

SB

192

(FILE 5)

<TARGET><BILL>SB 192</BILL><SUBJECT>SB 192 (FILE
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17.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas

PFC Energy

March 30, 2012



Discussion Slides: Alaska Senate Finance Committee

March 30, 2012

Janak Mayer
Manager, Upstream & Gas
PFC Energy

Difficulties in Existing Fiscal Structure

- The incorporation of progressivity into the Profit-Based Production Tax (Net) in ACES creates two significant problems
 - Large-scale gas production at low gas prices could in the future significantly reduce production tax revenue from existing oil production
 - Resolving this problem within the framework of ACES requires significant complexity
 - Approach to decoupling in CSSB 192 requires ability to split costs between oil and gas production, creating high degree of administrative burden, and limiting capacity of state to effectively audit
 - Options for incentivizing new production are limited, and relatively complex
 - Proposed incentives within existing framework focus on either allowances to reduce Production Tax Value , or revenue exclusions (tax holiday)

Summary of Progressive Severance Tax (Gross) Structure

- A Progressive Severance Tax (Gross) option would instead remove progressivity from the Profit-Based Production Tax (Net), instead levying this tax at the flat, base rate of 25%
- To retain an element of progressivity, a new Progressive Severance Tax (Gross) would then be added to the system. The tax would:
 - Be non-deductible for Profit-Based Production Tax purposes
 - Be levied on gross production (net of royalties)
 - Be levied solely on oil
 - The tax would use a progressivity structure not dissimilar to that under the current system, with progressivity coefficients that apply at different thresholds.

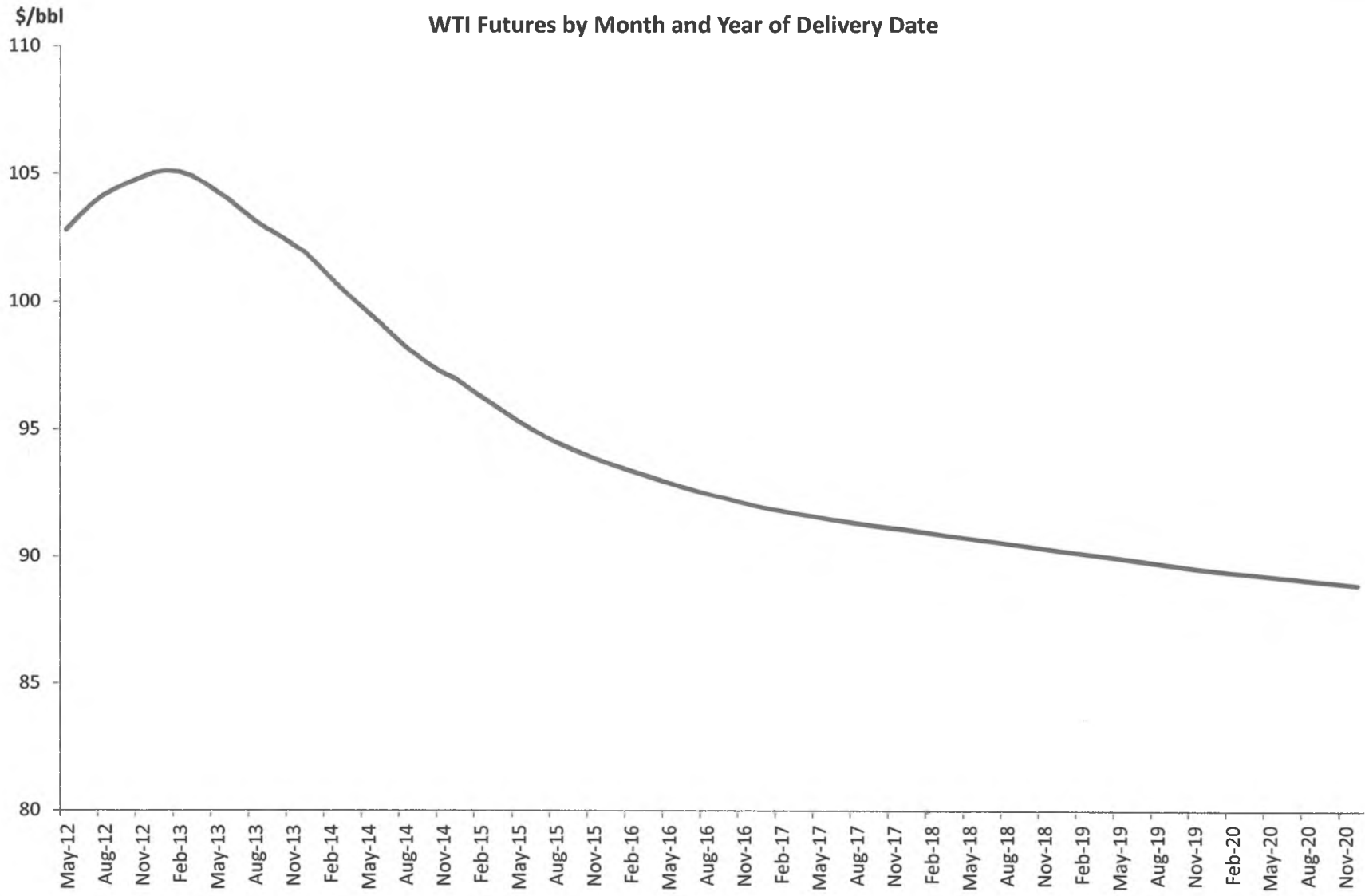
Summary of Progressive Severance Tax (Gross) Options

- The first option for the Progressive Severance Tax would use the following parameters:
 - No severance tax below \$65 Gross Value at Point of Production (GVPP)
 - Progressivity of .25% commencing at a threshold of \$65 GVPP
 - At \$125 GVPP, a tax rate of 15% is reached. At this point, progressivity is reduced to 0.05%
 - Progressivity is capped 20%
- A second option, which would freeze government take at 70% at \$100/bbl might look like this:
 - No severance tax below \$60 Gross Value at Point of Production (GVPP)
 - Progressivity of .25% commencing at a threshold of \$60 GVPP
 - At \$100 GVPP, a tax rate of 10% is reached. At this point, progressivity is reduced to 0.03%
 - Progressivity is capped 20%

Benefits of Progressive Severance Tax (Gross) Structure

- By removing progressivity from the Profit-Based Production Tax (Net), and having the progressive element of the structure be a Progressive Severance Tax (Gross), two things become much easier to achieve
 - The issue of gas production reducing production tax revenue ceases to be a problem without progressivity in the Profit-Based Production Tax
 - Complex provisions to split costs between oil and gas production under CSSB 192 are thus no longer required
 - Significant incentives can be provided to new production, by eliminating or reducing the Progressive Severance Tax (Gross) for new production
- A wide range of levels of government take can be achieved using this structure, depending on the parameters applied

WTI Light Sweet Crude - Forward Curve

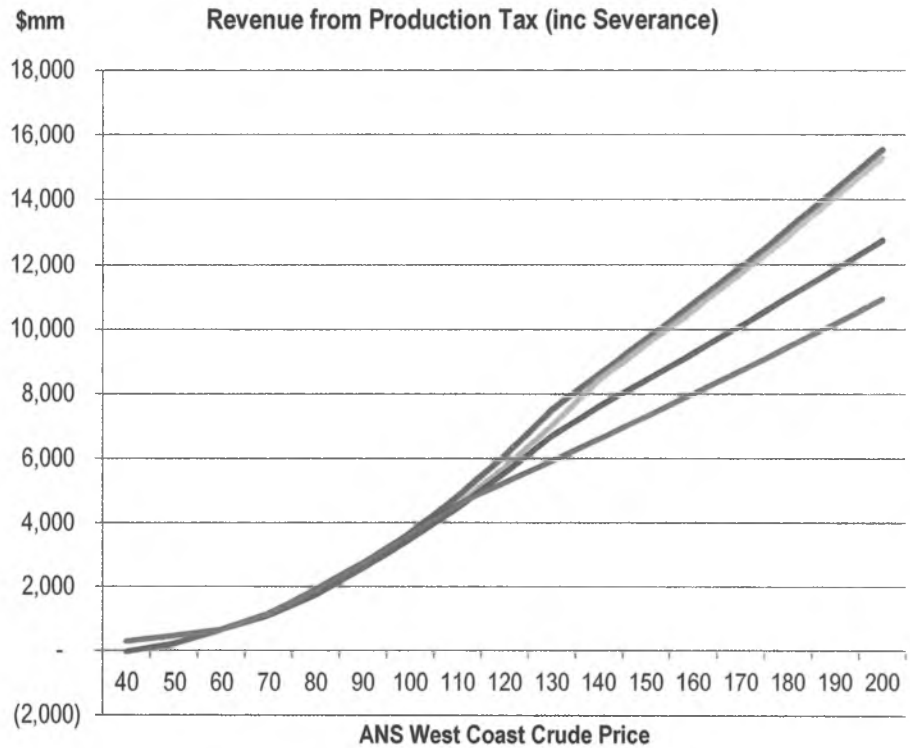


FY 2013 Revenue Comparison

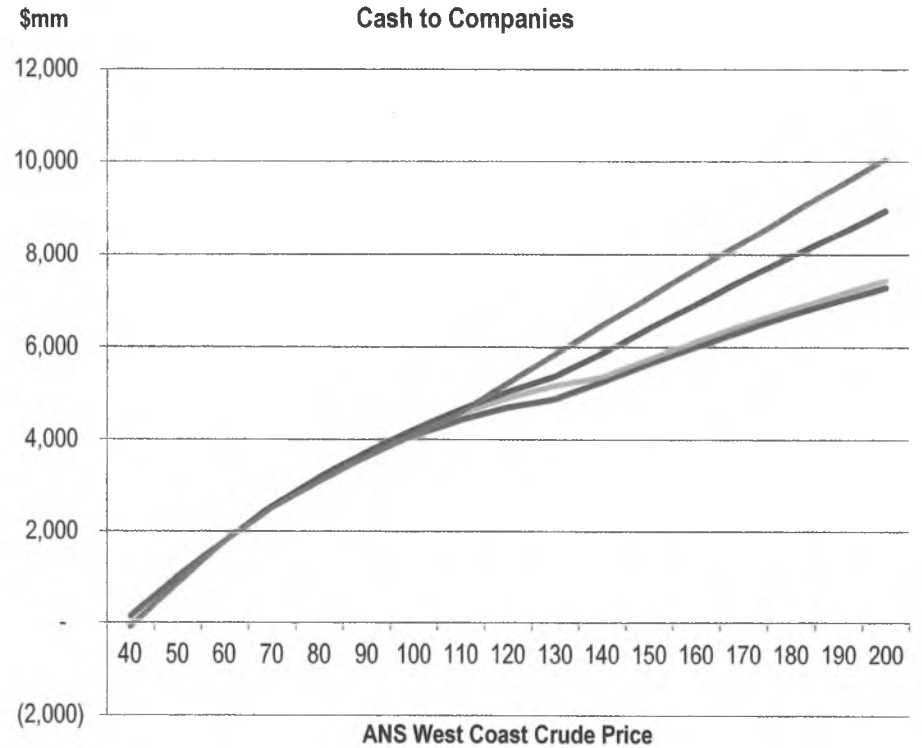
	Production Tax				Total State Take				Total Government Take				Cash to Companies				FY 2013 % Government Take			
	ACES	CSSB 192	Severance Tax Option 1	Severance Tax Option 2	ACES	CSSB 192	Severance Tax Option 1	Severance Tax Option 2	ACES	CSSB 192	Severance Tax Option 1	Severance Tax Option 2	ACES	CSSB 192	Severance Tax Option 1	Severance Tax Option 2	ACES	CSSB 192	Severance Tax Option 1	Severance Tax Option 2
40	(39)	289	289	289	1,352	1,660	1,660	1,660	1,427	1,660	1,660	1,660	139	(95)	(95)	(95)	91%	106%	106%	106%
50	222	461	461	461	1,983	2,202	2,202	2,202	2,527	2,669	2,669	2,669	1,010	868	868	868	71%	75%	75%	75%
60	653	653	653	653	2,769	2,769	2,769	2,769	3,728	3,728	3,728	3,728	1,780	1,780	1,780	1,780	68%	68%	68%	68%
70	1,109	1,106	1,084	1,157	3,577	3,575	3,555	3,621	4,943	4,941	4,929	4,972	2,536	2,538	2,551	2,508	66%	66%	66%	66%
80	1,831	1,792	1,754	1,909	4,631	4,595	4,560	4,702	6,318	6,294	6,272	6,364	3,133	3,157	3,179	3,087	67%	67%	66%	67%
90	2,692	2,599	2,571	2,747	5,811	5,725	5,699	5,861	7,775	7,719	7,703	7,807	3,648	3,703	3,720	3,615	68%	68%	67%	68%
100	3,691	3,527	3,474	3,671	7,117	6,966	6,918	7,099	9,314	9,216	9,184	9,302	4,080	4,178	4,209	4,092	70%	69%	69%	69%
110	4,827	4,575	4,463	4,577	8,549	8,318	8,215	8,320	10,935	10,785	10,718	10,786	4,430	4,581	4,647	4,579	71%	70%	70%	70%
120	6,102	5,744	5,538	5,240	10,108	9,781	9,592	9,319	12,638	12,425	12,302	12,125	4,698	4,911	5,034	5,212	73%	72%	71%	70%
130	7,515	7,035	6,700	5,914	11,794	11,354	11,047	10,327	14,424	14,138	13,939	13,470	4,884	5,170	5,370	5,838	75%	73%	72%	70%
140	8,614	8,445	7,598	6,597	13,192	13,037	12,261	11,345	16,023	15,922	15,417	14,822	5,257	5,357	5,862	6,458	75%	75%	72%	70%
150	9,684	9,512	8,417	7,291	14,563	14,406	13,402	12,372	17,604	17,502	16,849	16,179	5,647	5,749	6,402	7,072	76%	75%	72%	70%
160	10,787	10,601	9,253	7,996	15,965	15,794	14,559	13,408	19,205	19,094	18,291	17,543	6,017	6,128	6,931	7,679	76%	76%	73%	70%
170	11,925	11,723	10,106	8,710	17,399	17,214	15,732	14,454	20,827	20,707	19,744	18,913	6,367	6,487	7,450	8,281	77%	76%	73%	70%
180	13,098	12,880	10,977	9,435	18,864	18,665	16,921	15,509	22,470	22,340	21,207	20,289	6,696	6,825	7,959	8,876	77%	77%	73%	70%
190	14,305	14,072	11,864	10,171	20,361	20,148	18,126	16,574	24,133	23,994	22,680	21,671	7,004	7,143	8,457	9,465	78%	77%	73%	70%
200	15,546	15,298	12,769	10,917	21,890	21,662	19,346	17,649	25,816	25,668	24,163	23,060	7,292	7,440	8,945	10,048	78%	78%	73%	70%

Note: Consistent with DOR methodology, these revenue numbers do not include payments for tax credits which are not claimed against current production, as these are accounted for separately in the budget. In 2013, DOR forecasts a potential liability of \$400mm for these credits.

FY 2013 Revenue Comparison

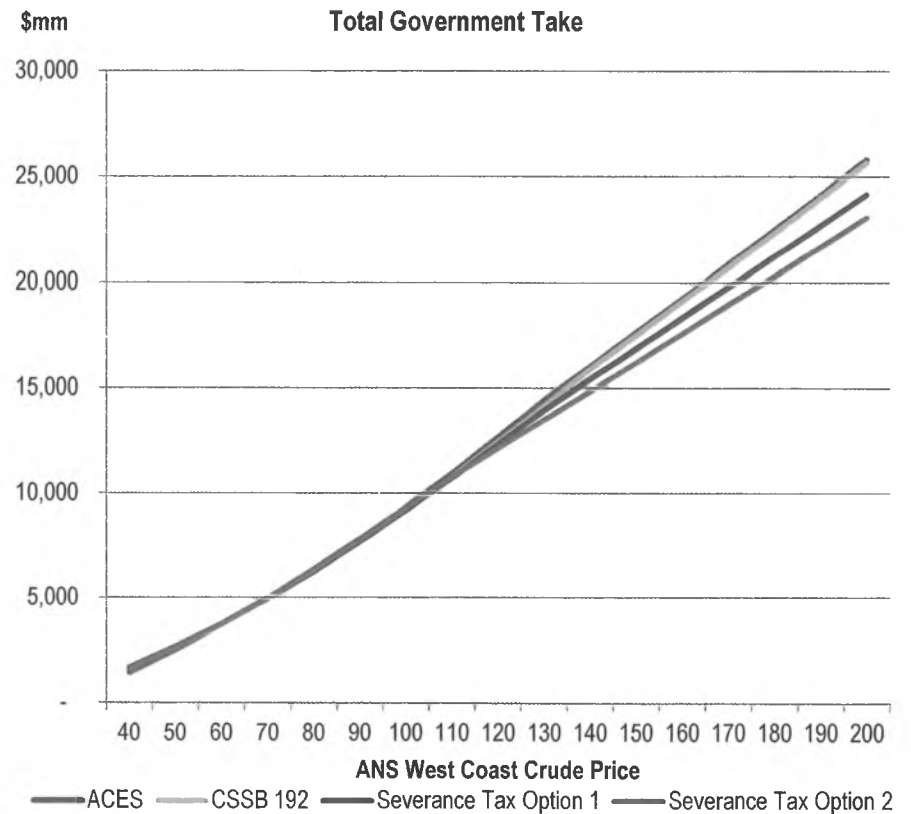
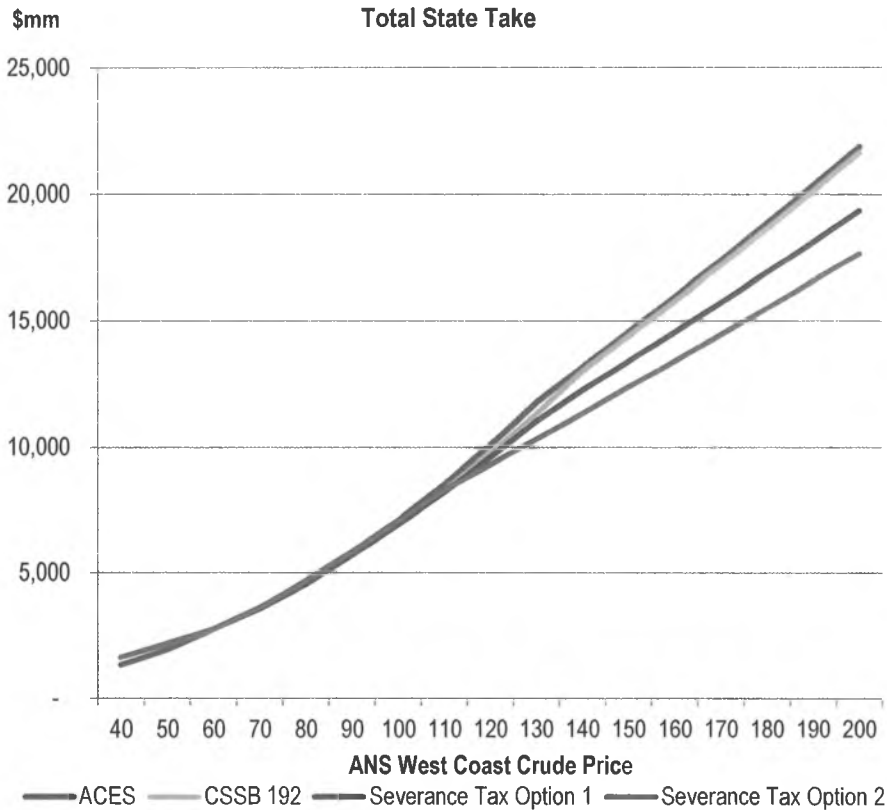


— ACES — CSSB 192 — Severance Tax Option 1 — Severance Tax Option 2



— ACES — CSSB 192 — Severance Tax Option 1 — Severance Tax Option 2

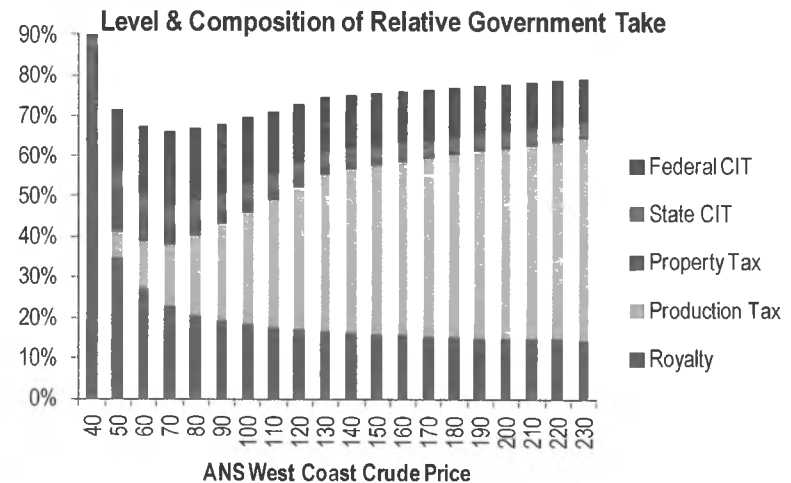
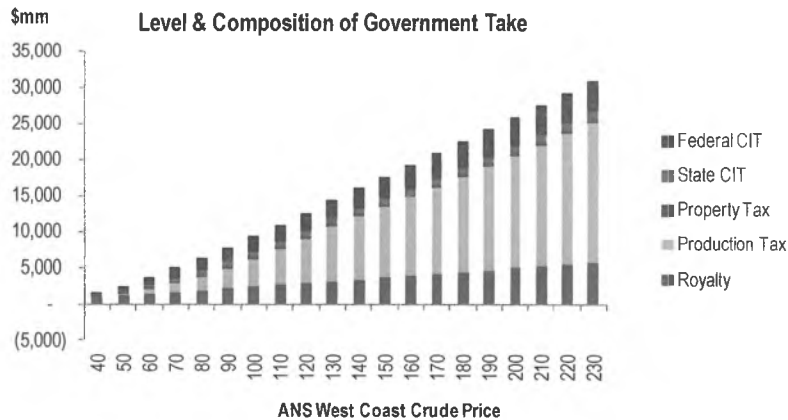
FY 2013 Revenue Comparison



ACES (FY 2013)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	986	(39)	386	20	1,352	75	1,427
50	1,232	222	386	143	1,983	544	2,527
60	1,479	653	386	251	2,769	959	3,728
70	1,725	1,109	386	358	3,577	1,366	4,943
80	1,971	1,831	386	442	4,631	1,687	6,318
90	2,218	2,692	386	515	5,811	1,964	7,775
100	2,464	3,691	386	576	7,117	2,197	9,314
110	2,711	4,827	386	625	8,549	2,386	10,935
120	2,957	6,102	386	663	10,108	2,530	12,638
130	3,204	7,515	386	689	11,794	2,630	14,424
140	3,450	8,614	386	742	13,192	2,831	16,023
150	3,696	9,684	386	797	14,563	3,041	17,604
160	3,943	10,787	386	849	15,965	3,240	19,205
170	4,189	11,925	386	898	17,399	3,428	20,827
180	4,436	13,098	386	945	18,864	3,605	22,470
190	4,682	14,305	386	988	20,361	3,771	24,133
200	4,929	15,546	386	1,029	21,890	3,926	25,816
210	5,175	16,822	386	1,066	23,450	4,070	27,520
220	5,421	18,133	386	1,101	25,042	4,203	29,245
230	5,668	19,478	386	1,133	26,665	4,325	30,990

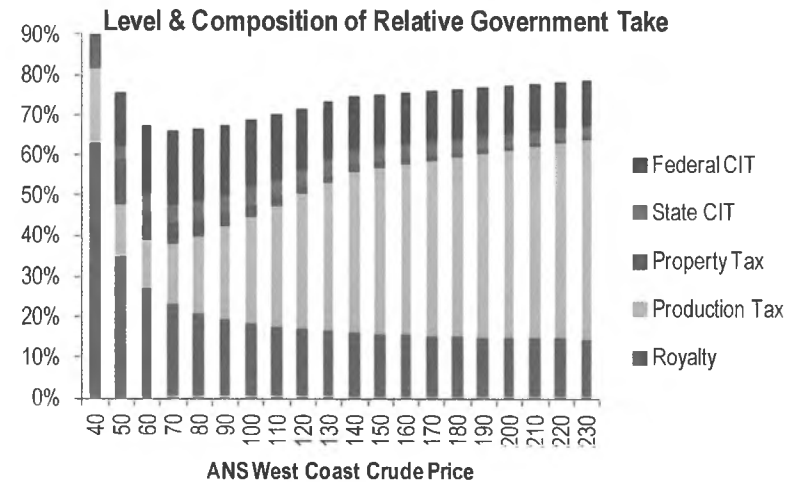
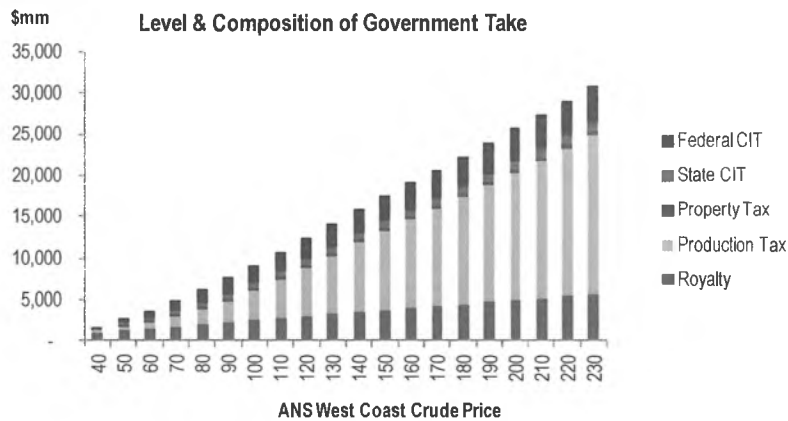
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-3%	25%	1%	66%	5%	91%
50	35%	6%	11%	4%	56%	15%	71%
60	27%	12%	7%	5%	50%	17%	68%
70	23%	15%	5%	5%	48%	18%	66%
80	21%	19%	4%	5%	49%	18%	67%
90	19%	24%	3%	5%	51%	17%	68%
100	18%	28%	3%	4%	53%	16%	70%
110	18%	31%	3%	4%	56%	16%	71%
120	17%	35%	2%	4%	58%	15%	73%
130	17%	39%	2%	4%	61%	14%	75%
140	16%	40%	2%	3%	62%	13%	75%
150	16%	42%	2%	3%	63%	13%	76%
160	16%	43%	2%	3%	63%	13%	76%
170	15%	44%	1%	3%	64%	13%	77%
180	15%	45%	1%	3%	65%	12%	77%
190	15%	46%	1%	3%	65%	12%	78%
200	15%	47%	1%	3%	66%	12%	78%
210	15%	48%	1%	3%	67%	12%	78%
220	15%	49%	1%	3%	68%	11%	79%
230	15%	50%	1%	3%	68%	11%	79%



CSSB 192 (FY 2013)

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	986	289	386	-	1,660	-	1,660
50	1,232	461	386	122	2,202	467	2,669
60	1,479	653	386	251	2,769	959	3,728
70	1,725	1,106	386	358	3,575	1,367	4,941
80	1,971	1,792	386	445	4,595	1,700	6,294
90	2,218	2,599	386	522	5,725	1,994	7,719
100	2,464	3,527	386	589	6,966	2,250	9,216
110	2,711	4,575	386	646	8,318	2,466	10,785
120	2,957	5,744	386	693	9,781	2,645	12,425
130	3,204	7,035	386	729	11,354	2,784	14,138
140	3,450	8,445	386	756	13,037	2,885	15,922
150	3,696	9,512	386	811	14,406	3,096	17,502
160	3,943	10,601	386	865	15,794	3,300	19,094
170	4,189	11,723	386	915	17,214	3,493	20,707
180	4,436	12,880	386	963	18,665	3,675	22,340
190	4,682	14,072	386	1,008	20,148	3,846	23,994
200	4,929	15,298	386	1,050	21,662	4,006	25,668
210	5,175	16,559	386	1,089	23,209	4,155	27,363
220	5,421	17,854	386	1,125	24,786	4,293	29,079
230	5,668	19,184	386	1,158	26,396	4,419	30,815

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	18%	25%	0%	106%	0%	106%
50	35%	13%	11%	3%	62%	13%	75%
60	27%	12%	7%	5%	50%	17%	68%
70	23%	15%	5%	5%	48%	18%	66%
80	21%	19%	4%	5%	49%	18%	67%
90	19%	23%	3%	5%	50%	17%	68%
100	18%	26%	3%	4%	52%	17%	69%
110	18%	30%	3%	4%	54%	16%	70%
120	17%	33%	2%	4%	56%	15%	72%
130	17%	36%	2%	4%	59%	14%	73%
140	16%	40%	2%	4%	61%	14%	75%
150	16%	41%	2%	3%	62%	13%	75%
160	16%	42%	2%	3%	63%	13%	76%
170	15%	43%	1%	3%	63%	13%	76%
180	15%	44%	1%	3%	64%	13%	77%
190	15%	45%	1%	3%	65%	12%	77%
200	15%	46%	1%	3%	65%	12%	78%
210	15%	47%	1%	3%	66%	12%	78%
220	15%	48%	1%	3%	67%	12%	78%
230	15%	49%	1%	3%	68%	11%	79%

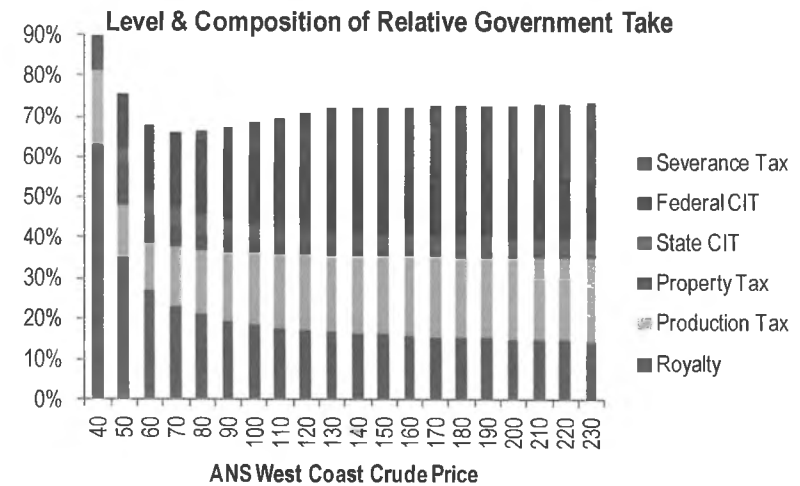
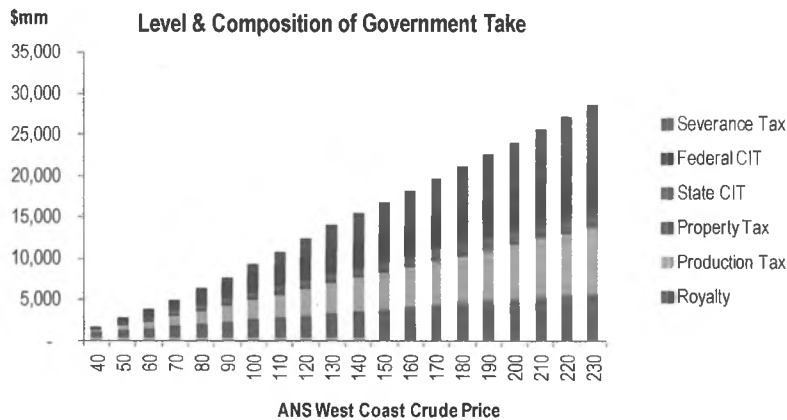


Severance Tax – 20% Maximum (FY 2013)

.25% progressivity from \$65 to \$125, then .10% progressivity

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	986	289	386	-	1,660	-	1,660
50	1,232	461	386	122	2,202	467	2,669
60	1,479	653	386	251	2,769	959	3,728
70	1,725	1,084	386	360	3,555	1,373	4,929
80	1,971	1,754	386	449	4,560	1,712	6,272
90	2,218	2,571	386	525	5,699	2,003	7,703
100	2,464	3,474	386	594	6,918	2,267	9,184
110	2,711	4,463	386	656	8,215	2,502	10,718
120	2,957	5,538	386	710	9,592	2,711	12,302
130	3,204	6,700	386	758	11,047	2,891	13,939
140	3,450	7,998	386	827	12,261	3,157	15,417
150	3,696	9,417	386	903	13,402	3,447	16,849
160	3,943	10,953	386	978	14,559	3,732	18,291
170	4,189	12,606	386	1,051	15,732	4,012	19,744
180	4,436	14,377	386	1,123	16,921	4,285	21,207
190	4,682	16,264	386	1,193	18,126	4,554	22,680
200	4,929	18,269	386	1,262	19,346	4,817	24,163
210	5,175	20,392	386	1,329	20,582	5,074	25,656
220	5,421	22,631	386	1,395	21,834	5,326	27,160
230	5,668	25,088	386	1,460	23,102	5,572	28,674

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	18%	25%	0%	106%	0%	106%
50	35%	13%	11%	3%	62%	13%	75%
60	27%	12%	7%	5%	50%	17%	68%
70	23%	14%	5%	5%	48%	18%	66%
80	21%	19%	4%	5%	48%	18%	66%
90	19%	23%	3%	5%	50%	18%	67%
100	18%	26%	3%	4%	52%	17%	69%
110	18%	29%	3%	4%	53%	16%	70%
120	17%	32%	2%	4%	55%	16%	71%
130	17%	35%	2%	4%	57%	15%	72%
140	16%	36%	2%	4%	58%	15%	72%
150	16%	36%	2%	4%	58%	15%	72%
160	16%	37%	2%	4%	58%	15%	73%
170	15%	37%	1%	4%	58%	15%	73%
180	15%	38%	1%	4%	58%	15%	73%
190	15%	38%	1%	4%	58%	15%	73%
200	15%	39%	1%	4%	58%	15%	73%
210	15%	39%	1%	4%	59%	14%	73%
220	15%	39%	1%	4%	59%	14%	73%
230	15%	40%	1%	4%	59%	14%	73%

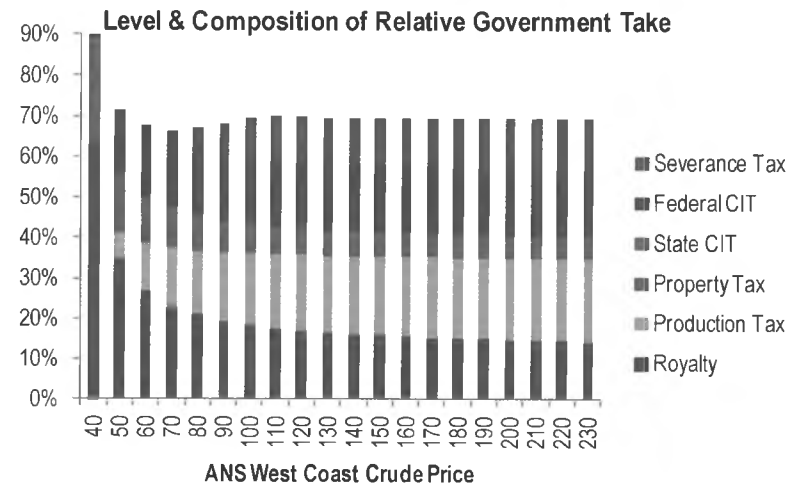
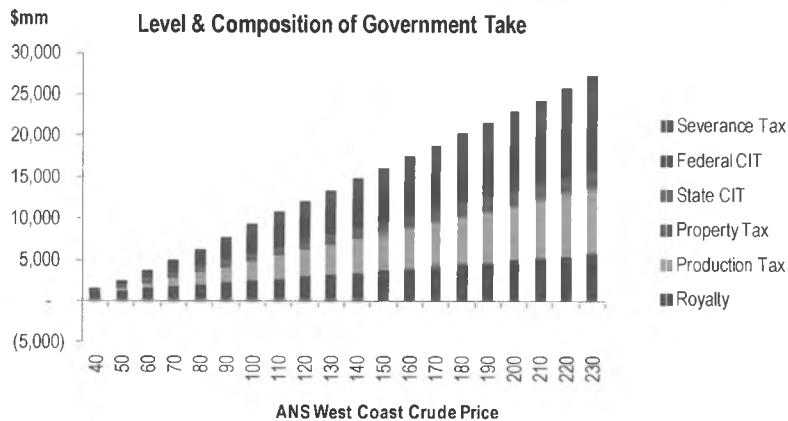


Severance Tax – 20% Maximum (FY 2013)

.25% progressivity from \$60 to \$100, then .03% progressivity

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	986	(39)	386	20	1,352	75	1,427
50	1,232	222	386	143	1,983	544	2,527
60	1,479	653	386	251	2,769	959	3,728
70	1,725	1,157	386	354	3,621	1,350	4,972
80	1,971	1,909	386	436	4,702	1,662	6,364
90	2,218	2,747	386	510	5,861	1,947	7,807
100	2,464	3,671	386	577	7,099	2,203	9,302
110	2,711	4,577	386	646	8,320	2,466	10,786
120	2,957	5,240	386	735	9,319	2,806	12,125
130	3,204	5,914	386	824	10,327	3,143	13,470
140	3,450	6,597	386	911	11,345	3,477	14,822
150	3,696	7,291	386	998	12,372	3,808	16,179
160	3,943	7,996	386	1,083	13,408	4,135	17,543
170	4,189	8,710	386	1,168	14,454	4,459	18,913
180	4,436	9,435	386	1,252	15,509	4,780	20,289
190	4,682	10,171	386	1,335	16,574	5,097	21,671
200	4,929	10,917	386	1,418	17,649	5,411	23,060
210	5,175	11,673	386	1,499	18,733	5,721	24,454
220	5,421	12,439	386	1,580	19,826	6,029	25,855
230	5,668	13,216	386	1,659	20,929	6,333	27,262

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	63%	-3%	25%	1%	86%	5%	91%
50	35%	6%	11%	4%	56%	15%	71%
60	27%	12%	7%	5%	50%	17%	68%
70	23%	15%	5%	5%	48%	18%	66%
80	21%	20%	4%	5%	50%	18%	67%
90	19%	24%	3%	4%	51%	17%	68%
100	18%	27%	3%	4%	53%	16%	69%
110	18%	30%	3%	4%	54%	16%	70%
120	17%	30%	2%	4%	54%	16%	70%
130	17%	31%	2%	4%	53%	16%	70%
140	16%	31%	2%	4%	53%	16%	70%
150	16%	31%	2%	4%	53%	16%	70%
160	16%	32%	2%	4%	53%	16%	70%
170	15%	32%	1%	4%	53%	16%	70%
180	15%	32%	1%	4%	53%	16%	70%
190	15%	33%	1%	4%	53%	16%	70%
200	15%	33%	1%	4%	53%	16%	70%
210	15%	33%	1%	4%	53%	16%	70%
220	15%	34%	1%	4%	54%	16%	70%
230	15%	34%	1%	4%	54%	16%	70%



Incentives for New Production

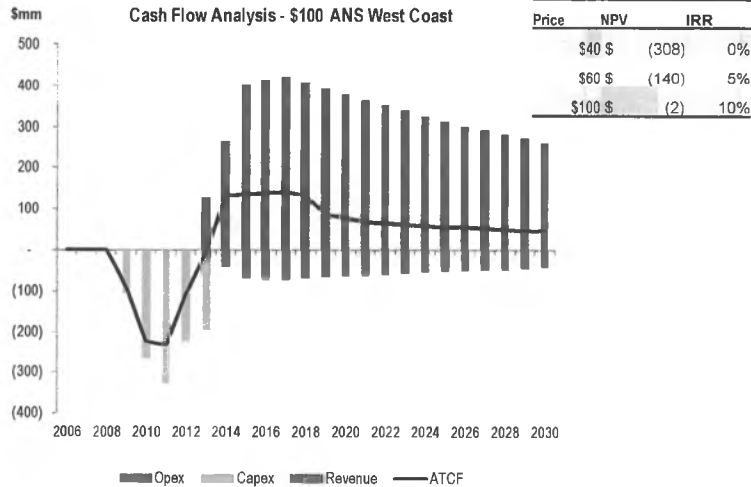
- Significant incentives can be provided to new production, by eliminating or reducing the Progressive Severance Tax (Gross) on any combination of:
 - Production from new areas
 - Production from new plans of development (determined through the regulatory process to be for “new production”)
 - Production above a fixed decline rate
- Here, a reduced rate of Progressive Severance Tax has been modeled, using the following parameters for new production:
 - Base rate of 0%
 - Progressivity of .05% commencing at a threshold of \$65 (gross value at point of production)
 - Progressivity is capped 5%
- Following slides show a new, high-cost 10 mb/d development under
 - The regular rate
 - The reduced rate (with a time limit of 7 years)
 - The reduced rate (with no time limit)

Note on Impact of Inflation

- Under ACES, thresholds and coefficients for progressivity are specified in nominal terms, without indexation
 - As a result, when economics over the long-term rather than just 2013 are examined, we see the effects of ‘bracket creep’ or ‘stealth tax’
 - In real terms, as prices increase, thresholds for progressivity decrease, and the higher take that comes with progressivity occurs at lower and lower price levels
- Severance tax options are also currently shown assuming nominal thresholds
 - As a result, in the charts, the impact of the severance tax can be seen below the \$60/\$65 level at which it applies – a result of bracket-creep over the lifetime of a project
- It is strongly worth considering the application of price indexation to thresholds for progressivity

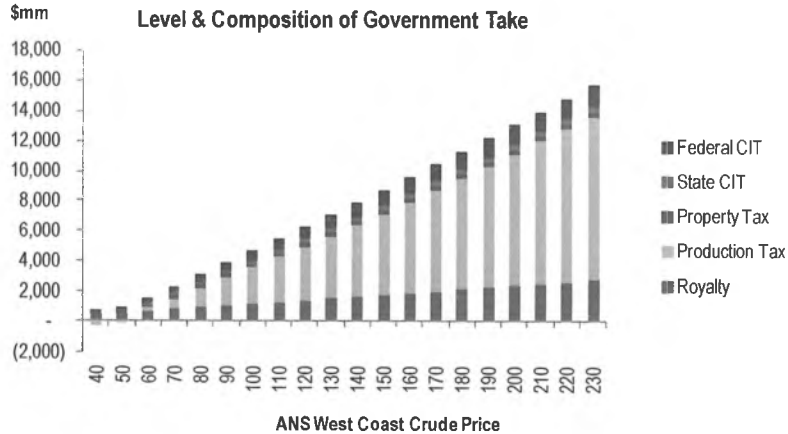
ACES (New Development)

Cash Flow Analysis - \$100 ANS West Coast

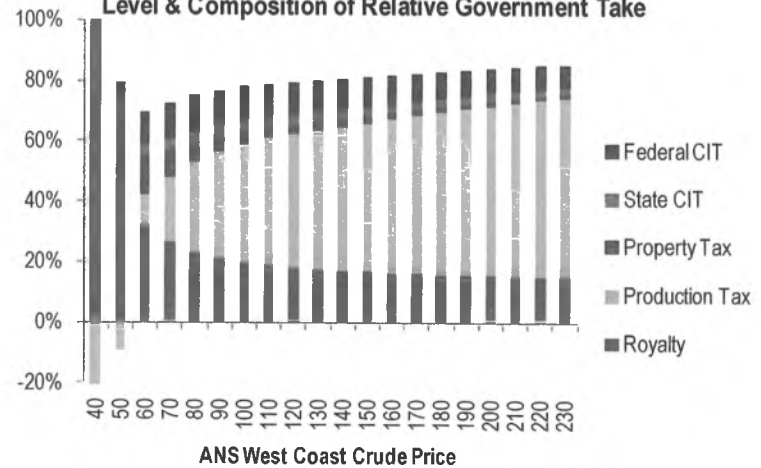


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	-114%	96%	0%	138%	0%	138%
50	47%	-9%	23%	2%	63%	7%	70%
60	32%	10%	13%	3%	58%	11%	70%
70	26%	22%	9%	3%	60%	12%	73%
80	23%	30%	7%	3%	63%	12%	75%
90	21%	35%	6%	3%	65%	12%	77%
100	20%	39%	5%	3%	67%	11%	78%
110	19%	42%	4%	3%	68%	11%	79%
120	18%	44%	4%	3%	69%	11%	80%
130	17%	46%	3%	3%	69%	11%	80%
140	17%	48%	3%	3%	70%	10%	81%
150	17%	49%	3%	3%	71%	10%	81%
160	16%	51%	2%	3%	72%	10%	82%
170	16%	52%	2%	2%	73%	9%	83%
180	16%	54%	2%	2%	74%	9%	83%
190	16%	55%	2%	2%	75%	9%	84%
200	15%	56%	2%	2%	76%	8%	84%
210	15%	57%	2%	2%	76%	8%	85%
220	15%	58%	2%	2%	77%	8%	85%
230	15%	59%	2%	2%	78%	8%	85%

Level & Composition of Government Take

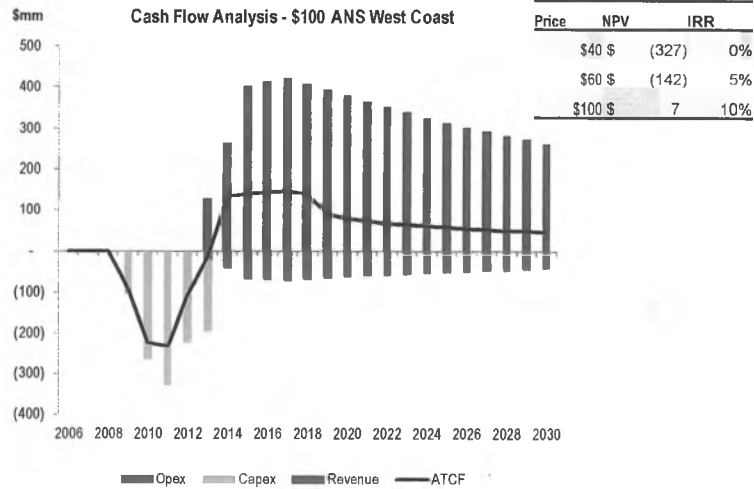


Level & Composition of Relative Government Take



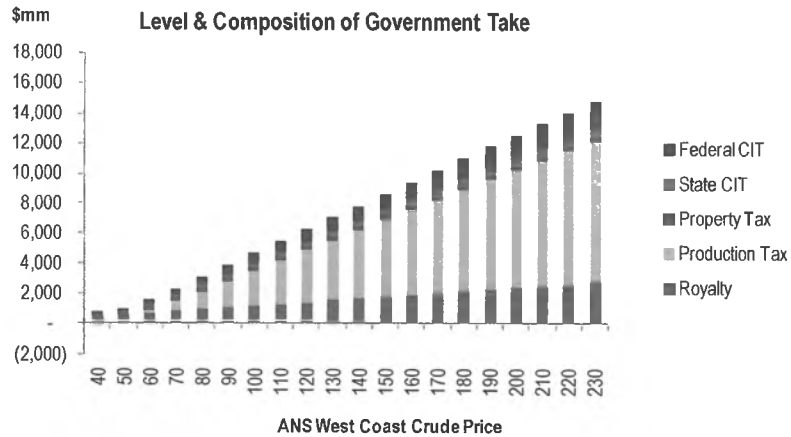
CSSB 192 (New Development)

Cash Flow Analysis - \$100 ANS West Coast

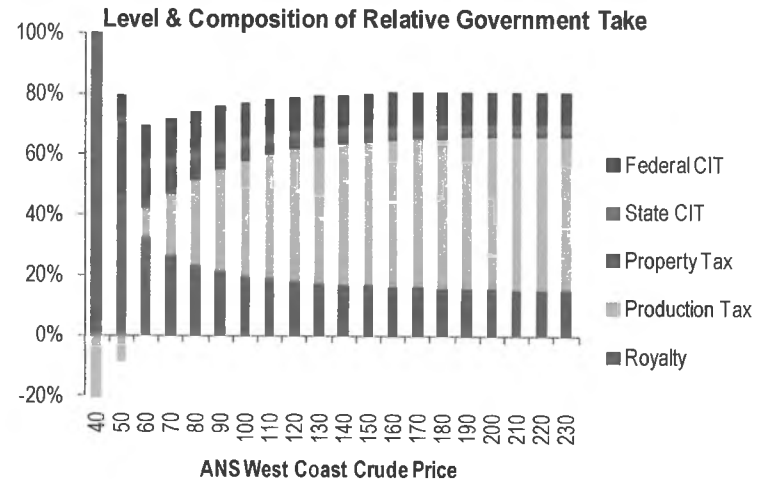


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	-81%	96%	0%	170%	0%	170%
50	47%	-9%	23%	2%	64%	7%	70%
60	32%	9%	13%	3%	58%	12%	70%
70	26%	20%	9%	3%	59%	13%	72%
80	23%	28%	7%	3%	62%	13%	74%
90	21%	34%	6%	3%	64%	12%	76%
100	20%	38%	5%	3%	65%	12%	77%
110	19%	41%	4%	3%	67%	11%	78%
120	18%	43%	4%	3%	68%	11%	79%
130	17%	45%	3%	3%	69%	11%	80%
140	17%	46%	3%	3%	69%	11%	80%
150	17%	47%	3%	3%	69%	11%	80%
160	16%	48%	2%	3%	70%	11%	80%
170	16%	49%	2%	3%	70%	10%	80%
180	16%	50%	2%	3%	70%	10%	81%
190	16%	50%	2%	3%	70%	10%	81%
200	15%	50%	2%	3%	70%	10%	81%
210	15%	51%	2%	3%	70%	10%	81%
220	15%	51%	2%	3%	70%	10%	80%
230	15%	51%	2%	3%	70%	10%	80%

Level & Composition of Government Take



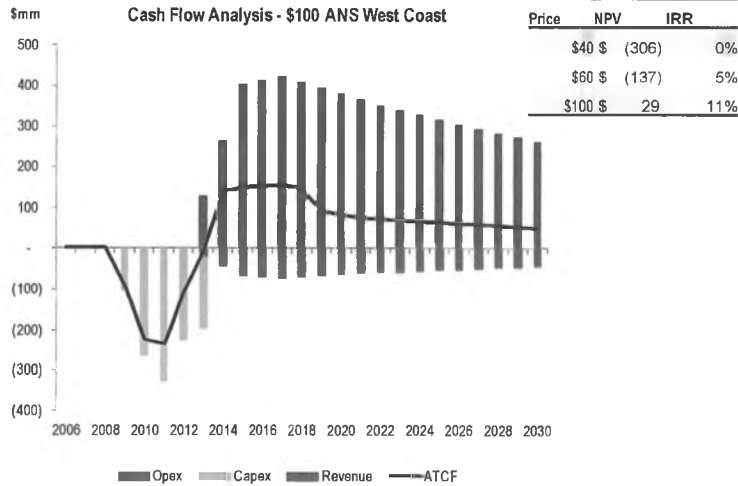
Level & Composition of Relative Government Take



Severance Tax – 20% Maximum (New Producer)

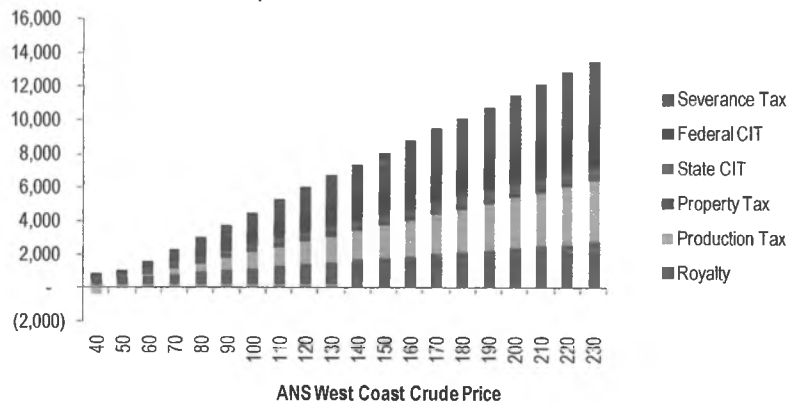
.25% progressivity from \$65 to \$125, then .10% progressivity

Cash Flow Analysis - \$100 ANS West Coast

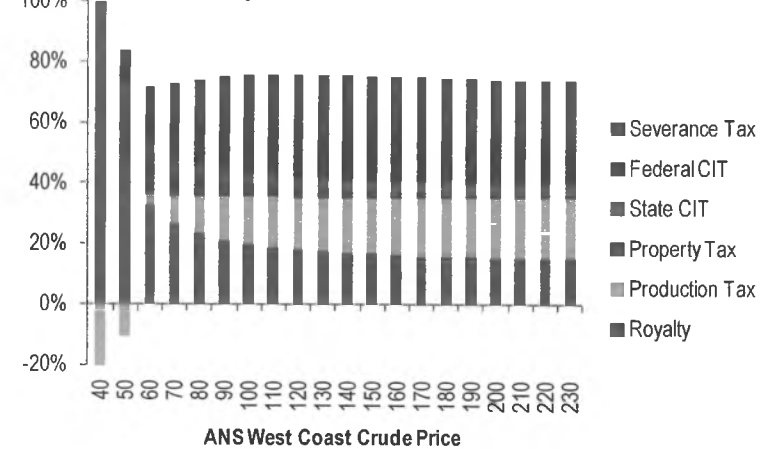


Price	Royalty	Severance Tax	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	4%	-115%	96%	0%	140%	0%	140%
50	47%	6%	-11%	23%	1%	67%	6%	73%
60	32%	9%	3%	13%	3%	61%	10%	71%
70	26%	13%	9%	9%	3%	61%	12%	73%
80	23%	16%	12%	7%	3%	62%	12%	74%
90	21%	18%	14%	6%	3%	63%	12%	75%
100	20%	20%	15%	5%	3%	63%	12%	75%
110	19%	21%	16%	4%	3%	63%	13%	76%
120	18%	21%	17%	4%	3%	63%	13%	76%
130	17%	22%	17%	3%	3%	63%	13%	76%
140	17%	22%	18%	3%	3%	63%	13%	75%
150	17%	22%	18%	3%	3%	62%	13%	75%
160	16%	21%	18%	2%	3%	62%	13%	75%
170	16%	21%	19%	2%	3%	62%	13%	75%
180	16%	21%	19%	2%	4%	61%	13%	75%
190	16%	21%	19%	2%	4%	61%	13%	74%
200	15%	21%	19%	2%	4%	60%	13%	74%
210	15%	20%	19%	2%	4%	60%	14%	74%
220	15%	20%	19%	2%	4%	60%	14%	74%
230	15%	20%	20%	2%	4%	60%	14%	74%

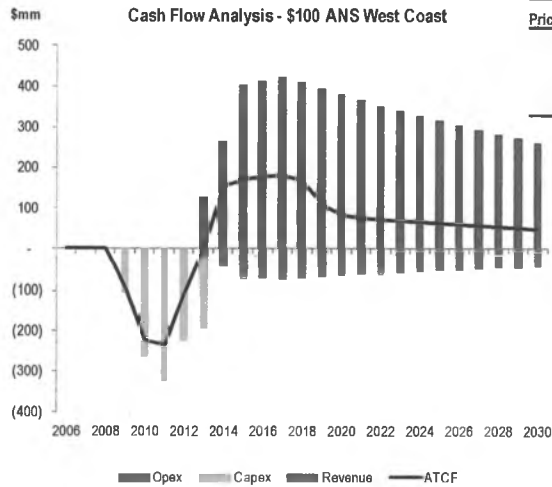
Level & Composition of Government Take



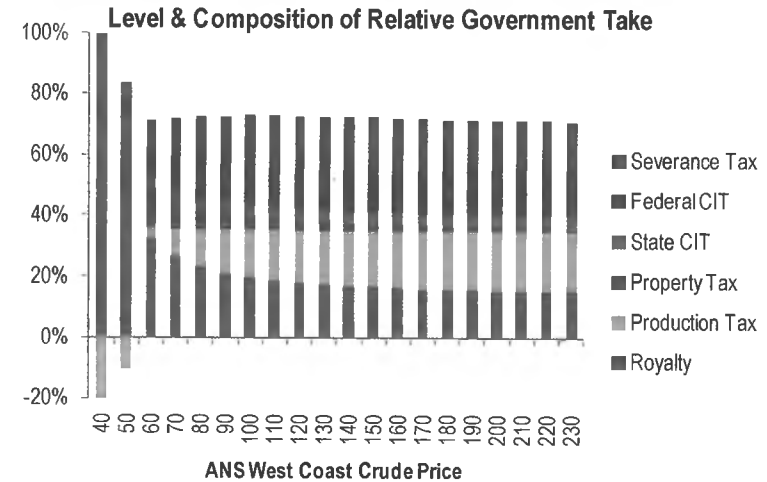
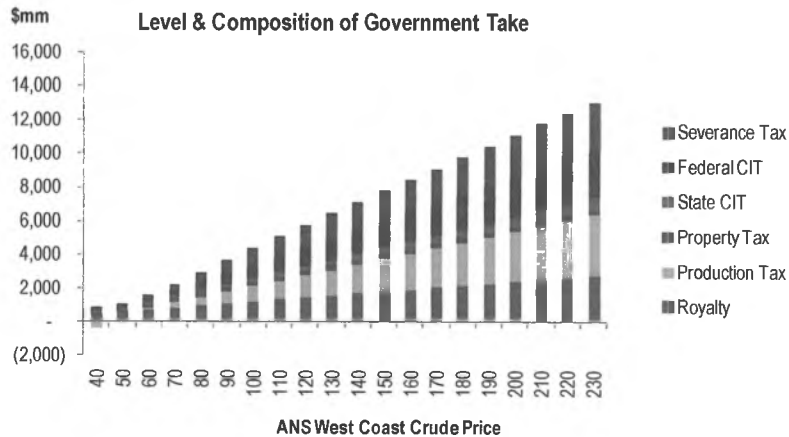
Level & Composition of Relative Government Take



Severance Tax – 20% Maximum with first 7 years at 5% (New Producer) .25% progressivity from \$65 to \$125, then .10% progressivity



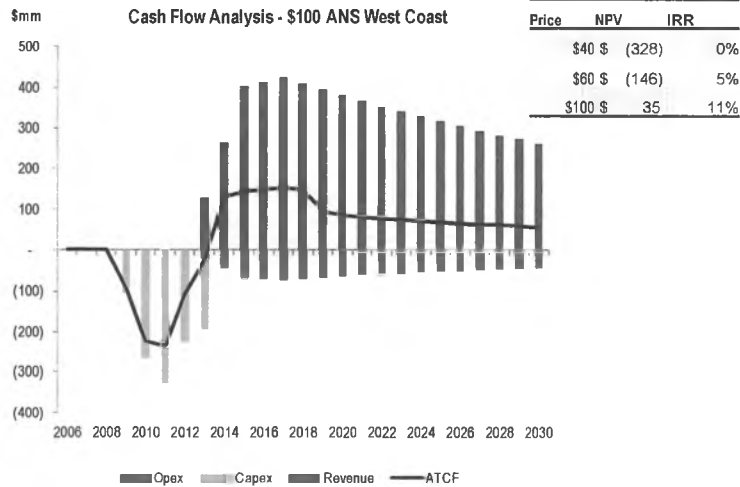
Price	Royalty	Severance Tax	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	4%	-115%	96%	0%	140%	0%	140%
50	47%	6%	-11%	23%	1%	67%	6%	73%
60	32%	9%	3%	13%	3%	61%	10%	71%
70	26%	12%	9%	9%	3%	60%	12%	72%
80	23%	15%	12%	7%	3%	60%	12%	73%
90	21%	16%	14%	6%	3%	61%	12%	73%
100	20%	17%	15%	5%	3%	60%	13%	73%
110	19%	18%	16%	4%	3%	60%	13%	73%
120	18%	18%	17%	4%	3%	60%	13%	73%
130	17%	18%	17%	3%	4%	59%	13%	73%
140	17%	18%	18%	3%	4%	59%	14%	73%
150	17%	18%	18%	3%	4%	59%	14%	72%
160	16%	17%	18%	2%	4%	58%	14%	72%
170	16%	17%	19%	2%	4%	58%	14%	72%
180	16%	17%	19%	2%	4%	57%	14%	72%
190	16%	17%	19%	2%	4%	57%	14%	71%
200	15%	17%	19%	2%	4%	57%	15%	71%
210	15%	16%	19%	2%	4%	57%	15%	71%
220	15%	16%	19%	2%	4%	56%	15%	71%
230	15%	16%	20%	2%	4%	56%	15%	71%



Severance Tax - 20% maximum (New Development)

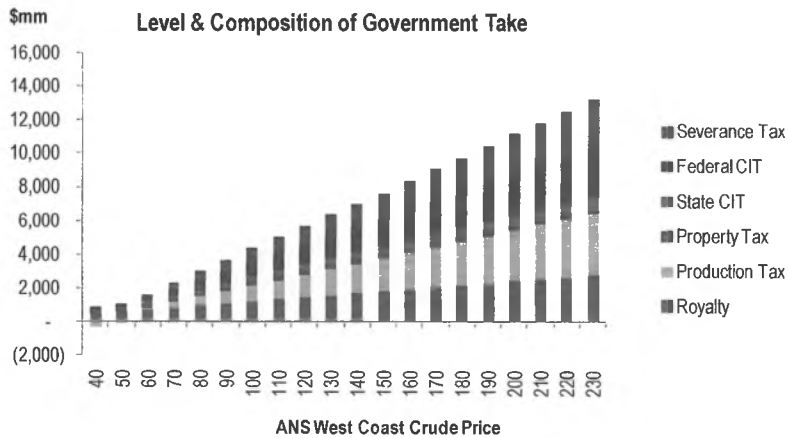
.25% progressivity from \$60 to \$100, then .03% progressivity

Cash Flow Analysis - \$100 ANS West Coast

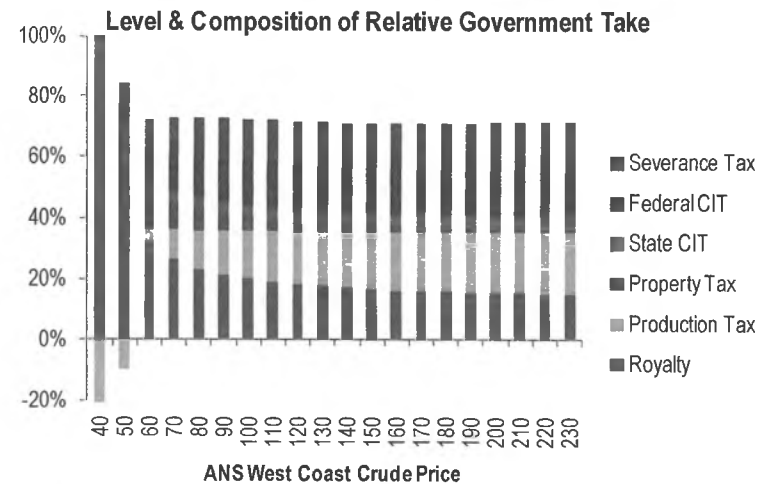


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	-81%	96%	0%	170%	0%	177%
50	47%	-10%	23%	1%	62%	5%	75%
60	32%	4%	13%	3%	52%	10%	72%
70	26%	10%	9%	3%	48%	12%	73%
80	23%	13%	7%	3%	46%	13%	73%
90	21%	15%	6%	4%	45%	14%	73%
100	20%	16%	5%	4%	44%	14%	73%
110	19%	17%	4%	4%	43%	14%	72%
120	18%	17%	4%	4%	43%	15%	72%
130	17%	18%	3%	4%	42%	15%	72%
140	17%	18%	3%	4%	42%	15%	71%
150	17%	18%	3%	4%	42%	15%	71%
160	16%	19%	2%	4%	41%	15%	72%
170	16%	19%	2%	4%	41%	15%	71%
180	16%	19%	2%	4%	41%	15%	71%
190	16%	19%	2%	4%	41%	15%	71%
200	15%	19%	2%	4%	40%	15%	72%
210	15%	20%	2%	4%	40%	15%	72%
220	15%	20%	2%	4%	40%	15%	72%
230	15%	20%	2%	4%	40%	15%	72%

Level & Composition of Government Take

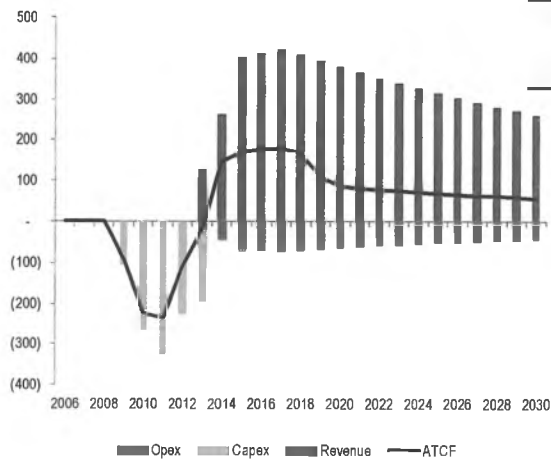


Level & Composition of Relative Government Take



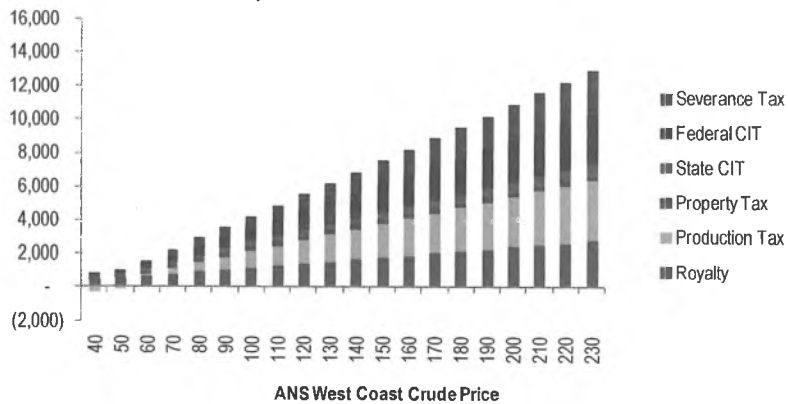
Severance Tax – 20% Maximum with first 7 years at 5% (New Producer) .25% progressivity from \$60 to \$100, then .03% progressivity

Cash Flow Analysis - \$100 ANS West Coast

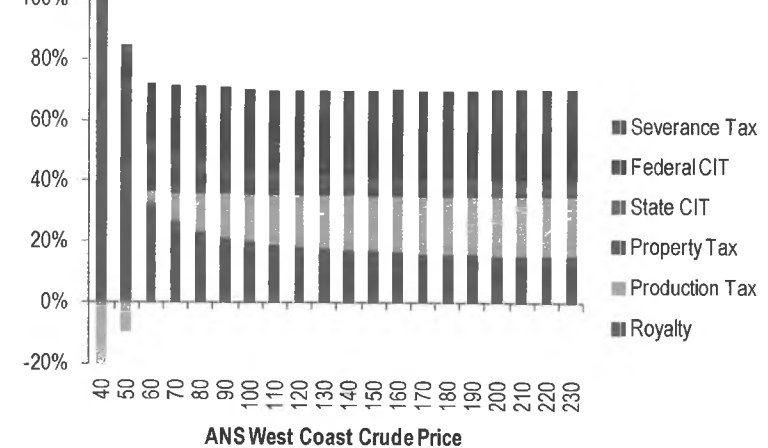


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	-81%	96%	0%	170%	0%	177%
50	47%	-10%	23%	1%	62%	5%	75%
60	32%	4%	13%	3%	52%	10%	72%
70	26%	10%	9%	3%	48%	12%	72%
80	23%	13%	7%	3%	46%	13%	71%
90	21%	15%	6%	4%	45%	14%	71%
100	20%	16%	5%	4%	44%	14%	70%
110	19%	17%	4%	4%	43%	15%	70%
120	18%	17%	4%	4%	43%	15%	70%
130	17%	18%	3%	4%	42%	15%	70%
140	17%	18%	3%	4%	42%	15%	70%
150	17%	18%	3%	4%	42%	15%	70%
160	16%	19%	2%	4%	41%	15%	70%
170	16%	19%	2%	4%	41%	15%	70%
180	16%	19%	2%	4%	41%	15%	70%
190	16%	19%	2%	4%	41%	15%	70%
200	15%	19%	2%	4%	41%	15%	70%
210	15%	20%	2%	4%	41%	15%	70%
220	15%	20%	2%	4%	40%	15%	70%
230	15%	20%	2%	4%	40%	15%	70%

Level & Composition of Government Take

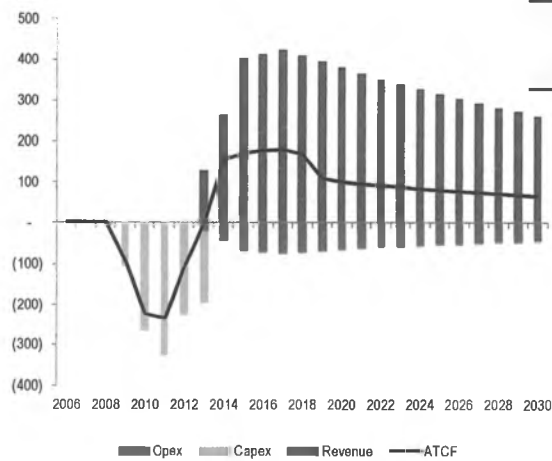


Level & Composition of Relative Government Take



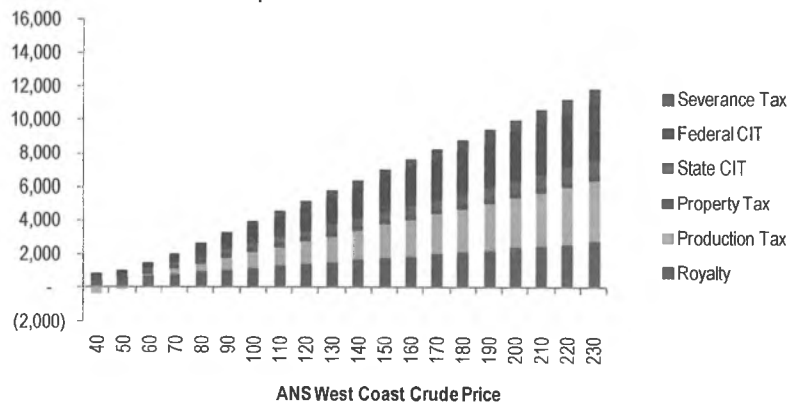
Severance Tax – 5% Maximum (New Producer)

Cash Flow Analysis - \$100 ANS West Coast

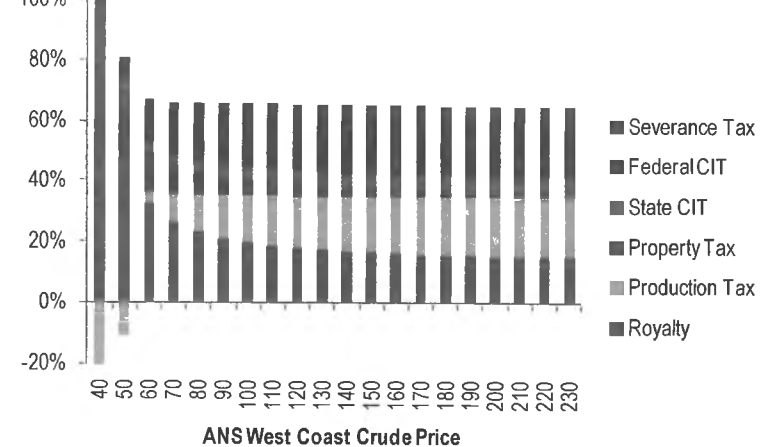


Price	Royalty	Severance Tax	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	156%	1%	-115%	96%	0%	137%	0%	137%
50	47%	1%	-11%	23%	2%	63%	7%	69%
60	32%	2%	3%	13%	3%	54%	13%	67%
70	26%	3%	9%	9%	4%	51%	15%	66%
80	23%	4%	12%	7%	4%	50%	16%	66%
90	21%	4%	14%	6%	4%	49%	16%	66%
100	20%	5%	15%	5%	4%	49%	17%	66%
110	19%	5%	16%	4%	4%	49%	17%	66%
120	18%	5%	17%	4%	5%	48%	17%	65%
130	17%	5%	17%	3%	5%	48%	17%	65%
140	17%	5%	18%	3%	5%	48%	17%	65%
150	17%	5%	18%	3%	5%	47%	18%	65%
160	16%	5%	18%	2%	5%	47%	18%	65%
170	16%	5%	19%	2%	5%	47%	18%	65%
180	16%	5%	19%	2%	5%	47%	18%	65%
190	16%	5%	19%	2%	5%	46%	18%	65%
200	15%	5%	19%	2%	5%	46%	18%	65%
210	15%	5%	19%	2%	5%	46%	18%	65%
220	15%	5%	19%	2%	5%	46%	18%	65%
230	15%	5%	20%	2%	5%	46%	19%	64%

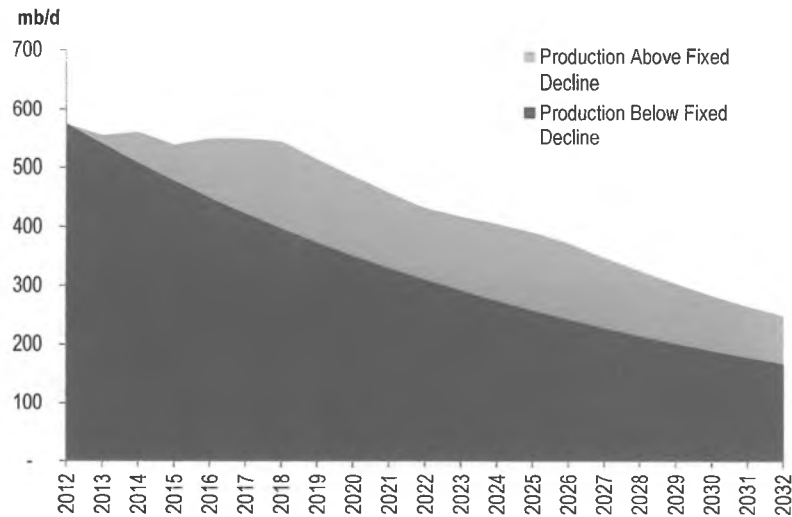
Level & Composition of Government Take



Level & Composition of Relative Government Take



20 Year Revenue Impact of Reduced Rate for New Production (Using Severance Tax Option 1)



20 Year NPV of Cash Flows - Severance Option 1

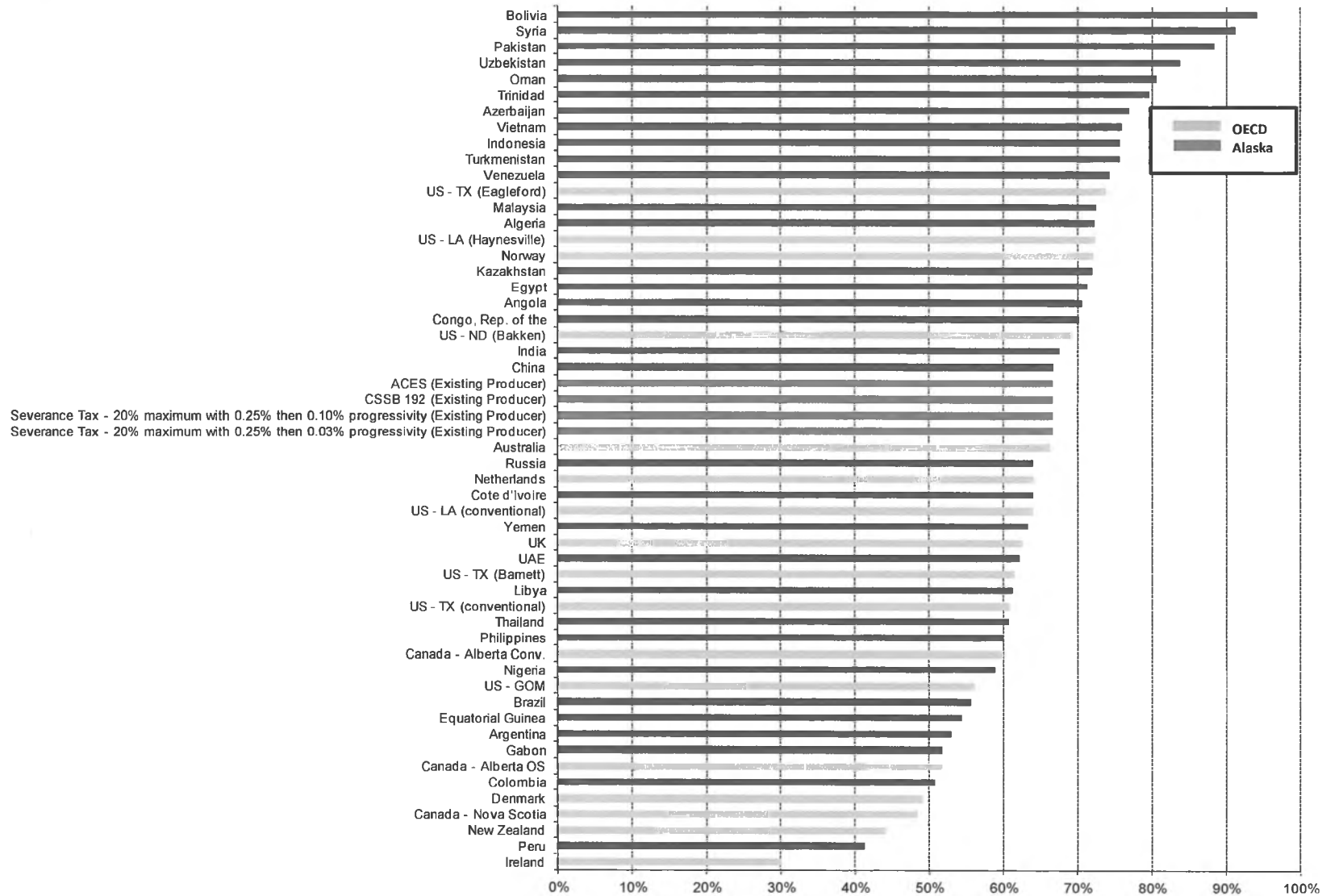
	Production Tax		Total State Take		Total Government Tak		Cash to Companies	
	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production
ANS West Coast Oil Price								
40	2,397	2,397	18,074	18,074	22,497	22,497	7,800	7,800
50	5,155	5,127	25,267	25,241	35,402	35,385	18,407	18,424
60	10,952	10,718	35,245	35,030	50,117	49,978	27,205	27,345
70	18,969	18,227	47,256	46,576	66,154	65,712	34,682	35,124
80	29,238	27,781	61,330	59,995	83,532	82,664	40,817	41,685
90	40,501	38,236	76,314	74,239	101,501	100,152	46,361	47,709
100	52,361	49,303	91,845	89,044	119,825	118,005	51,550	53,370
110	64,411	60,646	107,550	104,101	138,263	136,022	56,625	58,866
120	76,124	71,799	122,946	118,985	156,501	153,926	61,900	64,475
130	86,904	82,096	137,488	133,084	174,182	171,320	67,732	70,595
140	97,030	91,691	151,431	146,540	191,475	188,296	73,952	77,131
150	107,336	101,401	165,539	160,102	208,875	205,341	80,066	83,599

20 Year NPV of Cash Flows - Severance Option 2

	Production Tax		Total State Take		Total Government Tak		Cash to Companies	
	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production	High Rate Only	Reduced Rate for New Production
ANS West Coast Oil Price								
40	2,397	2,397	18,074	18,074	22,497	22,497	7,800	7,800
50	5,323	5,257	25,421	25,361	35,502	35,463	18,307	18,346
60	11,634	11,269	35,870	35,536	50,523	50,306	26,799	27,016
70	20,482	19,563	48,641	47,800	67,055	66,507	33,781	34,328
80	30,396	28,904	62,391	61,024	84,221	83,333	40,128	41,016
90	40,472	38,512	76,287	74,492	101,484	100,317	46,378	47,545
100	49,999	47,776	89,681	87,645	118,419	117,095	52,956	54,280
110	58,364	55,970	102,011	99,818	134,663	133,238	60,225	61,650
120	66,563	63,978	114,188	111,820	150,808	149,269	67,593	69,132
130	74,910	72,095	126,501	123,924	167,041	165,365	74,873	76,549
140	83,405	80,307	138,951	136,113	183,363	181,518	82,065	83,909
150	92,050	88,595	151,537	148,372	199,773	197,716	89,167	91,224

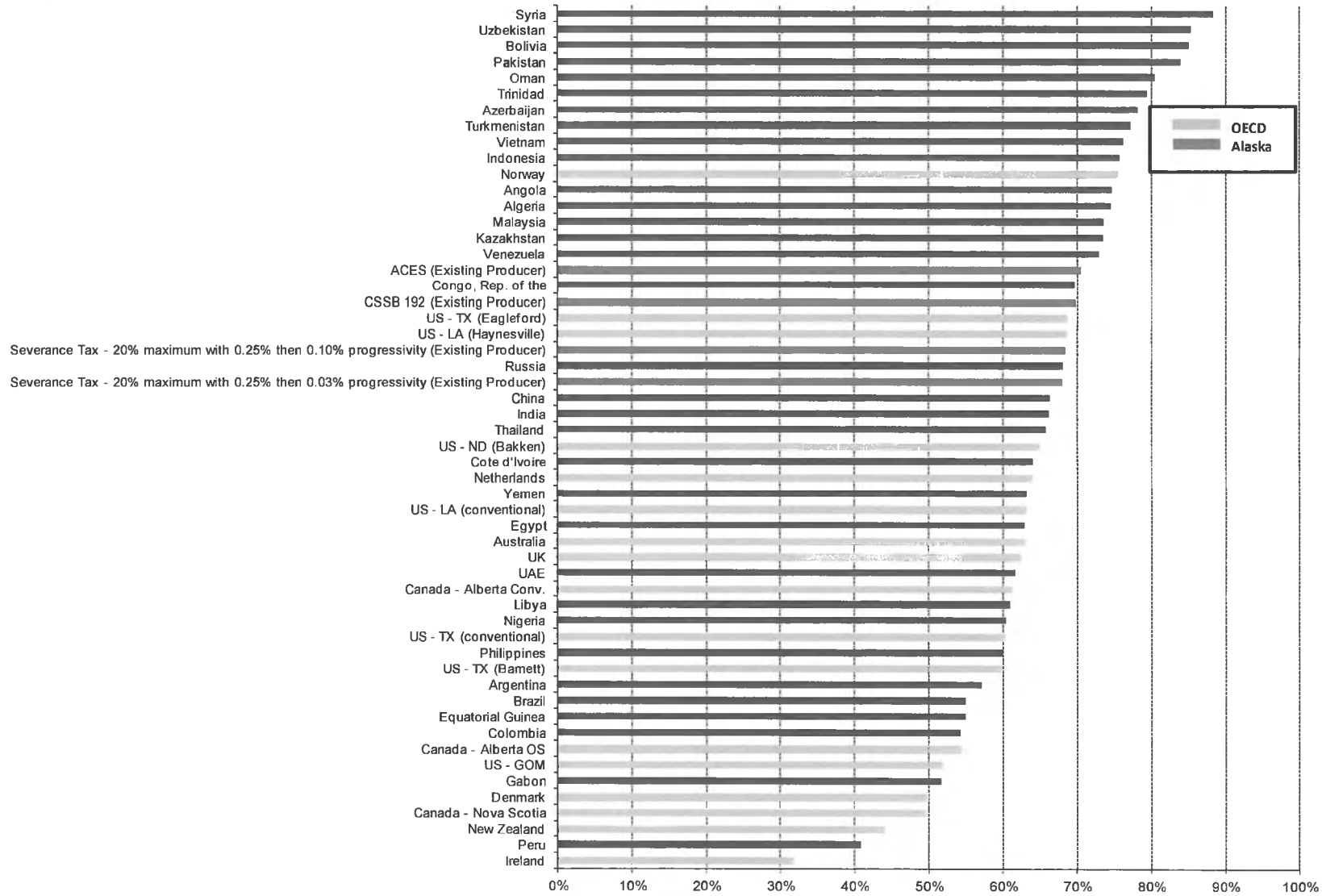
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$60/bbl



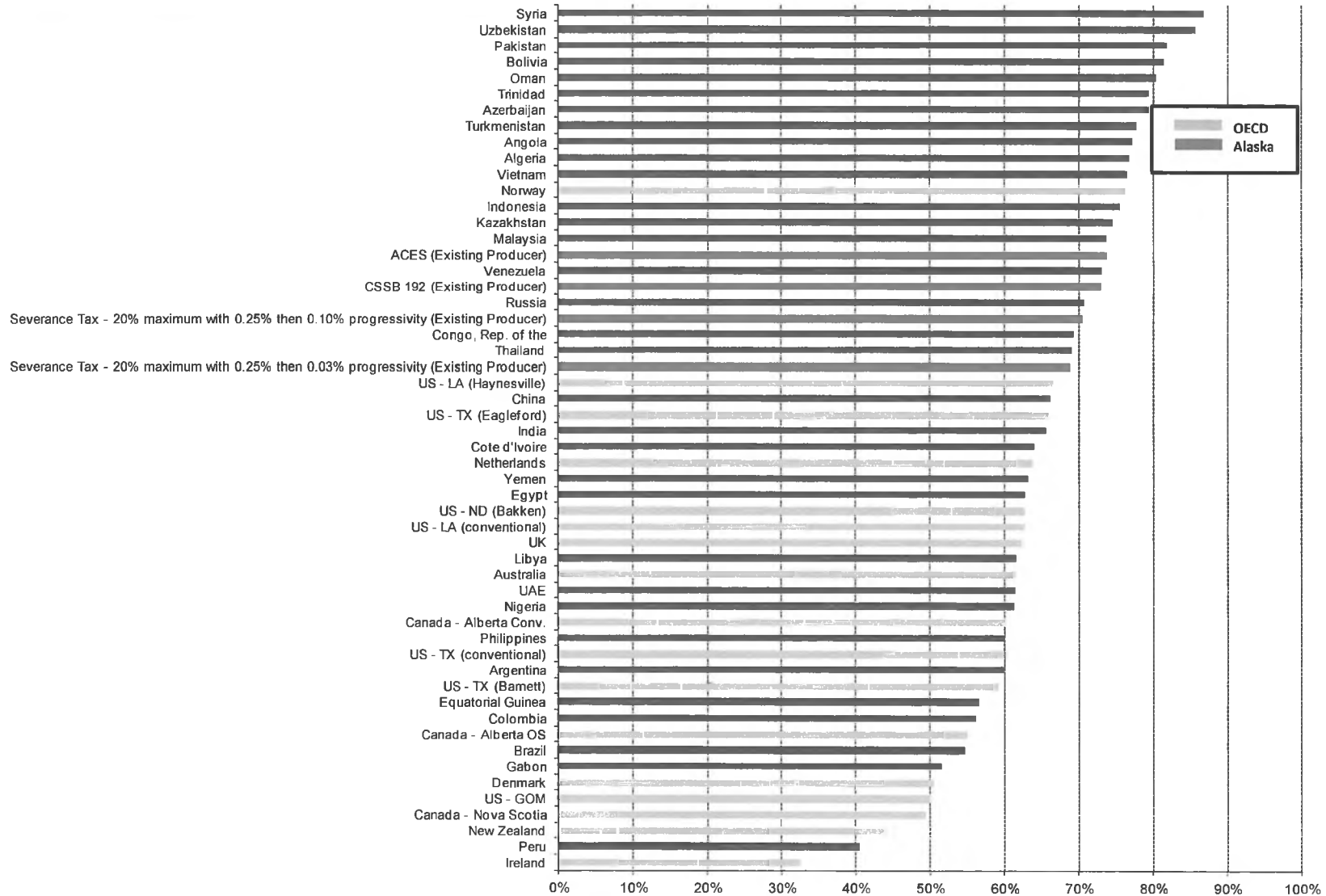
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$80/bbl



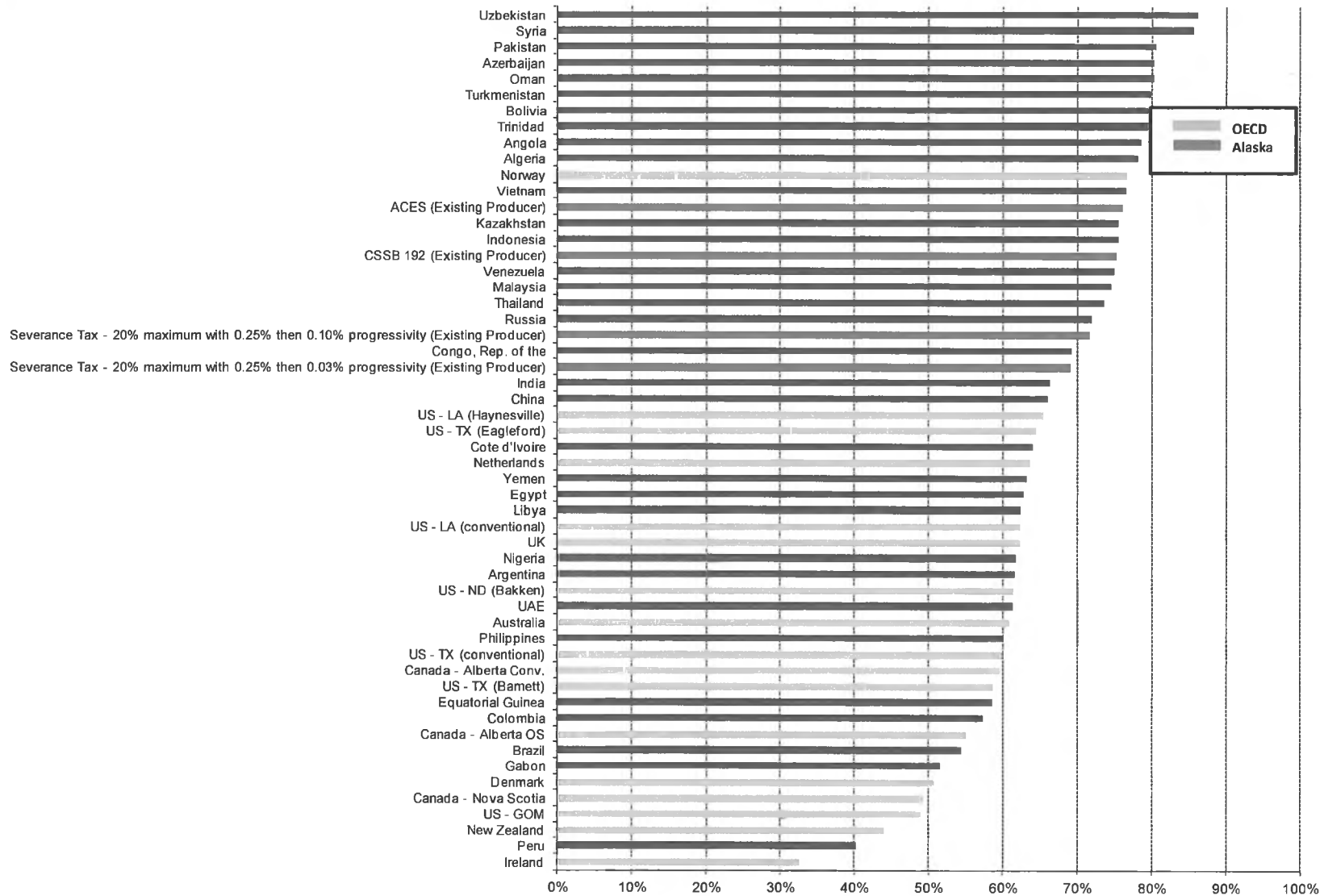
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$100/bbl



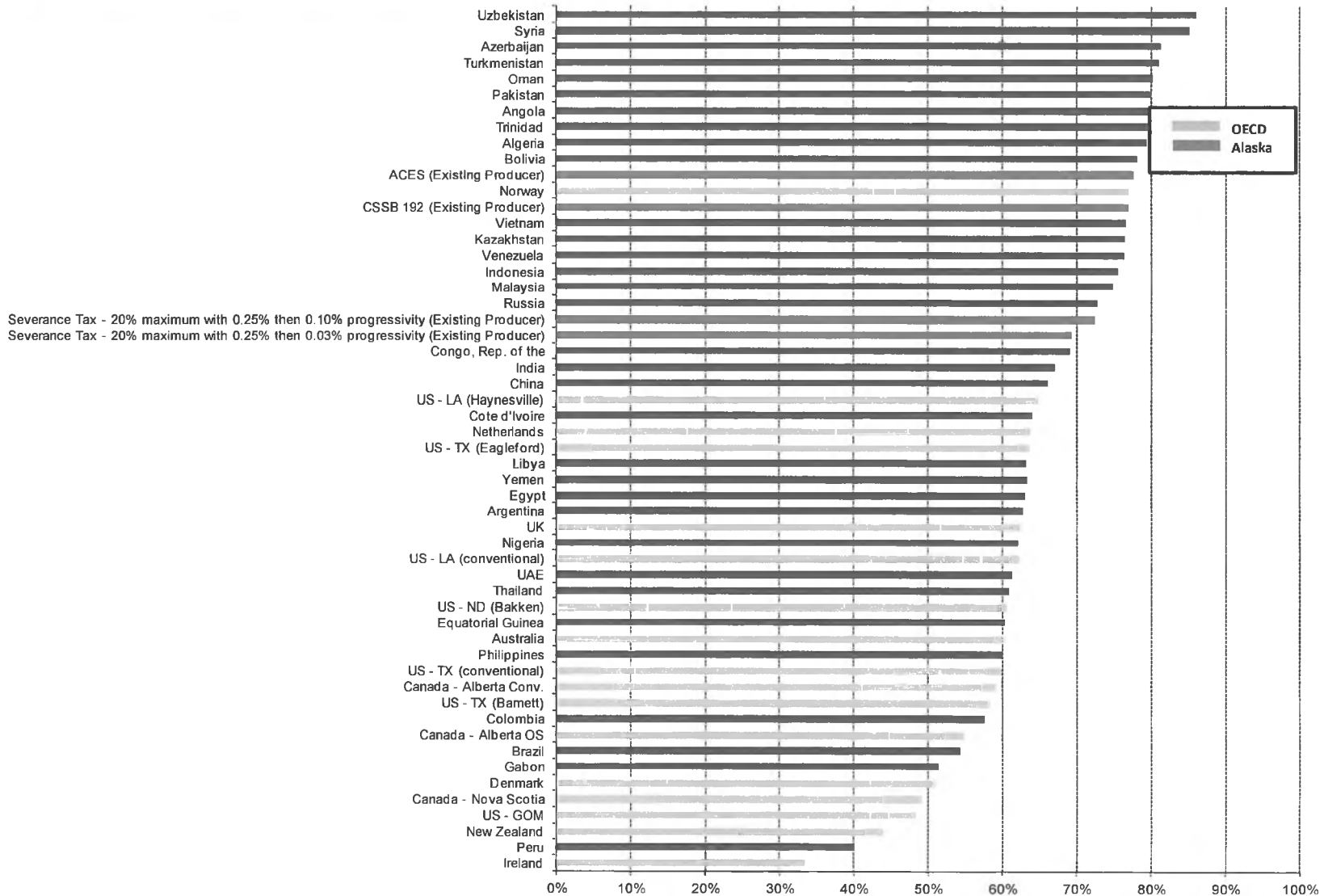
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$120/bbl



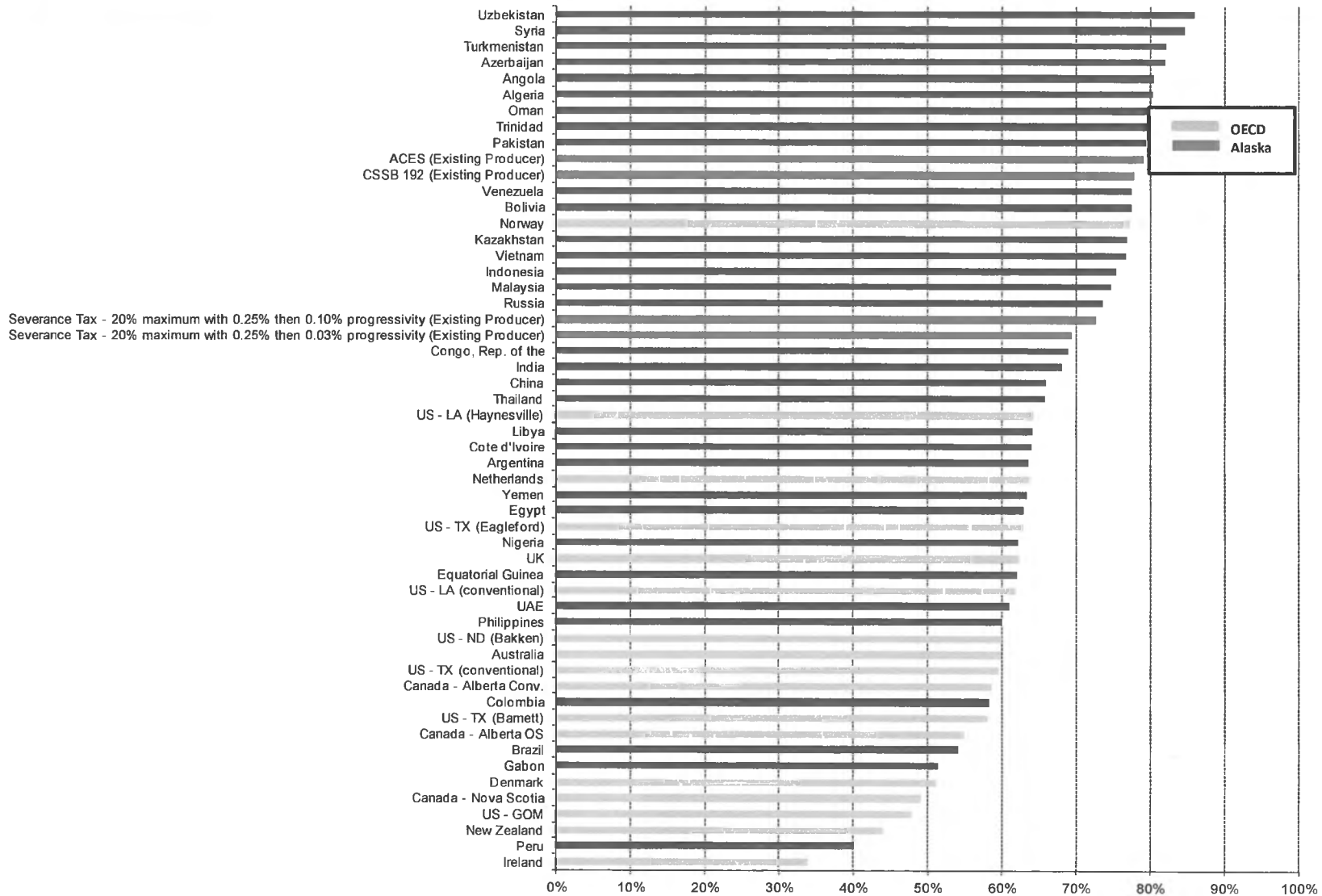
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$140/bbl



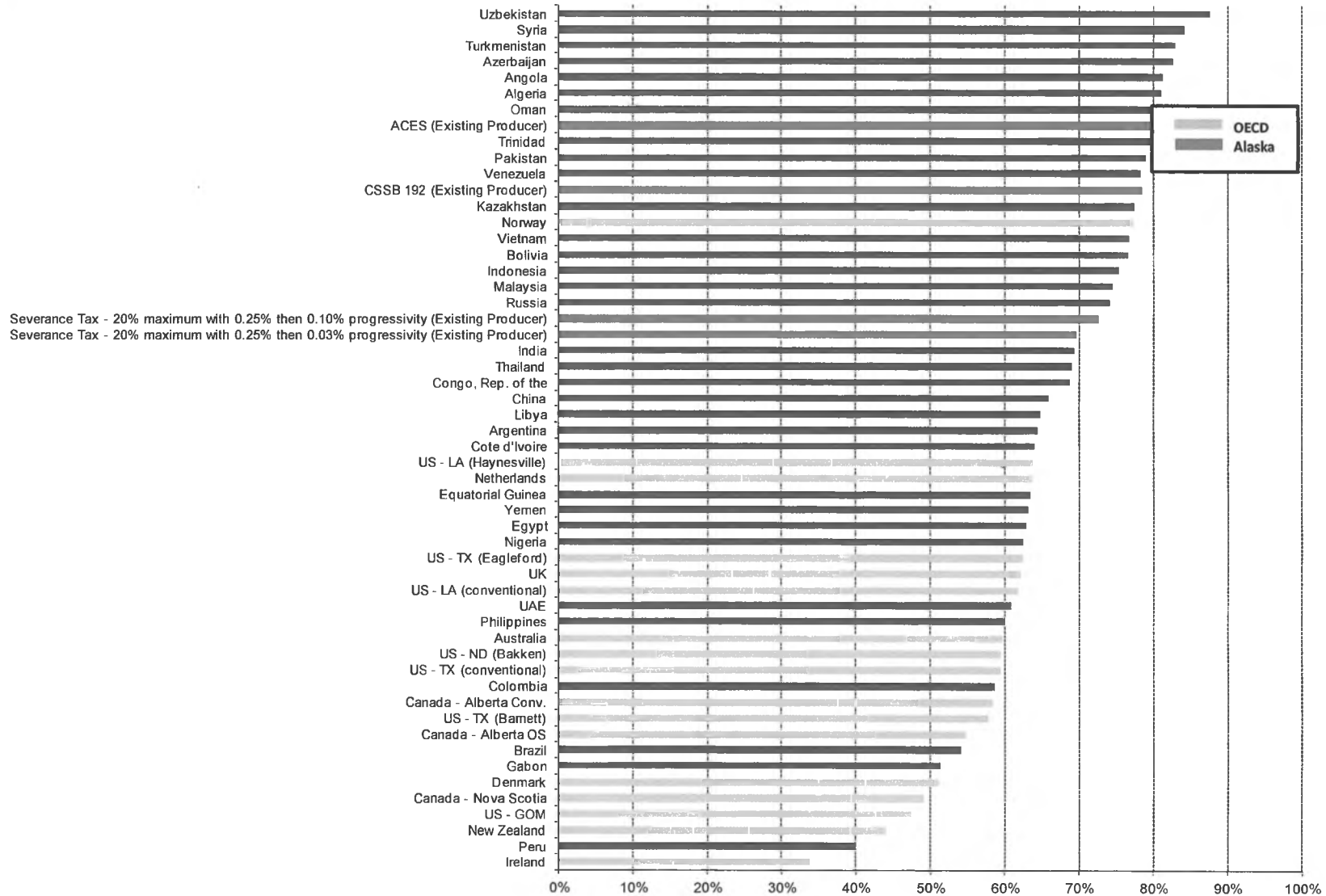
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$160/bbl



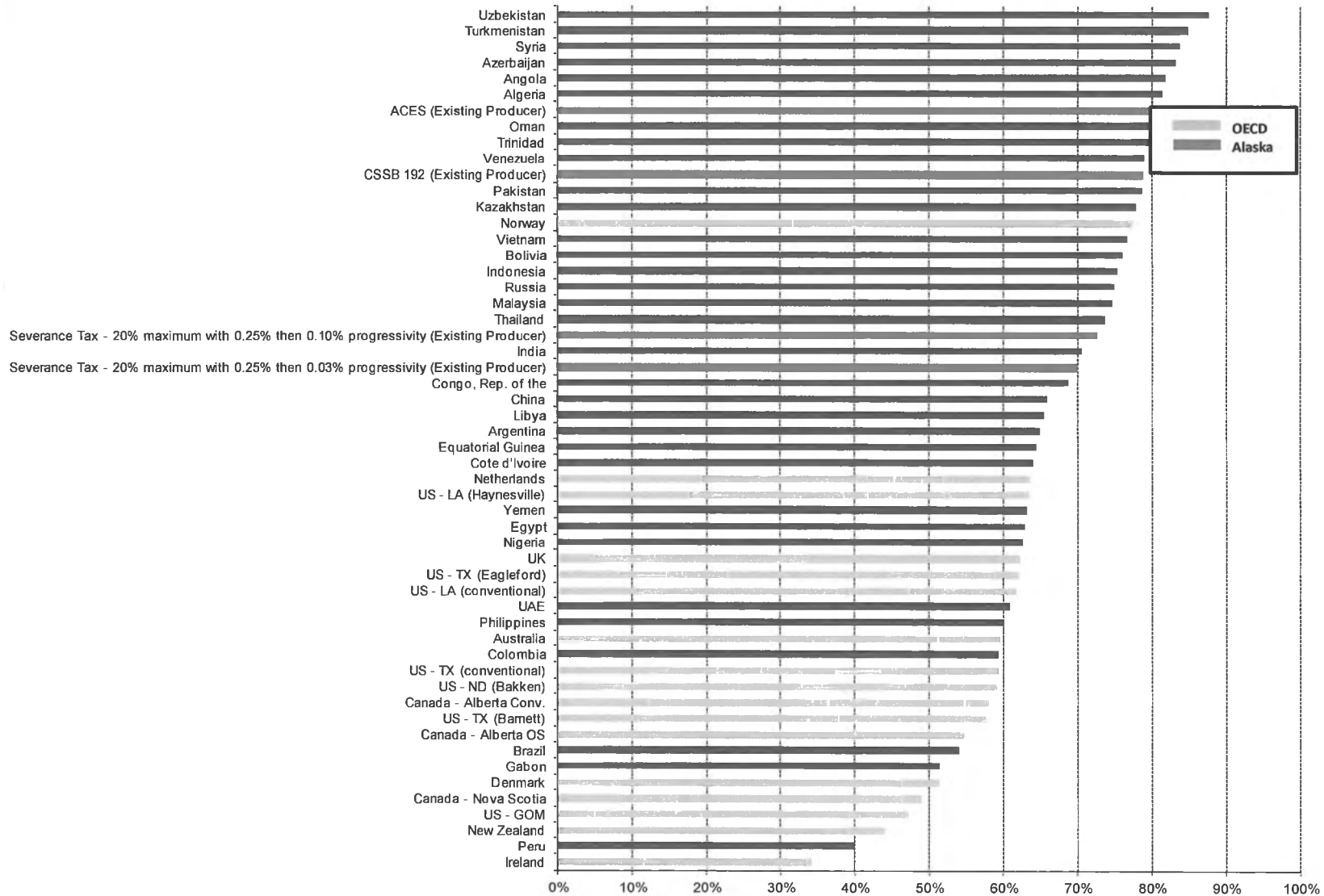
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$180/bbl



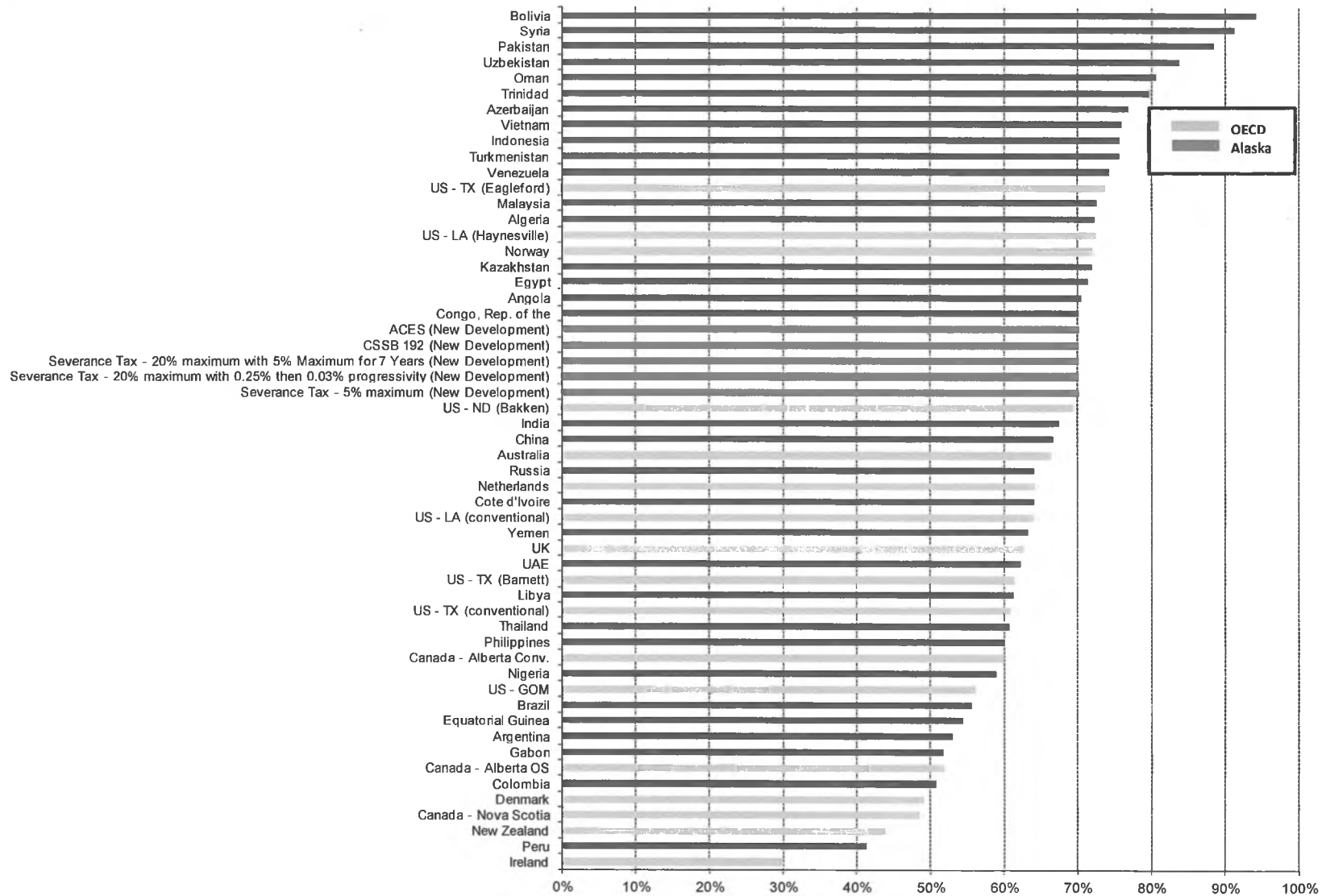
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$200/bbl



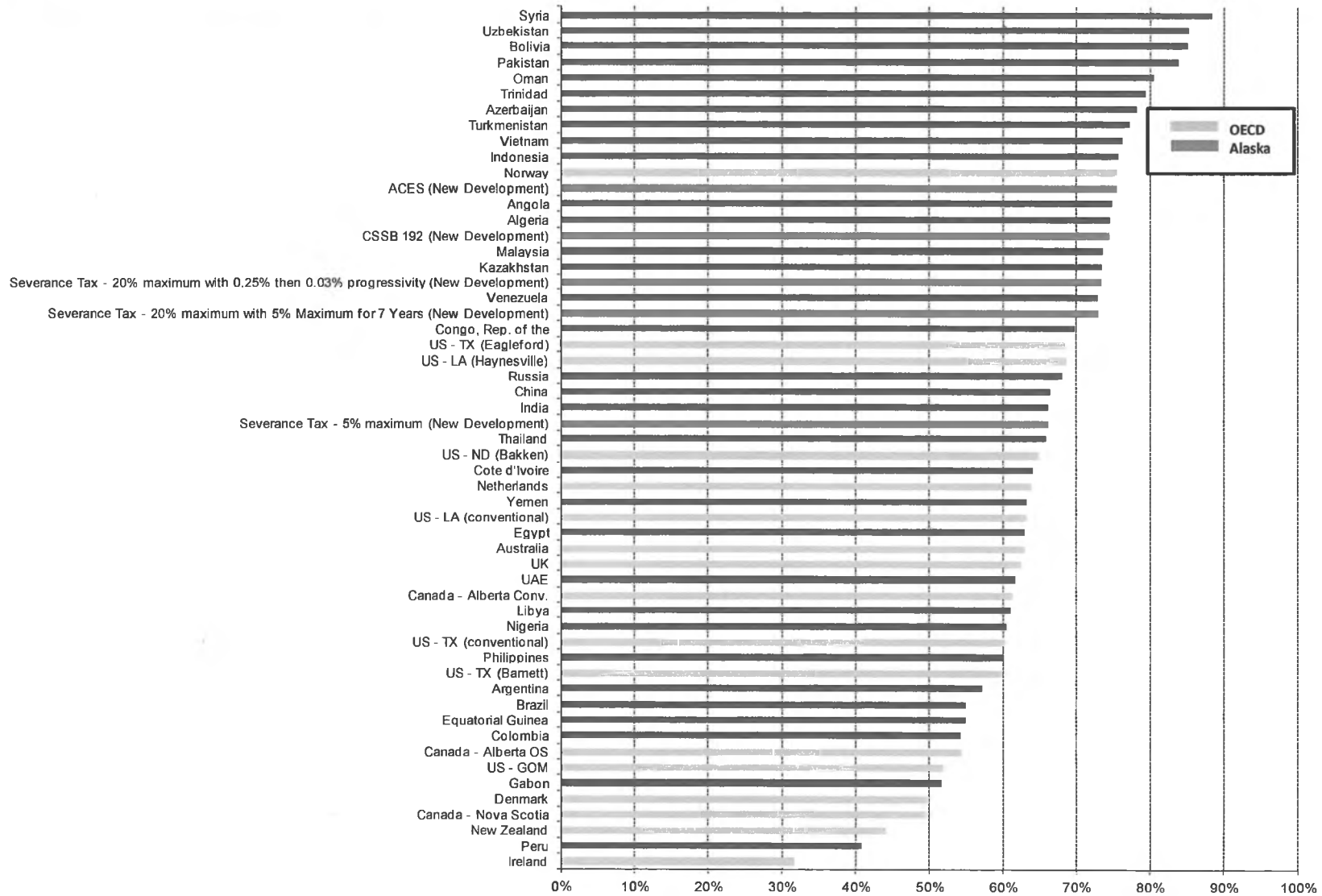
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$60/bbl



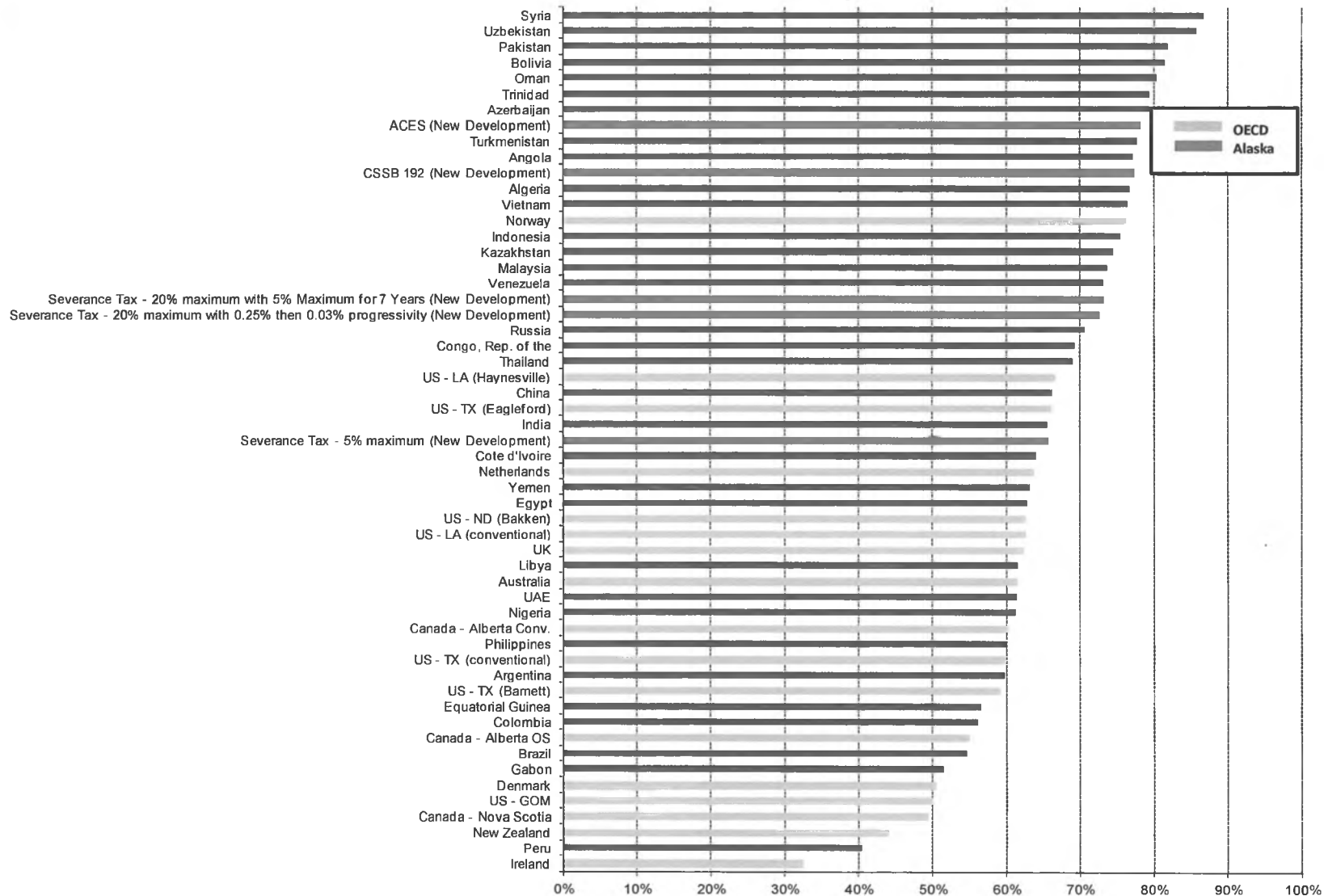
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$80/bbl



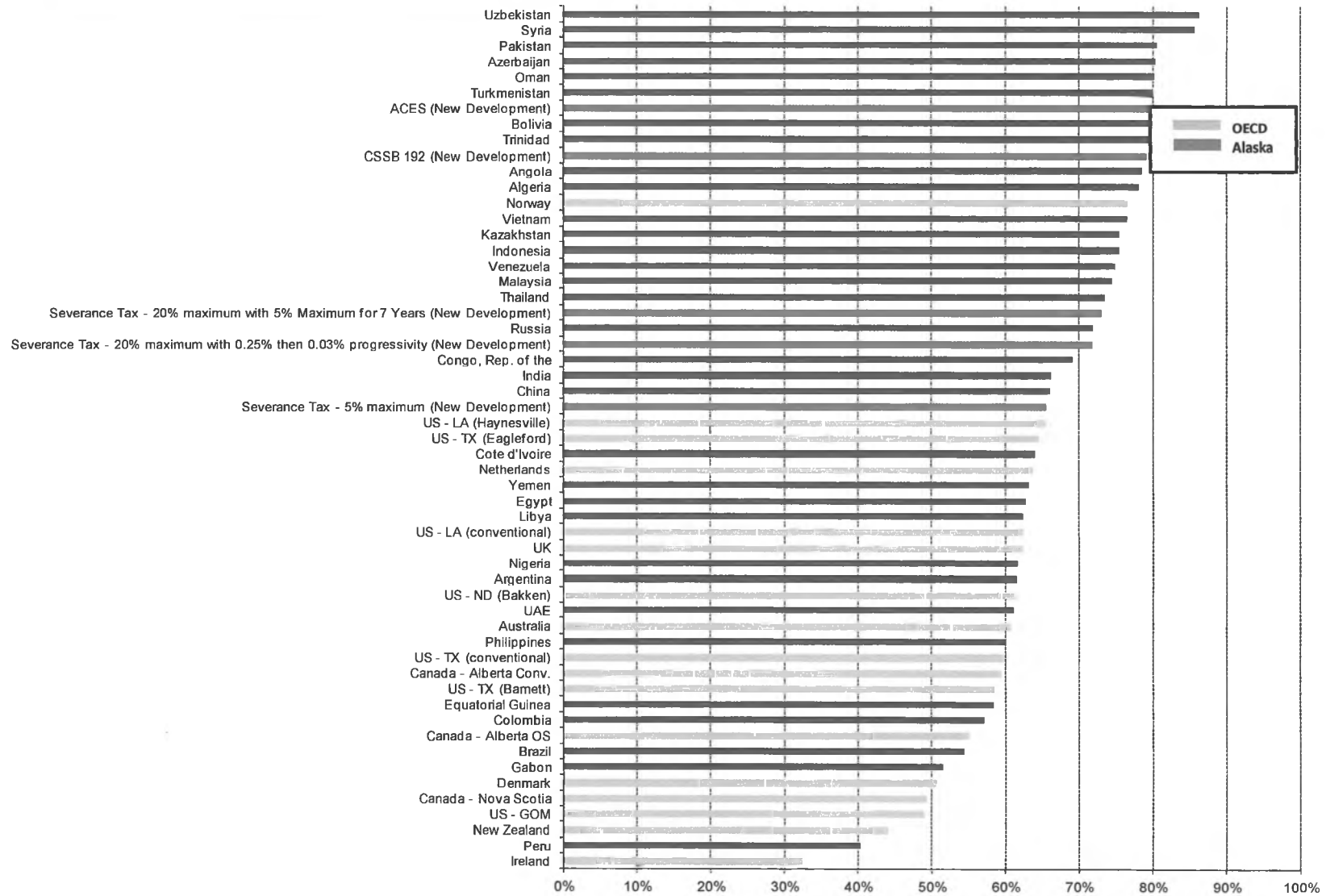
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$100/bbl



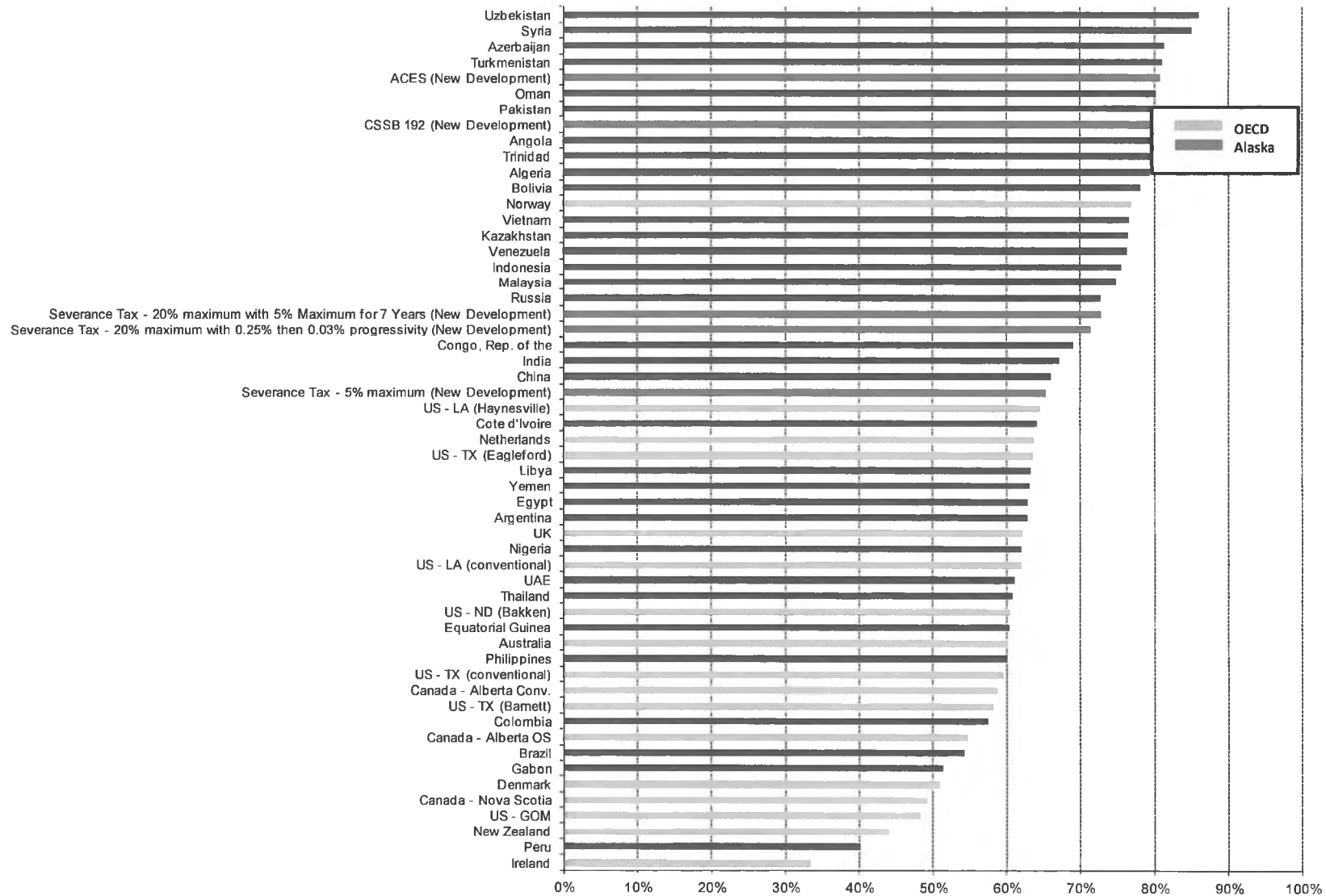
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$120/bbl



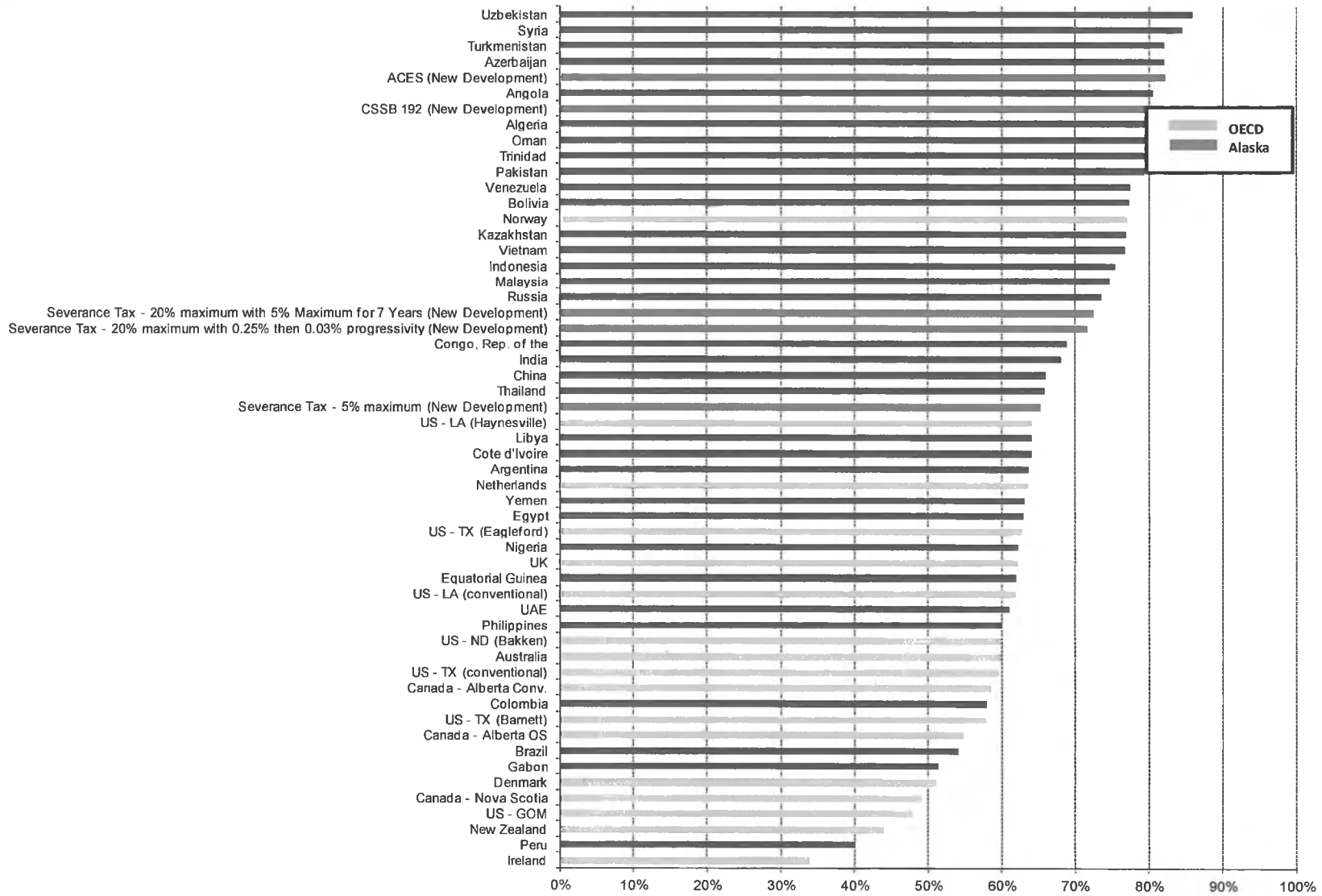
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$140/bbl



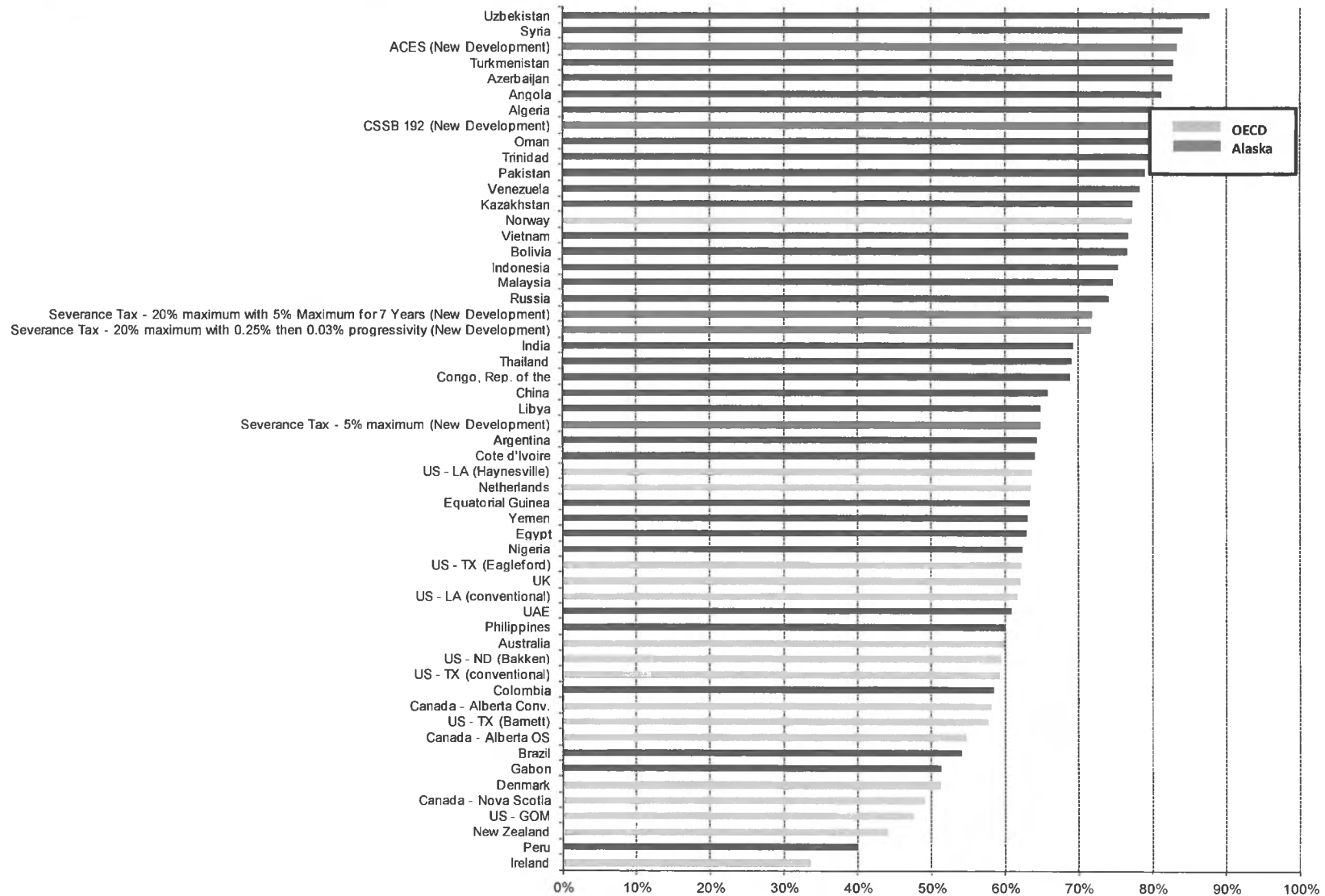
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$160/bbl



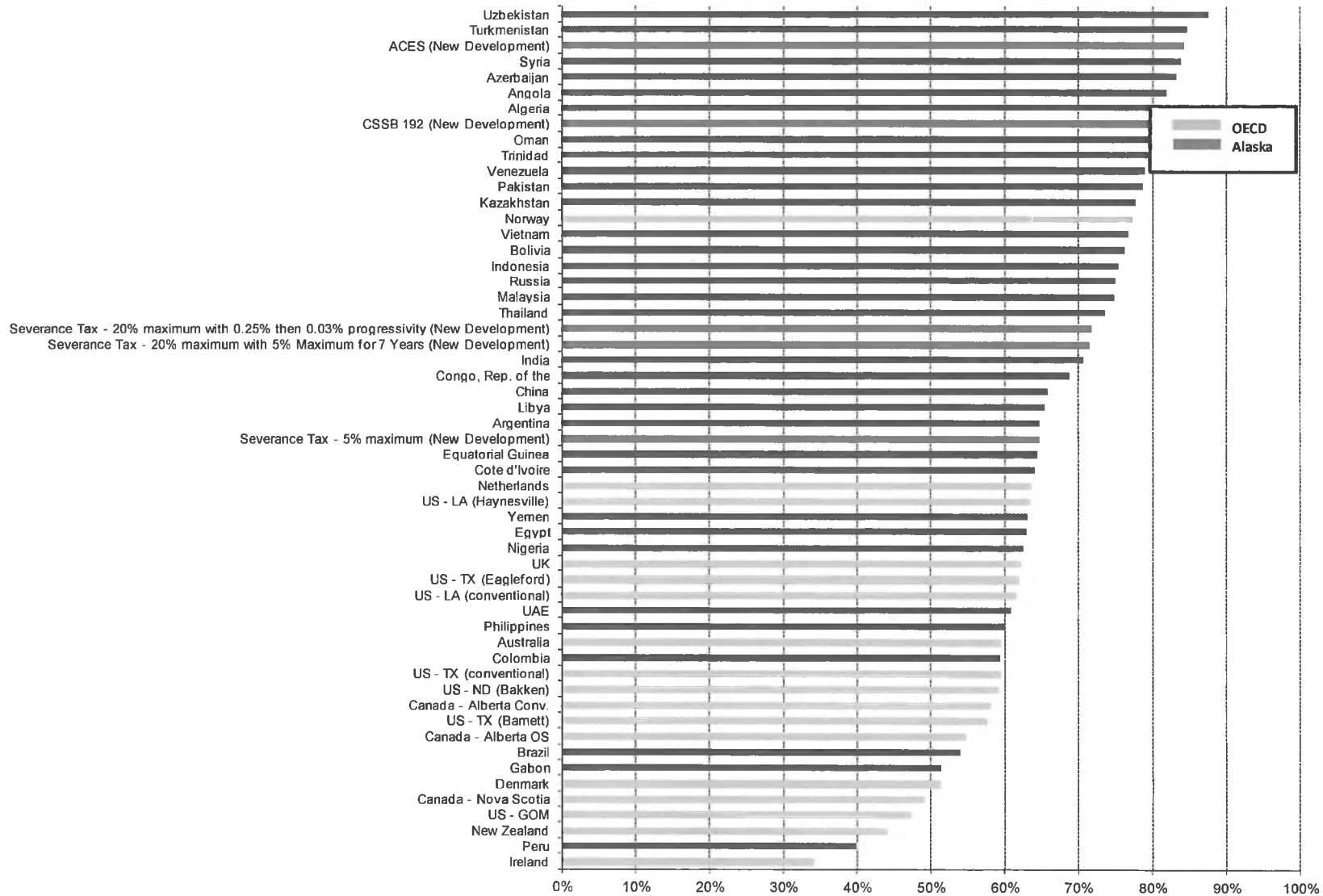
Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$180/bbl

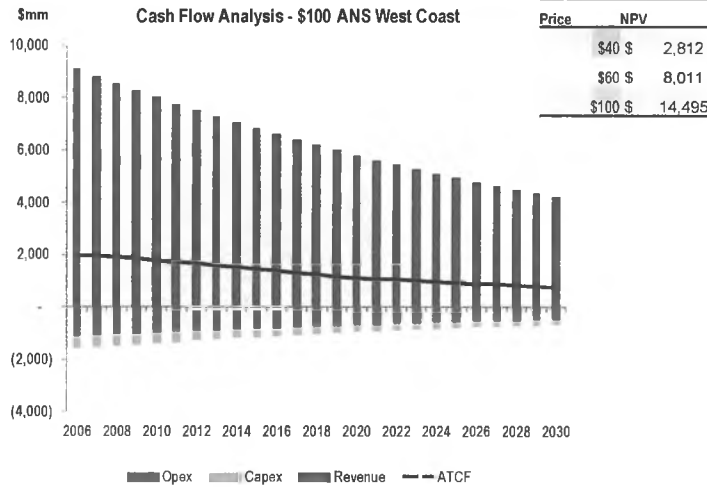


Regime Competitiveness: Relative Government Take

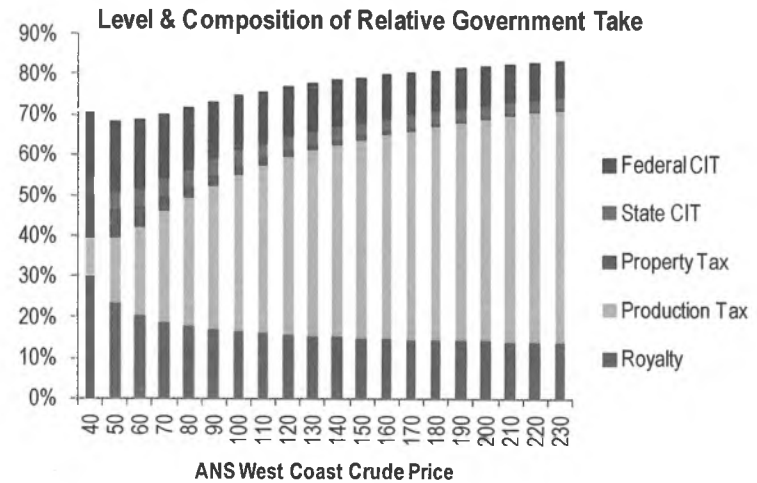
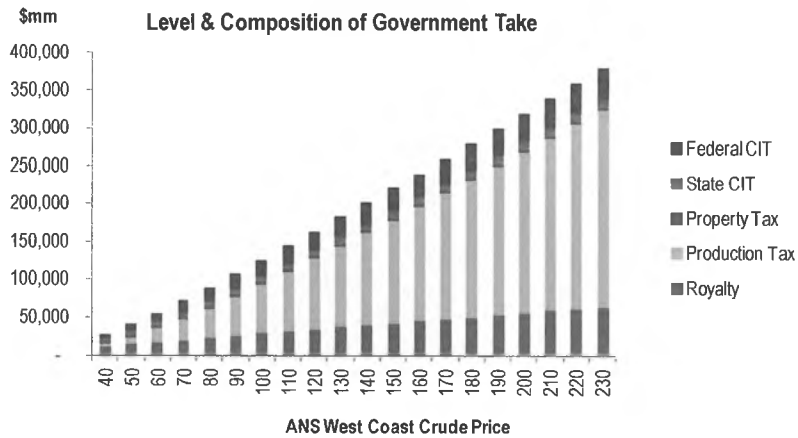
Average Government Take of Global Fiscal Regimes at \$200/bbl



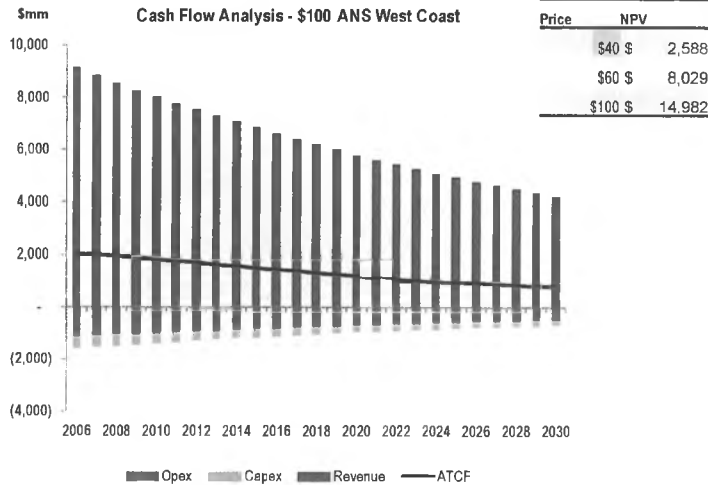
ACES (Existing Producer)



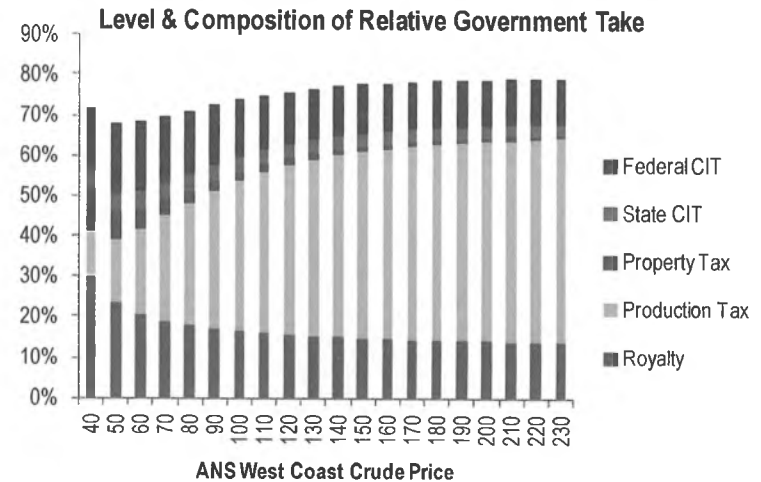
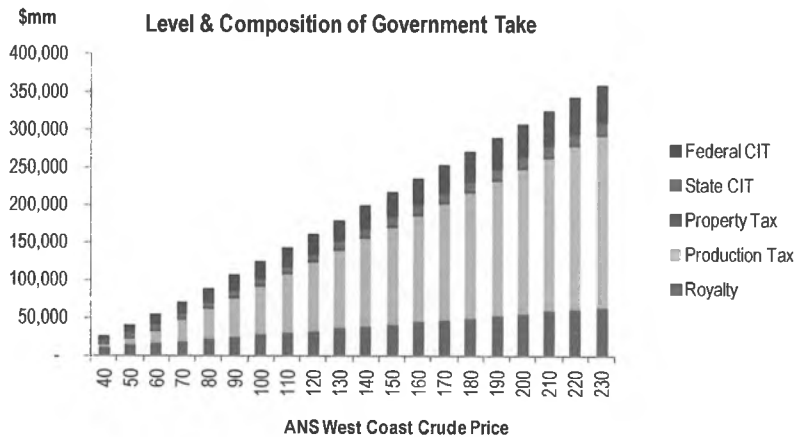
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	30%	9%	11%	4%	54%	16%	71%
50	23%	16%	7%	5%	51%	17%	68%
60	20%	22%	5%	4%	52%	17%	69%
70	19%	27%	4%	4%	54%	16%	70%
80	18%	31%	3%	4%	56%	15%	72%
90	17%	35%	3%	4%	59%	15%	73%
100	16%	39%	2%	4%	61%	14%	75%
110	16%	41%	2%	3%	63%	13%	76%
120	16%	44%	2%	3%	64%	13%	77%
130	15%	46%	2%	3%	66%	12%	78%
140	15%	47%	2%	3%	67%	12%	79%
150	15%	49%	1%	3%	68%	11%	79%
160	15%	50%	1%	3%	69%	11%	80%
170	14%	51%	1%	3%	70%	11%	80%
180	14%	52%	1%	3%	71%	10%	81%
190	14%	54%	1%	3%	72%	10%	82%
200	14%	55%	1%	3%	72%	10%	82%
210	14%	55%	1%	2%	73%	9%	82%
220	14%	56%	1%	2%	74%	9%	83%
230	14%	57%	1%	2%	74%	9%	83%



CSSB 192 (Existing Producer)

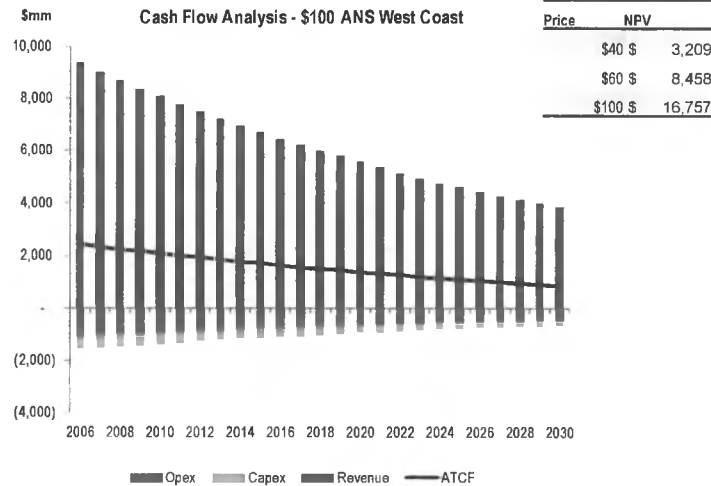


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
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50	23%	16%	7%	5%	51%	17%	68%
60	20%	21%	5%	5%	51%	17%	68%
70	19%	26%	4%	4%	53%	17%	70%
80	18%	30%	3%	4%	55%	16%	71%
90	17%	34%	3%	4%	58%	15%	72%
100	16%	37%	2%	4%	60%	14%	74%
110	16%	40%	2%	4%	61%	14%	75%
120	16%	42%	2%	3%	63%	13%	76%
130	15%	44%	2%	3%	64%	13%	77%
140	15%	45%	2%	3%	65%	12%	77%
150	15%	46%	1%	3%	65%	12%	78%
160	15%	47%	1%	3%	66%	12%	78%
170	14%	48%	1%	3%	66%	12%	78%
180	14%	48%	1%	3%	67%	12%	78%
190	14%	49%	1%	3%	67%	12%	79%
200	14%	49%	1%	3%	67%	11%	79%
210	14%	50%	1%	3%	68%	11%	79%
220	14%	50%	1%	3%	68%	11%	79%
230	14%	50%	1%	3%	68%	11%	79%

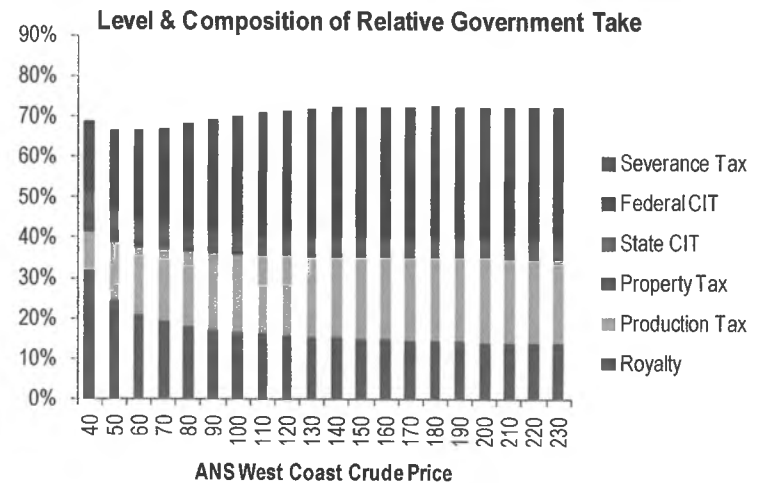
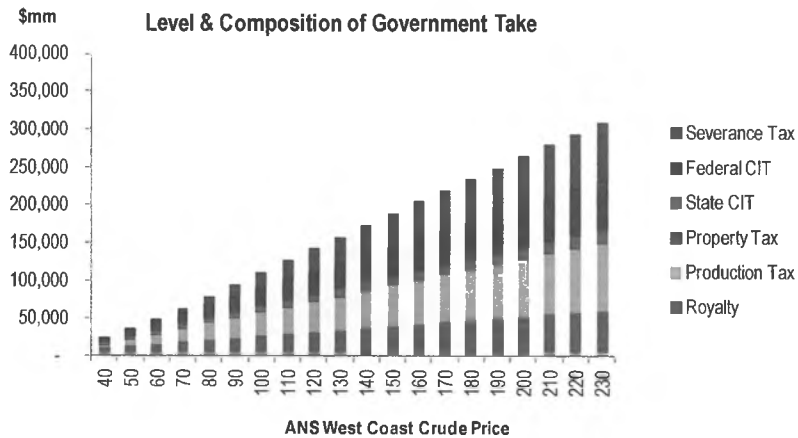


Severance Tax - 20% maximum (Existing Producer)

.25% progressivity from \$65 to \$125, then .10% progressivity

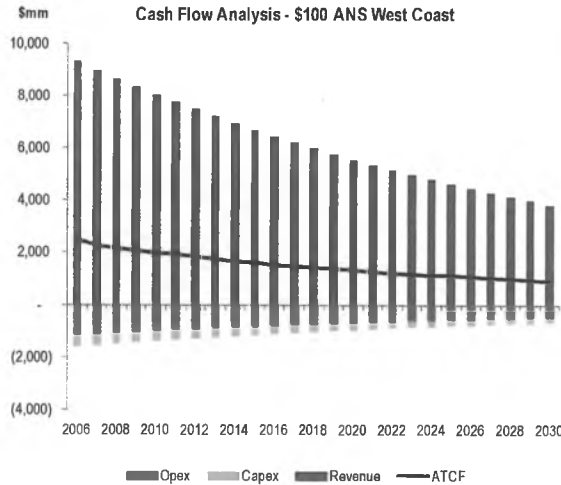


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	9%	5%	5%	51%	17%	69%
50	24%	14%	3%	5%	47%	18%	67%
60	21%	16%	2%	5%	44%	18%	67%
70	19%	18%	2%	5%	43%	18%	67%
80	18%	18%	1%	5%	42%	17%	68%
90	17%	19%	1%	4%	42%	17%	69%
100	17%	19%	1%	4%	41%	16%	70%
110	16%	20%	1%	4%	41%	16%	71%
120	16%	20%	1%	4%	40%	15%	72%
130	15%	20%	1%	4%	40%	15%	72%
140	15%	20%	1%	4%	40%	15%	72%
150	15%	20%	1%	4%	40%	15%	72%
160	15%	20%	1%	4%	40%	15%	72%
170	15%	21%	1%	4%	40%	15%	73%
180	14%	21%	1%	4%	39%	15%	73%
190	14%	21%	0%	4%	39%	15%	73%
200	14%	21%	0%	4%	39%	15%	72%
210	14%	21%	0%	4%	39%	15%	72%
220	14%	21%	0%	4%	39%	15%	72%
230	14%	21%	0%	4%	39%	15%	72%



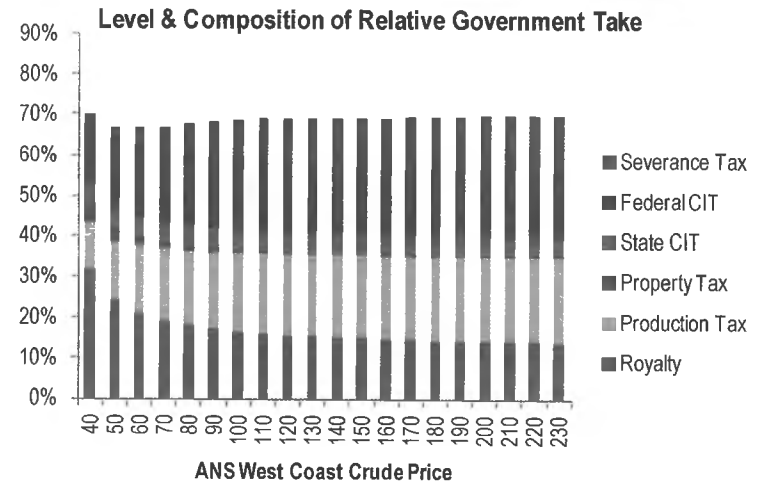
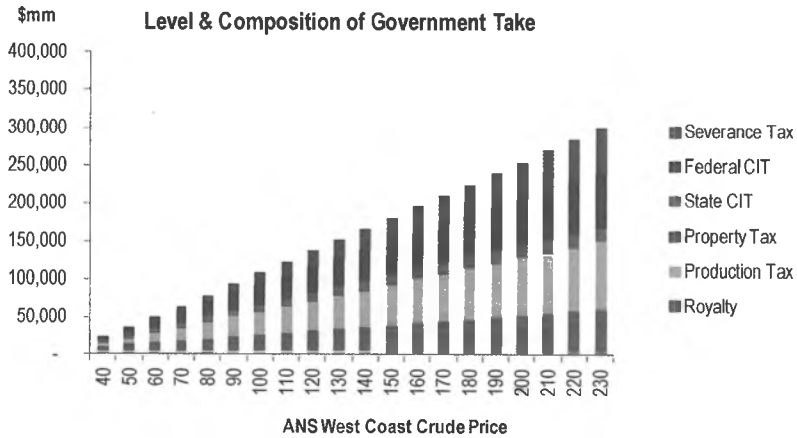
Severance Tax - 20% maximum (Existing Producer)

.25% progressivity from \$60 to \$100, then .03% progressivity



NPV	
\$40 \$	3,117
\$60 \$	8,420
\$100 \$	16,768

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40	32%	11%	5%	4%	53%	17%	70%
50	24%	14%	3%	5%	46%	18%	67%
60	21%	16%	2%	5%	44%	18%	67%
70	19%	18%	2%	5%	43%	18%	67%
80	18%	18%	1%	5%	42%	17%	68%
90	17%	19%	1%	4%	42%	17%	68%
100	17%	19%	1%	4%	41%	17%	68%
110	16%	20%	1%	4%	41%	17%	69%
120	16%	20%	1%	4%	41%	17%	69%
130	15%	20%	1%	4%	41%	17%	69%
140	15%	20%	1%	4%	40%	17%	69%
150	15%	20%	1%	4%	40%	17%	69%
160	15%	20%	1%	4%	40%	17%	69%
170	15%	21%	1%	4%	40%	17%	69%
180	14%	21%	1%	4%	40%	16%	68%
190	14%	21%	0%	4%	40%	16%	70%
200	14%	21%	0%	4%	40%	16%	70%
210	14%	21%	0%	4%	40%	16%	70%
220	14%	21%	0%	4%	40%	16%	70%
230	14%	21%	0%	4%	40%	16%	70%



18.

**Department of
Revenue Response
to Questions
April 1, 2012**

State of Alaska
Department of Revenue

Commissioner Bryan Butcher



SEAN PARNELL, GOVERNOR
333 Willoughby Avenue, 11th Floor
P.O. Box 110400
Juneau, Alaska 99811-0400
Phone: (907) 465-2300
Fax: (907) 465-2389

The Honorable Bert Stedman
Alaska State Senator
State Capitol, Room 516
Juneau, Alaska 99801

March 30, 2012

Dear Senator Stedman:

This letter is in response to a request from your office to provide a summary of all state revenues generated from oil and gas activities in Cook Inlet, and all deductible lease expenditures and applicable tax credits from oil and gas activities in Cook Inlet. You had requested that we provide this information as forecasted for FY 2012 and FY 2013.

The Department of Revenue forecasts oil and gas production from Cook Inlet, and royalties attributable to that production. The Department also forecasts property tax revenue by property, and therefore has Cook Inlet-specific projections. The Department does not forecast other revenues attributable specifically to Cook Inlet, for two reasons: (1) production tax received for Cook Inlet production is less than one percent of the total production tax received by the State; and (2) companies do not separate out state corporate income tax paid for Cook Inlet operations from other oil and gas operations in the state. Credit activity for Cook Inlet is also difficult to determine, as some companies have oil and gas operations in Cook Inlet and other parts of the state, and credits are not always identified by the region in which they were earned.

We can, however, provide your office with a summary of estimates for the items you requested, for historical years. It is important to note that this summary was compiled manually from various sources, including monthly information reports, annual tax returns, property tax records, and credit spreadsheets. Most of these sources contain unaudited, company-reported data that may or may not be accurate. As such, the information in the enclosed table should be viewed as estimates only.

The attached table shows estimated actual data for the fiscal years 2009, 2010, and 2011.

I hope this answer addresses your questions about Cook Inlet. Please let me know if you need further information.

Sincerely,

Bruce Tangeman
Deputy Commissioner

**Estimated Lease Expenditures, Credits, and Revenue related to Cook Inlet Oil
and Gas Activity, FY 2009 - FY 2011 in \$Millions**

	FY 2009	FY 2010	FY 2011
Lease Expenditures			
Operating Expenditures	\$201.31	\$164.44	\$190.14
Capital Expenditures	\$297.29	\$161.94	\$109.55
Total Lease Expenditures	\$498.60	\$326.38	\$299.69
Production Tax Credits	\$11.17	\$9.13	\$43.11
Production Tax Revenue after Credits	<\$10.00	<\$10.00	<\$10.00
Royalty Revenue	\$81.31	\$78.24	\$78.63
Property Tax Revenue	\$3.51	\$3.57	\$3.49
Corporate Income Tax Revenue	-- indeterminate --		
Total Revenue after Credits excluding State Corporate Income Tax	<\$95.00	<\$92.00	<\$93.00

Sources: Monthly Information Forms, Annual Tax Filings, Credit spreadsheets, property tax records.

Notes: This information was compiled manually from unaudited, company-reported data. Some of the information, such as the production tax credit information, is not reported separately when companies have oil and gas operations in Cook Inlet and other parts of the state. As such, this information should be used for illustration only and be considered estimates.

19.

Discussion

Slides:

**Janak Mayer,
Manager, Upstream &
Gas and Tony
Reinsch, Senior
Director Upstream &
Gas**

PFC Energy

April 2, 2012



Discussion Slides: Alaska Senate Finance Committee

April 2, 2012

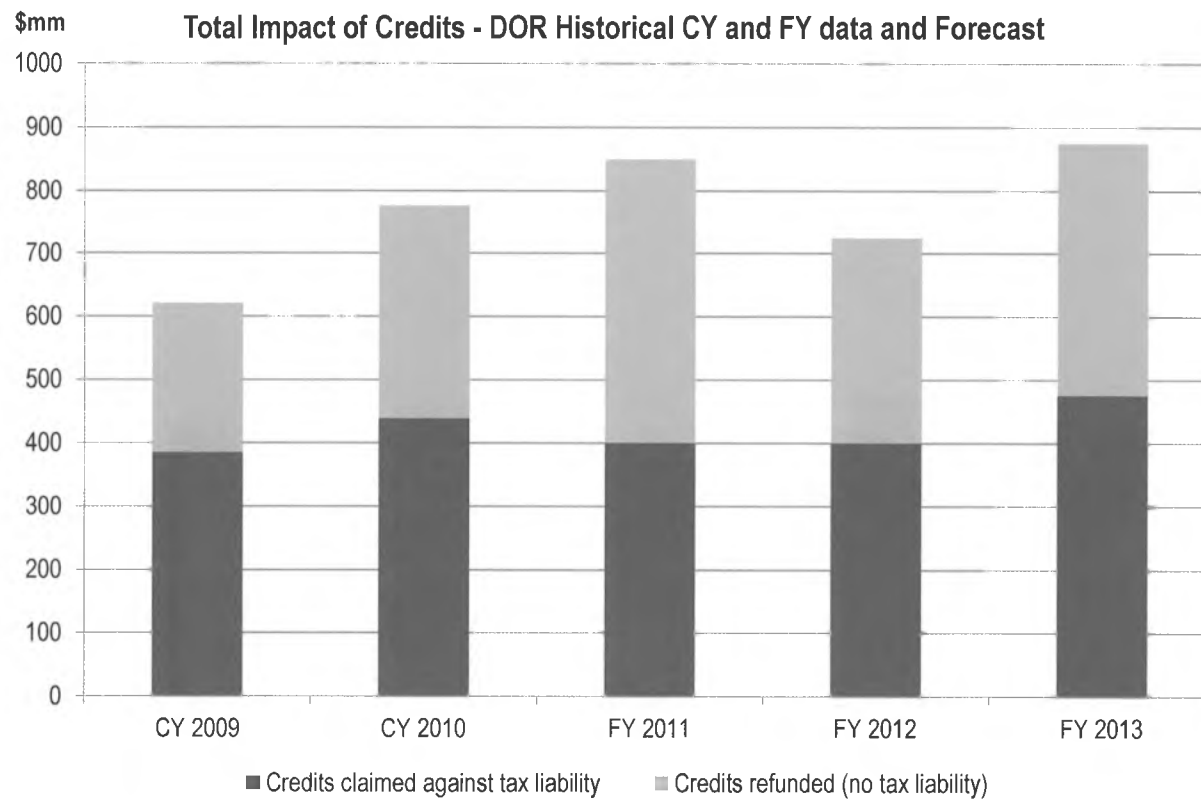
Janak Mayer
Manager, Upstream & Gas
PFC Energy

Tony Reinsch
Senior Director, Upstream & Gas
PFC Energy

Tax Credits Under ACES

Credit	Rate	Qualifying Expenditures	Certificates Can Be Submitted to State for Cash?
AS 43.55.023(a) Qualified Capital Expenditures Credit	20%	Qualified Capital Expenditures (including exploration)	Yes
AS 43.55.023(b) Carried-Forward Annual Loss Credit	25%	Excess Lease Expenditures (where Production Tax liability is insufficient to deduct costs)	Yes
AS 43.55.023(l) Well Lease Expenditure Credit	40%	Well Lease Expenditures (Intangible Drilling Costs) below North Slope	Yes
AS 43.55.025(a)(1-4) Alternative Credit for Exploration	30%	Exploration expenditures for wells more than 3 miles outside an existing area (if outside Cook Inlet)	Yes
AS 43.55.025(a)(1-4) Alternative Credit for Exploration	40%	Exploration expenditures for wells more than 25 miles outside an existing area (10 miles in Cook Inlet)	Yes
AS 43.55.025(a)(5) Cook Inlet Jack Up Rig	Up to 100%	First 3 unaffiliated wells drilled by same jack-up rig in Cook Inlet	Yes
AS 43.55.019 Education Credit	Max \$5 million	Cash donations to educational institutions	No
AS 43.55.023(i) Transitional Investment Credit	20%	Expenses before March 31 2006 (pre-PPT)	No
AS 43.55.024(a) Middle Earth Credit	\$6 million	Production below North Slope and outside Cook Inlet (Expires 2016)	No
AS 43.55.024(c) Small Producer Credit	\$12 million	Producers with less than 50 mb/d average production (Expires 2016)	No

Total Impact of Credits





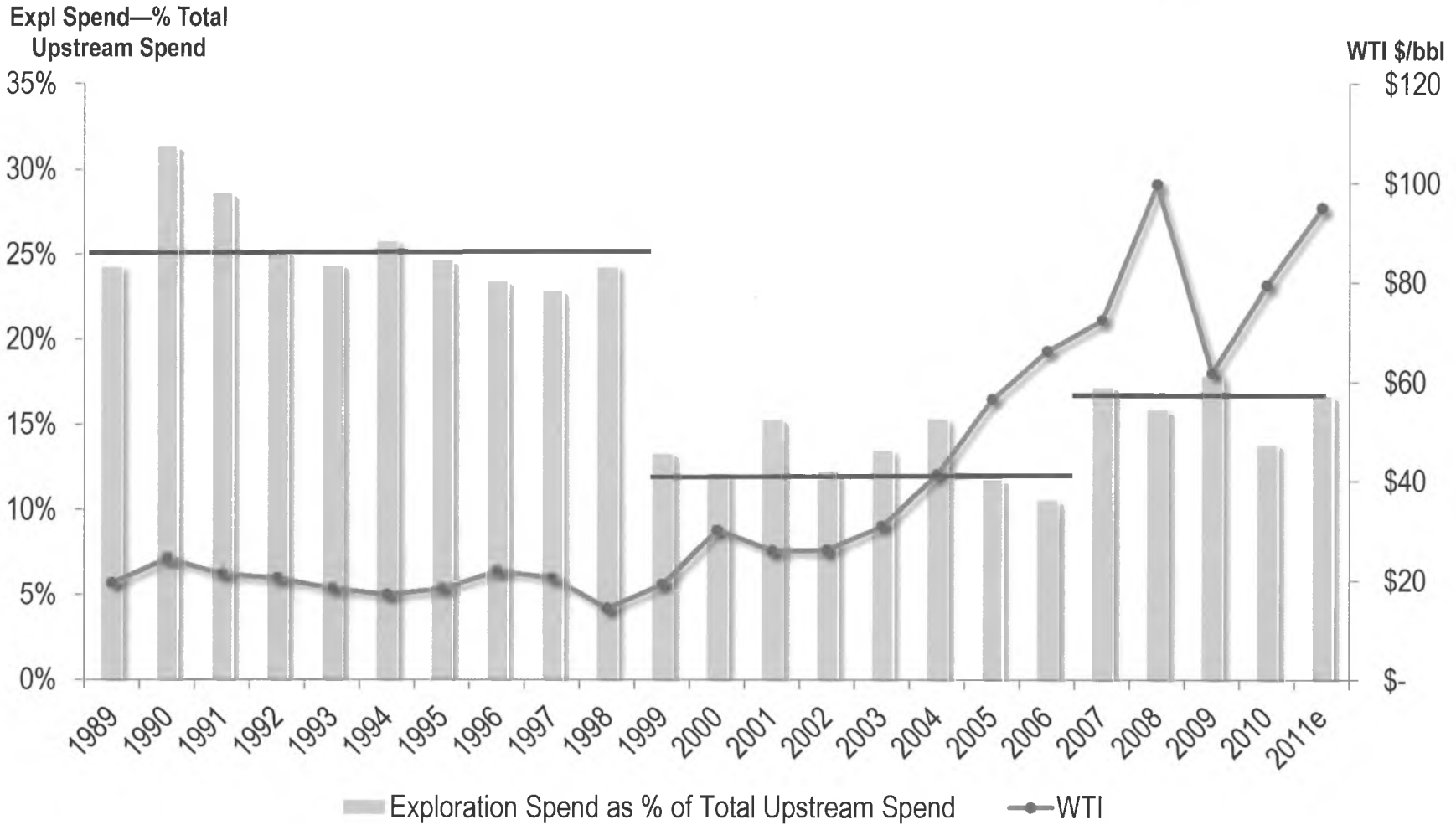
Exploration Credits

Content

- ***Recent Trends in Exploration Activity and Basin Focus***
- Credits and Incentives: Lessons from the Past
 - National Energy Program (Canada)
 - Norwegian Continental Shelf (Norway)
- Development Cycle Time: Incenting the Required Activities

Rebound in Exploration Spending

Exploration Spend as % of Total Upstream Spend*



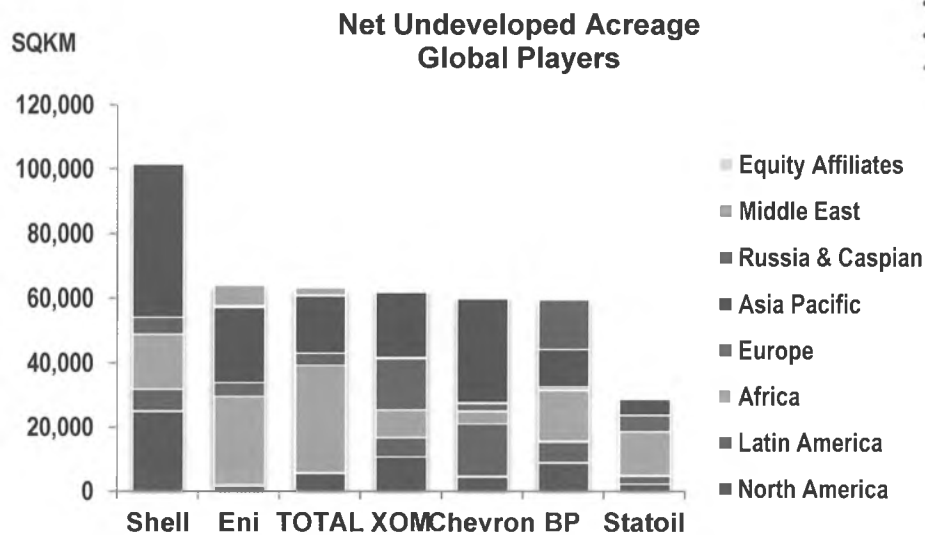
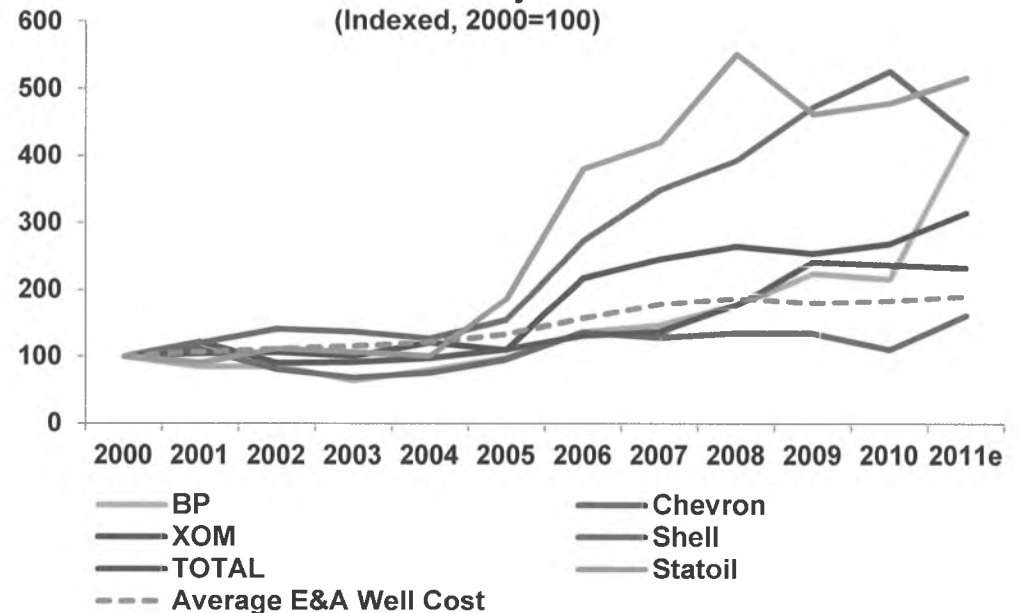
* Data reflects Total Consolidated Operations for BP, CVX, ExxonMobil (excludes purchase of XTO), TOTAL, Shell, Eni (1992-2011 only), Anadarko, Apache, BG, ConocoPhillips, Devon, Hess, Marathon, Repsol, and Talisman

Source: Upstream Competition Service

Trend in Worldwide Exploration: Global Players

- Exploration spending by many of the Global Players accelerated sharply in 2005-2006 as focus shifted to restocking the portfolio of development projects
- Statoil (North Sea) and Shell (Asia, North America) were early movers, quadrupling exploration spending since 2004
- The growth represents real activity gains, substantially outpacing the Exploration & Appraisal (E&A) Index

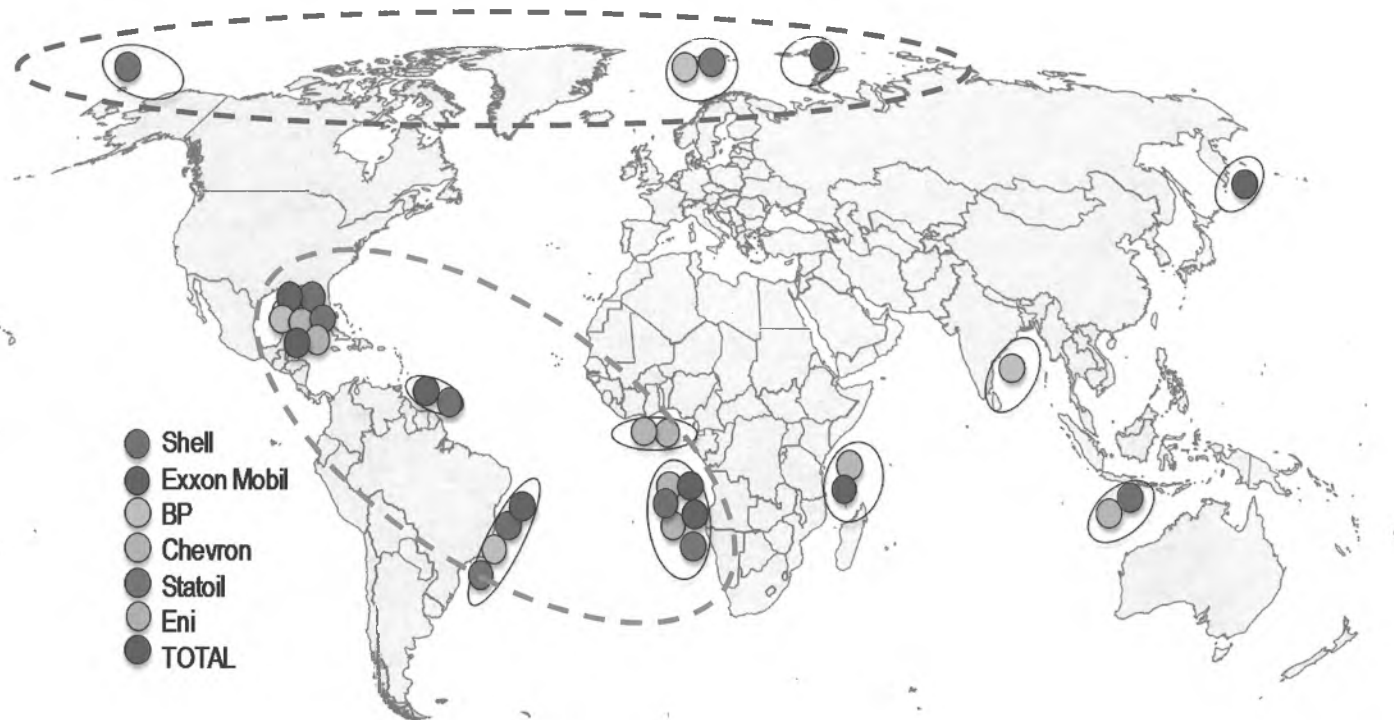
**Total Worldwide Exploration Spending
Global Players
(Indexed, 2000=100)**



- Shell is the leader in undeveloped acreage holdings, at over 100 million sq.kms, in keeping with their “Last Land Grab” growth strategy.
 - Majority of acreage held by the Majors is in Asia and Africa; North America is material undeveloped acreage holding for Shell, XOM, and BP

Selected Global Players: Regions of Exploration Focus

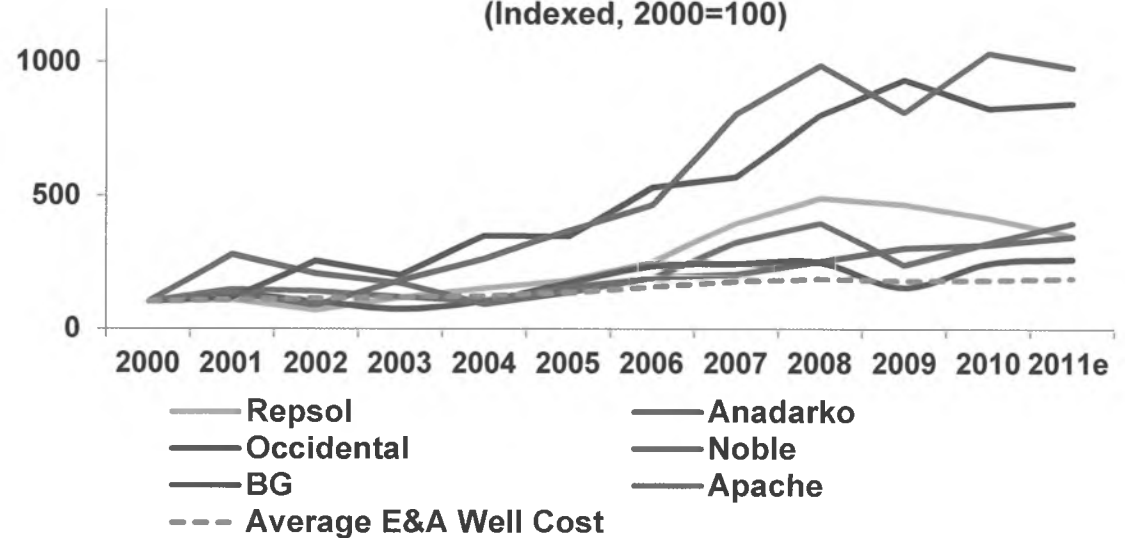
- Setting aside the move by virtually all of the Global Players into the US/Canada onshore resource plays (oil sands, shale gas, Shale oil), the focus of exploration interest is in the deepwater plays of the Atlantic Basin
- Emerging interest in a return to the Arctic Resource play, led by Shell in the Chuckchi Sea, BP and Statoil in the Norway and Barents Deepwater, and ExxonMobil securing a strategic association with Rosneft in the Russia Arctic
- Of note is the near complete decline of the Middle East as a growth driver for these large companies



Trend in International Exploration: Independents

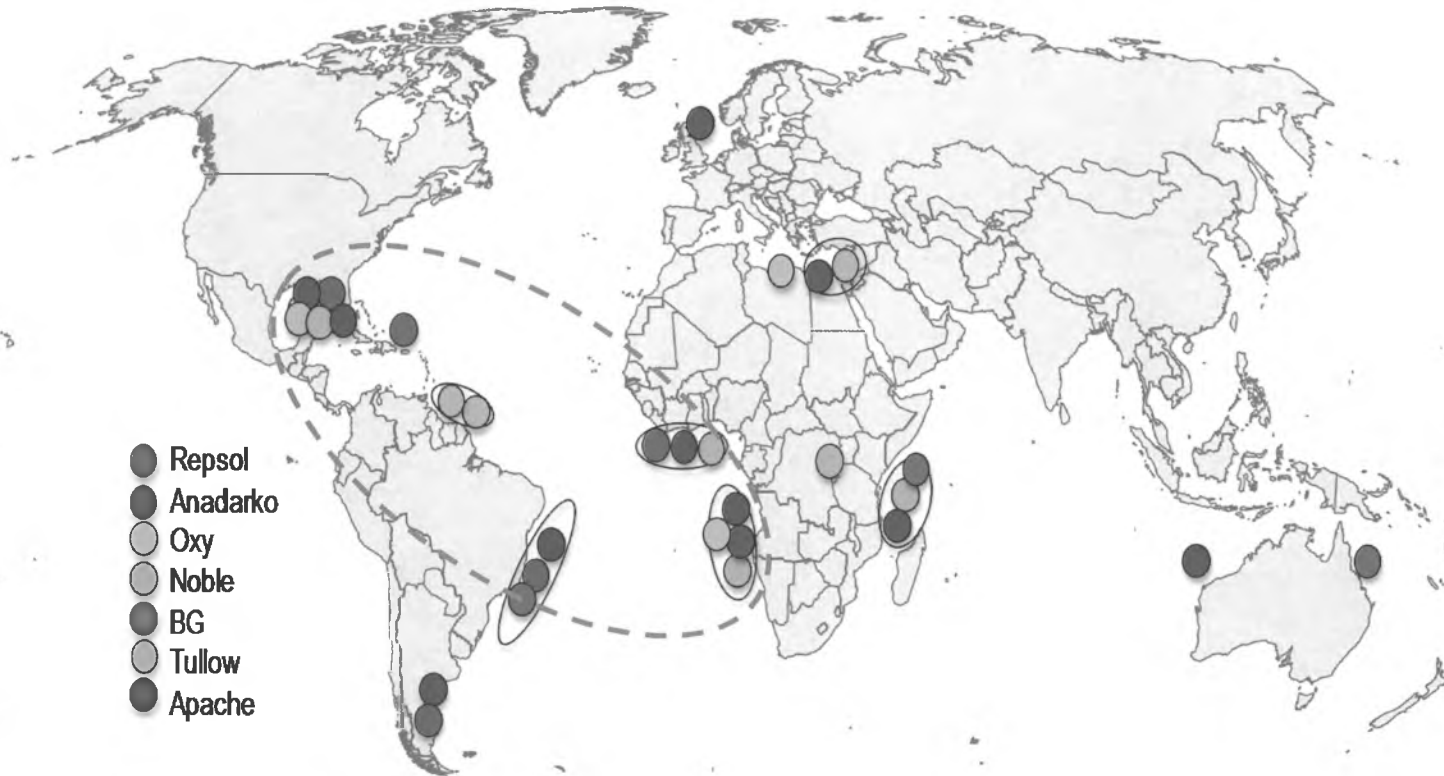
- The International Independents are a more disparate group when it comes to exploration activity:
 - Some, like Anadarko, have been material exploration players through the last decade;
 - Some, like BG and Apache, have aggressively growth their exploration activities through the past decade;
 - Others, like Occidental and Noble, have focused on development activity in a small number of play areas
- Exploration spending by Anadarko, BG, and Apache has hovered around the \$1.3-1.5 bn mark for the last few years, high for the Indies and ~60% that of the smaller Global Players

**Total Worldwide Exploration Spending
International Independents**
(Indexed, 2000=100)



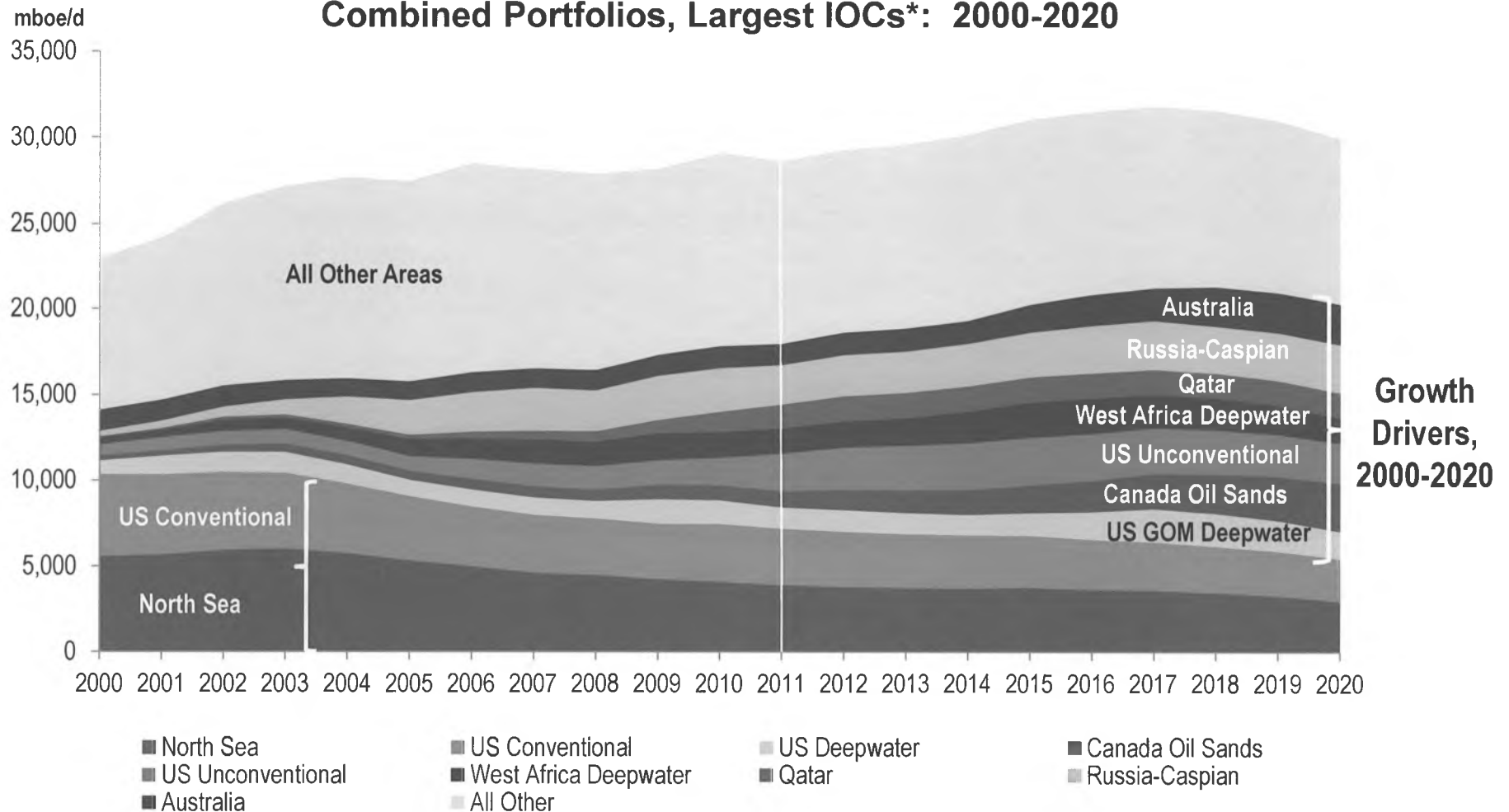
Selected International Players: Regions of Exploration Focus

- The Independents are similarly positioned in the US/Canada onshore resource plays (oil sands, shale gas. Shale oil), and the deepwater plays of the Atlantic Basin
- The Independents are also at the forefront of new basin development, such as the Equatorial Margin, East Africa Deepwater, South America “North Tier” deepwater play, Argentina shale gas, and Lake Albert basin (Uganda)
- The Independents are not as prominent in the high cost, high risk exploration opportunities in the Arctic offshore



IOC Growth Centered on Successful “New Frontiers” ...

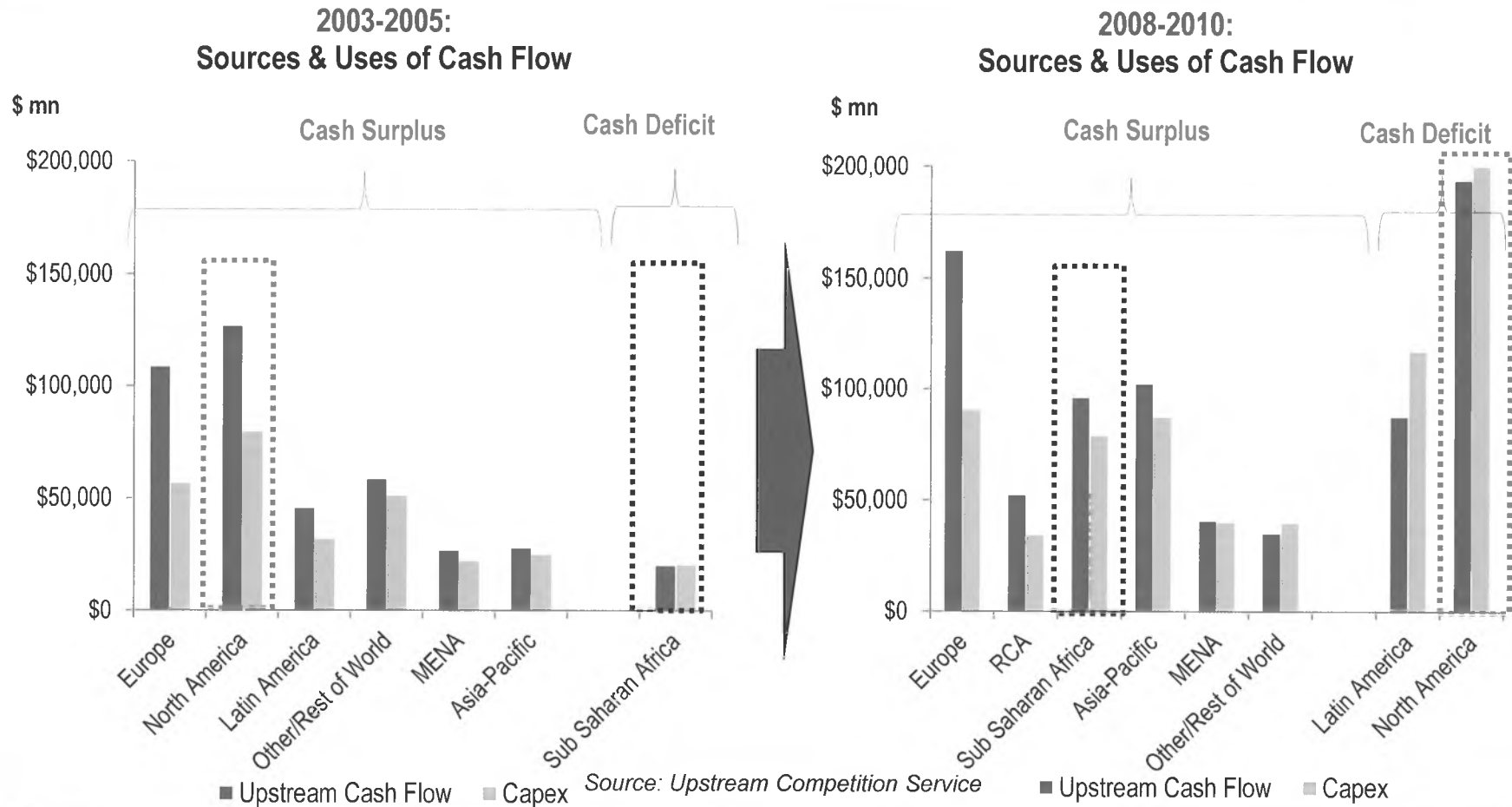
Combined Portfolios, Largest IOCs*: 2000-2020



Source: Upstream Competition Service

* Includes: Anadarko, Apache, BG, BHP, BP, CNRL, Chevron, ConocoPhillips, Devon, EnCana, Eni, ExxonMobil, Hess, Husky Oil, Marathon, Murphy, Nexen, Noble Energy, Oxy, Repsol, Santos, Shell, Suncor, Talisman, TOTAL, Woodside

...Financed by Redirection of Free Cash Flow



Along with Europe, Sub-Saharan Africa is now a key cash generating region for the Global Players—with surplus cash flow now supporting growth in North America

* Includes data from the following companies: Anadarko, Apache, BG, BHP, BP, CNRL, Chevron, ConocoPhillips, Devon, EnCana, Eni, ExxonMobil, Hess, Husky Oil, Marathon, Murphy, Nexen, Noble Energy, Oxy, Petrobras, Repsol YPF, Santos, Shell, Statoil, Suncor, Talisman, TOTAL, Woodside

Content

- Recent Trends in Exploration Activity and Basin Focus
- ***Credits and Incentives: Sharing Exploration Risk***
 - National Energy Program (Canada)
 - Norwegian Continental Shelf (Norway)
- Development Cycle Time: Incenting the Required Activities

Exploration and Government Risk Taking

- By and large, Governments have refrained from engaging in the business of upstream risk
 - In emerging basins, nascent National Oil Companies (NOCs) will usually have “back-in provisions” within Production Sharing contracts, allowing entry into development projects as an equity participant at the point of sanction. Are prohibited from engaging in exploration activity
 - In more mature basins, the NOC may engage fully from license award to production (Petora in Norway, ONGC in India, PDVSA in Venezuela) assuming it has internalized the necessary degree of technical sophistication and dry-hole tolerance
- Exploration credits/rebates are, in essence, a direct engagement by the government in exploration risk. As such, they have been used sparingly outside of the context of the tax and royalty regime

Canada's National Energy Program: An Experiment in Intervention Gone Awry

- The NEP was introduced to both enhance Canadian ownership in Upstream activities, and to accelerate the discovery and development of domestic resources to enhance security of supply and support energy subsidies to domestic consumers

Jurisdiction	Petroleum Incentive Payments: Exploration Activity	Other Government Risk Sharing	Comments
Alberta	<ul style="list-style-type: none"> Cdn Ownership >50%: 10% approved costs Cdn Ownership >60%: 25% approved costs Cdn Ownership >65%: 35% approved costs 	<ul style="list-style-type: none"> Development projects: <ul style="list-style-type: none"> Cdn Ownership > 10%: 10% approved costs Cdn Ownership >65%: 20% approved costs Same applied to oil sands and EOR developments 	<ul style="list-style-type: none"> Incentives provided to both exploration and development activities
Federal Lands	<ul style="list-style-type: none"> Cdn Ownership >50%: 35% approved costs Cdn Ownership >60%: 65% approved costs Cdn Ownership >65%: 80% approved costs 	<ul style="list-style-type: none"> PetroCanada given 25% carried back-in option, convertible up to sanction decision. Paid by P-C share of production (grossed up by 15% per annum to reflect interest and inflation) 	<ul style="list-style-type: none"> Incentive exploratory well had to be >3 miles from a cased well, OR to a deeper horizon => incented deeper drilling in less prospective areas 5 year Royalty holiday applied on production

National Energy Program (Canada) and Exploration Incentives

- NEP introduced substantial distortions into the E&P decision making process. In particular, incented Upstream activity towards less prospective and higher cost areas, and introduced “artificial” demand for Upstream services
 - Drilling costs (seismic, rigs, etc.) accelerated rapidly as demand soared in new and unsupported exploration environments
 - Many companies were effectively “drilling for PIP grants” with commercial discoveries representing the Failure case

Exploration Well Costs	Canadian Arctic	Atlantic Offshore
1966-1970	\$4.3 mm	\$1.2 mm
1971-1975	\$3.6 mm	\$3.8 mm
1976-1980	\$24.4 mm	\$22.4 mm
1981-1985	\$63.2 mm	\$45.8 mm
1986-1990	\$44.2 mm	\$20.5 mm

Canada's National Energy Program:

- The decline in crude prices in the mid-1980s forced the withdrawal of virtually all aspects of the NEP
- Alberta:
 - PIP grants replaced by Royalty Tax Credits (75% rising to 90% with maximum credit per well)
 - Exploration Incentives restructured as either:
 - 12 month Royalty holiday on eligible wells to a maximum per well;
 - Royalty exemption on cumulative production, linked to well depth and location
 - Exploration Drilling Incentive Program: 50% credit set off against subsequent royalties
 - Moved away from credits/rebates outside of the royalty and tax environment => *reward success, not simply effort.*
- Federal:
 - PetroCanada back-in eliminated;
 - Royalty linked to “payout” of development
 - 1% royalty rising to 5% at rate of 1% per 18 months
 - Royalty jumps to 30% net CF after Payout
 - Exploration Tax Credit of 25% for well costs above \$5 mm, used to reduce Federal Income Tax. If not taxable => direct refund of up to 40% of non-utilized credit

Norwegian Continental Shelf: Incentives in a Modern Context

- Oil production in Norway peaked in 2001 and has fallen by ~45% since then. Growth in gas production allowed BOE volumes to rise till 2004, and have been in decline ever since
- Fiscal system provides incentives for exploration activity

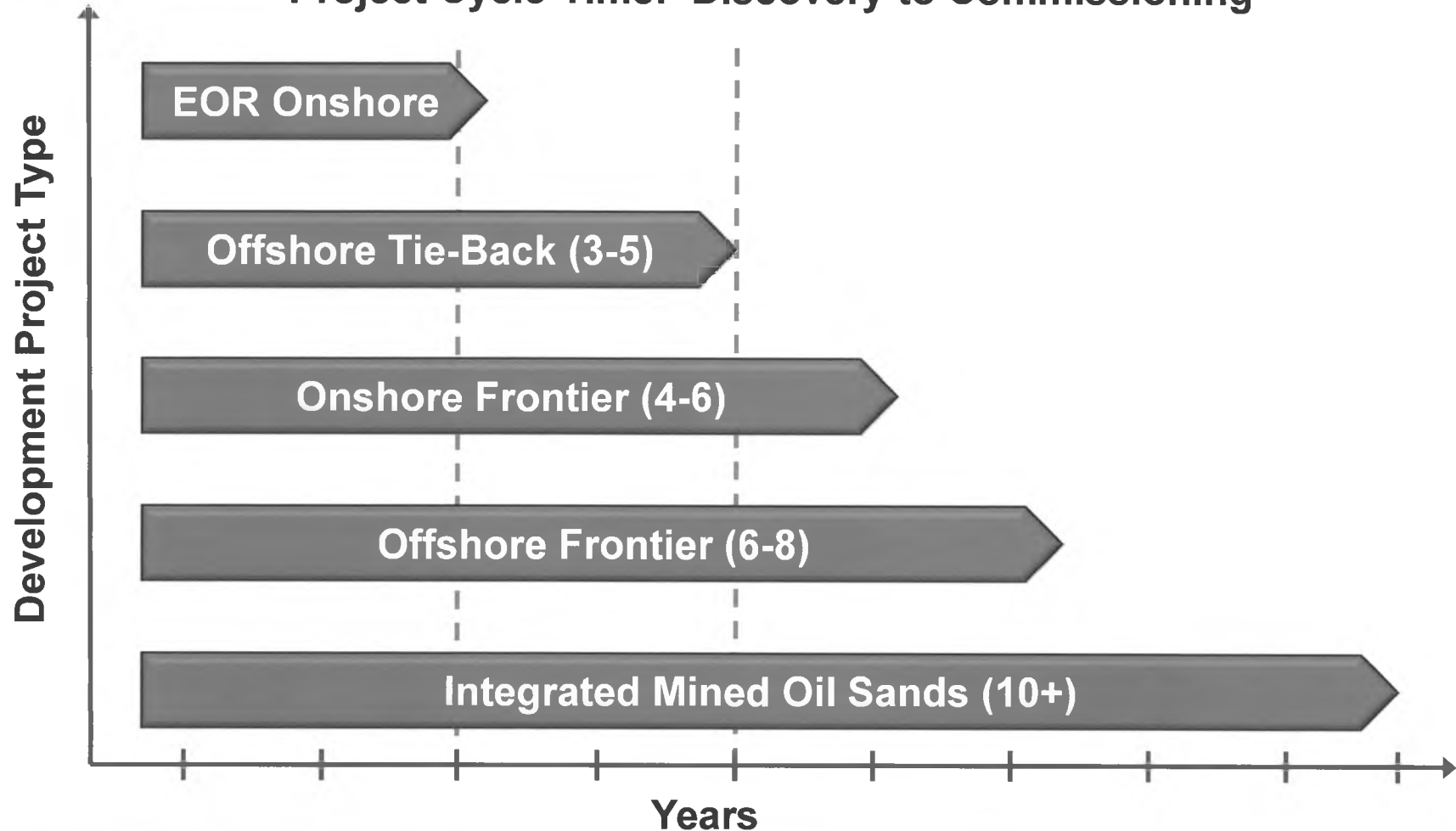
Initiative		Comment
Base Production Tax	• 25%	• Applied to net income from Petroleum activities
Special Tax	• 50%	• Applied to net income generated from petroleum activities, to capture resource rent above “normal profits”
Government Investment	• Petoro	• Engages in exploration and development activity as full equity partner; pays share of costs and receives 100% of revenue from its working interest position
Exploration Incentives	• 78%	<ul style="list-style-type: none"> • Applies to companies in non-taxable position. Since government allows uplift of loss carry-forward at a risk-free interest rate, it is indifferent between refund or offset • Introduced to expand the competitor landscape, bringing in new Upstream companies
License access		• All companies require <i>pre-approval for financial, technical, and operating capability</i> prior to bidding on a License in the Norwegian Continental Shelf (NCS)

Content

- Recent Trends in Exploration Activity and Basin Focus
- Credits and Incentives: Lessons from the Past
 - National Energy Program (Canada)
 - Norwegian Continental Shelf (Norway)
- ***Development Cycle Time: Incenting the Required Activities***

Cycle Time to Production

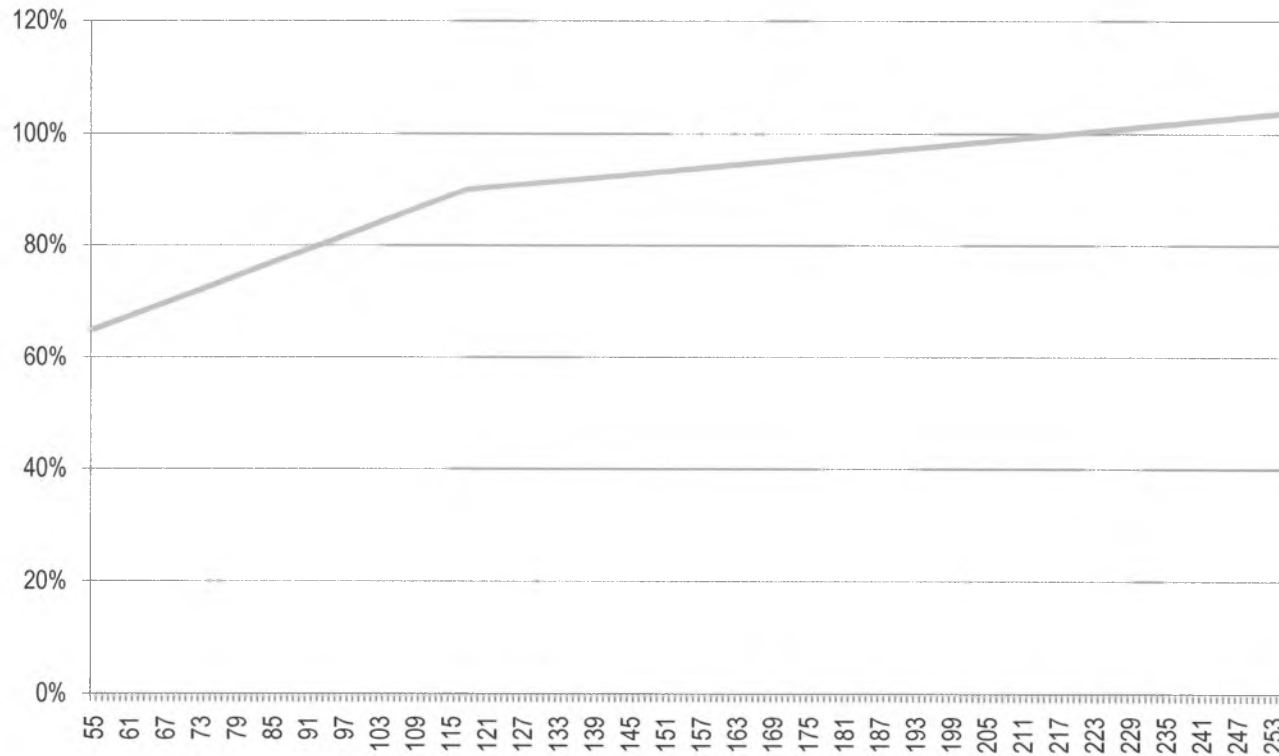
Project Cycle-Time: Discovery to Commissioning



Tool and Target: Direct Incentives to the Desired Outcome

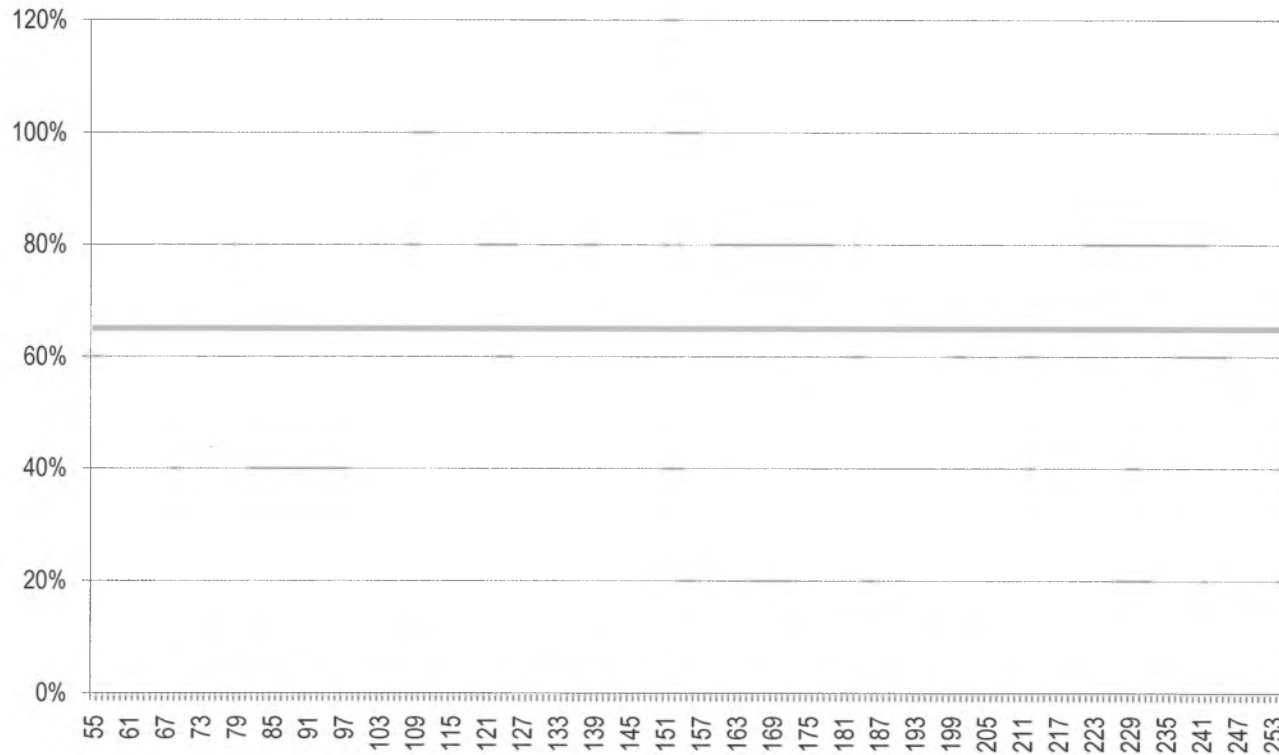
High Levels of Exploration Support under ACES

After Tax Effective Government Exploration Contribution With 40% Credit

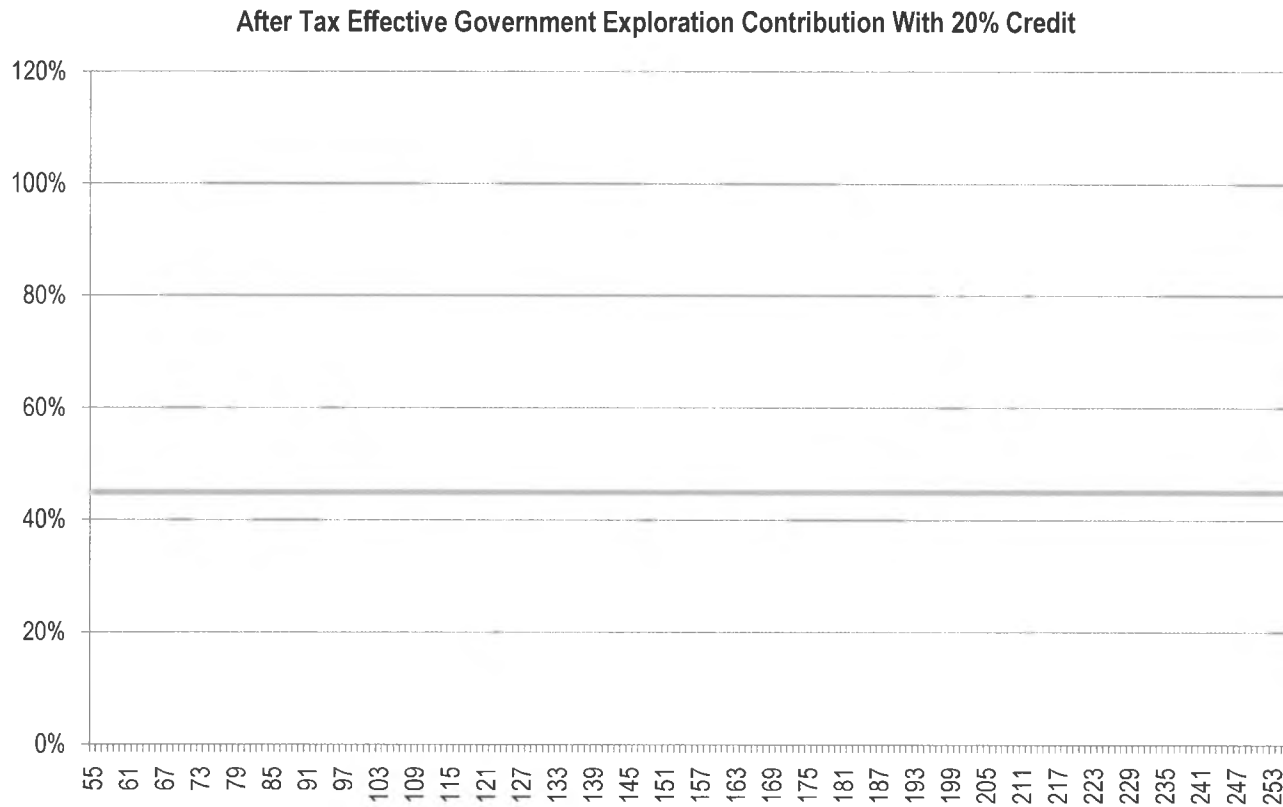


Reduced Levels of Exploration Support under Progressive Severance Option

After Tax Effective Government Exploration Contribution With 40% Credit



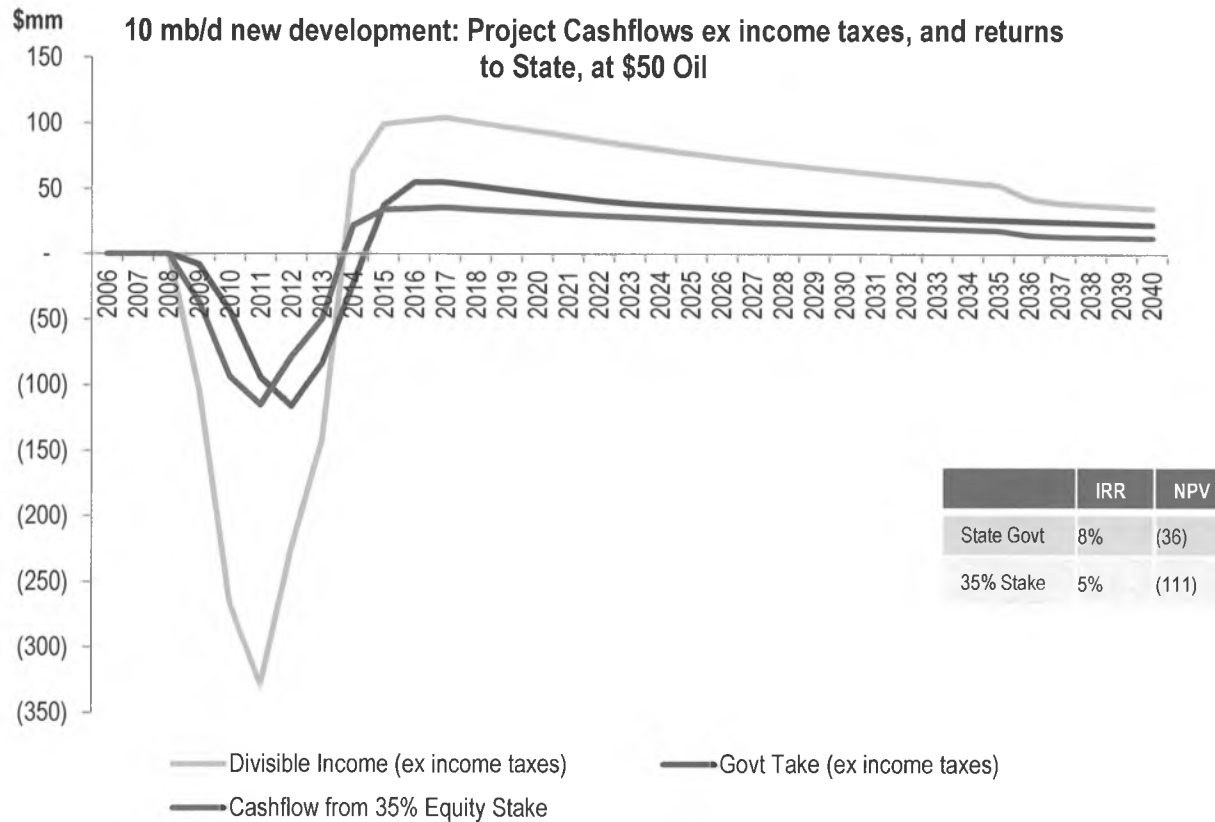
Levels of Exploration Support under Progressive Severance Option with 20% Exploration Credit



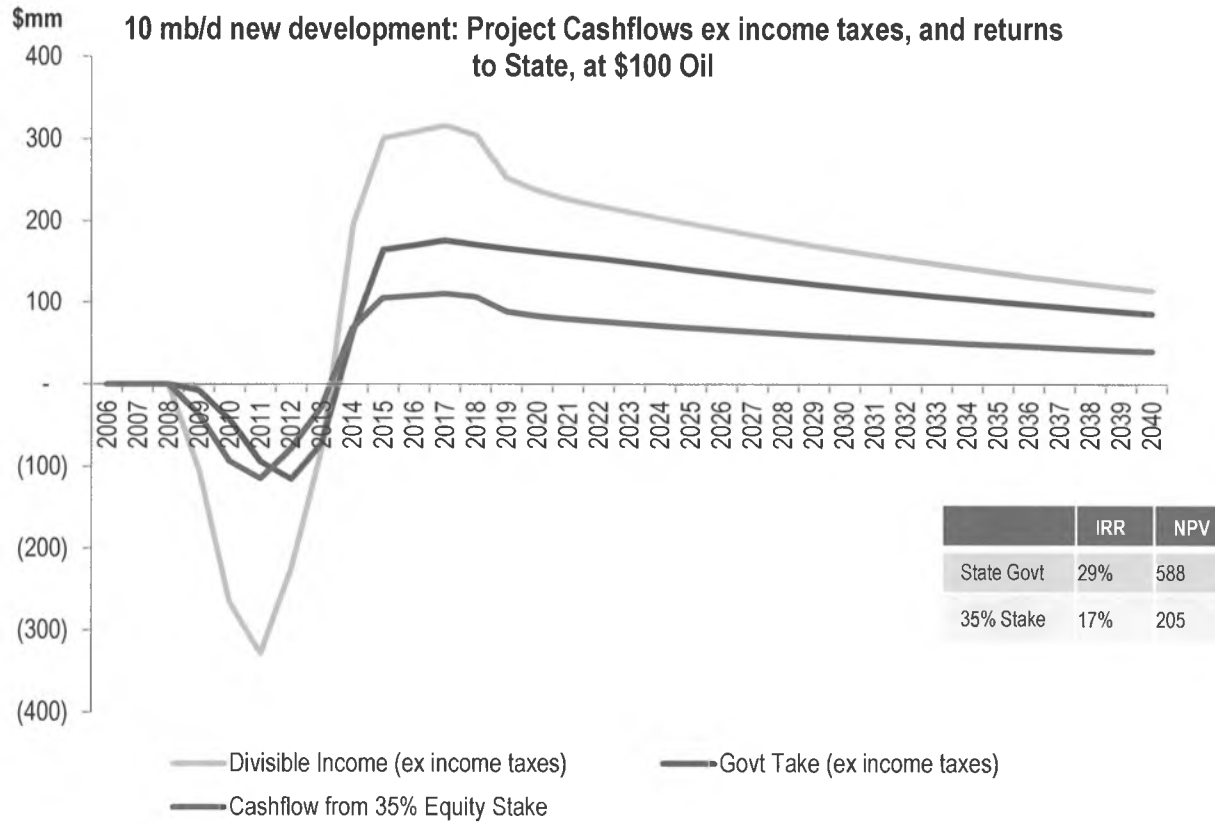


Capital Credits

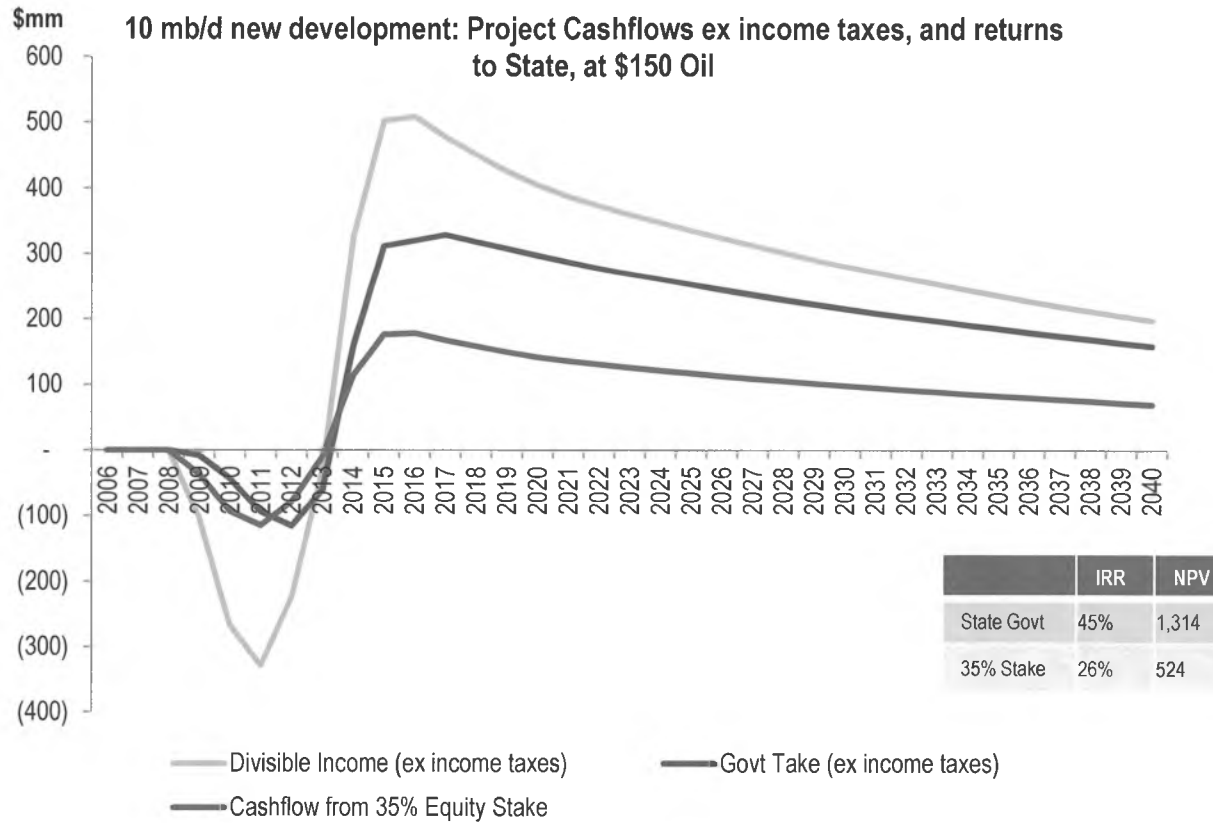
Capital Credit – Return on Investment Under ACES at \$50 Oil



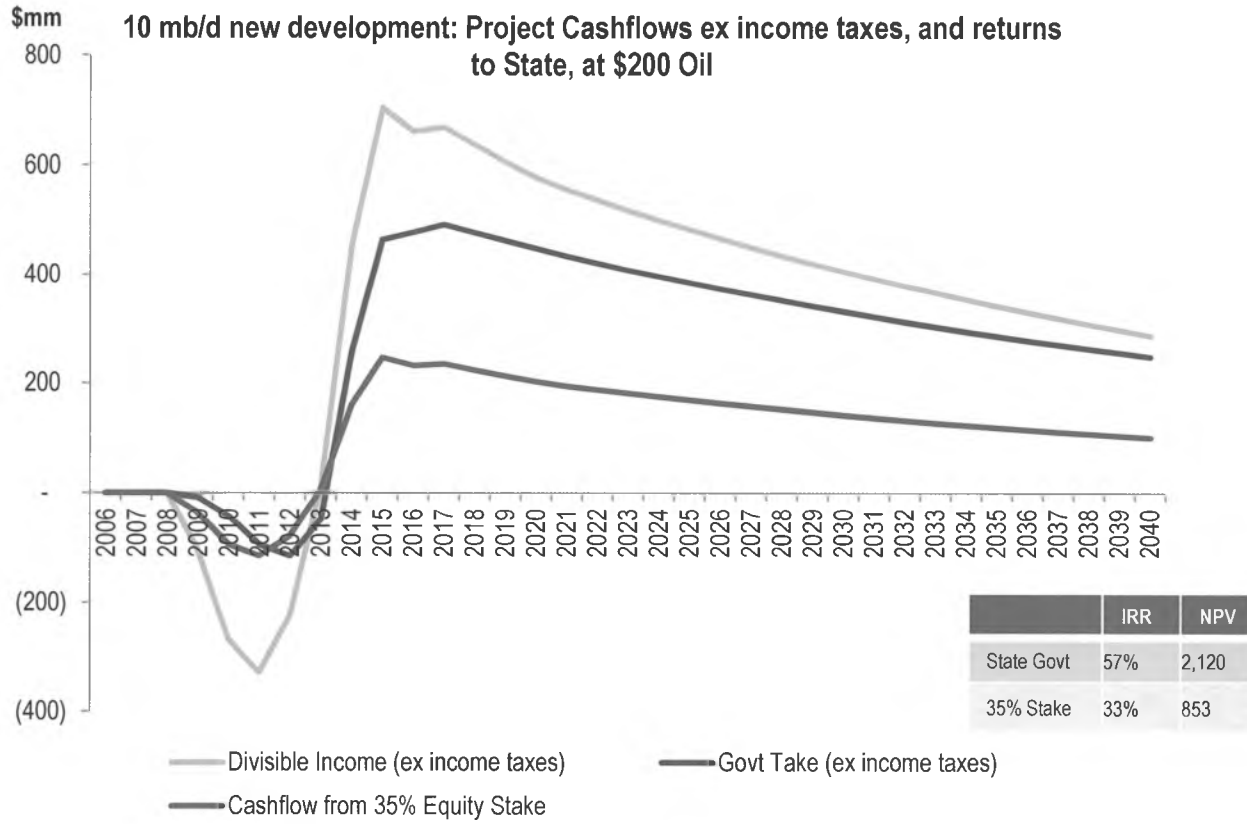
Capital Credit – Return on Investment Under ACES at \$100 Oil



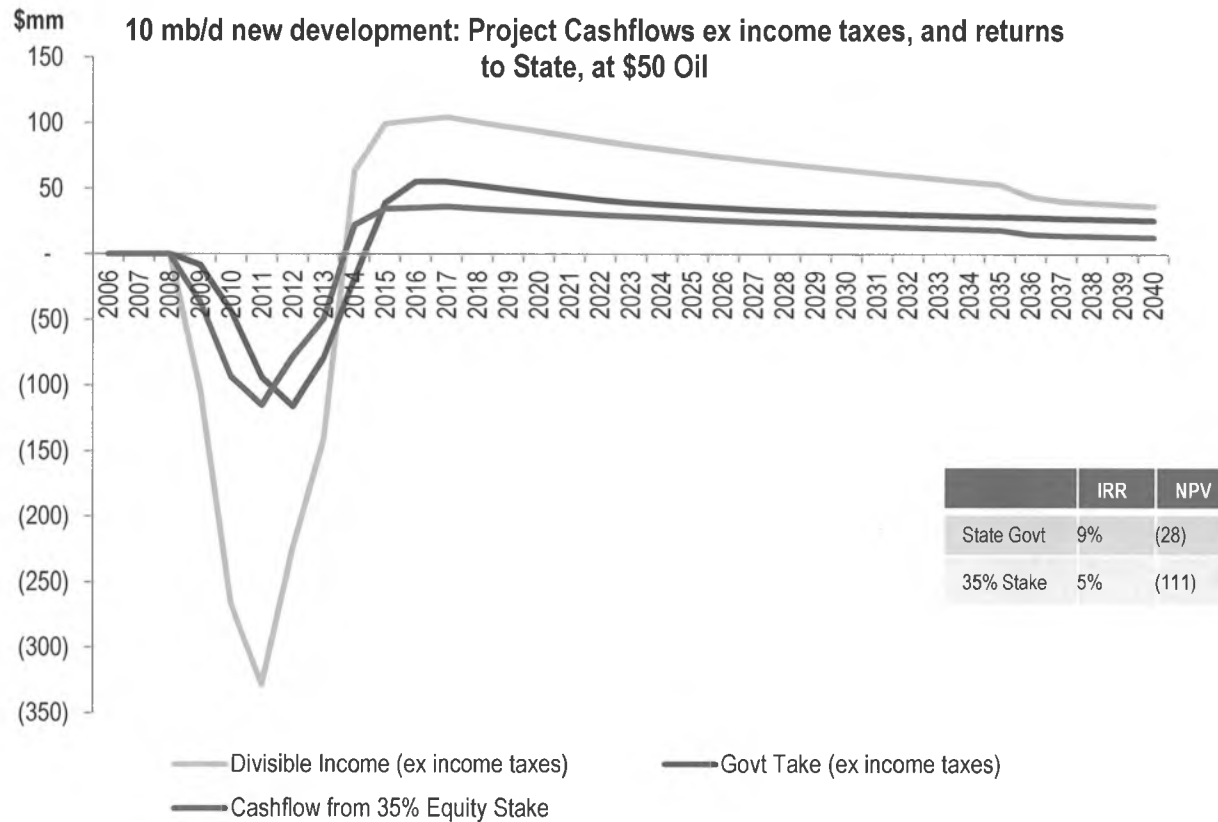
Capital Credit – Return on Investment Under ACES at \$150 Oil



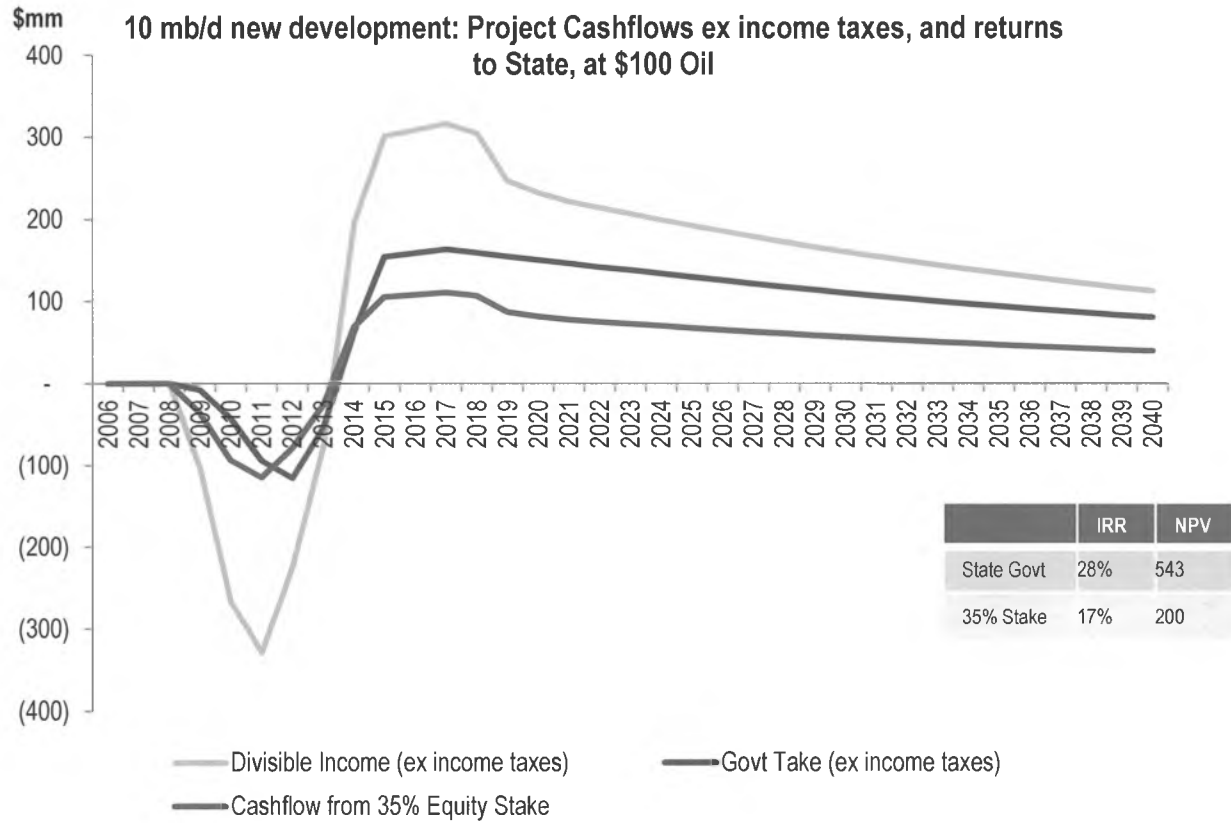
Capital Credit – Return on Investment Under ACES at \$200 Oil



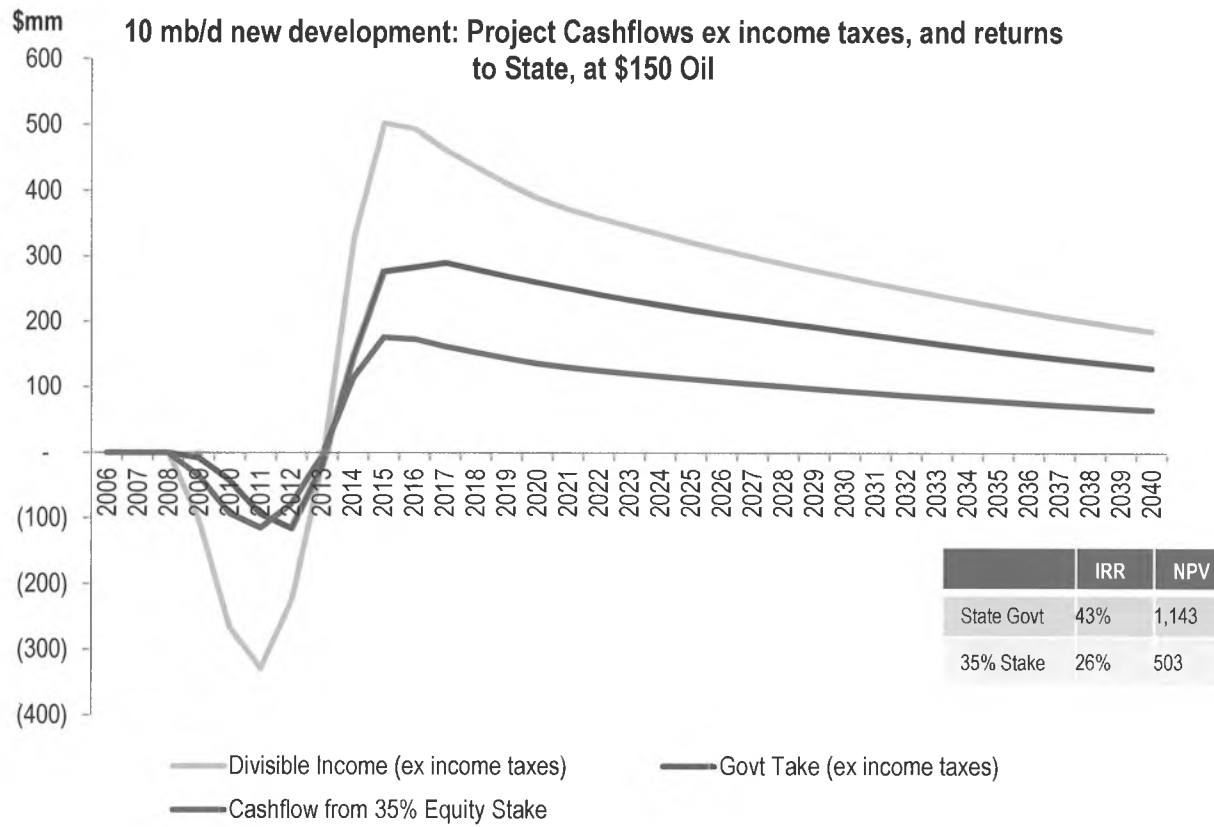
Capital Credit – Return on Investment Under Severance Option 1 at \$50 Oil



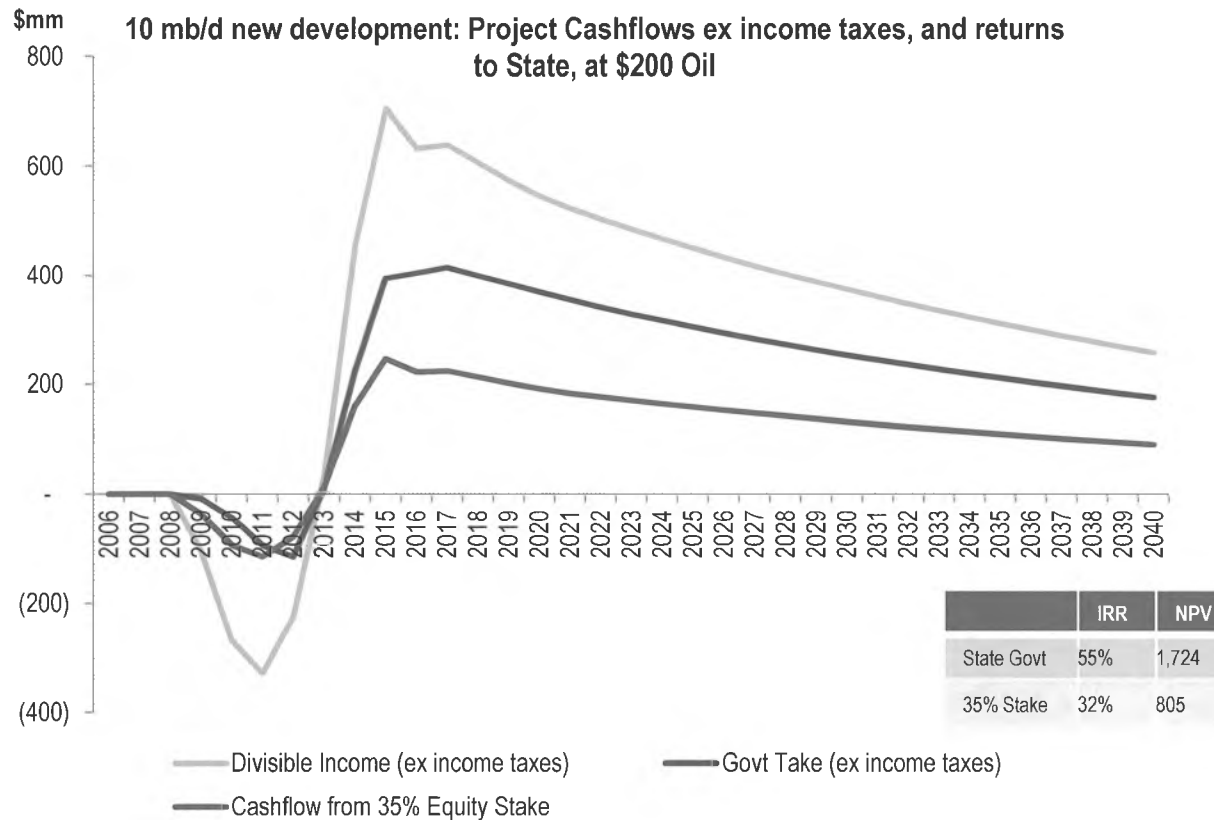
Capital Credit – Return on Investment Under Severance Option 1 at \$100 Oil



Capital Credit – Return on Investment Under Severance Option 1 at \$150 Oil



Capital Credit – Return on Investment Under Severance Option 1 at \$200 Oil



20.

**Table of Tax
Credits**

Table of Tax Credits under AS 43.55 - The Alaska

Below is a table relating to credits under AS 43.55, the Oil and Gas Production Tax, for the State of Alaska. This is intended as an informational guide. For current statutes and regulations, refer to the official printed version of the statutes and regulations. This

Credits under AS 43.55							
Updated 1/17/12, DMG							
Credits that May be Issued as Certificates and Submitted to the State for Cash Purchase							
	AS 43.55.023(a)(1)	AS 43.55.023(a)(2)	AS 43.55.023(b)	AS 43.55.023(f)(1)	AS 43.55.023(f)(2)	AS 43.55.023(g)	
Informal Title	Qualified Capital Expenditures Credit	Qualified Capital Expenditures Credit in Relation to Exploration	Carried-Forward Annual Loss Credit	Well Lease Expenditure Credit	Well Lease Expenditure Credit in Relation to Exploration	Alternative Exploration Credit	
Initial and Most Recent Effective Date(s)	4/1/2006, amended 7/1/2007	4/1/2006, amended 7/1/2007	4/1/2006, amended 7/1/2008	7/1/2010	7/1/2010	2003, amended 7/1/08	
Credit Percentage / Amount	20%	20%	25% (pre-7/1/07 20%)	40%	40%	30% (pre-7/1/08)	
Description	A Qualified Capital Expenditure (QCE) must be a lease expenditure and treated as a capitalized cost under 26 IRC. For credits south of 68 degrees North latitude these are issued as one certificate. For the North Slope, these credits are issued as two certificates (one available in year issued, the other available the following calendar year).	A Qualified Capital Expenditure (QCE) must be a lease expenditure and related to exploration. For credits south of 68 degrees North latitude these are issued as one certificate. For the North Slope, these credits are issued as two certificates (one available in year issued, the other available the following calendar year).	The carried forward annual loss is calculated for each segment by taking 25% of excess lease expenditures (lease expenditures not deductible in calculating production tax values). For credits south of 68 degrees North latitude these are issued as one certificate. For the North Slope, these credits are issued as two certificates (one available in year issued, the other available the following calendar year).	A Well Lease Expenditure (WLE) must be a lease expenditure, QCE, AND an Intangible Drilling and Development Cost (IDC) south of 68 degrees North latitude.	A Well Lease Expenditure (WLE) must be a lease expenditure, QCE, AND an Intangible Drilling and Development Cost (IDC) of 68 degrees North latitude.	These credits defined by both statute and regulation directly relate to exploration activities. An exploratory well may receive either 40% depending on seismicity may receive	
DNR Data Requirements	No	Yes	No	No	Yes	Yes	
Location Requirements	No	No	No	Yes - must be south of 68 degrees North latitude	Yes - must be south of 68 degrees North latitude	For some of these are required for wells	
Regulations*	15 AAC 55.310-320	15 AAC 55.310-320	15 AAC 55.310-320	None	None	15 AAC 55.310-320	
Combinations	Same expenditures may also qualify for credit under AS 43.55.023(b)	Same expenditures may also qualify for credit under AS 43.55.023(b)	Same expenditures may also qualify for credit under AS 43.55.023(a), (f), or 025(a)(1-4)	Same expenditures may also qualify for credit under AS 43.55.023(b)	Same expenditures may also qualify for credit under AS 43.55.023(b)	Same expenditures may also qualify for credit under AS 43.55.023(b)	
Uses to Credit	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.	Applied directly to tax or issued as a certificate and then transferred, applied to tax, or "cashed" out with the State under AS 43.55.028 - or a combination of the above. Note: the recipient of a transferred certificate may not "cash" out the certificate with the State.
Filing Requirements	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	Form 0405-330 must be submitted as well as all backup required under regulation to support the credit claim.	

*Other regulations under 15 AAC 55 may apply to these credits, this section only lists the regulations directly related. Please read all of 15 AAC 55 for complete information and treatments of the

21.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

April 3, 2012



Discussion Slides: Alaska Senate Finance Committee

April 3, 2012
Janak Mayer
Manager, Upstream & Gas
PFC Energy

Difficulties in Existing Fiscal Structure

- The incorporation of progressivity into the Profit-Based Production Tax (Net) in ACES creates three significant problems
 - Large-scale gas production at low gas prices could in the future significantly reduce production tax revenue from existing oil production
 - Resolving this problem within the framework of ACES requires significant complexity
 - Approach to decoupling in CSSB 192 requires ability to split costs between oil and gas production, creating high degree of administrative burden, and limiting capacity of state to effectively audit
 - Combination of high credits with high tax rates can produce excessive levels of support for certain spending, and weak incentives for cost control
 - Effective After-Tax rate of Government support for exploration can be over 100% at high price levels
 - Options for incentivizing new production are limited, and relatively complex
 - Proposed incentives within existing framework focus on either allowances to reduce Production Tax Value , or revenue exclusions (tax holiday)

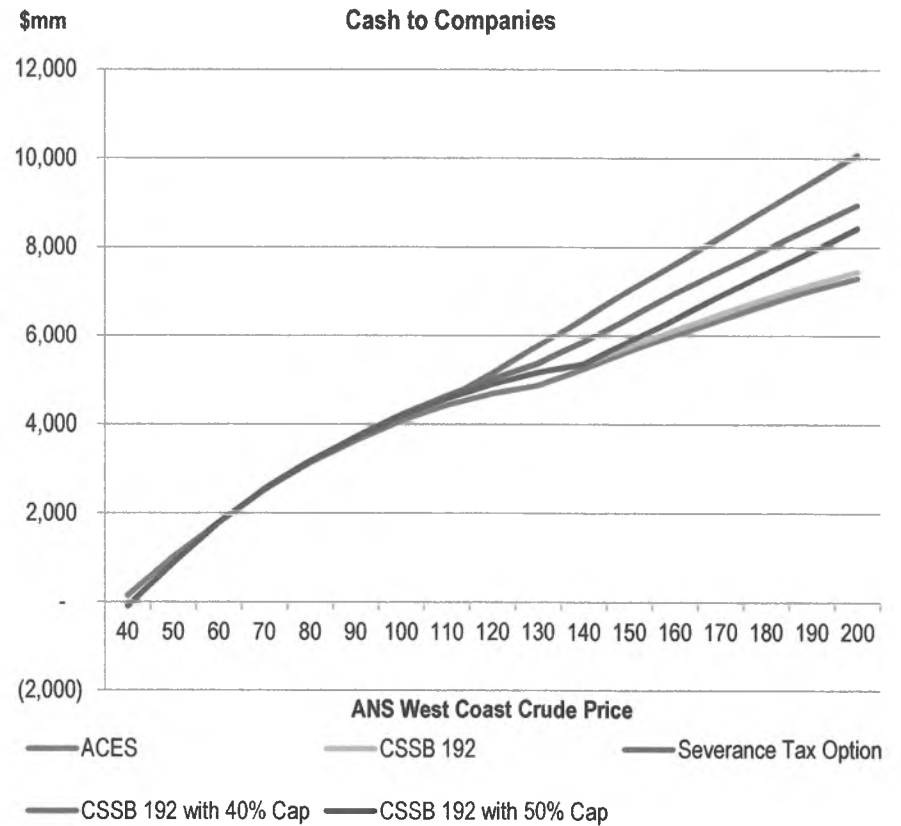
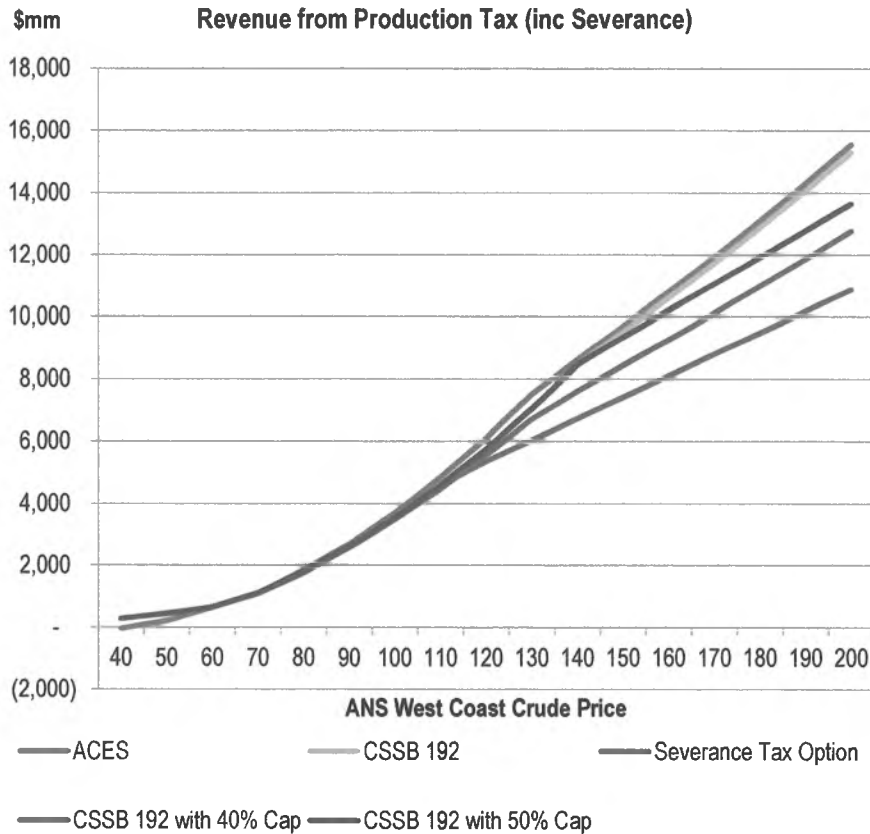
Summary of Progressive Severance Tax (Gross) Structure

- A Progressive Severance Tax (Gross) option would instead remove progressivity from the Profit-Based Production Tax (Net), instead levying this tax at the flat, base rate of 25%
- To retain an element of progressivity, a new Progressive Severance Tax (Gross) would then be added to the system. The tax would:
 - Be non-deductible for Profit-Based Production Tax purposes
 - Be levied on gross production (net of royalties)
 - Be levied solely on oil
 - The tax would use a progressivity structure not dissimilar to that under the current system, with progressivity coefficients that apply at different thresholds.
- The proposed Progressive Severance Tax would use the following parameters:
 - No severance tax below \$65 Gross Value at Point of Production (GVPP)
 - Progressivity of .25% commencing at a threshold of \$65 GVPP
 - At \$125 GVPP, a tax rate of 15% is reached. At this point, progressivity is reduced to 0.05%
 - Progressivity is capped at 20%

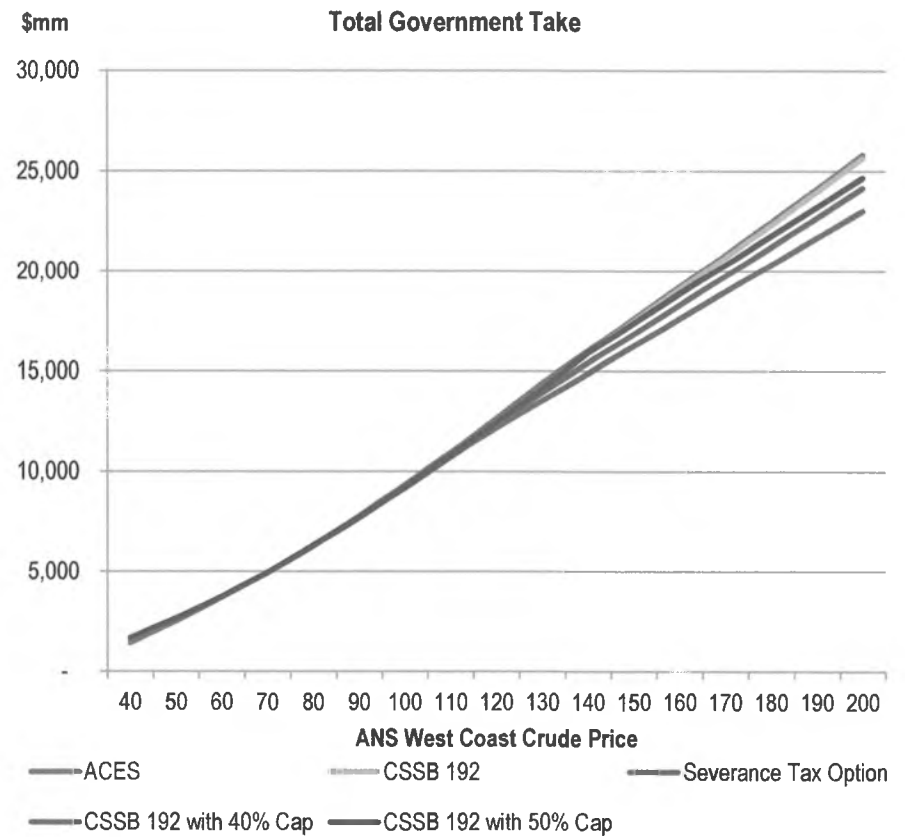
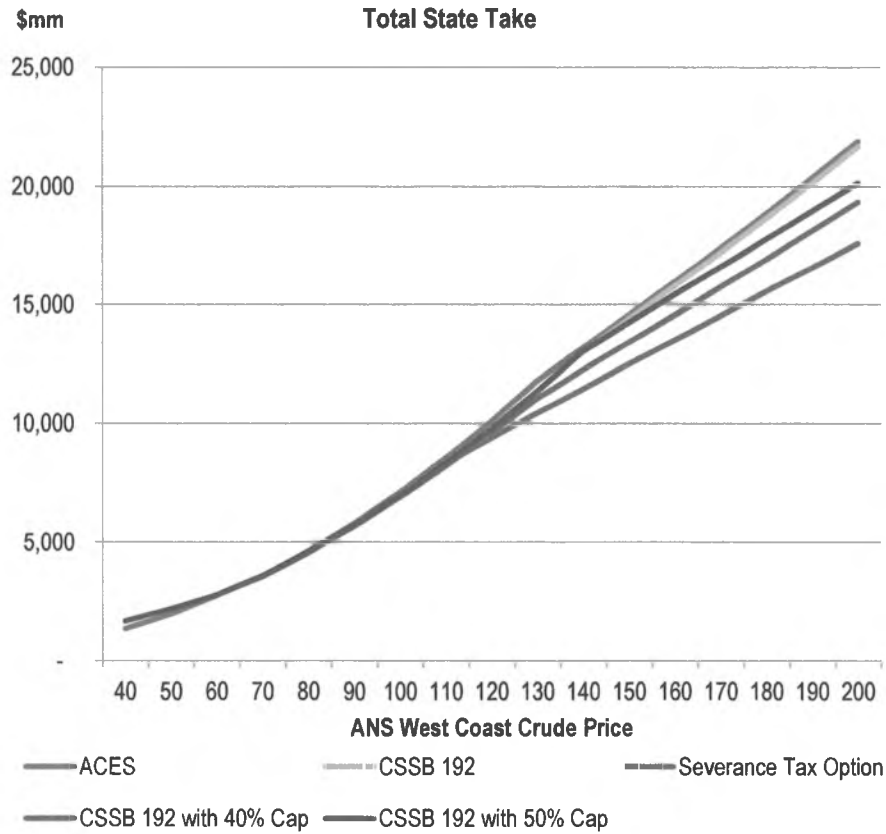
Benefits of Progressive Severance Tax (Gross) Structure

- By removing progressivity from the Profit-Based Production Tax (Net), and having the progressive element of the structure be a Progressive Severance Tax (Gross), two things become much easier to achieve
 - The issue of gas production reducing production tax revenue ceases to be a problem without progressivity in the Profit-Based Production Tax
 - Complex provisions to split costs between oil and gas production under CSSB 192 are thus no longer required
 - Much of the issue of excessive spending support ceases to be a problem
 - Even with 40% exploration credit, effective after-tax Government support for exploration flat at 65%
 - Significant incentives can be provided to new production, by eliminating or reducing the Progressive Severance Tax (Gross) for new production
- A wide range of levels of government take can be achieved using this structure, depending on the parameters applied

FY 2013 Revenue Comparison



FY 2013 Revenue Comparison



FY 2013 Revenue Comparison

	Production Tax					Total State Take					Total Government Take				
	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option
40	(39)	289	289	289	289	1,352	1,660	1,660	1,660	1,660	1,427	1,660	1,660	1,660	1,660
50	222	461	461	461	461	1,983	2,202	2,202	2,202	2,202	2,527	2,669	2,669	2,669	2,669
60	653	653	653	653	653	2,769	2,769	2,769	2,769	2,769	3,728	3,728	3,728	3,728	3,728
70	1,109	1,106	1,106	1,106	1,084	3,577	3,575	3,575	3,575	3,555	4,943	4,941	4,941	4,941	4,929
80	1,831	1,792	1,792	1,792	1,754	4,631	4,595	4,595	4,595	4,560	6,318	6,294	6,294	6,294	6,272
90	2,692	2,599	2,599	2,599	2,571	5,811	5,725	5,725	5,725	5,699	7,775	7,719	7,719	7,719	7,703
100	3,691	3,527	3,527	3,527	3,474	7,117	6,966	6,966	6,966	6,918	9,314	9,216	9,216	9,216	9,184
110	4,827	4,575	4,575	4,575	4,463	8,549	8,318	8,318	8,318	8,215	10,935	10,785	10,785	10,785	10,718
120	6,102	5,744	5,340	5,744	5,538	10,108	9,781	9,410	9,781	9,592	12,638	12,425	12,184	12,425	12,302
130	7,515	7,035	6,030	7,035	6,700	11,794	11,354	10,433	11,354	11,047	14,424	14,138	13,539	14,138	13,939
140	8,614	8,445	6,720	8,445	7,598	13,192	13,037	11,457	13,037	12,261	16,023	15,922	14,895	15,922	15,417
150	9,684	9,512	7,410	9,327	8,417	14,563	14,406	12,480	14,236	13,402	17,604	17,502	16,250	17,391	16,849
160	10,787	10,601	8,100	10,189	9,253	15,965	15,794	13,503	15,417	14,559	19,205	19,094	17,605	18,849	18,291
170	11,925	11,723	8,790	11,052	10,106	17,399	17,214	14,527	16,599	15,732	20,827	20,707	18,960	20,307	19,744
180	13,098	12,880	9,480	11,914	10,977	18,864	18,665	15,550	17,780	16,921	22,470	22,340	20,315	21,765	21,207
190	14,305	14,072	10,170	12,777	11,864	20,361	20,148	16,573	18,961	18,126	24,133	23,994	21,671	23,223	22,680
200	15,546	15,298	10,860	13,639	12,769	21,890	21,662	17,597	20,143	19,346	25,816	25,668	23,026	24,681	24,163

	Cash to Companies					FY 2013 % Government Take				
	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option
40	139	(95)	(95)	(95)	(95)	91%	106%	106%	106%	106%
50	1,010	868	868	868	868	71%	75%	75%	75%	75%
60	1,780	1,780	1,780	1,780	1,780	68%	68%	68%	68%	68%
70	2,536	2,538	2,538	2,538	2,551	66%	66%	66%	66%	66%
80	3,133	3,157	3,157	3,157	3,179	67%	67%	67%	67%	66%
90	3,648	3,703	3,703	3,703	3,720	68%	68%	68%	68%	67%
100	4,080	4,178	4,178	4,178	4,209	70%	69%	69%	69%	69%
110	4,430	4,581	4,581	4,581	4,647	71%	70%	70%	70%	70%
120	4,698	4,911	5,152	4,911	5,034	73%	72%	70%	72%	71%
130	4,884	5,170	5,769	5,170	5,370	75%	73%	70%	73%	72%
140	5,257	5,357	6,385	5,357	5,862	75%	75%	70%	75%	72%
150	5,647	5,749	7,001	5,860	6,402	76%	75%	70%	75%	72%
160	6,017	6,128	7,617	6,373	6,931	76%	76%	70%	75%	73%
170	6,367	6,487	8,234	6,887	7,450	77%	76%	70%	75%	73%
180	6,696	6,825	8,850	7,400	7,959	77%	77%	70%	75%	73%
190	7,004	7,143	9,466	7,914	8,457	78%	77%	70%	75%	73%
200	7,292	7,440	10,082	8,428	8,945	78%	78%	70%	75%	73%

Note: Consistent with DOR methodology, these revenue numbers do not include payments for tax credits which are not claimed against current production, as these are accounted for separately in the budget. In 2013, DOR forecasts a potential liability of \$400mm for these credits.

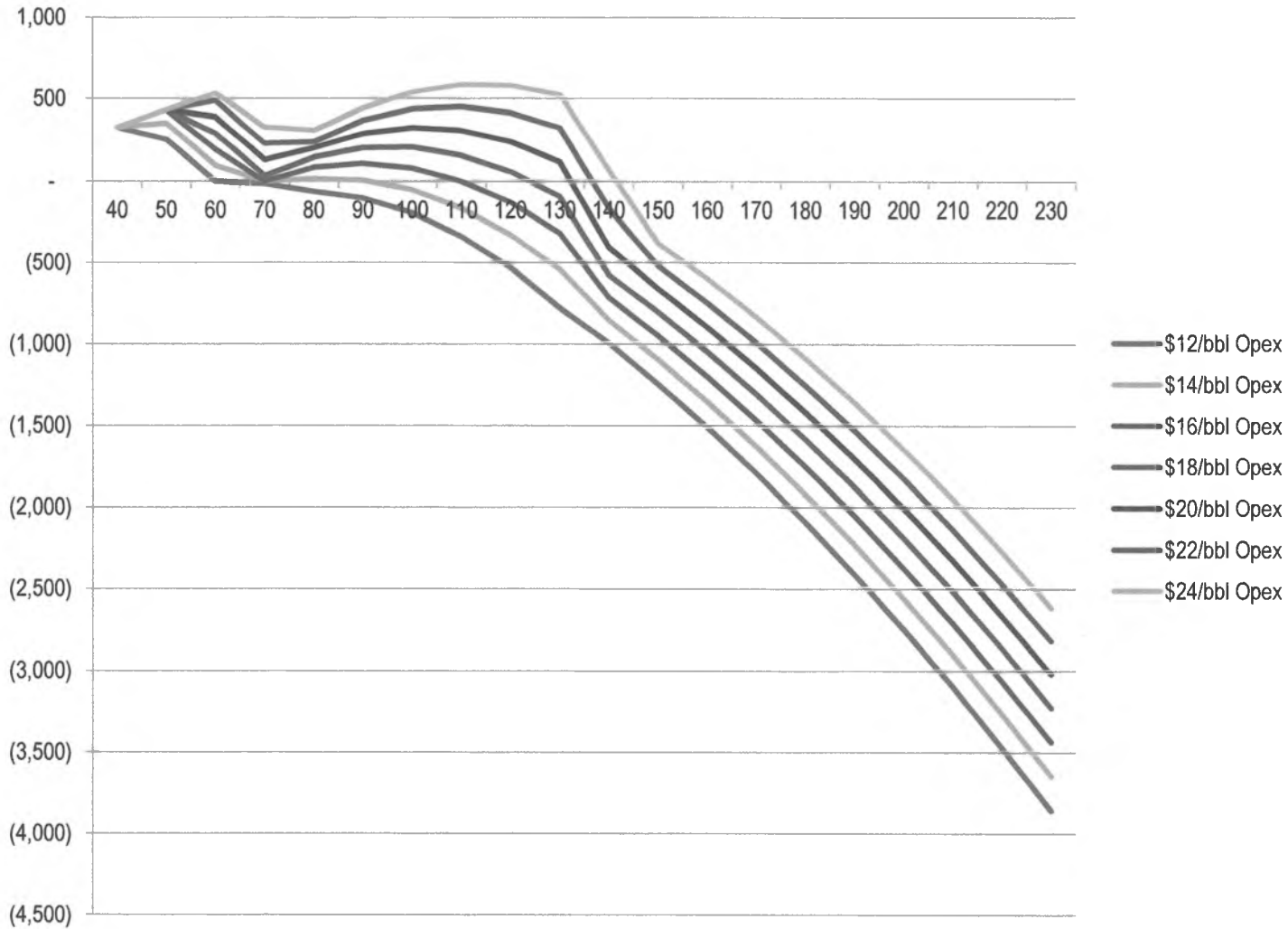
FY 2013 Revenue Comparison – Adjusted for Credits Not Claimed Against Current Production

	Production Tax					Total State Take				
	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option	ACES	CSSB 192	CSSB 192 with 40% Cap	CSSB 192 with 50% Cap	Severance Tax Option
40	(439)	(111)	(111)	(111)	(111)	952	1,260	1,260	1,260	1,260
50	(178)	61	61	61	61	1,583	1,802	1,802	1,802	1,802
60	253	253	253	253	253	2,369	2,369	2,369	2,369	2,369
70	709	706	706	706	684	3,177	3,175	3,175	3,175	3,155
80	1,431	1,392	1,392	1,392	1,354	4,231	4,195	4,195	4,195	4,160
90	2,292	2,199	2,199	2,199	2,171	5,411	5,325	5,325	5,325	5,299
100	3,291	3,127	3,127	3,127	3,074	6,717	6,566	6,566	6,566	6,518
110	4,427	4,175	4,175	4,175	4,063	8,149	7,918	7,918	7,918	7,815
120	5,702	5,344	4,940	5,344	5,138	9,708	9,381	9,010	9,381	9,192
130	7,115	6,635	5,630	6,635	6,300	11,394	10,954	10,033	10,954	10,647
140	8,214	8,045	6,320	8,045	7,198	12,792	12,637	11,057	12,637	11,861
150	9,284	9,112	7,010	8,927	8,017	14,163	14,006	12,080	13,836	13,002
160	10,387	10,201	7,700	9,789	8,853	15,565	15,394	13,103	15,017	14,159
170	11,525	11,323	8,390	10,652	9,706	16,999	16,814	14,127	16,199	15,332
180	12,698	12,480	9,080	11,514	10,577	18,464	18,265	15,150	17,380	16,521
190	13,905	13,672	9,770	12,377	11,464	19,961	19,748	16,173	18,561	17,726
200	15,146	14,898	10,460	13,239	12,369	21,490	21,262	17,197	19,743	18,946

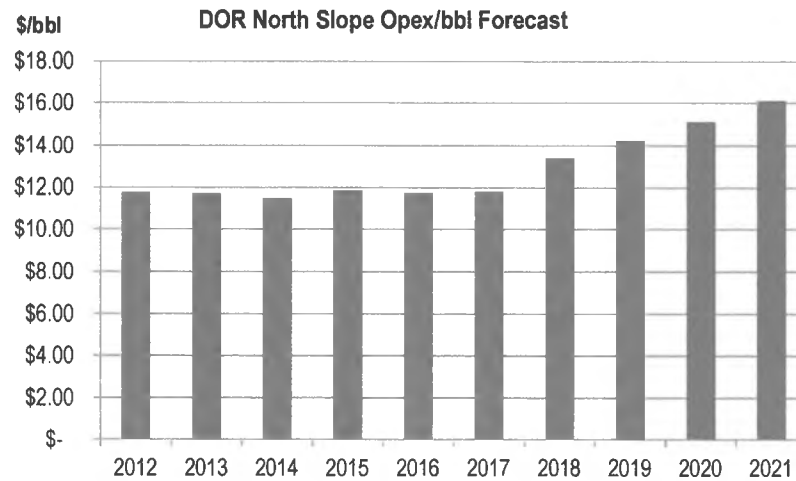
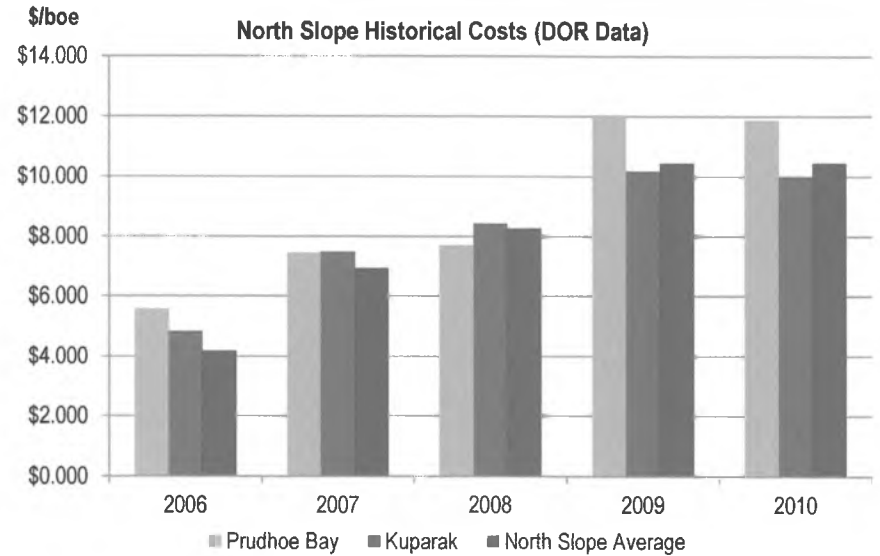
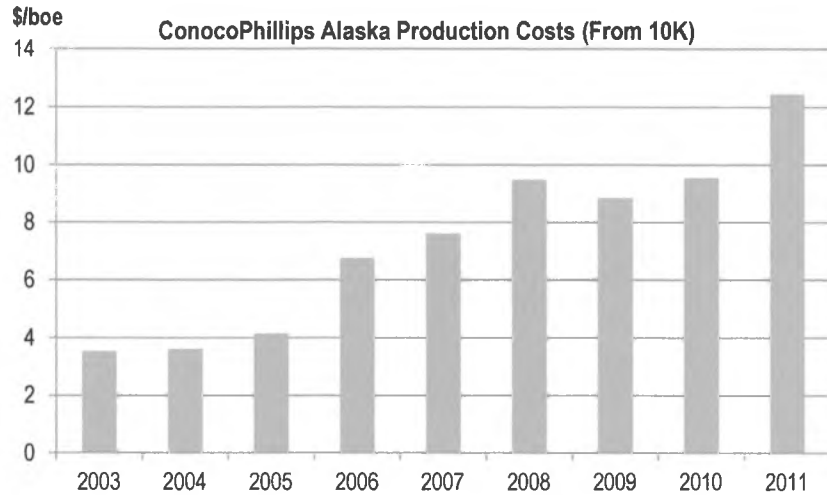
ANS West Coast Oil Price

Impact of Rising Operating Costs

Revenue Difference Between ACES and Progressive Severance Option under Different Opex/bbl Assumptions



Data on Operating Costs



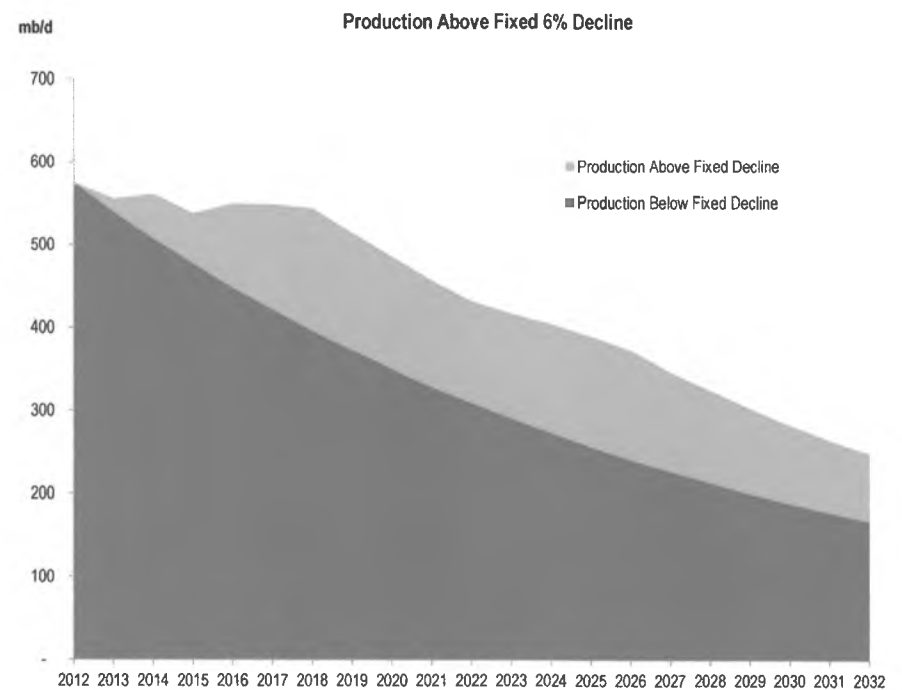
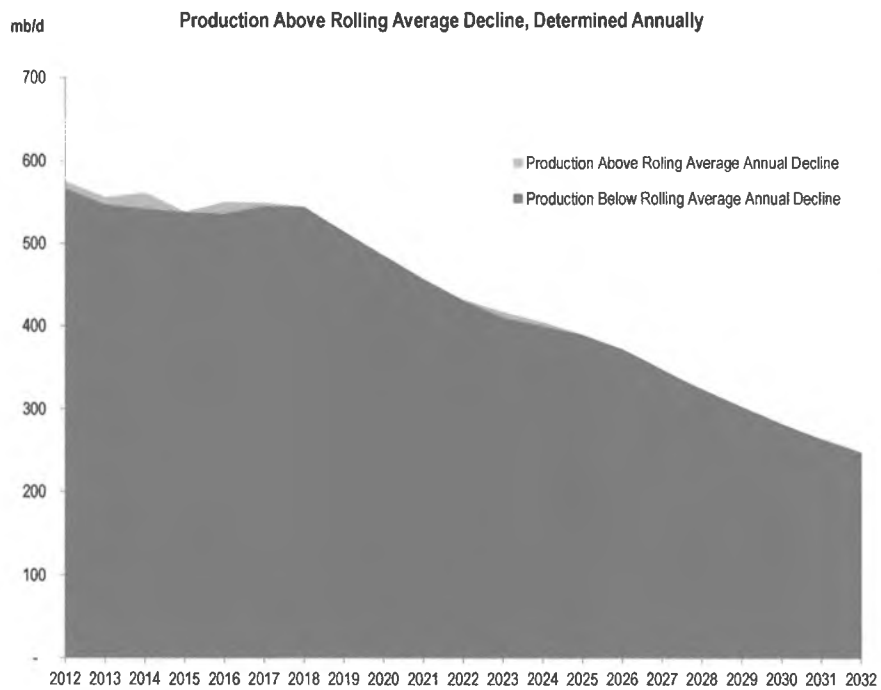
Impact of Inflation

- Under ACES, thresholds and coefficients for progressivity are specified in nominal terms, without indexation
 - As a result, when economics over the long-term rather than just 2013 are examined, we see the effects of ‘bracket creep’ or ‘stealth tax’
 - In real terms, as prices increase, thresholds for progressivity decrease, and the higher take that comes with progressivity occurs at lower and lower price levels
- Similarly, unless progressive severance thresholds are indexed to inflation, progressive severance will apply at steadily lower thresholds over time
 - Indexing thresholds will also go some way to addressing the cost sensitivity issue

Incentives for New Production

- Significant incentives can be provided to new production, by eliminating or reducing the Progressive Severance Tax (Gross) on any combination of:
 - Production from new areas
 - Production from new plans of development (determined through the regulatory process to be for “new production”)
 - Production above a fixed decline rate
- One possibility for a reduced rate of Progressive Severance Tax is:
 - No severance tax below \$65 Gross Value at Point of Production (GVPP)
 - Progressivity of .05% commencing at a threshold of \$65 GVPP
 - Progressivity capped at 5%

Production Above a Decline – Fixed v Annual Calculation



22.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

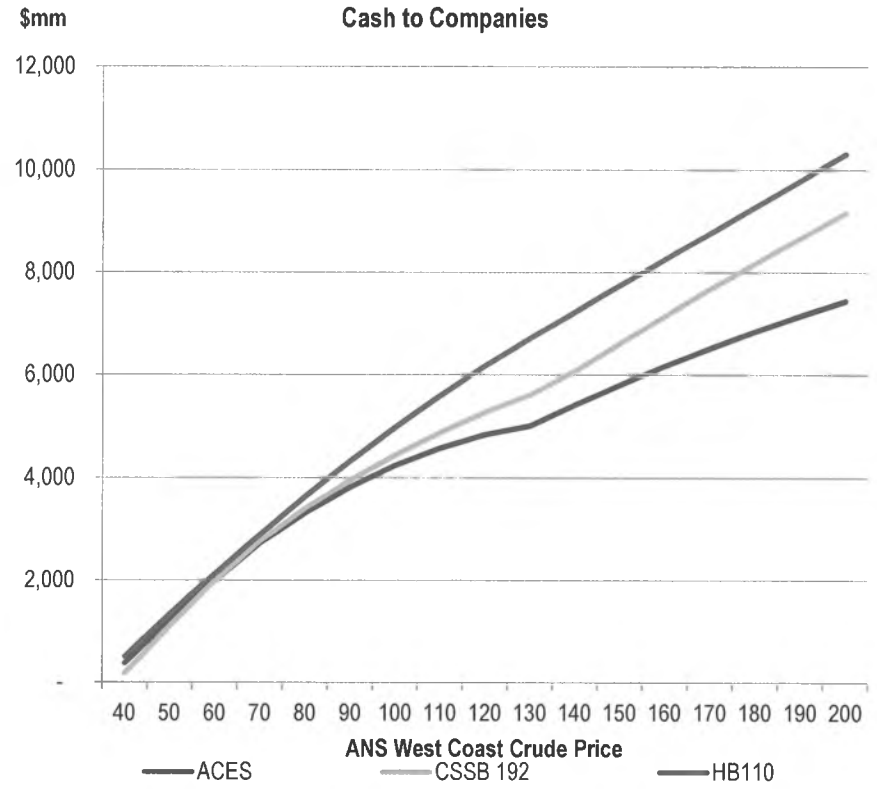
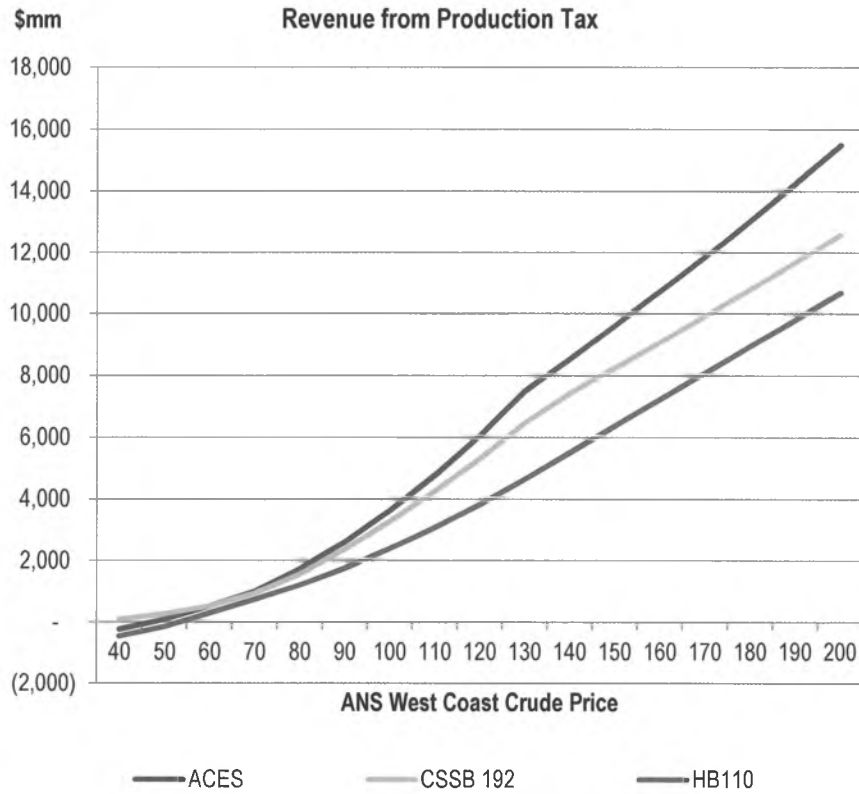
April 4, 2012



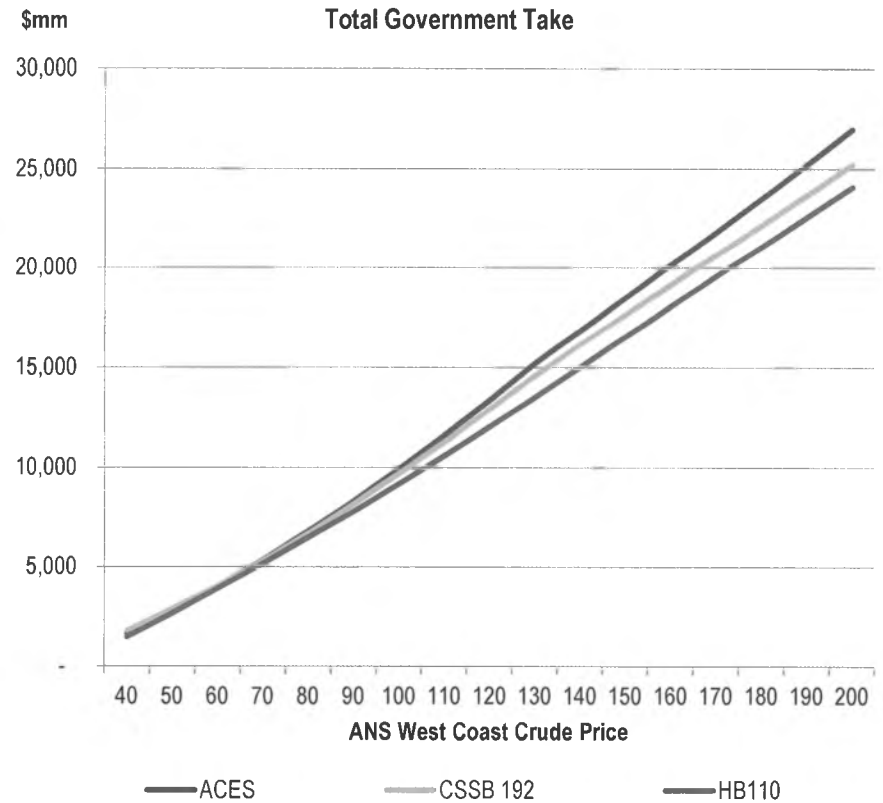
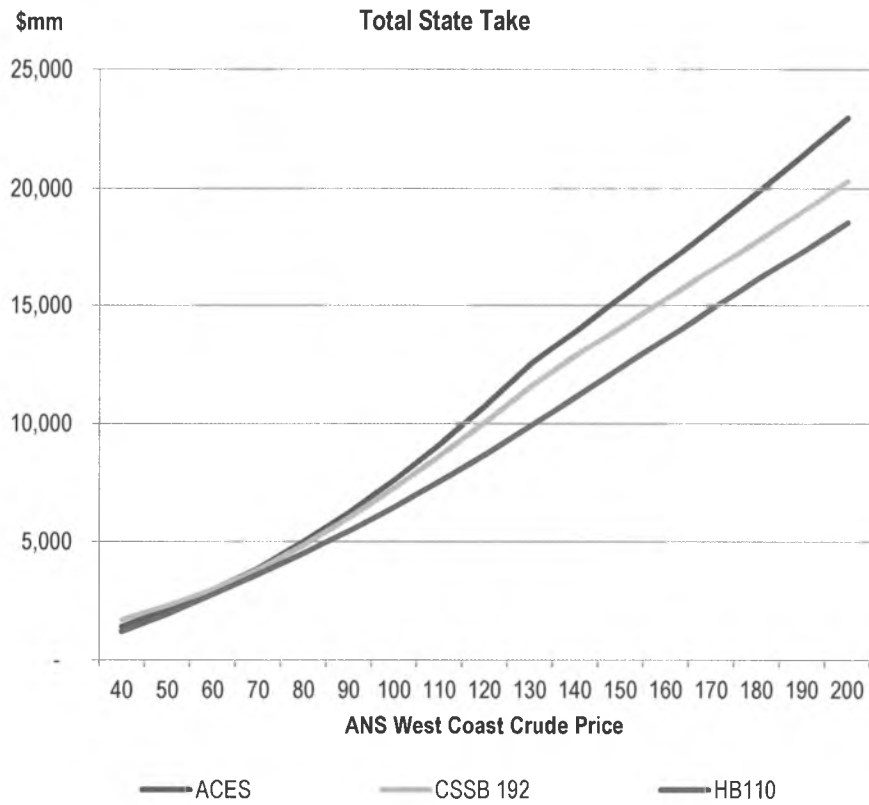
Discussion Slides: Alaska Senate Finance Committee

April 4, 2012
Janak Mayer
Manager, Upstream & Gas
PFC Energy

FY 2013 Revenue Comparison



FY 2013 Revenue Comparison



FY 2013 Revenue Comparison

	Production Tax			Total State Take			Total Government Take			Cash to Companies			FY 2013 % Government Take		
	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110
40	(233)	92	(458)	1,413	1,711	1,207	1,616	1,810	1,482	378	184	512	81%	91%	74%
50	82	265	(143)	2,148	2,315	1,941	2,803	2,912	2,669	1,218	1,109	1,352	70%	72%	66%
60	513	513	288	2,989	2,989	2,783	4,060	4,060	3,926	1,988	1,988	2,122	67%	67%	65%
70	996	944	729	3,878	3,831	3,634	5,347	5,316	5,188	2,727	2,758	2,886	66%	66%	64%
80	1,736	1,574	1,204	5,002	4,854	4,515	6,787	6,690	6,470	3,314	3,411	3,631	67%	66%	64%
90	2,613	2,384	1,763	6,252	6,042	5,473	8,308	8,172	7,802	3,819	3,955	4,325	69%	67%	64%
100	3,628	3,281	2,387	7,629	7,310	6,491	9,913	9,705	9,173	4,241	4,448	4,981	70%	69%	65%
110	4,782	4,263	3,075	9,132	8,657	7,568	11,599	11,290	10,583	4,582	4,890	5,598	72%	70%	65%
120	6,073	5,332	3,828	10,761	10,082	8,705	13,367	12,926	12,031	4,840	5,281	6,176	73%	71%	66%
130	7,503	6,488	4,648	12,517	11,587	9,902	15,218	14,613	13,518	5,016	5,620	6,716	75%	72%	67%
140	8,550	7,437	5,510	13,922	12,903	11,138	16,841	16,178	15,031	5,420	6,082	7,230	76%	73%	68%
150	9,623	8,255	6,372	15,352	14,099	12,374	18,479	17,665	16,544	5,808	6,622	7,743	76%	73%	68%
160	10,730	9,089	7,235	16,813	15,310	13,611	20,138	19,161	18,057	6,175	7,152	8,257	77%	73%	69%
170	11,873	9,941	8,097	18,306	16,537	14,847	21,818	20,668	19,570	6,522	7,672	8,770	77%	73%	69%
180	13,049	10,811	8,960	19,830	17,780	16,084	23,518	22,185	21,083	6,849	8,182	9,284	77%	73%	69%
190	14,261	11,697	9,822	21,386	19,038	17,320	25,239	23,712	22,596	7,155	8,681	9,797	78%	73%	70%
200	15,506	12,601	10,685	22,974	20,312	18,557	26,980	25,250	24,109	7,440	9,170	10,311	78%	73%	70%

Note: Consistent with DOR methodology, these revenue numbers do not include payments for tax credits which are not claimed against current production, as these are accounted for separately in the budget. In 2013, DOR forecasts a potential liability of \$400mm for these credits.

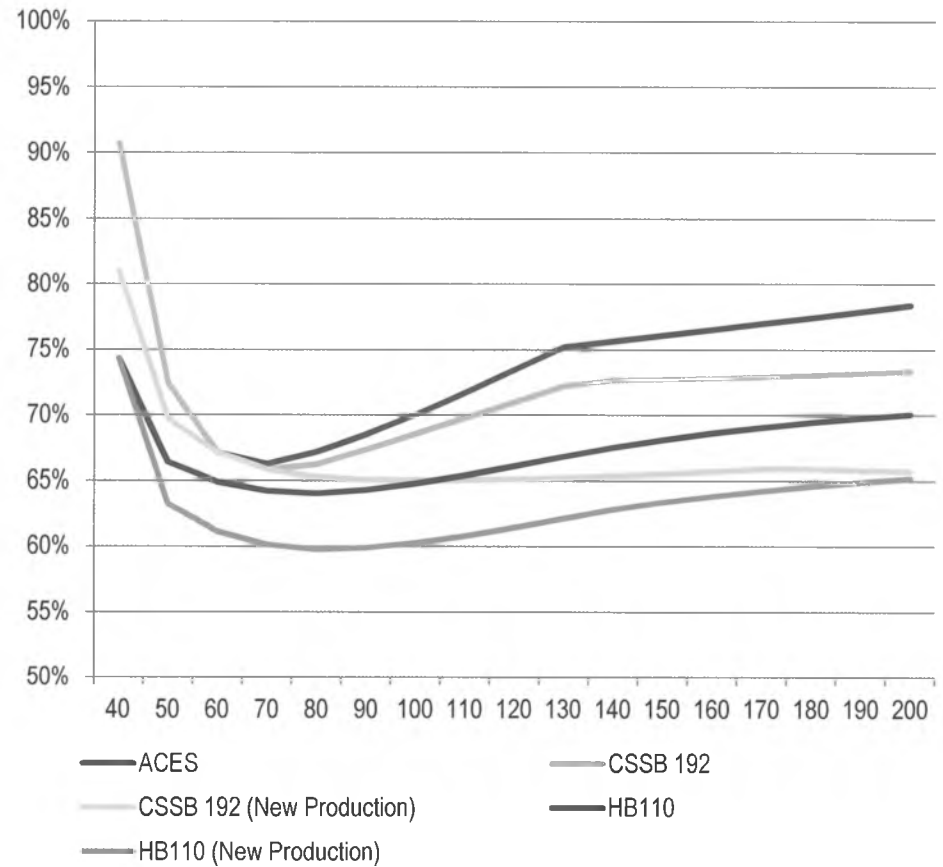
FY 2013 Revenue Comparison – Adjusted for \$400mm Credits Not Claimed Against Current Production

	Production Tax			Total State Take		
	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110
40	(633)	(308)	(858)	1,013	1,311	807
50	(318)	(135)	(543)	1,748	1,915	1,541
60	113	113	(112)	2,589	2,589	2,383
70	596	544	329	3,478	3,431	3,234
80	1,336	1,174	804	4,602	4,454	4,115
90	2,213	1,984	1,363	5,852	5,642	5,073
100	3,228	2,881	1,987	7,229	6,910	6,091
110	4,382	3,863	2,675	8,732	8,257	7,168
120	5,673	4,932	3,428	10,361	9,682	8,305
130	7,103	6,088	4,248	12,117	11,187	9,502
140	8,150	7,037	5,110	13,522	12,503	10,738
150	9,223	7,855	5,972	14,952	13,699	11,974
160	10,330	8,689	6,835	16,413	14,910	13,211
170	11,473	9,541	7,697	17,906	16,137	14,447
180	12,649	10,411	8,560	19,430	17,380	15,684
190	13,861	11,297	9,422	20,986	18,638	16,920
200	15,106	12,201	10,285	22,574	19,912	18,157

ANS West Coast Oil Price

Total Government Take Comparison Including New Production Incentives

		FY 2013 % Government Take				
		ACES	CSSB 192	CSSB 192 (New Production)	HB110	HB110 (New Production)
ANS West Coast Oil Price	40	81%	91%	81%	74%	74%
	50	70%	72%	70%	66%	63%
	60	67%	67%	67%	65%	61%
	70	66%	66%	66%	64%	60%
	80	67%	66%	65%	64%	60%
	90	69%	67%	65%	64%	60%
	100	70%	69%	65%	65%	60%
	110	72%	70%	65%	65%	61%
	120	73%	71%	65%	66%	61%
	130	75%	72%	65%	67%	62%
	140	76%	73%	65%	68%	63%
	150	76%	73%	66%	68%	63%
	160	77%	73%	66%	69%	64%
	170	77%	73%	66%	69%	64%
	180	77%	73%	66%	69%	65%
	190	78%	73%	66%	70%	65%
	200	78%	73%	66%	70%	65%



23.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

April 4, 2012

(PM)



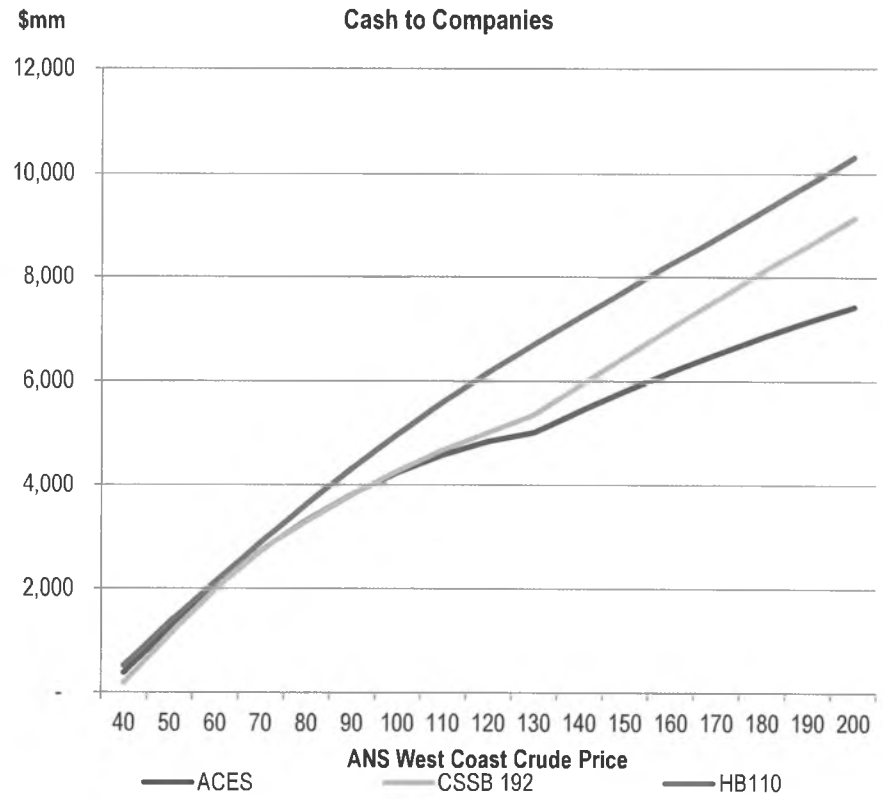
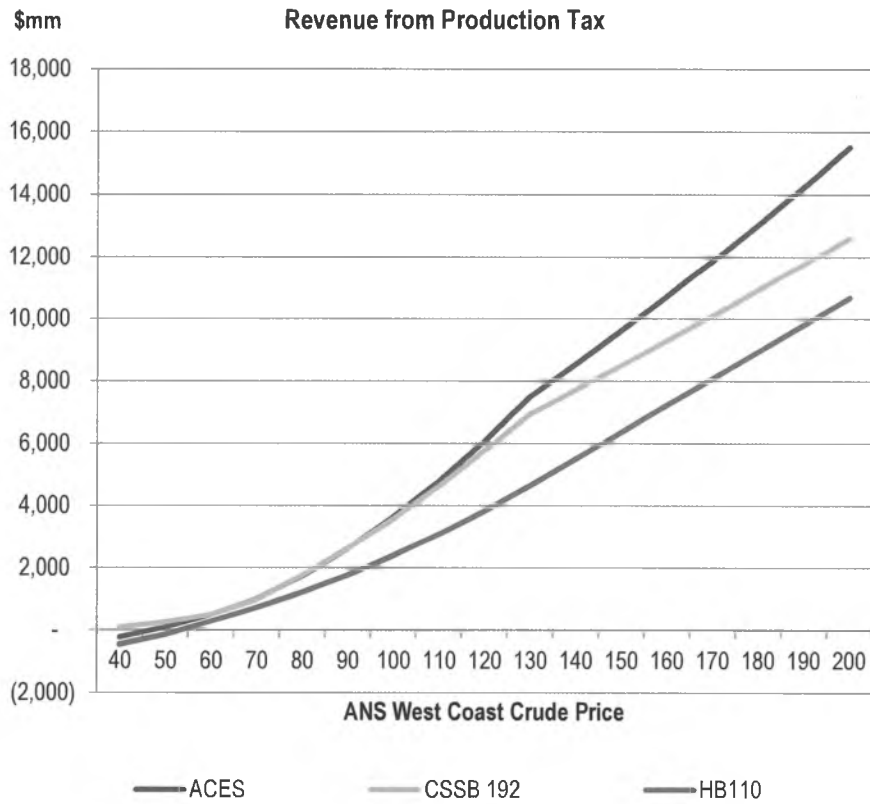
Discussion Slides: Alaska Senate Finance Committee

April 4, 2012
Janak Mayer
Manager, Upstream & Gas
PFC Energy

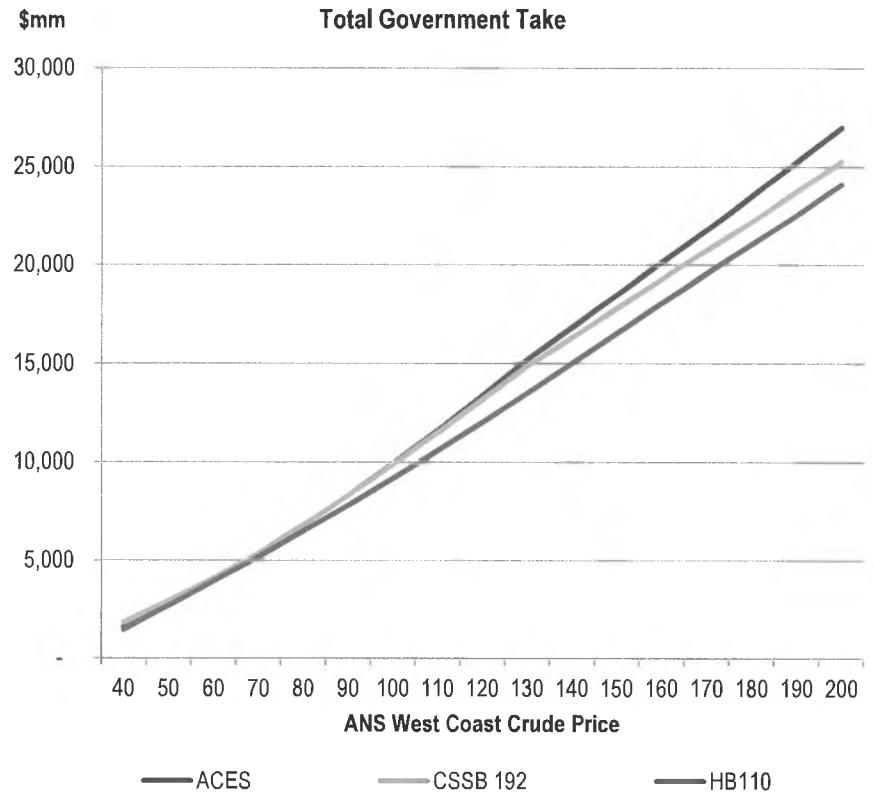
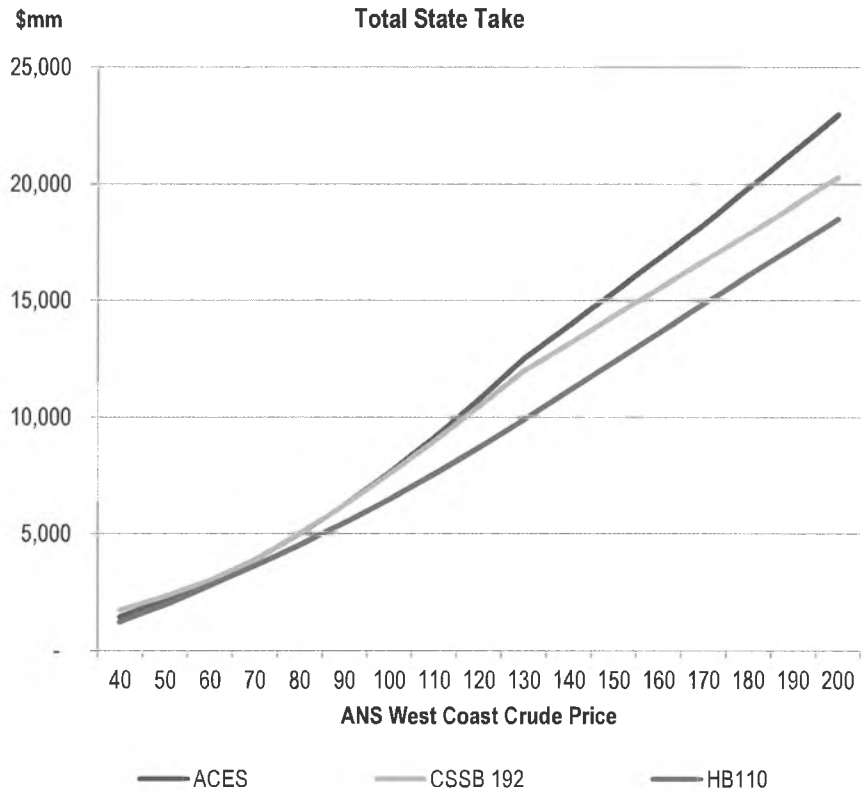
Summary of Progressive Severance Tax (Gross) Structure

- A Progressive Severance Tax (Gross) option would instead remove progressivity from the Profit-Based Production Tax (Net), instead levying this tax at the flat, base rate of 25%
- To retain an element of progressivity, a new Progressive Severance Tax (Gross) would then be added to the system. The tax would:
 - Be non-deductible for Profit-Based Production Tax purposes
 - Be levied on gross production (net of royalties)
 - Be levied solely on oil
 - The tax would use a progressivity structure not dissimilar to that under the current system, with progressivity coefficients that apply at different thresholds.
- The proposed Progressive Severance Tax would use the following parameters:
 - No severance tax below \$60 Gross Value at Point of Production (GVPP)
 - Progressivity of .27% commencing at a threshold of \$60 GVPP
 - At \$120 GVPP, a tax rate of 16.2% is reached. At this point, progressivity is reduced to 0.03%
 - Progressivity is capped at 20%

FY 2013 Revenue Comparison



FY 2013 Revenue Comparison



FY 2013 Revenue Comparison

	Production Tax			Total State Take			Total Government Take			Cash to Companies			FY 2013 % Government Take		
	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110
	40	(233)	92	(458)	1,413	1,711	1,207	1,616	1,810	1,482	378	184	512	81%	91%
50	82	265	(143)	2,148	2,315	1,941	2,803	2,912	2,669	1,218	1,109	1,352	70%	72%	66%
60	513	513	288	2,989	2,989	2,783	4,060	4,060	3,926	1,988	1,988	2,122	67%	67%	65%
70	996	985	729	3,878	3,868	3,634	5,347	5,340	5,188	2,727	2,734	2,886	66%	66%	64%
80	1,736	1,756	1,204	5,002	5,021	4,515	6,787	6,799	6,470	3,314	3,302	3,631	67%	67%	64%
90	2,613	2,620	1,763	6,252	6,259	5,473	8,308	8,313	7,802	3,819	3,815	4,325	69%	69%	64%
100	3,628	3,577	2,387	7,629	7,582	6,491	9,913	9,882	9,173	4,241	4,272	4,981	70%	70%	65%
110	4,782	4,627	3,075	9,132	8,990	7,568	11,599	11,507	10,583	4,582	4,674	5,598	72%	71%	65%
120	6,073	5,770	3,828	10,761	10,484	8,705	13,367	13,187	12,031	4,840	5,020	6,176	73%	72%	66%
130	7,503	6,934	4,648	12,517	11,996	9,902	15,218	14,879	13,518	5,016	5,354	6,716	75%	74%	67%
140	8,550	7,714	5,510	13,922	13,157	11,138	16,841	16,343	15,031	5,420	5,917	7,230	76%	73%	68%
150	9,623	8,504	6,372	15,352	14,327	12,374	18,479	17,813	16,544	5,808	6,474	7,743	76%	73%	68%
160	10,730	9,304	7,235	16,813	15,506	13,611	20,138	19,289	18,057	6,175	7,025	8,257	77%	73%	69%
170	11,873	10,114	8,097	18,306	16,695	14,847	21,818	20,771	19,570	6,522	7,569	8,770	77%	73%	69%
180	13,049	10,935	8,960	19,830	17,894	16,084	23,518	22,259	21,083	6,849	8,107	9,284	77%	73%	69%
190	14,261	11,766	9,822	21,386	19,101	17,320	25,239	23,754	22,596	7,155	8,640	9,797	78%	73%	70%
200	15,506	12,608	10,685	22,974	20,319	18,557	26,980	25,254	24,109	7,440	9,166	10,311	78%	73%	70%

Note: Consistent with DOR methodology, these revenue numbers do not include payments for tax credits which are not claimed against current production, as these are accounted for separately in the budget. In 2013, DOR forecasts a potential liability of \$400mm for these credits.

FY 2013 Revenue Comparison – Adjusted for \$400mm Credits Not Claimed Against Current Production

	Production Tax			Total State Take		
	ACES	CSSB 192	HB110	ACES	CSSB 192	HB110
40	(633)	(308)	(858)	1,013	1,311	807
50	(318)	(135)	(543)	1,748	1,915	1,541
60	113	113	(112)	2,589	2,589	2,383
70	596	585	329	3,478	3,468	3,234
80	1,336	1,356	804	4,602	4,621	4,115
90	2,213	2,220	1,363	5,852	5,859	5,073
100	3,228	3,177	1,987	7,229	7,182	6,091
110	4,382	4,227	2,675	8,732	8,590	7,168
120	5,673	5,370	3,428	10,361	10,084	8,305
130	7,103	6,534	4,248	12,117	11,596	9,502
140	8,150	7,314	5,110	13,522	12,757	10,738
150	9,223	8,104	5,972	14,952	13,927	11,974
160	10,330	8,904	6,835	16,413	15,106	13,211
170	11,473	9,714	7,697	17,906	16,295	14,447
180	12,649	10,535	8,560	19,430	17,494	15,684
190	13,861	11,366	9,422	20,986	18,701	16,920
200	15,106	12,208	10,285	22,574	19,919	18,157

ANS West Coast Oil Price

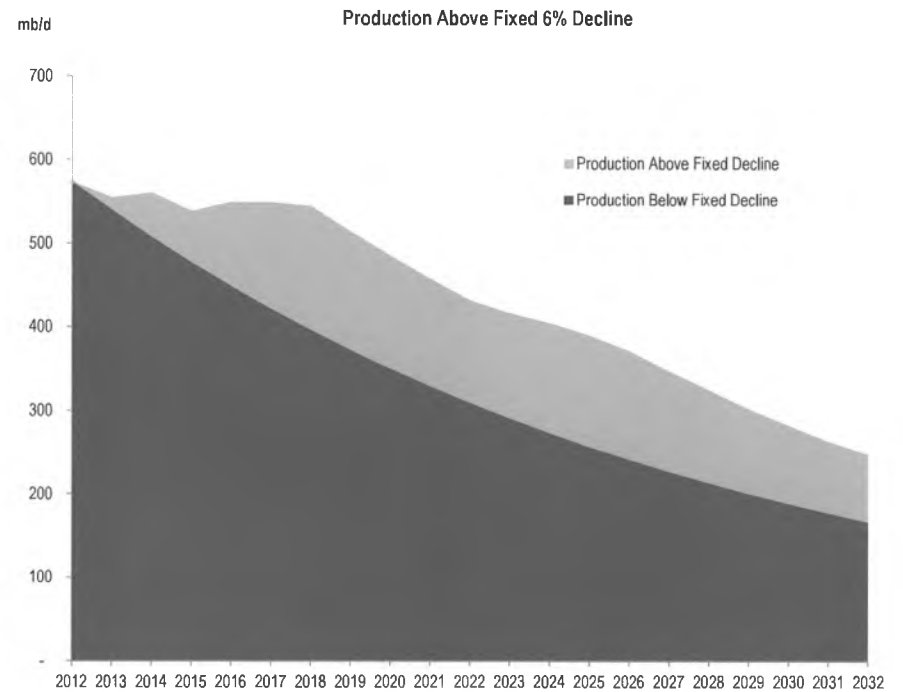
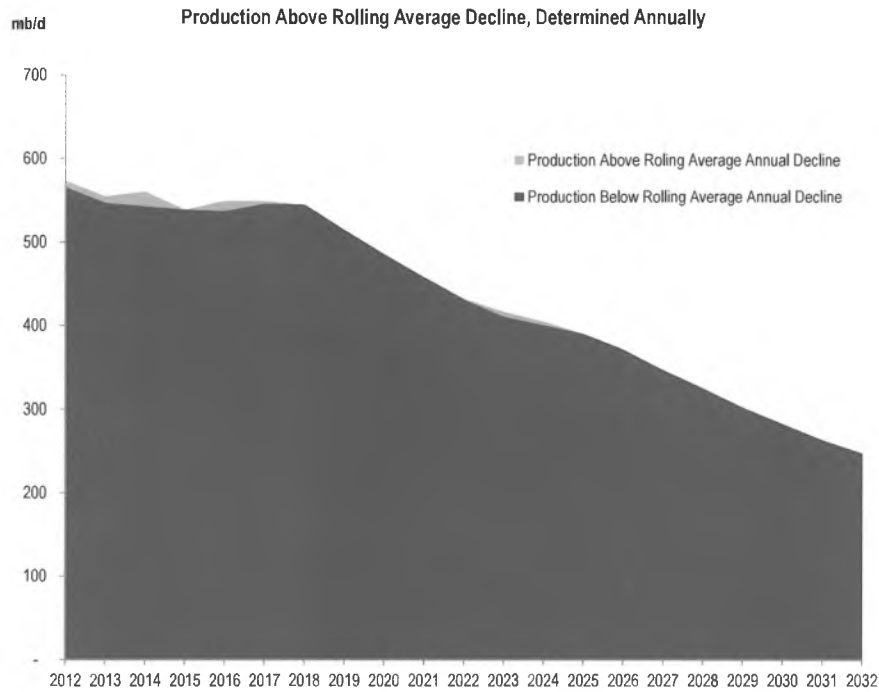
Issues with Tax Floor for Large Fields

- Two significant issues with specifying the tax floor for large fields only
 - Specifying particular units to which a floor applies means that costs then need to be allocated at the unit level – costs for Prudhoe and for Kuparuk need to be calculated separately to that for all other production
 - The 100 mb/d production threshold may create an undesirable incentive
- An administratively easier approach would be to make the distinction at the company, rather than the asset level
 - If the desire is simply to ensure that small producers do not face this floor, this can be more easily accomplished directly
 - One option would be to use the existing definition of a “small producer” for credit purposes, and exclude such producers from the floor

Incentives for New Production

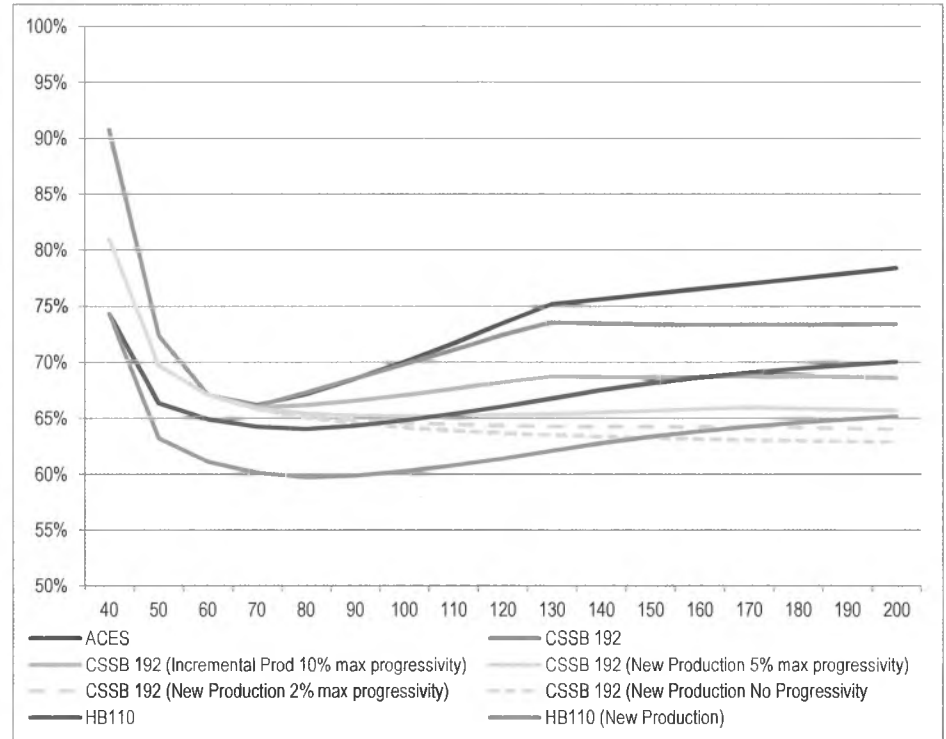
- Significant incentives can be provided to new production, by eliminating or reducing the Progressive Severance Tax (Gross) on any combination of:
 - Production from new areas
 - Production above a fixed decline rate
- One possibility for a reduced rate of Progressive Severance Tax is:
 - No severance tax below \$60 Gross Value at Point of Production (GVPP)
 - Progressivity of .05% commencing at a threshold of \$60 GVPP
 - Progressivity capped at 5%
 - Reduced rate applied for 7 years
- Since Production above a decline curve cannot have a specific time limit, one option would be an intermediate regime with no time limit for incremental production, for instance:
 - Progressivity of .14% commencing at a threshold of \$60 GVPP
 - At \$120 GVPP, a tax rate of 8.4% is reached. At this point, progressivity is reduced to 0.03%
 - Progressivity is capped at 10%

Production Above a Decline – Fixed v Annual Calculation



Total Government Take Comparison Including New Production Incentives

		FY 2013 % Government Take							
		ACES	CSSB 192	CSSB 192 (Incremental Prod 10% max progressivity)	CSSB 192 (New Production 5% max progressivity)	CSSB 192 (New Production 2% max progressivity)	CSSB 192 (New Production No Progressivity)	HB110	HB110 (New Production)
ANS West Coast Oil Price	40	81%	91%	81%	81%	81%	81%	74%	74%
	50	70%	72%	70%	70%	70%	70%	66%	63%
	60	67%	67%	67%	67%	67%	67%	65%	61%
	70	66%	66%	66%	66%	66%	66%	64%	60%
	80	67%	67%	66%	65%	65%	65%	64%	60%
	90	69%	69%	67%	65%	65%	65%	64%	60%
	100	70%	70%	67%	65%	65%	64%	65%	60%
	110	72%	71%	68%	65%	64%	64%	65%	61%
	120	73%	72%	68%	65%	64%	64%	66%	61%
	130	75%	74%	69%	65%	64%	64%	67%	62%
	140	76%	73%	69%	66%	64%	63%	68%	63%
	150	76%	73%	69%	66%	64%	63%	68%	63%
	160	77%	73%	69%	66%	64%	63%	69%	64%
	170	77%	73%	69%	66%	64%	63%	69%	64%
	180	77%	73%	69%	66%	64%	63%	69%	65%
	190	78%	73%	69%	66%	64%	63%	70%	65%
	200	78%	73%	69%	66%	64%	63%	70%	65%



24.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

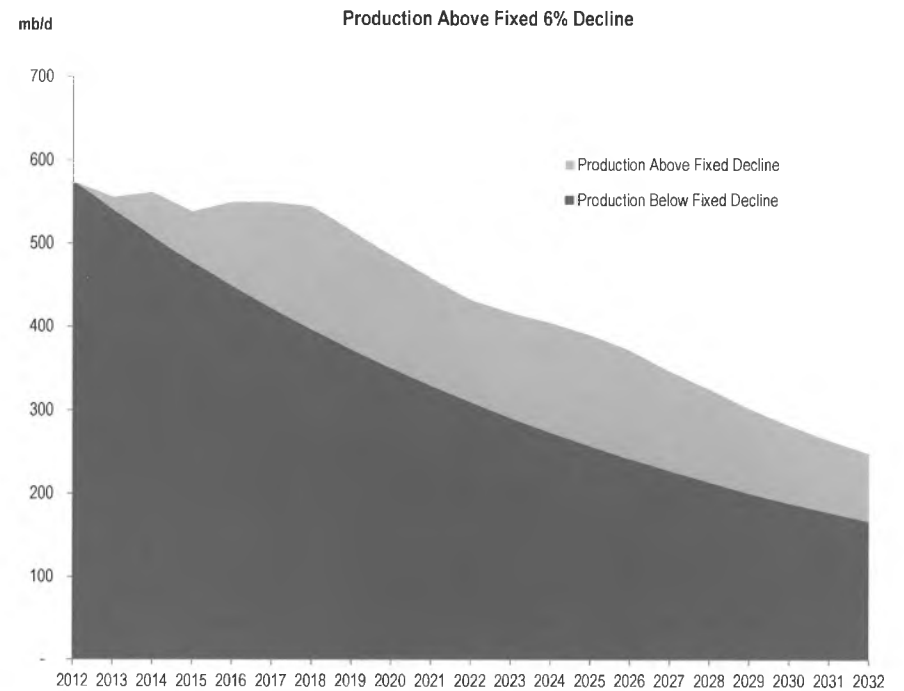
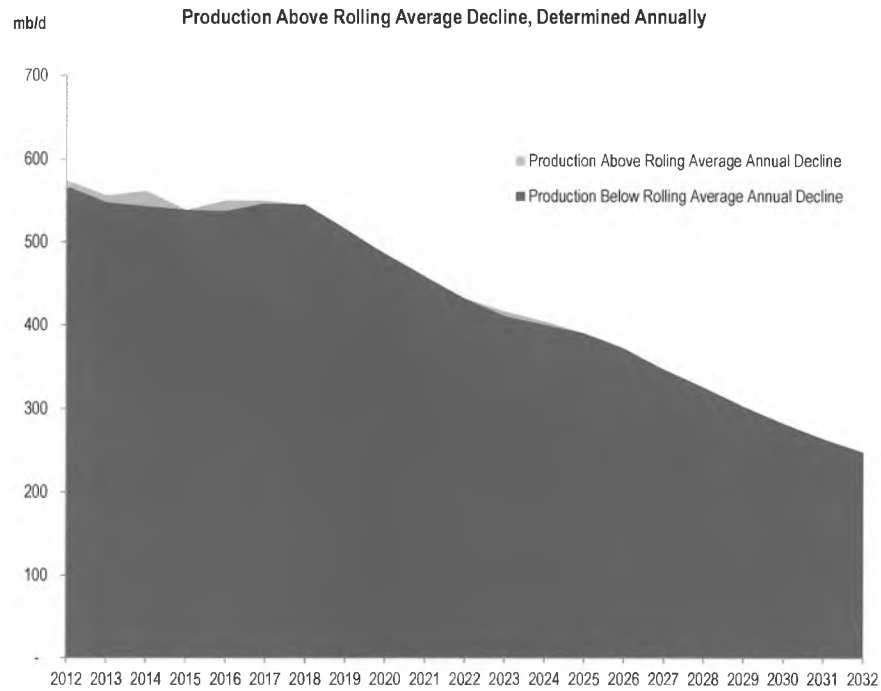
April 5, 2012



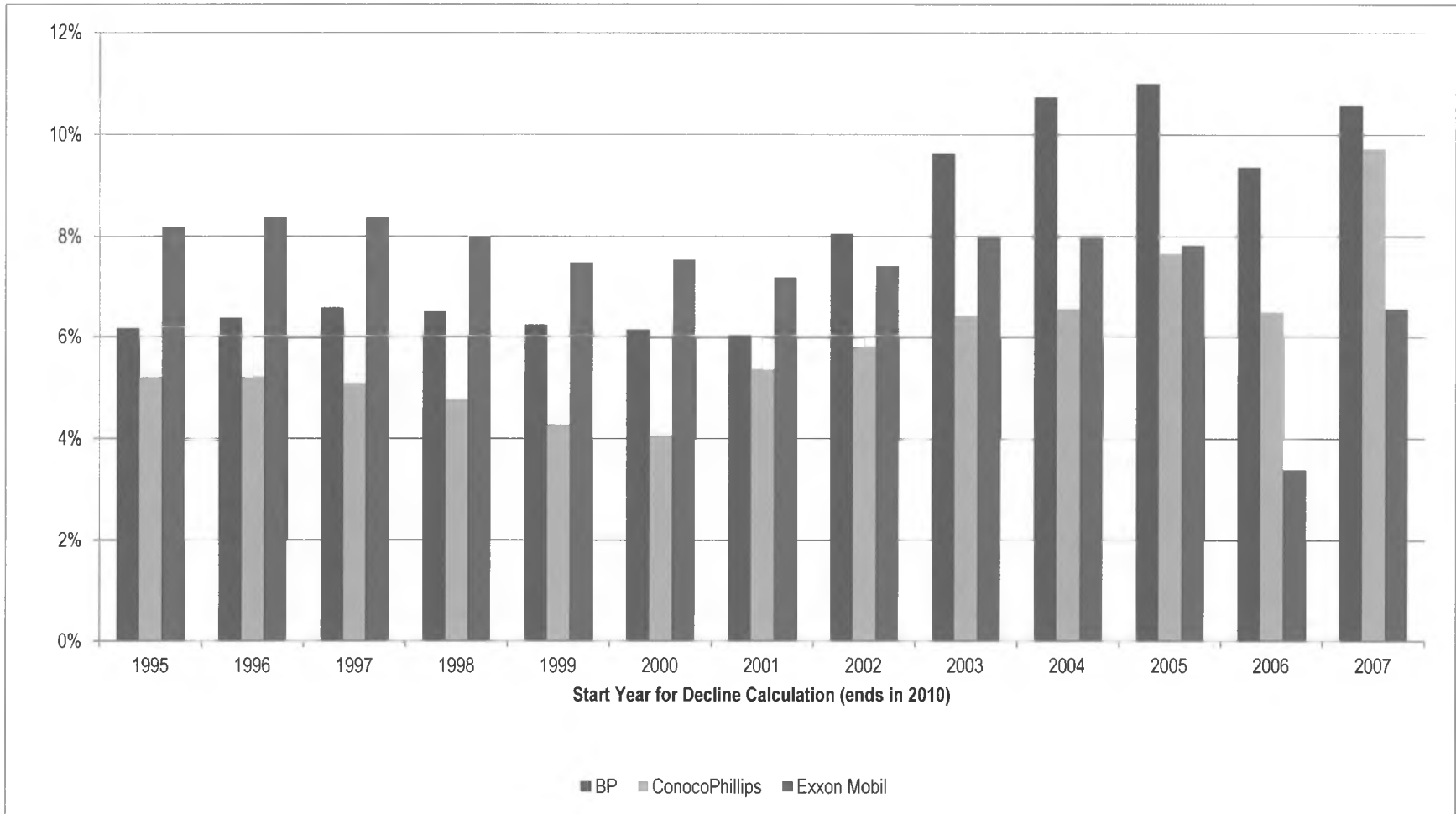
Discussion Slides: Alaska Senate Finance Committee

April 5, 2012
Janak Mayer
Manager, Upstream & Gas
PFC Energy

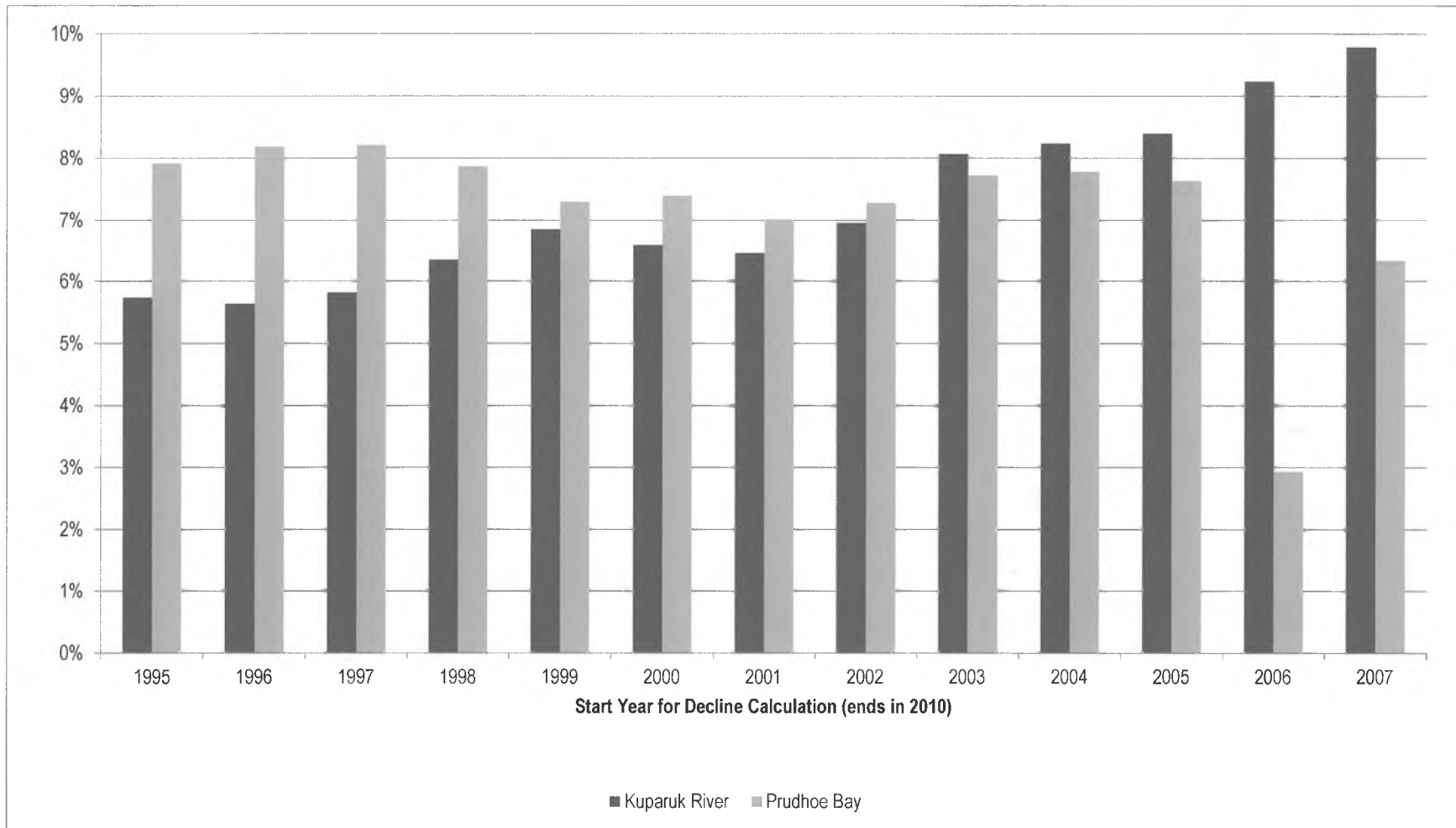
Production Above a Decline – Fixed v Annual Calculation



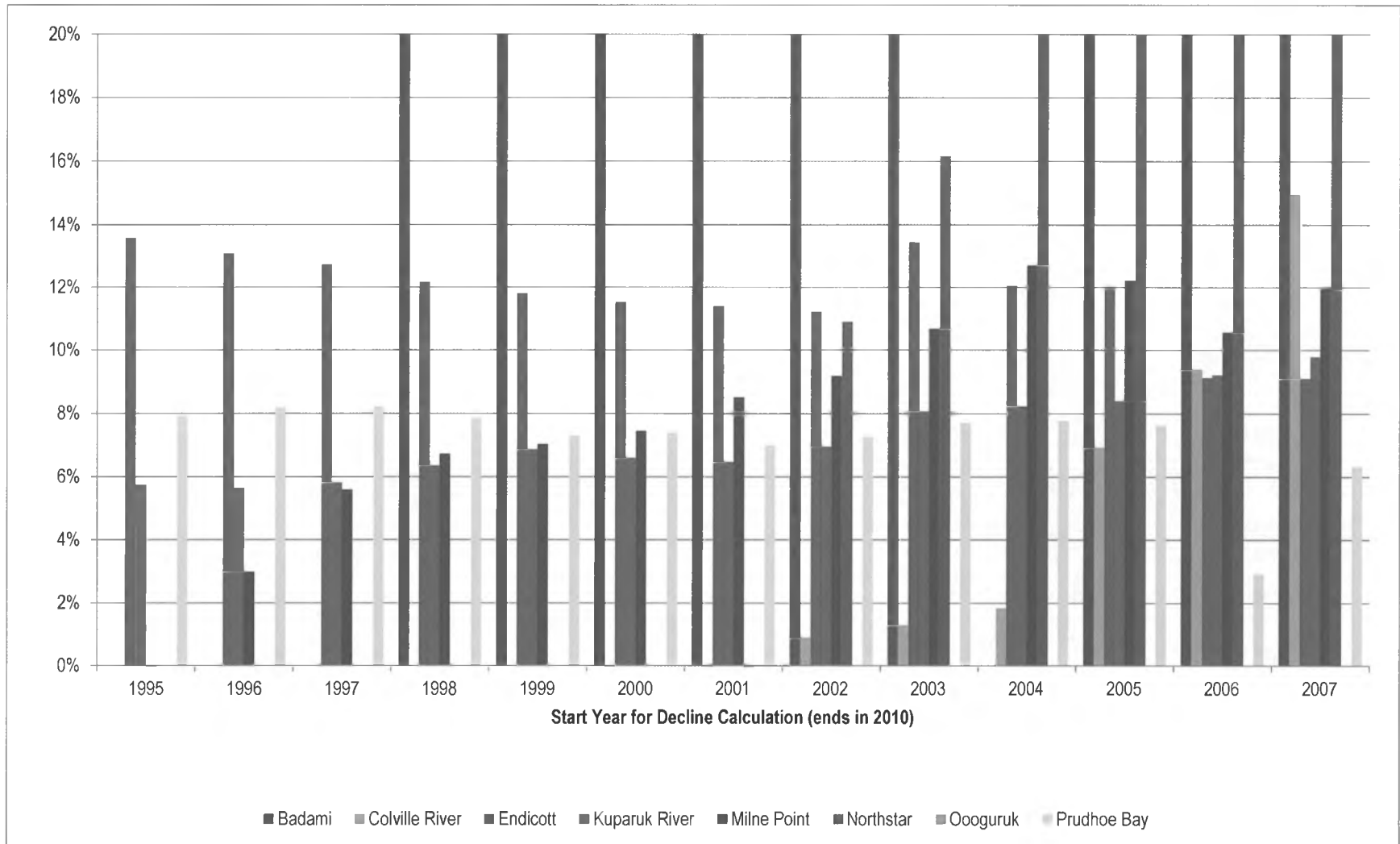
Approximate Decline Rates to 2010 by Start Year



Approximate Decline Rates to 2010 by Start Year

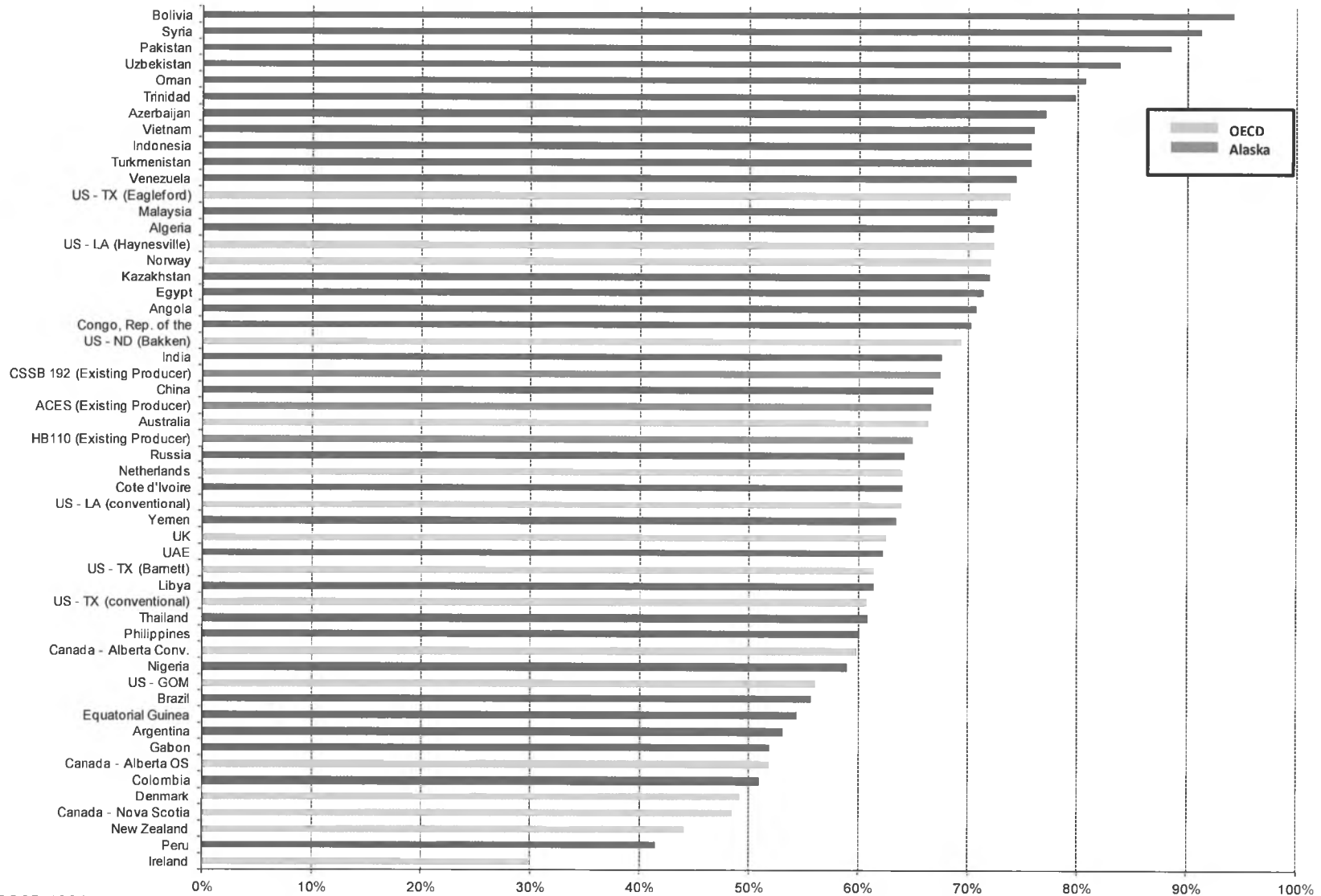


Approximate Decline Rates to 2010 by Start Year



Regime Competitiveness: Relative Government Take

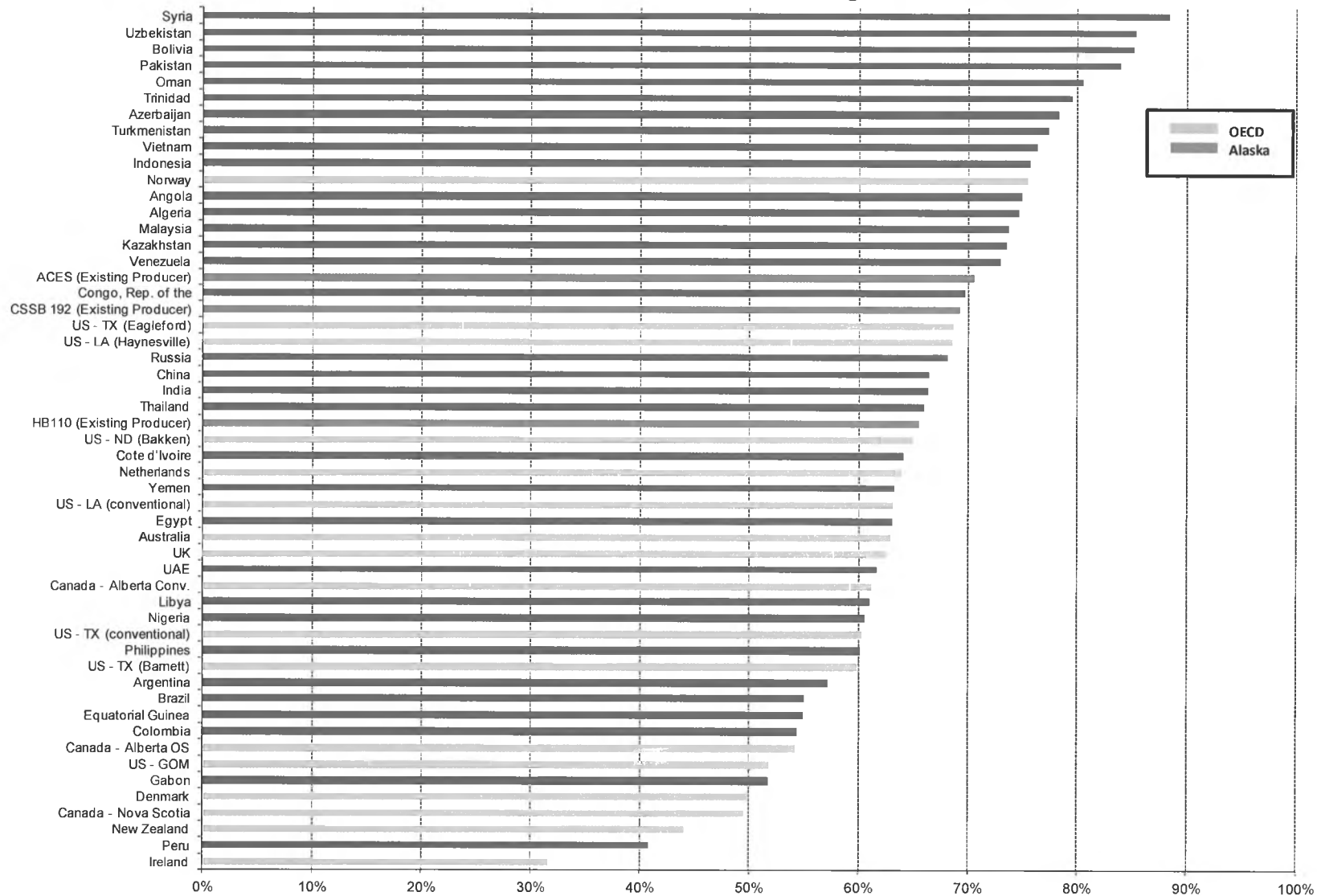
Average Government Take of Global Fiscal Regimes at \$60/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

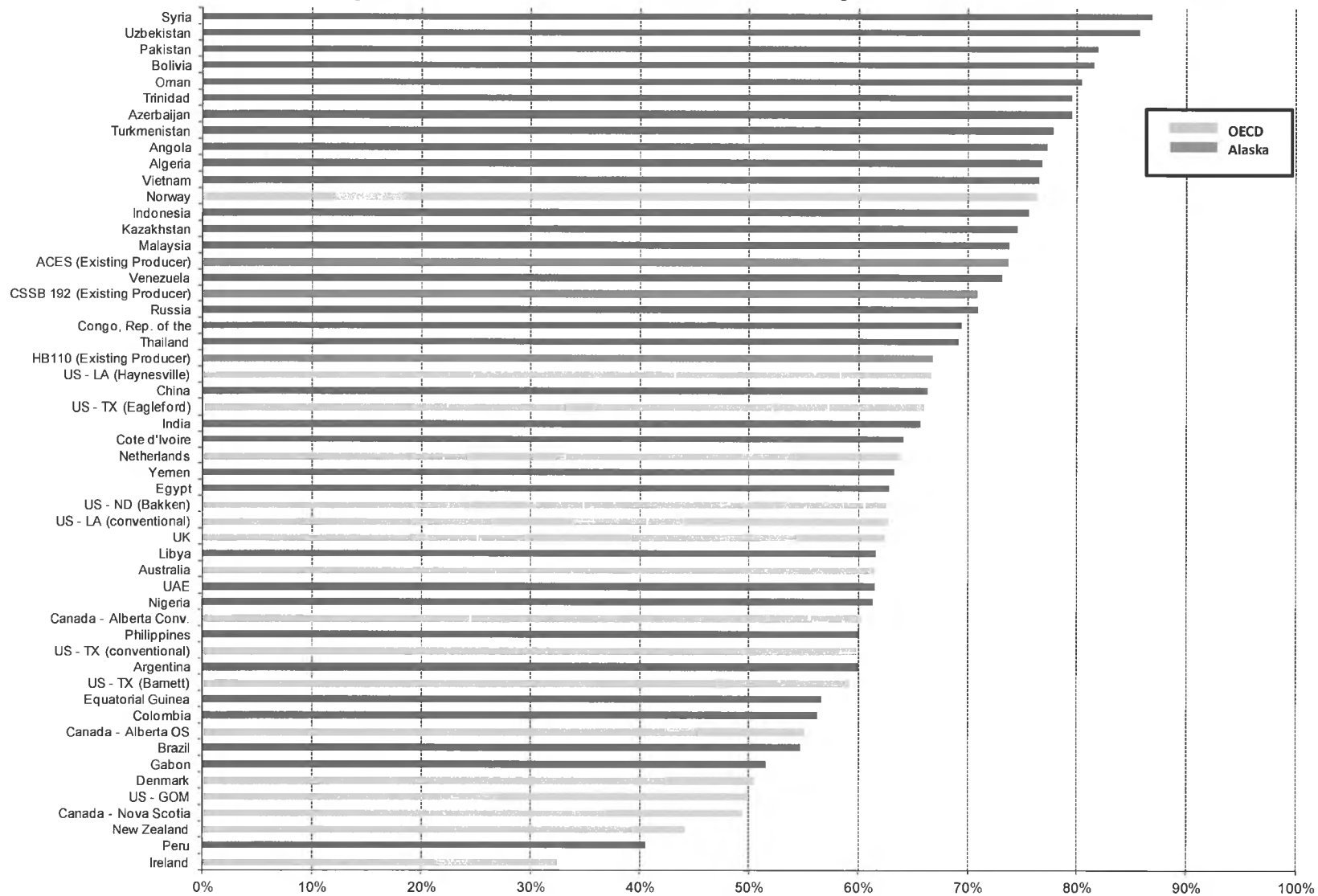
Average Government Take of Global Fiscal Regimes at \$80/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

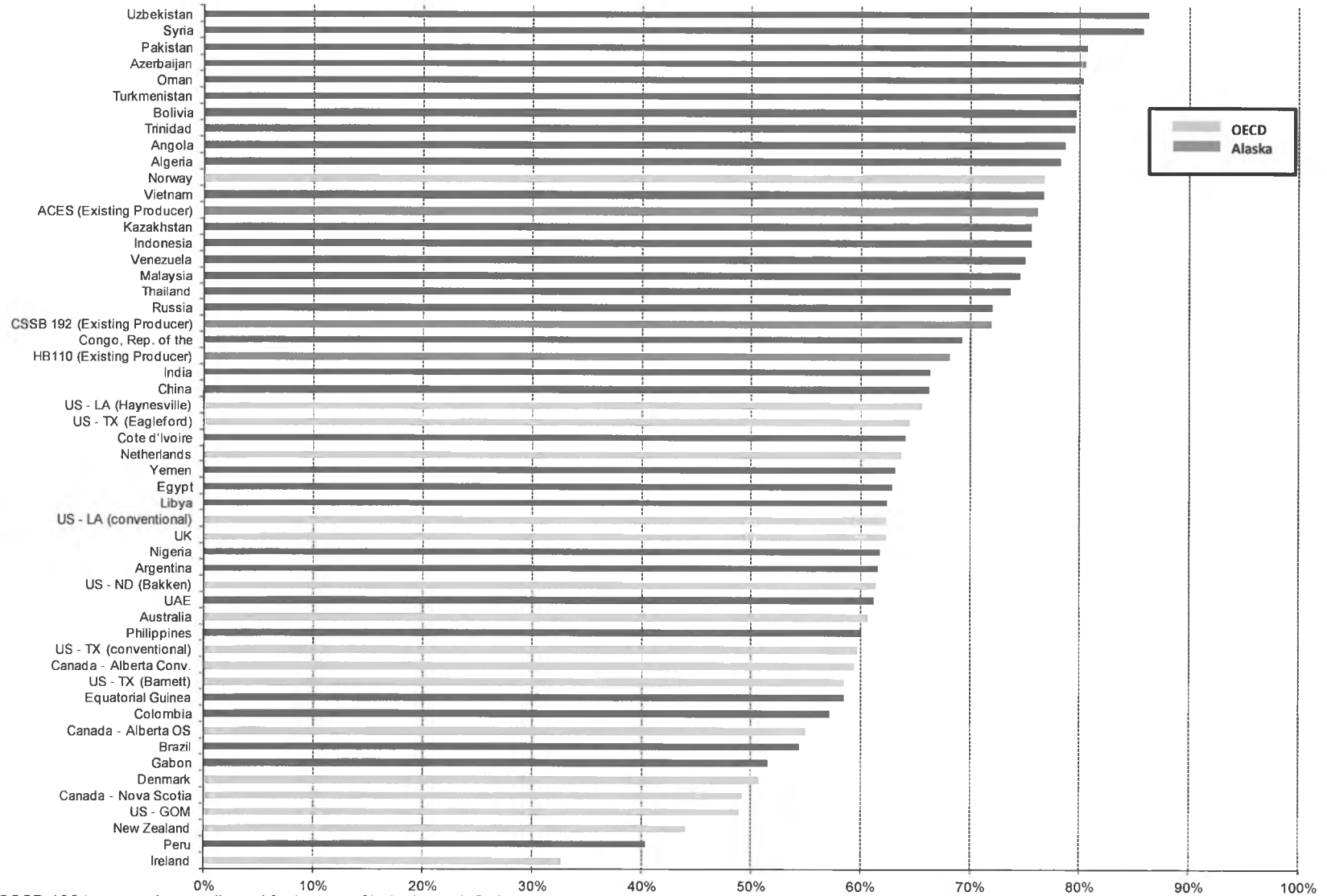
Average Government Take of Global Fiscal Regimes at \$100/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

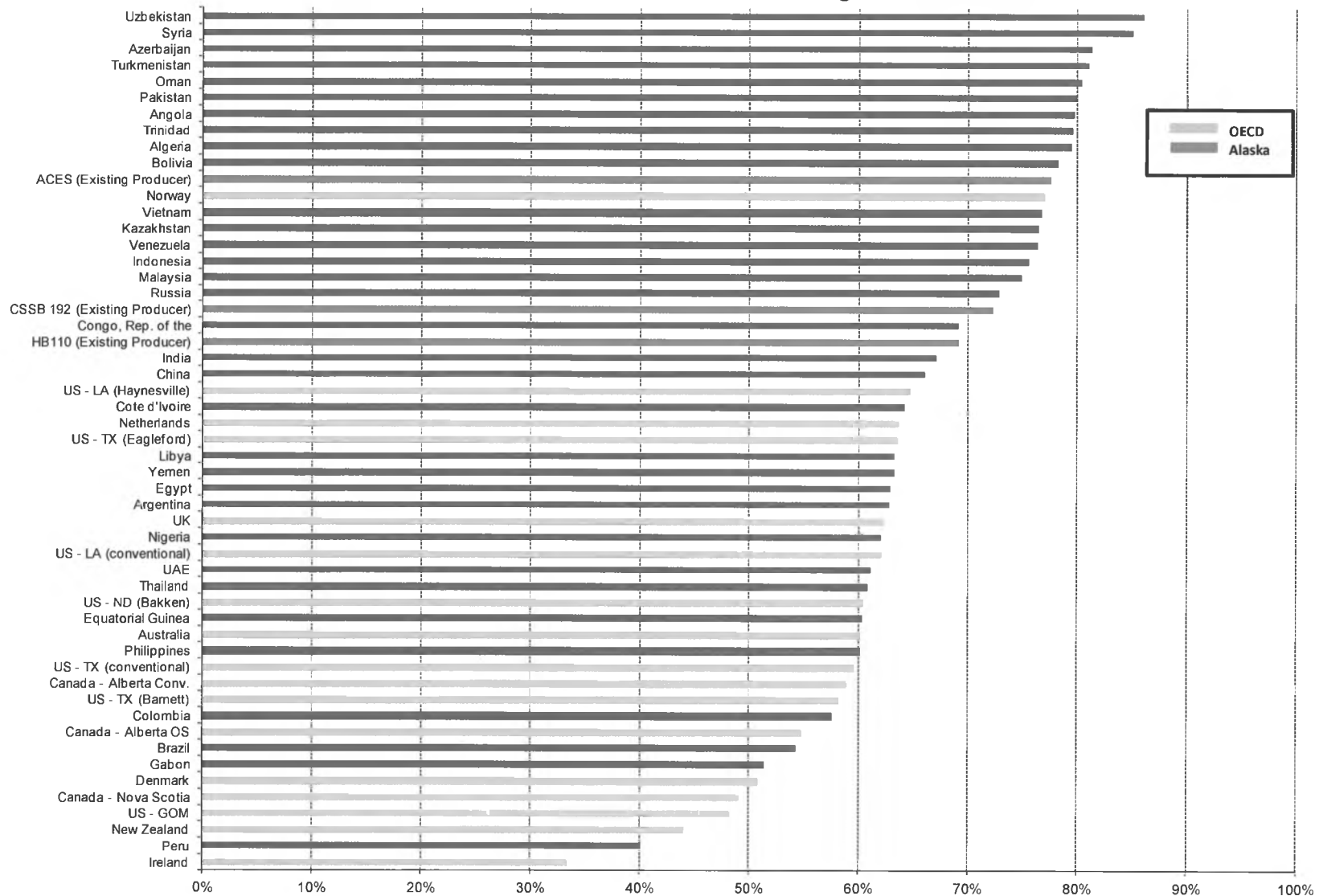
Average Government Take of Global Fiscal Regimes at \$120/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

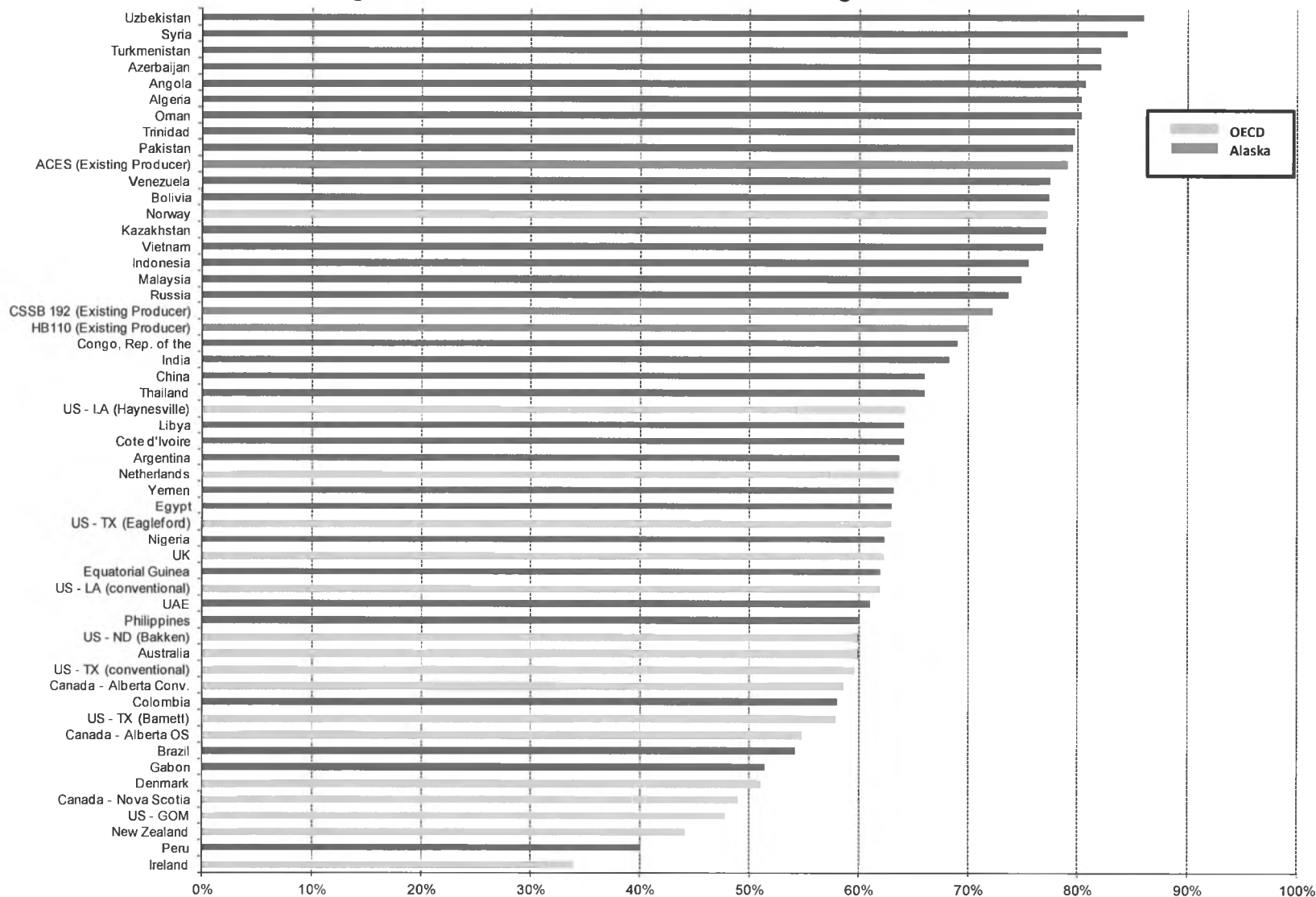
Average Government Take of Global Fiscal Regimes at \$140/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

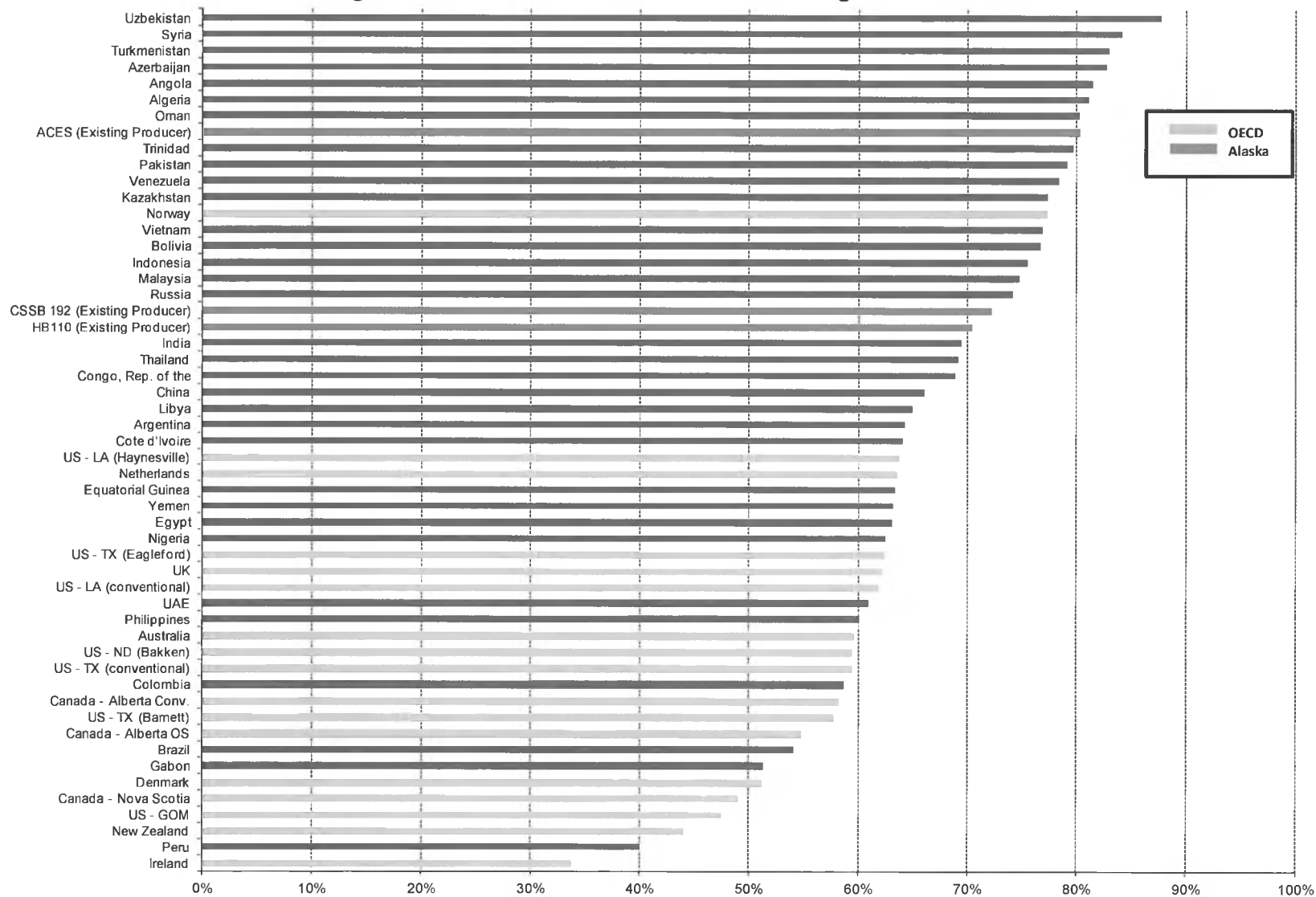
Average Government Take of Global Fiscal Regimes at \$160/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

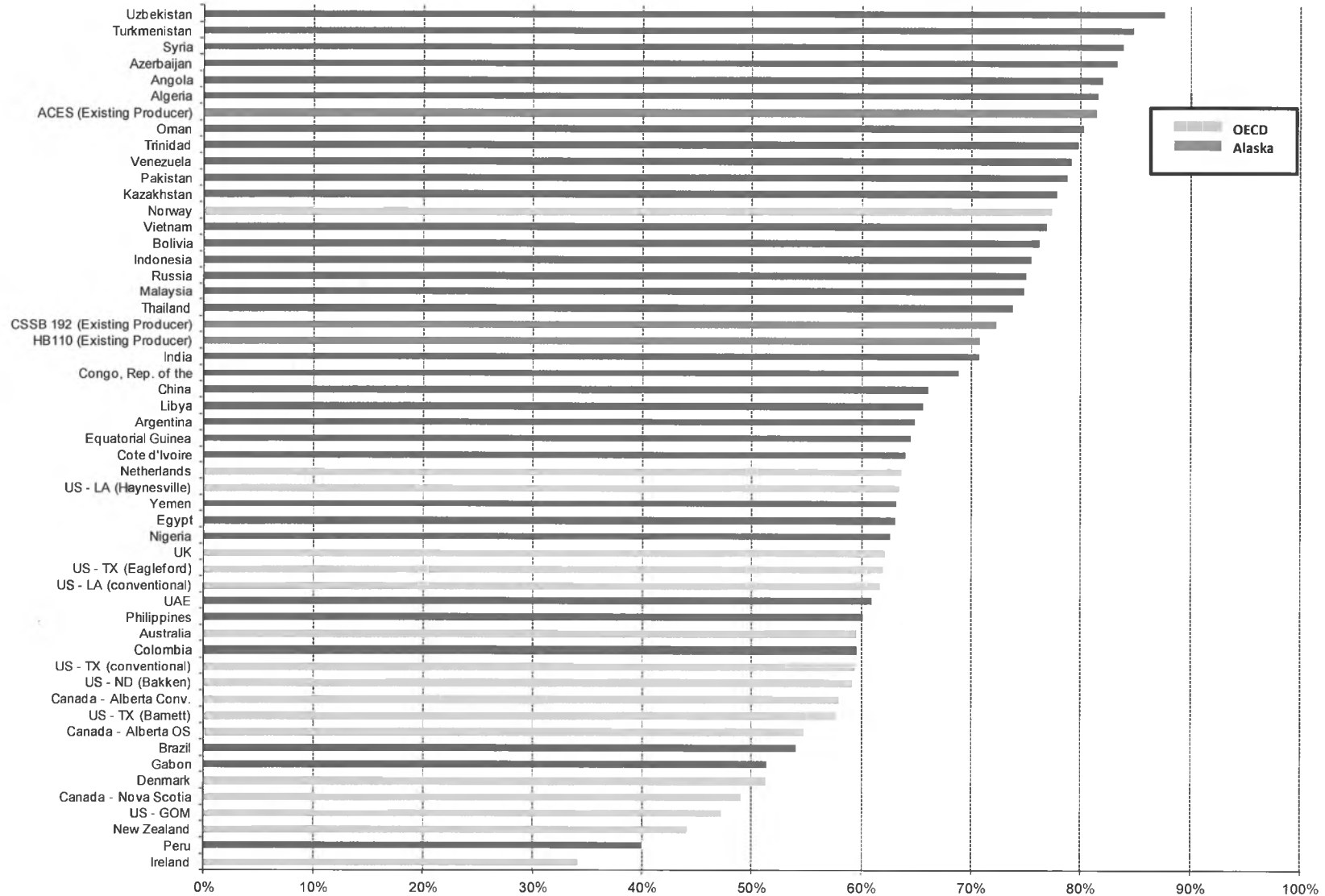
Average Government Take of Global Fiscal Regimes at \$180/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

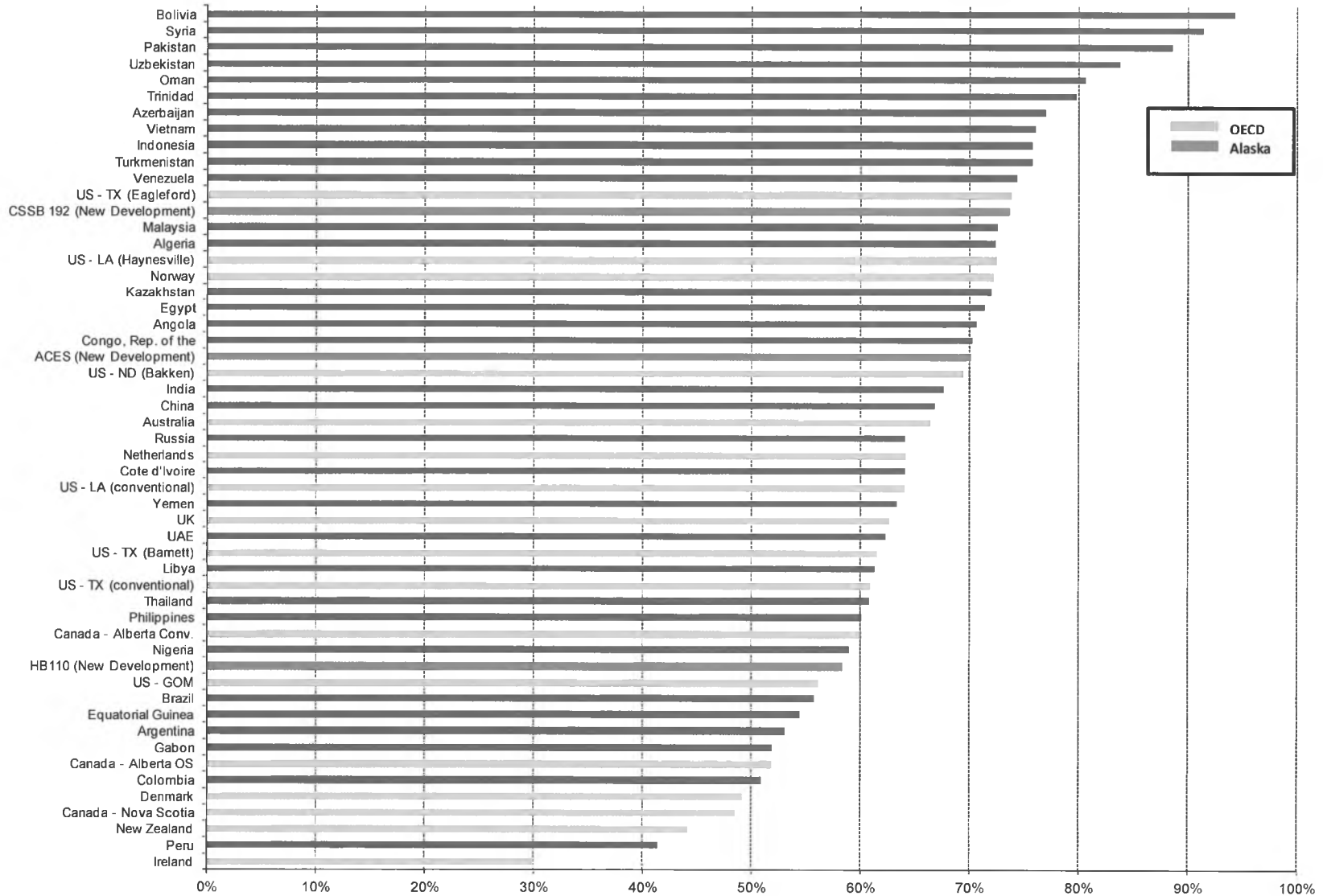
Average Government Take of Global Fiscal Regimes at \$200/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

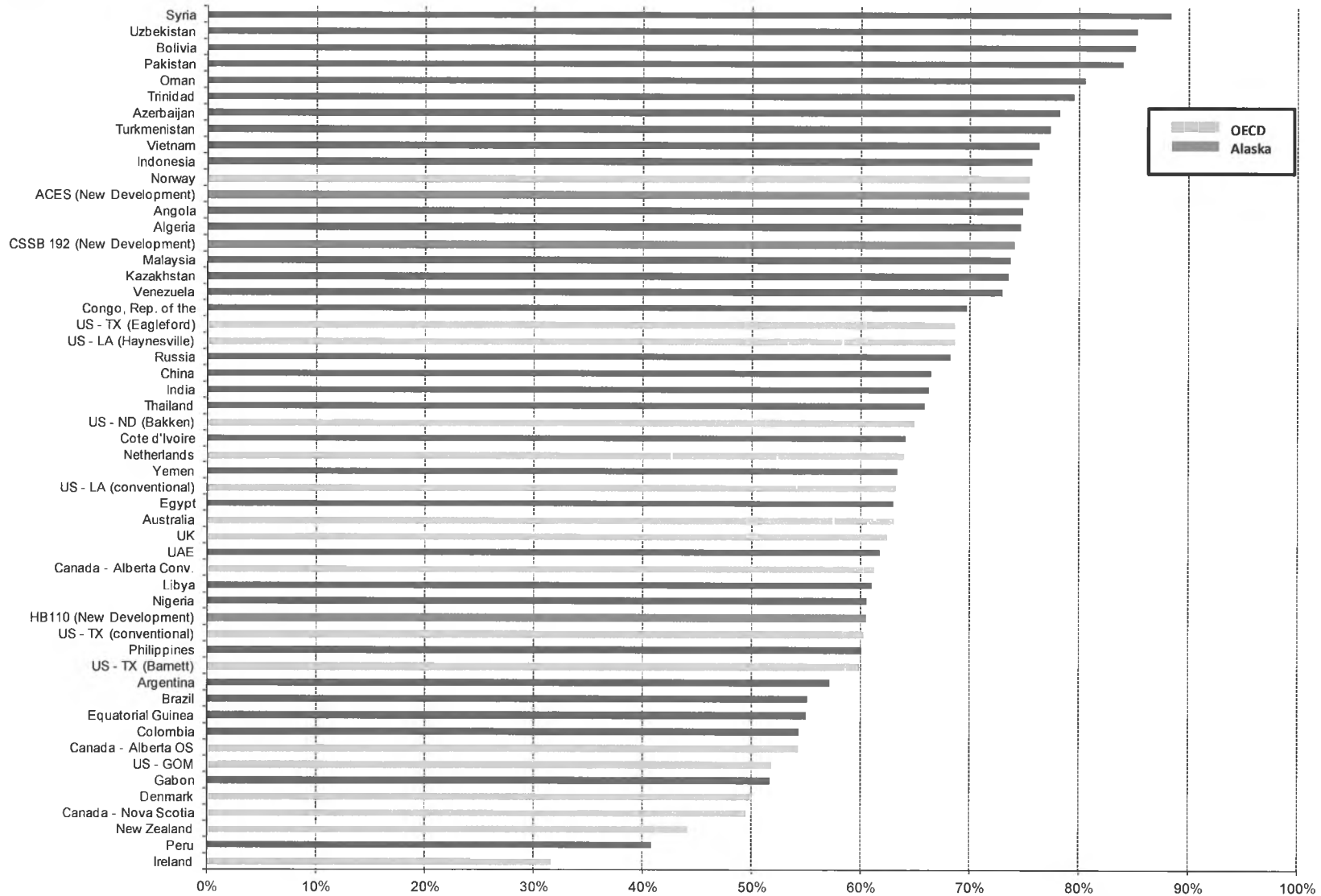
Average Government Take of Global Fiscal Regimes at \$60/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

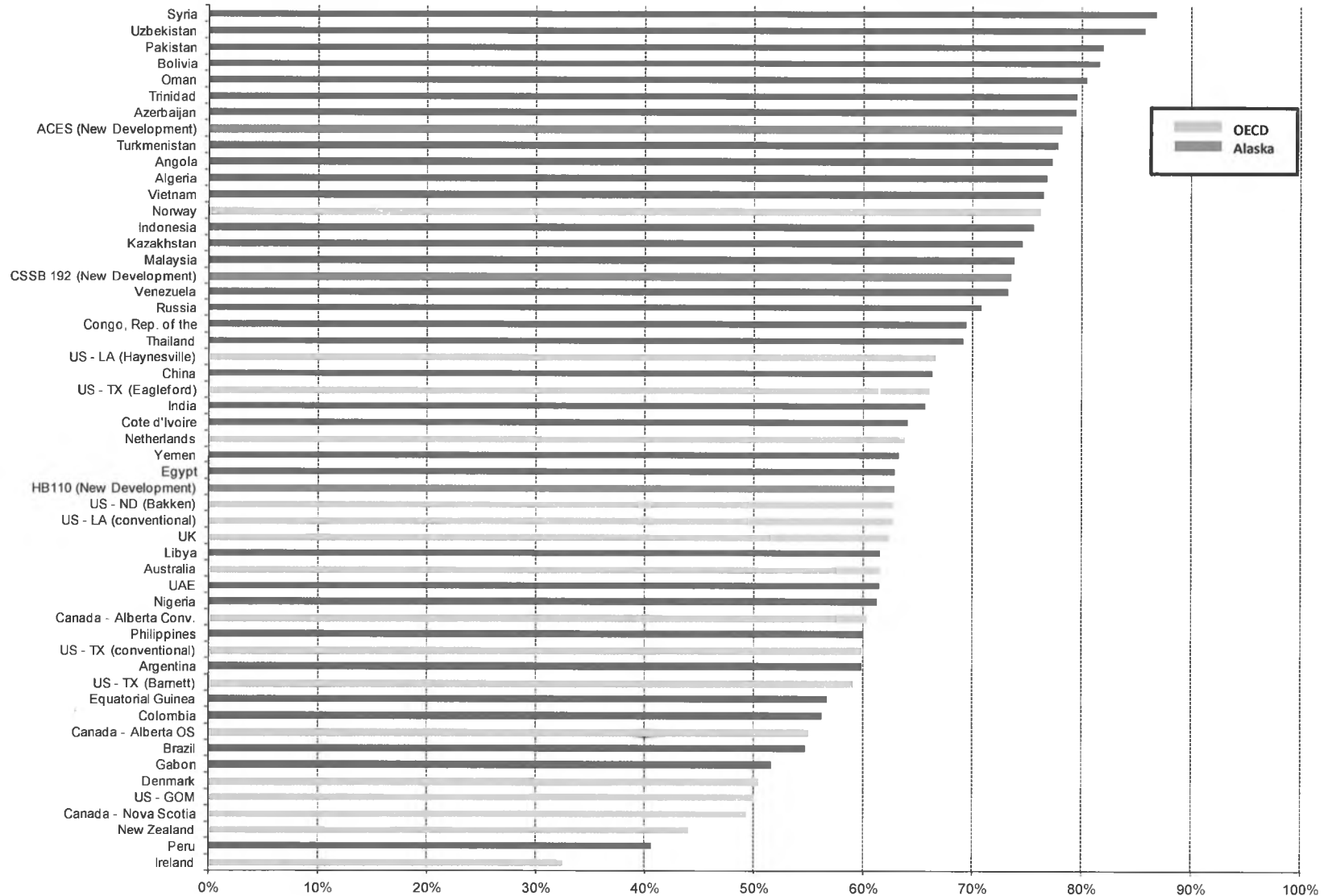
Average Government Take of Global Fiscal Regimes at \$80/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

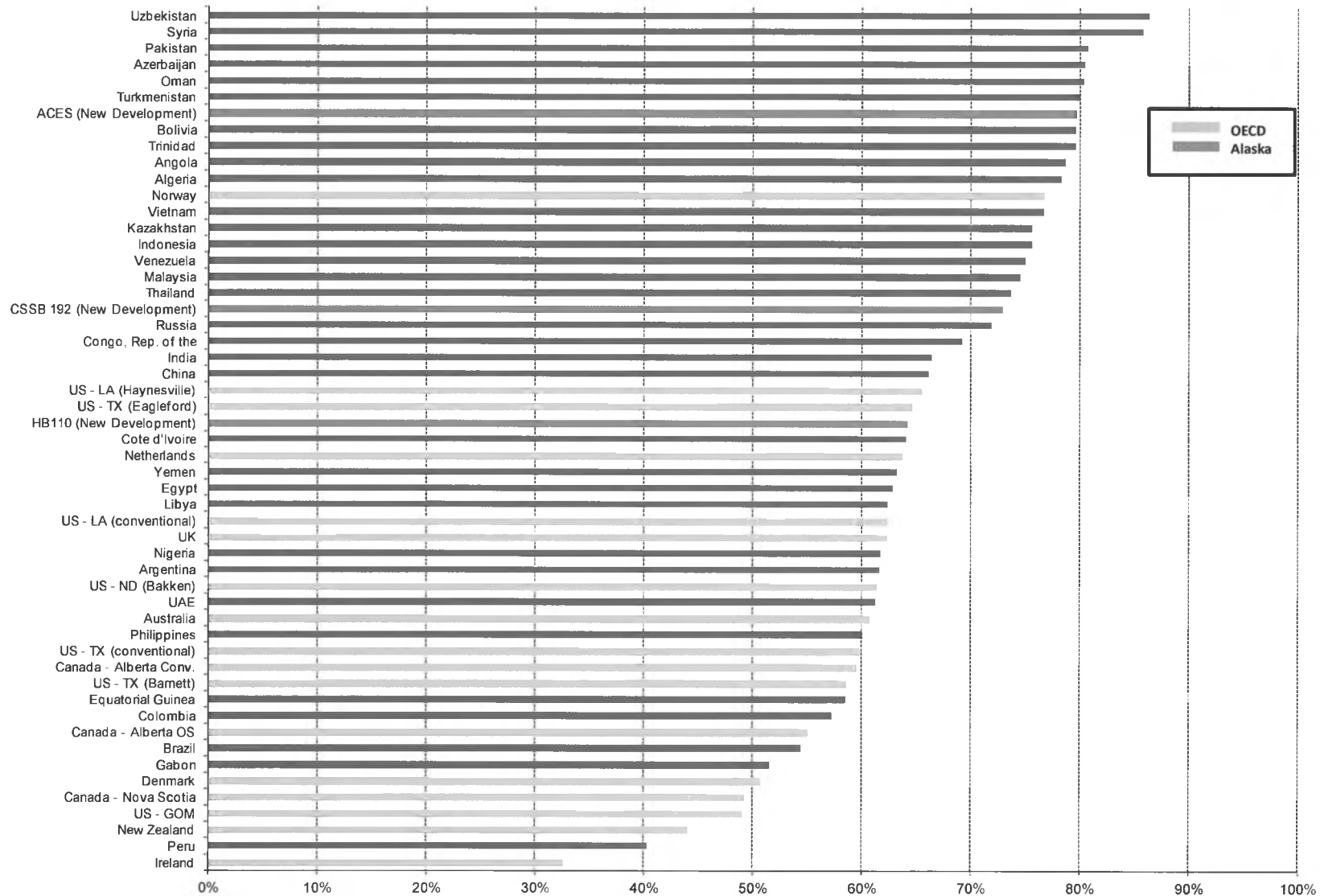
Average Government Take of Global Fiscal Regimes at \$100/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

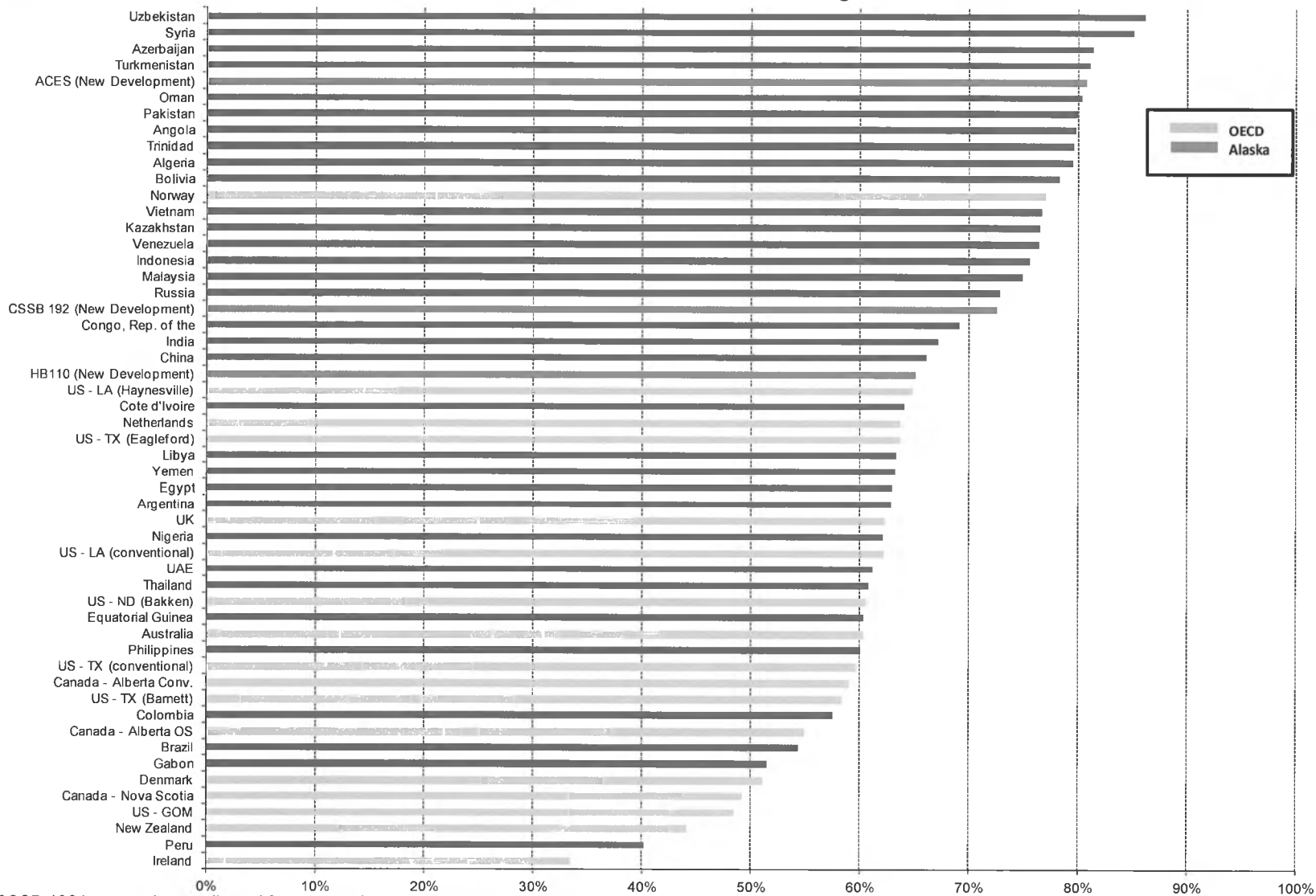
Average Government Take of Global Fiscal Regimes at \$120/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

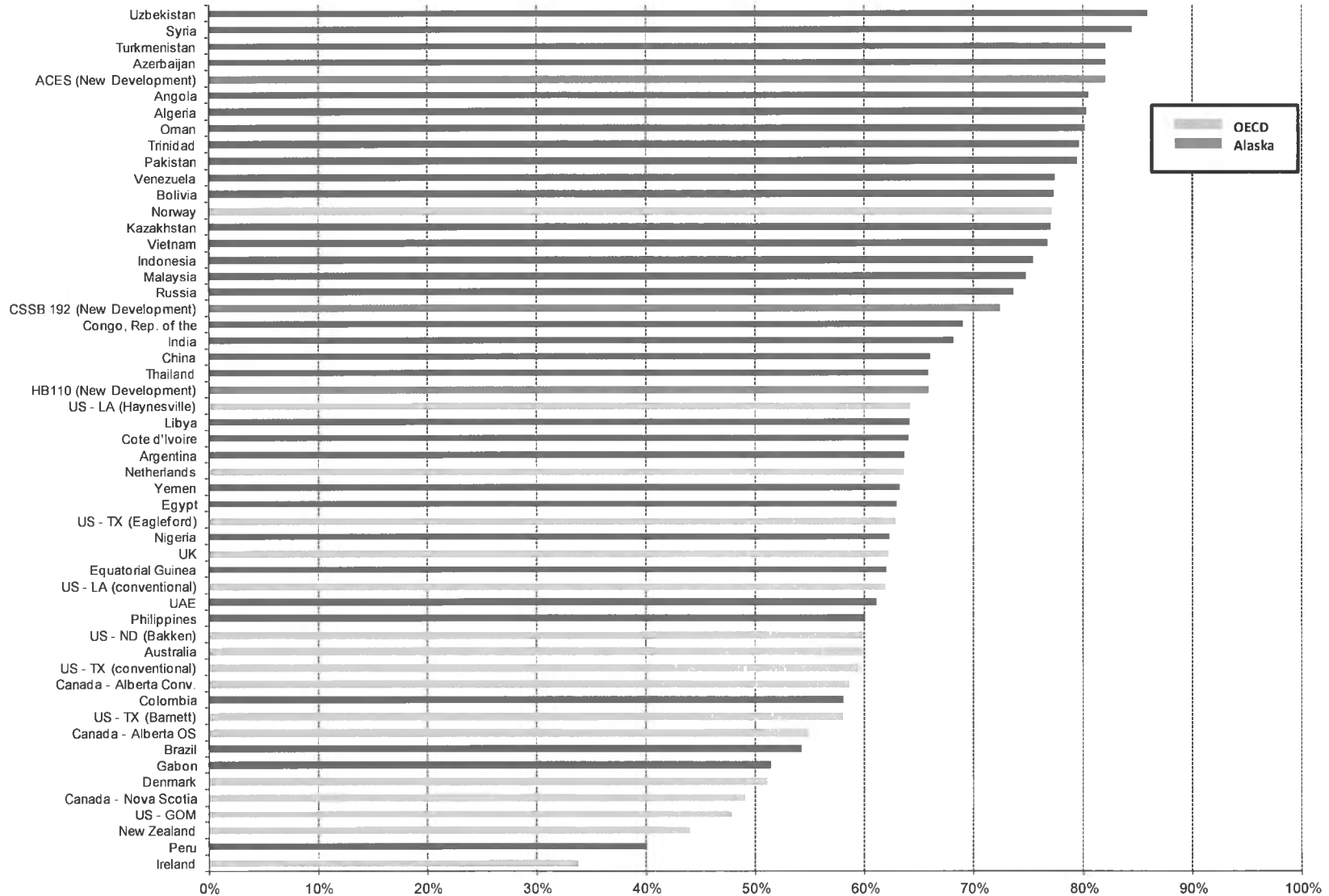
Average Government Take of Global Fiscal Regimes at \$140/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

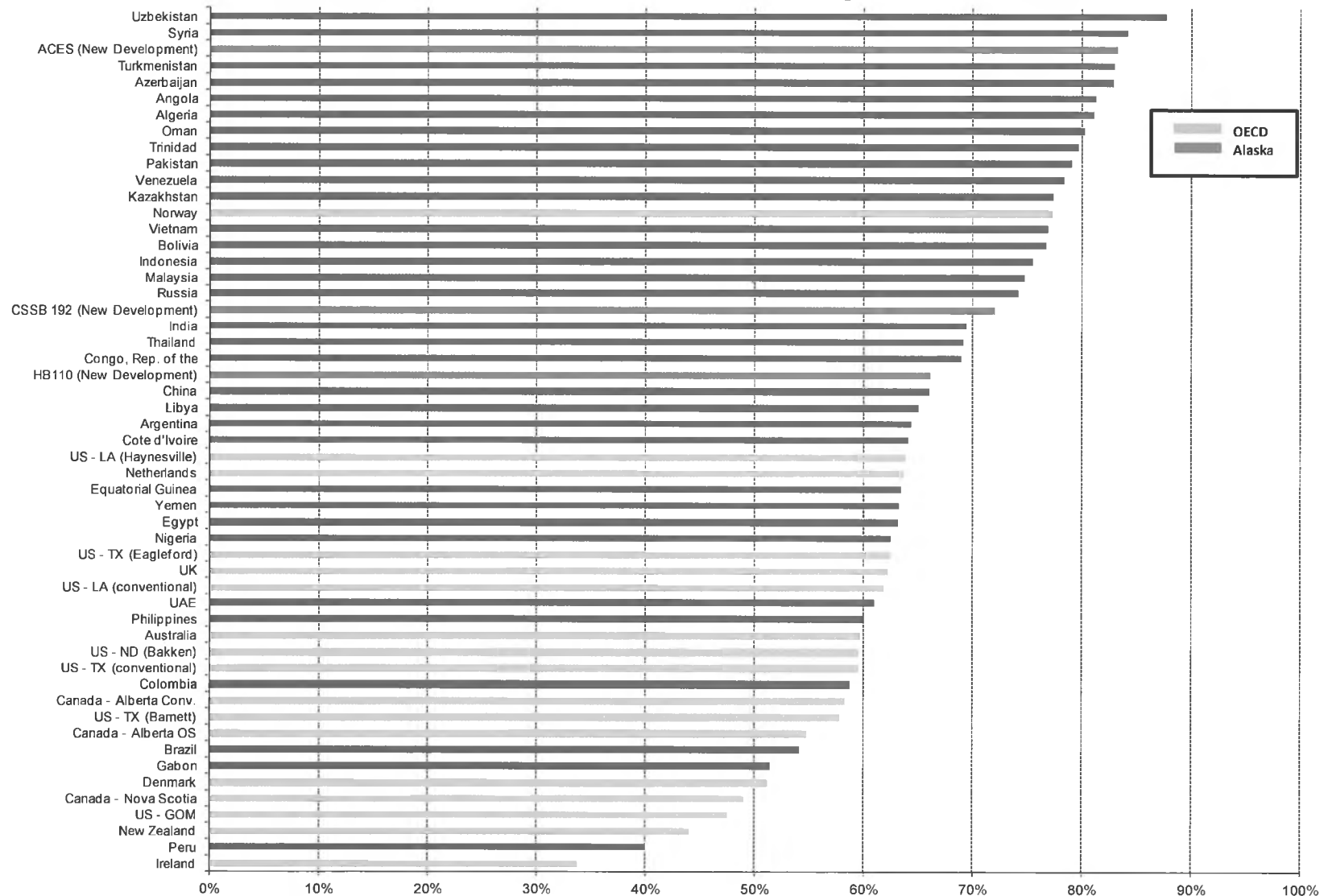
Average Government Take of Global Fiscal Regimes at \$160/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

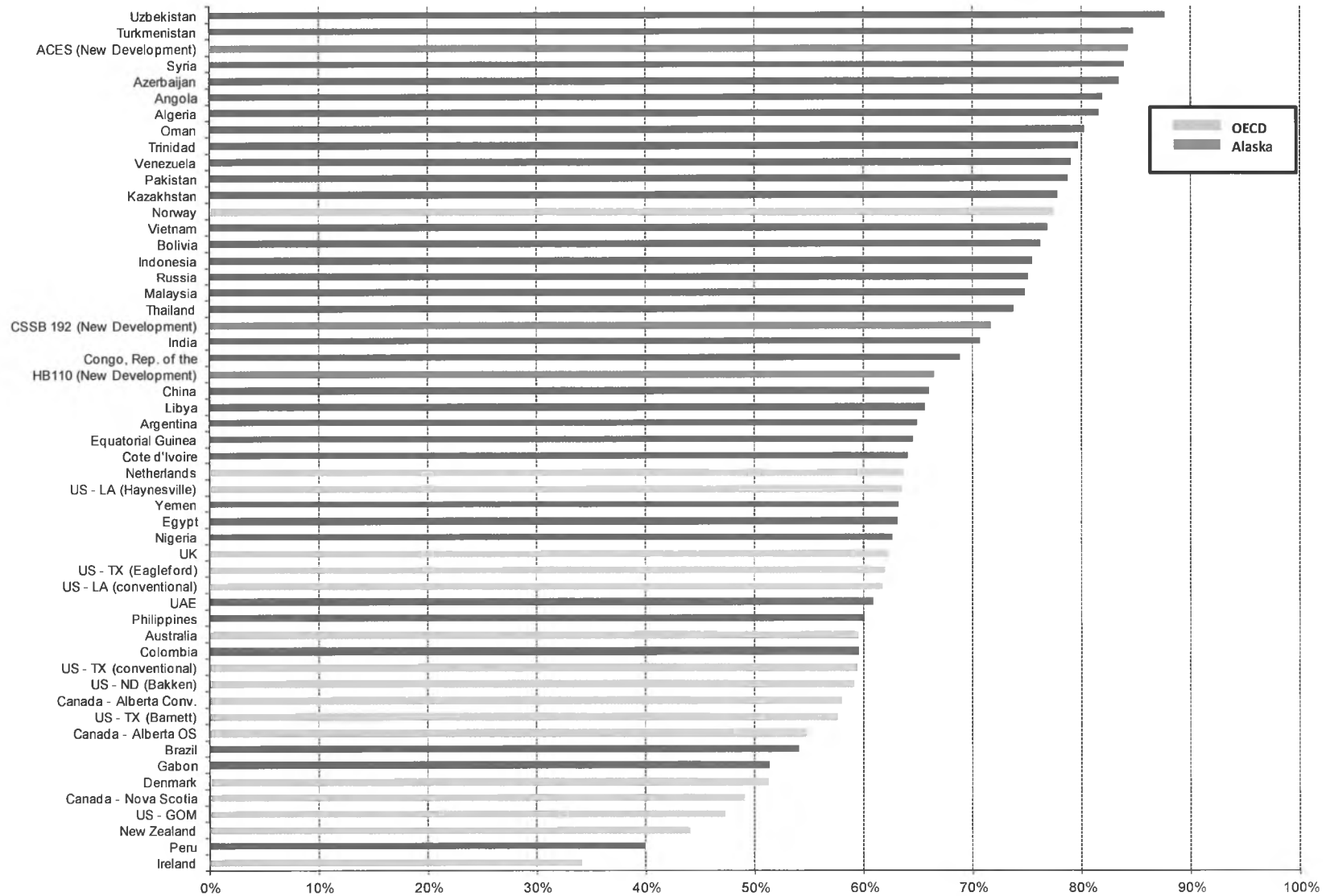
Average Government Take of Global Fiscal Regimes at \$180/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$200/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

25.

Department of
Revenue Comments
on CSSB 192 (FIN)
Version 0
April 6, 2012



**Comments on
CSSB 192 (FIN)
Work Draft 27-LS1305\O**



*Presentation to the
Senate Finance Committee
Department of Revenue
April 6, 2012*



Presentation Organization



- DOR comments on components of CSSB 192(FIN) Version 0
- DOR comments on complexity of tax law changes and additional requirements for Department



Questions To Consider



- Does this bill make Alaska more competitive?
- Does this bill make Alaska more appealing to potential investors?
- Does this bill make our tax structure less complicated & more understandable to investors?
- Are these changes meaningful enough to compete for investment capital?



Impact of Change to Progressivity on Production Tax Liability



- Tax is increased for many companies below \$100 per barrel
- Tax is about the same as current law at \$100 per barrel (on average)
- Tax is a small reduction for many companies above \$100 per barrel
- Tax change will impact all companies differently



Comments on Change to Progressivity



- Tax effect of progressivity change on currently producing fields is *very sensitive* to a producer's lease expenditures
 - Appears to reduce incentive to invest in North Slope fields
 - Appears to reduce incentive to develop high cost fields
 - Appears to encourages harvest mode and keeping development costs low
 - Appears to reward those that did the least to stem the decline during ACES



Comments on Minimum Tax



- Provision creates a substantial tax increase at lower prices (<\$60/barrel).
- Creates a disincentive to investment for qualifying producers
- Could create incentive to stay below 50,000 BOE/day



Petroleum Information Management System (PIMS)



- Requires the Department to have the information management system in place by January 1, 2014
- Competes with core mission of the Tax Division, which is to assess and collect taxes
- Competes with daily staff goals of interacting with taxpayers, forecasting revenues, and auditing tax returns
- Will likely delay the completion of those core duties and result in slower responses to legislative policy questions



PIMS Continued

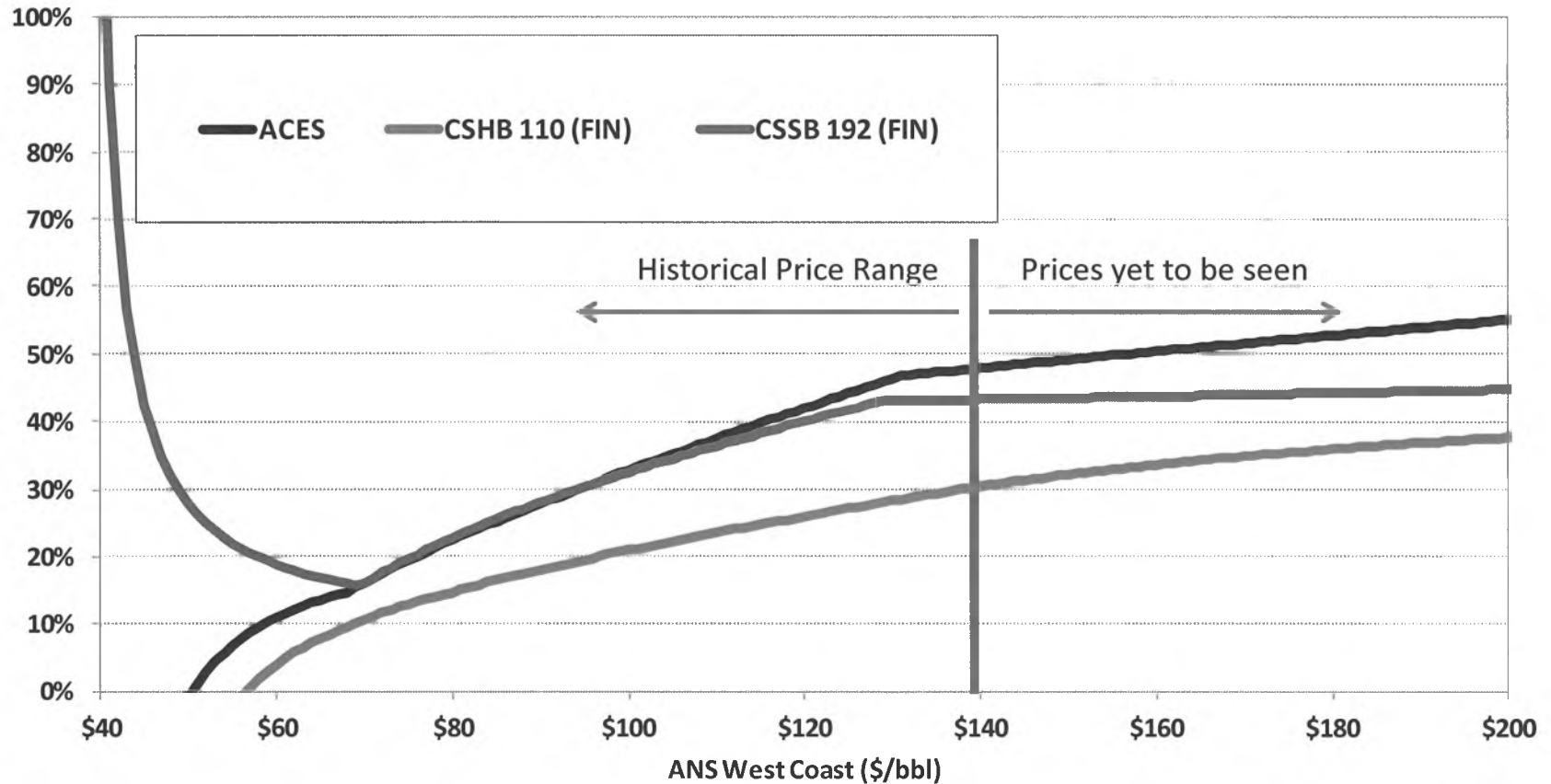


- Millions of data elements would have to be manually uploaded to the system, in various formats including electronic copies of Excel spreadsheets, PDFs, Word documents, and in hard copy format
- Determination would have to be made as to the confidentiality of each item for uploading to the system, which would take thousands of employee hours
- Department currently has only begun long-awaited Tax Revenue Management System (TRMS) project, which is expected to take 3 – 5 years to complete
- PIMS would likely delay the implementation of that important tax-specific project
- Would require significant funding and additional staff resources for the Department



Effective tax rates

Effective Production Tax Rate (Post-Credits)



Assumes FY 2013 Transport costs of \$8.56/ bbl, Opex of \$13.75 per taxable barrel, and Capex of \$15.36 per taxable bbl.

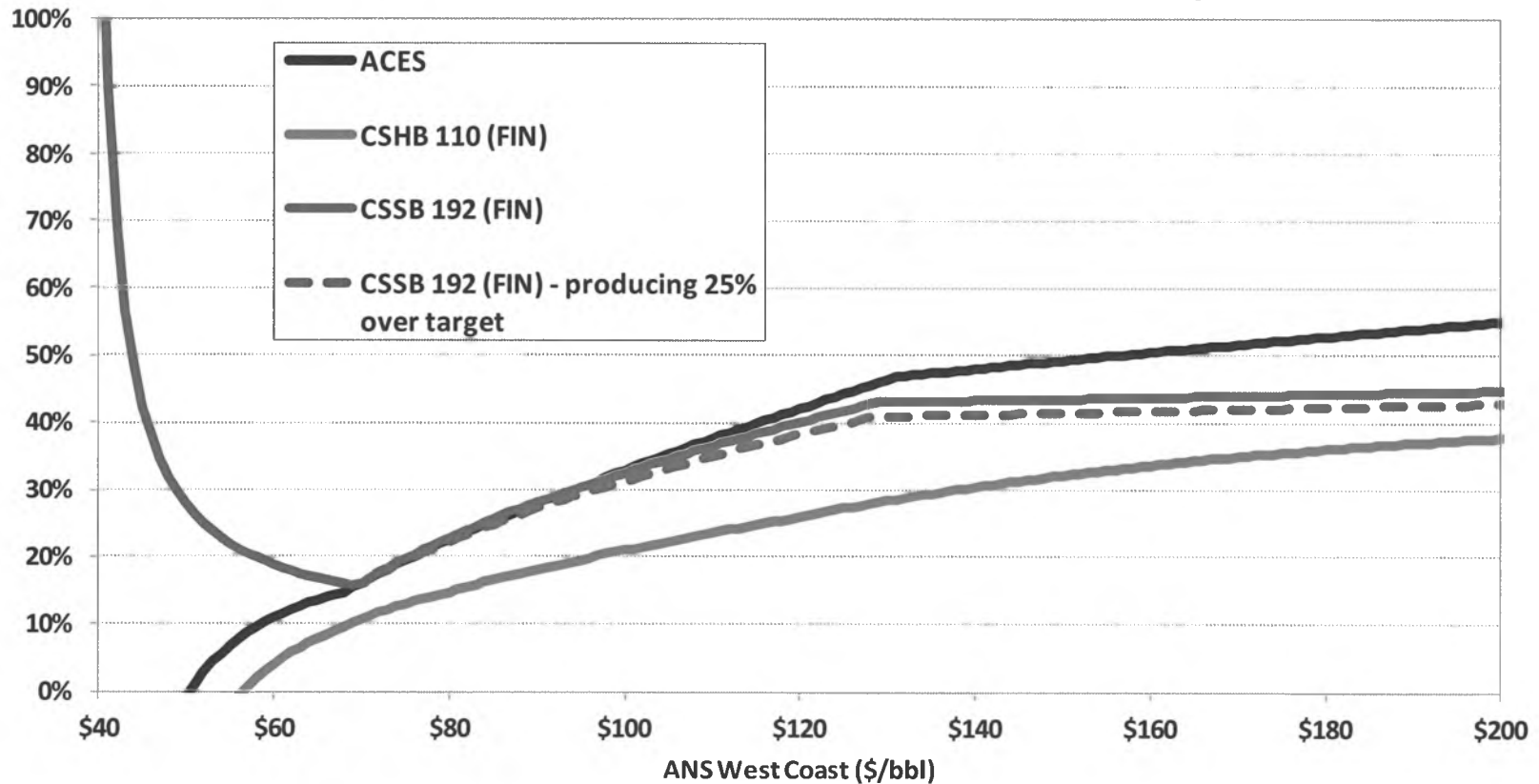
CSSB 192(FIN) Work Draft 27-LS1305\O



Effective tax rates

Impact of producing 25% over target (i.e. 1/5 of production at lower rate)

Effective Production Tax Rate (Post-Credits)



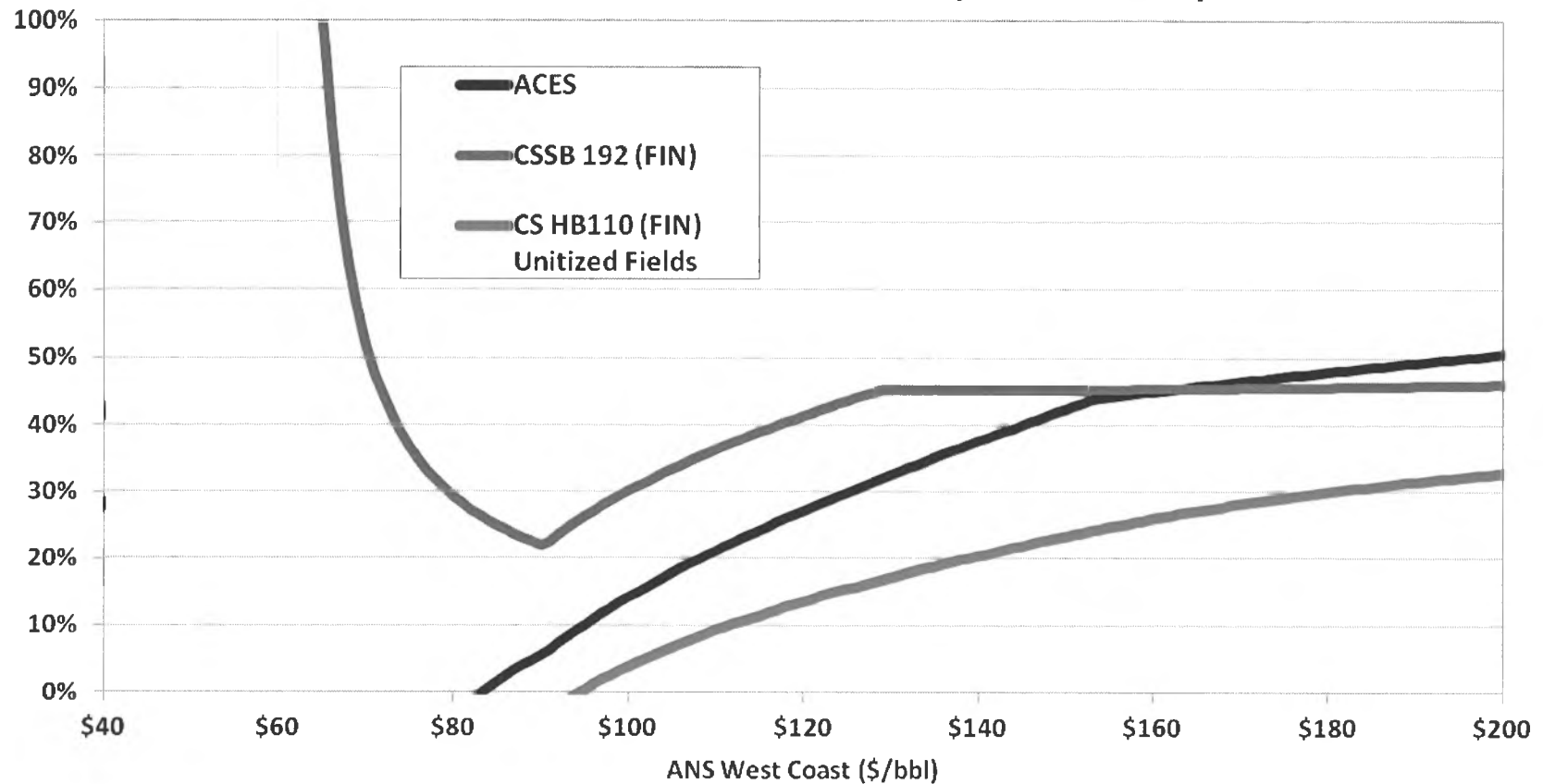
Assumes FY 2013 Transport costs of \$8.56/ bbl, Opex of \$13.75 per taxable barrel, and Capex of \$15.36 per taxable bbl.

CSSB 192(FIN) Work Draft 27-LS1305\O



Effective tax rates High-cost producer

Effective Production Tax Rate (Post-Credits)



Assumes FY 2013 Transport costs of \$8.56/ bbl, Opex of \$20 per barrel, and Capex of \$25 per bbl.

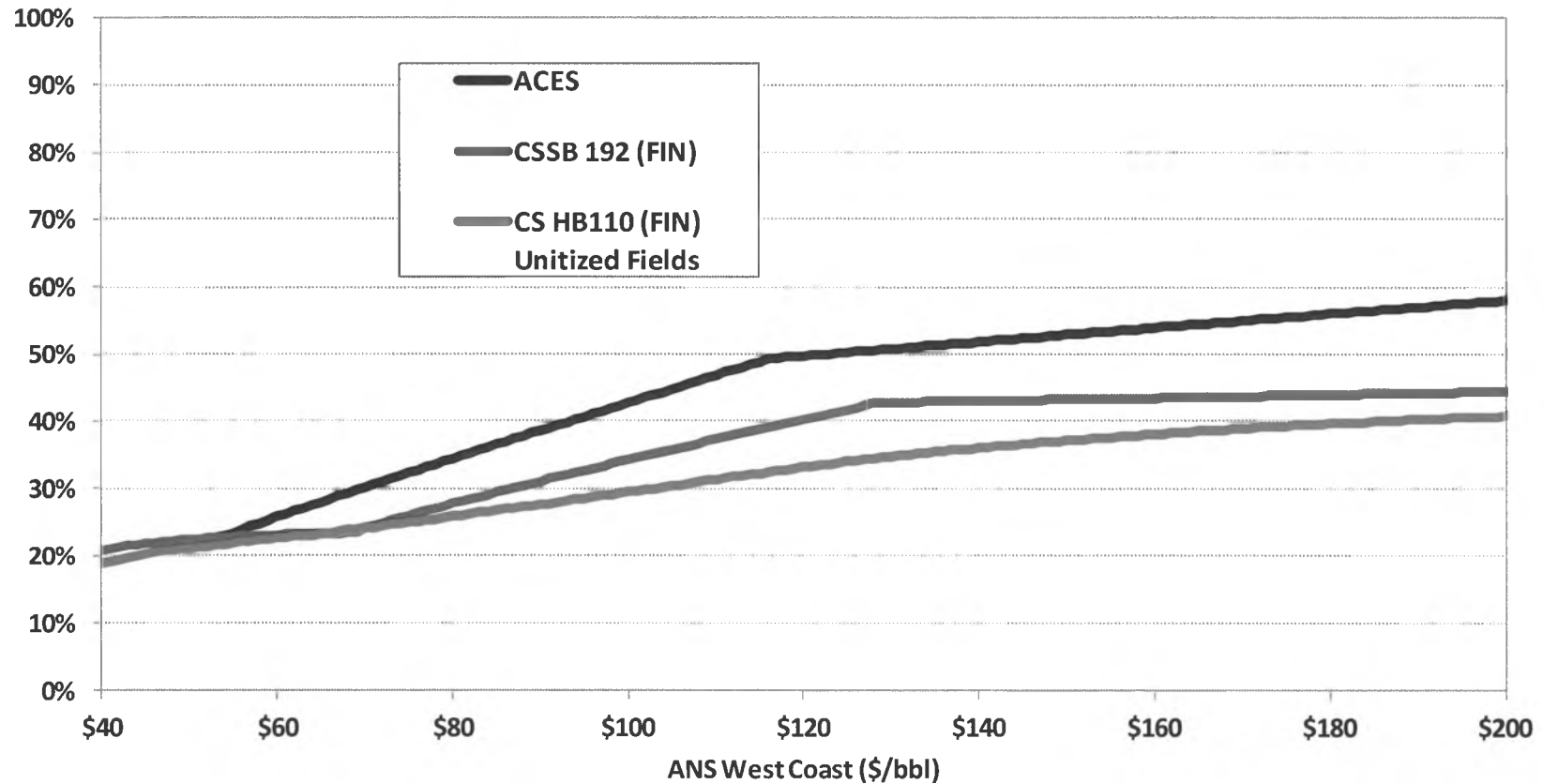
CSSB 192(FIN) Work Draft 27-LS1305\O



Effective tax rates Low-cost producer



Effective Production Tax Rate (Post-Credits)



Assumes FY 2013 Transport costs of \$8.56/ bbl, Opex of \$10 perbarrel, and Capex of \$3 per bbl.

CSSB 192(FIN) Work Draft 27-LS1305\O



Summary of DOR Comments on CSSB 192(FIN)



- Changes move in the wrong direction – they discourage investment and encourage harvest mode
- Changes to progressivity do not adequately address government / producer take imbalance
- One of the most complicated tax structures in the world will be made even more complicated
- Additional duties of PIMS will add a significant burden to a Department already dealing with years of significant tax changes
- This change will likely require a complete overhaul of the 70+ regulations put in place over the past 4 years
- There appears to be potential constitutionality issues



Questions ?

26.

Comments on CSSB

192 (FIN)

Version 0

Kara Moriarty,

Executive

Director, AOGA

April 6, 2012

Alaska Oil and Gas Association



121 W. Fireweed Lane, Suite 207
Anchorage, Alaska 99503-2035
Phone: (907) 272-1481 Fax: (907) 279-8114

6 April 2012

The Honorable Bert Stedman, Co-Chair
The Honorable Lyman Hoffman, Co-Chair
Senate Finance Committee
Alaska State Capitol
Juneau, AK 99801

Re: Work-Draft "O" of CSSB 192(FIN)

Dear Senators Stedman and Hoffman and Members of the Senate Finance Committee:

On behalf of the member companies of the Alaska Oil and Gas Association, who account for the majority of oil and gas exploration, production, transportation, refining and marketing in this state, I would like to offer the following comments regarding work-draft "O" of a Senate Finance CS for Senate Bill 192. Despite the diversity of our membership, my comments reflect a 100% consensus among them.

On March 16 we testified to you about the Senate Resources version of the Bill. At that time we told you that, unless one is satisfied to see North Slope oil production continue to decline at about 6% a year or more, meaningful changes need to be made to the present ACES tax. We pointed out a number of measures that the Resources CS could have taken but didn't, as well as a number of things that it proposed to do that would be counterproductive.

Despite all the time and effort that have gone into work-draft "O", we have to say that this new CS also falls short of the meaningful tax change that is called for in order to meet the challenge of stopping decline, much less the even harder goal of getting back to a million barrels a day flowing through the TAPS oil pipeline.

The CS does indeed provide a slightly less onerous tax treatment for new fields and increases in production. But we would remind you that two very new fields — Oooguruk and Nikaitchuq — are each expected to peak at around 20,000 barrels a day. This year the North Slope at a 6% decline will decline by roughly 40,000 barrels a day, as much as these two new fields *combined*. In other words, to offset the decline, two new fields like Oooguruk and Nikaitchuq would need to come into production *each* year. These slight improvements are not likely to generate even this level of development.

The producers of the existing non-legacy fields on the Slope, and the developers of any new fields that may be discovered, need as much production as possible flowing from the legacy

fields through the TAPS oil pipeline in order to keep the costs affordable to ship their oil from the Slope to its refinery destinations. Unaffordably high transportation costs could cripple the economics of any new fields that might be found, as well as the economics of non-legacy fields currently in production.

In other words, the North Slope oil province is like a tree, with the two great legacy fields being its trunk, and with the other fields being branches rising out of the trunk. If one peels the bark off all the way around the trunk and make it unhealthy, all the other branches will become unhealthy too, no matter how robust they might have been if the trunk had stayed strong.

It has been openly acknowledged during the Committee's hearings that the intent is to keep the tax essentially the same as the present tax for the legacy fields at \$100 oil, and work-draft "O" reflects that intent. But that intent is just the opposite of what we urged you to do in our March 16th testimony on the Resources CS, and it is the opposite of what we urge you to do now.

Throughout the Twenty-seventh Legislature, AOGA and others have been testifying about what is happening with their businesses on the North Slope, about the interrelationship between the level of new investment each year and the rate of decline in ANS production, and about the effects taxes have on investment decisions. These explanations are not threats, but they are not bluffs either. They have been candid attempts to describe to you how those companies evaluate their investment opportunities here against their opportunities elsewhere, and how Alaska's tax regime can influence the decisions about which opportunities to take.

Those decisions reflect the expectations of the companies' respective shareholders that each company will chose the opportunities that it perceives to be best, all things considered – including taxes. If an Alaskan opportunity is better than one elsewhere and there is enough budgeted money only for one of them, the shareholders expect, and in a very real sense demand, that the Alaska opportunity be taken. The reductions in the level of companies' investments in Alaska since the enactment of ACES are not any kind of retaliation for ACES' enactment, nor does a company cut back here to spite its face. The investments are nothing more, and nothing less, than the result of the competition of the Alaskan opportunities against opportunities elsewhere.

Any one is free to believe that the declining investments and declining production on the North Slope are due to something other than these reasons ... but they will be mistaken. Unfortunately, by the time they are proven to be mistaken, the opportunity for Alaska to have addressed the situation will have passed. And there aren't any "do overs."

Without meaningful tax relief for the legacy fields as well as the other production, the bark will continue to be peeled off the tree trunk, harming the entire tree. Work-draft "O" threatens harm for every member in AOGA.

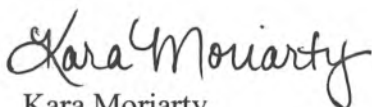
Thank you, Mr. Chairman and Members of the Senate Finance Committee, for this opportunity to share our deep and grave concerns with you about work-draft "O" of the Finance CS. We respectfully ask you to take another look at what it would do, and to replace it with a CS

that would provide meaningful tax change to enable the additional investments the state and its future need.

In closing, let me repeat that these comments have the unanimous support of AOGA's members: Apache, BP, Chevron, eni petroleum, ExxonMobil, Flint Hills, Hilcorp, Marathon, Petro Star, Pioneer, Repsol, Shell, Statoil, Tesoro, XTO Energy, and Alyeska Pipeline Service Company. Thank you for this opportunity to share them with you.

Very truly yours,

ALASKA OIL AND GAS ASSOCIATION

A handwritten signature in black ink that reads "Kara Moriarty". The signature is written in a cursive, flowing style.

Kara Moriarty
Executive Director

Cc: Governor Sean Parnell
All Members of the Alaska State Legislature

27.

**BP Testimony to
Senate Finance:
Damian Bilbao, Head
of Finance,
Developments &
Resources
and Tom Williams,
Senior Tax &
Royalty Counsel
April 6, 2012**



BP Testimony to Senate Finance

Damian Bilbao, Head of Finance, Developments and Resources

Tom Williams, Senior Tax & Royalty Counsel

April 6, 2012

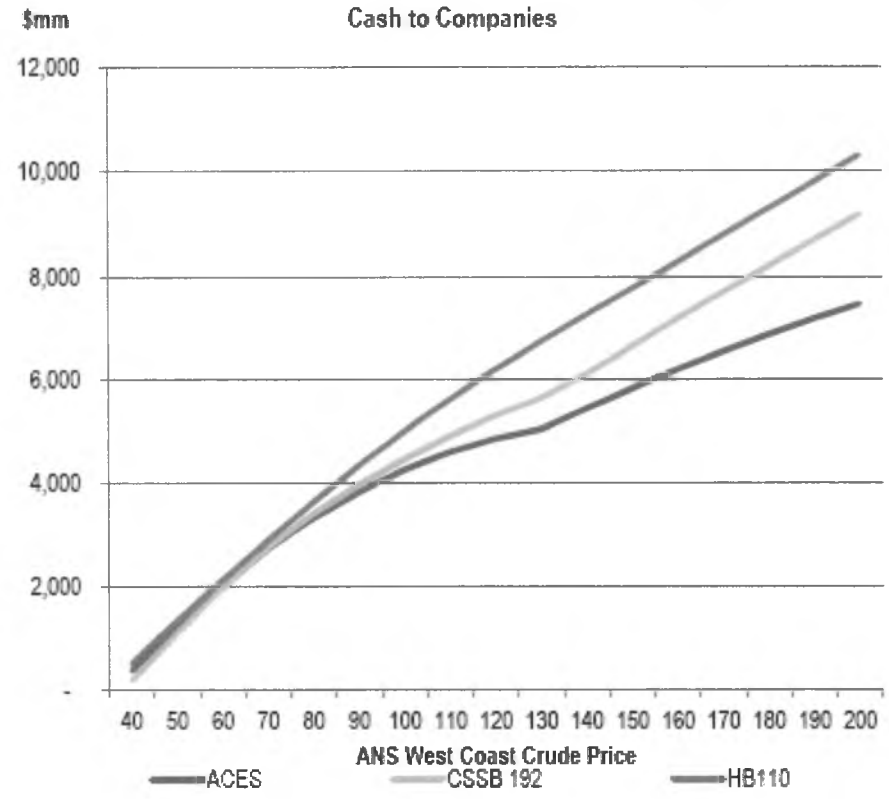
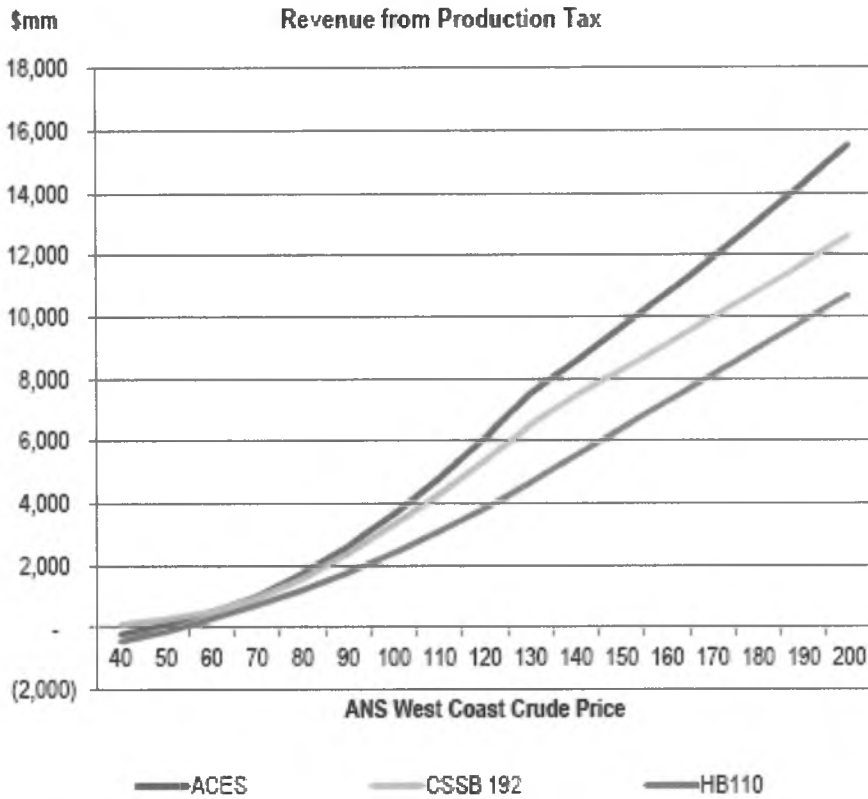


Key Messages

- CSSB 192 (Fin):
 - is a **tax increase** that will cause us to re-evaluate existing activity plans
 - is **not meaningful** and will **not** lead to more investment
 - likely to create **misalignment between producers** that slows/stops activity
 - creates **more disincentive than ACES** to invest in the long-term



CSSB 192(T) Will Not Draw More Investment



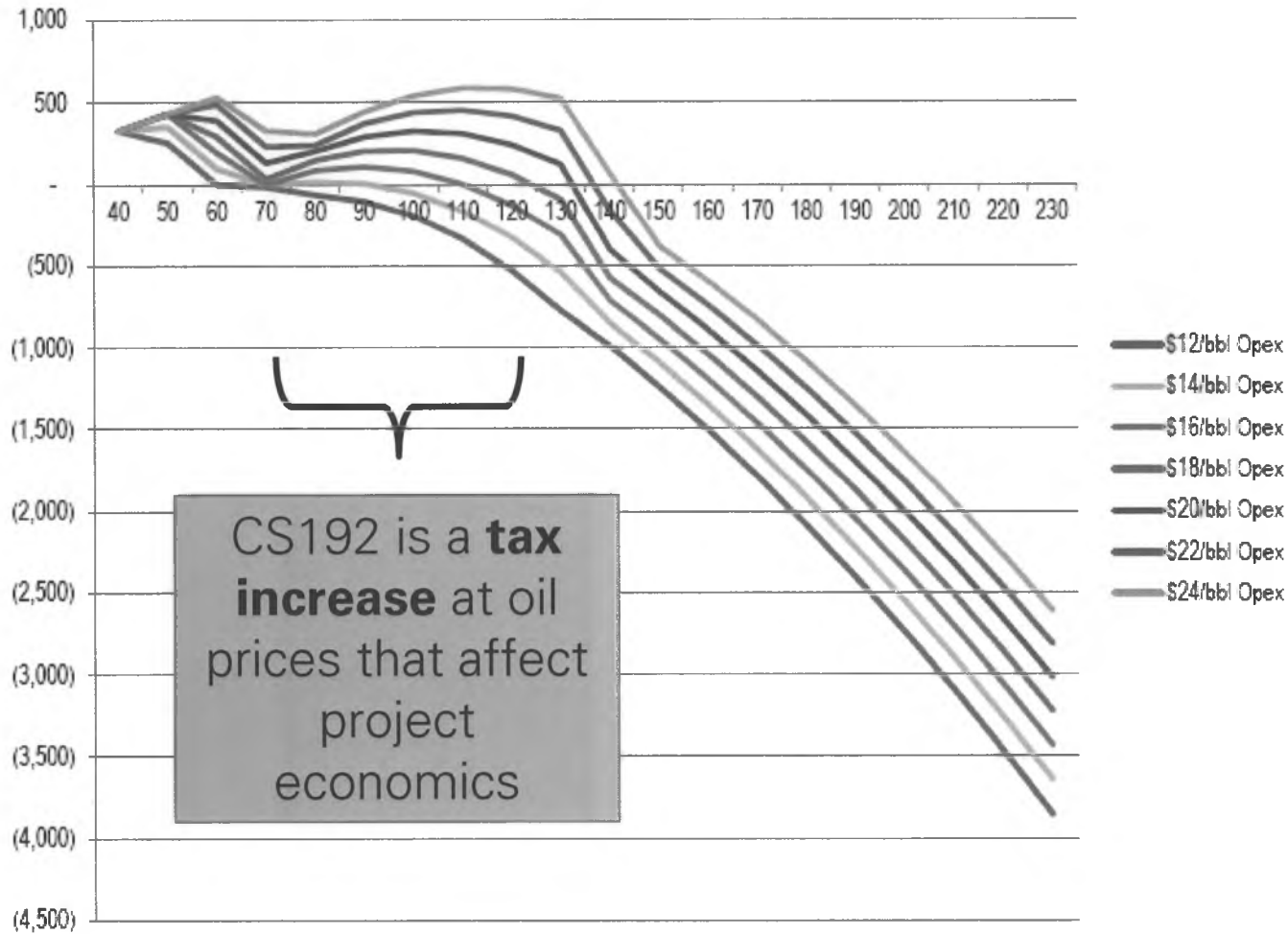
And CSSB 192(O) is less attractive

Source: PFC Senate Finance Presentation, April 4, 2012



CSSB 192(O) is a Tax Increase

Revenue Difference Between ACES and Progressive Severance Option under Different Opex/bbl Assumptions





Unintended Consequences

Incremental Production Incentives		
Issue	Concept	Impact to the state
Economic risk	Existing production from the legacy fields is the foundation for North Slope present and future; SB 192 penalizes the base business	Weakens the foundation of the Alaska economy
Likely misalignment between operators	SB 192 provides each producer with a different production target; creating misalignment around projects	Delay of short-term projects
Short versus Long-term focus	SB 192 provides a financial incentive to shift effort and resources away from long-term projects in support of short-term rate	Delay of long-term projects



What does meaningful look like

EFFICIENCY
 +
TECHNOLOGY
 +
TAX CHANGE
 =
PRODUCTION GROWTH

SB192-O

Oil Progressivity Table		
Price	Cumulative Rates	Progressivity Rate
Base Tax	25.0%	-
\$60.00	-	0.27%
\$120.00	16.2%	0.03%
\$246.67	20.0%	

Meaningful Tax Change

Oil Progressivity Table		
Price	Cumulative Rates	Progressivity Rate
Base Tax	22.5%	-
Min Tax	5.0%	
\$80.00	-	0.20%
\$130.00	10.0%	0.10%
\$180.00	15.0%	-

No alternative provides meaningful tax change with a 25% base rate

28.

**ConocoPhillips
Discussion of
CSSB 192:**

**Bob Heinrich, VP
Finance & Scott
Jepsen, VP
External Affairs
April 6, 2012**

Senate Finance

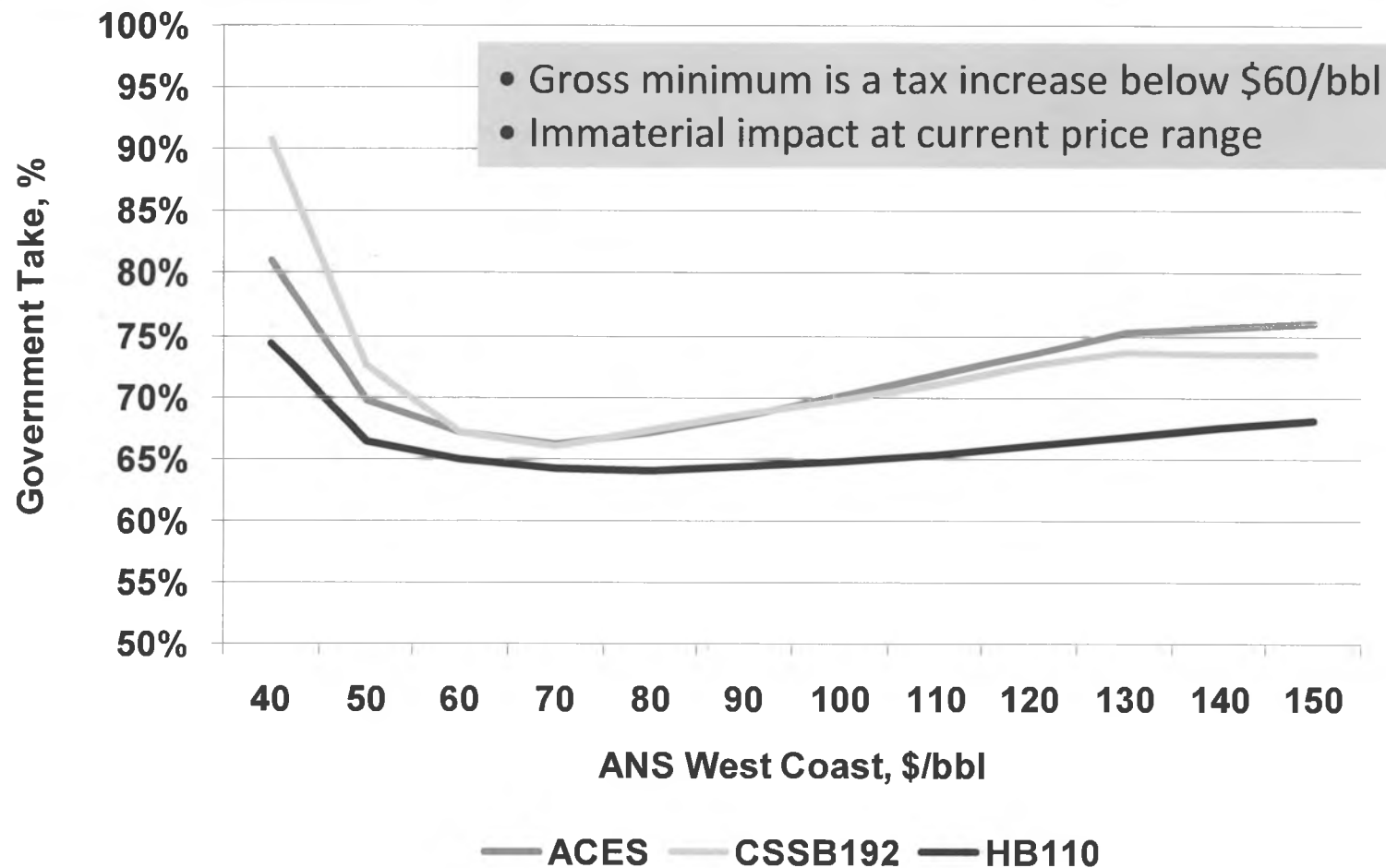
Discussion of CSSB192

Bob Heinrich, VP Finance
Scott Jepsen, VP External Affairs
ConocoPhillips Alaska

April 6, 2012

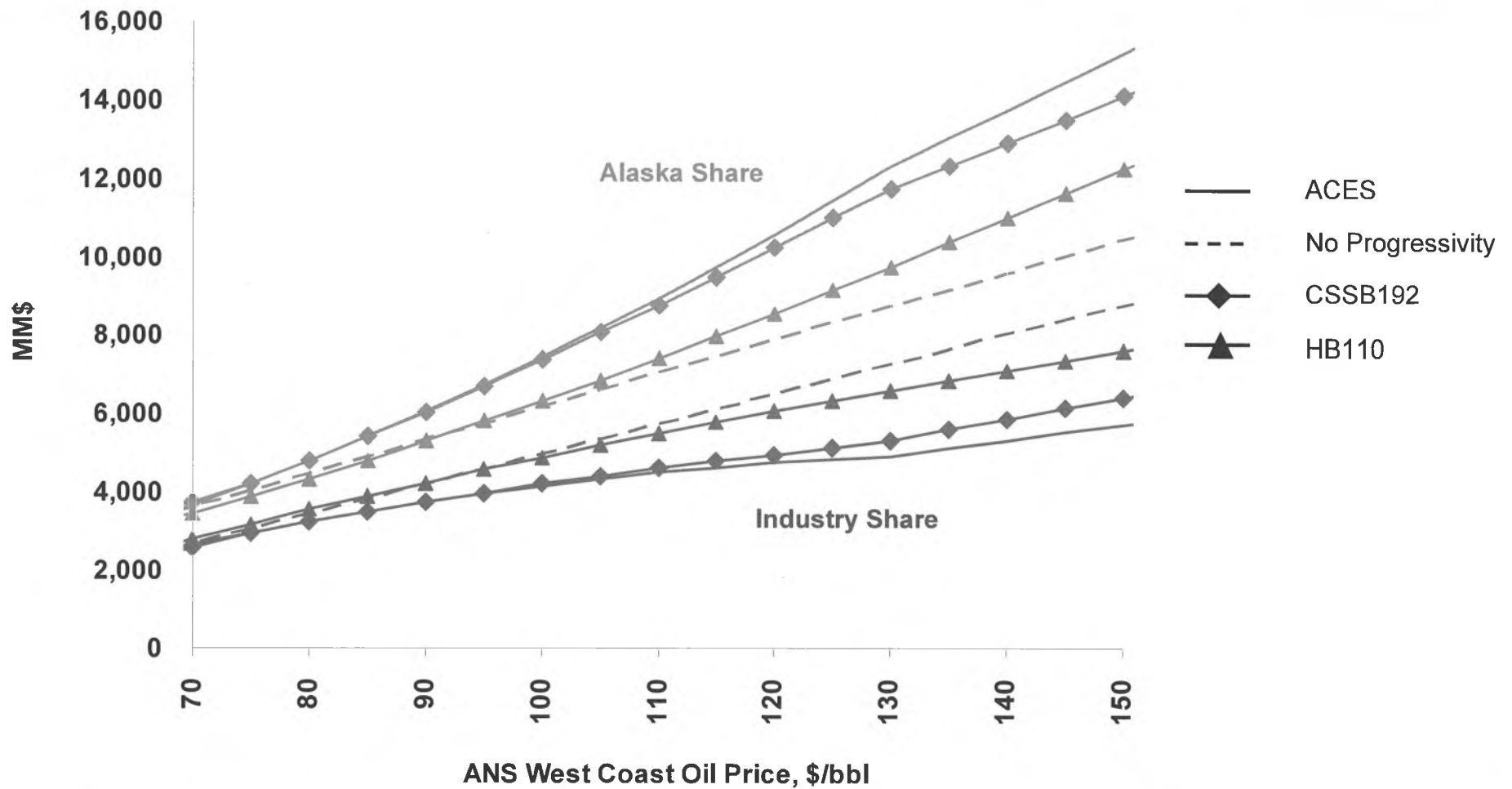
- Tax rate on base still too high
- New oil incentive insufficient to offset high base tax rate
- Floor represents a tax increase at low prices
- Indexing is a positive step
- CSSB192 insufficient to improve the investment climate and attract capital necessary to stem the decline

Government Take Comparison vs ACES



CSSB192 does not improve the investment climate

State / Industry Share



CSSB192 Base Tax - does not improve the investment climate

- New production incentive insufficient to overcome high base tax rate
- All new production investments challenged by costs and smaller targets
- Maintaining base decline will require more investment over time
- Increases complexity
- Production incentive does not go as far as HB-110

Last spring, ConocoPhillips made the following commitments to Alaska if HB110 or similar legislation is passed:

- We will pursue increased drilling activity on the North Slope
- We will aggressively pursue more satellite developments at Alpine and Kuparuk
- We will work with partners to develop major projects at Prudhoe Bay
- We will proactively pursue other projects that can move the needle on oil production

An Open Letter to All Alaskans from ConocoPhillips

Our Commitment to Moving Alaska Forward

Dear Alaskans:

The oil industry in Alaska is at a crossroads. The amount of oil in the Trans Alaska Pipeline is declining at a faster rate than projected even a year ago. State and federal officials are, for the first time, talking openly about the challenges with TAPS low flow in light of the recent shut down of TAPS.

No other state's production has declined more than Alaska in the past eight years. But it doesn't have to be that way. The oil industry and the state of Alaska must work together now to put more oil in the pipeline and bridge the more than 10-year gap between now and when oil from offshore and other sources can hopefully refill TAPS.

Governor Parnell has introduced a bill, HB 110/SB 49, to reduce oil taxes in an effort to restart development and create new jobs. However, some have questioned the oil industry's commitment to Alaska.

In Alaska this week, ConocoPhillips reinforced that commitment to the state. If the business environment is changed, we at ConocoPhillips will do more to help bring Alaska's challenged oil to the market.

We will increase our drilling activity on the North Slope.

We will proactively pursue more North Slope projects that can move the needle on oil production while employing Alaskans and creating new opportunities for Alaska businesses.

We will work with BP and ExxonMobil to advance significant projects like Gas Partial Processing (GPP) and IPAD at Prudhoe Bay.

We will aggressively pursue more satellite developments at both Kuparuk and Alpine.

Our company believes Governor Parnell's goal of producing 1 million barrels of oil per day is a goal around which we can all unite.

At ConocoPhillips, we believe in the potential that Alaska has to offer. We have demonstrated our commitment to the environment by continuing to operate in the cleanest and safest way we can. We have shown a long history of investment, both human and financial, to bring the resources of this great state to the market. We have stood with many Alaska companies, including Alaska Native corporations, to build an oil and gas industry that has provided many jobs to Alaskans.

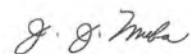
If the Legislature provides for an effective date of 2012, ConocoPhillips will do our part to accelerate new activity on the North Slope.

Alaska has tremendous resource potential, and we at ConocoPhillips have over 50 years in Alaska in solving technical and environmental challenges associated with oil development. We support improving the investment climate and believe changing oil taxes will lead to a better future with more production and jobs for Alaska families than the current path we are on.

Sincerely,


Trond-Erik Johansen

President
ConocoPhillips Alaska Inc.


Jim Mulwa

Chairman and Chief Executive Officer
ConocoPhillips


Alaska's Oil & Gas Company

29.

Fiscal Notes
April 7, 2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB192
 Fiscal Note Number _____
 () Publish Date _____

Identifier (file name) SB192CS(FIN)-DOA-AOGCC-4-6-12 Dept. Affected Administration
 Title Oil and Gas Production Tax Rates Appropriation AOGCC
 Allocation Alaska Oil and Gas Conservation
 Sponsor Senate Resources Commission
 Requester Senate Finance OMB Component Number 2010

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	150.0		150.0	150.0	150.0	150.0	150.0	150.0
Travel								
Services								
Commodities								
Capital Outlay								
Grants, Benefits								
Miscellaneous								
TOTAL OPERATING	150.0	0.0	150.0	150.0	150.0	150.0	150.0	150.0

FUND SOURCE		(Thousands of Dollars)						
		FY13	FY14	FY15	FY16	FY17	FY18	
1002	Federal Receipts							
1003	GF Match							
1004	GF	150.0	150.0	150.0	150.0	150.0	150.0	
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		150.0	0.0	150.0	150.0	150.0	150.0	

POSITIONS							
Full-time							
Part-time							
Temporary	1		1	1	1	1	1

CHANGE IN REVENUES							

Estimated SUPPLEMENTAL (FY12) operating costs _____ (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

CSSB 192 has been significantly amended as to the responsibilities of Alaska Oil and Gas Conservation Commission in this bill.

Prepared by Jody J. Colombie
 Division Alaska Oil and Gas Conservation Commission
 Approved by John Cramer, Deputy Commissioner
Department of Administration

Phone (907) 793-1221
 Date/Time 4/7/12 1:08 PM
 Date 4/6/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192

Analysis

CSSB 192 states that the Alaska Oil and Gas Conservation Commission is responsible to provide the Department of Revenue its non-confidential data in a format usable by the Department of Revenue's system. In order for the Alaska Oil and Gas Conservation Commission to accomplish this they must hire one contract employee to establish and maintain a link to Department of Revenue's database, as well as to answer questions and provide other miscellaneous support.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

cost # codes

Bill Version

CS SB 192 (FIN)

Fiscal Note Number

Publish Date

Identifier (file name) SB192CS(FIN)-DOR-TAX-04-07-12

Title Oil and Gas Production Tax Rates

Dept. Affected

Revenue

Appropriation

Treasury and Taxation

Allocation

Tax Division

Sponsor (S) RES

Requester (S) FIN

OMB Component Number

2476

Expenditures/Revenues

(Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	943.9		943.9	943.9	943.9	943.9	943.9	943.9
Travel	50.0		50.0	50.0	50.0	50.0	50.0	50.0
Services	12,532.6		1,037.6	1,037.6	1,037.6	1,037.6	1,037.6	1,037.6
Commodities	4.0		4.0	4.0	4.0	4.0	4.0	4.0
Capital Outlay								
Grants, Benefits								
Miscellaneous								
TOTAL OPERATING	13,530.5		2,035.5	2,035.5	2,035.5	2,035.5	2,035.5	2,035.5

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	13,530.5	2,035.5	2,035.5	2,035.5	2,035.5	2,035.5	2,035.5
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		13,530.5	0.0	2,035.5	2,035.5	2,035.5	2,035.5	2,035.5

POSITIONS								
Full-time		8.0		8	8	8	8	8
Part-time								
Temporary								

CHANGE IN REVENUES	***	***	***	***	***	***	***

Estimated SUPPLEMENTAL (FY12) operating costs _____ (separate supplemental appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs _____ (separate capital appropriation required)
 (discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

Updated to reflect changes provided for in the CS, version U.

Prepared by Dan Stickel and Cherie Nienhuis, Economists
 Division Tax
 Approved by Bruce Tangeman, Deputy Commissioner
Department of Revenue

Phone 907-465-3279
 Date/Time 04/07/12 2:40pm
 Date 4/7/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CS SB 192 (FIN)

Analysis

The revenue impact of this bill is indeterminate.

This bill makes several changes to the oil and gas production tax system. Each of the major changes, along with its potential revenue impact, is discussed below.

1. **Creates three different progressive surcharge tax rates that are based on the gross value at the point of production.** Under this bill, the progressive surcharge is changed from one based on the net value of oil and gas production to one based on the gross value at the point of production (GVPP) of oil. The three rates are as follows: for oil in fields that are currently under production, the rate is 0.27% per dollar when the GVPP reaches \$60 per barrel, and then decreasing to .03% per dollar at a price \$60 over the initial threshold, up to a maximum progressive tax rate of 20%. For the first 7 years of production for oil produced from a lease or property containing land that was not in a unit or commercial production prior to January 1, 2008, the rate is 0.05% per dollar when the GVPP reaches \$60 per barrel up to a maximum progressive tax rate of 5%. For producers that increase oil production above a company-specific production target based on each company's decline rate from 2008 and 2011, the rate for that incremental production is 0.14% per dollar when the GVPP reaches \$60 per barrel, and then decreasing to .03% per dollar at a price \$60 over the initial threshold, up to a maximum progressive tax rate of 10%. The initial \$60 progressive surcharge tax thresholds would be adjusted annually by the increase in U.S. consumer price index for all urban consumers. Under Fall 2011 forecast assumptions, these provisions would impact revenue by the following amounts.

Change in State Revenue due to Progressivity Provisions of CSSB 192(FIN) in \$millions						
	FY 2013	FY 2014	FY 2015	FY 2016	FY 2017	FY 2018
"Base" production from currently producing fields	-110	-75	+25	-150	-225	-200
"Incremental" production from currently producing fields	-10	-75	-75	-125	-150	-175
Qualifying new fields	0	0	0	0	0	-150
Total	-120	-150	-50	-275	-375	-525

2. **Implements a 10% gross minimum tax for companies with average daily production of more than 50,000 BTU-equivalent barrels per day.** This provision of the bill creates a minimum tax of 10% of GVPP for companies producing more than 50,000 BTU-equivalent barrels per day. There are currently three companies that are subject to this provision. Under Fall 2011 revenue forecast assumptions, this provision would not result in a tax increase for any companies, unless oil prices are \$80 per barrel or below. At a \$50 per barrel oil price, the increase in revenue to the state ranges between \$500 million and \$650 million per year over the time horizon of this fiscal note.

3. **Requires that the Department of Revenue develop regulations to allocate lease expenditures between oil and gas.** This provision of the bill instructs the Department of Revenue, when lease expenditure allocation is necessary, to allocate lease expenditures between oil and gas based on gross value at point of production "to the extent possible." This provision is expected to impact revenue to the state by less than \$10 million per year.

4. **Provides for a new Petroleum Information Management System to be implemented by the Department of Revenue.** This provision of the bill provides for a new information management system for publicly available oil and gas information, to be operational before January 1, 2014. This provision is a major new responsibility for the Department, to be implemented on an accelerated timeframe, and will compete with the core mission of the Tax Division, which is to assess and collect taxes.

The bill has an effective date of January 1, 2013.

Agency Costs for Implementing Changes to Production Tax

This bill would require the Department of Revenue to draft and pass several new regulations to address the changes in progressive surcharge tax rates, the minimum tax rates, and the allocation of costs between oil and gas. The Department of Revenue expects that it would need a reimbursable services agreement with the Department of Law and other costs totaling \$495,000. With passage of this bill in the 2012 legislative session, the workshop and public forum process would likely begin in the summer or fall of 2012, and the majority of the regulation costs would be incurred in FY 13.

(continued on next page)

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CS SB 192 (FIN)

Analysis Continued

Specific costs for each major regulation project include the following:

\$75,000 for contracted professional services for regulation consulting.

\$270,000 for regulations costs including Department of Law, public notice and registry.

\$150,000 for public forums for education of taxpayers and public participation, including preparation materials and legal support, and possibly travel.

In addition to the one-time costs, the provisions of this bill will require four additional auditor positions to handle the increased complexity of the tax law created by this legislation. The positions would be at the Oil and Gas Revenue Auditor IV (Range 24) level, at an annual cost of \$546,000 for payroll and benefits, with additional cost for office space, supplies, travel, etc.

Agency costs for Petroleum Information Management System

Estimated one-time costs to the Department of Revenue for the Petroleum Information Management system are approximately \$12 million. This includes an estimated \$10 million for contract services to procure, design, build, and implement the system. An additional \$2 million is estimated for procurement of new hardware (data storage devices, servers, etc.) to create a robust system that can be replicated for access in both Juneau and Anchorage. An increased annual cost of \$1 million per year is estimated for ongoing system maintenance, support, storage, server space, and licensing.

Additional staff resources would be required to oversee the information management program, and maintain the data warehouse and disaster recovery plans. We estimate that we would need the following new positions: one Petroleum Economist II (Range 22), one Analyst Programmer V (Range 22), one Database Administrator (Range 15), and one Office Assistant III (Range 11). The total annual cost for these four positions is \$397,900 for payroll and benefits, with additional cost for office space, supplies, travel, etc.

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB192(FIN)
Fiscal Note Number _____
() Publish Date _____

Identifier (file name) CSSB192(FIN)-DNR-O&G-04-06-12 Dept. Affected Natural Resources
Title Oil and Gas Production Tax Rate Appropriation Oil and Gas
Allocation Oil and Gas
Sponsor Senate Resources Committee
Requester Senate Finance OMB Component Number 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	743.4	0.0	743.4	743.4	441.2	441.2	441.2	
Travel								
Services	139.0		139.0	99.0	47.5	47.5	47.5	
Commodities	75.0							
Capital Outlay								
Grants, Benefits								
Miscellaneous								
TOTAL OPERATING	957.4	0.0	882.4	842.4	488.7	488.7	488.7	

FUND SOURCE		(Thousands of Dollars)						
1002	Federal Receipts							
1003	GF Match							
1004	GF	957.4	882.4	842.4	488.7	488.7	488.7	
1005	GF/Prgm (DGF)							
1037	GF/MH (UGF)							
1178	temp code (UGF)							
TOTAL		957.4	0.0	882.4	842.4	488.7	488.7	488.7

POSITIONS							
Full-time	8	0	8	8	5	5	5
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***
--------------------	-----	-----	-----	-----	-----	-----	-----

Estimated SUPPLEMENTAL (FY12) operating costs 0.0 (separate supplemental appropriation required)
(discuss reasons and fund source(s) in analysis section)

Estimated CAPITAL (FY13) costs 0.0 (separate capital appropriation required)
(discuss reasons and fund source(s) in analysis section)

Why this fiscal note differs from previous version (if initial version, please note as such)

The Senate Finance committee substitute moves the petroleum information management system from the Department of Administration to the Department of Revenue. The Division of Oil and Gas develops, stores, and maintains much of the information identified for inclusion in the system.

Prepared by William C. Barron, Director
Division Division of Oil and Gas
Approved by Daniel Sullivan, Commissioner
Department of Natural Resources

Phone 907-269-8800
Date/Time 4/6/12 5:00 PM
Date 4/6/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192(FIN)

Analysis

CSSB 192 version U has an indeterminate impact on state royalty revenue. There are tax benefits for new fields, and for old fields at certain price and cost combinations. However, at low oil prices or at high operating costs, the proposed tax incentives become burdens. It is difficult to determine whether the proposed changes will increase or decrease oil production, and therefore, royalty revenue to the State.

Section 10 amends AS 31.05 by adding a new section (AS 44.25.025) which requires the Department of Revenue (DOR) to develop and maintain an electronic petroleum information management system (PIMS) to archive state oil and gas information. The system will only include non-confidential information identified in this bill and other information identified in section 10 relating to oil and gas exploration, development, and production. The Division of Oil and Gas (DO&G) collects and maintains much of the information and materials listed in the proposed bill.

DO&G will be a major contributor to the petroleum management system - likely designing, developing, and maintaining the system and associated materials. DO&G currently houses the following information on: 1) unit and joint operating agreements, 2) state oil and gas exploration licenses and oil and gas leases, 3) exploration activities including seismic data, drilling reports, logs, geological models and maps, 4) development activities including development plans minus expenditure projections and reservoir characteristics, 5) facility maps and studies, and 6) abandonment plans and progress reports. DO&G will conceivably have a role in contributing other information DOR needs for oil and gas exploration, development, and production. DO&G stores and maintains more than 40 years of information from Alaska's oil and gas activities. We find the directives in the proposed bill to initiate a significant undertaking by our department and others involved in supplying the requested information.

It is assumed our information will need to re-integrated into new formats compatible with a sophisticated system easily navigated by the public. The DOR and DO&G data collection and management systems may be different in scale and scope, and synchronizing the systems will take considerable resources. In some cases, information could be linked or transferred to the PIMS site quickly; however, the information requested in the bill will demand extensive time and resources to adapt, redact, and restructure records and materials before inclusion in the PIMS.

Developing and maintaining a petroleum information management system will not likely provide any more information to the public than is currently available from our division. Non-confidential oil and gas information is currently available on DO&G's website or upon request in electronic and hard copy formats. We estimate the proposed bill will initially require eight new FTEs in the division and funds necessary to hire contractors for information technology work.

The division would need five new natural resources specialists (2 NRS II and 3 NRS III) with one administrative assistant (range 12) and two analysts (range 20) for IT functions during build-out starting in FY13. In addition to staff increases, approximately \$75,000 in funding for software, licenses, and back-up systems is needed. Storage for DO&G seismic data (2-3 terrabytes) would need to be contracted to electronic storage provider which could cost hundreds of thousands of dollar annually. After the system build-out and population, we should be able to maintain the system with 4-5 FTEs. We project roughly \$75,000 for contract services in FY13 and FY 14, \$35,000 in FY15, and potentially no funds thereafter. Since we are not forecasting additional state revenue for these sections of the proposed bill, the significant costs incurred in developing and maintaining a new location for DO&G information results in a negative fiscal impact to the state for years to come.

30.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

April 9, 2012

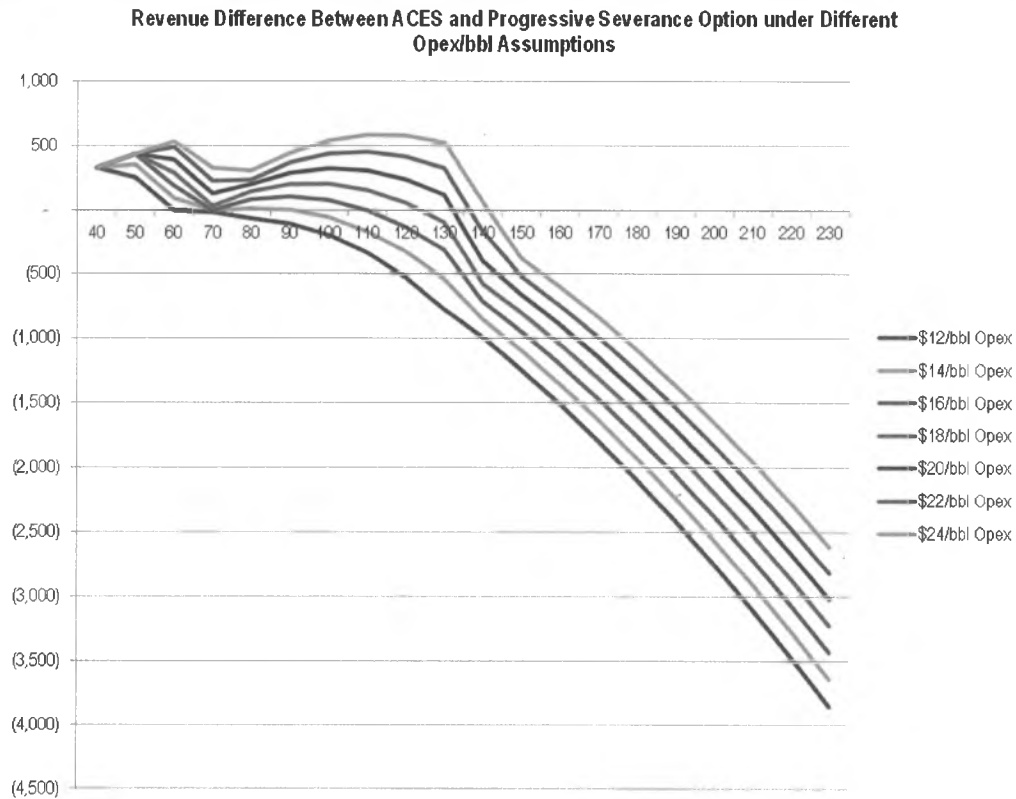


Discussion Slides: Alaska Senate Finance Committee

April 9, 2012
Janak Mayer
Manager, Upstream & Gas
PFC Energy

Cost Sensitivity – From April 3 Testimony and Discussion

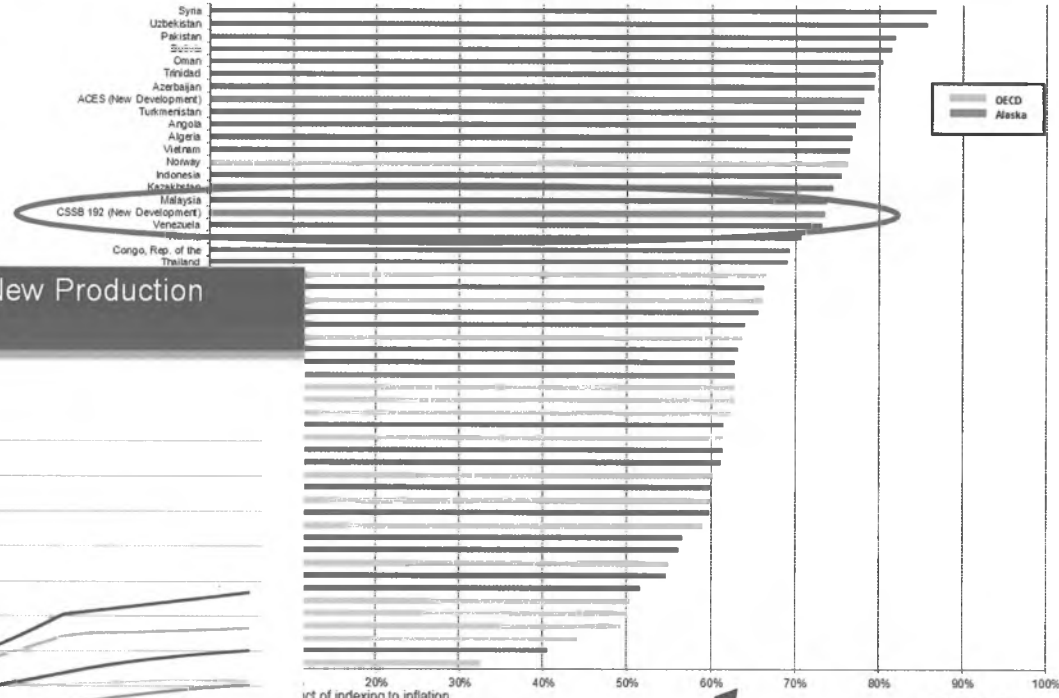
Impact of Rising Operating Costs



FY 2013 v Lifecycle Analysis – Impact of Costs & 7 year Time Limit

Regime Competitiveness: Relative Government Take

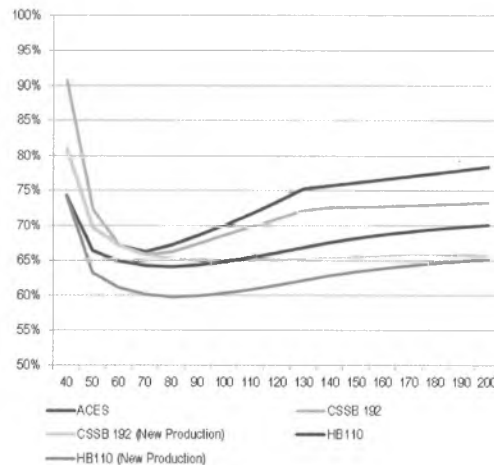
Average Government Take of Global Fiscal Regimes at \$100/bbl



From April 4 Slides

Total Government Take Comparison Including New Production Incentives

ANS West Coast Oil Price	FY 2013 % Government Take					
	ACES	CSSB 192	CSSB 192 (New Production)	HB110	HB110 (New Production)	
40	81%	91%	81%	74%	74%	
50	70%	72%	70%	66%	63%	
60	67%	67%	67%	65%	61%	
70	68%	68%	68%	64%	60%	
80	67%	66%	65%	64%	60%	
90	69%	67%	65%	64%	60%	
100	70%	69%	65%	65%	60%	
110	72%	70%	65%	65%	61%	
120	73%	71%	65%	66%	61%	
130	75%	72%	65%	67%	62%	
140	76%	73%	65%	68%	63%	
150	76%	73%	66%	68%	63%	
160	77%	73%	66%	69%	64%	
170	77%	73%	66%	69%	64%	
180	77%	73%	66%	69%	65%	
190	78%	73%	66%	70%	65%	
200	78%	73%	66%	70%	65%	



Index of indexing to inflation
July 2012 | Page 16 | April 9, 2012

From April 5 Slides

PFC Energy

Some Goals Are Mutually Exclusive

- Achieve decoupling
- Reduce high levels of support for spending, and poor incentives for cost control
- Minimize complexity, including need for separate cost accounting
- Reduce government take on new/incremental production
- No increases on any taxpayers
- Revenue neutral at \$100+ /bbl
- More even split between state and companies above \$100/\$120 / bbl

Some Goals Are Mutually Exclusive

ACES with 40% Cap

- Achieve decoupling
- Reduce high levels of support for spending, and poor incentives for cost control
- **Minimize complexity, including need for separate cost accounting**
- Reduce government take on new/incremental production
- **No increases on any taxpayers**
- **Revenue neutral at \$100+ /bbl**
- **More even split between state and companies above \$100/\$120 / bbl**

Some Goals Are Mutually Exclusive

ACES with 40% Cap & SB305-style decoupling

- Achieve decoupling
- Reduce high levels of support for spending, and poor incentives for cost control
- Minimize complexity, including need for separate cost accounting
- Reduce government take on new/incremental production
- No increases on any taxpayers
- Revenue neutral at \$100+ /bbl
- More even split between state and companies above \$100/\$120 / bbl

Some Goals Are Mutually Exclusive

HB110

- Achieve decoupling
- Reduce high levels of support for spending, and poor incentives for cost control
- Minimize complexity, including need for separate cost accounting
- Reduce government take on new/incremental production
- No increases on any taxpayers
- Revenue neutral at \$100+ /bbl
- More even split between state and companies above \$100/\$120 / bbl

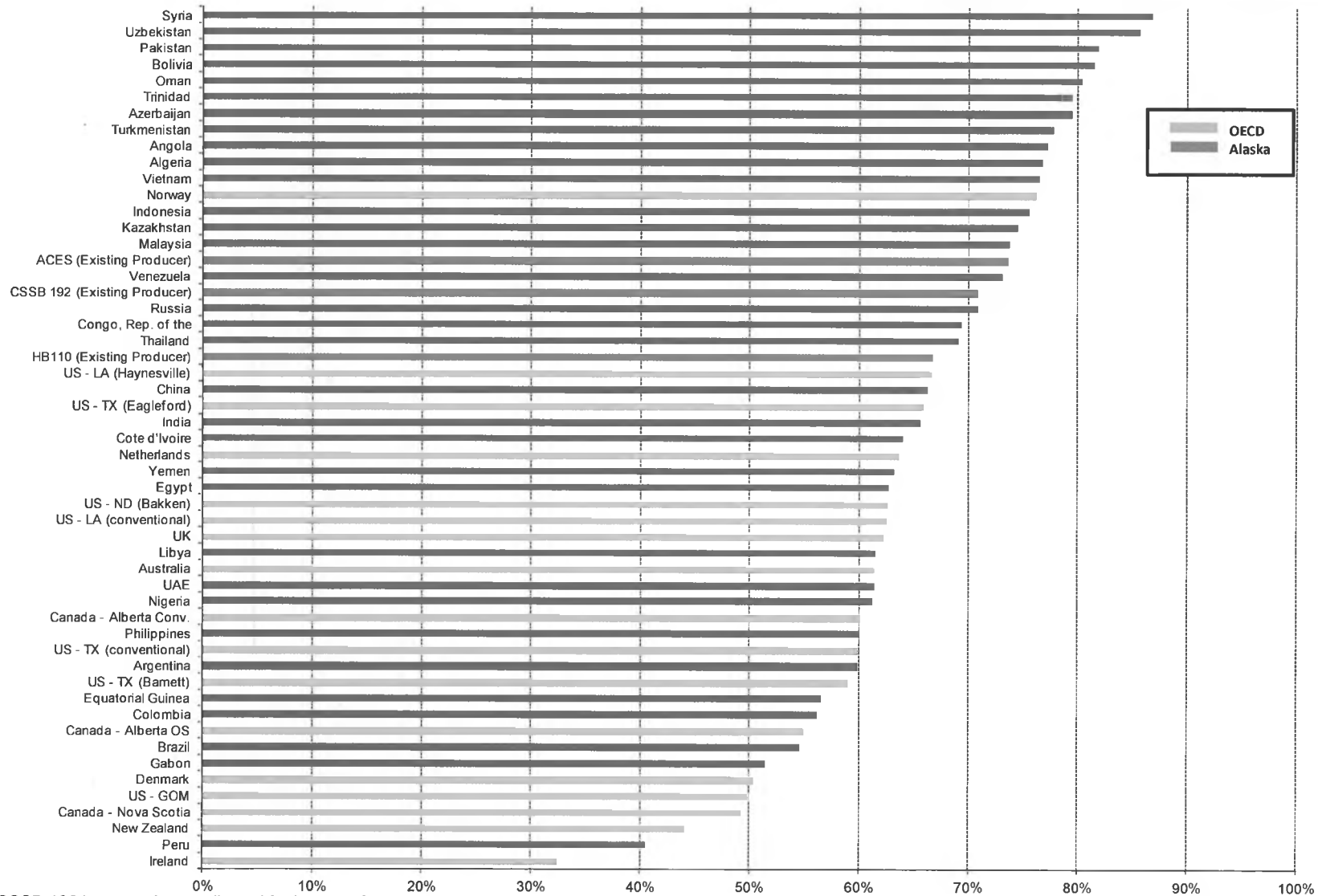
Some Goals Are Mutually Exclusive

CSSB192

- Achieve decoupling
- Reduce high levels of support for spending, and poor incentives for cost control
- Minimize complexity, including need for separate cost accounting
- Reduce government take on new/incremental production
- No increases on any taxpayers
- Revenue neutral at \$100+ /bbl
- More even split between state and companies above \$100/\$120 / bbl

Regime Competitiveness: Relative Government Take

Average Government Take of Global Fiscal Regimes at \$100/bbl



Note: CSSB 192 have not been adjusted for impact of indexing to inflation

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

Bill Version CSSB192(FIN)
 Fiscal Note Number _____
 () Publish Date _____

Identifier (file name) CSSB192(FIN)-DNR-O&G-04-06-12 Dept. Affected Natural Resources
 Title Oil and Gas Production Tax Rate Appropriation Oil and Gas
 Allocation Oil and Gas
 Sponsor Senate Resources Committee
 Requester Senate Finance OMB Component Number 439

Expenditures/Revenues (Thousands of Dollars)

Note: Amounts do not include inflation unless otherwise noted below.

	FY13 Appropriation Requested	Included in Governor's FY13 Request	Out-Year Cost Estimates					
			FY13	FY14	FY15	FY16	FY17	FY18
OPERATING EXPENDITURES								
Personal Services	743.4	0.0	743.4	743.4	441.2	441.2	441.2	
Travel								
Services	139.0		139.0	99.0	47.5	47.5	47.5	
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Capital Outlay								
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Miscellaneous								
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TOTAL		957.4	0.0	882.4	842.4	488.7	488.7	488.7

POSITIONS							
Full-time	8	0	8	8	5	5	5
Part-time							
Temporary							

CHANGE IN REVENUES	***	***	***	***	***	***	***
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Estimated SUPPLEMENTAL (FY12) operating costs 0.0 (separate supplemental appropriation required)
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Prepared by William C. Barron, Director
 Division Division of Oil and Gas
 Approved by Daniel Sullivan, Commissioner
Department of Natural Resources

Phone 907-269-8800
 Date/Time 4/6/12 5:00 PM
 Date 4/6/2012

FISCAL NOTE

STATE OF ALASKA
2012 LEGISLATIVE SESSION

BILL NO. CSSB192(FIN)

Analysis

CSSB 192 version U has an indeterminate impact on state royalty revenue. There are tax benefits for new fields, and for old fields at certain price and cost combinations. However, at low oil prices or at high operating costs, the proposed tax incentives become burdens. It is difficult to determine whether the proposed changes will increase or decrease oil production, and therefore, royalty revenue to the State.

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31.

Discussion

Slides:

Janak Mayer,

Manager,

Upstream & Gas,

PFC Energy

April 11, 2012

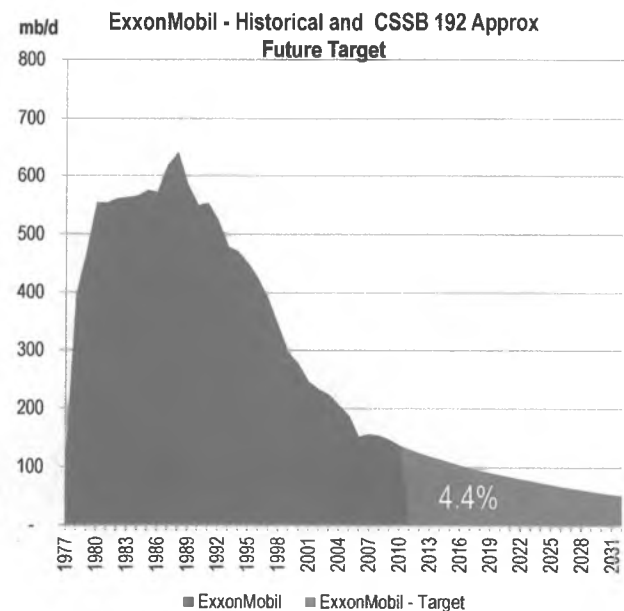
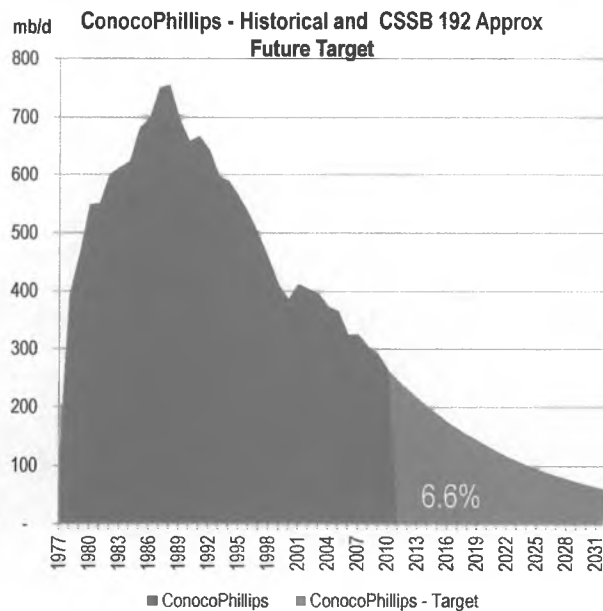
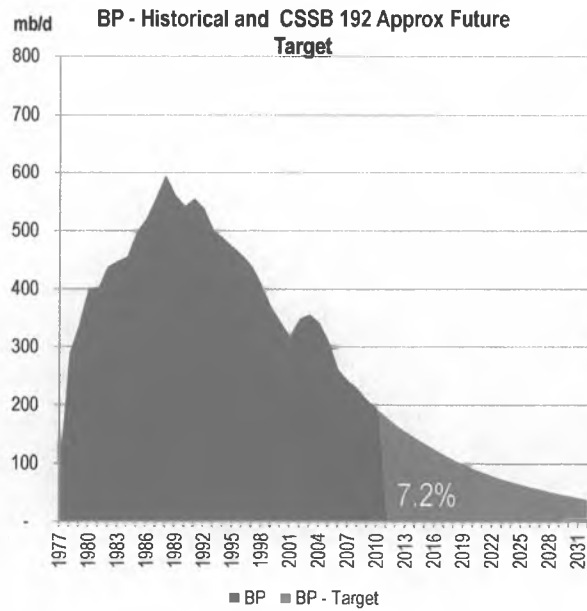


Discussion Slides: Alaska Senate Finance Committee

April 11, 2012

Janak Mayer
Manager, Upstream & Gas
PFC Energy

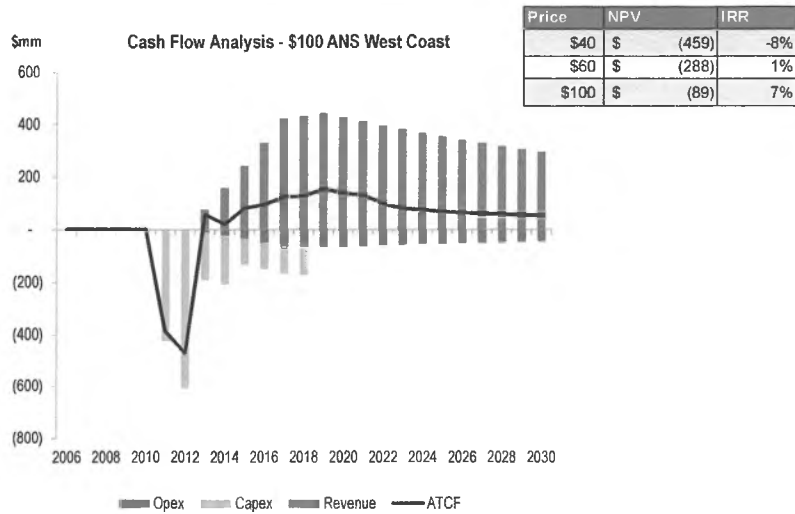
CSSB 192 – Approximated Company Decline-Based Production Targets



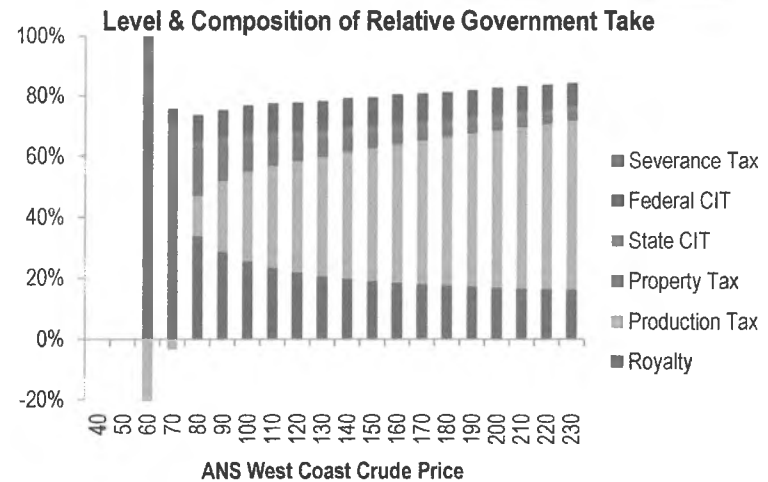
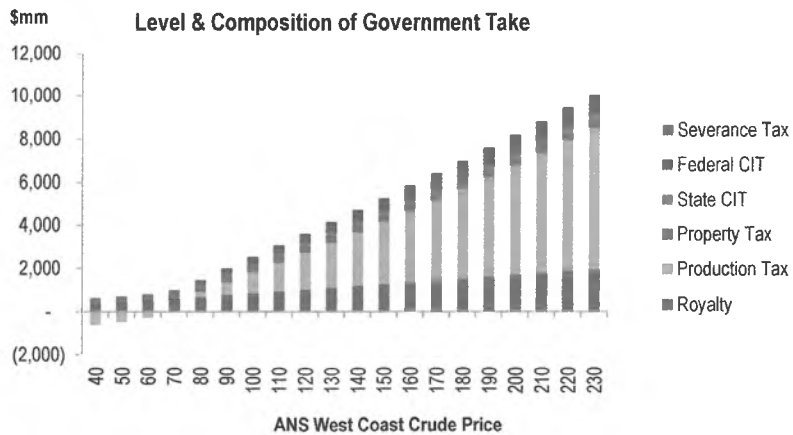
	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
BP	369	343	318	349	356	342	309	260	242	228	209	180	167	155	144	133	124	115	107	99	92	85	79	74	68	63
ConocoPhillips	411	386	412	404	395	373	365	325	326	305	292	248	232	216	202	189	176	165	154	144	134	125	117	109	102	95
ExxonMobil	296	276	247	234	224	206	188	151	156	153	146	130	124	119	114	109	104	99	95	91	87	83	79	76	72	69

ACES

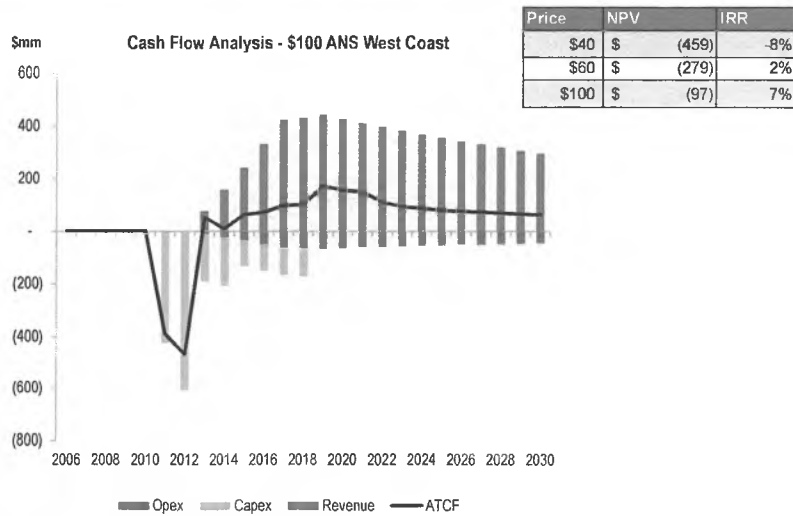
(\$34/bbl Capex New Development)



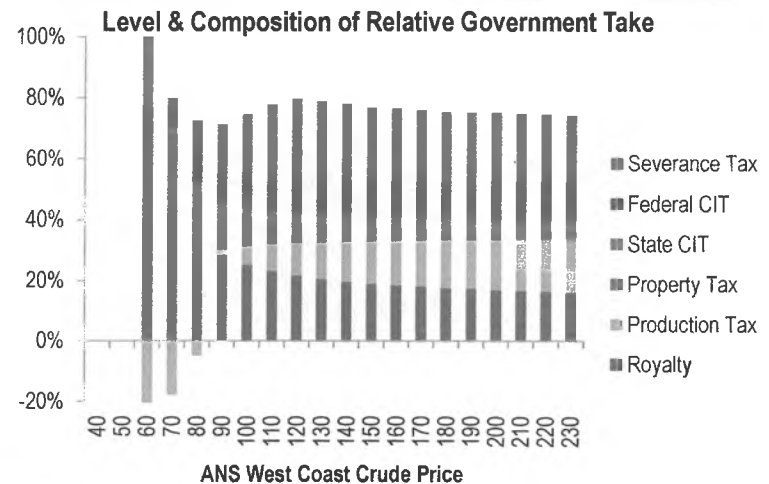
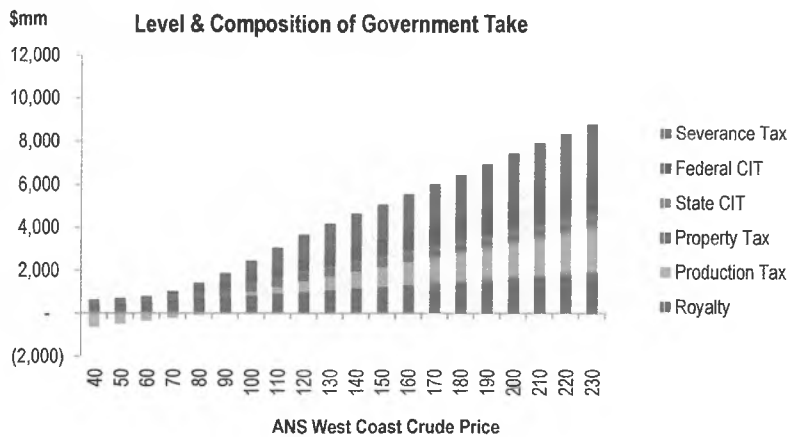
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50							
60	77%	-45%	48%	0%	79%	0%	79%
70	44%	-3%	24%	2%	66%	6%	72%
80	34%	13%	16%	2%	65%	9%	74%
90	28%	24%	12%	2%	66%	9%	75%
100	25%	30%	9%	3%	67%	10%	77%
110	23%	34%	8%	3%	67%	10%	77%
120	22%	37%	7%	3%	68%	10%	78%
130	20%	40%	6%	3%	68%	10%	78%
140	19%	42%	5%	3%	69%	10%	79%
150	19%	44%	5%	3%	70%	10%	79%
160	18%	46%	4%	3%	71%	10%	80%
170	18%	47%	4%	2%	71%	9%	81%
180	17%	49%	4%	2%	72%	9%	81%
190	17%	50%	3%	2%	73%	9%	82%
200	17%	52%	3%	2%	74%	9%	83%
210	16%	53%	3%	2%	75%	9%	83%
220	16%	54%	3%	2%	76%	8%	84%
230	16%	56%	3%	2%	76%	8%	84%



CSSB 192 20% Max Rate (\$34/bbl Capex New Development)

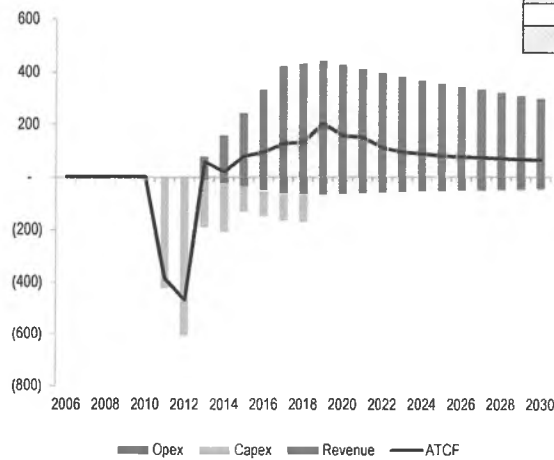


Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50							
60	77%	-56%	48%	0%	69%	0%	69%
70	44%	-15%	24%	2%	55%	7%	62%
80	34%	5%	16%	3%	57%	11%	68%
90	28%	17%	12%	3%	60%	11%	71%
100	25%	25%	9%	3%	63%	12%	75%
110	23%	33%	8%	3%	67%	11%	78%
120	22%	38%	7%	3%	69%	11%	80%
130	20%	39%	6%	3%	68%	11%	79%
140	19%	39%	5%	3%	67%	12%	78%
150	19%	39%	5%	3%	65%	12%	77%
160	18%	39%	4%	3%	65%	12%	77%
170	18%	39%	4%	3%	64%	12%	76%
180	17%	39%	4%	3%	63%	12%	75%
190	17%	39%	3%	3%	63%	13%	75%
200	17%	39%	3%	3%	62%	13%	75%
210	16%	39%	3%	3%	62%	13%	75%
220	16%	39%	3%	3%	61%	13%	75%
230	16%	39%	3%	3%	61%	13%	74%



CSSB 192 5% Max Rate for 7 yrs (\$34/bbl Capex New Development)

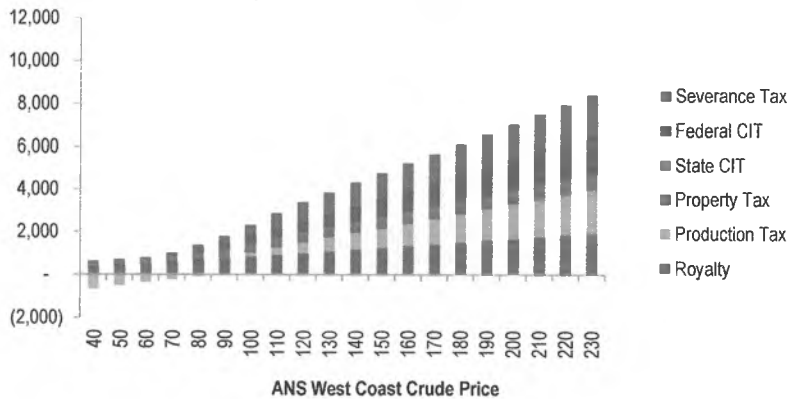
Cash Flow Analysis - \$100 ANS West Coast



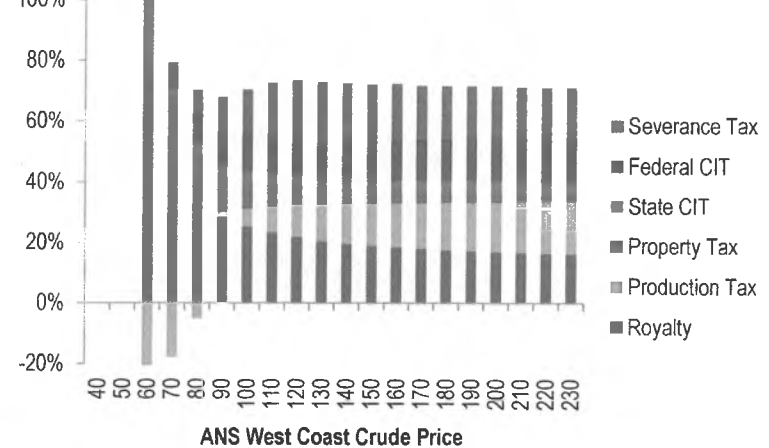
Price	NPV	IRR
\$40	\$ (459)	-8%
\$60	\$ (279)	2%
\$100	\$ (51)	8%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50							
60	77%	-56%	48%	0%	69%	0%	69%
70	44%	-16%	24%	2%	54%	7%	62%
80	34%	3%	16%	3%	55%	11%	65%
90	28%	13%	12%	3%	56%	11%	68%
100	25%	21%	9%	3%	58%	12%	70%
110	23%	28%	8%	3%	62%	11%	73%
120	22%	32%	7%	3%	63%	11%	74%
130	20%	32%	6%	3%	62%	11%	73%
140	19%	33%	5%	3%	61%	12%	73%
150	19%	33%	5%	3%	60%	13%	72%
160	18%	33%	4%	3%	59%	13%	72%
170	18%	33%	4%	3%	58%	13%	72%
180	17%	33%	4%	4%	58%	14%	72%
190	17%	33%	3%	4%	58%	14%	71%
200	17%	34%	3%	4%	57%	14%	71%
210	16%	34%	3%	4%	57%	14%	71%
220	16%	34%	3%	4%	57%	14%	71%
230	16%	34%	3%	4%	56%	15%	71%

Level & Composition of Government Take

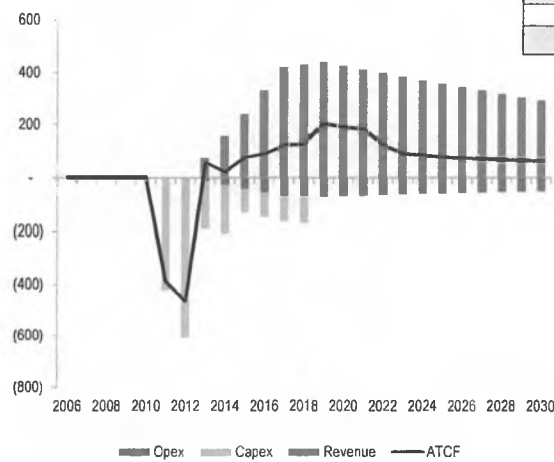


Level & Composition of Relative Government Take



CSSB 192 5% Max Rate for 10 yrs (\$34/bbl Capex New Development)

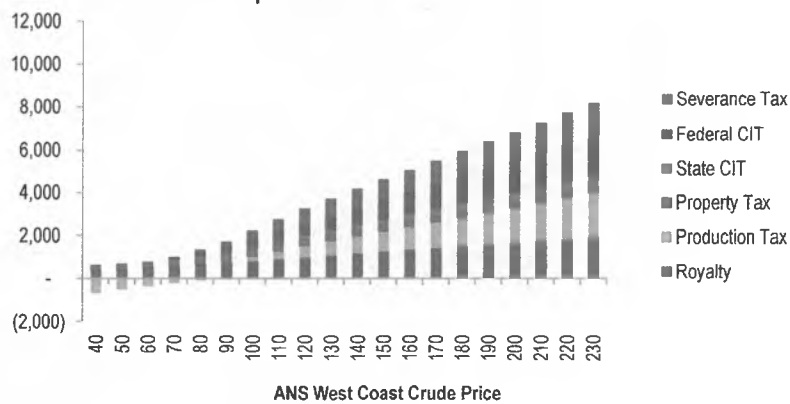
Cash Flow Analysis - \$100 ANS West Coast



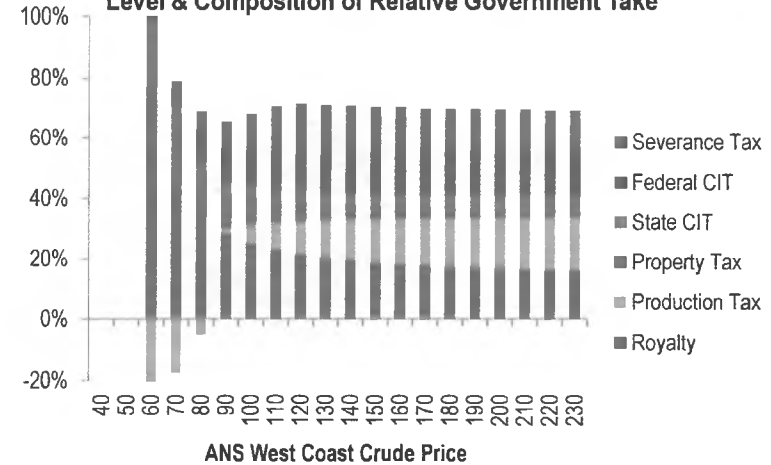
Price	NPV	IRR
\$40	\$ (459)	-8%
\$60	\$ (279)	2%
\$100	\$ (34)	9%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50							
60	77%	-56%	48%	0%	69%	0%	69%
70	44%	-16%	24%	2%	54%	7%	61%
80	34%	1%	16%	3%	53%	11%	64%
90	28%	11%	12%	3%	54%	11%	66%
100	25%	18%	9%	3%	56%	12%	68%
110	23%	25%	8%	3%	59%	12%	70%
120	22%	28%	7%	3%	59%	12%	71%
130	20%	29%	6%	3%	58%	12%	71%
140	19%	29%	5%	3%	57%	13%	71%
150	19%	29%	5%	4%	57%	14%	70%
160	18%	30%	4%	4%	56%	14%	70%
170	18%	30%	4%	4%	55%	14%	70%
180	17%	30%	4%	4%	55%	15%	70%
190	17%	30%	3%	4%	55%	15%	70%
200	17%	30%	3%	4%	54%	15%	70%
210	16%	31%	3%	4%	54%	15%	69%
220	16%	31%	3%	4%	54%	15%	69%
230	16%	31%	3%	4%	54%	16%	69%

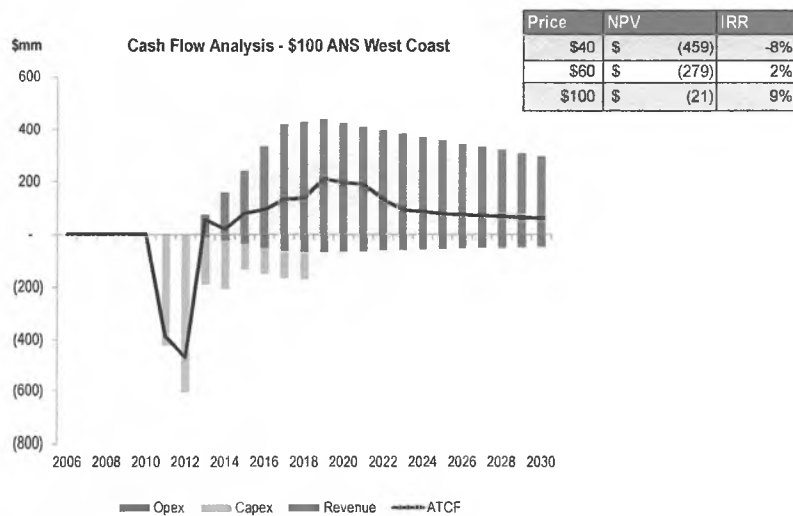
Level & Composition of Government Take



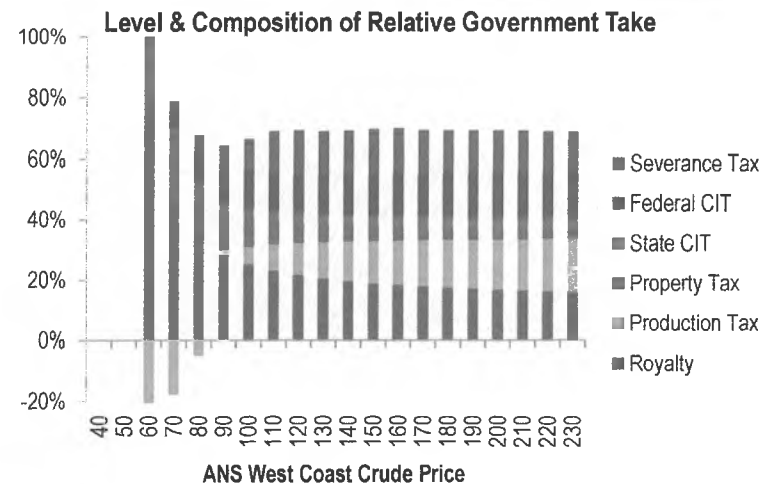
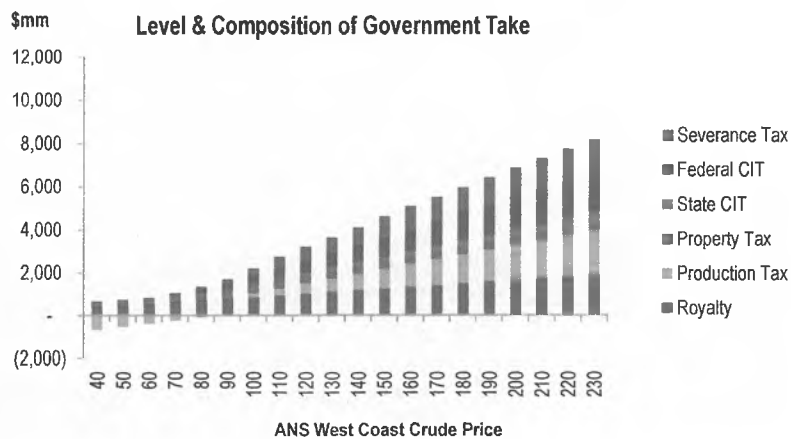
Level & Composition of Relative Government Take



CSSB 192 5% Max Rate, \$90 Threshold, for 10 yrs (\$34/bbl Capex New Development)



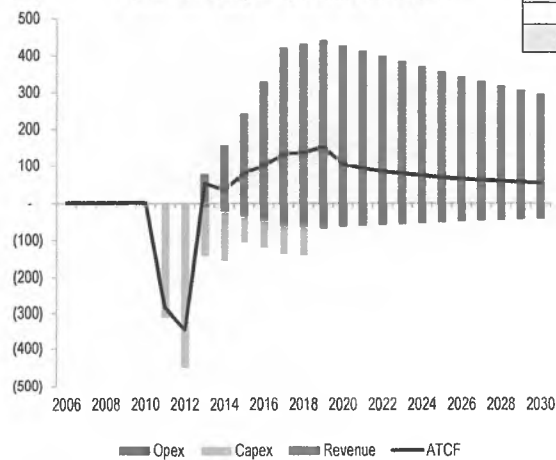
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50							
60	77%	-56%	48%	0%	69%	0%	69%
70	44%	-16%	24%	2%	54%	7%	61%
80	34%	0%	16%	3%	53%	11%	63%
90	28%	10%	12%	3%	53%	11%	65%
100	25%	17%	9%	3%	54%	12%	67%
110	23%	23%	8%	3%	57%	12%	69%
120	22%	26%	7%	3%	57%	12%	69%
130	20%	27%	6%	3%	56%	13%	69%
140	19%	28%	5%	4%	56%	14%	69%
150	19%	29%	5%	4%	56%	14%	70%
160	18%	30%	4%	4%	56%	14%	70%
170	18%	30%	4%	4%	55%	14%	70%
180	17%	30%	4%	4%	55%	15%	70%
190	17%	30%	3%	4%	55%	15%	70%
200	17%	30%	3%	4%	54%	15%	70%
210	16%	31%	3%	4%	54%	15%	69%
220	16%	31%	3%	4%	54%	15%	69%
230	16%	31%	3%	4%	54%	16%	69%



ACES

(\$25/bbl Capex Incremental Development)

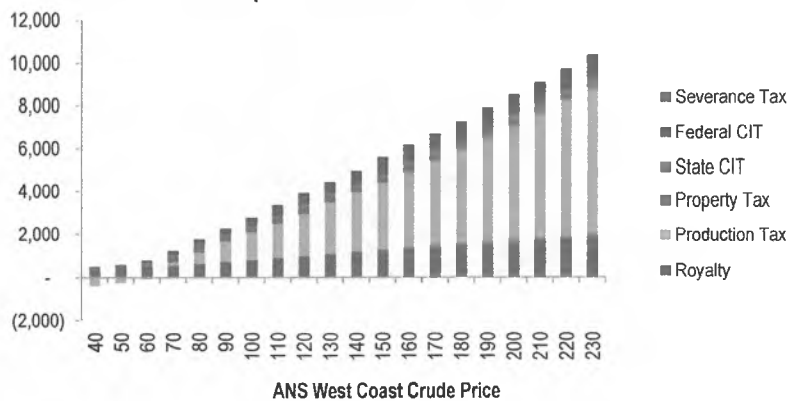
Cash Flow Analysis - \$100 ANS West Coast



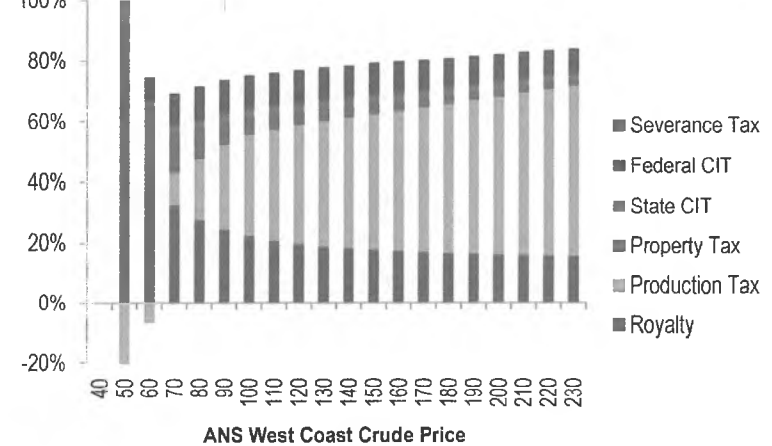
Price	NPV	IRR
\$40	\$ (308)	-5%
\$60	\$ (142)	4%
\$100	\$ 25	11%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50	91%	-60%	50%	0%	81%	0%	81%
60	44%	-7%	21%	2%	60%	8%	68%
70	33%	10%	13%	3%	59%	11%	69%
80	27%	21%	9%	3%	60%	11%	72%
90	24%	29%	7%	3%	63%	11%	74%
100	22%	34%	6%	3%	64%	11%	75%
110	21%	37%	5%	3%	65%	11%	76%
120	20%	39%	5%	3%	66%	11%	77%
130	19%	42%	4%	3%	67%	11%	78%
140	18%	43%	4%	3%	68%	11%	78%
150	18%	45%	3%	3%	69%	11%	79%
160	17%	47%	3%	3%	69%	10%	80%
170	17%	48%	3%	3%	70%	10%	80%
180	16%	50%	3%	3%	71%	10%	81%
190	16%	51%	2%	2%	72%	9%	81%
200	16%	52%	2%	2%	73%	9%	82%
210	16%	54%	2%	2%	74%	9%	83%
220	16%	55%	2%	2%	75%	9%	83%
230	15%	56%	2%	2%	76%	8%	84%

Level & Composition of Government Take

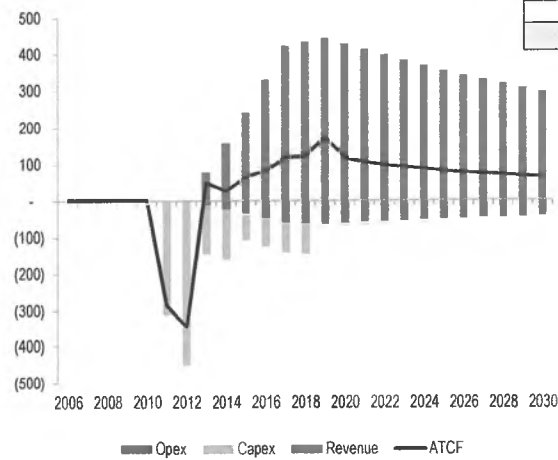


Level & Composition of Relative Government Take



CSSB 192 20% Max Rate (\$25/bbl Capex Incremental Development)

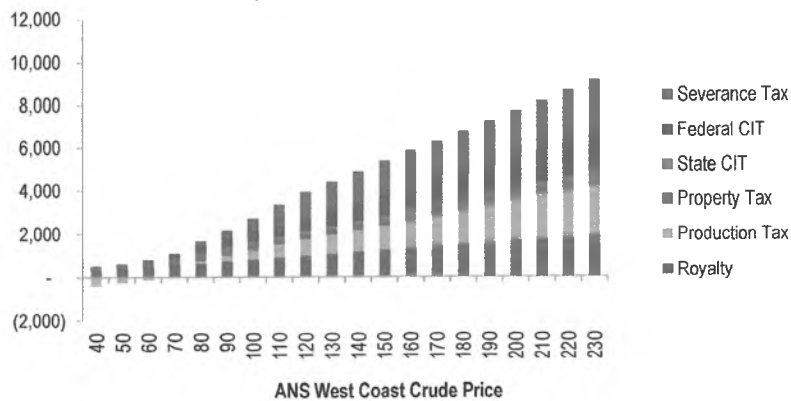
Cash Flow Analysis - \$100 ANS West Coast



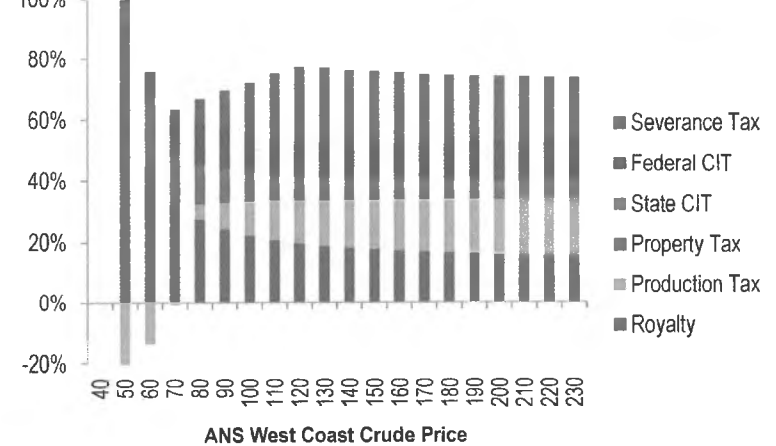
Price	NPV	IRR
\$40	\$ (308)	-5%
\$60	\$ (133)	5%
\$100	\$ 25	11%

Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50	91%	-61%	50%	0%	80%	0%	80%
60	44%	-14%	21%	2%	54%	9%	62%
70	33%	1%	13%	3%	50%	13%	63%
80	27%	13%	9%	4%	53%	14%	67%
90	24%	22%	7%	4%	57%	13%	70%
100	22%	28%	6%	3%	60%	13%	72%
110	21%	35%	5%	3%	64%	12%	76%
120	20%	39%	5%	3%	66%	11%	77%
130	19%	39%	4%	3%	65%	12%	77%
140	18%	39%	4%	3%	64%	12%	76%
150	18%	39%	3%	3%	63%	13%	76%
160	17%	39%	3%	3%	63%	13%	76%
170	17%	39%	3%	3%	62%	13%	75%
180	16%	39%	3%	3%	62%	13%	75%
190	16%	39%	2%	3%	61%	13%	74%
200	16%	39%	2%	3%	61%	13%	74%
210	16%	39%	2%	4%	61%	13%	74%
220	16%	39%	2%	4%	60%	14%	74%
230	15%	39%	2%	4%	60%	14%	74%

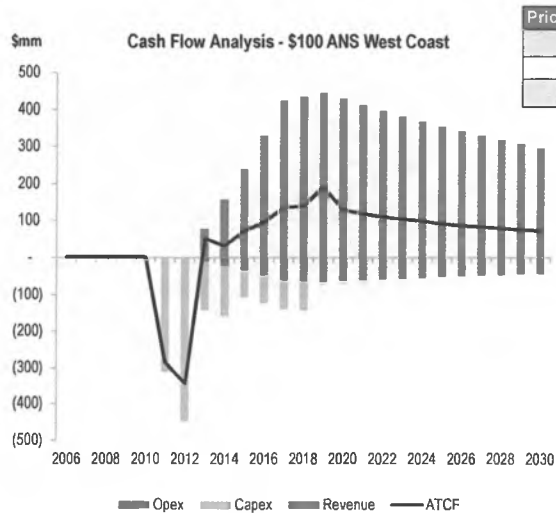
Level & Composition of Government Take



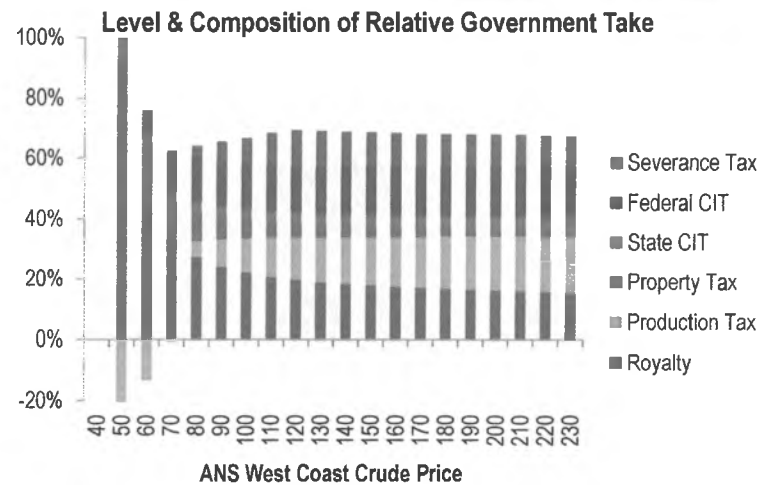
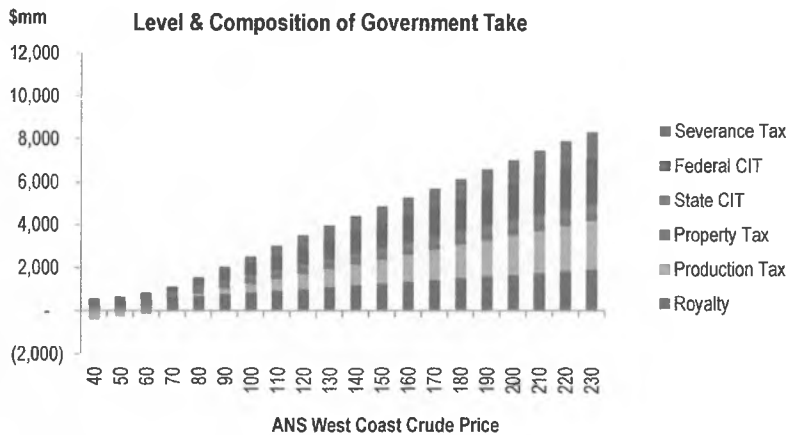
Level & Composition of Relative Government Take



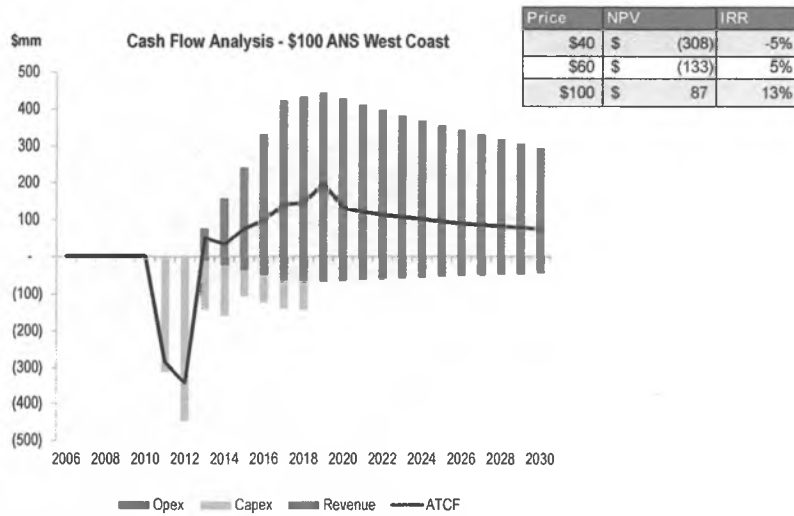
CSSB 192 10% Max Rate (\$25/bbl Capex Incremental Development)



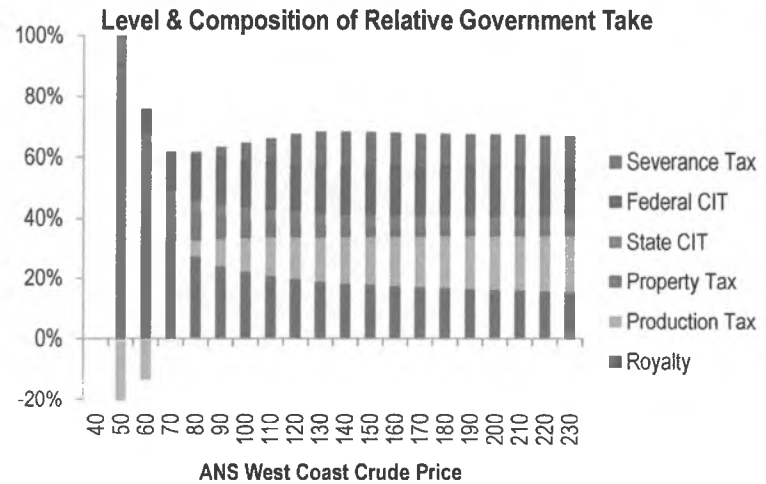
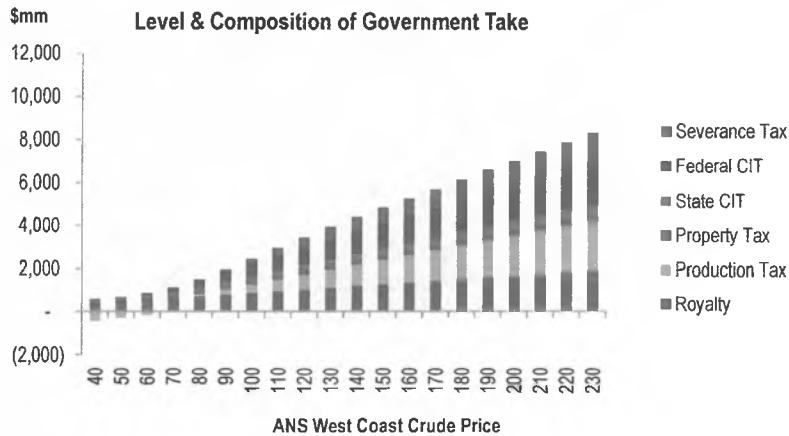
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50	91%	-61%	50%	0%	80%	0%	80%
60	44%	-14%	21%	2%	54%	9%	62%
70	33%	0%	13%	3%	49%	13%	62%
80	27%	9%	9%	4%	50%	14%	64%
90	24%	16%	7%	4%	51%	15%	66%
100	22%	20%	6%	4%	52%	15%	67%
110	21%	24%	5%	4%	54%	15%	68%
120	20%	26%	5%	4%	54%	15%	69%
130	19%	27%	4%	4%	54%	15%	69%
140	18%	28%	4%	4%	53%	15%	69%
150	18%	28%	3%	4%	53%	16%	69%
160	17%	28%	3%	4%	52%	16%	68%
170	17%	28%	3%	4%	52%	16%	68%
180	16%	28%	3%	4%	52%	16%	68%
190	16%	29%	2%	4%	51%	16%	68%
200	16%	29%	2%	4%	51%	17%	68%
210	16%	29%	2%	4%	51%	17%	68%
220	16%	29%	2%	4%	51%	17%	68%
230	15%	29%	2%	4%	51%	17%	67%



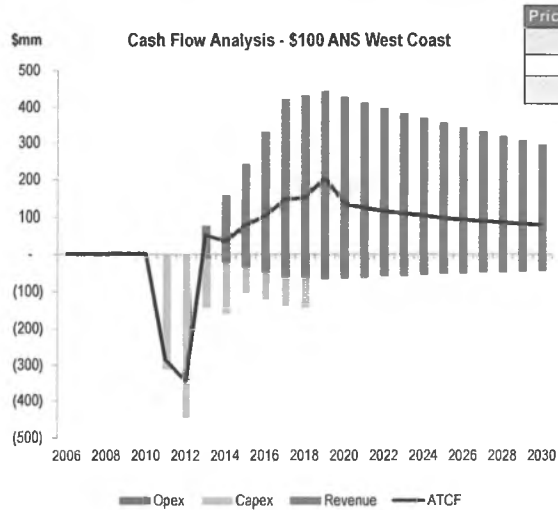
CSSB 192 10% Max Rate, \$70 Threshold (\$25/bbl Capex Incremental Development)



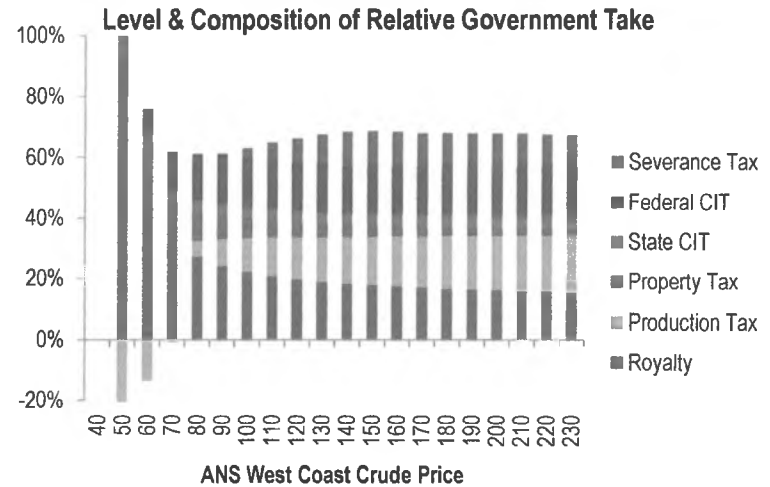
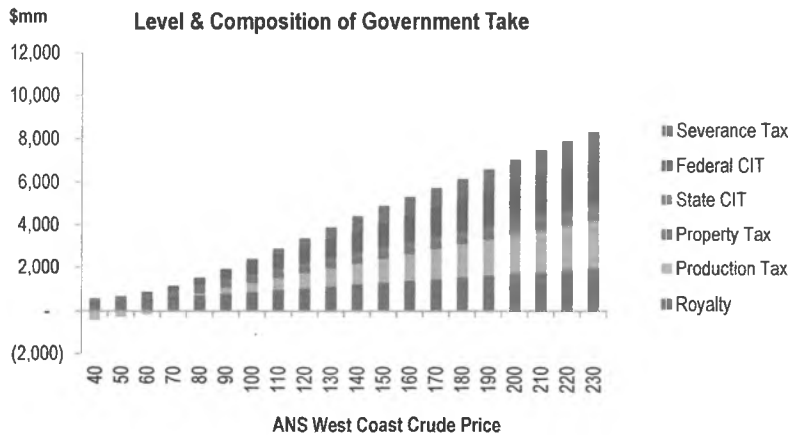
Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50	91%	-61%	50%	0%	80%	0%	80%
60	44%	-14%	21%	2%	54%	9%	62%
70	33%	-1%	13%	3%	48%	13%	61%
80	27%	6%	9%	4%	47%	15%	62%
90	24%	13%	7%	4%	48%	15%	63%
100	22%	17%	6%	4%	50%	15%	65%
110	21%	21%	5%	4%	51%	16%	67%
120	20%	25%	5%	4%	53%	15%	68%
130	19%	27%	4%	4%	54%	15%	69%
140	18%	28%	4%	4%	53%	15%	69%
150	18%	28%	3%	4%	53%	16%	69%
160	17%	28%	3%	4%	52%	16%	68%
170	17%	28%	3%	4%	52%	16%	68%
180	16%	28%	3%	4%	52%	16%	68%
190	16%	29%	2%	4%	51%	16%	68%
200	16%	29%	2%	4%	51%	17%	68%
210	16%	29%	2%	4%	51%	17%	68%
220	16%	29%	2%	4%	51%	17%	68%
230	15%	29%	2%	4%	51%	17%	67%



CSSB 192 10% Max Rate, \$80 Threshold (\$25/bbl Capex Incremental Development)



Price	Royalty	Production Tax	Property Tax	State CIT	Total State Take	Federal CIT	Total GT
40							
50	91%	-61%	50%	0%	80%	0%	80%
60	44%	-14%	21%	2%	54%	9%	62%
70	33%	-1%	13%	3%	48%	13%	61%
80	27%	5%	9%	4%	46%	15%	61%
90	24%	10%	7%	4%	45%	16%	61%
100	22%	15%	6%	4%	47%	16%	63%
110	21%	19%	5%	4%	49%	16%	65%
120	20%	22%	5%	4%	50%	16%	66%
130	19%	25%	4%	4%	52%	16%	68%
140	18%	27%	4%	4%	53%	16%	68%
150	18%	28%	3%	4%	53%	16%	69%
160	17%	28%	3%	4%	52%	16%	68%
170	17%	28%	3%	4%	52%	16%	68%
180	16%	28%	3%	4%	52%	16%	68%
190	16%	29%	2%	4%	51%	16%	68%
200	16%	29%	2%	4%	51%	17%	68%
210	16%	29%	2%	4%	51%	17%	68%
220	16%	29%	2%	4%	51%	17%	68%
230	15%	29%	2%	4%	51%	17%	67%



Comparison of Oil Tax Proposals

	Achieves decoupling	Reduces high levels of support for spending/poor incentives for cost control	Minimizes complexity	Reduces gov take on new/incremental production	No increase on any taxpayers	Revenue neutral at \$100+/bbl	More even split between state and companies above \$100-\$120/bbl
CSSB192	●	●	●	●		●	●
HB110		●		●	●		●
ACES w/40% Cap			●		●	●	●
ACES w/40% Cap & SB305-Style Decoupling	●					●	●

Prepared by Senate Finance - 4/9/2012

32.

CSSB 192 (FIN)

Work Drafts

Version U (4/5/12)

Version O (4/5/12)

Version T (4/2/12)

27-LS1305\U
Bullock
4/5/12

Adopted 4/6/12

CS FOR SENATE BILL NO. 192(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE FINANCE COMMITTEE

**Offered:
Referred:**

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the oil and gas production tax; providing for a minimum tax on oil**
2 **and gas production so that the state receives a minimum production tax of 10 percent of**
3 **the gross value at the point of production for certain oil and gas production; relating to**
4 **that part of the monthly production tax on the gross value at the point of production of**
5 **oil produced by a producer that produced oil in 2008 and 2011 but did not produce a**
6 **volume of taxable oil in excess of a defined target volume or that did not produce taxable**
7 **oil before January 1, 2008, and produced taxable oil for more than seven consecutive**
8 **years during a specified time period, and providing that the applicable tax rate on the**
9 **gross value at the point of production on that category of oil production is 0.27 percent**
10 **multiplied by the number that represents the difference between the average gross value**
11 **at the point of production for a barrel of oil and \$60 or, if the average gross value at the**
12 **point of production is greater than \$60 above the base amount of \$60, that the applicable**

1 tax rate is the sum of 16.2 percent and the product of 0.03 percent multiplied by the
2 number that represents the difference between the average monthly gross value at the
3 point of production for a barrel of oil and \$60 above the base amount of \$60, except that
4 the tax rate applicable to that category of oil production may not exceed 20 percent;
5 relating to that part of the monthly production tax on the gross value at the point of
6 production of oil produced by a producer that produced oil in 2008 and 2011 and
7 produces a volume of taxable oil for the year in excess of a defined target volume, and
8 providing that the applicable tax rate on the gross value at the point of production for
9 that category of oil production is 0.14 percent multiplied by the number that represents
10 the difference between that average monthly gross value at the point of production for a
11 barrel of oil and the base amount of \$60 or, if the average gross value at the point of
12 production is greater than \$60 above the base amount of \$60, that the applicable tax rate
13 is the sum of 16.2 percent and the product of 0.03 percent multiplied by the number that
14 represents the difference between the average monthly gross value at the point of
15 production for a barrel of oil and \$60 above the base amount of \$60, except that the tax
16 rate applicable to that category of oil production may not exceed 20 percent; relating to
17 that part of the tax on the gross value at the point of production of oil produced by a
18 producer during the first seven consecutive years after the start of sustained production
19 or during the first seven consecutive years of sustained production after December 31,
20 2012, whichever is later, from a lease or property containing land that was not or
21 previously had not been within a unit or in commercial production before January 1,
22 2008, and providing that the applicable tax rate on the gross value at the point of
23 production for that category of oil is determined by multiplying the monthly gross value
24 at the point of production of the taxable oil produced during the month by the tax rate

1 **determined by multiplying 0.05 percent by the number that represents the difference**
2 **between that average monthly gross value at the point of production for a barrel of oil**
3 **and the base amount of \$60, except that the tax rate determined for that category of oil**
4 **production may not exceed five percent; relating to payments of the oil and gas**
5 **production tax; relating to an adjustment to the base amount of \$60 based on an**
6 **increase in the United States Consumer Price Index for all urban consumers for the**
7 **most recent year; relating to the allocation of lease expenditures and adjustments to**
8 **lease expenditures; relating to the duties of the Department of Revenue; relating to a**
9 **petroleum information management system; relating to the duties of the Alaska Oil and**
10 **Gas Conservation Commission, the Department of Natural Resources, and the**
11 **Department of Labor and Workforce Development that relate to providing the**
12 **Department of Revenue with certain information relating to oil and gas; and providing**
13 **for an effective date."**

14 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

15 * **Section 1.** AS 43.55.011(e) is amended to read:

16 (e) There is levied on the producer of oil or gas a tax for all oil and gas
17 produced each calendar year from each lease or property in the state, less any oil and
18 gas the ownership or right to which is exempt from taxation or constitutes a
19 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
20 this section, the tax is equal to the sum of

21 (1) the annual production tax value of the taxable oil and gas as
22 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

23 (2) the sum, over all months of the calendar year, of the tax amounts
24 determined under (g) of this section **on the gross value at the point of production of**
25 **oil.**

26 * **Sec. 2.** AS 43.55.011(f) is repealed and reenacted to read:

1 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of
2 this section, the provisions of this subsection apply to oil and gas produced by a
3 producer that had average daily oil and gas production during the most recent calendar
4 year of more than 50,000 BTU equivalent barrels. Notwithstanding any contrary
5 provision of law, a producer may not apply tax credits to reduce its total tax liability
6 under (e) and (g) of this section for oil and gas produced from all leases or properties
7 below 10 percent of the total gross value at the point of production of that oil and gas.
8 If the amount of tax calculated by applying the tax rates in (e) and (g) of this section to
9 the total production tax value of the oil and gas taxable under (e) and (g) of this
10 section produced from all of the producer's leases or properties is less than 10 percent
11 of the total gross value at the point of production of that oil and gas, the tax levied by
12 (e) and (g) of this section for that oil and gas is equal to 10 percent of the total gross
13 value at the point of production of that oil and gas.

14 * **Sec. 3.** AS 43.55.011(g) is repealed and reenacted to read:

15 (g) For each month of the calendar year for which the producer's average
16 monthly gross value at the point of production for a barrel of taxable oil is above the
17 base amount of \$60, the producer shall determine the tax for the purposes of (e)(2) of
18 this section as follows:

19 (1) for oil not subject to (2) or (3) of this subsection produced by a
20 producer that produced oil in 2008 and 2011, for oil not subject to (3) of this
21 subsection produced by a producer who did not produce oil in 2008 and 2011, and for
22 oil production that was subject to (3) of this subsection but is no longer subject to (3)
23 of this subsection, the amount of tax is determined by multiplying the monthly gross
24 value at the point of production of the taxable oil produced during the month by the
25 tax rate calculated as follows:

26 (A) if the producer's average monthly gross value at the point
27 of production for a barrel of the taxable oil for the month is not more than \$60
28 above the base amount of \$60, the tax rate is 0.27 percent multiplied by the
29 number that represents the difference between that average monthly gross
30 value at the point of production for a barrel of oil and the base amount of \$60;
31 or

1 (B) if the producer's average monthly gross value at the point
2 of production for a barrel of taxable oil is more than \$60 above the base
3 amount of \$60, the tax rate is the sum of 16.2 percent and the product of 0.03
4 percent multiplied by the number that represents the difference between the
5 average monthly gross value at the point of production for a barrel of oil and
6 \$60 above the base amount of \$60, except that the tax rate determined under
7 this subparagraph may not exceed 20 percent;

8 (2) for oil not subject to (3) of this subsection produced by a producer
9 that produced taxable oil in 2008 and 2011 that is in excess of the target volume
10 determined under (q) of this section, the amount of tax on the volume of oil above the
11 target volume is determined by multiplying the monthly gross value at the point of
12 production of the taxable oil produced during the month by the tax rate calculated as
13 follows:

14 (A) if the producer's average monthly gross value at the point
15 of production for a barrel of the taxable oil for the month is not more than \$60
16 above the base amount of \$60, the tax rate is 0.14 percent multiplied by the
17 number that represents the difference between that average monthly gross
18 value at the point of production for a barrel of oil and the base amount of \$60;
19 or

20 (B) if the producer's average monthly gross value at the point
21 of production for a barrel of taxable oil is more than \$60 above the base
22 amount of \$60, the tax rate is the sum of 8.4 percent and the product of 0.03
23 percent multiplied by the number that represents the difference between the
24 average monthly gross value at the point of production for a barrel of oil and
25 \$60 above the base amount of \$60, except that the tax rate determined under
26 this subparagraph may not exceed 10 percent;

27 (3) for oil produced by a producer during the first seven consecutive
28 years after the start of sustained production or during the first seven consecutive years
29 of sustained production after December 31, 2012, whichever is later, from a lease or
30 property containing land that was not or previously had not been within a unit or in
31 commercial production before January 1, 2008, the amount of tax is determined by

1 multiplying the monthly gross value at the point of production of the taxable oil
2 produced during the month by the tax rate determined by multiplying 0.05 percent by
3 the number that represents the difference between that average monthly gross value at
4 the point of production for a barrel of oil and \$60, except that the tax rate determined
5 under this paragraph may not exceed five percent; after the rate determination of this
6 paragraph no longer applies, oil produced from a lease or property that was subject to
7 the rate determination under this paragraph is subject to the rate determination under
8 (1) of this subsection; in this paragraph, "sustained production" has the meaning given
9 in AS 43.55.025(l).

10 * **Sec. 4.** AS 43.55.011 is amended by adding new subsections to read:

11 (p) Beginning on March 1, 2014, and on March 1 of each year thereafter, the
12 commissioner shall adjust the base amount of \$60 in (g) of this section by the percent
13 increase in the annual United States Consumer Price Index for all urban consumers for
14 the most recent year. The index for January 2013 is the reference base index. The
15 commissioner shall publish the percent increase and the adjusted base amount on the
16 department's Internet website as soon as is practicable after the commissioner
17 determines the adjusted base amount. The adjustment made by the commissioner is
18 retroactive to January 1 of the year in which the adjustment is made. The department
19 shall adopt a regulation providing for the payment of the increase in an installment
20 payment required under AS 43.55.020(a) that results from the retroactive application
21 of the adjustment to the base amount of \$60 in (g) of this section.

22 (q) When determining whether a producer is subject to (g)(1) or (2) of this
23 section,

24 (1) the target volume is determined under the following formula,
25 where V is the volume of the oil produced by the producer in 2011, D is the decline
26 percentage calculated by taking the cube root of the ratio of the volume of taxable oil
27 produced by the producer in 2011 to the volume of taxable oil produced by the
28 producer in 2008, and Y is the year, expressed in four digits, for which the target
29 volume is being determined:

30
$$\text{Target Volume} = V \times D^{(Y - 2011)}; \text{ and}$$

31 (2) the target volume for a producer that increases its volume of

1 production through the purchase, merger, or other acquisition of another producer is
2 the sum of the producer's target volume and the target volume for the producer that is
3 purchased, merged with, or otherwise acquired; however, if the producer that is
4 purchased, merged with, or otherwise acquired did not have production in 2008 and
5 2011, the volume of the increased production that is attributable to the purchase,
6 merger, or other acquisition may not be considered for the purpose of determining
7 whether the producer that acquired the additional production has increased the volume
8 of production above its target volume.

9 * **Sec. 5.** AS 43.55.020(a) is amended to read:

10 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
11 shall pay the tax as follows:

12 (1) an installment payment of the estimated tax levied by
13 AS 43.55.011(e) **and (g)**, net of any tax credits applied as allowed by law, is due for
14 each month of the calendar year on the last day of the following month; except as
15 otherwise provided under (2) of this subsection, the amount of the installment payment
16 is the sum of the following amounts, less 1/12 of the tax credits that are allowed by
17 law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but
18 the amount of the installment payment may not be less than zero:

19 (A) for oil and gas produced from leases or properties in the
20 state outside the Cook Inlet sedimentary basin but not subject to
21 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
22 greater of

23 (i) zero; or

24 (ii) the sum of **the tax determined under**
25 **AS 43.55.011(g) on the gross value at the point of production for oil**
26 **produced for the month added to the product of 25 percent and**
27 **[THE TAX RATE CALCULATED FOR THE MONTH UNDER**
28 **AS 43.55.011(g) MULTIPLIED BY]** the remainder obtained by
29 subtracting 1/12 of the producer's adjusted lease expenditures for the
30 calendar year of production under AS 43.55.165 and 43.55.170 that are
31 deductible for the leases or properties under AS 43.55.160 from the

1 gross value at the point of production of the oil and gas produced from
2 the leases or properties during the month for which the installment
3 payment is calculated;

4 (B) for oil and gas produced from leases or properties subject
5 to AS 43.55.011(f), the **greater** [GREATEST] of

6 (i) **10 percent of the gross value at the point of**
7 **production for oil and gas described in AS 43.55.011(f)** [ZERO];

8 (ii) ZERO PERCENT, ONE PERCENT, TWO
9 PERCENT, THREE PERCENT, OR FOUR PERCENT, AS
10 APPLICABLE, OF THE GROSS VALUE AT THE POINT OF
11 PRODUCTION OF THE OIL AND GAS] produced [FROM ALL
12 LEASES OR PROPERTIES] during the month for which the
13 installment payment is calculated; or

14 (ii) [(iii)] the sum of **the tax determined under**
15 **AS 43.55.011(g) on the gross value at the point of production for oil**
16 **produced for the month added to the product of** 25 percent and the
17 tax rate calculated for the month under AS 43.55.011(g)
18 [MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
19 producer's adjusted lease expenditures for the calendar year of
20 production under AS 43.55.165 and 43.55.170 that are deductible for
21 those leases or properties under AS 43.55.160 from the gross value at
22 the point of production of the oil and gas produced from those leases or
23 properties during the month for which the installment payment is
24 calculated;

25 (C) for oil and gas produced from each lease or property
26 subject to AS 43.55.011(j), (k), or (o), the greater of

27 (i) zero; or

28 (ii) the sum of **the tax determined under**
29 **AS 43.55.011(g) on the gross value at the point of production for**
30 **the oil produced for the month added to the product of** 25 percent
31 and [THE TAX RATE CALCULATED FOR THE MONTH UNDER

1 AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by
2 subtracting 1/12 of the producer's adjusted lease expenditures for the
3 calendar year of production under AS 43.55.165 and 43.55.170 that are
4 deductible under AS 43.55.160 for oil or gas, respectively, produced
5 from the lease or property from the gross value at the point of
6 production of the oil or gas, respectively, produced from the lease or
7 property during the month for which the installment payment is
8 calculated;

9 (2) an amount calculated under (1)(C) of this subsection for oil or gas
10 produced from a lease or property subject to AS 43.55.011(j), (k), or (o) may not
11 exceed the product obtained by carrying out the calculation set out in
12 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
13 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
14 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
15 gas produced during the month for the amount of taxable gas produced during the
16 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
17 amount of taxable oil produced during the month for the amount of taxable oil
18 produced during the calendar year;

19 (3) an installment payment of the estimated tax levied by
20 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
21 on the last day of the following month; the amount of the installment payment is the
22 sum of

23 (A) the applicable tax rate for oil provided under
24 AS 43.55.011(i), multiplied by the gross value at the point of production of the
25 oil taxable under AS 43.55.011(i) and produced from the lease or property
26 during the month; and

27 (B) the applicable tax rate for gas provided under
28 AS 43.55.011(i), multiplied by the gross value at the point of production of the
29 gas taxable under AS 43.55.011(i) and produced from the lease or property
30 during the month;

31 (4) any amount of tax levied by AS 43.55.011(e) and (g) or (i), net of

1 any credits applied as allowed by law, that exceeds the total of the amounts due as
2 installment payments of estimated tax is due on March 31 of the year following the
3 calendar year of production.

4 * **Sec. 6.** AS 43.55.160(c) is amended to read:

5 (c) Notwithstanding any contrary provision of AS 43.55.150, for purposes of
6 calculating **the tax due under AS 43.55.011(g)** [A MONTHLY PRODUCTION TAX
7 VALUE UNDER (a)(2) OF THIS SECTION], the gross value at the point of
8 production of the oil and gas is calculated under regulations adopted by the department
9 that provide for using an appropriate monthly share of the producer's costs of
10 transportation for the calendar year.

11 * **Sec. 7.** AS 43.55.160 is amended by adding new subsections to read:

12 (f) For purposes of (a) of this section, a lease expenditure is applicable to oil
13 or gas produced from a lease or property, or to oil or gas produced from leases or
14 properties in an area of the state, if the lease expenditure is

15 (1) a cost to explore, develop, or produce oil or gas from that lease or
16 property, or to explore, develop, or produce oil or gas from one of those leases or
17 properties in that area of the state, respectively; and

18 (2) incurred on or after the commencement of commercial production
19 of oil or gas from the lease or property.

20 (g) For purposes of (a) of this section, a lease expenditure incurred during a
21 calendar year to explore land that is not a lease or property, or to explore or develop a
22 lease or property before commencement of commercial production of oil or gas from
23 the lease or property, shall be allocated as provided in a regulation adopted by the
24 department under AS 43.55.165(h) to and among oil, gas subject to AS 43.55.011(o),
25 and gas not subject to AS 43.55.011(o) produced by the producer during that calendar
26 year from leases or properties in the same area of the state as the land being explored
27 or the lease or property being explored or developed, respectively.

28 (h) For purposes of (f) and (g) of this section, an area of the state is one of the
29 following:

30 (1) land north of 68 degrees North latitude;

31 (2) land outside the Cook Inlet sedimentary basin not including any

1 land north of 68 degrees North latitude; or

2 (3) the Cook Inlet sedimentary basin.

3 * **Sec. 8.** AS 43.55.165(h) is amended to read:

4 (h) The department shall adopt regulations that provide for reasonable
5 methods of allocating costs between oil and gas, between gas subject to
6 AS 43.55.011(o) and other gas, and between leases or properties in those
7 circumstances where an allocation of costs is required to determine lease expenditures
8 that are costs of exploring for, developing, or producing oil deposits or costs of
9 exploring for, developing, or producing gas deposits, or that are costs of exploring for,
10 developing, or producing oil or gas deposits located within different leases or
11 properties. **When adopting a regulation for determining a reasonable method of**
12 **allocating lease expenditures between the production of oil and the production of**
13 **gas, the department shall, to the extent possible, provide for the allocation of**
14 **lease expenditures in proportion to the gross value at the point of production for**
15 **oil produced and gas produced.**

16 * **Sec. 9.** AS 43.55.170 is amended by adding a new subsection to read:

17 (d) The department shall adopt regulations that provide for reasonable
18 methods of allocating the adjustments to a producer's lease expenditures in (a) of this
19 section and the payments and credits described in (b) of this section between oil and
20 gas, between gas subject to AS 43.55.011(o) and other gas, and between leases or
21 properties in those circumstances where an allocation of costs is required to determine
22 lease expenditures that are costs of exploring for, developing, or producing oil
23 deposits, or costs of exploring for, developing, or producing gas deposits, or that are
24 costs of exploring for, developing, or producing oil or gas deposits located within
25 different leases or properties. When determining a reasonable method of allocating the
26 adjustments to a producer's lease expenditures between the production of oil and the
27 production of gas, the department shall consider allocating the adjustments in
28 proportion to the lease expenditures allocated to the production of oil and the
29 production of gas under regulations adopted by the department under
30 AS 43.55.165(h).

31 * **Sec. 10.** AS 44.25 is amended by adding a new section to read:

1 **Sec. 44.25.025. Petroleum information management system.** (a) The
2 Department of Revenue shall develop and maintain an electronic petroleum
3 information management system to collect, secure, distribute, store, retrieve, and
4 archive information related to oil and gas exploration, development, and production in
5 the state. The purposes of the petroleum information management system are to
6 improve the administration of the oil and gas production tax and to facilitate
7 exploration, development, and production of oil and gas resources. The petroleum
8 information management system shall be accessible by the public.

9 (b) To the extent the information is available and is not confidential, the
10 petroleum information management system must include the following information:

- 11 (1) unit and joint operating agreements;
12 (2) state oil and gas exploration licenses and oil and gas leases;
13 (3) for exploration activities,
14 (A) exploration work programs and budgets;
15 (B) seismic data;
16 (C) drilling reports;
17 (D) logs;
18 (E) well tests;
19 (F) geological models and maps;
20 (4) for development activities,
21 (A) development plans with operating and capital expenditure
22 projections;
23 (B) construction progress reports;
24 (C) drilling reports;
25 (D) reservoir characterization;
26 (5) for production activities,
27 (A) production work programs and budgets;
28 (B) oil and gas sales, revenue, and pricing;
29 (C) transportation agreements;
30 (D) production data;
31 (E) injection data;

1 (F) operating and capital expenditures;

2 (G) facility maps and studies;

3 (6) for abandonment of oil and gas wells, leases, and production and
4 transportation facilities,

5 (A) abandonment plans and budgets;

6 (B) progress reports;

7 (7) for oil and gas related employment information,

8 (A) the number of resident and nonresident hires for each year;

9 (B) training opportunities; and

10 (8) other information the Department of Revenue determines necessary
11 and relevant to the oil and gas production tax and to the exploration, development, and
12 production of oil and gas resources.

13 (c) The Alaska Oil and Gas Conservation Commission, the Department of
14 Natural Resources, and the Department of Labor and Workforce Development, in
15 consultation with the Department of Revenue, shall provide information described in
16 (b) of this section that is not confidential and within the control of the commission and
17 each department to the Department of Revenue for inclusion in the petroleum
18 information management system. The information provided by the Alaska Oil and Gas
19 Conservation Commission or by a department under this subsection shall be in a form
20 suitable for the Department of Revenue to include in the petroleum information
21 management system.

22 * **Sec. 11.** AS 43.55.160(a)(2) is repealed.

23 * **Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to
24 read:

25 **IMPLEMENTATION OF THE PETROLEUM INFORMATION MANAGEMENT**
26 **SYSTEM.** The Department of Revenue shall develop and implement a work plan for the
27 development of the petroleum information management system required by AS 44.25.025,
28 enacted by sec. 10 of this Act, so that the system is operational before January 1, 2014.

29 * **Sec. 13.** Sections 1 - 9 and 11 of this Act take effect January 1, 2013.

30 * **Sec. 14.** Except as provided in sec. 13 of this Act, this Act takes effect immediately under
31 AS 01.10.070(c).

adopted 4/5/12

27-LS1305\O
Bullock
4/5/12

CS FOR SENATE BILL NO. 192(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE FINANCE COMMITTEE

Offered:

Referred:

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the oil and gas production tax; providing for a minimum tax on oil**
2 **and gas production so that the state receives a minimum production tax of 10 percent of**
3 **the gross value at the point of production for certain oil and gas production; relating to**
4 **that part of the monthly production tax on the gross value at the point of production of**
5 **oil produced by a producer that produced oil in 2008 and 2011 but did not produce a**
6 **volume of taxable oil in excess of a defined target volume or that did not produce taxable**
7 **oil before January 1, 2008, and produced taxable oil for more than seven consecutive**
8 **years during a specified time period, and providing that the applicable tax rate on the**
9 **gross value at the point of production on that category of oil production is 0.27 percent**
10 **multiplied by the number that represents the difference between the average gross value**
11 **at the point of production for a barrel of oil and \$60 or, if the average gross value at the**
12 **point of production is greater than \$60 above the base amount of \$60, that the applicable**

1 tax rate is the sum of 16.2 percent and the product of 0.03 percent multiplied by the
2 number that represents the difference between the average monthly gross value at the
3 point of production for a barrel of oil and \$60 above the base amount of \$60, except that
4 the tax rate applicable to that category of oil production may not exceed 20 percent;
5 relating to that part of the monthly production tax on the gross value at the point of
6 production of oil produced by a producer that produced oil in 2008 and 2011 and
7 produces a volume of taxable oil for the year in excess of a defined target volume, and
8 providing that the applicable tax rate on the gross value at the point of production for
9 that category of oil production is 0.14 percent multiplied by the number that represents
10 the difference between that average monthly gross value at the point of production for a
11 barrel of oil and the base amount of \$60 or, if the average gross value at the point of
12 production is greater than \$60 above the base amount of \$60, that the applicable tax rate
13 is the sum of 16.2 percent and the product of 0.03 percent multiplied by the number that
14 represents the difference between the average monthly gross value at the point of
15 production for a barrel of oil and \$60 above the base amount of \$60, except that the tax
16 rate applicable to that category of oil production may not exceed 20 percent; relating to
17 that part of the tax on the gross value at the point of production of oil produced by a
18 producer during the first seven consecutive years after the start of sustained production
19 or during the first seven consecutive years of sustained production after December 31,
20 2012, whichever is later, from a lease or property containing land that was not or
21 previously had not been within a unit or in commercial production before January 1,
22 2008, and providing that the applicable tax rate on the gross value at the point of
23 production for that category of oil is determined by multiplying the monthly gross value
24 at the point of production of the taxable oil produced during the month by the tax rate

1 determined by multiplying 0.05 percent by the number that represents the difference
2 between that average monthly gross value at the point of production for a barrel of oil
3 and the base amount of \$60, except that the tax rate determined for that category of oil
4 production may not exceed five percent; relating to payments of the oil and gas
5 production tax; relating to an adjustment to the base amount of \$60 based on an
6 increase in the United States Consumer Price Index for all urban consumers for the
7 most recent year; relating to the allocation of lease expenditures and adjustments to
8 lease expenditures; relating to the duties of the Department of Revenue; relating to a
9 petroleum information management system; relating to the duties of the Alaska Oil and
10 Gas Conservation Commission, the Department of Natural Resources, and the
11 Department of Labor and Workforce Development that relate to providing the
12 Department of Revenue with certain information relating to oil and gas; and providing
13 for an effective date."

14 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

15 * **Section 1.** AS 43.55.011(e) is amended to read:

16 (e) There is levied on the producer of oil or gas a tax for all oil and gas
17 produced each calendar year from each lease or property in the state, less any oil and
18 gas the ownership or right to which is exempt from taxation or constitutes a
19 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
20 this section, the tax is equal to the sum of

21 (1) the annual production tax value of the taxable oil and gas as
22 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

23 (2) the sum, over all months of the calendar year, of the tax amounts
24 determined under (g) of this section on the gross value at the point of production of
25 oil.

26 * **Sec. 2.** AS 43.55.011(f) is repealed and reenacted to read:

1 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of
2 this section, the provisions of this subsection apply to oil and gas produced by a
3 producer that had average daily oil and gas production during the most recent calendar
4 year of more than 50,000 BTU equivalent barrels. Notwithstanding any contrary
5 provision of law, a producer may not apply tax credits to reduce its total tax liability
6 under (e) and (g) of this section for oil and gas produced from all leases or properties
7 below 10 percent of the total gross value at the point of production of that oil and gas.
8 If the amount of tax calculated by applying the tax rates in (e) and (g) of this to the
9 total production tax value of the oil and gas taxable under (e) and (g) of this section
10 produced from all of the producer's leases or properties is less than 10 percent of the
11 total gross value at the point of production of that oil and gas, the tax levied by (e) and
12 (g) of this section for that oil and gas is equal to 10 percent of the total gross value at
13 the point of production of that oil and gas.

14 * **Sec. 3.** AS 43.55.011(g) is repealed and reenacted to read:

15 (g) For each month of the calendar year for which the producer's average
16 monthly gross value at the point of production for a barrel of taxable oil is above the
17 base amount of \$60, the producer shall determine the tax for the purposes of (e)(2) of
18 this section as follows:

19 (1) for oil not subject to (3) of this subsection produced by a producer
20 that produced oil in 2008 and 2011 but failed to produce a volume of taxable oil for
21 the year in excess of the target volume determined under (q) of this section, for oil not
22 subject to (3) of this subsection produced by a producer who did not produce oil in
23 2008 and 2011, and for oil production that was subject to (3) of this subsection but is
24 no longer subject to (3) of this subsection, the amount of tax is determined by
25 multiplying the monthly gross value at the point of production of the taxable oil
26 produced during the month by the tax rate calculated as follows:

27 (A) if the producer's average monthly gross value at the point
28 of production for a barrel of the taxable oil for the month is not more than \$60
29 above the base amount of \$60, the tax rate is 0.27 percent multiplied by the
30 number that represents the difference between that average monthly gross
31 value at the point of production for a barrel of oil and the base amount of \$60;

1 or

2 (B) if the producer's average monthly gross value at the point
3 of production for a barrel of taxable oil is more than \$60 above the base
4 amount of \$60, the tax rate is the sum of 16.2 percent and the product of 0.03
5 percent multiplied by the number that represents the difference between the
6 average monthly gross value at the point of production for a barrel of oil and
7 \$60 above the base amount of \$60, except that the tax rate determined under
8 this subparagraph may not exceed 20 percent;

9 (2) for oil not subject to (3) of this subsection produced by a producer
10 that produced taxable oil in 2008 and 2011 and produces a volume of taxable oil for
11 the year in excess of the target volume determined under (q) of this section, the
12 amount of tax is determined by multiplying the monthly gross value at the point of
13 production of the taxable oil produced during the month by the tax rate calculated as
14 follows:

15 (A) if the producer's average monthly gross value at the point
16 of production for a barrel of the taxable oil for the month is not more than \$60
17 above the base amount of \$60, the tax rate is 0.14 percent multiplied by the
18 number that represents the difference between that average monthly gross
19 value at the point of production for a barrel of oil and the base amount of \$60;

20 or

21 (B) if the producer's average monthly gross value at the point
22 of production for a barrel of taxable oil is more than \$60 above the base
23 amount of \$60, the tax rate is the sum of 8.4 percent and the product of 0.03
24 percent multiplied by the number that represents the difference between the
25 average monthly gross value at the point of production for a barrel of oil and
26 \$60 above the base amount of \$60, except that the tax rate determined under
27 this subparagraph may not exceed 10 percent;

28 (3) for oil produced by a producer during the first seven consecutive
29 years after the start of sustained production or during the first seven consecutive years
30 of sustained production after December 31, 2012, whichever is later, from a lease or
31 property containing land that was not or previously had not been within a unit or in

1 commercial production before January 1, 2008, the amount of tax is determined by
 2 multiplying the monthly gross value at the point of production of the taxable oil
 3 produced during the month by the tax rate determined by multiplying 0.05 percent by
 4 the number that represents the difference between that average monthly gross value at
 5 the point of production for a barrel of oil and \$60, except that the tax rate determined
 6 under this paragraph may not exceed five percent; after the rate determination of this
 7 paragraph no longer applies, oil produced from a lease or property that was subject to
 8 the rate determination under this paragraph is subject to the rate determination under
 9 (1) of this subsection; in this paragraph, "sustained production" has the meaning given
 10 in AS 43.55.025(l).

11 * **Sec. 4.** AS 43.55.011 is amended by adding new subsections to read:

12 (p) Beginning on March 1, 2014, and on March 1 of each year thereafter, the
 13 commissioner shall adjust the base amount of \$60 in (g) of this section by the percent
 14 increase in the annual United States Consumer Price Index for all urban consumers for
 15 the most recent year. The index for January 2013 is the reference base index. The
 16 commissioner shall publish the percent increase and the adjusted base amount on the
 17 department's Internet website as soon as is practicable after the commissioner
 18 determines the adjusted base amount. The adjustment made by the commissioner is
 19 retroactive to January 1 of the year in which the adjustment is made. The department
 20 shall adopt a regulation providing for the payment of the increase in an installment
 21 payment required under AS 43.55.020(a) that results from the retroactive application
 22 of the adjustment to the base amount of \$60 in (g) of this section.

23 (q) For purposes of determining whether a producer is subject to (g)(1) or (2)
 24 of this section, the target volume is determined under the following formula, where V
 25 is the volume of the oil produced by the producer in 2011, D is the decline percentage
 26 calculated by taking the cube root of the ratio of the volume of taxable oil produced by
 27 the producer in 2011 to the volume of taxable oil produced by the producer in 2008,
 28 and Y is the year, expressed in four digits, for which the target volume is being
 29 determined:

$$\text{Target Volume} = V \times D^{(Y - 2011)}$$

30
 31 * **Sec. 5.** AS 43.55.020(a) is amended to read:

1 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
2 shall pay the tax as follows:

3 (1) an installment payment of the estimated tax levied by
4 AS 43.55.011(e) **and (g)**, net of any tax credits applied as allowed by law, is due for
5 each month of the calendar year on the last day of the following month; except as
6 otherwise provided under (2) of this subsection, the amount of the installment payment
7 is the sum of the following amounts, less 1/12 of the tax credits that are allowed by
8 law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but
9 the amount of the installment payment may not be less than zero:

10 (A) for oil and gas produced from leases or properties in the
11 state outside the Cook Inlet sedimentary basin but not subject to
12 AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the
13 greater of

14 (i) zero; or

15 (ii) the sum of **the tax determined under**
16 **AS 43.55.011(g) on the gross value at the point of production for oil**
17 **produced for the month added to the product of 25 percent and**
18 **[THE TAX RATE CALCULATED FOR THE MONTH UNDER**
19 **AS 43.55.011(g) MULTIPLIED BY]** the remainder obtained by
20 subtracting 1/12 of the producer's adjusted lease expenditures for the
21 calendar year of production under AS 43.55.165 and 43.55.170 that are
22 deductible for the leases or properties under AS 43.55.160 from the
23 gross value at the point of production of the oil and gas produced from
24 the leases or properties during the month for which the installment
25 payment is calculated;

26 (B) for oil and gas produced from leases or properties subject
27 to AS 43.55.011(f), the **greater** [GREATEST] of

28 (i) **10 percent of the gross value at the point of**
29 **production for oil and gas described in AS 43.55.011(f)** [ZERO;

30 (ii) ZERO PERCENT, ONE PERCENT, TWO
31 PERCENT, THREE PERCENT, OR FOUR PERCENT, AS

1 APPLICABLE, OF THE GROSS VALUE AT THE POINT OF
2 PRODUCTION OF THE OIL AND GAS] produced [FROM ALL
3 LEASES OR PROPERTIES] during the month for which the
4 installment payment is calculated; or

5 (ii) [(iii)] the sum of the tax determined under
6 AS 43.55.011(g) on the gross value at the point of production for oil
7 produced for the month added to the product of 25 percent and the
8 tax rate calculated for the month under AS 43.55.011(g)
9 [MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
10 producer's adjusted lease expenditures for the calendar year of
11 production under AS 43.55.165 and 43.55.170 that are deductible for
12 those leases or properties under AS 43.55.160 from the gross value at
13 the point of production of the oil and gas produced from those leases or
14 properties during the month for which the installment payment is
15 calculated;

16 (C) for oil and gas produced from each lease or property
17 subject to AS 43.55.011(j), (k), or (o), the greater of

18 (i) zero; or

19 (ii) the sum of the tax determined under
20 AS 43.55.011(g) on the gross value at the point of production for
21 the oil produced for the month added to the product of 25 percent
22 and [THE TAX RATE CALCULATED FOR THE MONTH UNDER
23 AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by
24 subtracting 1/12 of the producer's adjusted lease expenditures for the
25 calendar year of production under AS 43.55.165 and 43.55.170 that are
26 deductible under AS 43.55.160 for oil or gas, respectively, produced
27 from the lease or property from the gross value at the point of
28 production of the oil or gas, respectively, produced from the lease or
29 property during the month for which the installment payment is
30 calculated;

31 (2) an amount calculated under (1)(C) of this subsection for oil or gas

1 produced from a lease or property subject to AS 43.55.011(j), (k), or (o) may not
2 exceed the product obtained by carrying out the calculation set out in
3 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
4 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in
5 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
6 gas produced during the month for the amount of taxable gas produced during the
7 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
8 amount of taxable oil produced during the month for the amount of taxable oil
9 produced during the calendar year;

10 (3) an installment payment of the estimated tax levied by
11 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
12 on the last day of the following month; the amount of the installment payment is the
13 sum of

14 (A) the applicable tax rate for oil provided under
15 AS 43.55.011(i), multiplied by the gross value at the point of production of the
16 oil taxable under AS 43.55.011(i) and produced from the lease or property
17 during the month; and

18 (B) the applicable tax rate for gas provided under
19 AS 43.55.011(i), multiplied by the gross value at the point of production of the
20 gas taxable under AS 43.55.011(i) and produced from the lease or property
21 during the month;

22 (4) any amount of tax levied by AS 43.55.011(e) **and (g)** or (i), net of
23 any credits applied as allowed by law, that exceeds the total of the amounts due as
24 installment payments of estimated tax is due on March 31 of the year following the
25 calendar year of production.

26 * **Sec. 6.** AS 43.55.160(c) is amended to read:

27 (c) Notwithstanding any contrary provision of AS 43.55.150, for purposes of
28 calculating **the tax due under AS 43.55.011(g)** [A MONTHLY PRODUCTION TAX
29 VALUE UNDER (a)(2) OF THIS SECTION], the gross value at the point of
30 production of the oil and gas is calculated under regulations adopted by the department
31 that provide for using an appropriate monthly share of the producer's costs of

1 transportation for the calendar year.

2 * **Sec. 7.** AS 43.55.160 is amended by adding new subsections to read:

3 (f) For purposes of (a) of this section, a lease expenditure is applicable to oil
4 or gas produced from a lease or property, or to oil or gas produced from leases or
5 properties in an area of the state, if the lease expenditure is

6 (1) a cost to explore, develop, or produce oil or gas from that lease or
7 property, or to explore, develop, or produce oil or gas from one of those leases or
8 properties in that area of the state, respectively; and

9 (2) incurred on or after the commencement of commercial production
10 of oil or gas from the lease or property.

11 (g) For purposes of (a) of this section, a lease expenditure incurred during a
12 calendar year to explore land that is not a lease or property, or to explore or develop a
13 lease or property before commencement of commercial production of oil or gas from
14 the lease or property, shall be allocated as provided in a regulation adopted by the
15 department under AS 43.55.165(h) to and among oil, gas subject to AS 43.55.011(o),
16 and gas not subject to AS 43.55.011(o) produced by the producer during that calendar
17 year from leases or properties in the same area of the state as the land being explored
18 or the lease or property being explored or developed, respectively.

19 (h) For purposes of (f) and (g) of this section, an area of the state is one of the
20 following:

21 (1) land north of 68 degrees North latitude;

22 (2) land outside the Cook Inlet sedimentary basin not including any
23 land north of 68 degrees North latitude; or

24 (3) the Cook Inlet sedimentary basin.

25 * **Sec. 8.** AS 43.55.165(h) is amended to read:

26 (h) The department shall adopt regulations that provide for reasonable
27 methods of allocating costs between oil and gas, between gas subject to
28 AS 43.55.011(o) and other gas, and between leases or properties in those
29 circumstances where an allocation of costs is required to determine lease expenditures
30 that are costs of exploring for, developing, or producing oil deposits or costs of
31 exploring for, developing, or producing gas deposits, or that are costs of exploring for,

1 developing, or producing oil or gas deposits located within different leases or
2 properties. When adopting a regulation for determining a reasonable method of
3 allocating lease expenditures between the production of oil and the production of
4 gas, the department shall, to the extent possible, provide for the allocation of
5 lease expenditures in proportion to the gross value at the point of production for
6 oil produced and gas produced.

7 * **Sec. 9.** AS 43.55.170 is amended by adding a new subsection to read:

8 (d) The department shall adopt regulations that provide for reasonable
9 methods of allocating the adjustments to a producer's lease expenditures in (a) of this
10 section and the payments and credits described in (b) of this section between oil and
11 gas, between gas subject to AS 43.55.011(o) and other gas, and between leases or
12 properties in those circumstances where an allocation of costs is required to determine
13 lease expenditures that are costs of exploring for, developing, or producing oil
14 deposits, or costs of exploring for, developing, or producing gas deposits, or that are
15 costs of exploring for, developing, or producing oil or gas deposits located within
16 different leases or properties. When determining a reasonable method of allocating the
17 adjustments to a producer's lease expenditures between the production of oil and the
18 production of gas, the department shall consider allocating the adjustments in
19 proportion to the lease expenditures allocated to the production of oil and the
20 production of gas under regulations adopted by the department under
21 AS 43.55.165(h).

22 * **Sec. 10.** AS 44.25 is amended by adding a new section to read:

23 **Sec. 44.25.025. Petroleum information management system.** (a) The
24 Department of Revenue shall develop and maintain an electronic petroleum
25 information management system to collect, secure, distribute, store, retrieve, and
26 archive information related to oil and gas exploration, development, and production in
27 the state. The purposes of the petroleum information management system are to
28 improve the administration of the oil and gas production tax and to facilitate
29 exploration, development, and production of oil and gas resources. The petroleum
30 information management system shall be accessible by the public.

31 (b) To the extent the information is available and is not confidential, the

1 petroleum information management system must include the following information:

- 2 (1) unit and joint operating agreements;
- 3 (2) state oil and gas exploration licenses and oil and gas leases;
- 4 (3) for exploration activities,
- 5 (A) exploration work programs and budgets;
- 6 (B) seismic data;
- 7 (C) drilling reports;
- 8 (D) logs;
- 9 (E) well tests;
- 10 (F) geological models and maps;
- 11 (4) for development activities,
- 12 (A) development plans with operating and capital expenditure
- 13 projections;
- 14 (B) construction progress reports;
- 15 (C) drilling reports;
- 16 (D) reservoir characterization;
- 17 (5) for production activities,
- 18 (A) production work programs and budgets;
- 19 (B) oil and gas sales, revenue, and pricing;
- 20 (C) transportation agreements;
- 21 (D) production data;
- 22 (E) injection data;
- 23 (F) operating and capital expenditures;
- 24 (G) facility maps and studies;
- 25 (6) for abandonment of oil and gas wells, leases, and production and
- 26 transportation facilities,
- 27 (A) abandonment plans and budgets;
- 28 (B) progress reports;
- 29 (7) for oil and gas related employment information,
- 30 (A) the number of resident and nonresident hires for each year;
- 31 (B) training opportunities; and

1 (8) other information the Department of Revenue determines necessary
2 and relevant to the oil and gas production tax and to the exploration, development, and
3 production of oil and gas resources.

4 (c) The Alaska Oil and Gas Conservation Commission, the Department of
5 Natural Resources, and the Department of Labor and Workforce Development, in
6 consultation with the Department of Revenue, shall provide information described in
7 (b) of this section that is not confidential and within the control of the commission and
8 each department to the Department of Revenue for inclusion in the petroleum
9 information management system. The information provided by the Alaska Oil and Gas
10 Conservation Commission or by a department under this subsection shall be in a form
11 suitable for the Department of Revenue to include in the petroleum information
12 management system.

13 * **Sec. 11.** AS 43.55.160(a)(2) is repealed.

14 * **Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to
15 read:

16 IMPLEMENTATION OF THE PETROLEUM INFORMATION MANAGEMENT
17 SYSTEM. The Department of Revenue shall develop and implement a work plan for the
18 development of the petroleum information management system required by AS 44.25.025,
19 enacted by sec. 10 of this Act, so that the system is operational before January 1, 2014.

20 * **Sec. 13.** Sections 1 - 9 and 11 of this Act take effect January 1, 2013.

21 * **Sec. 14.** Except as provided in sec. 13 of this Act, this Act takes effect immediately under
22 AS 01.10.070(c).

Adopted 4/3/12

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CS FOR SENATE BILL NO. 192(FIN)

IN THE LEGISLATURE OF THE STATE OF ALASKA

TWENTY-SEVENTH LEGISLATURE - SECOND SESSION

BY THE SENATE FINANCE COMMITTEE

**Offered:
Referred:**

Sponsor(s): SENATE RESOURCES COMMITTEE

A BILL

FOR AN ACT ENTITLED

1 **"An Act relating to the oil and gas production tax; relating to the minimum tax on oil**
2 **and gas production; relating to the tax rates applicable to the production of oil as the**
3 **gross value at the point of production of oil increases above \$65; relating to payments of**
4 **the oil and gas production tax; relating to the allocation of lease expenditures and**
5 **adjustments to lease expenditures; relating to the duties of the Department of Revenue;**
6 **relating to a petroleum information management system; relating to the duties of the**
7 **Alaska Oil and Gas Conservation Commission, the Department of Natural Resources,**
8 **and the Department of Labor and Workforce Development that relate to providing the**
9 **Department of Revenue with certain information relating to oil and gas; and providing**
10 **for an effective date."**

11 **BE IT ENACTED BY THE LEGISLATURE OF THE STATE OF ALASKA:**

12 *** Section 1. AS 43.55.011(e) is amended to read:**

1 (e) There is levied on the producer of oil or gas a tax for all oil and gas
2 produced each calendar year from each lease or property in the state, less any oil and
3 gas the ownership or right to which is exempt from taxation or constitutes a
4 landowner's royalty interest. Except as otherwise provided under (f), (j), (k), and (o) of
5 this section, the tax is equal to the sum of

6 (1) the annual production tax value of the taxable oil and gas as
7 calculated under AS 43.55.160(a)(1) multiplied by 25 percent; and

8 (2) the sum, over all months of the calendar year, of the tax amounts
9 determined under (g) of this section **on the gross value at the point of production of**
10 **oil.**

11 * **Sec. 2.** AS 43.55.011(f) is repealed and reenacted to read:

12 (f) Except for oil and gas subject to (i) of this section and gas subject to (o) of
13 this section, the provisions of this subsection apply to oil and gas produced from each
14 lease or property within a unit or nonunitized reservoir that has cumulatively produced
15 1,000,000,000 BTU equivalent barrels of oil or gas by the close of the most recent
16 calendar year and from which the average daily oil and gas production from the unit or
17 nonunitized reservoir during the most recent calendar year exceeded 100,000 BTU
18 equivalent barrels. Notwithstanding any contrary provision of law, a producer may not
19 apply tax credits to reduce its total tax liability under (e) and (g) of this section for oil
20 and gas produced from all leases or properties within the unit or nonunitized reservoir
21 below 10 percent of the total gross value at the point of production of that oil and gas.
22 If the amount of tax calculated by multiplying the tax rates in (e) and (g) of this
23 section by the total production tax value of the oil and gas taxable under (e) and (g) of
24 this section produced from all of the producer's leases or properties within the unit or
25 nonunitized reservoir is less than 10 percent of the total gross value at the point of
26 production of that oil and gas, the tax levied by (e) and (g) of this section for that oil
27 and gas is equal to 10 percent of the total gross value at the point of production of that
28 oil and gas.

29 * **Sec. 3.** AS 43.55.011(g) is repealed and reenacted to read:

30 (g) For each month of the calendar year for which the producer's average
31 monthly gross value at the point of production for a barrel of taxable oil

1 (1) produced from each lease or property within a unit or nonunitized
2 reservoir that has been in production for more than seven years or has cumulatively
3 produced 1,000,000,000 barrels of oil by the close of the most recent calendar year
4 and from which the average daily oil and gas production from the unit or nonunitized
5 reservoir during the most recent calendar year exceeded 100,000 barrels of oil is more
6 than \$65, the amount of tax for purposes of (e)(2) of this section is determined by
7 multiplying the monthly gross value at the point of production of the taxable oil
8 produced during the month by the tax rate calculated as follows:

9 (A) if the producer's average monthly gross value at the point
10 of production for a barrel of the taxable oil for the month is not more than
11 \$125, the tax rate is 0.25 percent multiplied by the number that represents the
12 difference between that average monthly gross value at the point of production
13 for a barrel of oil and \$65; or

14 (B) if the producer's average monthly gross value at the point
15 of production for a barrel of taxable oil is more than \$125, the tax rate is the
16 sum of 15 percent and the product of 0.05 percent multiplied by the number
17 that represents the difference between the average monthly gross value at the
18 point of production for a barrel of oil and \$125, except that the sum determined
19 under this subparagraph may not exceed 20 percent;

20 (2) not included in (1) of this subsection is more than \$65, the amount
21 of tax for purposes of (e)(2) of this section is determined by multiplying the monthly
22 gross value at the point of production of the taxable oil produced during the month by
23 the tax rate determined by multiplying 0.05 percent by the number that represents the
24 difference between that average monthly gross value at the point of production for a
25 barrel of oil and \$65, except that the tax rate determined under this paragraph may not
26 exceed five percent.

27 * **Sec. 4.** AS 43.55.020(a) is amended to read:

28 (a) For a calendar year, a producer subject to tax under AS 43.55.011(e) - (i)
29 shall pay the tax as follows:

30 (1) an installment payment of the estimated tax levied by
31 AS 43.55.011(e) and (g), net of any tax credits applied as allowed by law, is due for

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each month of the calendar year on the last day of the following month; except as otherwise provided under (2) of this subsection, the amount of the installment payment is the sum of the following amounts, less 1/12 of the tax credits that are allowed by law to be applied against the tax levied by AS 43.55.011(e) for the calendar year, but the amount of the installment payment may not be less than zero:

(A) for oil and gas produced from leases or properties in the state outside the Cook Inlet sedimentary basin but not subject to AS 43.55.011(o), other than leases or properties subject to AS 43.55.011(f), the greater of

(i) zero; or

(ii) the sum of the tax determined under AS 43.55.011(g) on the gross value at the point of production for oil produced for the month added to the product of 25 percent and [THE TAX RATE CALCULATED FOR THE MONTH UNDER AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the producer's adjusted lease expenditures for the calendar year of production under AS 43.55.165 and 43.55.170 that are deductible for the leases or properties under AS 43.55.160 from the gross value at the point of production of the oil and gas produced from the leases or properties during the month for which the installment payment is calculated;

(B) for oil and gas produced from leases or properties subject to AS 43.55.011(f), the greater [GREATEST] of

(i) 10 percent of the gross value at the point of production for oil and gas described in AS 43.55.011(f) [ZERO;

(ii) ZERO PERCENT, ONE PERCENT, TWO PERCENT, THREE PERCENT, OR FOUR PERCENT, AS APPLICABLE, OF THE GROSS VALUE AT THE POINT OF PRODUCTION OF THE OIL AND GAS] produced [FROM ALL LEASES OR PROPERTIES] during the month for which the installment payment is calculated; or

1 (ii) [(iii)] the sum of the tax determined under
2 AS 43.55.011(g) on the gross value at the point of production for oil
3 produced for the month added to the product of 25 percent and the
4 tax rate calculated for the month under AS 43.55.011(g)
5 [MULTIPLIED BY] the remainder obtained by subtracting 1/12 of the
6 producer's adjusted lease expenditures for the calendar year of
7 production under AS 43.55.165 and 43.55.170 that are deductible for
8 those leases or properties under AS 43.55.160 from the gross value at
9 the point of production of the oil and gas produced from those leases or
10 properties during the month for which the installment payment is
11 calculated;

12 (C) for oil and gas produced from each lease or property
13 subject to AS 43.55.011(j), (k), or (o), the greater of

14 (i) zero; or

15 (ii) the sum of the tax determined under
16 AS 43.55.011(g) on the gross value at the point of production for
17 the oil produced for the month added to the product of 25 percent
18 and [THE TAX RATE CALCULATED FOR THE MONTH UNDER
19 AS 43.55.011(g) MULTIPLIED BY] the remainder obtained by
20 subtracting 1/12 of the producer's adjusted lease expenditures for the
21 calendar year of production under AS 43.55.165 and 43.55.170 that are
22 deductible under AS 43.55.160 for oil or gas, respectively, produced
23 from the lease or property from the gross value at the point of
24 production of the oil or gas, respectively, produced from the lease or
25 property during the month for which the installment payment is
26 calculated;

27 (2) an amount calculated under (1)(C) of this subsection for oil or gas
28 produced from a lease or property subject to AS 43.55.011(j), (k), or (o) may not
29 exceed the product obtained by carrying out the calculation set out in
30 AS 43.55.011(j)(1) or (2) or 43.55.011(o), as applicable, for gas or set out in
31 AS 43.55.011(k)(1) or (2), as applicable, for oil, but substituting in

1 AS 43.55.011(j)(1)(A) or (2)(A) or 43.55.011(o), as applicable, the amount of taxable
2 gas produced during the month for the amount of taxable gas produced during the
3 calendar year and substituting in AS 43.55.011(k)(1)(A) or (2)(A), as applicable, the
4 amount of taxable oil produced during the month for the amount of taxable oil
5 produced during the calendar year;

6 (3) an installment payment of the estimated tax levied by
7 AS 43.55.011(i) for each lease or property is due for each month of the calendar year
8 on the last day of the following month; the amount of the installment payment is the
9 sum of

10 (A) the applicable tax rate for oil provided under
11 AS 43.55.011(i), multiplied by the gross value at the point of production of the
12 oil taxable under AS 43.55.011(i) and produced from the lease or property
13 during the month; and

14 (B) the applicable tax rate for gas provided under
15 AS 43.55.011(i), multiplied by the gross value at the point of production of the
16 gas taxable under AS 43.55.011(i) and produced from the lease or property
17 during the month;

18 (4) any amount of tax levied by AS 43.55.011(e) and (g) or (i), net of
19 any credits applied as allowed by law, that exceeds the total of the amounts due as
20 installment payments of estimated tax is due on March 31 of the year following the
21 calendar year of production.

22 * **Sec. 5.** AS 43.55.160(c) is amended to read:

23 (c) Notwithstanding any contrary provision of AS 43.55.150, for purposes of
24 calculating the tax due under AS 43.55.011(g) [A MONTHLY PRODUCTION TAX
25 VALUE UNDER (a)(2) OF THIS SECTION], the gross value at the point of
26 production of the oil and gas is calculated under regulations adopted by the department
27 that provide for using an appropriate monthly share of the producer's costs of
28 transportation for the calendar year.

29 * **Sec. 6.** AS 43.55.160 is amended by adding new subsections to read:

30 (f) For purposes of (a) of this section, a lease expenditure is applicable to oil
31 or gas produced from a lease or property, or to oil or gas produced from leases or

1 properties in an area of the state, if the lease expenditure is

2 (1) a cost to explore, develop, or produce oil or gas from that lease or
3 property, or to explore, develop, or produce oil or gas from one of those leases or
4 properties in that area of the state, respectively; and

5 (2) incurred on or after the commencement of commercial production
6 of oil or gas from the lease or property.

7 (g) For purposes of (a) of this section, a lease expenditure incurred during a
8 calendar year to explore land that is not a lease or property, or to explore or develop a
9 lease or property before commencement of commercial production of oil or gas from
10 the lease or property, shall be allocated as provided in a regulation adopted by the
11 department under AS 43.55.165(h) to and among oil, gas subject to AS 43.55.011(o),
12 and gas not subject to AS 43.55.011(o) produced by the producer during that calendar
13 year from leases or properties in the same area of the state as the land being explored
14 or the lease or property being explored or developed, respectively.

15 (h) For purposes of (f) and (g) of this section, an area of the state is one of the
16 following:

17 (1) land north of 68 degrees North latitude;

18 (2) land outside the Cook Inlet sedimentary basin not including any
19 land north of 68 degrees North latitude; or

20 (3) the Cook Inlet sedimentary basin.

21 * Sec. 7. AS 43.55.165(h) is amended to read:

22 (h) The department shall adopt regulations that provide for reasonable
23 methods of allocating costs between oil and gas, between gas subject to
24 AS 43.55.011(o) and other gas, and between leases or properties in those
25 circumstances where an allocation of costs is required to determine lease expenditures
26 that are costs of exploring for, developing, or producing oil deposits or costs of
27 exploring for, developing, or producing gas deposits, or that are costs of exploring for,
28 developing, or producing oil or gas deposits located within different leases or
29 properties. **When adopting a regulation for determining a reasonable method of**
30 **allocating lease expenditures between the production of oil and the production of**
31 **gas, the department shall, to the extent possible, provide for the allocation of**

1 lease expenditures in proportion to the gross value at the point of production for
2 oil produced and gas produced.

3 * **Sec. 8.** AS 43.55.170 is amended by adding a new subsection to read:

4 (d) The department shall adopt regulations that provide for reasonable
5 methods of allocating the adjustments to a producer's lease expenditures in (a) of this
6 section and the payments and credits described in (b) of this section between oil and
7 gas, between gas subject to AS 43.55.011(o) and other gas, and between leases or
8 properties in those circumstances where an allocation of costs is required to determine
9 lease expenditures that are costs of exploring for, developing, or producing oil
10 deposits, or costs of exploring for, developing, or producing gas deposits, or that are
11 costs of exploring for, developing, or producing oil or gas deposits located within
12 different leases or properties. When determining a reasonable method of allocating the
13 adjustments to a producer's lease expenditures between the production of oil and the
14 production of gas, the department shall consider allocating the adjustments in
15 proportion to the lease expenditures allocated to the production of oil and the
16 production of gas under regulations adopted by the department under
17 AS 43.55.165(h).

18 * **Sec. 9.** AS 44.25 is amended by adding a new section to read:

19 **Sec. 44.25.025. Petroleum information management system.** (a) The
20 Department of Revenue shall develop and maintain an electronic petroleum
21 information management system to collect, secure, distribute, store, retrieve, and
22 archive information related to oil and gas exploration, development, and production in
23 the state. The purposes of the petroleum information management system are to
24 improve the administration of the oil and gas production tax and to facilitate
25 exploration, development, and production of oil and gas resources. The petroleum
26 information management system shall be accessible by the public.

27 (b) To the extent the information is available and is not confidential, the
28 petroleum information management system must include the following information:

- 29 (1) unit and joint operating agreements;
30 (2) state oil and gas exploration licenses and oil and gas leases;
31 (3) for exploration activities,

- 1 (A) exploration work programs and budgets;
2 (B) seismic data;
3 (C) drilling reports;
4 (D) logs;
5 (E) well tests;
6 (F) geological models and maps;
7 (4) for development activities,
8 (A) development plans with operating and capital expenditure
9 projections;
10 (B) construction progress reports;
11 (C) drilling reports;
12 (D) reservoir characterization;
13 (5) for production activities,
14 (A) production work programs and budgets;
15 (B) oil and gas sales, revenue, and pricing;
16 (C) transportation agreements;
17 (D) production data;
18 (E) injection data;
19 (F) operating and capital expenditures;
20 (G) facility maps and studies;
21 (6) for abandonment of oil and gas wells, leases, and production and
22 transportation facilities,
23 (A) abandonment plans and budgets;
24 (B) progress reports;
25 (7) for oil and gas related employment information,
26 (A) the number of resident and nonresident hires for each year;
27 (B) training opportunities; and
28 (8) other information the Department of Revenue determines necessary
29 and relevant to the oil and gas production tax and to the exploration, development, and
30 production of oil and gas resources.
31 (c) The Alaska Oil and Gas Conservation Commission, the Department of

1 Natural Resources, and the Department of Labor and Workforce Development, in
2 consultation with the Department of Revenue, shall provide information described in
3 (b) of this section that is not confidential and within the control of the commission and
4 each department to the Department of Revenue for inclusion in the petroleum
5 information management system. The information provided by the Alaska Oil and Gas
6 Conservation Commission or by a department under this subsection shall be in a form
7 suitable for the Department of Revenue to include in the petroleum information
8 management system.

9 * **Sec. 10.** AS 43.55.160(a)(2) is repealed.

10 * **Sec. 11.** The uncodified law of the State of Alaska is amended by adding a new section to
11 read:

12 **IMPLEMENTATION OF THE PETROLEUM INFORMATION MANAGEMENT**
13 **SYSTEM.** The Department of Revenue shall develop and implement a work plan for the
14 development of the petroleum information management system required by AS 44.25.025,
15 enacted by sec. 9 of this Act, so that the system is operational before January 1, 2014.

16 * **Sec. 12.** This Act takes effect January 1, 2013.

SENATE FINANCE COMMITTEE REPORT

DATE: 3/5/12

FURTHER:

DATE TURNED
IN TO OFFICE: _____

Finance Committee considered SENATE BILL NO. 192

SB 192-OIL AND GAS PRODUCTION TAX RATES

"An Act relating to the oil and gas production tax; and providing for an effective date."

and recommends:

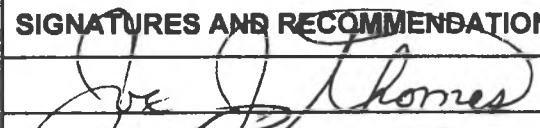






- be replaced with CS SB 192 (FIN) Same Title New Title
- adopt previous CS _____ (_____) Same Title New Title
- attached amendment(s)
- adopt _____ Letter of Intent
- further referral to _____ Committee

Dept Abbr.	
ADM	LEG
CED	LAW
COR	LWF
CRT	MVA
EED	DNR
DEC	DPS
DFG	REV
GOV	DOT
DHS	UA

NEW FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #
DNR	X			
ADM	X			
REV	X			

PREVIOUS FISCAL NOTE(S)				
Dept.	Fiscal	Indet.	Zero	FN #

APPROPRIATION - no fiscal note

SIGNATURES AND RECOMMENDATIONS:	PRINTED LAST NAME	Do PASS	Do NOT PASS	No Rec	AMEND
	THOMAS	✓			
	E G P	✓			
	McQuinn				✓
	Orson	✓			
	ELLIS	X			
CO-CHAIR: 	Hoffman	✓			
CO-CHAIR: 	Stedman	✓			