PRELIMINARY REPORT ON FISCAL DESIGNS FOR THE DEVELOPMENT OF ALASKA NATURAL GAS

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For

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Section 4.4

Base-case model: fiscal performance of a range of field types

Part 4: Analysis of Alternative Upstream Fiscal Models for Alaska

4.4 Base-case model: fiscal performance of a range of field types

The economic performance and fiscal contribution details calculated for each of the ten hypothetical gas fields modelled in this study are presented in **Appendix 4** as a series of graphs and tables applying base-case production, cost, price and oil (C5+) and gas reserves assumptions. The economic performance measures are presented to reflect several perspectives: 1) those focused on Alaska state take and the fiscal components that constitute that take; 2) those focused on total government take (“total government” meaning the total of Alaska state take and federal government take); 3) those focused on the producer take (“producer” being a company or joint-venture group of companies holding the lease(s) in which the field is located); and 4) those focused on total project performance.

Fiscal design analysis needs to review performance from all such perspectives and therefore involves the calculation and analysis of a significant number of economic and production yardsticks. It also needs to review performance from a wide range of potential field types, reserve sizes and production profiles. This is the reason for analysing ten hypothetical fields from different stakeholder perspectives’. Comparison of a substantial number of performance yardsticks for each field makes it possible to review the overall performance of the prevailing Alaska fiscal terms for a wide range of potential oil and gas field sizes and types. This lays the groundwork for establishing the impact of potential adjustments to this prevailing fiscal design in subsequent sections of this study.

In this section the performance of **gas field #4** under base-case assumptions and prevailing fiscal terms is presented and discussed. The analysis of the other fields is referred to for comparison in certain places, but the main focus is gas field #4, which is considered in detail here because it produces large gas reserves (some 5 tcf) plus some 100 million barrels of associated oil (C5+) in the form of condensate. Total gas and oil (C5+) reserves produced from Field #4, over a 17-year production period in the model constructed amount to some 941 million boe.

For base-case price, cost, escalation, inflation and production assumptions the project destination value revenue in MOD ($ millions) is US$ 66.3 billion. By dividing that amount by the 941 boe of reserves produced, the project’s destination value may be expressed in unit of production terms of $ 70.5/boe. The model reveals that the destination value is made up of the following US $/boe components:

Capex	4.22
Opex	2.83
Gas TT&T	29.40
Liquids TT&T	0.70
Producer take	11.49

Alaska state take 15.52
Federal government take 6.30

Figure 4.4.1 expresses these components in percentage terms of destination value.

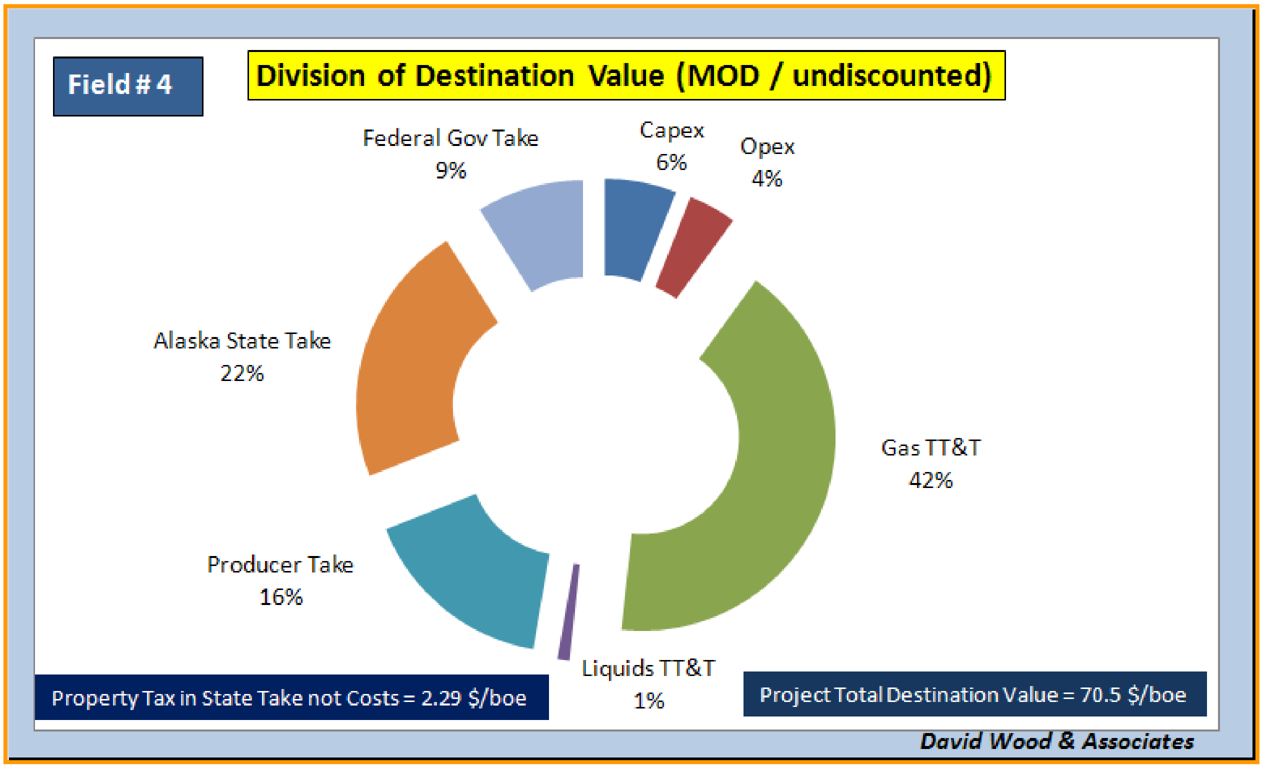

Figure 4.4.1. Division of destination value between parties and costs for gas field #4.

It is useful, depending upon the purpose, to express such values in absolute U.S. dollar ($) terms, in US$/boe terms and in percentage (%) terms. Production is expressed mainly in volume terms (barrels, mcf and boe) and in some cases in energy terms (mmbtu) as appropriate. Unit costs (TT&T, capex and opex) are expressed in mmbtu and boe terms.

Expressing values in MOD, real, undiscounted and discounted terms

Various cases can be argued for what discount rate should be used to adjust state fiscal revenues for the time-value of money. However, it is generally accepted that government discount rates are lower than those appropriate for equity investors and producing companies (i.e. producer). The Alaska Permanent Fund's long term rate of return (a possible value to use for the state incremental dollar) is approximately 7.5% real (PFC www.apfc.org/_amiReportsArchive/2007_Realized_Unrealized.pdf). Black & Veatch (2008) in its gas pipeline analyses for the administration used a discount rate of 5% which contrasts with the discount rate of 10% applied to producer cash flows. This study also uses a 5% discount rate; however, as noted below, the 5% discount rates are not the same.

Total government (i.e., total state and federal government) and Alaska state percentage takes of cash flow are presented here on an undiscounted basis and using a 10% discount rate in order to show the impact of discounting on these takes (the 10% discounted take is how many producers view state and total government take, i.e. with their own cost of capital as a frame of reference). All other discounted values involving total government and Alaska state revenues apply a 5% discount rate. When discounted rates are expressed in US$/boe terms the production is also discounted at the discount rate used for the value. This is identified as "US$/discounted boe".

Cash flows of dollars are summed and stated as either: real dollars (in the analysis presented this means real year 0 $); or with an inflation component remaining in them when they are referenced as MOD. In developing the MOD cash flows prices and costs are escalated at nominal rates, which could in a specific case differ depending upon the prices and costs involved. Here gas price is escalated nominally at 2% per year and costs are escalated at 2% per year. In both cases that full 2% is an inflation component with no escalation component in real terms (i.e. real escalation is 0% for prices and 0% for costs). To remove the effects of inflation from cash flow profiles expressed in MOD terms, a broader buying power deflator is applied to the MOD cash flows to adjust them to real year 0 dollars. The buying power deflator applied here is 2% per year. So, deflated real cash flows are expressed in dollars of year 0.

Both the MOD cash flows and the real cash flows (removing the effects of inflation) are discounted to provide net present values (NPV). The author takes the view that discount rates are best used solely for the purpose for which they were designed, i.e. to adjust future values for the time-value of money and to express future values in present value terms. Hence all adjustments for inflation in this study are calculated separately from the discounting (time-value adjustment) process. If a value is discounted by 10% in this study, that 10% figure does not include an inflation component. Inflation is dealt with separately by applying the buying power deflator of 2% to adjust MOD values to real values. If MOD cash flows are discounted, the NPV remains in MOD terms; whereas, if real cash flows are discounted, the NPV is expressed in real terms in dollars of the year selected to which the deflator is applied. In this study the selected year for deflation is year 0 so real values are expressed in dollars of year 0. Real and MOD values are clearly distinguished in all graphs and tables presented below and in the following sections and appendices of this report.

It is the author's understanding that Black & Veatch (2008) quote NPV_5 values which are discounted nominal government cash flows. In this study real NPVs are calculated on real cash flows (i.e. nominal cash flows deflated at 2%), so the real NPV at 5% discount rate is not the same as a Black & Veatch (nominal) NPV_5.

Stakeholders' net present values compared

For the base-case price, cost and production assumptions outlined in Sections 4.1 and 4.2 field #4, under the prevailing Alaska fiscal terms, provides the State of Alaska with a US$5.629 billion (NPV real discounted at 5%) return compared with a producer return of US$1.508 billion (NPV real discounted at 10%) and a producer IRR real of 20.1%. This compares with small negative NPVs discounted at 10% for the producer from the smaller fields (e.g. field #2: Alaska NPV@5% real = US$700 million, and producer NPV@10% real = minus US$0.051 million, IRR real of 8.9%). A NPV@10% loss for the producer versus a $700 million NPV@5% fiscal take for Alaska highlights the regressive nature of the fiscal design and suggests that fields below about 1 tcf of gas reserves will provide only marginal returns at best for a producer based upon base case field costs, TT&T costs and destination market value assumptions applied in this study.

Total government take and producer take of cash flows are compared in Figure 4.4.2 for field #4.

Stakeholder Take Comparisons		
	Total Government	**Producer**
Take % of undiscounted MOD cash flows	65.50%	34.50%
Take % of undiscounted real cash flows	66.18%	33.82%
Take % of NPV real (5 % discount rate)	68.98%	31.02%
Take % of NPV real (10 % discount rate)	74.07%	25.93%
Take ($ millions) from MOD cash flows	20,536	10,816
Take ($ millions) from real cash flows	15,436	7,887
Take ($ millions), NPV real (5 % discount rate)	7,915	3,559
Take ($ millions), NPV real (10 % discount rate)	4,308	1,508
Take ($/boe) from MOD cash flows	21.82	11.49
Take ($/boe) from real cash flows	16.40	8.38
Take ($/disc boe), NPV real (5 % discount rate)	16.03	7.21
Take ($/disc boe), NPV real (10 % discount rate)	15.68	5.49
Total production undiscounted million boe = 941	494 boe disc @5 %	275 boe disc @10 %

Figure 4.4.2. Comparison of total government and producer takes for gas field #4.

Stakeholder takes versus cost components

Alaska takes some 22% of undiscounted MOD destination value over the life of field #4 (Figure 4.4.1), which combined with federal income tax amounts to a 31% total government take of destination value. For the smaller gas fields (e.g. Field #1 and #2) the total government take of destination value falls below 30% (some 20% to Alaska) because costs take up a larger component of the revenue stream. For the large gas field #4, total costs (capex plus opex plus tariffs) amounts to some 53% of destination value, but this increases to some 63% for the smallest field. Producer share of destination value falls from 16% in field #4 to 10% in field #1.

For oil fields #6 to #10 costs are generally around 25% of undiscounted MOD destination value (lower than for gas fields). Alaska takes some 46% of undiscounted MOD destination value over the life of field #10. Field #10 provides the following returns: Alaska NPV@5% real = US$9.7 billion, and producer US$ NPV@10% real = US$ 2.0 billion, producer IRR real 31.5%. The total government take is some 57% (Alaska 46%) of undiscounted MOD destination value, leaving the producer (excluding costs of 23%) also with some 20% of undiscounted MOD destination value.

Clearly oil fields are substantially more profitable for all parties under the high oil price assumptions used by the models.

The Impact of progressivity tax on Alaska state take

Alaska manages to take a larger share of revenues from the oil fields because the combined progressivity tax (CPT) component was structured to provide a higher state take when oil prices are high. The CPT thresholds and sliding scale rates are linked to specific production tax values (PTV)/boe. Translating production tax value gas on an energy equivalent basis into US$/boe PTV units and using those values with the current CPT thresholds (devised for oil) does not yield such significant revenues for the gas fields. This highlights a significant flaw with the current CPT mechanism. In situations such as those prevailing in September 2008 (destination market oil prices ~US$100/barrel, natural gas Henry Hub ~US$7.5/mmbtu), when market oil prices are high (generating high PTV values) and market gas prices are low (generating low PTV values), converting the gas PTV into US$/boe PTV unit prices actually has a negative impact on the amount of CPT paid (i.e. it dilutes the PTV unit price). In such situations the more gas quantity that is sold the lower the CPT liability for the producer (values derived from cheap gas dilute the high-value oil).

Alaska's take amounts to some 73% of the total government share of undiscounted MOD destination value for the gas fields (Field # 1 to 5) with base-case assumptions, but this increases to some 80% for the oil fields (Field # 6 to 10).

Graphical illustrations of stakeholders' cash flows profiles

Figures 4.4.3 and 4.4.4 show Alaska and producer cumulative discounted cash flows in real terms. These graphs are placed on the same page to ease comparison.

Figures 4.4.5 and 4.4.6 show Alaska undiscounted annual MOD cash flows for gas field #4, identifying contributions of individual fiscal instruments, and producer post-FIT (post all fiscal elements deducted) undiscounted MOD annual cash flows. These graphs are placed on the same page to ease comparison.

Figure 4.4.5 highlights the contribution of CPT progressivity tax in comparison to other fiscal elements to the Alaska state take. For gas field #4 CPT amounts to just 4 % of Alaska's MOD undiscounted cash flow. For oil field #10 CPT amounts to ~32% of Alaska's MOD undiscounted cash flow (BPT ~35% net of investment credits; royalty~24%, property tax 3%).

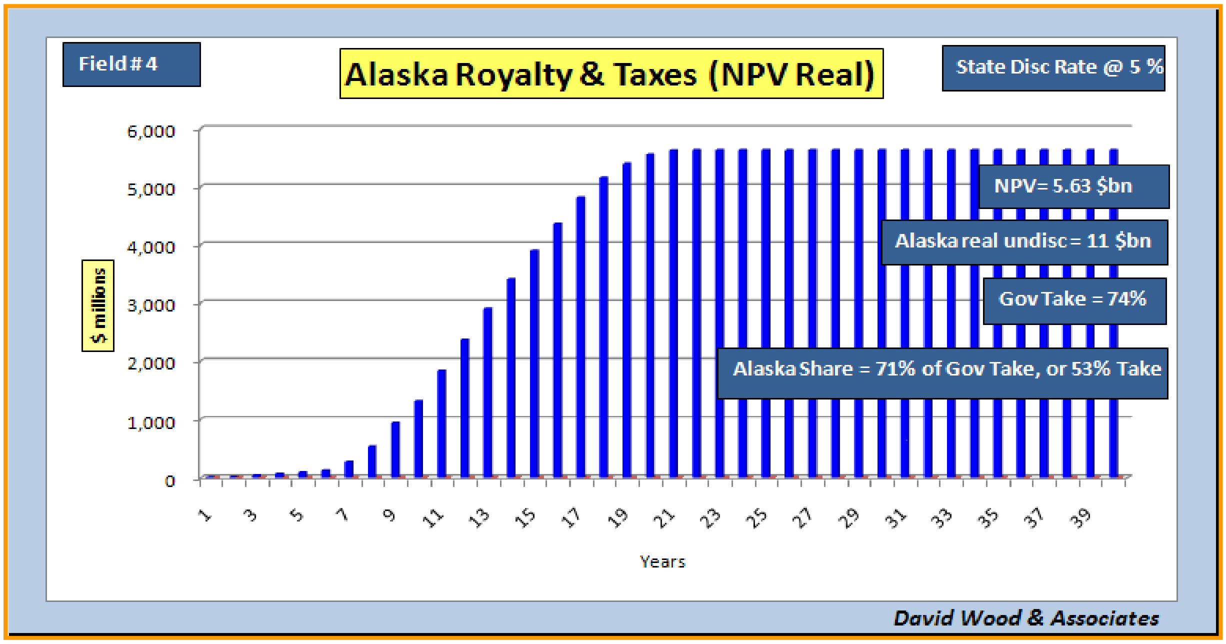

Figure 4.4.3. Alaska's cumulative discounted real fiscal cash flows for gas field #4. Total government take of discounted cash flow NPV@5% real is 74% (Alaska receives 71% of the total government take, or 53%) for this large gas field. For Field #10 (oil with gas) total government take of discounted cash flow NPV@5% real is 76% (Alaska 60%) with oil progressivity tax proceeds boosting Alaska's share. These graphics are fixed for a 40-year time period for two reasons: 1) sensitivity analysis varies the field life in some model iterations; 2) although production and cash flow end in this case in year 23 the extra years shown for cumulative NPV enables labels to be added without obscuring the years in which cash flow occurs.

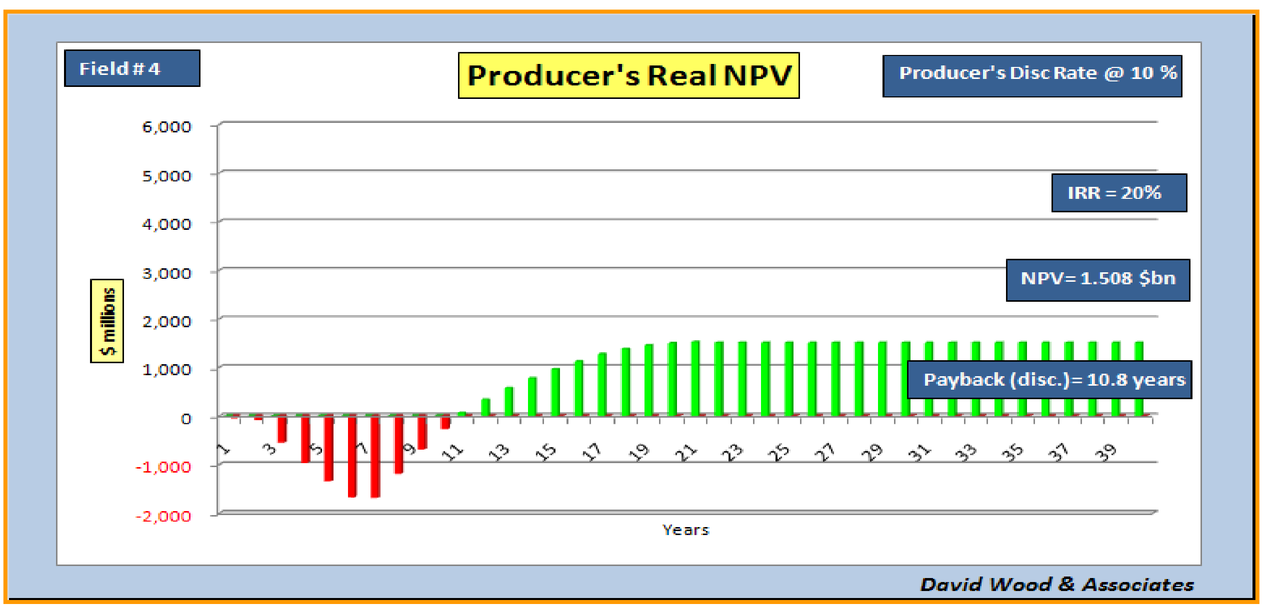

Figure 4.4.4. Producer's discounted cumulative real cash flows for gas field #4.

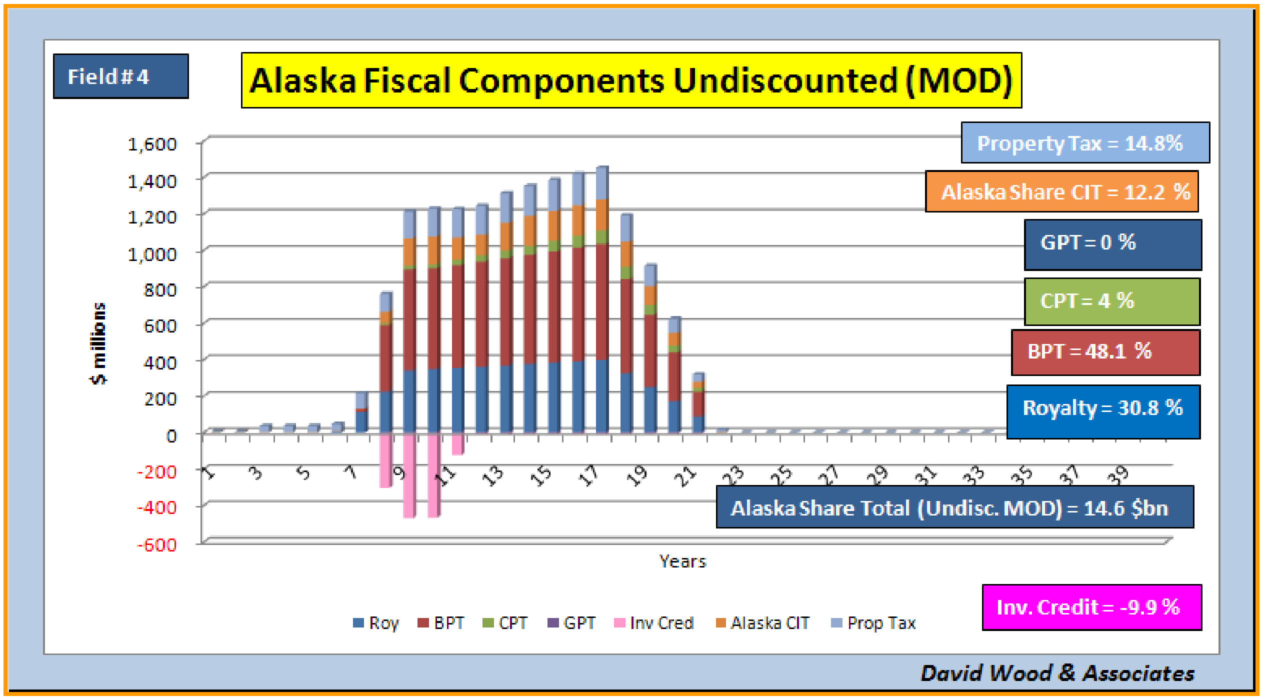

Figure 4.4.5. Alaska's undiscounted annual MOD cash flows for gas field #4 identifying contributions of individual fiscal instruments. BPT amounts to some 48% (or 38% net of investment credits) of Alaska's cash flow and royalty some 31%. The progressivity tax (CPT) amounts to some 4% of Alaska's cash flow.

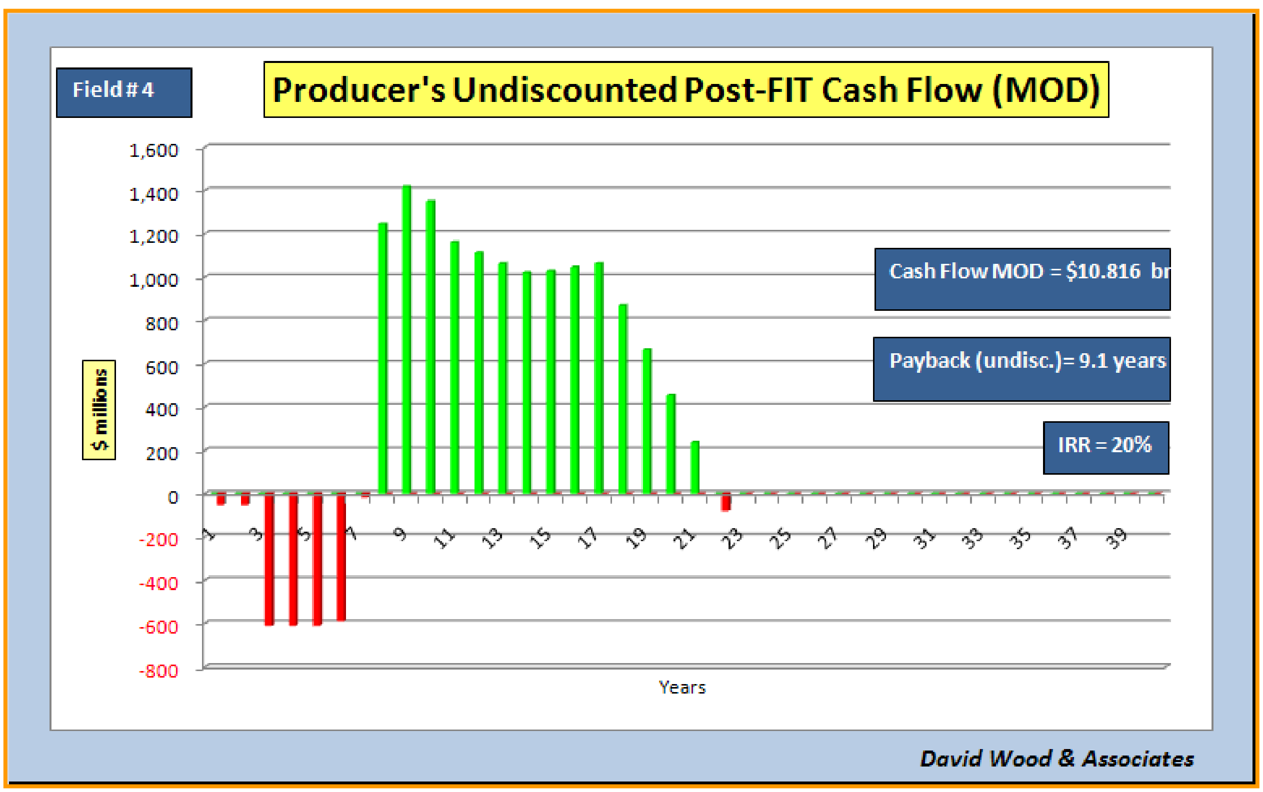

Figure 4.4.6. Producer's undiscounted annual MOD cash flows for gas field #4.

Figure 4.4.7 shows a pie chart of project destination value on an undiscounted MOD basis divided between total government take, Producer take and costs for gas field #4.

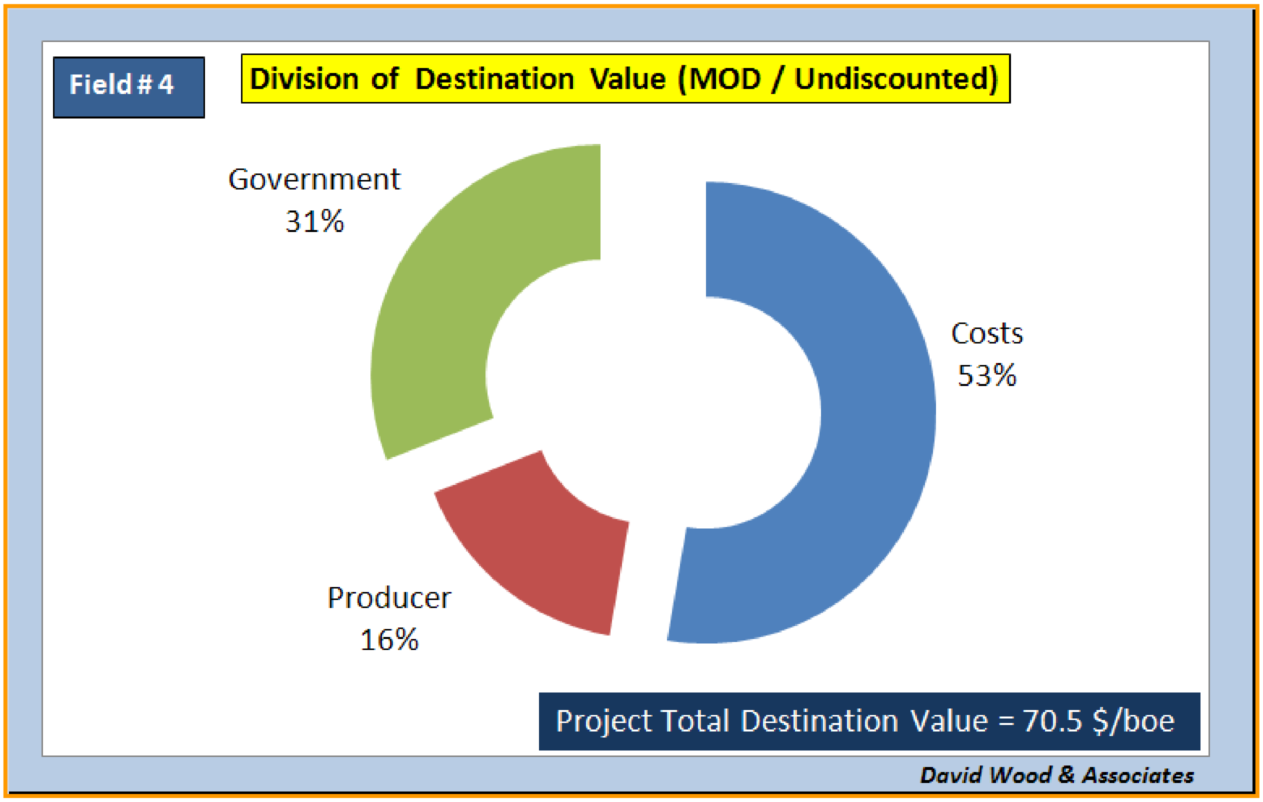

Figure 4.4.7. Division of destination value between government, producer and costs for gas field #4.

Figure 4.4.8 shows pie chart divisions of cash flow between Alaska, U.S. government and producer on a real and discounted basis in percentage terms for gas field #4. Total government take is some 74% when expressed on a 10% discounted and real basis (i.e. from the producer's perspective)

For the smaller more costly gas fields Alaska's take (discounted at 5%) increases to 77% and total government take is essentially 100% (producer NPV@10% real =$0) for those small fields (e.g. field #2). For the oil fields Alaska's take (discounted at 5%) is 60%, with total government take at some 76% on an NPV@10% real basis.

Figures 4.4.9 shows the total government take components on an undiscounted basis yielding a 65.5% government take. In contrast to Figure 4.4.8 this is more likely to be the take percentage that the federal government might use to quote U.S. take of cash flow, as it is more representative of the government and state perspectives.

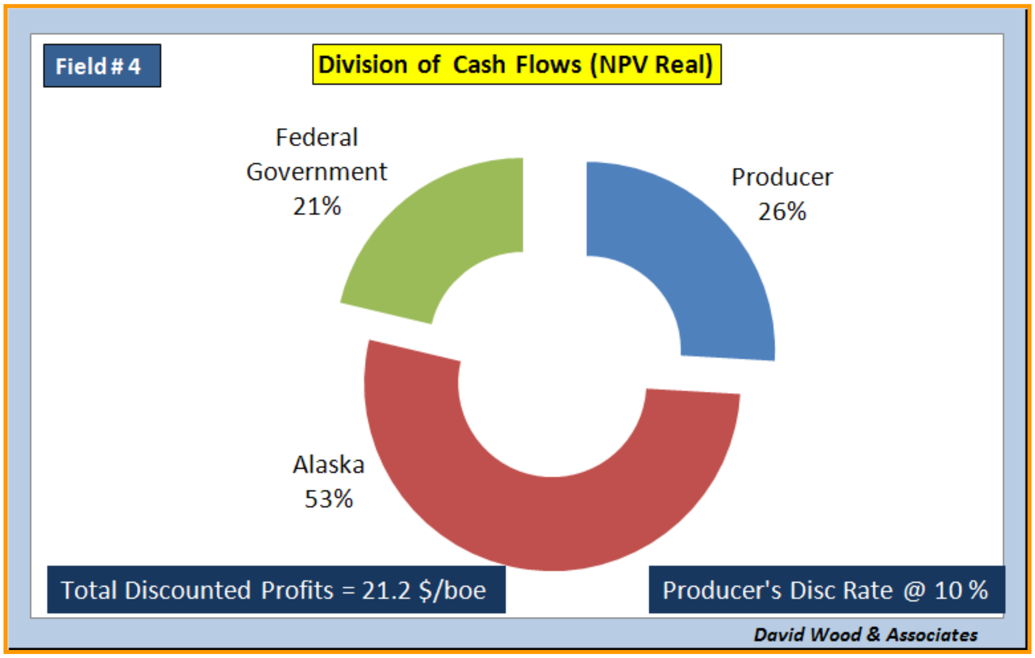

Figure 4.4.8. Division of real discounted cash flows (NPV@10%) between Alaska, US government and producer for gas field #4. The producer discount rate is applied in this case. This figure illustrates how many producers would evaluate investment opportunities in Alaska. The government would appropriately apply a lower (e.g. 5% discount rate) to evaluate its share of cash flows.

Fiscal Takes for Gas Field #4 Base Case

Government Take = Alaska state take + federal income tax

30.8%	Royalties as fraction of Alaska Take (MOD / undiscounted)
48.2%	BPT (incl. floor) as fraction of Alaska Take (MOD / undisc)
4.0%	Combined Oil & Gas Prog. Tax (CPT) Paid (MOD / undisc)
0.0%	Separate Gas Progressivity Tax GPT Paid (MOD / undisc)
12.2%	CIT fraction of Alaska Take (MOD / undisc)
-9.9%	Invest. Credit (offsets BPT) of Alaska Take (MOD / undisc)
14.8%	Property Tax as fraction of Alaska Take (MOD /undisc)
100.0%	Sum of Components of Alaska State Take
22.0%	Alaska Take % of Undisc mod Destination Value
31.0%	Government Take % of Undisc MOD Destination Value
46.6%	Alaska Take % of Undiscounted MOD Cash Flow
65.5%	Government Take % of Undiscounted MOD Cash Flow
Investment Credits Reduce Alaska Take by some -9.9 %	

Figure 4.4.9. Contributions to Alaska's fiscal take for field #4 on an undiscounted MOD basis, plus comparison of Alaska state and total government take of destination value and cash flow. In this figure, rows marked "Government Take" refer to total government (i.e. total state and federal government).

Figures 4.4.10 and 4.4.11 show the fiscal component contributions to Alaska state take on an undiscounted and MOD basis for gas field #4.

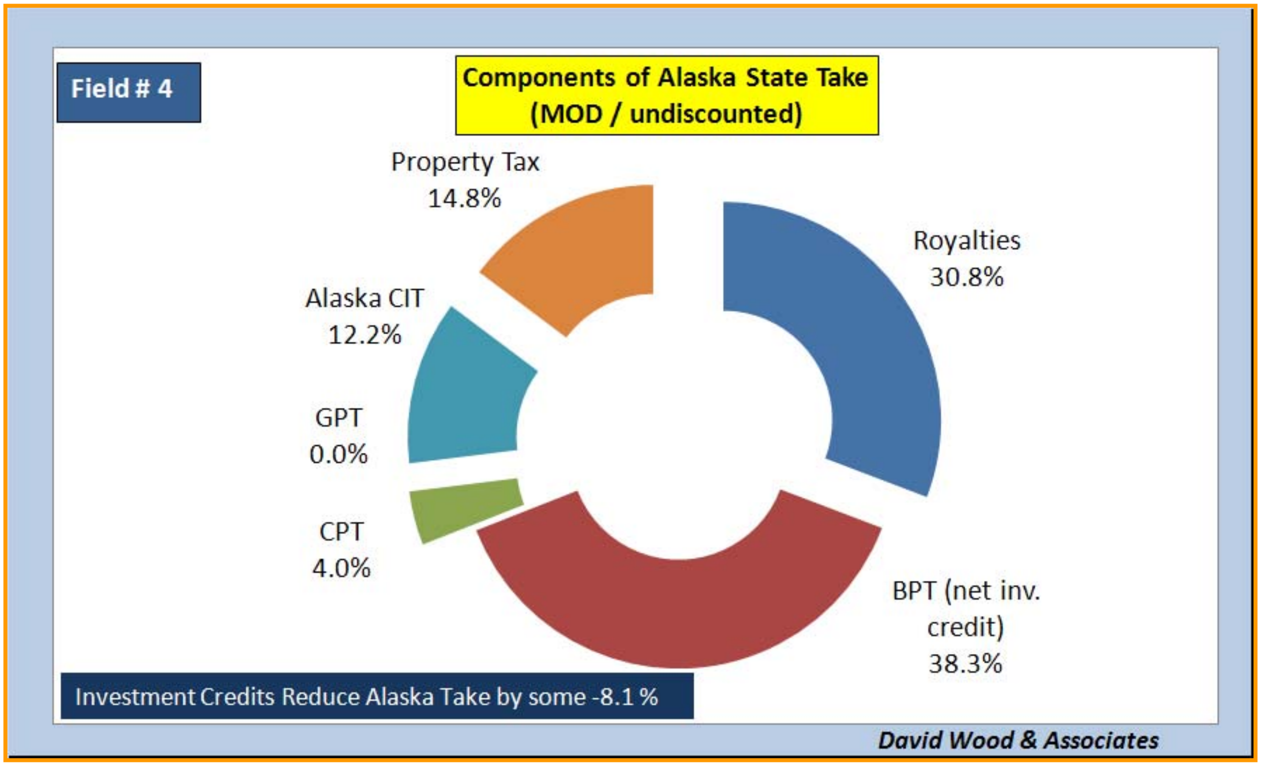

Figure 4.4.10. Components of Alaska's fiscal take for gas field #4. The investment credit is deducted from production tax (BPT). BPT and royalties dominate the take for the base-case assumptions. GPT is zero because for the base-case gas and oil progressivity are combined in CPT calculated using $/boe PTV values for oil equivalents.

Alaska Take Components			
Fiscal Elements	$ millions	$boe	%
Royalties	4,493	4.77	30.8%
BPT (net inv. credit)	5,588	5.94	38.3%
CPT	585	0.62	4.0%
GPT	0	0.00	0.0%
Alaska CIT	1,781	1.89	12.2%
Property Tax	2,156	2.29	14.8%
Totals	**14,603**	**15.52**	**100.0%**
Undiscounted and MOD			

Figure 4.4.11. Components of Alaska's fiscal take for gas field #4. The investment credit is deducted from production tax (BPT).

As mentioned by way of introduction to this base case for fiscal design analysis, it is necessary to calculate and review a wide range of performance benchmarks. Those benchmarks that will be reviewed in subsequent sections of the report have been introduced in this section. A more complete listing of all the performance benchmarks calculated for field #4 is provided in Figure 4.4.12. This compilation provides an extensive set of numbers, ideal for systematically reviewing performance of a large number of sensitivity cases from a wide range of oil and gas fields and from the perspectives of the key stakeholders. Such detail is required if quantitative fiscal design analysis is to go beyond the simplistic concepts of stakeholder takes expressed in percentage takes of gross or net values.

Summary of Model Calculations

Key Values Calculated for Model Field #:	4	Key Field & Government / Alaska Metrics	
Sales Gas Produced 5.584 quad btu or (bcf)	4994	7.50	Initial Gas Destination Price ($/mmbtu)
Oil (C5+) Produced (millons barrels)	109	11.59	Maximum Gas Destination Price ($/mmbtu)
Gas + Oil(C5+) Produced 5646 bcfe or (millions boe)	941	80.00	Initial Oil Destination Price ($/barrel)
Peak Average Daily Natural Gas (mmcf)	1,150	123.68	Maximum Oil Destination Price ($/barrel)
Peak Average Daily Oil (C5+) (bopd)	25,000	74.8	Initial LPG Destination Price ($/barrel)
Maximum water cut (%)	76.9%	115.61	Maximum LPG Destination Price ($/barrel)
Capex /unit 0.651 $/mmbtu or ($/boe) MOD	4.37	6	Year on stream real values refer to year: 0 $
Opex /unit 0.454 $/mmbtu or ($/boe) MOD	3.05	66,298	Project Destination Value Revenue MOD ($ millions)
Gas TT&T/unit 4.668 $/mmbtu or ($/boe) MOD	31.32	**70.46**	Project Dest. Val. MOD ($/boe) - Average "boe" Price
Oil (C5+) TT&T/unit 0.104 $/mmbtu or ($/boe) MOD	0.70	4.77	($/boe) Total Royalties 4493 $ millions MOD
Field on-stream (Years)	16	7.48	($/boe) BPT (incl. Floor: no Inv Credit) 7037 $ millions MOD
Field Shut-in (Year)	22	0.62	($/boe) CPT Paid 585 $ millions MOD
Producer's Post-Royalty Operating Cash Flow ($/boe) MOD	30.62	0.00	No separate GPT under 2007 law
Producer's Pre-Production Tax Cashflow ($/boe) MOD	26.25	-1.54	($/boe) Inv Credit Paid to Company -1449 $millions MOD
Producer's Post-BPTCashflow ($/boe) MOD	18.80	1.89	($/boe) Alaska CIT 1781 $millions MOD
Producer's Post-PTCash Flow-NoInvCred($/boe) MOD	16.44	6.30	($/boe) Federal Income Tax 5933 $millions MOD
Producer's Post-ProgressivityInvCredit Cash Flow ($/boe) MOD	19.69	21.82	($/boe)Total Gov. Share Undisc 20536 $millions MOD
Producer's Post-FIT Cash Flow 10816 $millions & ($/boe) MOD	11.49	15.52	($/boe)Total Alaska Share Undisc 14603 $millions MOD
Producer's Post-FIT Cash Flow 7887 $millions ($/boe) real	8.38	71.1%	Alaska Percentage of Total Government Share (%)
Producer's NPV 2232 $millions @ 10% ($/disc boe) MOD	8.12	65.5%	Government Undiscounted Share of Cash Flow MOD (%)
Producer's NPV @ 10% ($/discounted boe) real	**5.49**	16.40	($/boe)Total Gov. Share Undisc 15436 $millions real
Producer's NPV @ 10% ($millions) real	**1,508**	11.66	($/boe)Total Alaska Share Undisc 10974 $millions real
Producer's IRR (%) MOD	22.6%	**16.03**	($/dicounted boe) Total Gov Share NPV @5% real
Producer's IRR (%) real	**20.1%**	**11.40**	($/dicounted boe) Total Alaska Share NPV @5% real
Producer's Payback Time (years) MOD undiscounted	9.09	71.3%	Alaska Share of Government Take real & Disc @10 (%)
Producer's Payback Time (years) real discounted	**10.83**	**74.1%**	Government Share of Cash Flow real & Disc @10 (%)
Producer's NPV / Investment real Discounted	0.72	**7,915**	Total Government Share NPV @5% real ($ millions)
Note: "$/boe" refers to "boe" commercially produced		**5,629**	Total Alaska Share NPV @5% real ($ millions)

Figure 4.4.12 summarizes the economic analysis that the base-case fiscal model generates for gas field #4. Undiscounted and discounted values in absolute and in unit of production terms are shown on the left side (including real and MOD values) from an IOC investor's perspective (i.e. producer). The right-hand side of the table lists prices and the value of specific fiscal instruments and total Alaska and total government (i.e. total state and federal government) takes of gross value and net cash flow on MOD, real, undiscounted and discounted (i.e. Net Present Value, NPV) basis.

Similar graphs to those included in this section are presented for all ten hypothetical fields analysed in this study in **Appendix 5** so that more detailed comparisons of different field sizes and types can be made for the base-case model assumptions from the perspectives of all stakeholders. The detailed analysis of these fields reveals that for the larger gas fields total government take of real cash flows discounted at 5% is close to 69%, whereas this figure rises to 74% for large oil fields under the base-case assumptions. For the large gas fields basic production tax (BPT) makes the largest contribution to government take (38% of total fiscal take) followed by royalty (31% of total fiscal take). For the large oil fields the combined progressivity component of production tax (CPT) makes the second largest contribution to government take (32% of total fiscal take), slightly less than basic production tax (BPT at 34.5% of total fiscal take) and royalty (24% of total fiscal take). It is concluded that CPT is very effective at taking a sizeable share of economic rent from oil fields producing under highly profitable market conditions, but quite ineffective at achieving the same outcome for natural gas fields.