of non-taxable oil or gas used in lease operations.]

Section 21

AS 43.55.160(a)

. . . is the total of the
of . . . oil and gas . . .
in the state, less
. . . as . . . and
from
. . .
. . . 1/72 of . . .

Section 21

AS 43.55.160(g)

. . . transitional investment expenditures are . . . [incurred] . . . less . . . [proceeds from] the . . . acquired . . . as a result of [those] capital expenditures

Section 21

AS 43.55.160(i)

. . . a producer that is . . . may reduce the net value by . . .

[T]he total of the allowances . . . during the calendar year does . . .

An unused allowance . . . may . . . .

Section 7

AS 43.55.020(a)

. . . The tax levied under AS 43.55.011, applied under this chapter, is due

. . . .

Section 12

AS 43.55.024(a)

. . . a producer . . . that incurs a
. . . may . . . elect . . . to take a
in the amount of of that
expenditure.

Section 12

AS 43.55.024(h)(2)

"qualified capital expenditure" -

[is a lease expenditure for G&G exploration, intangible drilling costs, and other expenditures capitalized under IRC]

[does not include purchase of a previously acquired or used asset]

Section 12

AS 43.55.024(b)

A producer may elect to take a

. . . of of a carried-forward

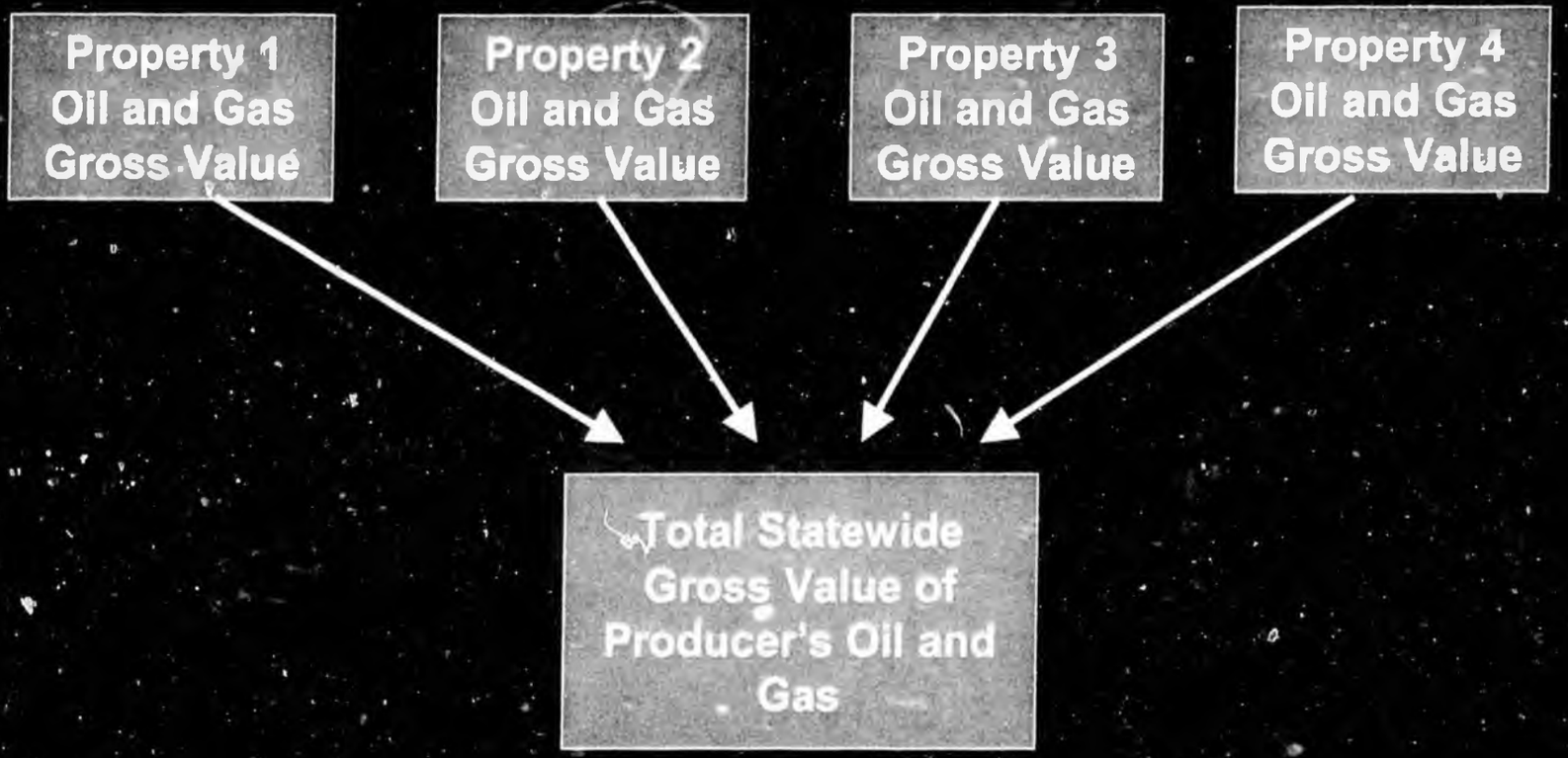
[which is the amount of a previous year's

that were

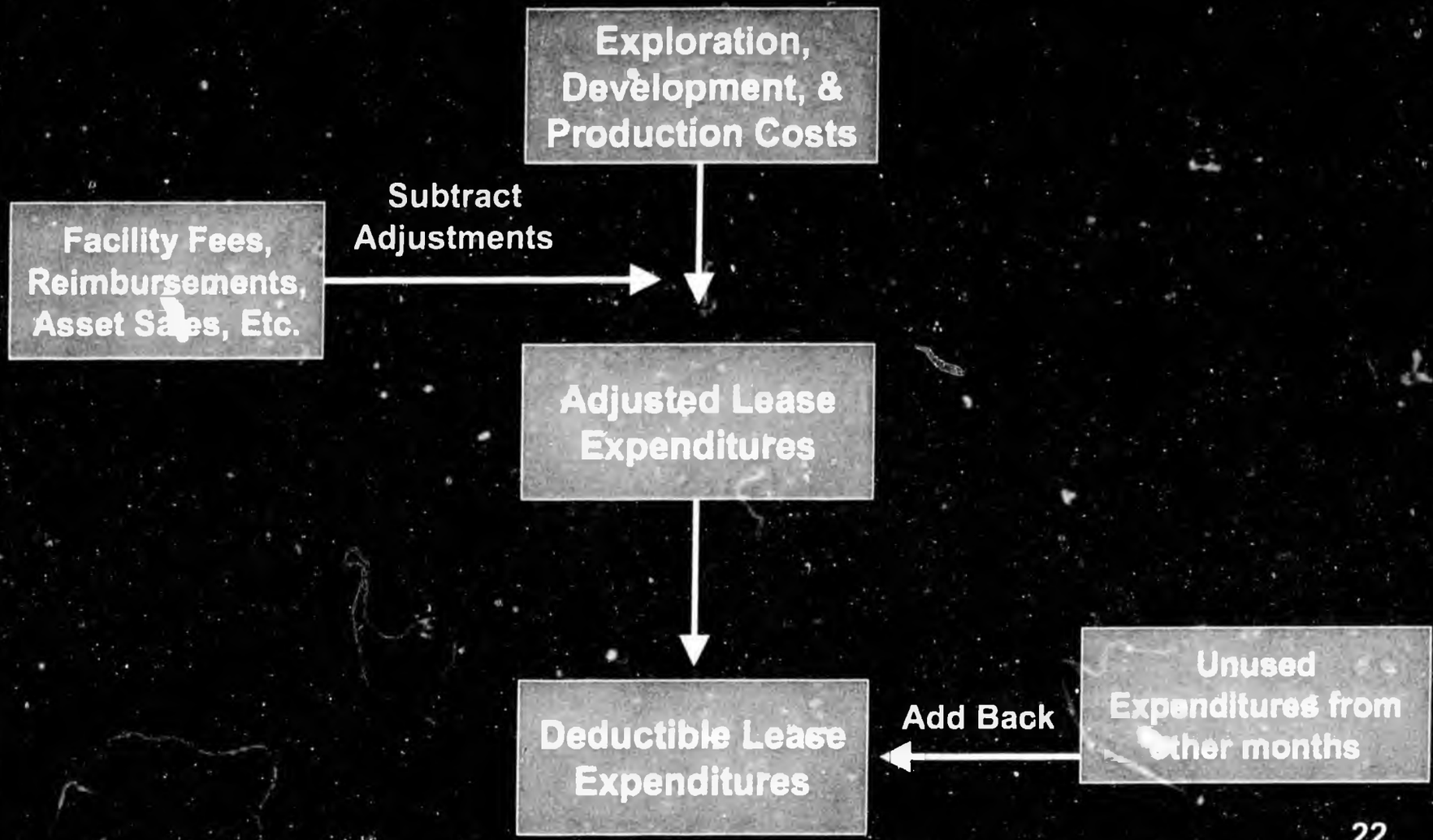
because they would have reduced the net value of the oil and gas below zero].

STEPS IN TAX CALCULATION

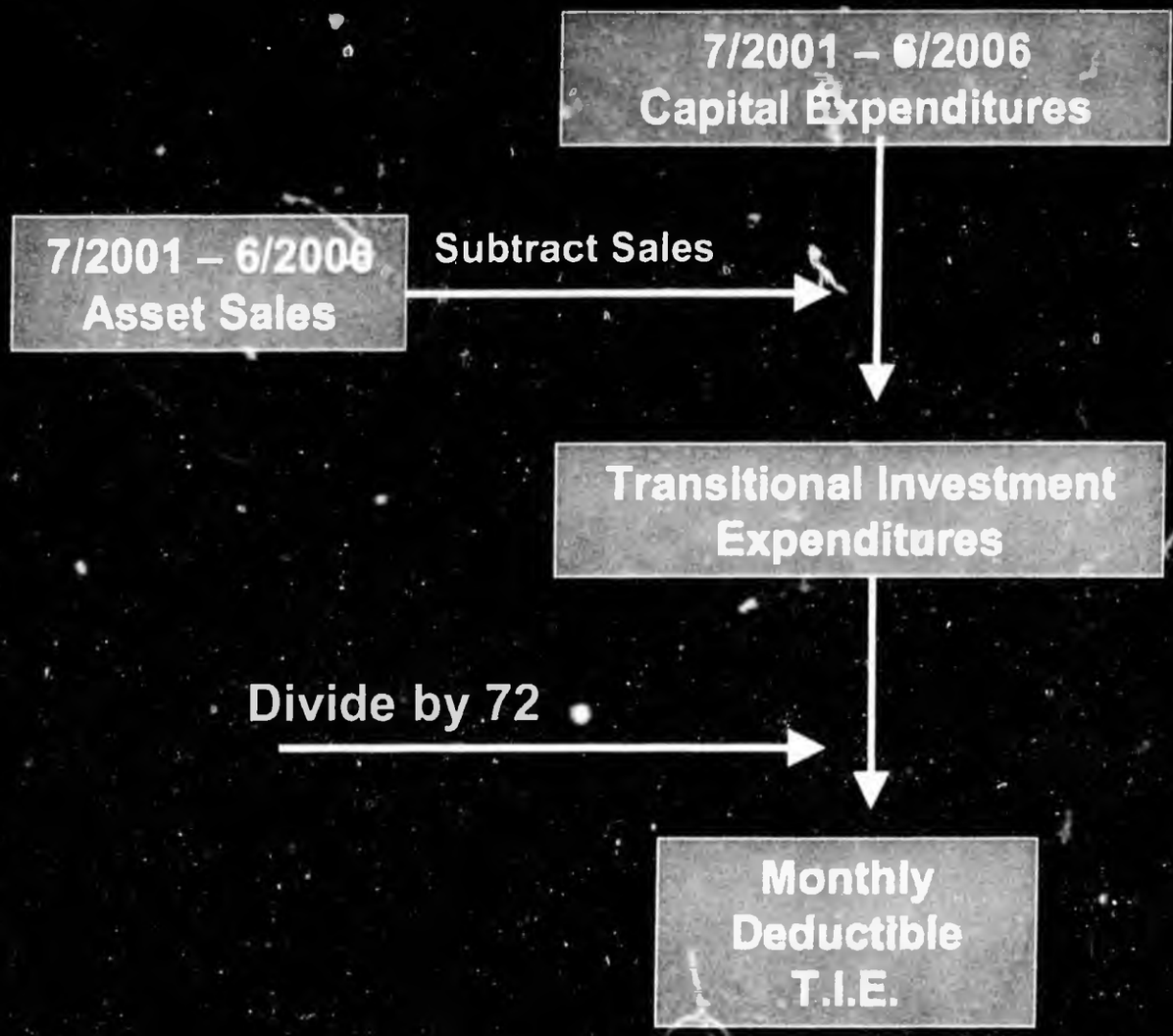
GROSS VALUE
AS 43.55.150, AS 43.55.900



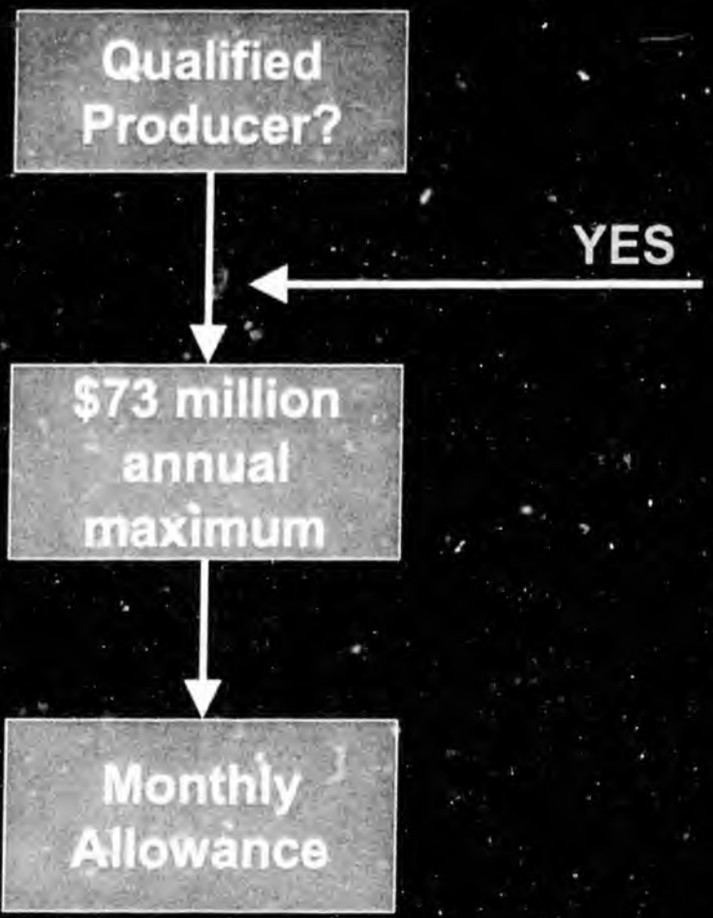
LEASE EXPENDITURES
AS 43.55.160(b) – (f)



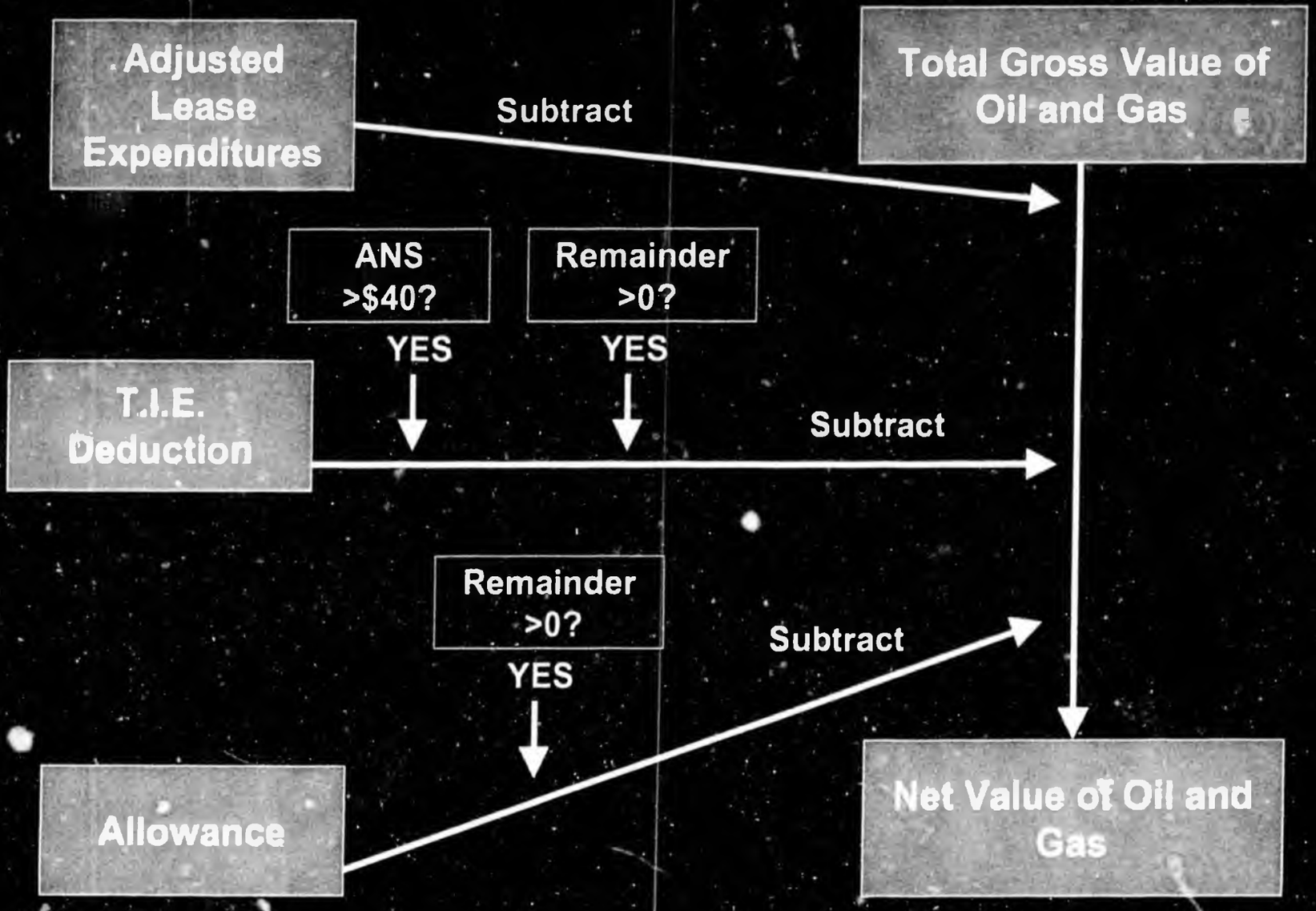
TRANSITIONAL INVESTMENT EXPENDITURES - AS 43.55.160(g)



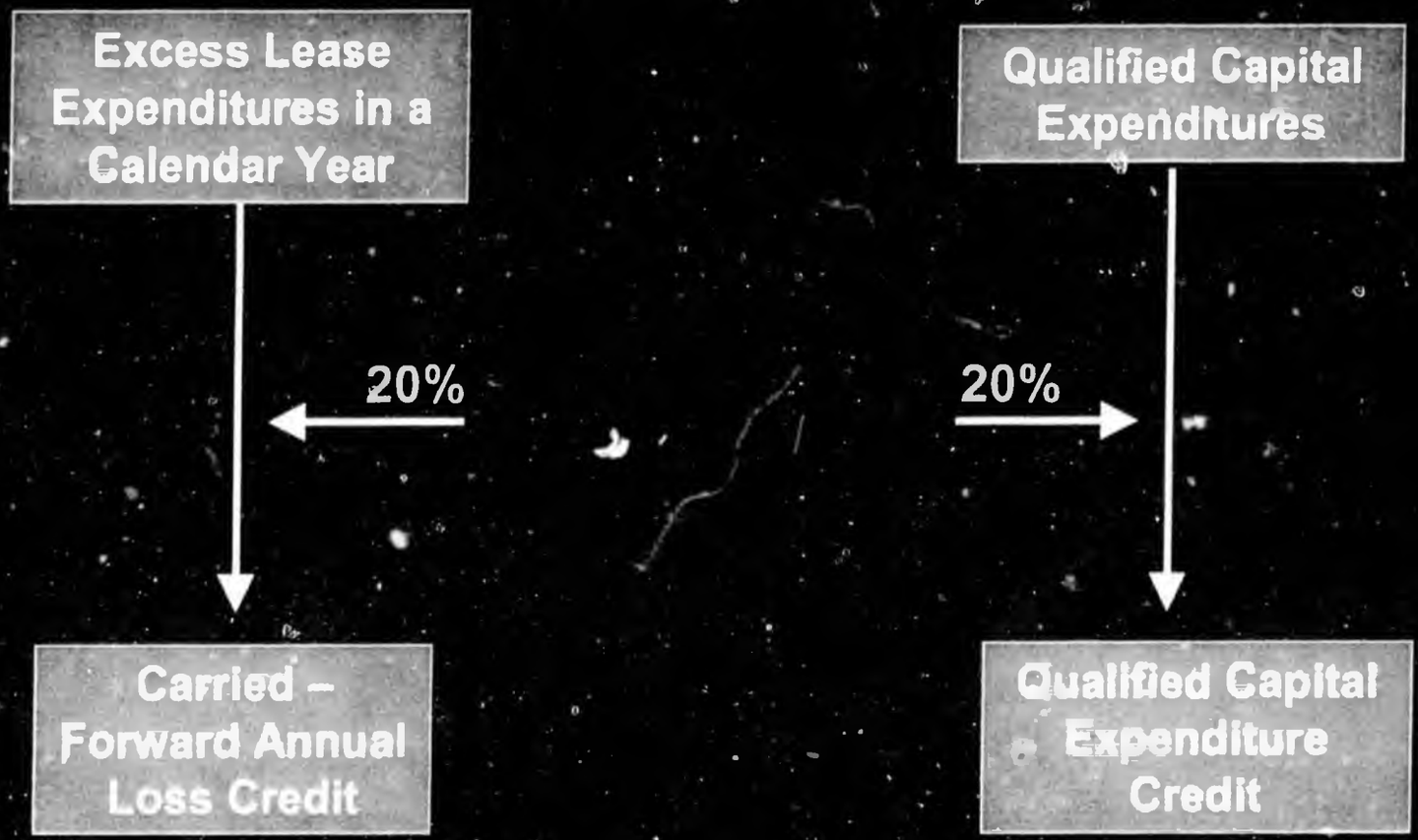
ALLOWANCE
AS 43.55.160(i) and (j)



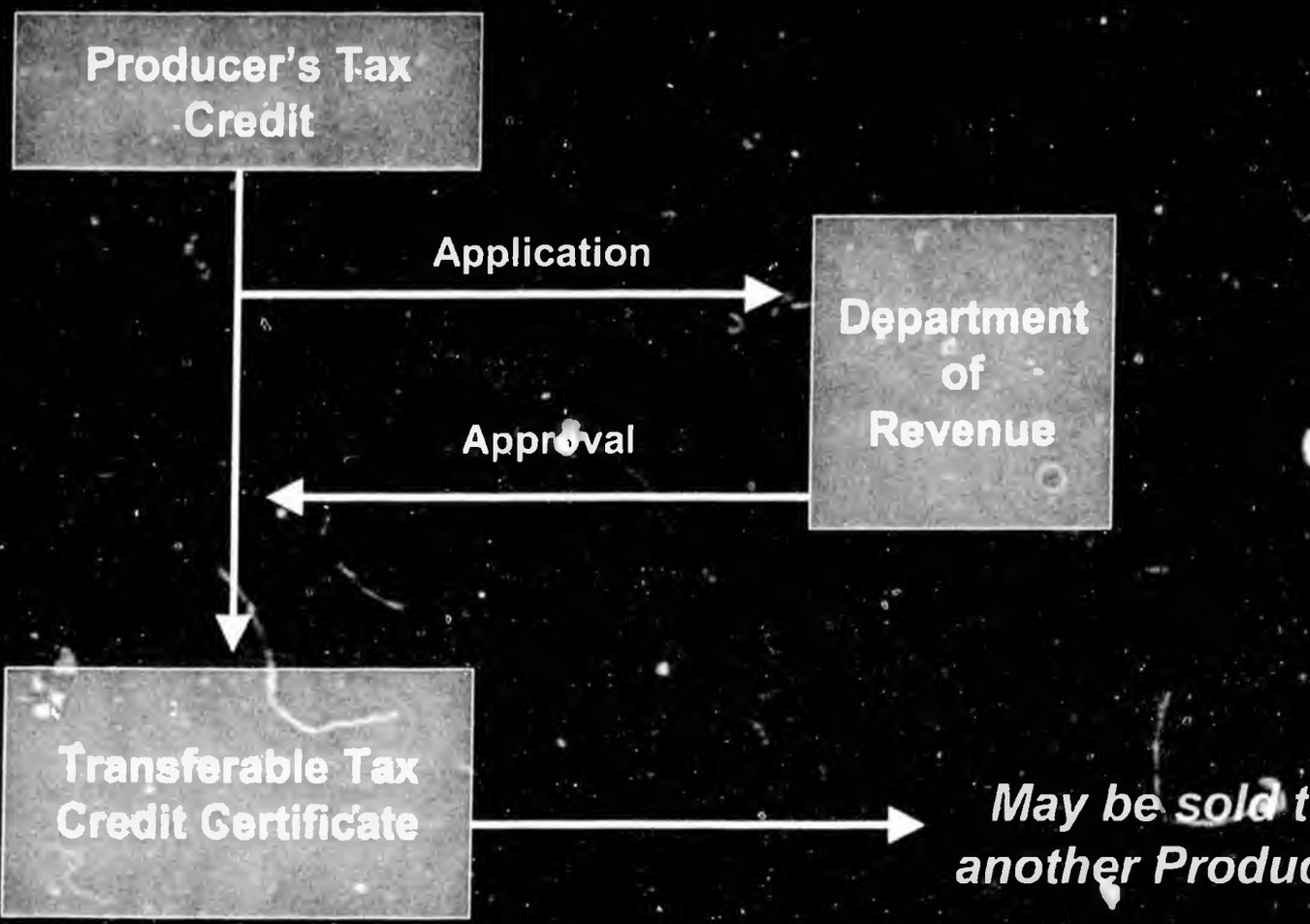
NET VALUE
AS 43.55.160 (a), (g), and (i)



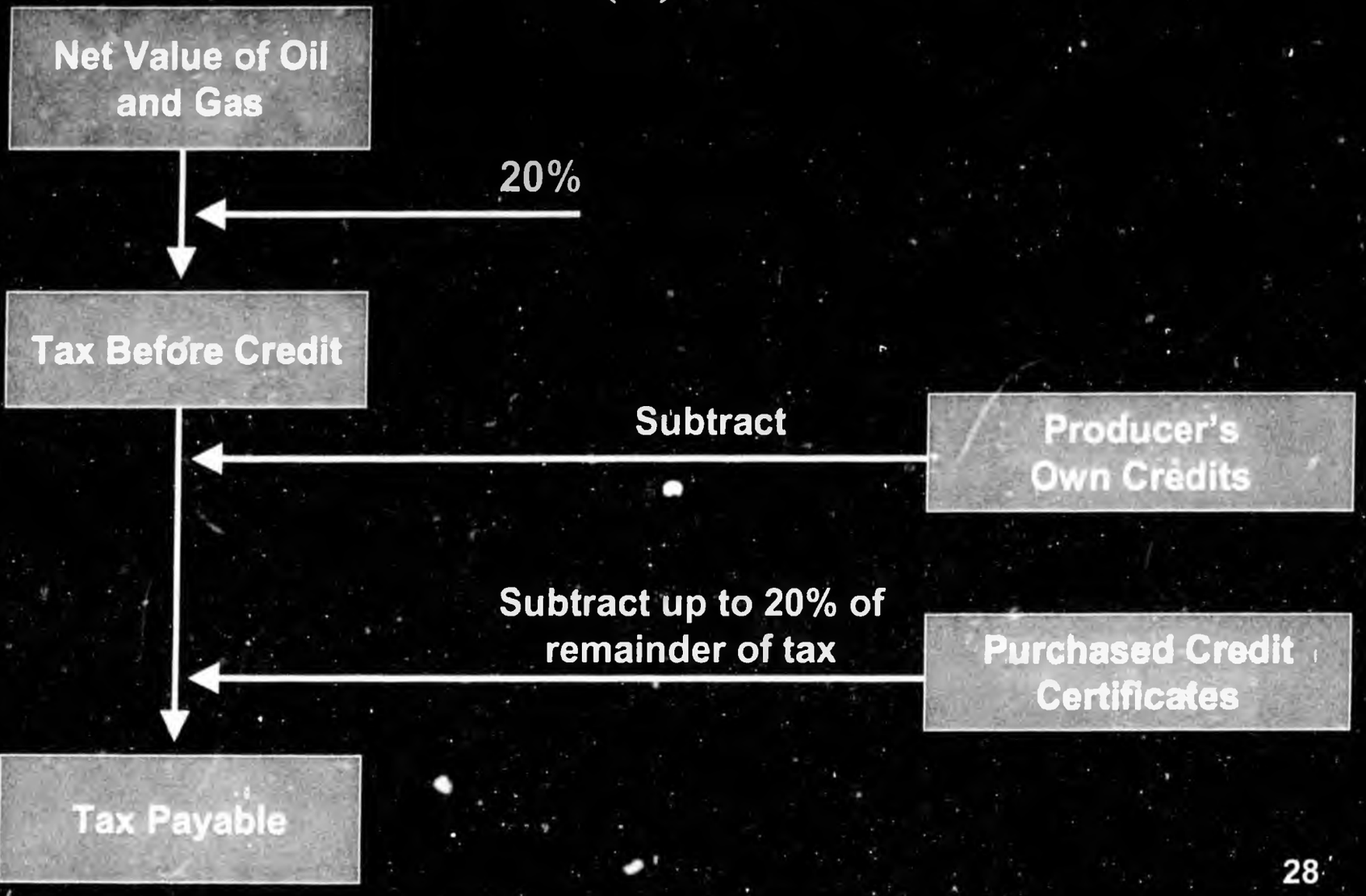
TAX CREDITS
AS 43.55.024 (a) and (b)



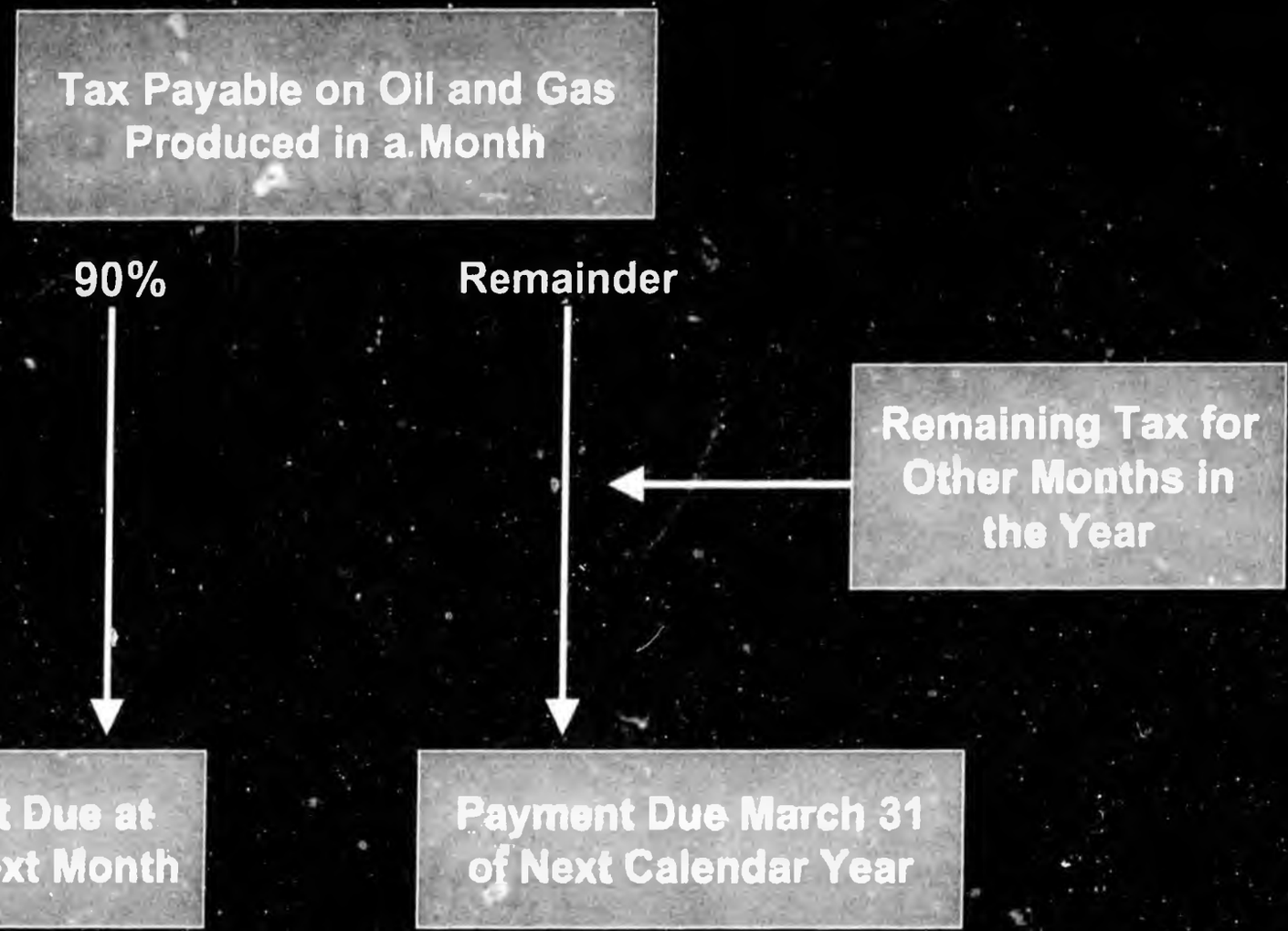
TRANSFERABLE TAX CREDIT CERTIFICATES - AS 43.55.024 (d)-(f)



TAX CALCULATION
AS 43.55.011(a) and 43.55.024



TAX PAYMENT
AS 43.55.020(a)



PROPOSAL FOR A PROFIT BASED PRODUCTION TAX FOR ALASKA

February 14, 2006

Dr. Pedro van Meurs

EXECUTIVE SUMMARY

The severance tax (production tax) of the State of Alaska has essentially remained unchanged since 1989. The current tax is based on a percentage of the gross revenues less the royalty. The percentage is adjusted with a formula (Economic Limit Factor or ELF), which for oil is based on field size and well productivity. This formula has served Alaska well for more than a decade. However, the economic framework on which the ELF formula was based is no longer realistic for North Slope conditions. As a result, based on the formula, the amount of tax will significantly decrease over the coming decade to a point were less than 20% of the oil is actually taxed. This is not in the interest of Alaska. Furthermore, the current ELF formula is not sensitive to variations in oil price creating significant losses for Alaska under current conditions. Also the production tax does not provide incentives to re-invest in Alaska.

It is suggested to repeal sections of the current act dealing with production tax (AS 43.55) and replace them with a profit based tax, the Profit based Production Tax ("PPT").

The profit based approach is a widely accepted international practice, including for instance Norway, the UK, Nigeria and Angola adopted this approach for the offshore. Alberta is using this approach to develop the oil sands.

The international competitive situation with respect to oil has changed drastically over the last two years. It is now apparent that there is strong upward pressure on the government take for oil. This is the result of many factors. Many of the oil producing nations had adopted in the past progressive fiscal systems which adjust the government take automatically upward in case of higher prices. Therefore, in these nations the average government take is now higher compared to two years ago.

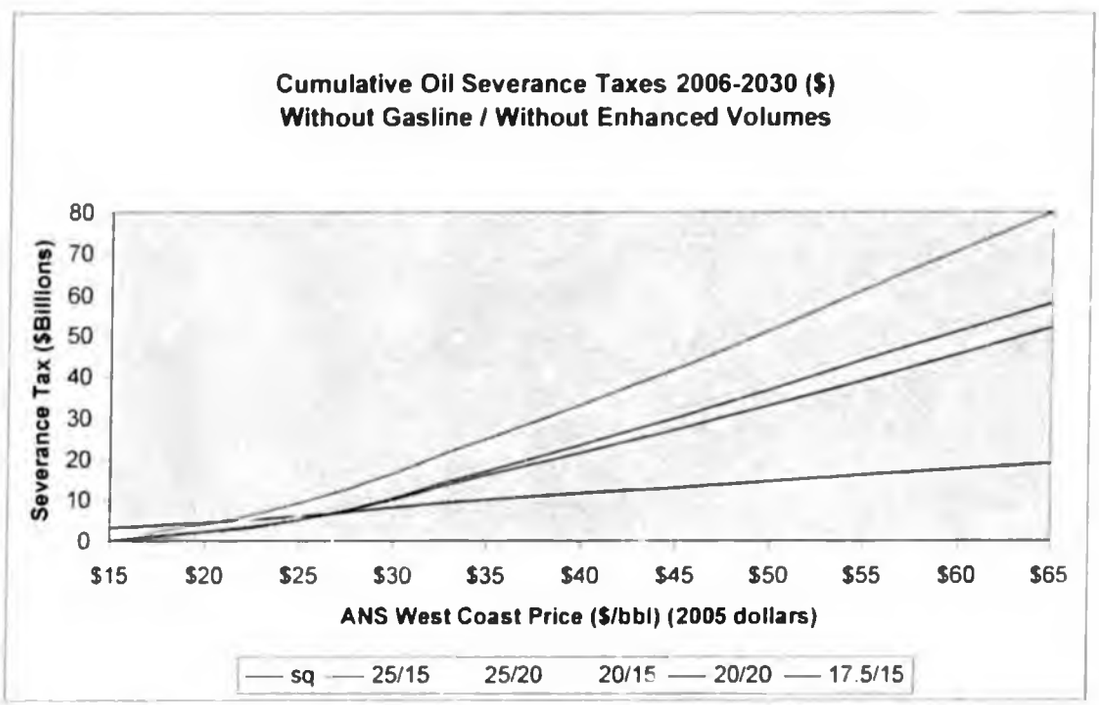
The higher oil prices are the result of difficulties in the supply of the strongly increasing world oil demand. Good exploration and development areas for oil are increasingly difficult to obtain. This puts now a premium on Alaska acreage for oil.

At the same time, new and aggressive players have entered world exploration and production. New companies from China, India, Russia, Latin America, Australia and Europe are willing to pay more for exploration and development acreage, driving up world wide government take.

All these factors make a re-evaluation of the production tax in Alaska highly desirable and appropriate at this moment. A much higher tax under average and high oil prices is justified.

Therefore, a PPT of 25% on the net revenues is proposed, with tax credits of 20% on all capital expenditures.

The Department of Revenue ("DOR") presented a number of alternative PPT's to the Alaska Legislature. The following graph from this presentation shows the cumulative revenues under various options based on existing production and modest new developments.



This graph shows how under the proposed PPT (25/20 in the graph) and at an average ANS price of $ 40 per barrel the cumulative production tax revenues over 25 years to Alaska will increase from the current estimate of $ 10 billion to about $ 30 billion. At $ 60 per barrel the cumulative revenues will increase to $ 70 billion. These revenues would be largely derived from existing production.

It is important to ensure that the new PPT encourages investment in Alaska.

On the North Slope smaller conventional oil fields and reservoirs are now the main target. Furthermore, heavy oil is an important new resource to Alaska. Improved technology may unlock billions of additional barrels of oil.

Therefore, tax credits are important to encourage such developments. A loss in any year can be converted in a tax credit by taking the 25% tax value. Therefore, in total, a credit of 45% can be obtained for new investments in Alaska.

Furthermore a tax free allowance of $ 73 million per year per company is proposed in order to ensure that small companies are not subject to tax and that new investors are provided with a strong incentive to invest in Alaska.

Under low prices and high costs the strong tax credits create a situation where there will be no PPT. Under high prices and low costs the PPT will be considerable. The PPT is therefore a progressive system.

The tax credits can be traded. Therefore investments in exploration, small and marginal fields or heavy oils will result in immediate credits even when the investor does not have prior income in Alaska. This will strongly attract new investors.

The PPT will be levied on a corporate basis. The tax credits and the profit based system ensures that when oil companies actively re-invest in Alaska the PPT payable will be less, even zero. When companies do not re-invest the PPT will be much higher.

As can be seen from the DOR graph, the PPT is primarily a tax on <u>existing production.</u> This tax is very significant under average or high prices.

However, with respect to production from <u>new investments</u>, the PPT can be negative or positive. On average, for large producers, the PPT payable will be zero on new small 50 million barrel fields on the North Slope at a WTI price of $ 30 per barrel. Under low prices and high costs, the tax credits are more than the tax that will be paid eventually and therefore the PPT will be "negative" (provided a company has PPT payable or can trade its credits). Under high prices and low costs, the tax credits will be less than the tax that will be paid eventually and therefore the PPT will be "positive".

There is, of course, a State wide "floor" of zero for the total PPT. Under low prices Alaska may not receive PPT at all. No matter how many tax credits a company has, the tax cannot be reduced below zero. Also there will be no trade in tax credits under low price conditions because all tax payers will have zero taxes.

Royalties, property taxes and state corporate income tax will not be affected by the PPT (other than that the PPT will be a deduction for federal income tax).

This report contains an in depth international comparative analysis which confirms that the proposed PPT is indeed more attractive to new investors than the current system.

A detailed rating was done to compare the attractiveness of the PPT with the current system in Alaska and eight other fiscal systems around the world: the UK, Norway, US Gulf of Mexico, Alberta oil sands, Nigeria, Russia and Azerbaijan.

The considerable increase in international competitiveness of the Alaska PPT for new investors can be studied from the following table. The best fiscal system would be rated 48 and the worst 480.

The Alaska Current system has an index of 363. The PPT would improve the index to 244.

COMPETITIVENESS INDEX

Hypothetical best	48	
US GOM	54	#1
UK	139	#2
Alberta-Oil Sands	163	#3
Nigeria	179	#4
Alaska PPT	244	#5
Angola	322	#6
Azerbaijan	329	#7
Alaska Current	363	#8
Norway	402	#9
Russia-Sakhalin	445	#10
Hypothetical worst	480	

The rating was done taking into account the low well head prices for Alaska crude oil. For instance, in the economic analysis it was assumed that in the US Gulf of Mexico producers will receive $ 7 per barrel more at the well head than in laska. Therefore, the rating fully accounts for the geographical disadvantage of Alaska.

The competitiveness also improves modestly for large existing producers which re-invest in Alaska. Such companies do not benefit from the tax free allowance upon re-investment. The large producers will in particular see an improvement in the rate of return on new investment.

TABLE OF CONTENTS

1. INTRODUCTION

1.1. Preliminary Comments

This report is a draft which reflects the analysis carried out at the request of the Governor of Alaska to review the severance tax for oil and gas. In a report which I prepared on June 15, 2003 it was concluded that deep revisions were necessary. Two options were considered over time:

- a revision of the ELF factors to make them more sensitive to price and the introduction of tax credits to create more incentive for re-investment, and
- a replacement of the current severance tax with a profits based tax.

The purpose of the 2003 review was to:

- Make this tax more effective in the light of changed economic and technical circumstances
- Make the tax more progressive and better linked to the profitability of the operations resulting in a more reasonable balance between government and petroleum industry over a wider range of economic circumstances
- Provide stronger incentives to re-invest in Alaska

This report constitutes therefore a follow up on the earlier reports.

The first question to be raised is whether changes in the severance tax would create an environment of fiscal instability that would undermine the confidence of the petroleum industry in Alaska.

1.2. Changing the Severance Tax

The Alaska severance tax is a tax of general application to the petroleum industry and can therefore be changed by the Legislature.

Many jurisdictions have taxes that are only or primarily related to petroleum or minerals. Examples are the PRT in the United Kingdom, the Hydrocarbon Tax in Norway, the PRRT in Australia , the SPT in Trinidad , the SRB in Thailand or the APT in Papua New Guinea.

The international practice is to change these type of resource based taxes only occasionally. Frequent changes in resource taxes create instability because this makes it difficult for the petroleum industry to undertake the long term planning that is required for decisions on exploration and oil and gas field development.

Nevertheless, the implicit understanding with respect to a resource tax is that such a tax can be modified occasionally where new conditions justify such a change, where governments want to

implement a new policy or where deficiencies in the structure of the tax make adjustment desirable.

Alaska has introduced changes to the severance tax in 1977 and in 1989. If Alaska were to implement another change during 2006, it would mean that this tax is being changed seventeen years since the last major change in this tax. This is a reasonable frequency of change for a resource tax from an international perspective.

This then raises the issue as to whether there is a justification for adjustments to the Alaska severance tax.

Therefore the next section discusses why changes to the severance tax are appropriate.

1.3. ELF "design flaws" and technical and economic conditions on the North Slope.

When the recent ELF was introduced in 1989 it was from a fiscal perspective an advanced and modern feature.

The production tax (severance tax) for oil was based on a rate of 12.25% for the first five years of production of a field and 15% thereafter. The rate applies after the deduction of the royalty. A flat severance tax rate of this nature would be a severely regressive tax which would risk making smaller oil fields with modest well productivities uneconomic.

The ELF factor made this tax progressive with respect to field size and well productivity. This was achieved through multiplying the severance tax rate with the ELF factor, which varies between zero and one. Fields with high field and well productivities have a factor of close to one. Fields with low field and well productivities have a factor of close to zero. The formula is as follows:

$$ELF = \left[1 - \frac{(300 \times wells)}{volume}\right]^{\left[\left(\frac{150{,}000}{volume}\right)^{1.53333}\right]}$$

"wells" is the number of producing wells in the field, "volume" is the total daily production for the field

This formula contemplates that a marginal oil well would produce 300 barrels per day and that therefore fields with wells that produce less should not be taxed. The field also considers that a 150,000 barrel field is a marginal field.

The ELF therefore encouraged the development of smaller and less prolific oil fields. Alaska has benefited from this concept, because it is likely that as a result of the introduction of the ELF a number of additional oil fields and satellites to existing fields have been developed which otherwise might not have been economic

However, after the ELF has now been for 17 years in operation, five "flaws" have now been identified with the current ELF formula:

1. The ELF is no longer corresponding reasonably to oil field decline.
2. The ELF does not react reasonably to the current economics of field size and well productivity and the specific relief that is granted through the ELF does not seem appropriate for the circumstances.
3. The ELF does not relate rationally to incremental investments in oil field development, which now have become very important mode of operation in North Slope developments.
4. The ELF does not respond to higher or lower oil or gas prices.
5. The ELF does not provide an incentive for re-investment.

Following is a discussion of each of these five "flaws".

1.3.1. The ELF and field production decline

One issue relates to the decline of the ELF during the decline of production during the final phase of an oil field.

It is reasonable for the ELF to become gradually less if production declines in an oil field. Typically operating costs per barrel increase if production in an oil field declines. This is the result of the fact that some of the operating costs are fixed and therefore with declining production the costs per barrel go up. Also usually as the field production declines, gas and water production per barrel increase which means increased operating costs and sometimes additional facility requirements. For all these reasons it is reasonable to reduce the ELF gradually with declining field production.

Once the field approaches the end of the field life, it is reasonable to reduce the ELF to zero. This will help prolong the economic life of the field. The current ELF formula achieves this result.

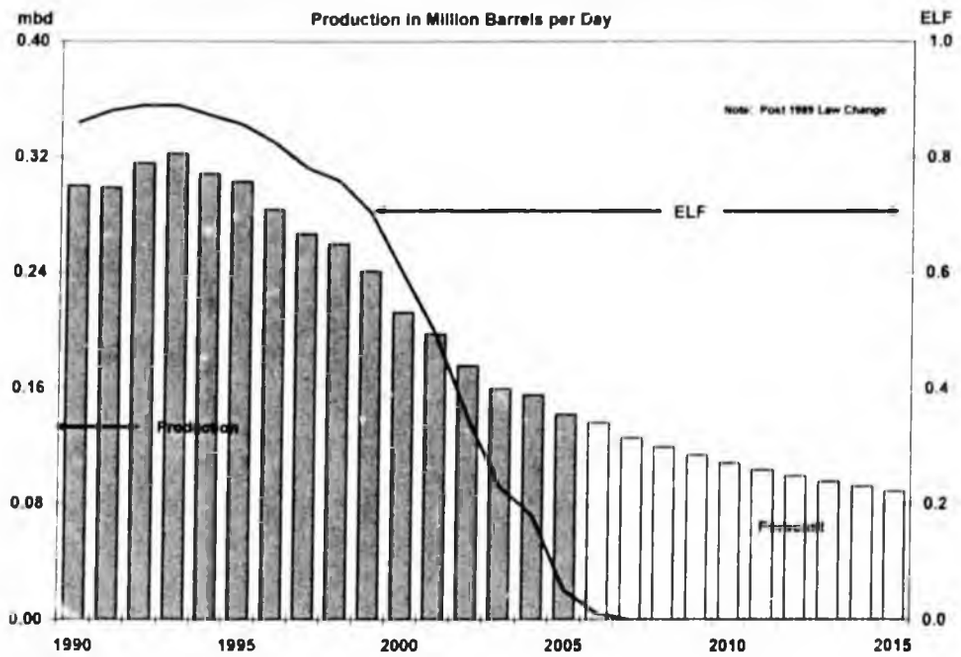
The main question is whether the current formula results in a reasonable decline of the ELF under declining production.

An important case is the Kuparuk field. In fiscal year 2000, this field produced 212,000 bopd. By the year 2011 it is estimated that the field will produce 98,000 bopd.

In the year 2000, the ELF on the field was 0.60. In March 2003 the same ELF factor was only 0.25. In the year 2007, the ELF will be 0.

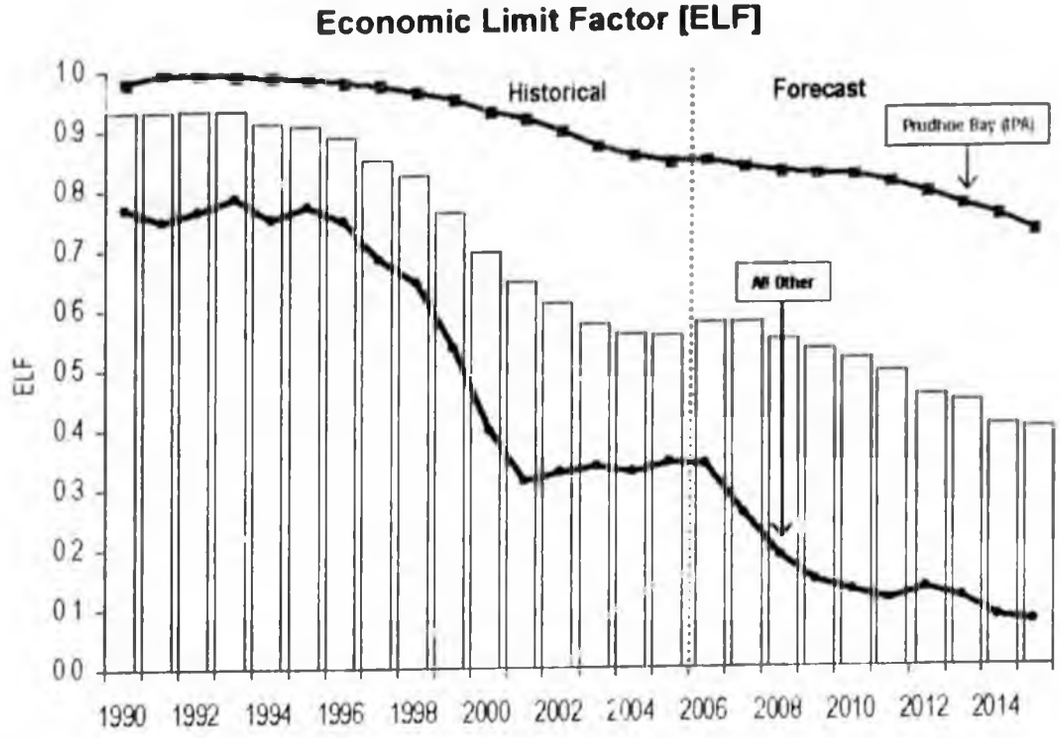
Following is the anticipated graphs of production and ELF decline:

Kuparuk Crude Oil Production & ELF



Therefore, the ELF reaches zero well before this is necessary as a result of the economic circumstances. This is unreasonable from a government perspective. Kuparuk is a world class and profitable oil field and there is no reason why Alaska should not receive production taxes from this field.

In general, the level of production tax will decline strongly due to a reduction of the ELF during the next decade as can be seen from the following graph:



The rapid decline of the ELF is not reasonable and unfair to Alaska, in particular under the current high oil prices. This aspect of the current production tax alone justifies a revision of the production tax.

1.3.2. General relationship between ELF and field and well production

The ELF formula is very sensitive to well productivity and has the following effects:

Well Prod bopd	Wells	Volume bopd	ELF
300	2000	600000	0.00
300	500	150000	0.00
1500	100	150000	0.80
1500	20	30000	0.07
6000	5	30000	0.55

It can be seen that a 150,000 bopd with 100 wells has an ELF of 0.8 and with 500 wells the ELF is down to zero. For a 30,000 bopd field, the ELF is 0.55 with 5 wells and 0.07 with 20 wells.

These relationships are no longer logical. The economics of a field is influenced by the number of wells. Obviously fields with more wells to achieve the same level of production typically require higher capital and operating costs. Nevertheless the relationship contained in the formula is extreme and no longer representative of current conditions.

In an oil field with declining production it is economic under current price conditions on the North Slope, to keep wells operating with well productivities that are well below 300 bopd. This automatically results in the rapid elimination of the ELF.

Also the strong sensitivity of the formula with respect to the number of wells provides an inducement to keep wells flowing that otherwise would be abandoned under normal economic circumstances. In other words producers would be able to manipulate the ELF downward with a "maximum number of flowing wells" strategy.

In 1989 a "marginal well" was set at 300 barrels per day. Today with $ 60 oil prices maintaining a 10 barrel a day well is economic. In effect, the higher the oil price the lower the production from a marginal well and therefore Alaska is very exposed to downward manipulation of the ELF under high oil prices.

Under current economic conditions the relationship between well productivity and the ELF is no longer in the interest of the State of Alaska.

1.3.3. ELF and incremental developments

A rather fundamental "design flaw" of the ELF relates to incremental developments.

Infill drilling in an existing field could result in significant increases in ELF if such wells have high well productivities, for instance in case of horizontal wells. The incremental production would result in a very significant increase in ELF **for the whole field.** For economic purposes the increase in ELF on the whole field needs to be attributed to the economics of the incremental wells.

This means the incremental ELF could be very high and could exceed 1.00.

As a result is it unattractive for companies to increase production in existing fields in case the incremental wells would have a higher well productivity.

This problem is rather important since over the last ten years many satellite fields have been developed. It could be argued that these satellite fields really are economically part of the main field and should be counted as production of the main field. However, over the years the government has approved these satellites as separate developments until some modest adjustments were made as of January 1, 2005.

Therefore, if new wells are drilled in a satellite field the severance tax rate is 0%. If the same additional production is developed as part of the original field the incremental severance tax may be as higher than 15%.

The wide discrepancy of the incremental severance tax rate between a development in the same field and a satellite field is illogical from an economic perspective and it is a major deficiency of the current formula.

The developments on the North Slope during the last decade have resulted in new trends. These trends are:

- Exploration for and development of new "stand alone" fields with maximum field production rates in the 25,000 to 100,000 bopd range.
- Development of satellite fields with maximum production levels in the range of 5,000 to 50,000 bopd.
- A rapid decline in the production of the primary fields.

All these developments result jointly in a situation where the average ELF factor for the production of the total North Slope is declining very rapidly.

This sharp decline in the overall ELF for the North Slope area as a whole is not correlated with rapidly deteriorating economics and is therefore not a reasonable result from a government perspective.

There is ample justification to deal with the current deficiencies in the ELF formula and bring this formula more in balance with reasonable economic conditions and consequences.

1..4. The ELF and international oil prices.

A major deficiency of the ELF factor is that it does not deal with the oil price.

This means that when oil prices are low, the burden on the petroleum industry is very high, while in case of high oil prices, the burden is very modest.

As a result Alaska leaves considerable possible revenues "on the table" during high oil prices and burdens the oil industry unreasonably during low oil prices.

This means that the fiscal system of Alaska is regressive with price. The higher the oil price the lower the share is that the government receives from the operations. This is not logical. It is a very unbalanced situation.

Many other major oil exporting jurisdictions have fiscal systems that are more balanced. The government take either stays more or less the same with higher prices or actually increases.

The recent high oil prices and the recent developments in fiscal terms around the world create a significant new environment which justifies a re-evaluation of the ELF system. In the next chapter a more detailed review will be provided of this matter.

Given the extreme volatility of the oil price during the last decade and the volatility that can be expected during the next decade, the current ELF factor is not appropriate for the circumstances.

1.3.5. Re-investment under the Severance Tax

One of the most important characteristics of the severance tax is that it is essentially based on gross income (after deduction of royalty) rather than net income.

Many jurisdictions have resource taxes, production shares or participations that are based on net income. These features are often applied in addition to a royalty and corporate income tax.

Alaska is one of the few jurisdictions in the world that has a resource tax that is based on gross income.

The fact that most other jurisdictions have fiscal features that are based on net income means that exploration and development expenditures are deductible from gross income. Therefore, payments to government can be reduced by re-investing in the country, through the deductions that can be claimed.

The final result of such fiscal features is that companies that re-invest in the jurisdiction pay less to government than companies that take their profits out.

Such re-investment incentive does not exist in Alaska.

The result of this may be that companies are actually induced through the fiscal terms to take their profits out of Alaska for re-investment in other parts of the world.

Therefore, the current severance tax may not provide sufficient incentive to maintain or increase re-investment in the State.

As an illustration, the table below provides the net investment per dollar related to an exploration well:

Azerbaijan	$ 0.05
Canada, Northwest Terr	$ 0.10
Australia	$ 0.18
Norway	$ 0.22
Qatar	$ 0.22
Brunei	$ 0.25
Malaysia	$ 0.30
Canada, Nova Scotia	$ 0.35
Oman	$ 0.35

Venezuela – Orinoco Belt	$ 0.35
Indonesia	$ 0.38
Thailand	$ 0.45, less depending on level of production
Colombia	$ 0.45
Trinidad & Tobago	$ 0.45
Abu Dhabi	$ 0.50
Kazakhstan	$ 0.55, some agreements much less
Alberta	$ 0.58
China	$ 0.60, less depending on level of production
United Kingdom	$ 0.60
Sakhalin, Russia	$ 0.62, much less depending on level of production
US Gulf of Mexico	$ 0.65
Alaska - Current	**$ 0.65**

As can be seen, the Alaska net exploration costs are among the highest in the world and compare very poorly with other similar frontier areas such as the Canadian North West Territories or Offshore Nova Scotia.

2. NEW INTERNATIONAL TRENDS IN GOVERNMENT TAKE

(Note: parts of this chapter have been published earlier in the Oxford Energy Forum, Volume 63, November 2005)

In general it can be predicted that the higher oil prices will lead to upward pressure on the government take for oil and a stabilization of the government take for gas. It is also likely that governments will base their fiscal terms increasingly on sliding scales which are progressive with oil and gas prices.

2.1. Developments during the last two decades

Over the last twenty years the world arithmetic average government take for oil and for gas has typically declined, from high levels of about 75% during the energy crisis in the late 1970's to about 60% today.

The main reason for the decline of the average government take has been the relative "over supply" of exploration and development opportunities until recently. This was caused by two separate trends:

- new jurisdictions opening up for investment, and
- increased access to petroleum basins through improved technology.

The government take is determined by competition among governments. In essence, the government take is the "price" for the "petroleum properties" a government has available. A large increase in new opportunities creates a drop in "price". Governments were forced to lower government take in order to attract investment or maintain or expand petroleum production. The decline in government take has been stronger for gas than for oil due to the new pipeline and LNG opportunities and large volumes of "stranded" gas.

Since the early 1980's, important new acreage became available for petroleum exploration and production in the People's Republic of China, the former Soviet Union and Eastern Europe, Venezuela, Argentina, Brazil, Bolivia and Peru, Vietnam and Cambodia, and Saudi Arabia and Iran.

During the last two decades we have also seen many new investment opportunities as a result of improvements in technology. Companies now are able to develop oil and gas discoveries in 2000 meter water depth. New pipeline technology, including deep water pipelines, has resulted in connecting many new areas to markets, such as Algeria to Europe. LNG developments now make it possible to ship LNG from Qatar to East Asia.

This significant increase in new development opportunities has resulted in a gradual lowering of the government take during the last two decades.

2.2. Current Situation

This process is now coming to a halt. Except for Kuwait and Iraq, there are no important jurisdictions left in the world that can still be opened up. Most of the continental shelves and slopes are now accessible. Most petroleum basins in the world are now connected to markets through pipelines or LNG shipments. From now onwards, petroleum companies will be forced to "pick over" the existing acreage in order to identify new exploration and development targets.

At the same time a large number of new "buyers" of "petroleum properties" have come in the market. During the last two decades many new petroleum companies from China, Russia, Latin America, Europe, Asia and the Middle East have entered world petroleum exploration and development. Also many small Canadian, Australian and British companies have decided to go "international". These new investors bid aggressively in the available bidding rounds in order to acquire new acreage positions.

Will these new trends in conjunction with the high oil prices drive the government take back up?

2.3. Future

There are two types of fiscal systems with respect to high oil and gas prices:

- Systems that are progressive with price, whereby the government take adjusts upward automatically with higher prices, and
- Systems that are regressive of neutral with price, whereby the government take remains about the same or even declines somewhat with higher prices.

There are a considerable number of countries with progressive systems. There are two ways in which the upward adjustment in government take is taking place.

- *"One Way" adjustments.* These are systems that are based on cumulative profitability. In these systems a higher government take "locks in" once certain levels of IRR, Profitability ratios or cumulative revenues are being reached. In other words if the oil price would decline again, the government take will stay high. These jurisdictions include:
    - IRR based profit oil and gas shares such as in Angola, Russia and Azerbaijan and IRR based profit shares or taxes, such as in Saudi Arabia, the Canadian frontier areas, Australia and Kazakhstan.
    - Profit ratio based profit oil and gas shares in Libya, Qatar, Azerbaijan and India, profit ratio based royalties and taxes in Peru and Tunisia.
    - The PRT in Algeria.

- *"Two Way" adjustments.* These are systems that are based on price related formula or shares. In these systems the government take goes up when prices are high, but the take comes down when prices decline again. This is done through windfall profits taxes,

supplemental payments, uplifts or other mechanisms. Examples are the fiscal systems of Alberta, Colombia, Trinidad and Tobago, Malaysia, Pakistan, Thailand, Indonesia, East Timor, Norway and the Netherlands.

Certain countries have service contracts with fees which are not price sensitive, such as in Iran, Mexico and Venezuela. These countries receive the entire price upside.

As can be seen from the above list, there will be an automatic upward adjustment of government take in a large group of important petroleum producing countries as a result of higher oil and gas prices. In all countries this upward adjustment applies to oil as well as gas, except for Trinidad and Tobago and Qatar where it only applies to oil.

Price Upside Countries.

The countries with regressive or neutral fiscal systems are "price upside countries", where investors will earn a significant "wind fall" as a result of the price increases.

These countries can be divided in two groups:

- Countries with systems that primarily consist of royalties and corporate income tax. In almost all of these countries there are no fiscal stability provisions and therefore governments are free to impose new petroleum taxes.
- Countries with production sharing agreements whereby the percentage profit oil or gas to government is determined on production levels only, rather than certain formulas. Many of these contracts are subject to fiscal stability provisions.

Countries with royalty-tax systems include the United States (federal as well as state fiscal systems), certain provinces of Canada, the Venezuelan concessions, Argentina and Brazil, onshore Australia and the new licenses in the UK.

Countries with production level based production sharing agreements include Congo, Gabon, Egypt, Sudan, Yemen, Bangladesh, certain Indonesian contracts, Vietnam and China.

Trends

The oil supply shortage will induce many countries to have new bidding rounds for remaining acreage or acreage that is being relinquished. The high oil prices and the large number of new companies interested in acreage will result in high bids.

The high bids and the automatic upward adjustment of the government take in many jurisdictions with progressive systems creates a "competitive space" for price upside countries. It makes it easier for these countries to adjust their government take upward without becoming less competitive. This will have the following effects:

- In countries which are not subject to fiscal stability provisions, it can be expected that certain governments will review their fiscal terms in order to determine whether the government take should be adjusted upward through new or increased taxes.
- In countries with contracts that are subject to fiscal stability, it can be expected that a higher government take will be established for new model contracts. In some cases, governments may try to renegotiate certain production sharing contracts.
- Price upside countries will consider moving to price progressive fiscal systems

Some nations are already in the process of reviewing or adjusting their fiscal terms. Venezuela cancelled the royalty holiday on heavy oil development and is currently trying to force investors into the new concession terms. Bolivia just introduced a new hydrocarbon law, which provides for a significantly higher government take. Trinidad and Tobago is reviewing its SPT terms. Kazakhstan is considering new fiscal terms with a very high government take. In the case of Bolivia and Kazakhstan the proposed increases are so strong that they may be counter-productive. Norway introduced a number of interesting small improvements in its fiscal terms, but this process may now come to a halt. Most recently in December 2005 the UK announced that it would increase its overall tax rate applicable to the petroleum industry from 40% to 50%.

Although it can be expected that the government take for oil will start to increase, the strong developments in gas pipeline and LNG technology are still creating significant new gas development opportunities. The ratio between world gas reserves and production is still 68 years and therefore there are considerable stranded gas reserves in nations which are still actively trying to market this gas. Following table[1] provides an overview of the major nations with stranded gas. In addition to the nations listed on the table there are six other nations with more modest gas reserves which are also actively trying to monetize their gas reserves, which are Vietnam, PNG, Peru, Yemen, Myanmar and Syria.

The possibility for still considerable supplies of gas, will depress the trend towards a higher government take. Therefore, the government take for gas may stabilize on average, with some countries leaving government take the same and other countries increasing or decreasing their take on gas.

[1] The table has been derived from the data of the Petroleum Encyclopedia, 2004.

WORLD GAS RESERVES AND PRODUCTION

	Reserves (Tcf)	Productio (Tcf)	Ratio years	
Canada	59	6.5	9.1	
USA	187	19.3	9.7	
Argentina	23	1.3	18.1	
Bolivia	**24**	**0.2**	**136.0**	**stranded gas**
Trinidad&Tobago	26	0.6	43.3	**stranded gas**
Venezuela	**148**	**1.0**	**155.3**	**stranded gas**
Netherlands	62	2.1	29.3	
Norway	75	2.3	32.7	
UK	22	3.6	6.1	
Iran	**940**	**2.3**	**409.7**	**stranded gas**
Iraq	**110**	**0.6**	**194.8**	**stranded gas**
Kuwait	**55**	**0.3**	**173.1**	
Oman	**29**	**0.5**	**54.8**	
Qatar	**910**	**1.0**	**888.9**	**stranded gas**
Saudi Arabia	**231**	**2.0**	**116.9**	
UAE	**212**	**1.6**	**130.6**	**stranded gas**
Algeria	**160**	**2.8**	**56.7**	**stranded gas**
Egypt	**59**	**0.8**	**72.7**	**stranded gas**
Libya	**46**	**0.2**	**217.2**	**stranded gas**
Nigeria	**159**	**0.6**	**250.2**	**stranded gas**
Azerbaijan	**30**	**0.2**	**170.0**	**stranded gas**
Kazakhstan	**65**	**0.4**	**153.4**	**stranded gas**
Russia	**1680**	**19.6**	**85.8**	**stranded gas**
Turkmenistan	71	1.8	40.2	**stranded gas**
Ukraine	**40**	**0.6**	**66.7**	
Uzbekistan	66	1.9	34.6	**stranded gas**
Australia	**90**	**1.2**	**72.8**	**stranded gas**
China	53	1.2	45.5	
India	30	1.0	30.4	
Indonesia	90	2.5	35.9	**stranded gas**
Malaysia	75	1.8	42.5	**stranded gas**
Pakistan	27	0.7	36.4	
Others	222	6.7	33.3	
Total	**6076**	**89.2**	**68.1**	

The speed with which these new trends will develop will depend in part on political developments which could create significant new opportunities, such as

- A stabilization of the security situation in Iraq and subsequent an opening of Iraq for new investment based on attractive contracts,
- The re-introduction of production sharing contracts in Russia.
- A strong opening of Mexico, in particular the deep water acreage.
- Resolution of political issues in Iran together with the introduction of more attractive upstream contracts.

However, none of these four above developments is expected to make a major impact during the next two years.

In general, it can therefore be concluded that it is clear that there is a new international environment with respect to the government take for oil. Previous competitive relationships have now been transformed in a new framework where it is obvious that there will be considerable upward pressure on government take for oil.

This matter justifies a review of the competitiveness of the severance tax in Alaska, in particular with respect to oil.

3. ECONOMIC ANALYSIS

3.1. Preliminary economic studies

During the last two years two broad alternative ways were evaluated to re-structure the severance tax:

- Modifications to the ELF structure, making the ELF more price sensitive and adjusting the ELF formula. This structure also included tax credits in order to encourage re-investment in the State.
- An new Petroleum Profits Tax ("PPT") regime, based entirely on profits and with tax credits in order to encourage re-investment in the State.

A complete study was done on the first option and was updated in the June 2003 report.

Subsequent, to the June 2003 report the Alaska Gas Project negotiations started and it was decided to first evaluate the result of these negotiations before finalizing the plans for a review of the severance tax.

However, during the last year, the high oil prices made an acceleration of the severance tax review imperative. It was decided that the PPT concept was more desirable than revising the ELF.

Geological and technical conditions in Alaska have now become widely different. The Cook Inlet, Yukon Flats, North Slope and other regions reflect very different geological and technical environments. On the North Slope there are very different geological-technical conditions represented by conventional oil fields, gas condensate field, heavy oils, fields in state offshore waters, etc.

The strong increases in oil prices made it obvious that a profit based system was more appropriate on an Alaska wide basis than a more complex ELF concept. Conditions have become too variable and different in order to "capture" all variations in a simple ELF formula.

A profit based system also is a stronger basis for encouraging re-investment and attracting new investment.

For these reasons it was decided to go forward with the introduction of a PPT that would replace the current severance tax for oil and gas.

In this report, the development, the structure and the international competitiveness of the PPT will be evaluated. In particular, the attractiveness of the PPT to new investors will be dealt with.

A separate analysis has been prepared by the Department of Revenue which analyzes the impact of the PPT on overall State revenues, based on the various models in operation by the State. The results of this analysis were presented to the Alaska Legislature.

3.2. Economic assumptions

3.2.1. Cost and field size estimates

In order to test the economics of the PPT, six alternative exploration targets were evaluated, with the following targets:

- 50 million barrels – low well productivity
- 150 million barrels – low well productivity
- 500 million barrels – low well productivity

- 50 million barrels – high well productivity
- 150 million barrels – high well productivity
- 500 million barrels – high well productivity

The production levels and number of wells is of great importance for the ELF calculations. The following assumptions were made:

Field Size	Maximum production	Maximum number of wells	Number of wells at abandonment
(million barrels)	(barrels of oil per day)		
50	13,700	15	8
150	35,600	24	10
500	109,600	52	11
50	13,700	8	2
150	35,600	12	4
500	109,600	28	6

As can be seen the economic runs assume that there will be a considerable number of wells abandoned during the decline of the field. This maintains the ELF factor at a relative attractive level and production taxes will be relatively robust.

If it would have been assumed that few wells would be abandoned, the ELF factors would be substantially less during the decline phase.

It was assumed that the exploration program would have a 1:4 success ratio.

Cost assumptions were made which are reflective of the Alaska North Slope environment. Following are the cost assumptions for each of the six cases in total costs:

COST SCENARIOS
Total Costs

			DRY HOLE	FIELD#1 50MM-LOW	FIELD#2 150MM-LOW	FIELD#3 500MM-LOW	FIELD#4 50MM-HIGH	FIELD#5 150MM-HIGH	FIELD#6 500MM-HIGH
TOTAL OIL PRODUCTION		(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
HIGH COSTS:									
TOTAL CAPEX	Exploration	(m$)	45	45	45	45	45	45	45
	Development	(m$)		375	900	2625	300	675	1500
TOTAL OPEX		(m$)		300.0	750.0	1875.0	225.0	525.0	1500.0
AVERAGE COSTS:									
TOTAL CAPEX	Exploration	(m$)	37.5	37.5	37.5	37.5	37.5	37.5	37.5
	Development	(m$)		312.5	750.0	2187.5	240.0	562.5	1250.0
TOTAL OPEX		(m$)		250.0	625.0	1562.5	187.5	437.5	1250.0
LOW COSTS:									
TOTAL CAPEX	Exploration	(m$)	30	30	30	30	30	30	30
	Development	(m$)		250.0	600.0	1750.0	200.0	450.0	1000.0
TOTAL OPEX		(m$)		200.0	500.0	1250.0	150.0	350.0	1000.0

Following are the per barrel costs:

COST SCENARIOS
Per barrel costs

			DRY HOLE	FIELD#1 50MM-LOW	FIELD#2 150MM-LOW	FIELD#3 500MM-LOW	FIELD#4 50MM-HIGH	FIELD#5 150MM-HIGH	FIELD#6 500MM-HIGH
TOTAL OIL PRODUCTION		(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
HIGH COSTS:									
TOTAL CAPEX	Exploration	(m$)	45	45	45	45	45	45	45
	Development	($/bbl)		7.50	6.00	5.25	6.00	4.50	3.00
TOTAL OPEX		($/bbl)		6.00	5.00	3.75	4.50	3.50	3.00
AVERAGE COSTS:									
TOTAL CAPEX	Exploration	(m$)	37.5	37.5	37.5	37.5	37.5	37.5	37.5
	Development	($/bbl)		6.25	5.00	4.37	4.80	3.75	2.50
TOTAL OPEX		($/bbl)		5.00	4.17	3.12	3.75	2.92	2.50
LOW COSTS:									
TOTAL CAPEX	Exploration	(m$)	30	30	30	30	30	30	30
	Development	($/bbl)		5.00	4.00	3.50	4.00	3.00	2.00
TOTAL OPEX		($/bbl)		4.00	3.33	2.50	3.00	2.33	2.00

It was assumed that the exploration period would be 4 years and that production would start in year 7 of the cash flow.

Broad price sensitivity was done in the $ 10 - $ 60 per barrel range and more detailed analysis in the $ 22 - $ 40 per barrel range.

Escalation and inflation were assumed to be 2% per year.

All cash flows were done in nominal US dollars and all results in this report are expressed on this basis.

A differential of $ 7 per barrel was assumed between the WTI price and the well head price at the North Slope due to transportation and quality differentials.

3.2.2. Profitability indicators

All profitability indicators were calculated on nominal cash flows.

The following profitability indicators were used:

- The internal rate of return on a cash flow basis (IRR). This indicator illustrates how fast profits are being made and the attractiveness of the cash flow relative to the investment.
- The net present value discounted at 10% (NPV@10%). This indicator illustrates the present value of an investment. It is a good indicator of the total amount of profits that is being made with the venture.
- The expected monetary value at 10% (EMV@10%). This is the weighted average of the exploration investment discounted at 10% and the NPV@10%. A success ration of 1:4 was used. This indicator illustrates the attractiveness of the fiscal system for exploration. A high EMV@10% is obtained through a high NPV@10%, or low net exploration expenditures (for instance as a result of exploration tax credits).
- The undiscounted Government Take. This is a good indicator of percentage that the government receives of the long term pre-tax cash flow. The remaining cash flow is the Corporate Take. A low Government Take and high Corporate Take is attractive to companies, in particular on large fields, since it indicates a long and large undiscounted cash flow.

4. ANALYSIS OF THE PETROLEUM PROFITS TAX ("PPT")

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in order to provide maximum information about the PPT it is desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

4.1. PPT terms of the 20/15 system.

Following is a description of the 20/15 option, which was used for much of the international comparative analysis.

The PPT is based on the yearly cash flow from oil and gas in Alaska of the tax payer (company). The PPT is therefore consolidated at the level of the company, not calculated on the basis of individual leases as is currently the case for the severance tax.

The PPT rate is 20% of the positive cash flow.

In order to calculate the Alaska cash flow for the company, the company takes all oil and gas gross revenues and deduct all lease expenditures, being capital and operating expenditures. These expenditures will be defined in more detail in the new PPT legislation. All expenditures are deducted in the year these costs are incurred for the full amount. In other words, it is not required to depreciate the capital expenditures.

If there is a negative cash flow, 20% of the "loss" can be converted to a tax credit against future PPT obligations. These tax credits can be traded with other companies.

Furthermore, there will be a 15% tax credit on all capital expenditures. These tax credits can also be traded.

In order to attract new investors and to protect the smaller companies in Alaska, there is a tax free allowance for the first $ 200,000 per day cash flow for a maximum of up to $ 73 million per year.

In other words if the positive cash flow is $ 40 million in a year, this amount will not be subject to tax. However, the $ 33 million difference between the $ 73 million maximum and the $ 40 million can not be used or carried forward. If the positive cash flow is $ 100 million per year, only $ 27 million will be subject to PPT.

If there would be a Stranded Gas Contract with the current Sponsors, and if this contract provides for taking tax gas in kind, than the respective provisions that would modify the general PPT law will be in the contract.

4.2. PPT analysis

The PPT payments depend on whether a field is developed while a company is benefiting in total or in part of the tax free allowance of up to $ 73 million. The economics will therefore be analyzed with and without the benefit of such allowance.

The large companies will receive the allowance, but most of their production operations under average oil prices will result in profits well above the $ 73 million and therefore new field investment will not benefit from this allowance.

The following table provides the general overview of all low and high well productivity cases that were studied for a $ 40 per barrel scenario for the first investment in Alaska which fully benefits from the $ 73 million tax free allowance.

PPT GOVERNMENT TAKE WITH $ 73 MILLION TAX FREE ALLOWANCE

		DRY HOLE	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
TOTAL OIL PRODUCTION	(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
TOTAL GROSS REVENUES	(m$)	0.0	2115.2	6565.2	22620.3	2115.2	6565.2	22620.3
TOTAL CAPEX	(m$)	46.8	472.7	1075.5	3082.1	397.6	825.4	1789.9
TOTAL OPEX	(m$)	0.0	389.3	1018.1	2654.3	290.0	708.6	2107.2
DIVISIBLE INCOME	(m$)	-46.8	1253.1	4471.5	16883.9	1427.5	5031.1	18723.2
ROYALTIES	(m$)	0.0	264.4	820.6	2827.5	264.4	820.6	2827.5
PPT	(m$)	-16.4	-86.5	234.4	1884.4	-42.0	381.9	2443.4
PROPERTY TAXES	(m$)	0.0	28.3	86.3	292.3	28.3	86.3	292.3
STATE CORPORATE TAX	(m$)	-2.9	98.4	313.0	1116.7	111.3	351.8	1237.0
TOTAL ALASKA	(m$)	-19.3	304.6	1454.4	6121.0	362.0	1640.7	6800.3
FEDERAL INCOME TAX	(m$)	-9.7	332.8	1058.7	3776.5	376.4	1189.7	4183.6
GOVERNMENT INCOME	(m$)	-28.9	637.4	2513.0	9897.5	738.4	2830.3	10983.8
STATE TAKE:		41.1%	24.3%	32.5%	36.3%	25.4%	32.6%	36.3%
FEDERAL TAKE:		20.7%	26.6%	23.7%	22.4%	26.4%	23.6%	22.3%
GOVERNMENT TAKE:		61.8%	50.9%	56.2%	58.6%	51.7%	56.3%	58.7%

The table illustrates a number of issues. Is shows how there would be a very significant support for an exploration well or dry hole from government. The PPT losses than can be converted into credits, the investment credits and the benefit from state and federal tax deductions would be in total 61.8% of the cost of the dry hole.

On the small 50 million barrel fields the PPT is negative. This means that the company will not pay PPT because it is benefiting from the $ 73 tax free allowance, but the company can trade the loss credits and the investment credits and receive the benefits of the tax credits.

The table also shows how the PPT becomes quite substantial in case of a large field. The equivalent PPT rates are provided below. The equivalent PPT rates are the production tax rates that would equate to the PPT payments. For the 50 million barrel field these rates are negative.

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
EQUIVALENT PPT RATES	-4.67%	4.08%	9.52%	-2.27%	6.65%	12.34%

The following table shows the results for a company who has already used its tax free allowance and considers reinvestment in new fields.

PPT GOVERNMENT TAKE FOR A COMPANY THAT HAS ALREADY USED ITS TAX FREE ALLOWANCE

		DRY HOLE	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
TOTAL OIL PRODUCTION	(MMbbls)	0.0	50.0	150.0	500.0	50.0	150.0	500.0
TOTAL GROSS REVENUES	(m$)	0.0	2115.2	6565.2	22620.3	2115.2	6565.2	22620.3
TOTAL CAPEX	(m$)	46.8	472.7	1075.5	3082.1	397.6	825.4	1789.9
TOTAL OPEX	(m$)	0.0	389.3	1018.1	2654.3	290.0	708.6	2107.2
DIVISIBLE INCOME	(m$)	-46.8	1253.1	4471.5	16883.9	1427.5	5031.1	18723.2
ROYALTIES	(m$)	0.0	264.4	820.6	2827.5	264.4	820.6	2827.5
PPT	(m$)	-16.4	121.2	551.6	2290.5	167.3	701.0	2852.2
PROPERTY TAXES	(m$)	0.0	28.3	86.3	292.3	28.3	86.3	292.3
STATE CORPORATE TAX	(m$)	-2.9	78.9	283.2	1078.5	91.6	321.8	1198.6
TOTAL ALASKA	(m$)	-19.3	492.8	1741.7	6488.8	551.6	1929.7	7170.6
FEDERAL INCOME TAX	(m$)	-9.7	266.8	957.8	3647.5	309.9	1088.2	4053.6
GOVERNMENT INCOME	(m$)	-28.9	759.6	2699.6	10136.3	861.5	3018.0	11224.2
STATE TAKE:		41.1%	39.3%	39.0%	38.4%	38.6%	38.4%	38.3%
FEDERAL TAKE:		20.7%	21.3%	21.4%	21.6%	21.7%	21.6%	21.7%
GOVERNMENT TAKE:		61.8%	60.6%	60.4%	60.0%	60.3%	60.0%	59.9%

It can be seen how the same exploration incentive is being provided. However, now the PPT on small fields is positive and generally the PPT is higher, resulting in a lower corporate income tax.

The equivalent PPT rates now range up to 14.41%. In other words under favorable field and price conditions the PPT is essentially restored to a situation that would be equivalent a PPT without ELF with the blended rate of 12.25% and 15%.

	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
EQUIVALENT PPT RATES	6.55%	9.60%	11.57%	9.04%	12.20%	14.41%

The equivalent rates also show how the PPT is progressive with field size and costs

The same is true for prices.

Following table provides the equivalent rates based on WTI prices:

PPT EQUIVALENT RATES FOR PRODUCTION TAX

WTI	50MM-LOW	150MM-LOW	500MM-LOW	50MM-HIGH	150MM-HIGH	500MM-HIGH
$20	-14.15%	-6.40%	-1.39%	-7.82%	0.21%	5.81%
$30	0.70%	5.08%	7.91%	4.28%	8.81%	11.98%
$40	6.55%	9.60%	11.57%	9.04%	12.20%	14.41%
$50	9.68%	12.02%	13.53%	11.59%	14.02%	15.71%
$60	11.62%	13.53%	14.75%	13.18%	15.15%	16.52%

As can be seen from the table, with a WTI price of $ 20 per barrel and a net back of $ 13 and costs of $ 13.50 per barrel as assumed for the 50 MM barrel case, the producer would sell his tax loss credits and his tax investment credits to others. It should be noted, however, that the PPT bill provides for the fact that the PPT cannot be negative, therefore, in a situation where all producers would have a loss in a year, the State would not be out of pocket on the PPT. There is no "negative" PPT on an Alaska wide basis.

At very high prices, the PPT would be equivalent to a 16.52% production tax without ELF.

It can be noted how the PPT is very progressive in terms of the production tax equivalent rate with field size, field costs and price for a situation where large producers have already used their tax free allowance.

The system is more progressive with field size as illustrated above, where the field is the first investment.

4.3. PPT payments

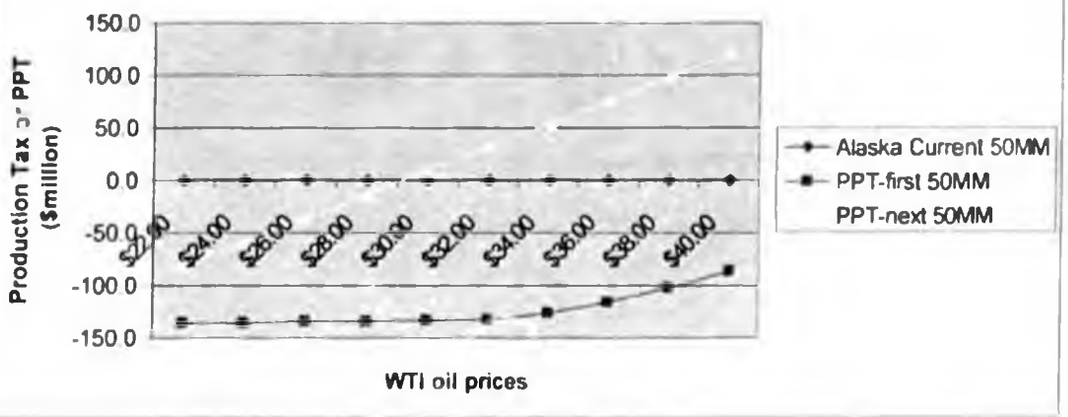
High Cost Fields

The following graphs illustrate the PPT payments relative to the current severance tax that would result under three cases:

- 50 million barrels, low well productivity, high costs
- 150 million barrels, low well productivity, high costs
- 500 million barrels, high well productivity, high costs

The economics with the tax free allowance is indicated as "First" in the graphs and without the tax free allowance as "Next".

Chart 4.1. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

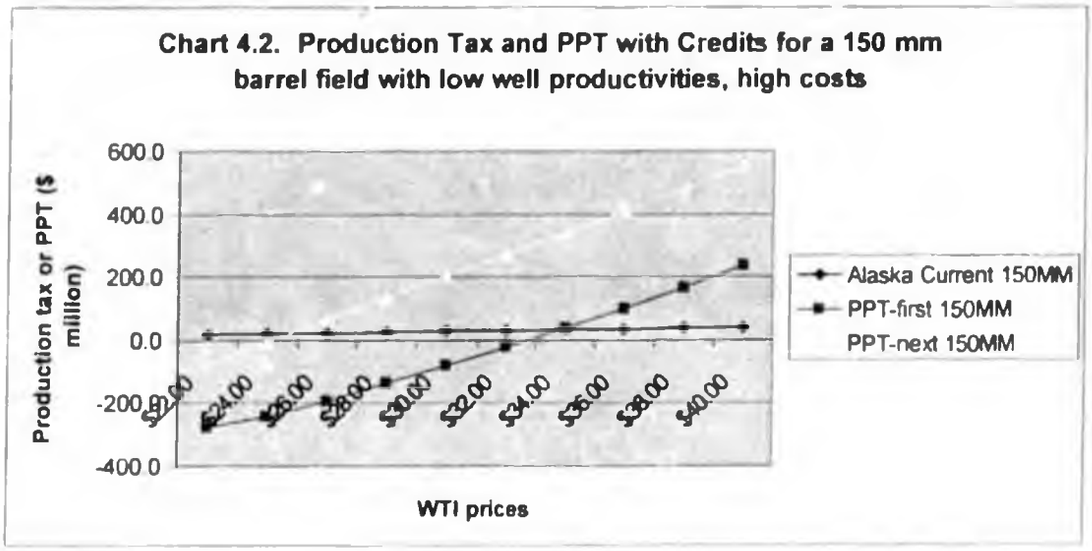


As can be seen from the 50 million barrel graph, a new investor or a small company developing a 50 million barrel field would not pay any PPT in the $ 22 - $ 40 per barrel price range. This is because the yearly tax free allowance would eliminate the obligation to pay taxes. However, such an investor would nevertheless receive the tax credits, whenever the cash flow is negative or as a result of his capital expenditures. These tax credits can be traded. Therefore, the new or small investors receives significant support through the PPT for such an investment.

Under the current severance tax system there is only an exploration tax credit which is being phased out (not included in this analysis). Therefore, the PPT is significantly more attractive to a new or small investor than the current severance tax with the ELF structure, despite the fact that under the current ELF there would be no severance tax payable on the 50 million barrel field.

A large oil company re-investing in a 50 million barrel field as provided in Chart 4.1 will find that for WTI prices below $ 29 per barrel the tax credits received under the PPT are higher an the PPT payable prior to tax credits and therefore PPT is "negative" and therefore this is better than the current severance tax. Over the $ 29 per barrel there is PPT payable and the system results therefore in more tax. Of course, these WTI benchmarks depend on the economic assumptions about capital and operating costs, production profiles, etc.

The 50 MM barrel high cost and low well productivity case is a very important benchmark for large producers because this is a fairly representative case of most of the incremental developments that may take place on the North Slope. This case will therefore see a significant improvement of overall economics while on average there is no increase in tax (assuming that large companies maintain a long term price forecast in the $ 25 to $ 30 range).



For the 150 million barrel field as assumed in our economic analysis a low amount of severance tax would be payable under the current system.

For a new investor, the cash flow under high prices would exceed the tax free allowance. Also the relative importance of tax credits is less. Therefore, PPT would be payable for WTI prices in excess of $ 33 per barrel. Below these prices the PPT would be less than the current system and would be negative.

A large oil company re-investing in a 150 million field would find a break-even point at a WTI price of $ 25 per barrel relative to the current system. Over this price the company would pay more tax.

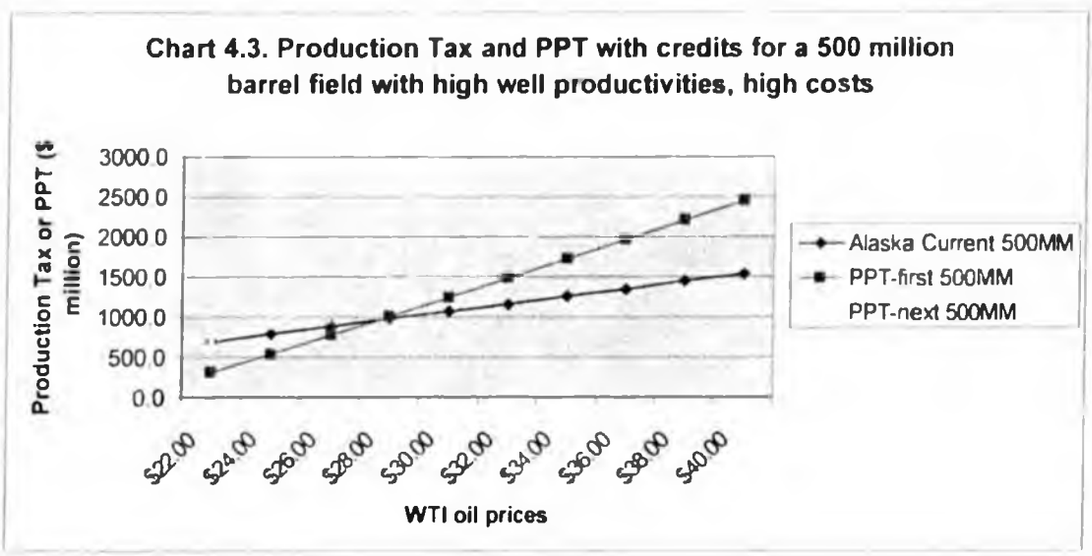


Chart 4.3 shows how for a 500 million barrel field with high well productivities, but high costs, the PPT results in more tax for a new investor at a break even WTI price of $ 29 per barrel and a large oil company would have a break even WTI price of $ 22 per barrel.

Lower Cost Fields

Because the PPT is profit sensitive and provides incentives through the tax credits, the break even WTI prices depend very much on cost assumptions. The graphs below show the same field 150 million barrel field of Chart 4.2, but now for lower costs.

Chart 4.4 shows how the WTI break even price for a new investor in a 150 million barrel field would drop from $ 33 to $ 31 per barrel, when average costs are being assumed. For a large company it drops from $ 25 to $ 22 per barrel.

Chart 4.4. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, average costs

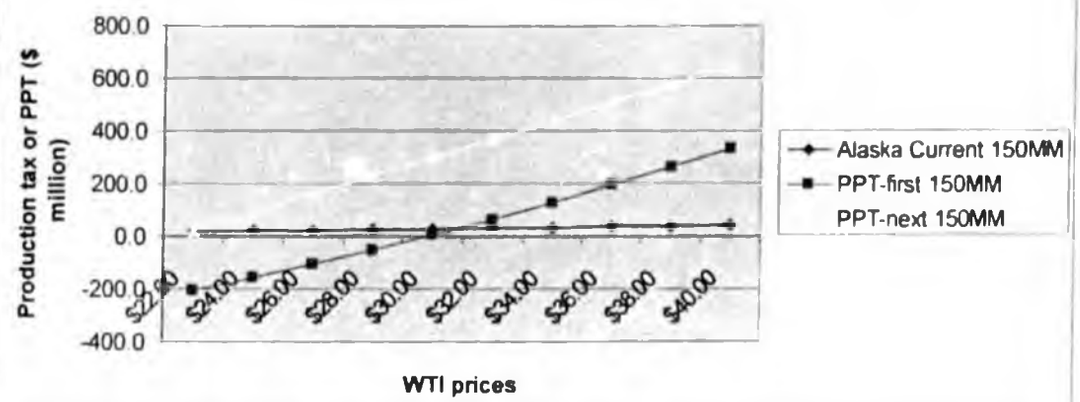
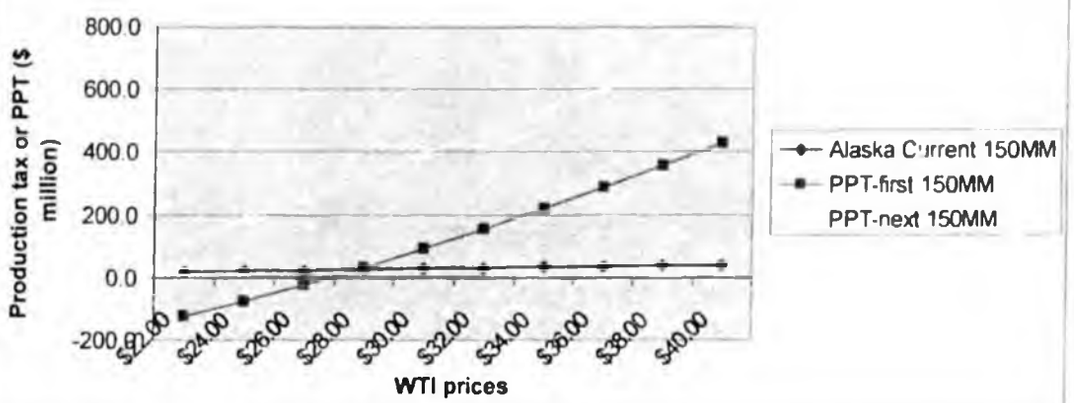


Chart 4.5. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, low costs



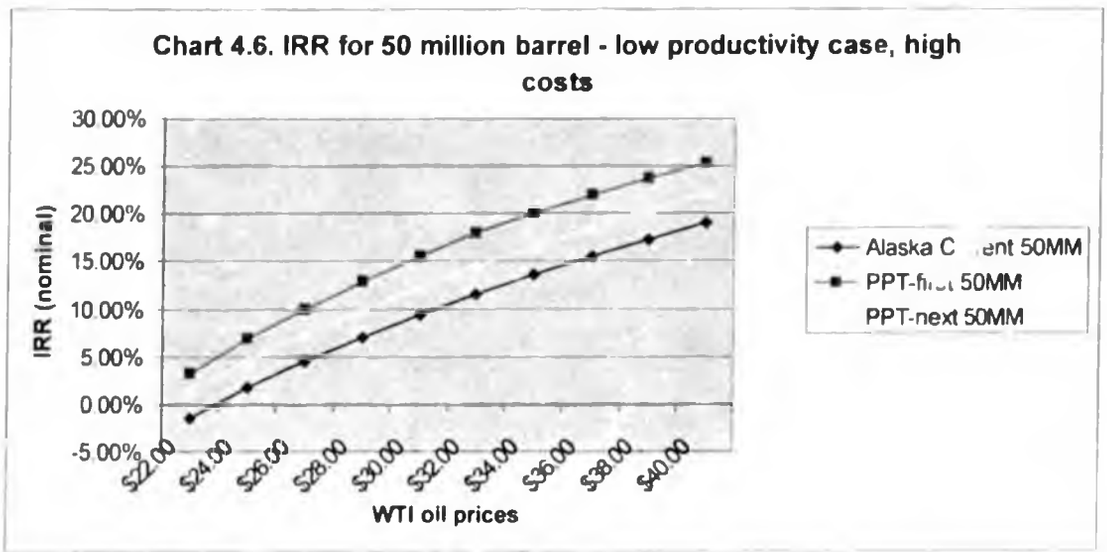
For low costs assumptions the WTI break even prices drop to $ 29 and $ 19 respectively as can be seen on Chart 4.5.

4.4. Investor economics

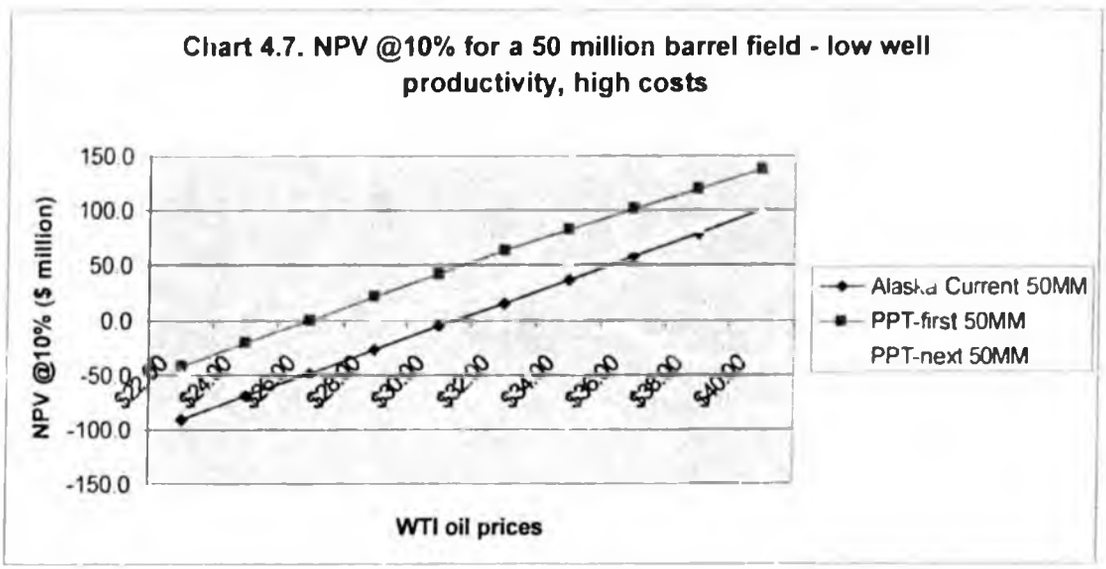
The investor economics are different depending on the field sizes.

50 million barrels

The following three graphs show the investor economics for the 50 million barrel field.



The IRR is much higher for the new investor or small investor and therefore small fields will become much more attractive targets. However, even for the large oil companies the IRR on small fields would improve considerably as a result of the tax credits, even if companies have already used their tax free allowance.

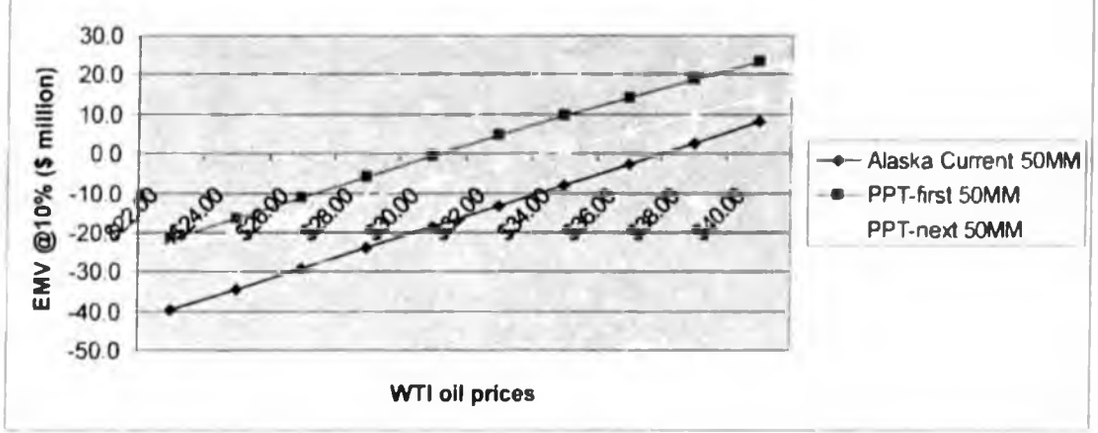


The NPV@10% is much better for new and small investors. For large companies, which have already used their tax free allowance, the NPV break even point is a WTI price of $ 40 per barrel.

For lower cost 50 million barrel fields the WTI break even prices for the NPV@10% are lower, as indicated in the small table below.

	First 50 million	Next 50 million
High Costs	< $ 60	$ 40
Average Costs	< $ 60	$ 35
Low Costs	<$ 50	$ 30

Chart 4.8. EMV @10% for a 50 million barrel field - low well productivity, high costs



The EMV@10% is much better for small and new investors. For large oil companies who have already used their tax free allowance, the EMV has a break even price which is in excess of $ 50 per barrel. This indicates that even for large oil companies, small fields would be more attractive exploration targets up to rather high WTI price levels under the PPT.

For EMV@10% the WTI breakeven prices are lower under lower costs, but higher than the NPV values.

Generally, the PPT makes exploration for 50 million barrel fields and their development economically more attractive, in particular at low or average prices.

150 million barrels

For the 150 million barrel field with low well productivities and high costs, the IRR is always much better for a new or small investor and also for a large company.

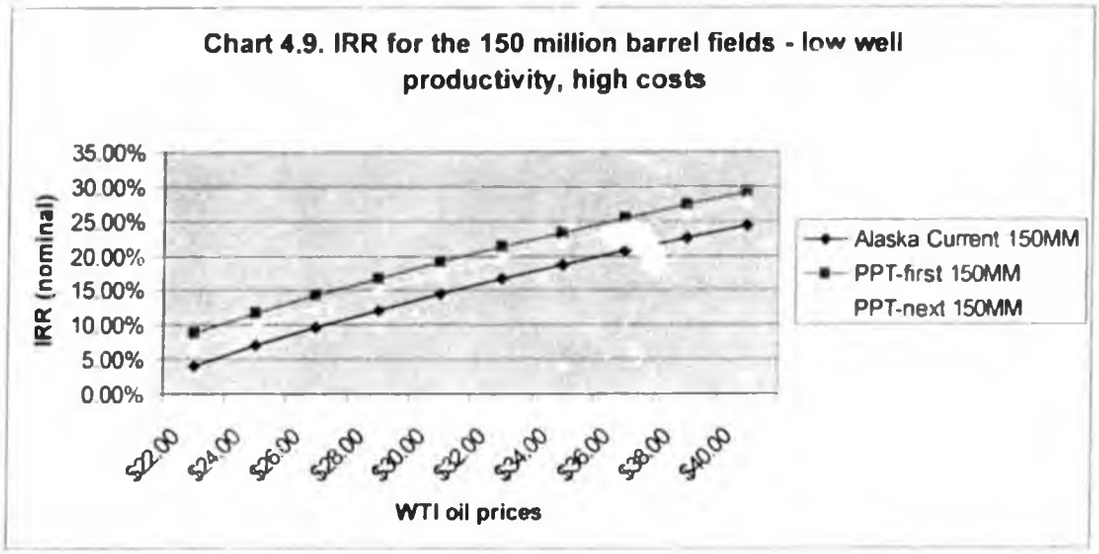
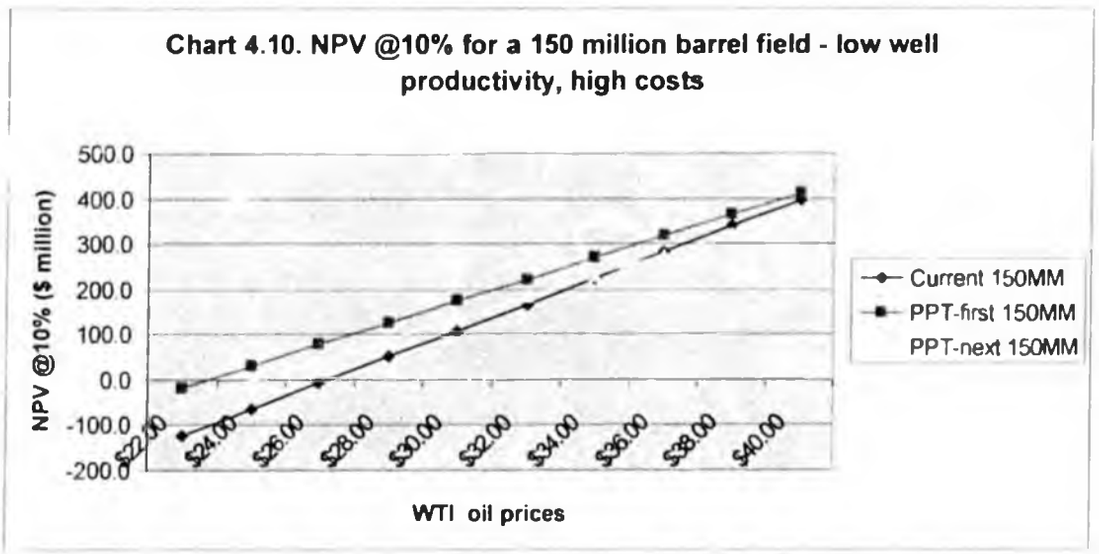
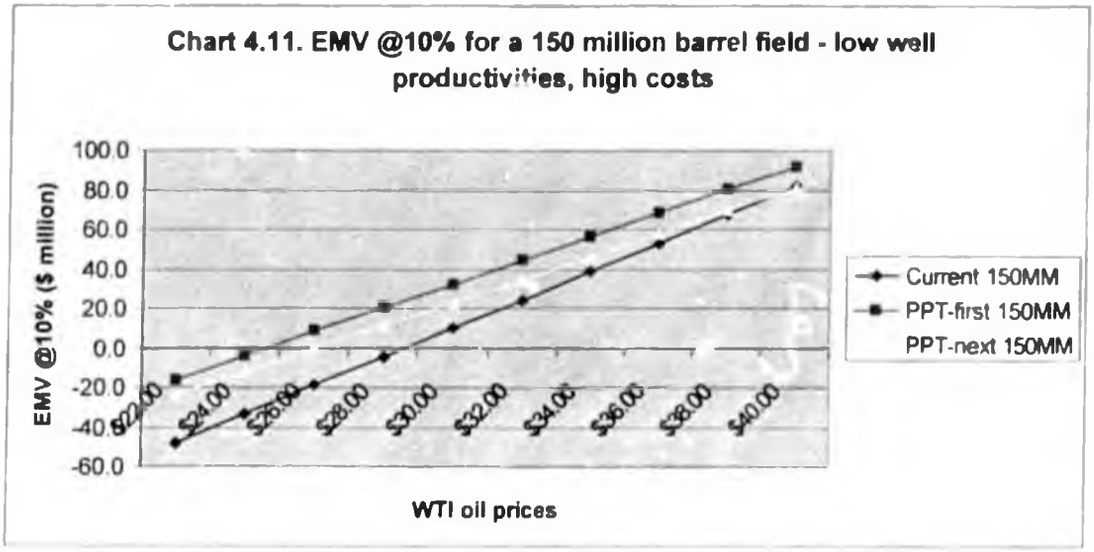


Chart 4.10 illustrates how also the NPV@10% for a 150 million fields for a new or small investor is better over $ 40 per barrel. The WTI break even point is about $ 35 per barrel for a large company, which has already used the tax free allowance.



The EMV@10% for a 150 million barrel field is better for a WTI price range of well over $ 40 per barrel. The WTI break even point for a large company is about $ 39 per barrel.

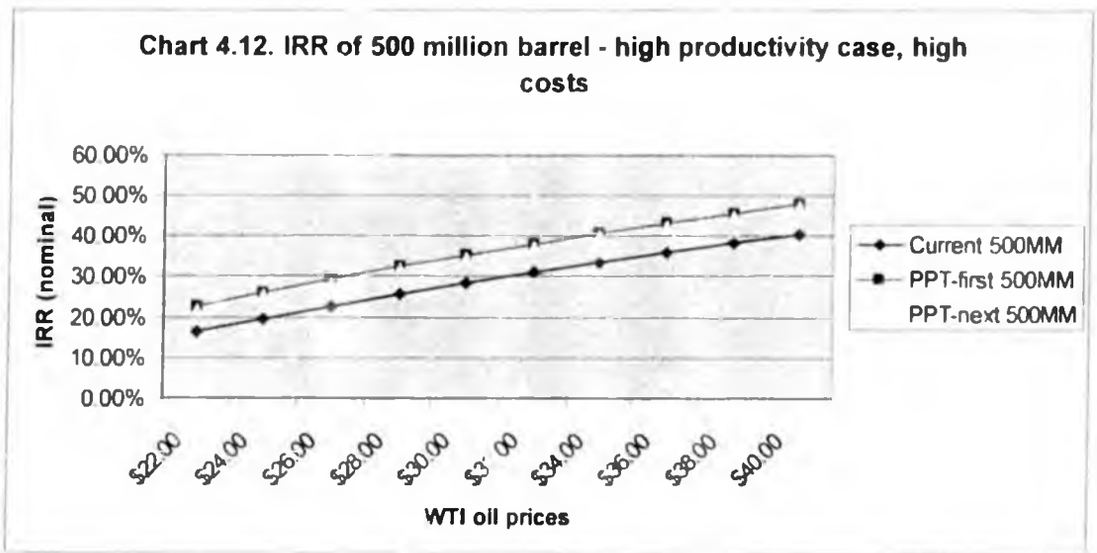


For the average and low cost scenarios, the break even points are somewhat less.

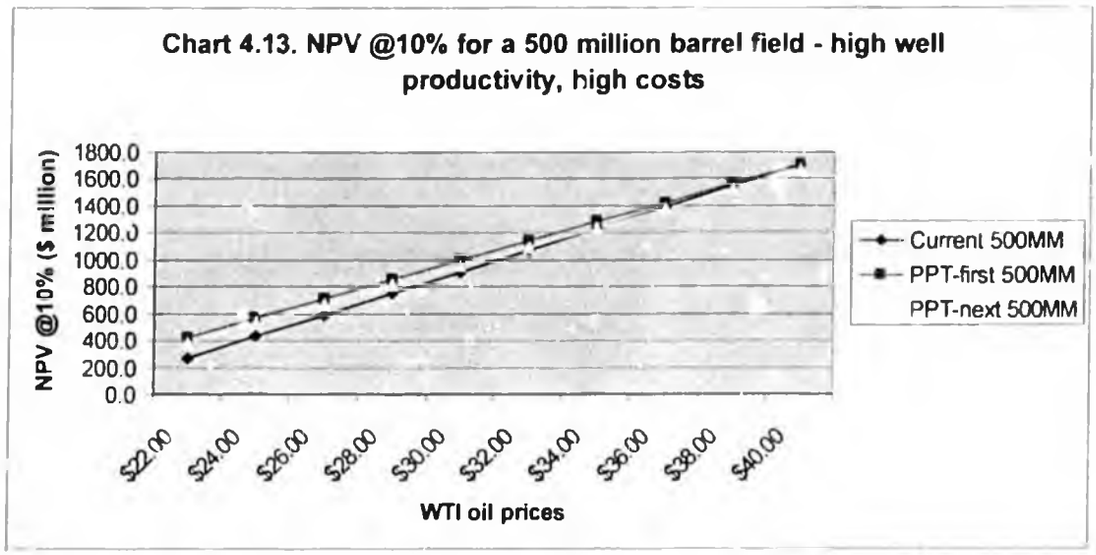
The analysis for the 150 million barrel field indicates that the economics of this field improves for both the new investor and large oil companies, in particular under low and average oil prices.

500 million barrels

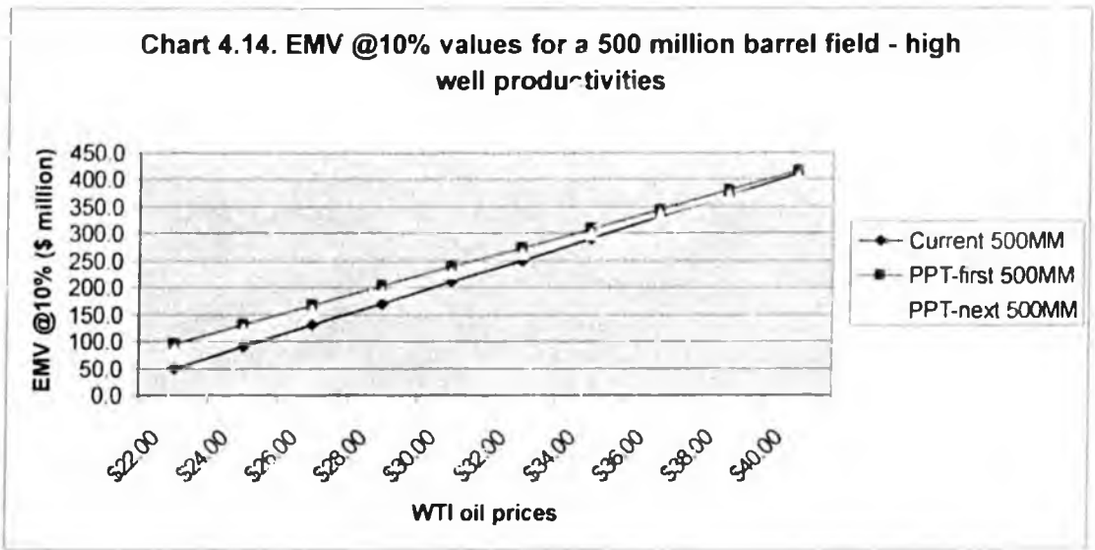
Even for a large field of 500 million barrels, the IRR improves considerably for both the new investor and a large company.



For the NPV@10% and EMV@10%, the WTI break even price for the 500 million barrel fields is about $ 40 per barrel for the new investor and $ 34 per barrel for a large company which already applied its tax free allowance.



For lower costs the break even prices for the NPV@10% and EMV@10% are somewhat lower. For the 500 million barrel, high well productivity, low cost case, the break even price of the NPV@10% is about $ 26 per barrel and for the EMV@10% about $ 28 per barrel for large companies.



It can be concluded that for a 500 million barrel field, the economics for new investors and large oil companies is better under the PPT, in particular for low prices.

Conclusion

In general it can be concluded that the PPT based on 20% tax and a 15% tax credit improves the IRR considerably of investments by new investors or large oil companies.

For targets in the 50 – 150 million barrel range, the NPV@10% and EMV@10% is typically better for new investors over a wide price range. For large oil companies, who have already used their tax free allowance, the NPV@ and EMV@10% is typically better for low and average prices.

For large targets, the NPV@10% and EMV@10% is typically better for low prices and for new investors also for average prices.

In general, the PPT will be a strong encouragement to invest for new investors or to re-invest for small investors since the profitability of ventures under the PPT well exceeds that of the current system.

For large companies with price expectations in the $ 25-$30 per barrel range, the PPT is more attractive from an IRR perspective and equally attractive from an NPV@10% or EMV@10% perspective than the current system. For small fields in the 50 million barrel class the tax is zero at the long term price range.

In general therefore the introduction of the PPT can be expected to result in a higher level of activity in the North Slope and other areas of Alaska.

5. ANALYSIS OF ALTERNATIVE PETROLEUM PROFITS TAX ("PPT") CONFIGURATIONS

(Note: After the initial scoping a PPT tax rate of 20% and a credit rate of 15% seemed a reasonable combination. Therefore much economic work was done on this combination. As a result of subsequent work it was concluded that a 25% tax rate and 20% tax credit rate is more in the interest of Alaska. Nevertheless in the interest of providing the maximum information about the PPT it was considered desirable to leave the Chapters that were based on the 20% tax rate and 15% credit rate in the report. These are Chapters 4,5,6,7 and 8. Chapter 9,10 and 11 are based on the recommended fiscal terms.)

5.1. PPT Rate

5.1.1. PPT income

Sensitivity analysis was done on the PPT rate. Rates from 10% to 30% were studied in detail. The following graphs show the results for the PPT income compared to the current severance tax for 10%, 20% and 30% PPT. These rates were analyzed in conjunction with a 15% tax credit on all capital. The negative cash flow credits were also adjusted to 10% of the negative cash flow, 20% and 30%.

For clarity, the $ 73 million yearly tax free allowance was not included in this analysis. The investment economics are therefore from the perspective of a re-investment by a large petroleum company who has already used the tax free allowance.

The following Charts 5.1, 5.2 and 5.3 show the PPT compared with the current severance tax for the three field combinations that were also displayed earlier in Chapter 4.

Chart 5.1. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

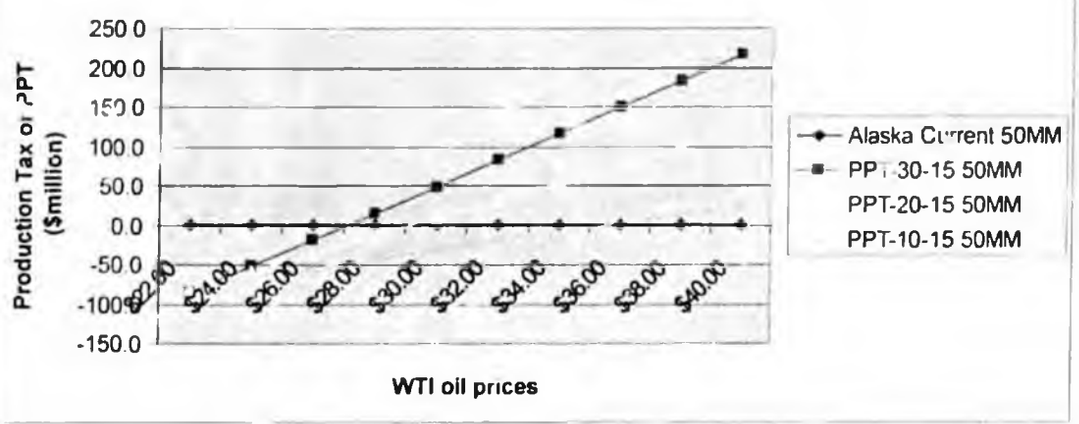


Chart 5.1 shows that a PPT of 10% would be less below WTI prices of $ 36 per barrel, a PPT of 20% would have a WTI break even point of $ 29 and a PPT of 30% a WTI break even point of $ 27 per barrel.

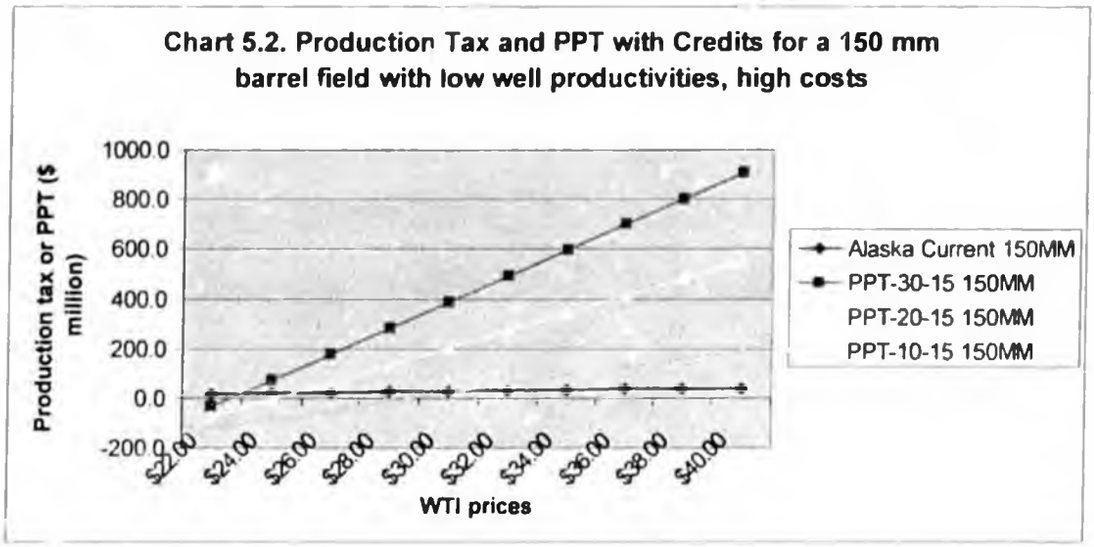


Chart 5.2 shows that a PPT of 10% would be less below WTI prices of $ 31 per barrel, a PPT of 20% would have a WTI break even point of $ 25 and a PPT of 30% a WTI break even point of $ 23 per barrel.

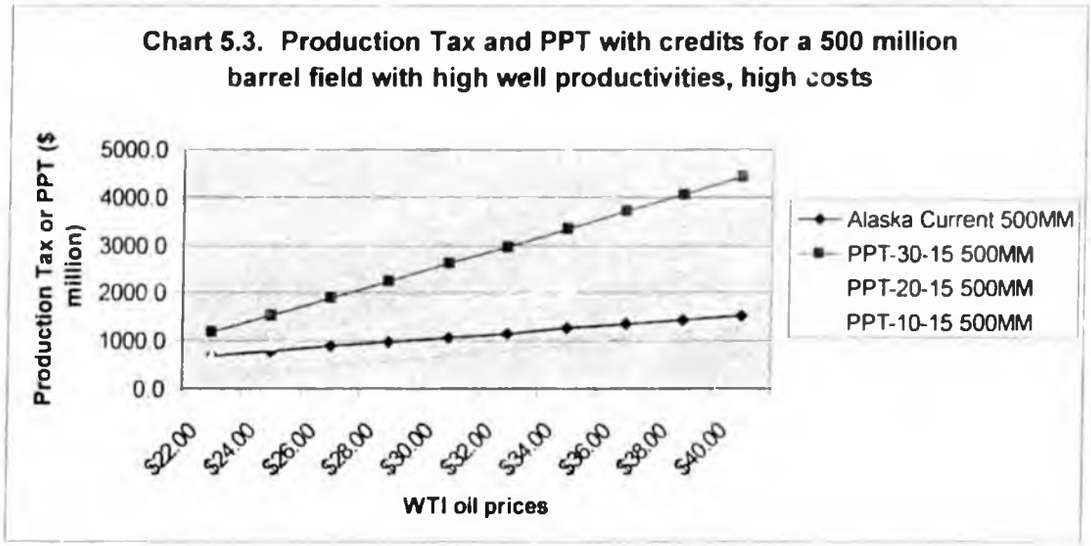


Chart 5.3 shows clearly that a 10% rate would result in less PPT than the current severance tax for the 500 million barrel field for the entire price range.

A PPT of 20% would have a break even point of $ 22 per barrel and a PPT of 30% would have a much lower break even point.

From these graphs it is clear that a PPT of 10% would be unattractive to Alaska. Both a PPT of 20% or 30% would be attractive and would under reasonable prices result in considerably more revenues for Alaska.

In chapter 8 the international competitiveness of the PPT with respect to re-investment will be analyzed and this analysis will conclude that a 30% rate would be too high.

The following graphs provide more detail for PPT rates between 15% and 20%.

Chart 5.4. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

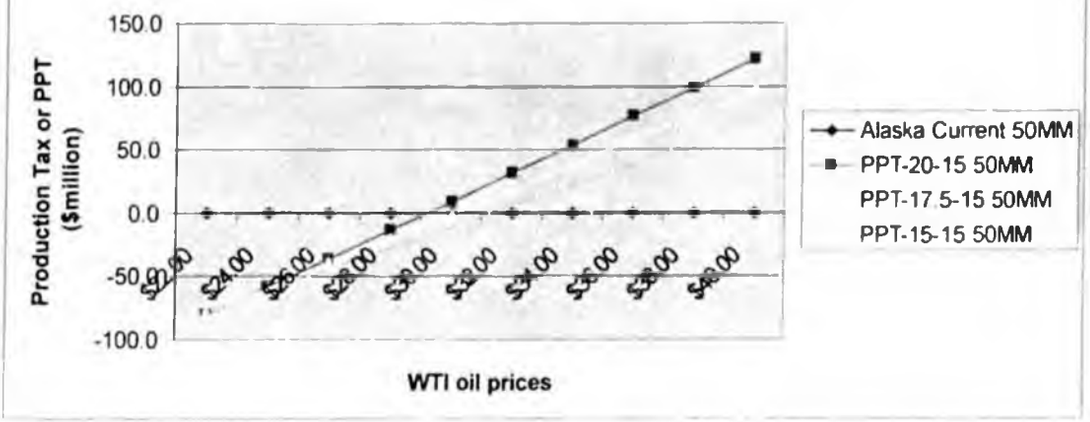
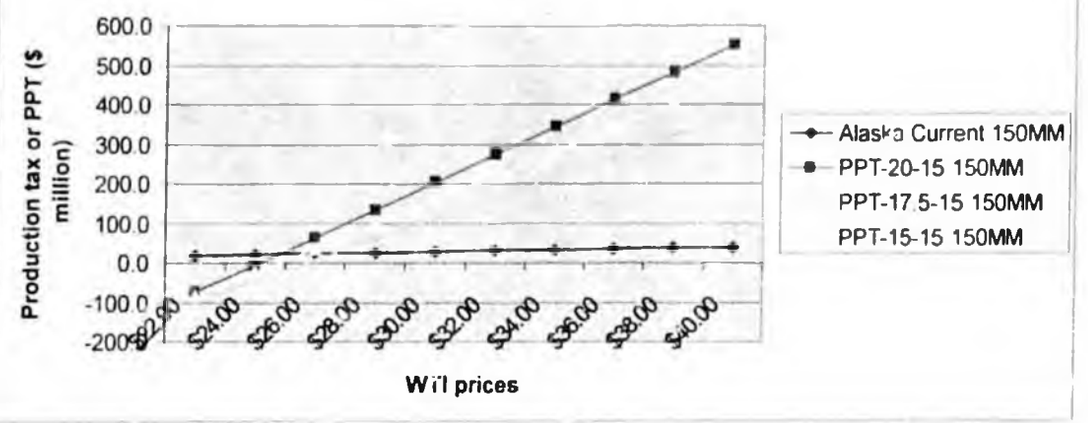
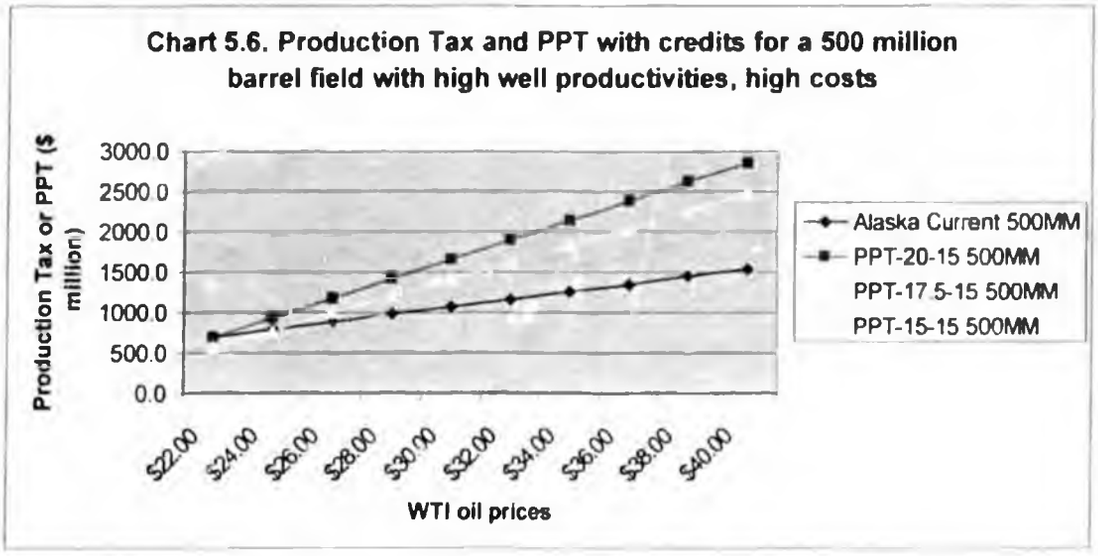


Chart 5.5. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs





It can be seen how even a 15% rate would not provide a clear advantage to Alaska. The WTI break even points for the various fields are too high. The WTI range of $ 27 - $ 31 would expose Alaska too much to the possibility that PPT revenues would actually be less than the current severance tax under average price scenarios.

Only the 20% rate seems reasonable from an Alaska perspective. This rate has a WTI break even range of $ 22 - $ 29 per barrel.

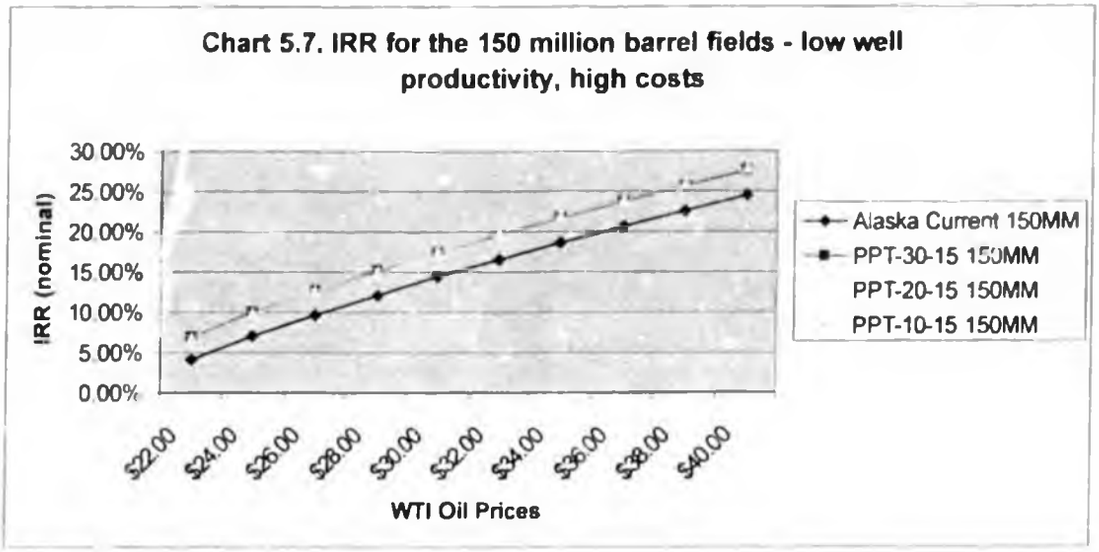
5.1.2. Impact on Investors

The following graphs are for the 150 million barrel field. However, the results for the other fields are similar in trend and nature.

Under all PPT rates the IRR is approximately the same and is much higher than the under the current severance tax. Whether the PPT rate is 30% or 10% results about in the same IRR. The reason is the fact that the negative cash flow losses can be converted into tax credits at the PPT rate and these credits can be traded. In other words the State of Alaska equally shares in the negative and positive cash flow. This creates a situation where the IRR is about the same for a high or low PPT rate. It should be remembered that the IRR is a profitability yardstick which measures the speed at which profits are being made, not the amount of profits.

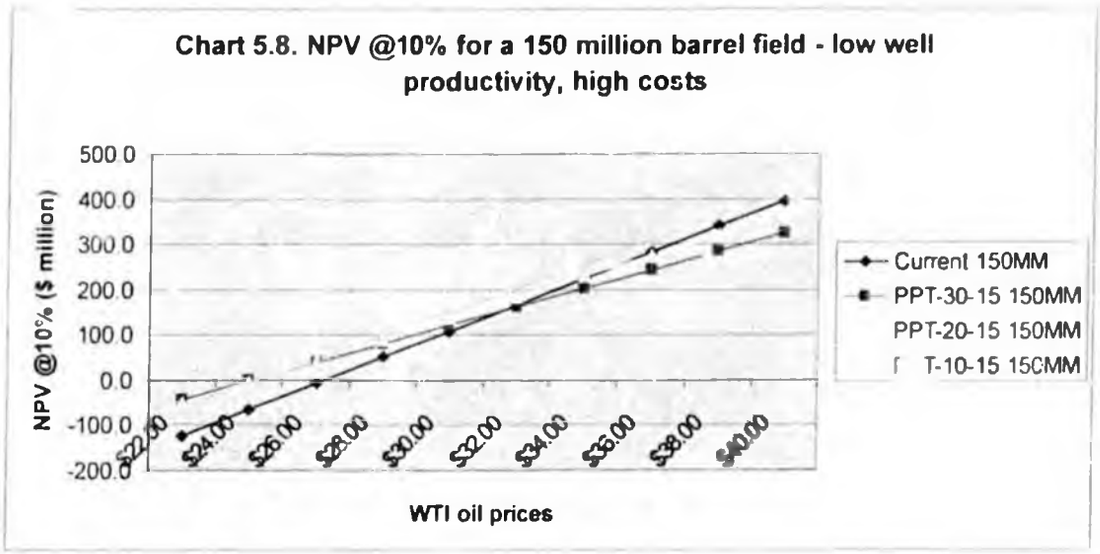
Additionally, there are the 15% tax credits on capital expenditures, which are unaffected by the PPT rate.

The IRR effect of different rates can be seen in Chart 5.7.



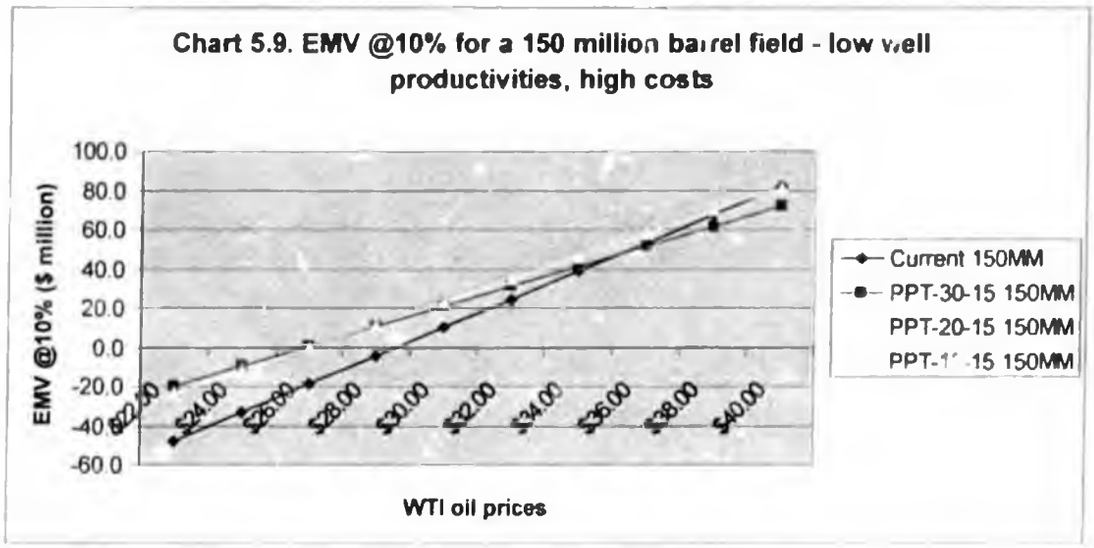
The NPV@10% nominal is, of course, affected by the PPT rate. As can be expected a PPT rate of 10% will result in a NPV@10% that is better than the current severance tax for the entire price range.

A PPT rate of 20% would result in a WTI price cross over point of US $ 35 per barrel and a PPT rate of 30% in a cross over point of US $ 32 per barrel.



Also on an EMV@10% basis, the PPT rate of 10% would be better than the current system for the entire price range used in this report.

The cross over points are a WTI price of US $ 39 per barrel for the 20% PPT and $ 35 for the 30% PPT.



Conclusion. From a large existing producer perspective the combination of a PPT rate of 10% and a tax credit rate of 15% would create economics that would be better than the current system for the entire price range. A 20% PPT rate would have a better IRR, but would have cross over points for the NPV@10% and EMV@10%, whereby at high prices, the current system would be more attractive.

5.2. Tax Credit Rate for Capital Expenditures

An important factor in the total package is the tax credit on capital expenditures. Therefore, a sensitivity analysis was done on this matter.

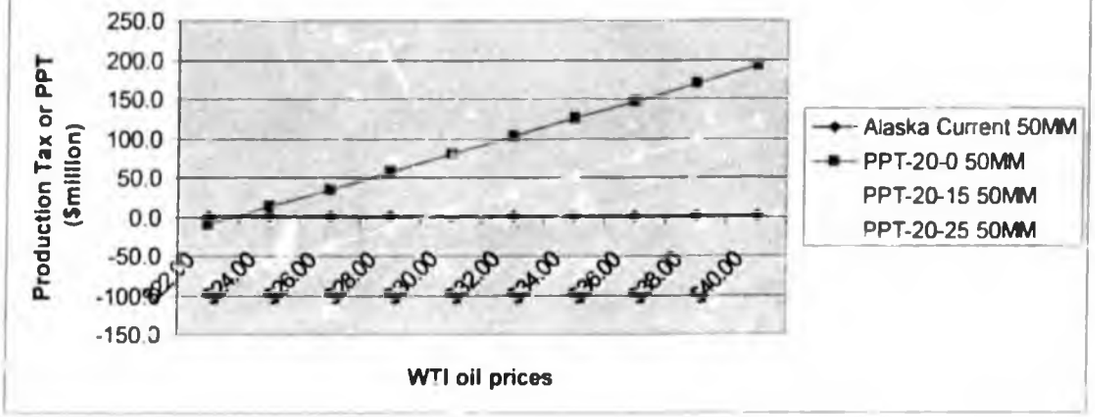
5.2.1. Impact on PPT

The impact of the tax credit on capital expenditures is independent of price. The tax credit is a fixed amount and depends on the level of capital expenditures, not the price. Therefore, in Chart 5.10 it can be noted that the PPT curves for the various levels of tax credit are parallel.

Chart 5.10 shows that above a WTI price of $ 22 per barrel, the PPT based on a 20% rate with no tax credits on capital expenditures would result in a significant level of PPT for a small field, compared with zero severance tax under the current system.

A PPT of 20% without tax free allowance and without a tax credit would therefore result in a rather negative impact on small companies and new investors. This was an important reason to consider the tax credits and the tax free allowance.

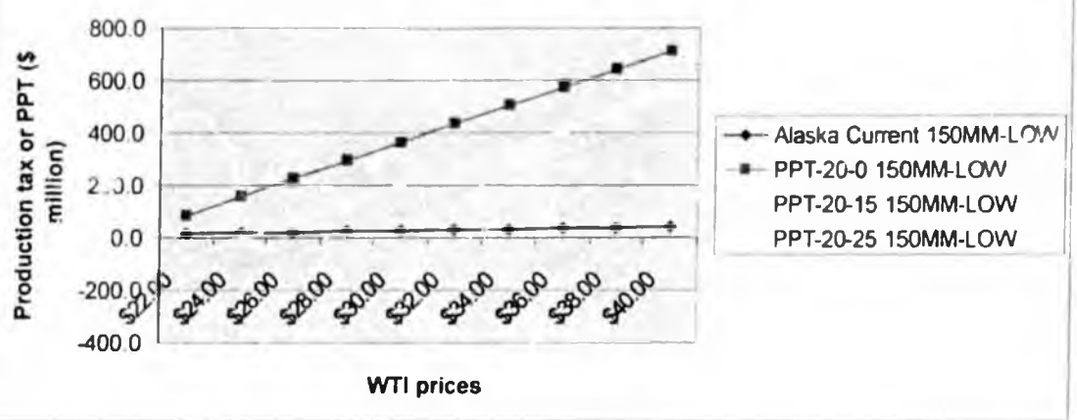
Chart 5.10. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs



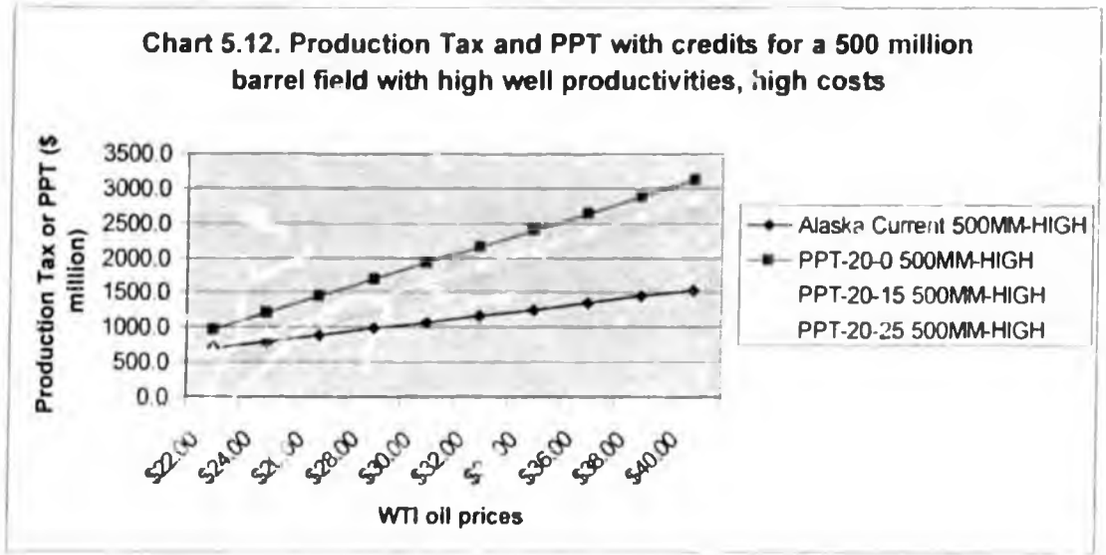
A PPT of 20% with a 15% tax credit results in a WTI break even point of $ 29 per barrel as previously discussed and a 25% tax credit results in a break even point of $ 34 per barrel for a 50 million barrel field.

For the 150 MM barrel field, as can be expected, a PPT of 20% without tax credit and without tax free allowance would result in considerably higher taxes over the entire $ 22 - $ 40 price range. The PPT with a 15% credit would result in a WTI break even price of $ 25 per barrel and a 25% credit would result in a break even price of $ 28 per barrel.

Chart 5.11. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs



The results for the 500 million barrel field are similar, only the break even prices are lower. For a 15% tax credit the break even price would be $ 22 per barrel and a 25% credit it would be $ 24 per barrel.

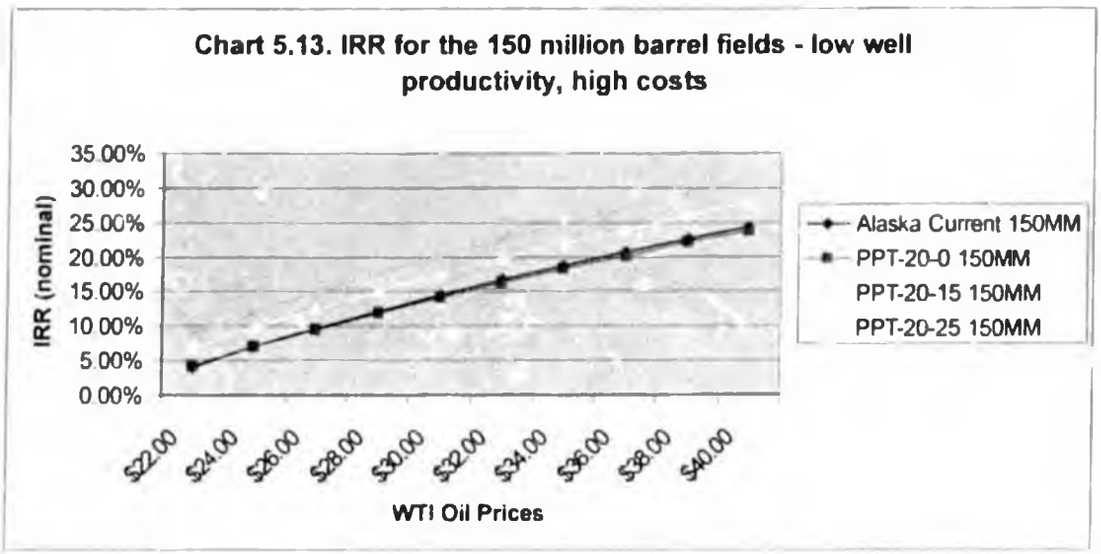


5.2.2. Impact on Investor Economics

The 150 million barrel field is again a good field to illustrate the overall investor economics. Based on this field size, a 20% PPT without tax credits and tax free allowance would result in about the same IRR as the current severance tax system.

It can be seen from Chart 5.13 that the boost in IRR is mainly created through the tax credits on capital expenditures. A tax credit of 15% significantly improves the IRR. A stronger improvement is obtained with a tax credit of 25%. The reason that the tax credits improve the IRR so significantly relates to the fact that the tax credits benefit the investor during the investment phase, early in the cash flow. Since the tax credits can be traded, this effect is the same for small and large companies.

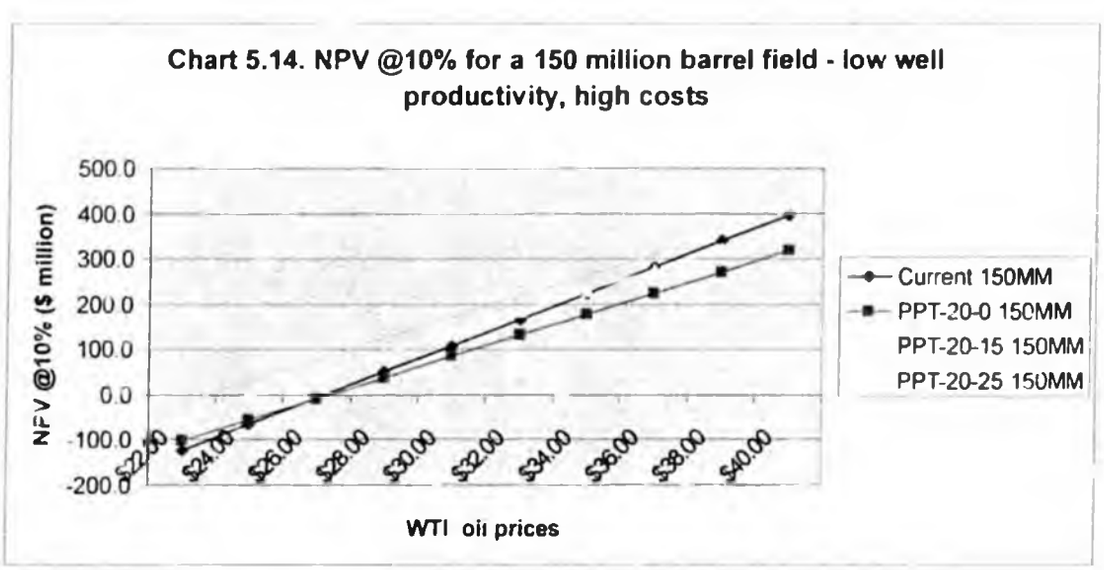
The overall improvement in IRR is an important feature for the world wide competitiveness of Alaska and therefore this is a powerful instrument to attract investment as can be seen from Chart 5.13.



The tax credits also play an important role with respect to the NPV@10%. If a 20% PPT would be introduced without tax credits and without tax free allowance, the result would be that the PPT would be less attractive over a WTI break even price of $ 24 per barrel.

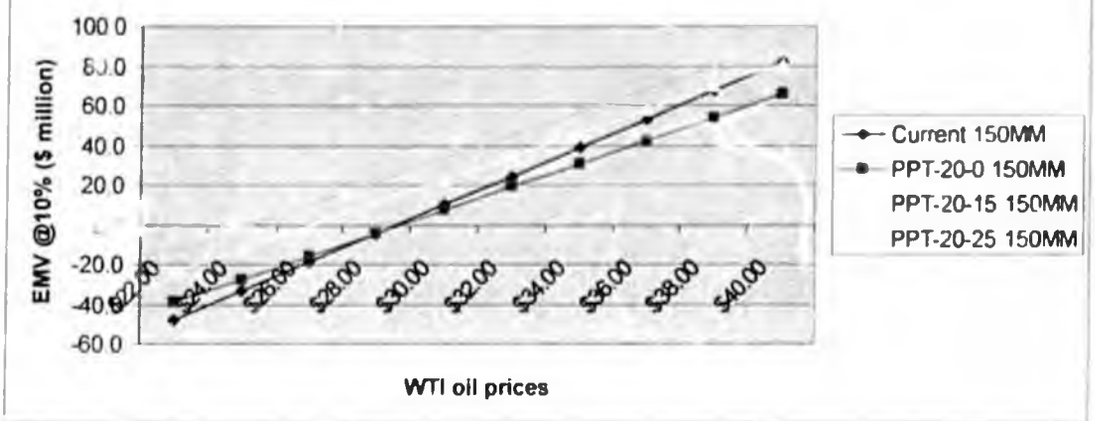
A tax credit of 15% moves the WTI break even price to $ 35 per barrel and a tax credit of 25% put is over the $ 40 per barrel level.

The tax credits therefore play a major role in creating a new fiscal package that results in higher taxes for Alaska above average price expectations, but at the same time encourages new investment.



The tax credits have even a more important impact on the EMV@10%, because these credits will also apply to the exploration phase. In case of a dry hole, the tax credit can be traded, in effect lowering the net costs of exploration. Therefore Chart 5.15 shows a significant impact on the EMV@15% of these credits. With no credits the break even price is about $ 28 per barrel. The break even price improves to $ 39 per barrel with a credit of 15% and well over $ 40 with a credit of 25%.

Chart 5.15. EMV @10% for a 150 million barrel field - low well productivities, high costs



The results of the analysis clearly indicate that a PPT without tax credits would be received unfavorably by investors.

At the same time a tax credit of 25% would make the fiscal system more attractive in the entire $ 22 - $ 40 price range. The introduction of such a strong tax credit would expose Alaska over time to the fact that PPT payments may decline over time, as fields become smaller and more costly. Tax payments may reduce strongly over time. This seems an incentive that is too strong and too risky for Alaska.

5.3. Tax Free Allowance

As was already concluded from Chart 5.10, even if a 15% tax credit would be adopted, small companies and new investors would still pay PPT over a WTI price of $ 29 per barrel. These companies would not pay severance tax at all on such small fields with under the current system. Therefore, a 20% PPT with a 15% tax credit may be considered unattractive by small companies, since it means that they may have to be PPT under high prices, even on small fields. Also for new investors, looking at modest oil field targets, the need to pay a PPT under high prices would be negative factor.

It is for this reason that an additional feature is recommended to protect the small companies and to encourage new investors more strongly. This feature is the tax free allowance on up to $ 73 million of cash flow per year.

Following is an analysis of this feature, with sensitivity to an allowance of $ 50 million per year and $ 100 million per year.

5.3.1. Impact on PPT

Chart 5.16 provides the PPT on a first 50 million barrel field with full application of the tax free allowance. The graphs shows clearly that for th ice range of $ 22 - $ 40 per barrel the PPT would be negative. This is because there is no or little tax payable and the tax credits easily offset the tax that may have to be paid.

However, the graph also shows that for the $ 50 million allowance, the WTI break even price would be about $ 43 per barrel. Therefore under high oil prices, over $ 43 per barrel, small companies would still pay some PPT. This still may create some concern, when compared to the current severance tax.

As indicated above, economic analysis was also done for the price range $ 10 - $ 60 per barrel. This analysis indicates that the WTI break even point for $ 73 million tax free allowance would be $ 50 per barrel and for $ 100 million it would be $ 56 per barrel.

It should be noted that the tax free allowance would be applicable to all companies, the large and small ones. The DOR analysis, to be presented in a separate report, indicated that a $ 100 million allowance would reduce the overall Alaska PPT payable too much. Therefore, this level is too high.

For this reason the $ 73 million level was selected. Despite, the fact that small companies and new investors will pay some PPT when prices are over $ 50 per barrel on this 50 million barrel field, it should be noted that otherwise the tax credits they receive improve the economics considerably. Therefore, this seems a reasonable balance.

Chart 5.16. Production Tax and PPT with credits for a 50 MM barrel field with low well productivities, high costs

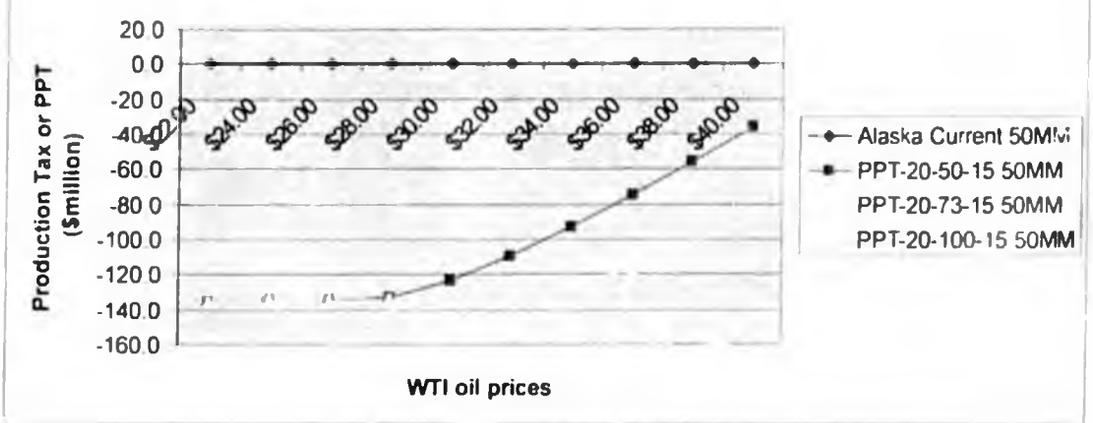


Chart 5.17 indicates that a $ 73 million tax free allowance would result in a significant reduction of PPT on the first 150 million barrel field as well, resulting in a very material improvement of economics. This means that some of the larger new companies may be interested in more actively considering Alaska for the new first investments.

Chart 5.17. Production Tax and PPT with Credits for a 150 mm barrel field with low well productivities, high costs

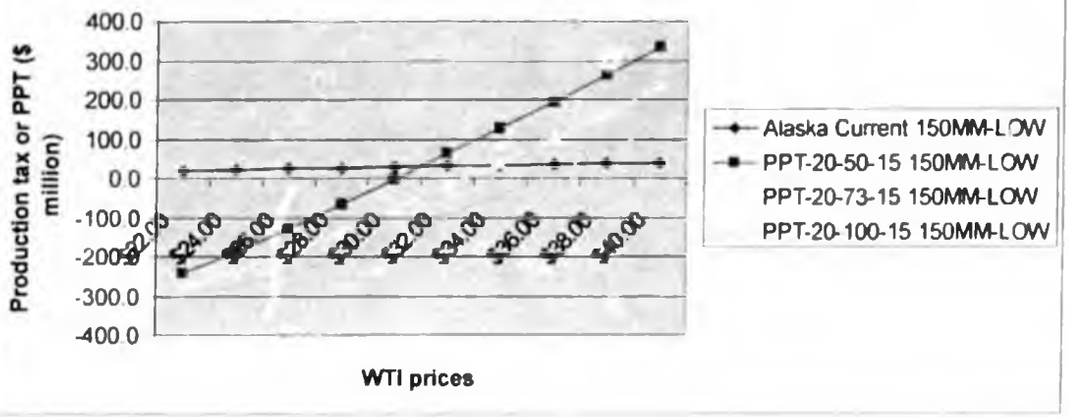
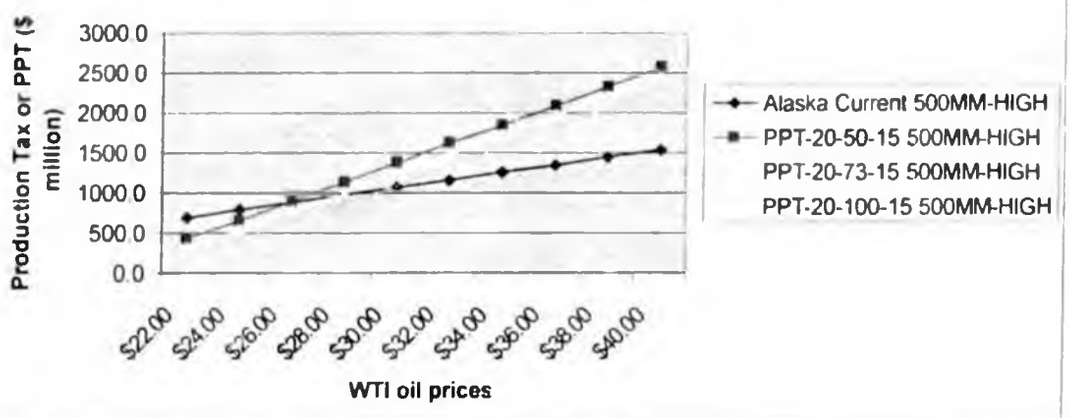


Chart 5.18 indicates that even on a $ 500 million target the tax free allowance will provide a material improvement in PPT for a new investor.

Chart 5.18. Production Tax and PPT with credits for a 500 million barrel field with high well productivities, high costs



The $ 73 million tax free allowance will not only assist small companies, but will also attract new large potential producers to Alaska. The positive impact is material on investments in the first large fields.

5.3.2. Impact on investor economics

The following graphs relate to the 50 MM barrel field, which is the important field to evaluate the impact on small and new investors.

All the charts 5.19, 5.20 and 5.21 indicate that at low prices it makes no difference whether a tax free allowance of $ 50 million, $ 73 million or $ 100 million is applied, since in all cases $ 50 million is sufficient not to pay the PPT and the higher levels of tax free allowance have therefore no impact.

For higher prices the impact is rather modest. The reason is that the amount of profit subject to tax in all cases is modest. The tax free allowance therefore does not impact much on the traditional profitability indicators for the small 50 MM barrel field.

Chart 5.19. IRR for 50 million barrel - low productivity case, high costs

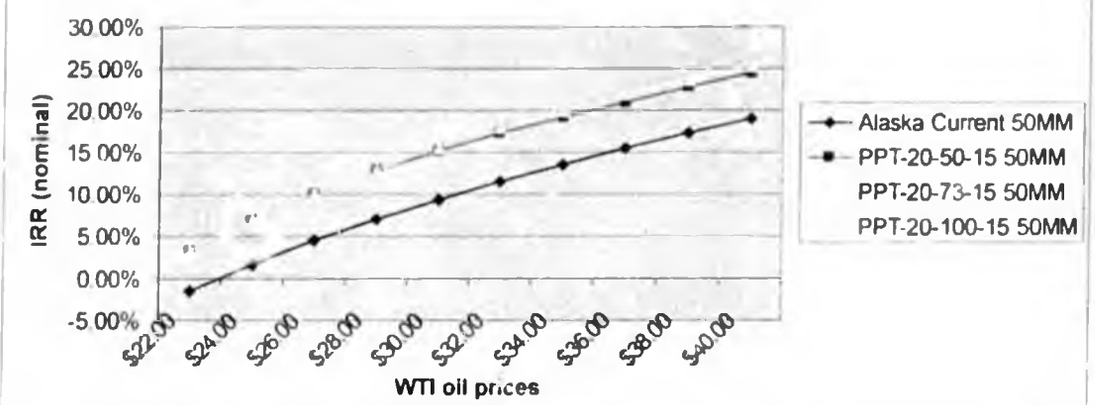
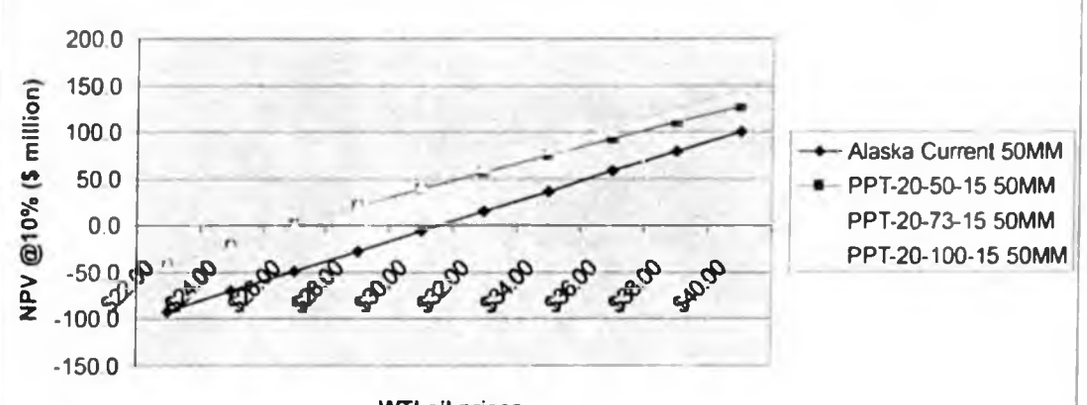
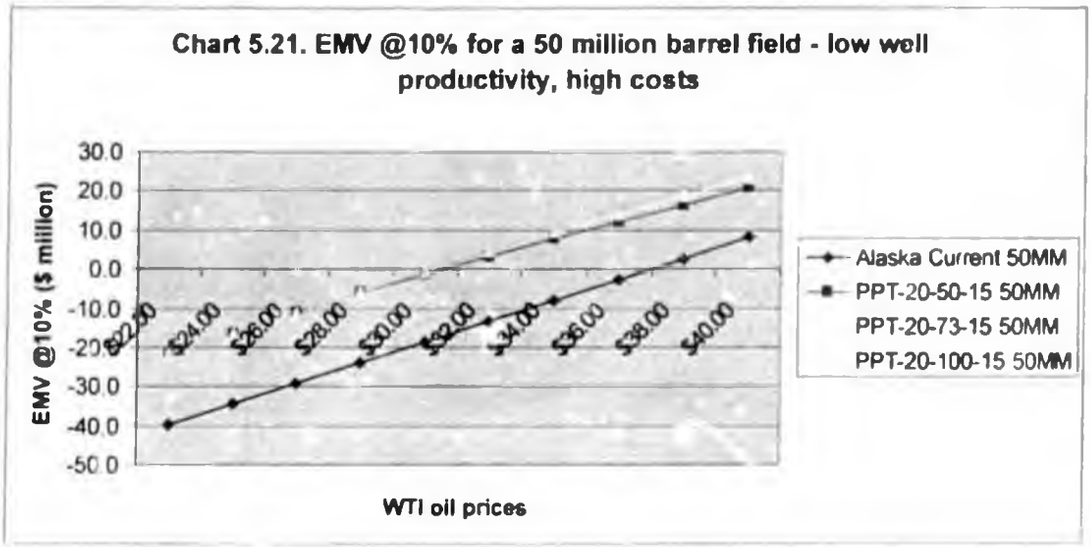


Chart 5.20 NPV @10% for a 50 million barrel field - low well productivity, high costs





With respect to small fields and tax free allowance in the range of $ 50 to $ 100 million is adequate. A level of $ 200,000 per day was selected because this is administratively easy and it is also material for larger fields, as was indicated above.

5.4. Other PTT variations

Other variations to the PPT were also considered, but are not recommended. Following is a listing of items that was considered.

Differential tax credit

Instead of a flat tax credit of 15%, it is possible to consider different levels of tax credits for different activities. For instance, development of conventional oil and gas could be a 10% credit, exploration could be a 15% credit and development of heavy oil a 20% credit. The advantage of this approach is that it makes the credit more targeted towards investments in opportunities that seem to justify such credits. The State of Alaska would therefore re-distribute the credit to "where it is most needed".

This approach is not recommended. The main reason is that it would be difficult to properly audit and verify all the different classes of capital expenditures. It could also lead to many disagreements among companies and the State of Alaska.

A more detailed analysis will be provided for Heavy Oils in Chapter 10.

Uplifts

Instead of tax credits it is possible to provide uplifts. Uplifts are extra deductions of capital expenditures. For a particular tax rate a particular level of uplift corresponds to a level of tax