

# HB 247: KEY ISSUES & ASSESSMENT

Presentation to House Finance Committee  
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Janak Mayer, Chairman & Chief Technologist › [janak.mayer@enalytica.com](mailto:janak.mayer@enalytica.com)  
(via teleconference) Nikos Tsafos, President & Chief Analyst › [nikos.tsafos@enalytica.com](mailto:nikos.tsafos@enalytica.com)

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# AGENDA

## HB 247: SUMMARY OF KEY ISSUES

NORTH SLOPE: FISCAL REGIME OVERVIEW

NORTH SLOPE: CHANGES PROPOSED UNDER HB 247

COOK INLET: KEY ISSUES AND PROPOSED CHANGES

HB 247: SUMMARY OF KEY ISSUES

## APPENDIX

<b>Fiscal System Feature</b>	<b>Status Quo</b>	<b>HB 247 Proposed Change</b>	<b>Impact</b>	<b>HRES CS HB247</b>
<b>Per-Barrel Credit and Gross Minimum Tax</b>	Tax liabilities assessed annually, smoothing impact of price volatility.	Calculate \$/bbl credit and Gross Minimum Tax interaction monthly.	State would have netted additional ~\$100mm in 2014 under this system.	Maintain status quo - tax liabilities assessed annually
<b>Gross Value Reduction and Net Operating Loss Credit</b>	Gross Value Reduction artificially reduces Production Tax Value, and NOL credit is based on PTV, so 35% NOL credit can be given on loss greater than actual loss - effectively more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Net impact is to reduce state support for all spending to 35%. Questions exist about whether >35% spending support for GVR oil was deliberate incentive or unintended consequence under SB21.	Adopt proposed fix to NOL calculation for GVR-eligible production
<b>Gross Minimum Tax</b>	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can reduce taxes below floor. "New," GVR-eligible production can take to zero due to \$5/bbl and small producer credit	Harden floor for all production: NOL credits can't take below floor for legacy, and NOL, small Producer and \$5/bbl can't take below floor for GVR-eligible production. Increase rate from 4% to 5%	State revenues rise at low oil prices. For many new fields, taxes rise from 0 to 5% at current prices. For legacy production, taxes rise at time when value is negative.	Maintain status quo - no further floor hardening

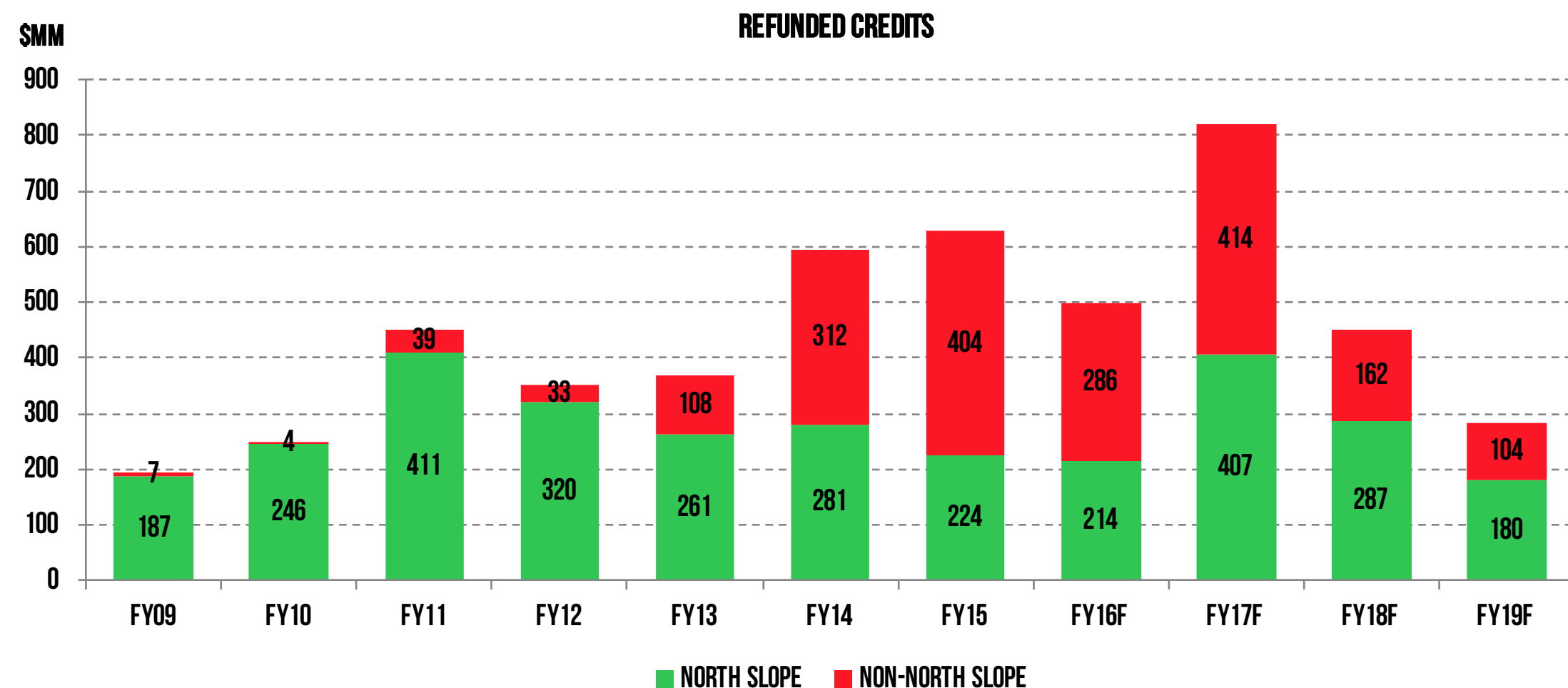
<b>Fiscal System Feature</b>	<b>Status Quo</b>	<b>HB 247 Proposed Change</b>	<b>Impact</b>	<b>HRES CS HB247</b>
<b>Net Operating Loss credit reimbursement</b>	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state	\$25mm per company annual limit on reimbursement. Companies with annual revenues > \$10bn must carry forward, regardless of production level.	Limit substantially increases capital needs for new developments; and if effective July 2016 would have major negative impact on developments underway. Raises hurdle/break-even price for projects by \$5 to \$15/bbl.	\$200mm per company annual limit on reimbursement.
<b>Gross Value at Point of Production calculation</b>	GVPP is calculated by subtracting transportation costs from sale price. If transportation costs for some production exceed price, GVPP is negative	GVPP cannot go below zero	Could limit deductibility of some transport costs. Particularly likely to be an issue at current prices if applied on a per-unit or per field basis.	Maintain status quo
<b>Cook Inlet Tax Credits</b>	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax	Repeal QCE and WLE credits effective July 1 2016, leaving only 25% NOL credit	Cook Inlet credit regime is clearly unsustainable in current environment; repeal in present year may have major impacts on capital commitments already made, and the viability of producers who have made those commitments	Reduce NOL credit to 10%, keep 20% QCE credit, reduce WLE credit to 20% by 2018

# REFUNDED CREDITS REACHED NEW HIGH IN FY 2015

Refundable credits in FY 2015 reached \$628 mm, the highest point ever

In both 2014 and 2015, the majority of these credits went to non-North Slope producers

Under DOR's current forecast, credits will exceed \$1.3 billion across FY 2016 and FY 2017



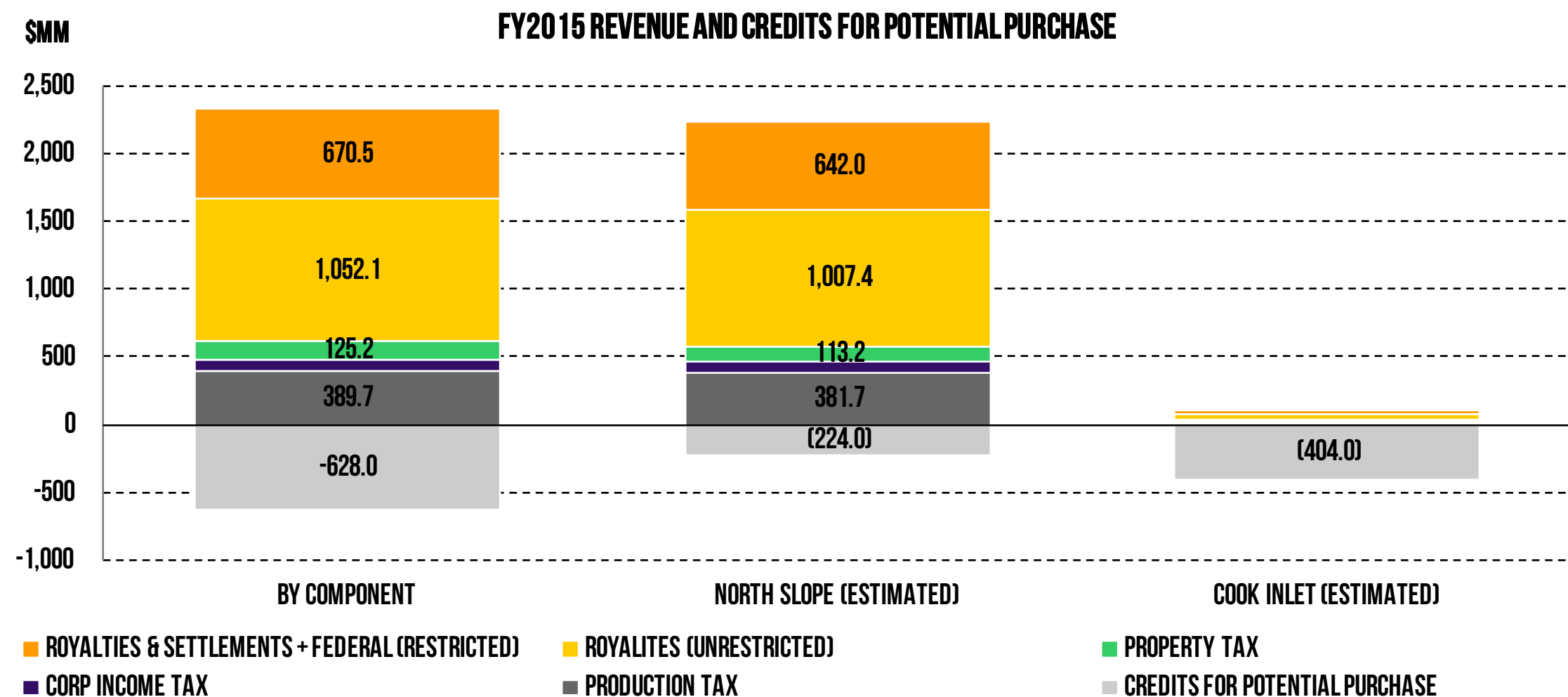
SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION

# BIG DIFFERENCE BETWEEN NORTH SLOPE AND COOK INLET

The majority of refundable credits go to Cook Inlet producers

Cook Inlet production, however, generates limited direct revenue for the state

Credits on the North Slope are more limited but also a far smaller fraction of total value generated



SOURCE: ALASKA DEPARTMENT OF REVENUE, REVENUE SOURCES BOOK; TAX DIVISION; ENALYTICA ESTIMATES

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# HARD TO BE BOTH NORWAY & N. DAKOTA AT SAME TIME

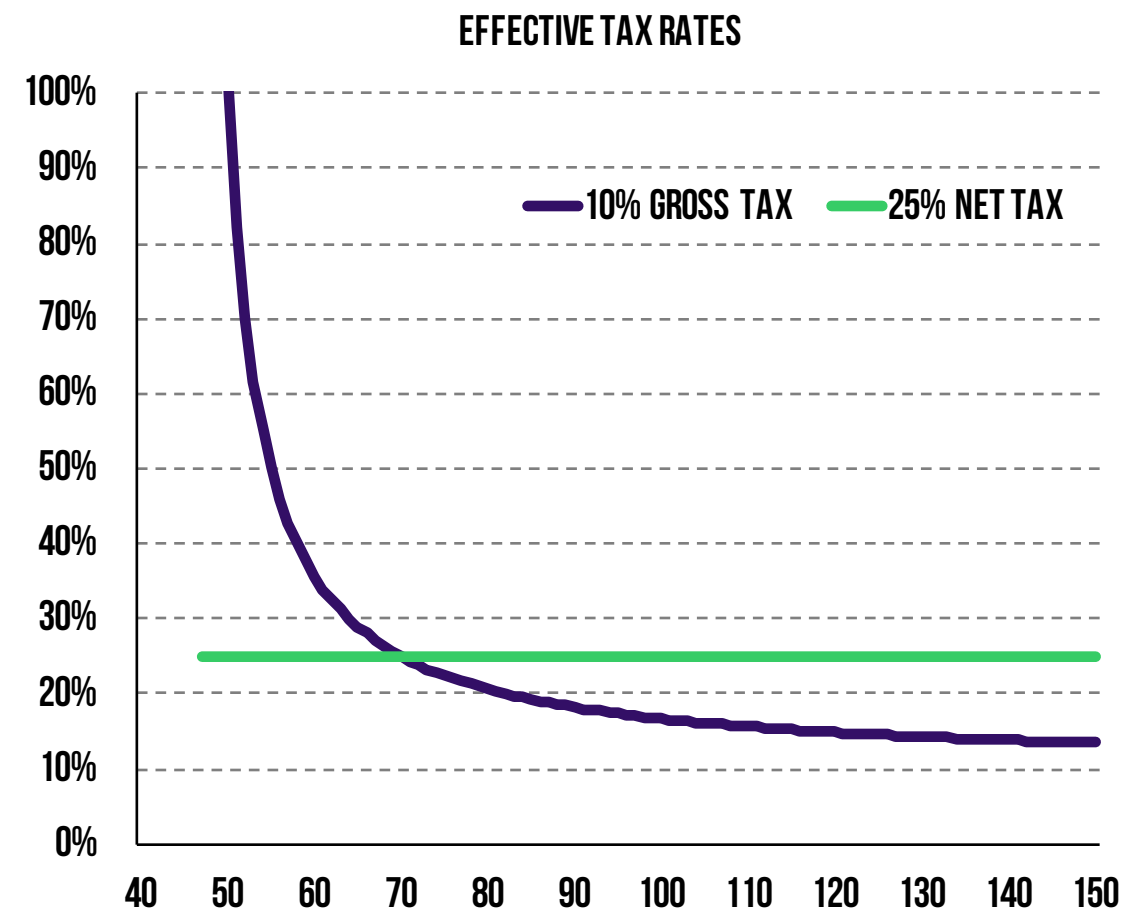
## Gross taxes

Less volatile, shift risk to private sector  
 Simple and easy to administer  
 High/low government take at low/high prices  
 Disadvantages marginal investment

## Net taxes

More volatile revenues for government  
 Harder to administer  
 Efficient—do not distort decision-making  
 Enable investment across commodity cycle

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	-6	14	34	54	74	94
<u>10% GROSS TAX</u>	3	5	7	9	11	13
% GROSS	10%	10%	10%	10%	10%	10%
% NET	#N/A	36%	21%	17%	15%	14%
<u>25% NET TAX</u>	-1.5	3.5	8.5	13.5	18.5	23.5
% GROSS	-5%	7%	12%	15%	17%	18%
% NET	25%	25%	25%	25%	25%	25%





# CASHFLOW TAXES: MORE EFFICIENT, MORE VOLATILE

Purpose of net tax is to **minimize distorting impact** on investment

Best achieved by making the state's fiscal cost/benefit as close as possible to **equity investor**

Results in **outflows** during development, **receipts** during production

## HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLs)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP (\$THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX	-	-	-	18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
<b>PRE-TAX CASHFLOW</b>	<b>(20,286)</b>	<b>(60,857)</b>	<b>(33,809)</b>	<b>11,714</b>	<b>32,000</b>	<b>28,800</b>	<b>25,920</b>	<b>23,328</b>	<b>20,995</b>	<b>18,896</b>
ASSET VALUE	-	-	-	135,238	108,190	86,552	69,242	55,393	44,315	35,452
DEPRECIATION	-	-	-	27,048	21,638	17,310	13,848	11,079	8,863	7,090
<b>NET INCOME</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>4,952</b>	<b>10,362</b>	<b>11,490</b>	<b>12,072</b>	<b>12,249</b>	<b>12,132</b>	<b>11,805</b>
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724
25% INCOME TAX	-	-	-	1,238	2,590	2,872	3,018	3,062	3,033	2,951

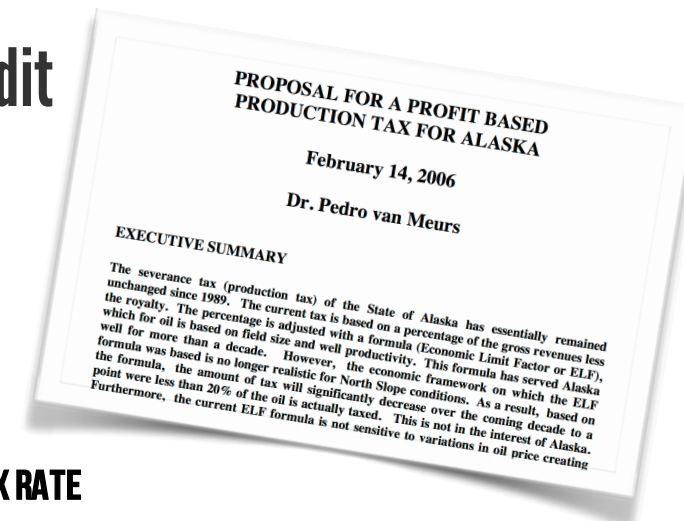
# ALASKA'S PRODUCTION TAX: ORIGINS IN 2006 PROPOSAL

PPT **as proposed** by Dr Pedro van Meurs useful to understand core of system and evolution to date

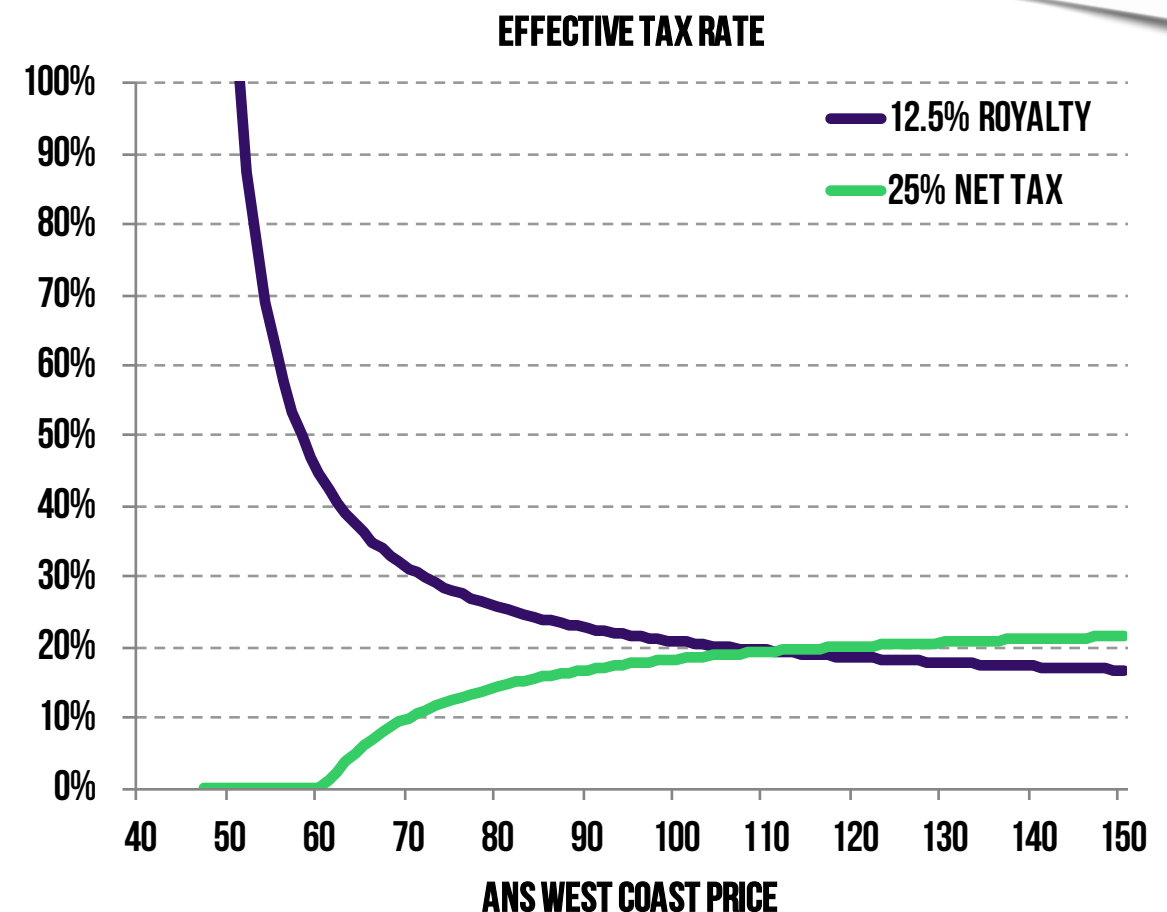
25% flat cashflow tax, 25% credit for net operating losses (NOLs), 20% capital credit

**45% government support for spending** for new and incumbent players alike

**Statewide floor of zero** (credits tradable rather than reimbursable)



ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
25% NET TAX	(1.5)	3.5	8.5	13.5	18.5	23.5
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(5.1)	(0.1)	4.9	9.9	14.9	19.9
% GROSS	-17%	0%	7%	11%	14%	15%
% NET	#N/	-1%	14%	18%	20%	21%



# NOL CREDIT AIMS TO EQUALIZE TAX SYSTEM IMPACT

Incumbent can deduct spending against liability at marginal tax rate: **25% gov't spending support**

Aim for NOL credit to **ensure same impact for new developer** with no liability

Alternative is to **carry forward**: same cash impact over time, but disadvantages new developer economics

In original proposal, credits **not refundable but tradable**

Aim was for **new developers** to **sell to incumbent producers** at close to face value

In reality credits sold for much less than face value - much **value captured by incumbents**

As a result, credits **made refundable** by the treasury, to direct full value to new developers

## HIGHLY SIMPLIFIED CASHFLOW AND INCOME EXAMPLE

YEAR	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
PRODUCTION (THOUSAND BBLS)	-	-	-	1,000	1,000	900	810	729	656	590
ANS WC	60	60	60	60	60	60	60	60	60	60
TRANSPORT	10	10	10	10	10	10	10	10	10	10
GVPP/BBL	50	50	50	50	50	50	50	50	50	50
GVPP (\$THOUSANDS)	-	-	-	50,000	50,000	45,000	40,500	36,450	32,805	29,525
OPEX	-	-	-	18,000	18,000	16,200	14,580	13,122	11,810	10,629
CAPEX	20,286	60,857	33,809	20,286	-	-	-	-	-	-
PRE-TAX CASHFLOW	(20,286)	(60,857)	(33,809)	11,714	32,000	28,800	25,920	23,328	20,995	18,896
25% CASHFLOW TAX	(5,071)	(15,214)	(8,452)	2,929	8,000	7,200	6,480	5,832	5,249	4,724

# ACES: STEEP PROGRESSIVITY, HIGH SPENDING SUPPORT

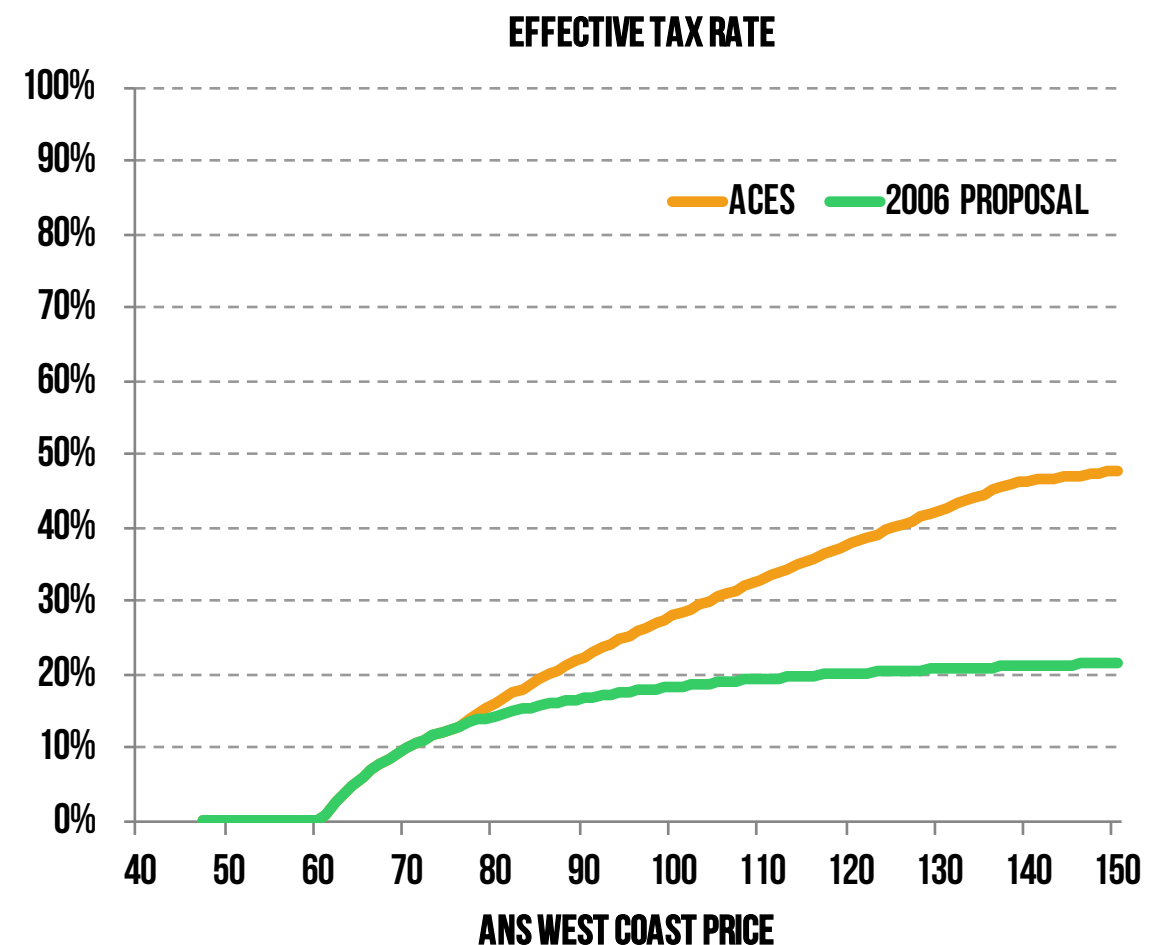
Tax rate 25% to 75% (variable with PTV/bbl), 20% capital credit, 40% exploration credit, 25% NOL credit

High progressivity: **high marginal tax rates** (up to 86%, higher at yet-unseen prices)

High marginal rates + credits = **very high state support for spending** (from 45% to over 100%)

With **high prices and low spending**, brought **huge revenue**; low prices and high spending **major risks**

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	25%	25%	27%	35%	43%	50%
NET TAX CALC	-	3.5	9.0	18.7	31.5	47.1
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE CREDITS	1.2	3.5	9.0	18.7	31.5	47.1
NOL CREDIT	1.5	-	-	-	-	-
CAPITAL CREDIT	3.6	3.6	3.6	3.6	3.6	3.6
TAX AFTER CREDITS	(3.9)	(0.1)	5.4	15.1	27.9	43.5
% GROSS	-13%	0%	8%	17%	25%	33%
% NET	#N/A	-1%	16%	28%	38%	46%



# SB21: PROTECT ON THE LOW END, GIVE BACK AT THE HIGH

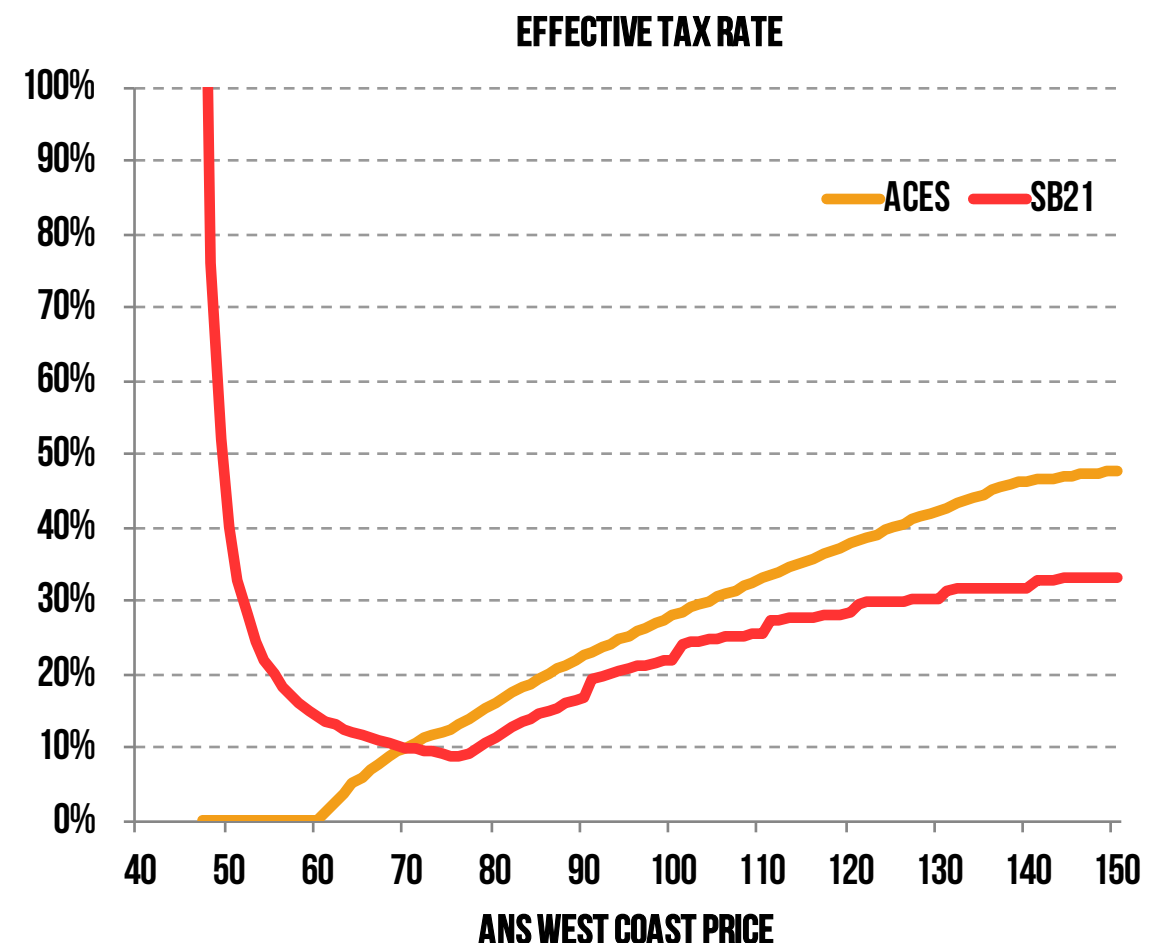
Tax rate 35%, \$0 to \$8 per-bbl credit, hardened gross floor, 35% NOL credit

Key aim was to **reduce state support for spending** and make predictable: **35% for everyone**

**Reduced rates at high prices** for competitiveness, but **4% gross floor binding** to protect at low end

Significantly reduced the risks brought by low prices and high spending

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP	30	50	70	90	110	130
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL	(6.0)	14.0	34.0	54.0	74.0	94.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX PRE \$/BBL	-	4.9	11.9	18.9	25.9	32.9
\$/BBL CREDIT	8.0	8.0	8.0	7.0	4.0	-
NET TAX CALC	(8.0)	(3.1)	3.9	11.9	21.9	32.9
4% GROSS FLOOR	1.2	2.0	2.8	3.6	4.4	5.2
TAX BEFORE NOL	1.2	2.0	3.9	11.9	21.9	32.9
NOL CREDIT	2.1	-	-	-	-	-
TAX AFTER CREDITS	(0.9)	2.0	3.9	11.9	21.9	32.9
% GROSS	-3%	4%	6%	13%	20%	25%
% NET	#N/A	14%	11%	22%	30%	35%



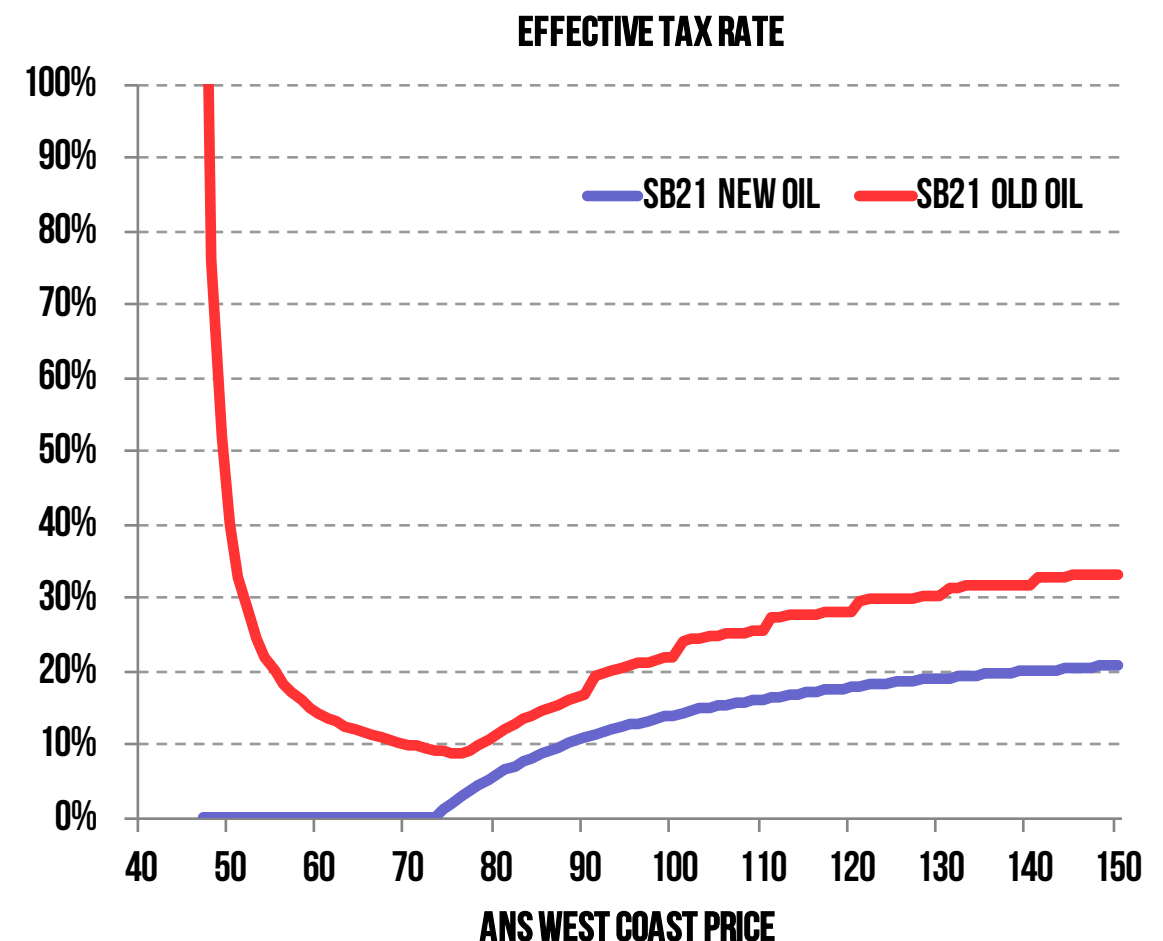
## SB21: SPECIAL INCENTIVES FOR “NEW OIL”

Gross Value Reduction (GVR) - reduce GVPP by 20% or 10% for certain units / participating areas

Purpose of GVR - **reduce effective tax rates** for particular fields **without ring-fencing** costs

GVR-eligible production receives **fixed \$5/bbl credit**, not variable \$0-\$8/bbl, **no hard floor**

ANS WC	40	60	80	100	120	140
TRANSPORT	10	10	10	10	10	10
GVPP BEFORE GVR	30	50	70	90	110	130
GVPP AFTER GVR	24	40	56	72	88	104
OPEX	18	18	18	18	18	18
CAPEX	18	18	18	18	18	18
PTV/BBL BEFORE GVR	(6.0)	14.0	34.0	54.0	74.0	94.0
PTV/BBL	(12.0)	4.0	20.0	36.0	52.0	68.0
NET TAX RATE	35%	35%	35%	35%	35%	35%
NET TAX	-	1.4	7.0	12.6	18.2	23.8
4% GROSS FLOOR	1.0	1.6	2.2	2.9	3.5	4.2
\$/BBL CREDIT	5.0	5.0	5.0	5.0	5.0	5.0
TAX BEFORE NOL	(4.0)	(3.4)	2.0	7.6	13.2	18.8
NOL CREDIT	4.2	-	-	-	-	-
TAX AFTER CREDITS	(8.2)	(3.4)	2.0	7.6	13.2	18.8
% GROSS	-27%	-7%	3%	8%	12%	14%
% NET	#N/A	-24%	6%	14%	18%	20%



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# MONTHLY GROSS MIN CALCULATION: NEUTRAL OR TAX HIKE

Under volatility, **gross minimum** tax may apply to some months, while annual remains **net profit**-based

In 2014, gross minimum would have applied Nov & Dec, but not full-year\*

Enforcing monthly gross minimum would have netted additional ~\$100mm\*

	ANS WC	TRANSPORT	OPEX	CAPEX	PTV/BBL	35%*PTV/BBL	LESS \$8/BBL	4% OF GVPP	PROD TAX / BBL	LIABILITY \$MM
<b>ANNUAL</b>										
2014	97.74	10.42	19.30	20.29	47.73	16.71	8.71	3.49	8.71	1,440.32
<b>MONTHLY</b>										
JAN-2014	103.82	10.42	19.30	20.29	53.81	18.83	10.83	3.74	10.83	
FEB-2014	106.30	10.42	19.30	20.29	56.29	19.70	11.70	3.84	11.70	
MAR-201	107.91	10.42	19.30	20.29	57.90	20.26	12.26	3.90	12.26	
APR-2014	107.36	10.42	19.30	20.29	57.35	20.07	12.07	3.88	12.07	
MAY-2014	108.06	10.42	19.30	20.29	58.05	20.32	12.32	3.91	12.32	
JUN-2014	110.76	10.42	19.30	20.29	60.75	21.26	13.26	4.01	13.26	
JUL-2014	107.63	10.42	19.30	20.29	57.62	20.17	12.17	3.89	12.17	
AUG-2014	101.78	10.42	19.30	20.29	51.77	18.12	10.12	3.65	10.12	
SEP-2014	96.05	10.42	19.30	20.29	46.04	16.12	8.12	3.43	8.12	
OCT-2014	84.91	10.42	19.30	20.29	34.90	12.21	4.21	2.98	4.21	
NOV-2014	77.41	10.42	19.30	20.29	27.40	9.59	1.59	2.68	2.68	
DEC-2014	60.90	10.42	19.30	20.29	10.89	3.81	(4.19)	2.02	2.02	
								9.31		1,540.94
INCREASE								0.61		100.62

\*single-taxpayer, taxable-barrel-based approximation, FY2014 DOR RSB costs, assumes no taxable production GVR-eligible



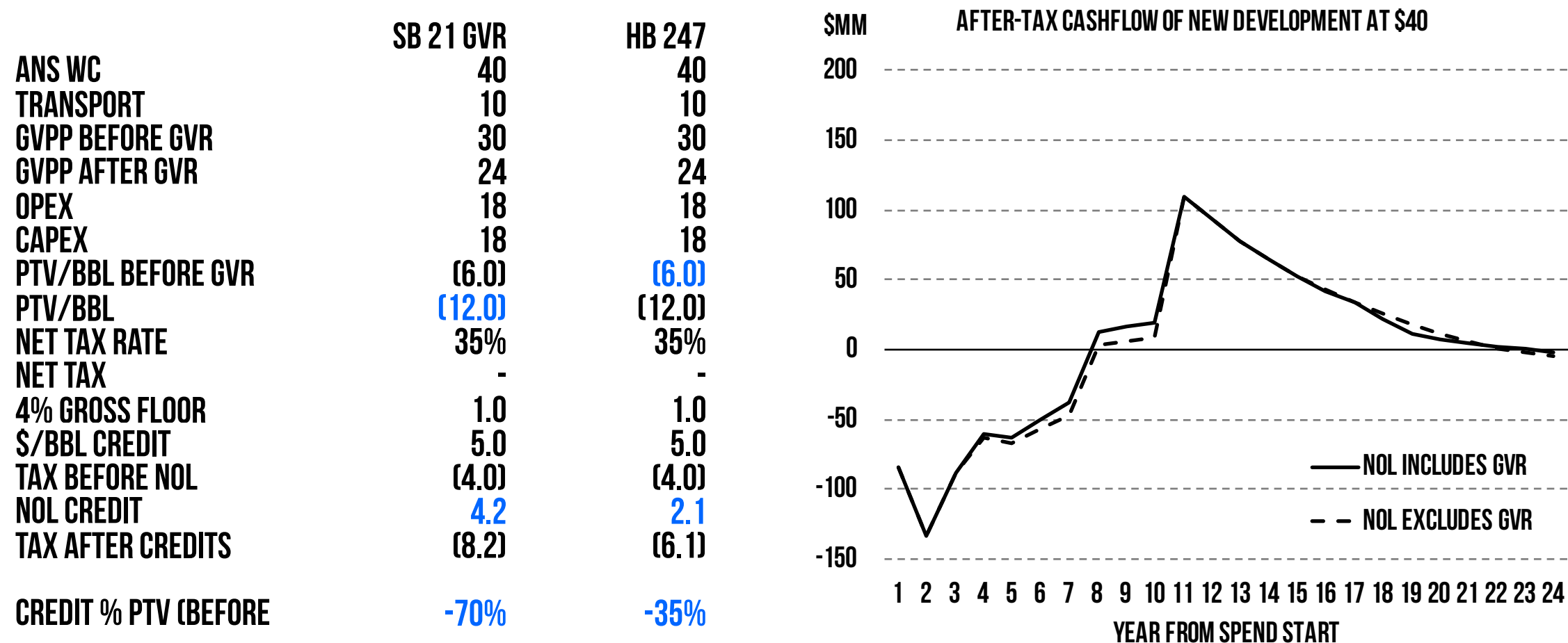
# GVR RAISES NOL CREDIT ABOVE 35% OF ACTUAL LOSS

The purpose of the Gross Value Reduction (GVR) is to **lower the effective tax rate** on new production

One surprising and counter-intuitive effect is to **raise the effective rate of the NOL** credit

Issue after production from new development starts, but ongoing drilling costs mean NOL eligible

**Exacerbated at low prices**, but impact <\$10mm yr for 20mb/d new development

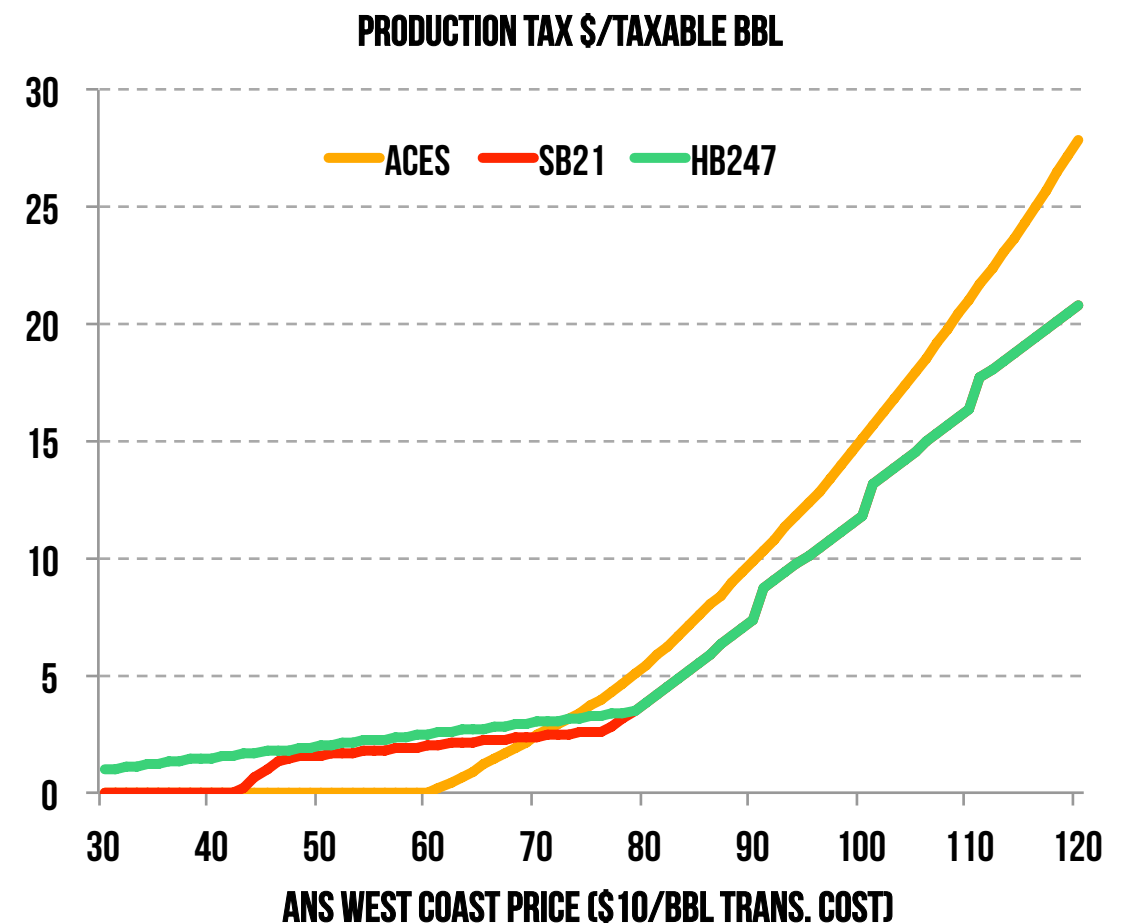
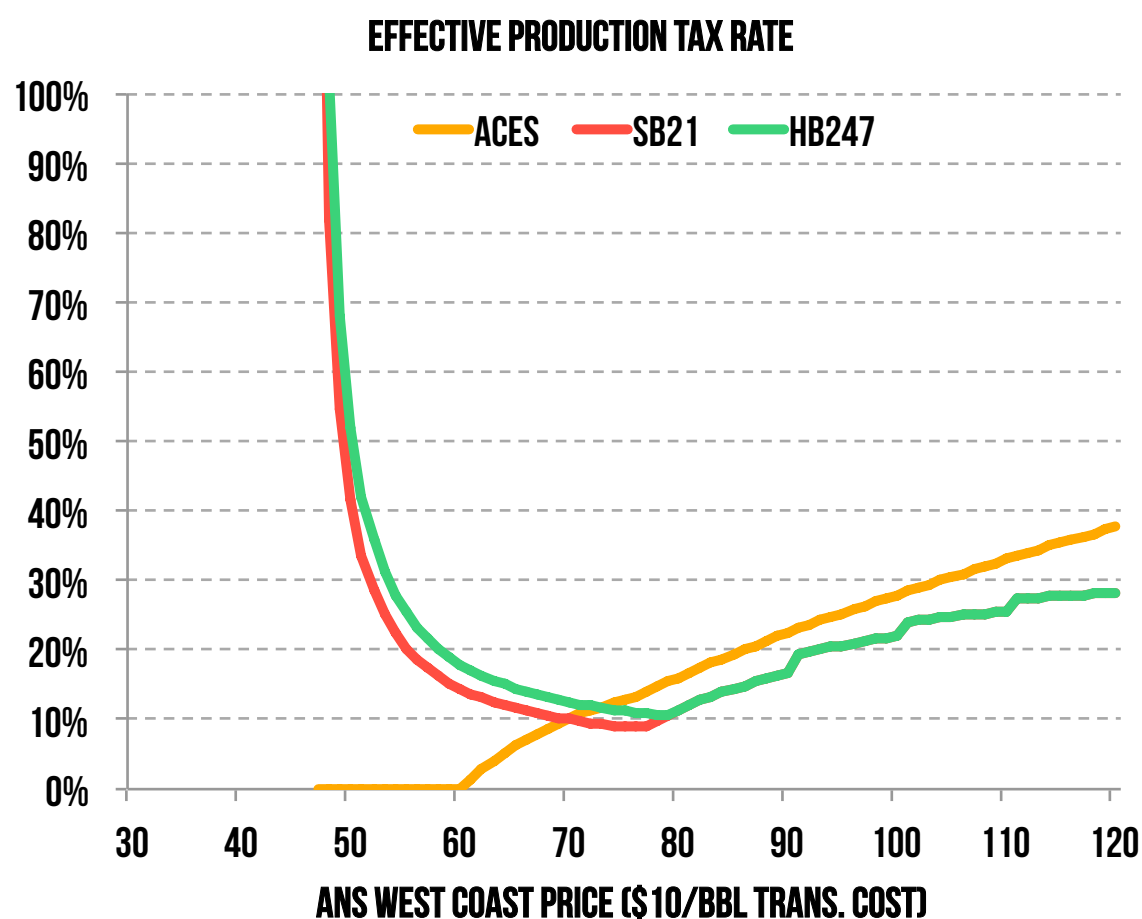


# HARDER, HIGHER FLOOR RAISES TAXES ON LOSSES

Effective tax rate under ACES could fall to zero because capital credits were applied after gross floor  
 SB21 applied a **hard gross floor** under \$/bbl credits - meaning skyrocketing net tax rate at low prices

Concern to **protect state at low prices** always valid

Competitive regimes **balance risk and reward** at low and high end

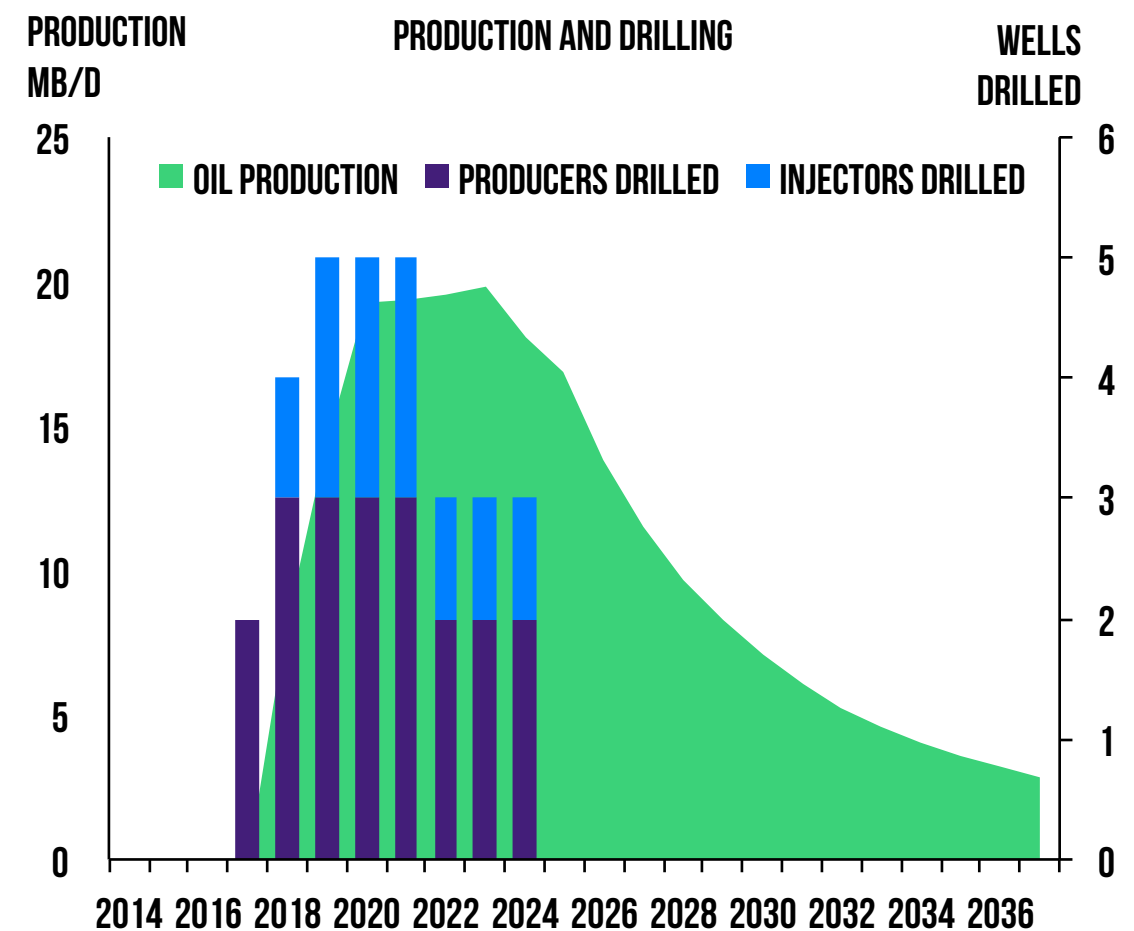
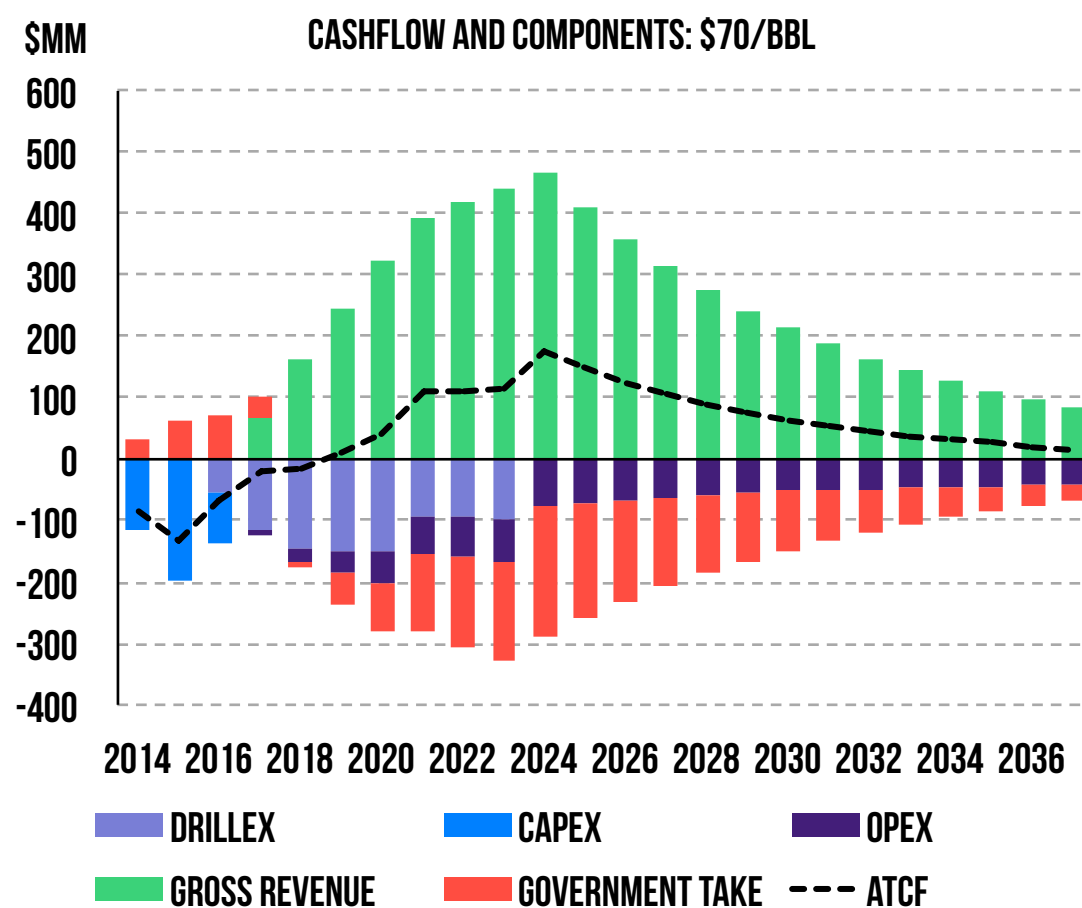


# HOW DO CHANGES IMPACT NEW FIELD DEVELOPMENT?

To understand the cumulative impact of the proposed changes, we look at a **sample NS investment**

Cumulative CAPEX and drillex of \$1.3 billion; average annual OPEX of about \$15/bbl

Peak production of 20 mb/d; 30 wells (production and injection) drilled over 8 years



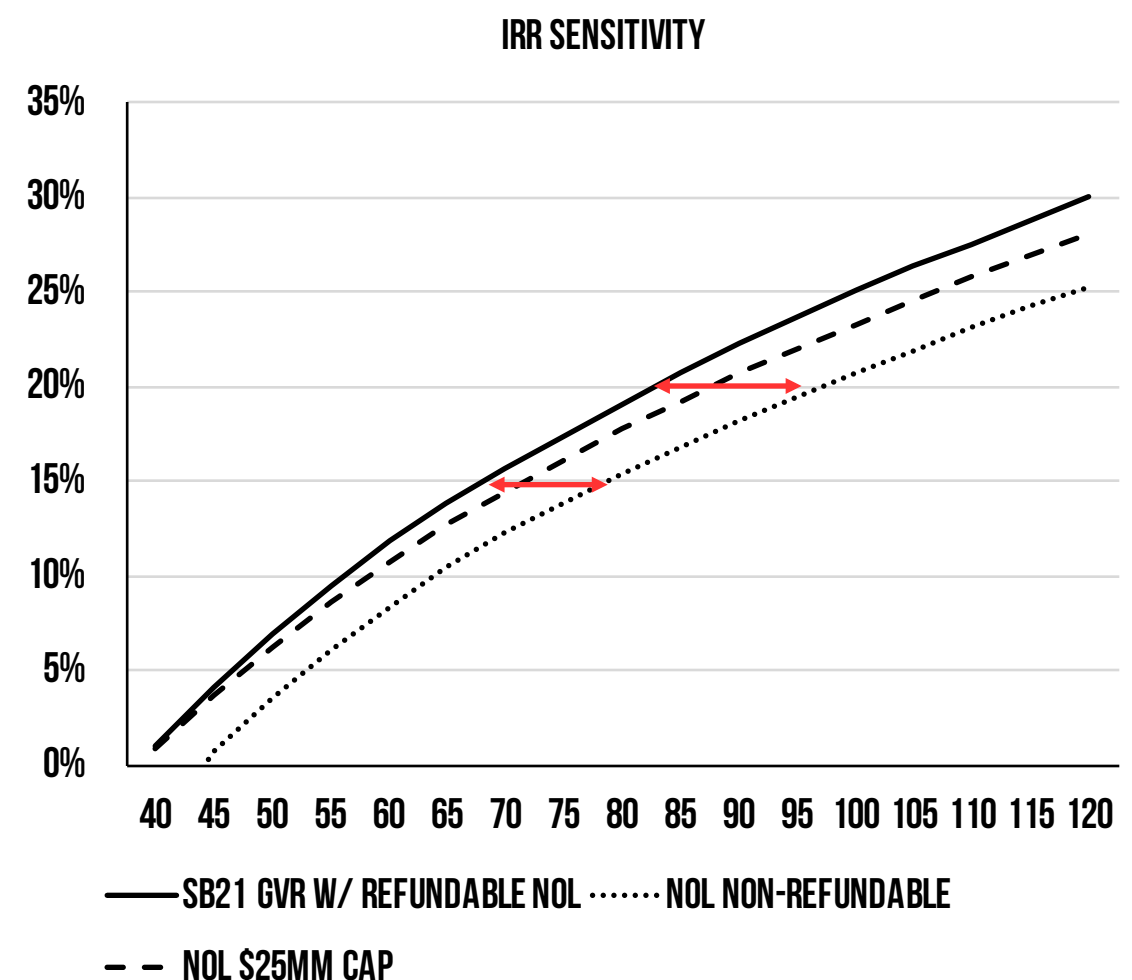
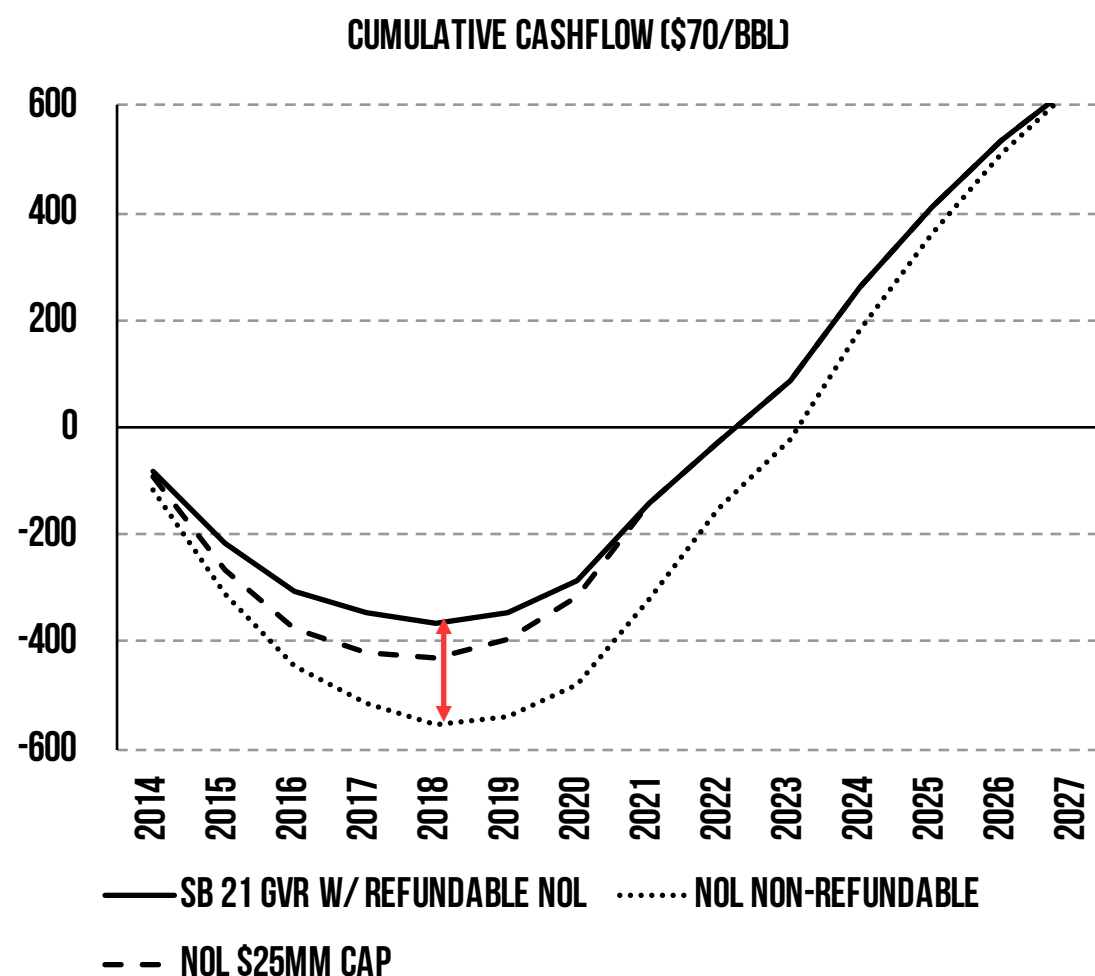
# REFUND LIMITS BOOST CAPITAL NEEDS AND LOWER IRR

Refundable credit limit would **increase capital needs** by up to 50% (from \$350mm to \$400–\$550mm)

Application to projects currently under development could have **major adverse impacts**

Near-Kuparak-sized new development could easily incur **>\$2bn in NOL credits** in development years

If per-company limit on refundability is the solution, what is the right level?

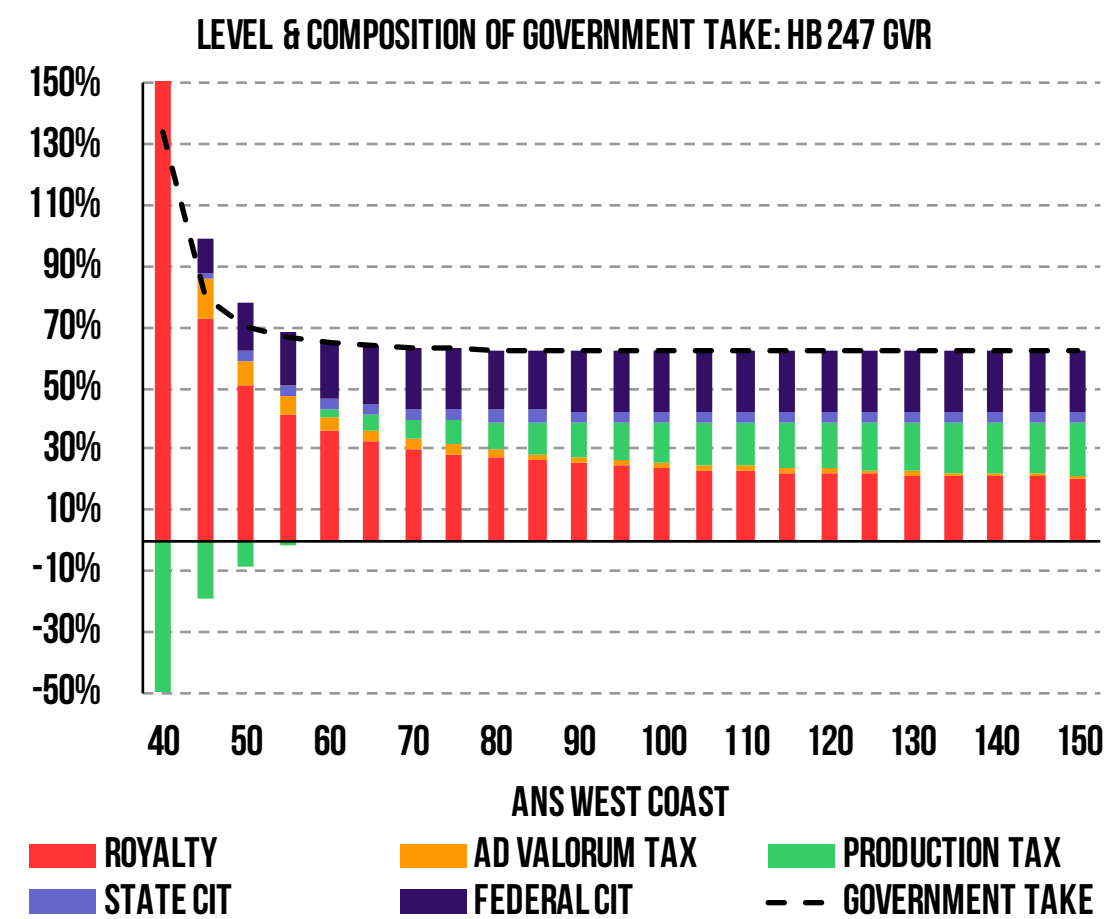
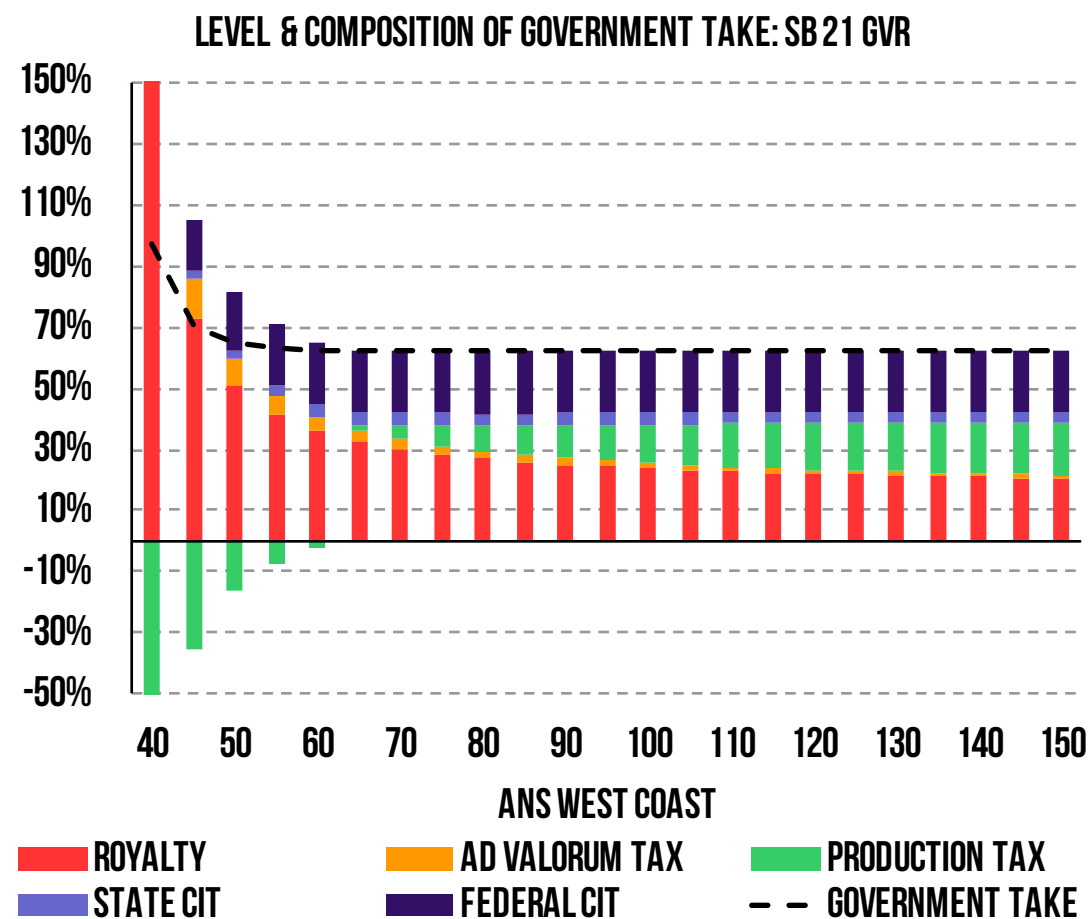


# CHANGES MAKE REGRESSIVE SYSTEM EVEN MORE SO

State of Alaska making negative production tax in today's prices; but overall gov't take is still high

Cumulative impact of proposed changes would be to shift up government take in lower oil prices

In times of high investment / low prices (as in 2016), **effective government take exceeds 100%**



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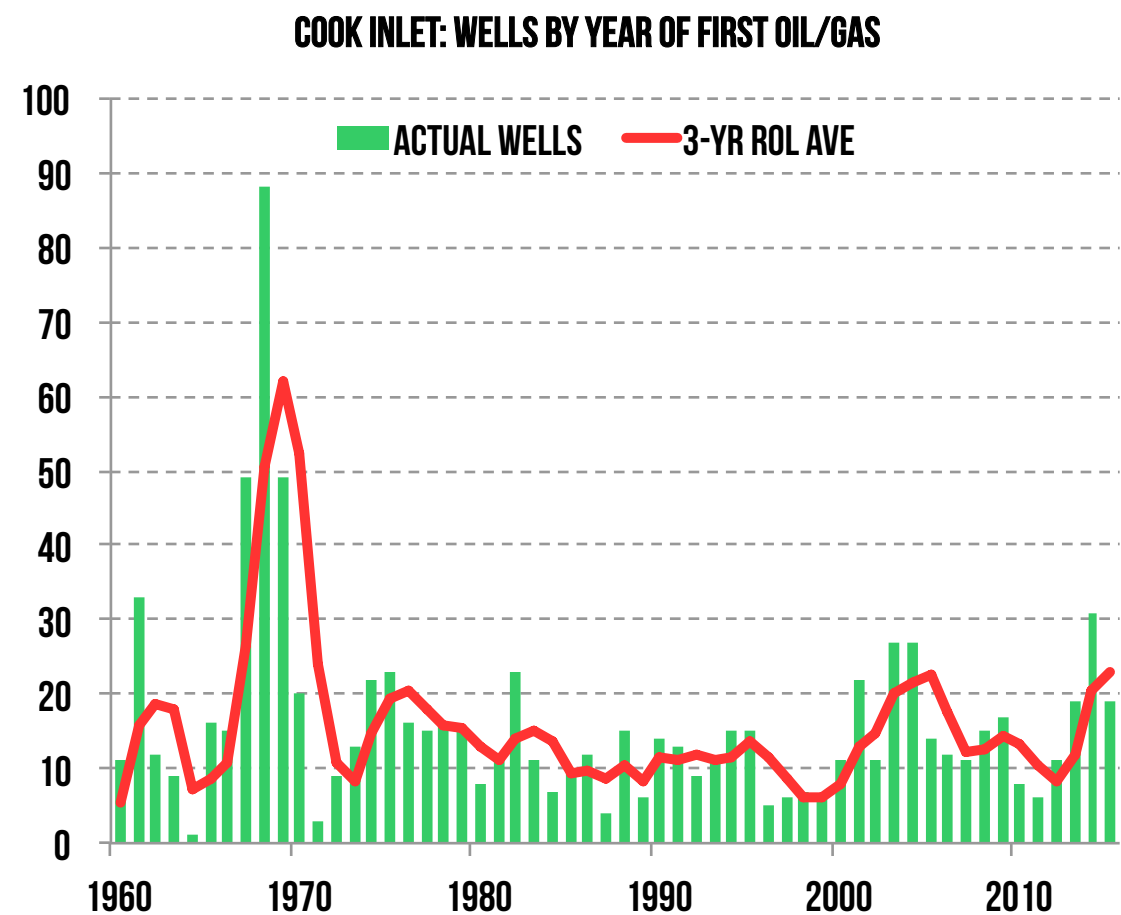
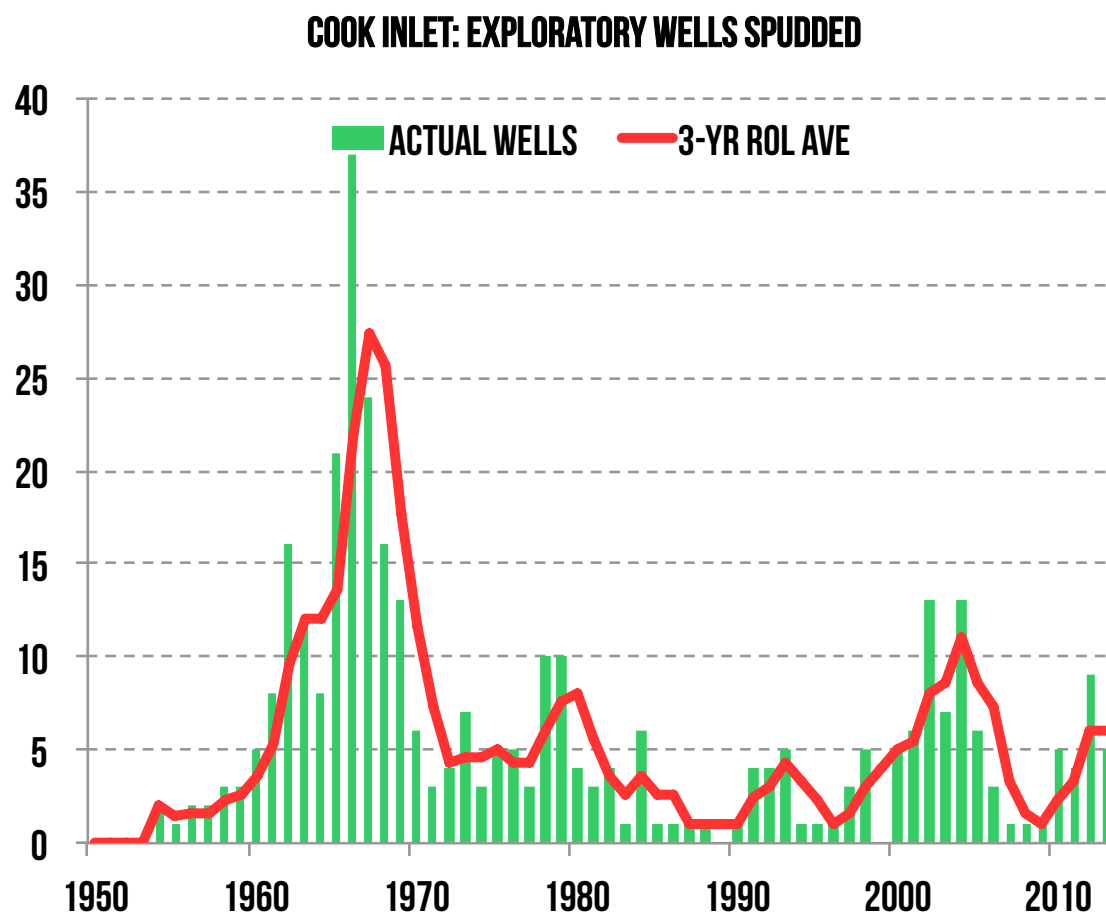
# ACTIVITY HAS RESPONDED IN RECENT YEARS

Exploration drilling in Cook Inlet has gone through several cycles since 1950s

Recent exploration activity (post 2010) on par with previous exploration peaks

Development drilling has been more stable over the years

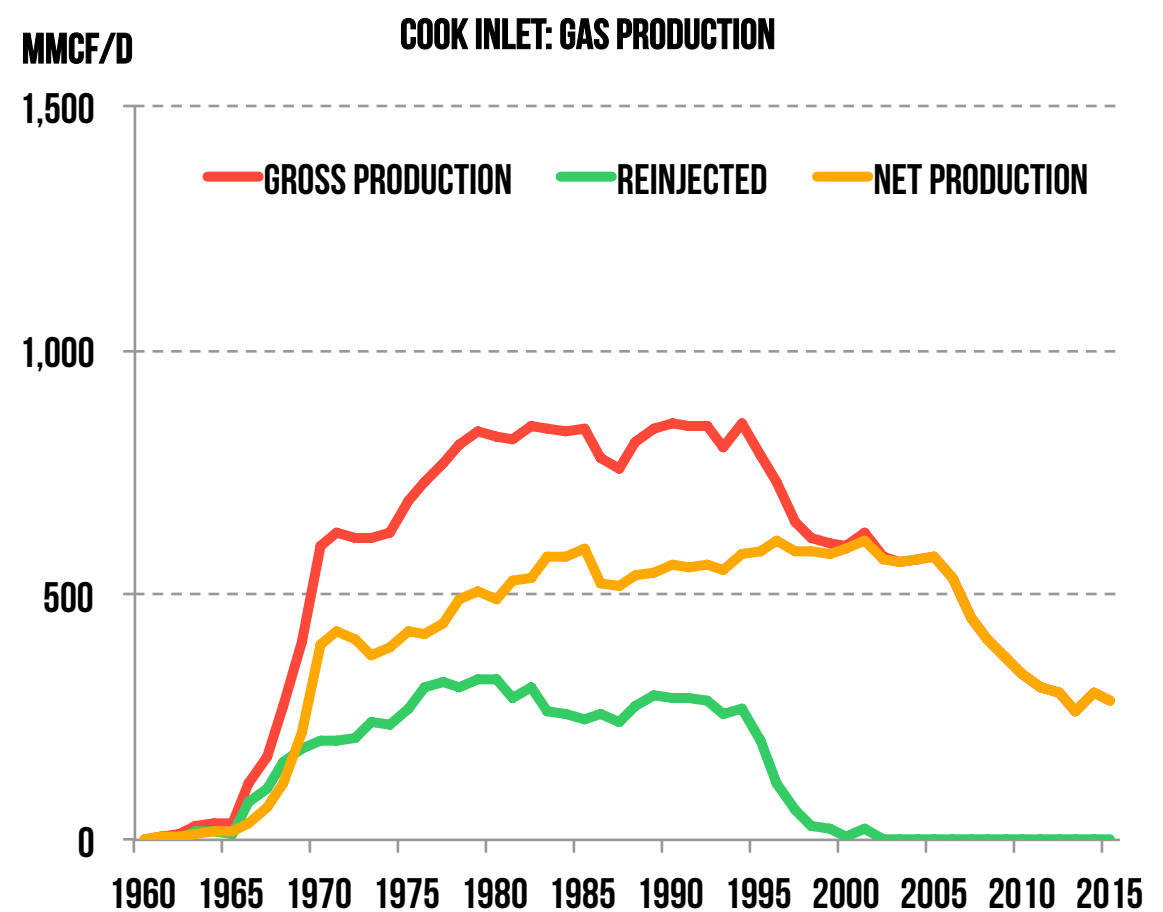
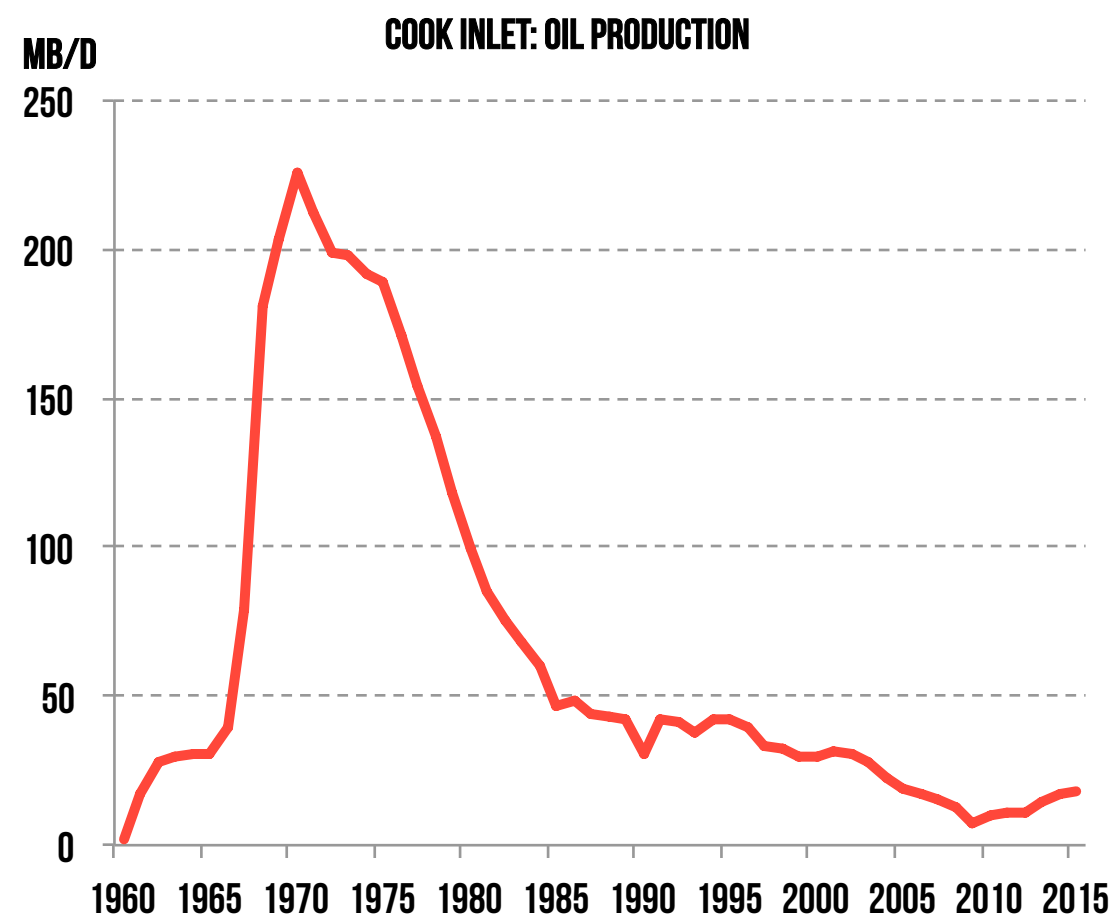
Recent growth placing three-year rolling average among highest in state's history



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

# COOK INLET OIL AND GAS PRODUCTION: BASIC FACTS

- Oil** Peak in 1970 at 226 mb/d; trough in 2009 at 7.5 mb/d; upturn post 2010 (+10.5 mb/d)
- Gross Gas** Peak in 1990 at 853 mmcf/d; big drops in 1994–1998 and 2005–2013; stable in 2014–15
- Net Gas** Peak in 1996; 1990s plateau from blowdown at Swanson River; fall post 2005, then stable



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)



# THE COOK INLET OIL AND GAS MARKET: A SCORECARD

**What has happened to oil and gas production and activity in the Cook Inlet in recent years?**

Oil production has risen from 7.5 mb/d in 2009 to almost 18 mb/d

Gas production has stabilized after years of steadier decline

**How has the gas market adjusted in recent years?**

Cook Inlet has undergone major transition in supply, demand, prices, competition and expectations

Some of these changes are typical in mature basins—others are unique to Cook Inlet

**What's the outlook and how sensitive is the outlook to changes in oil/gas fiscal system?**

DNR: 1,183 bcf in remaining 2P reserves; 1,600 bcf w/ Cosmopolitan and Kitchen Lights (ballpark)

Continued drilling at old fields plus Cosmopolitan and Kitchen Lights: current market well supplied

At current (gas) price levels, brownfield investment should be profitable under stricter fiscal regime

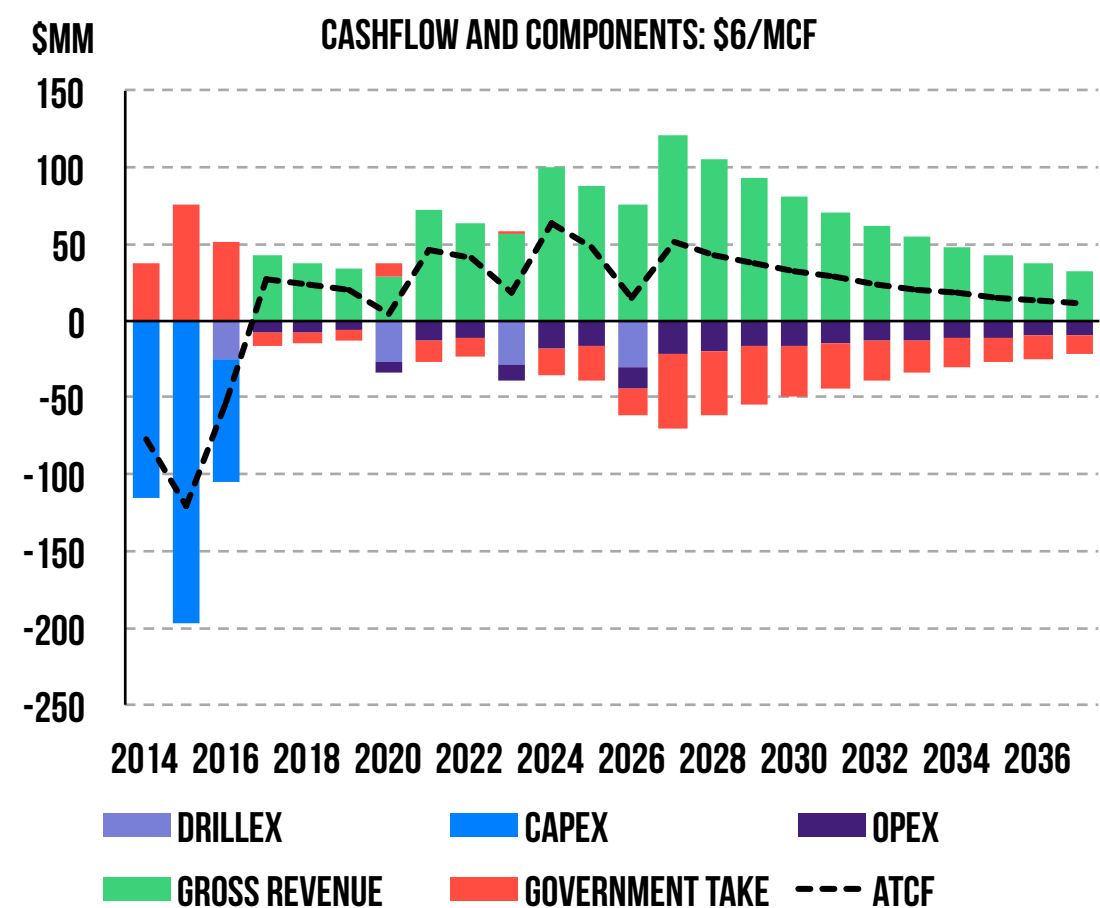
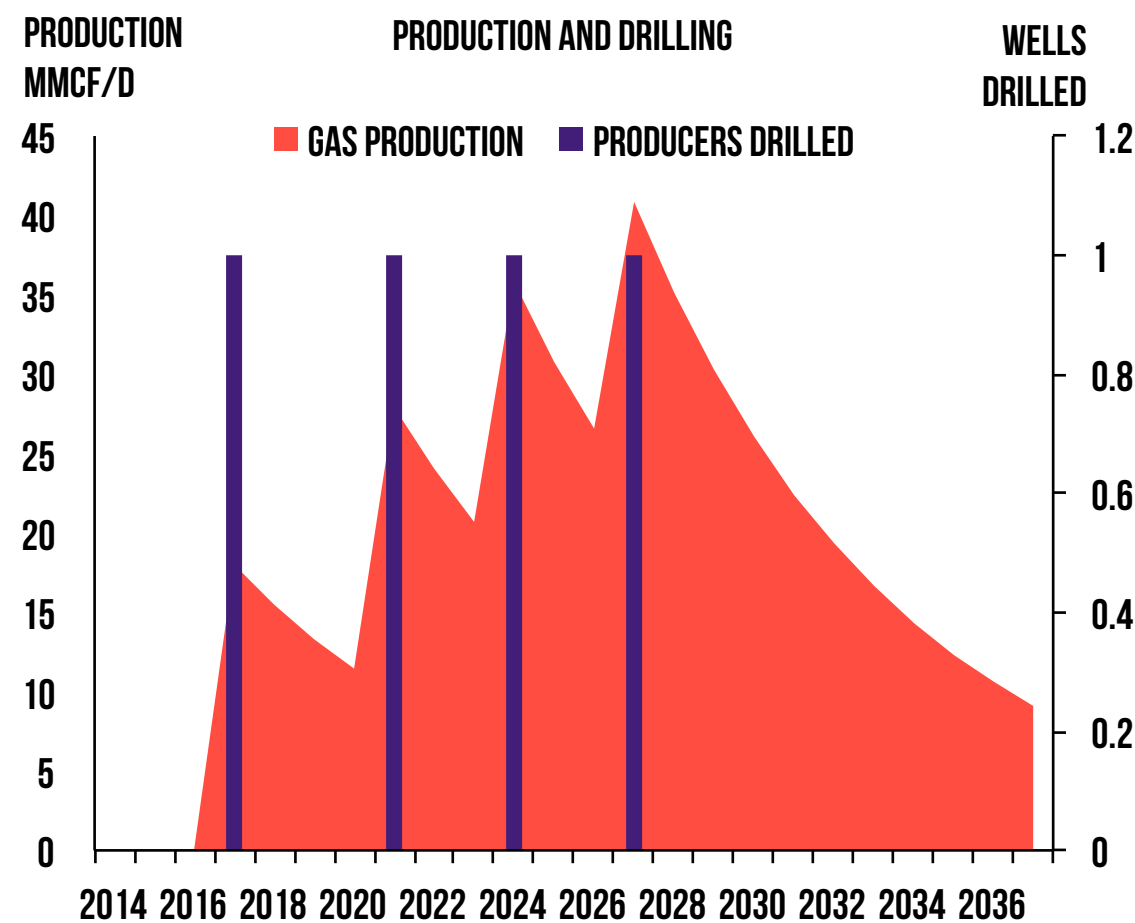
Credits more important for developing new resources, especially with demand constraints

Currently much uncertainty over future regime - setting a stable, sustainable system is paramount

# PROJECT #1: MARKET CONSTRAINED (ASSUMPTIONS)

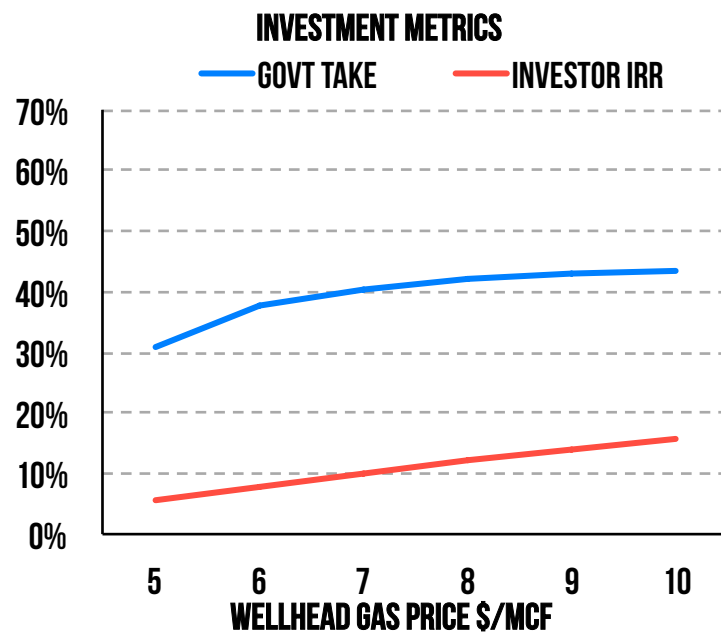
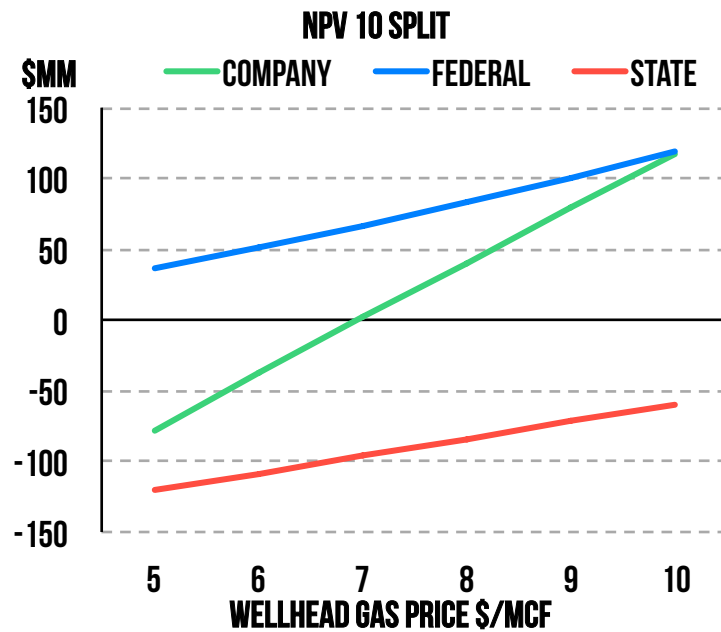
Large upfront investment but constrained gas market

Limited ability to sell gas: can only drill a well every few years

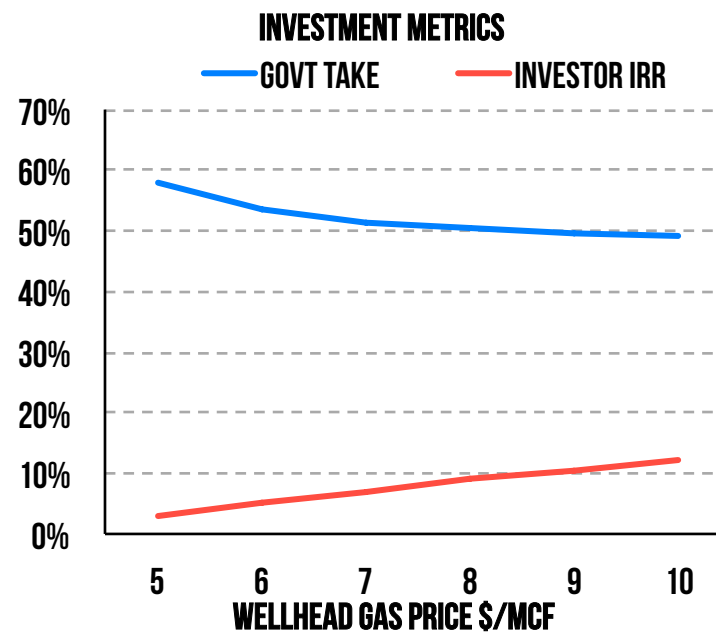
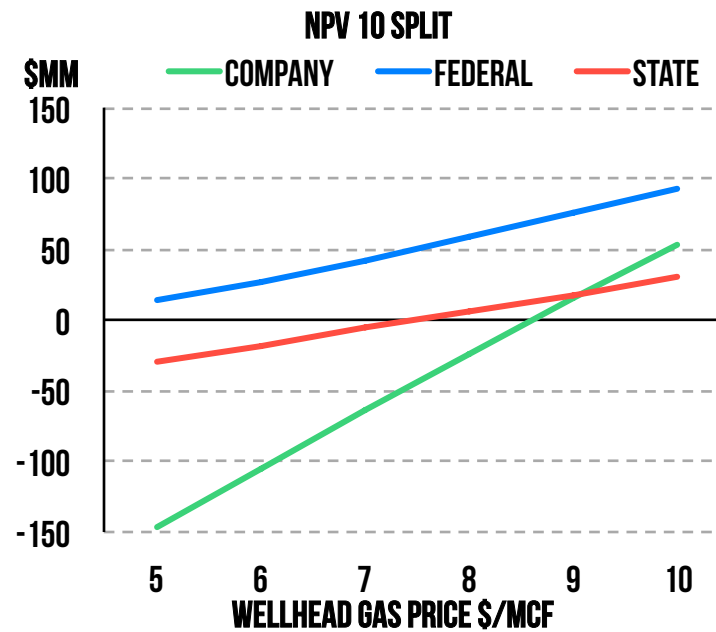


# PROJECT #1: MARKET CONSTRAINED (RESULTS)

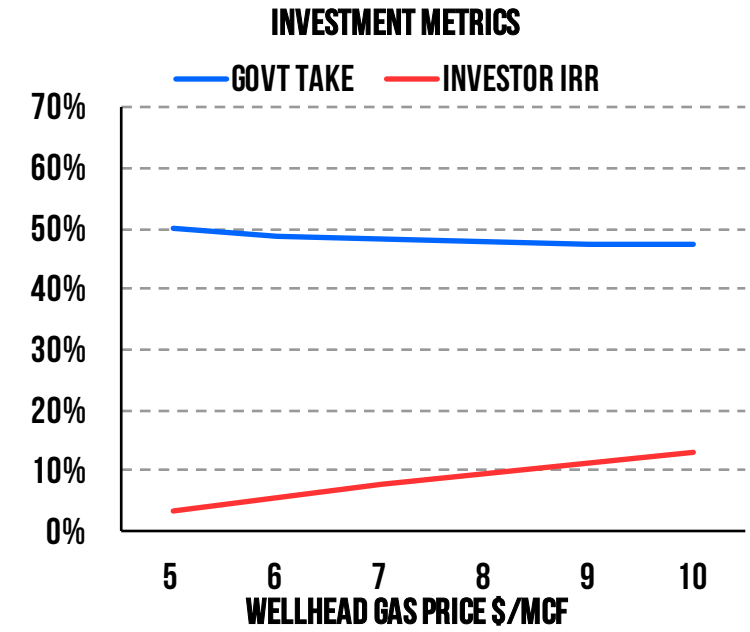
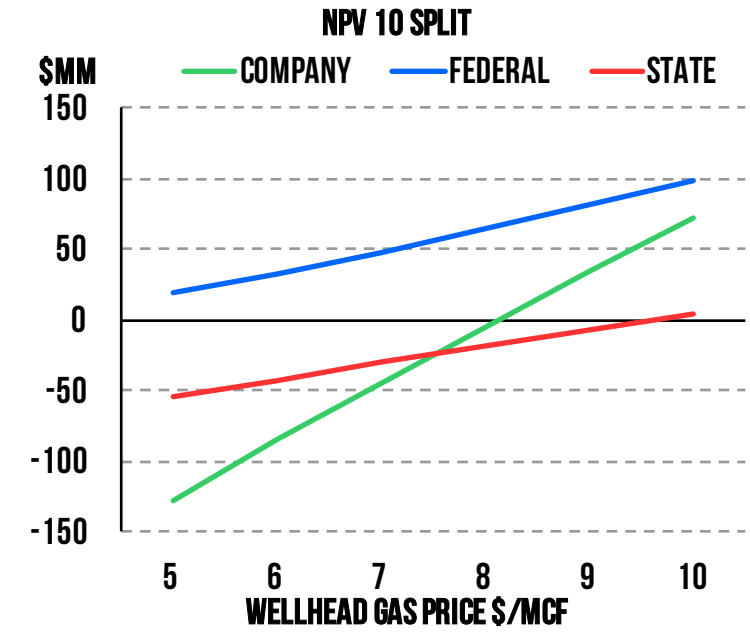
## STATUS QUO



## HB 247: NOL ONLY



## CS HB247: 10% NOL. 20% CAP

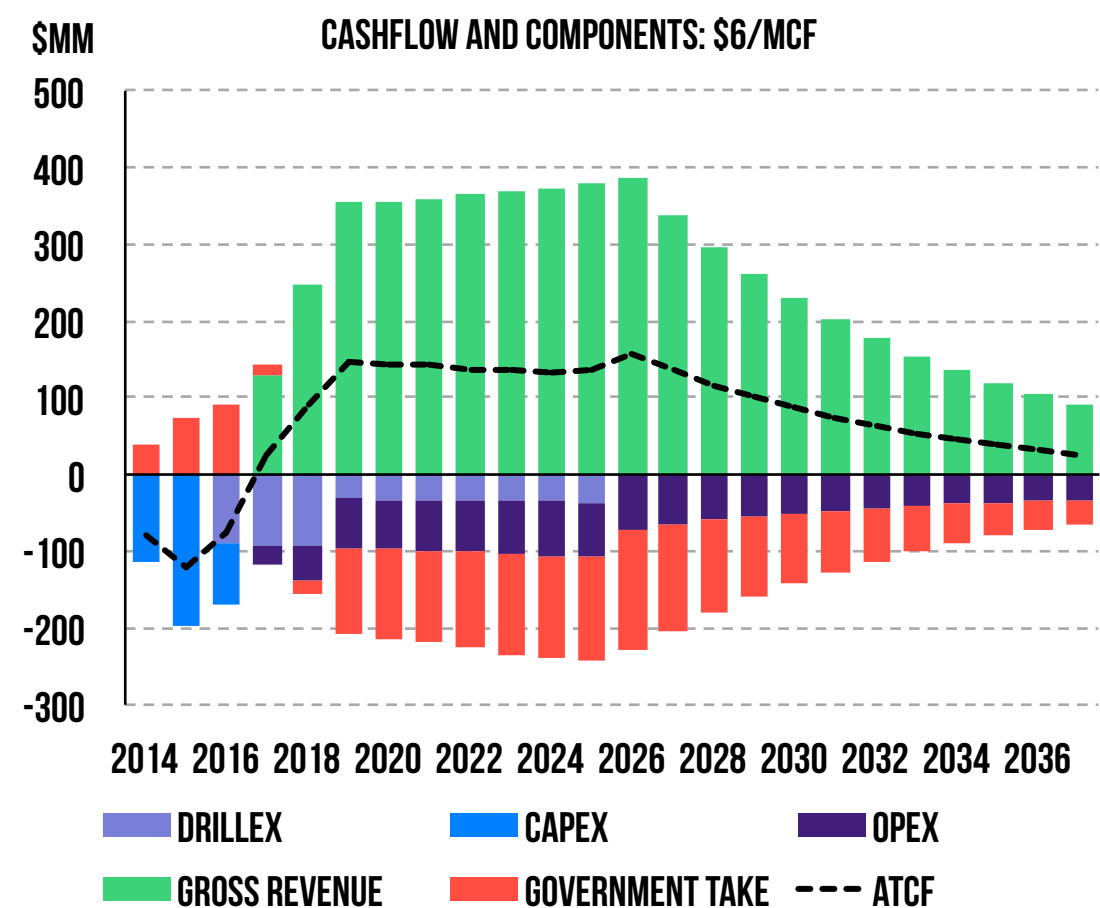
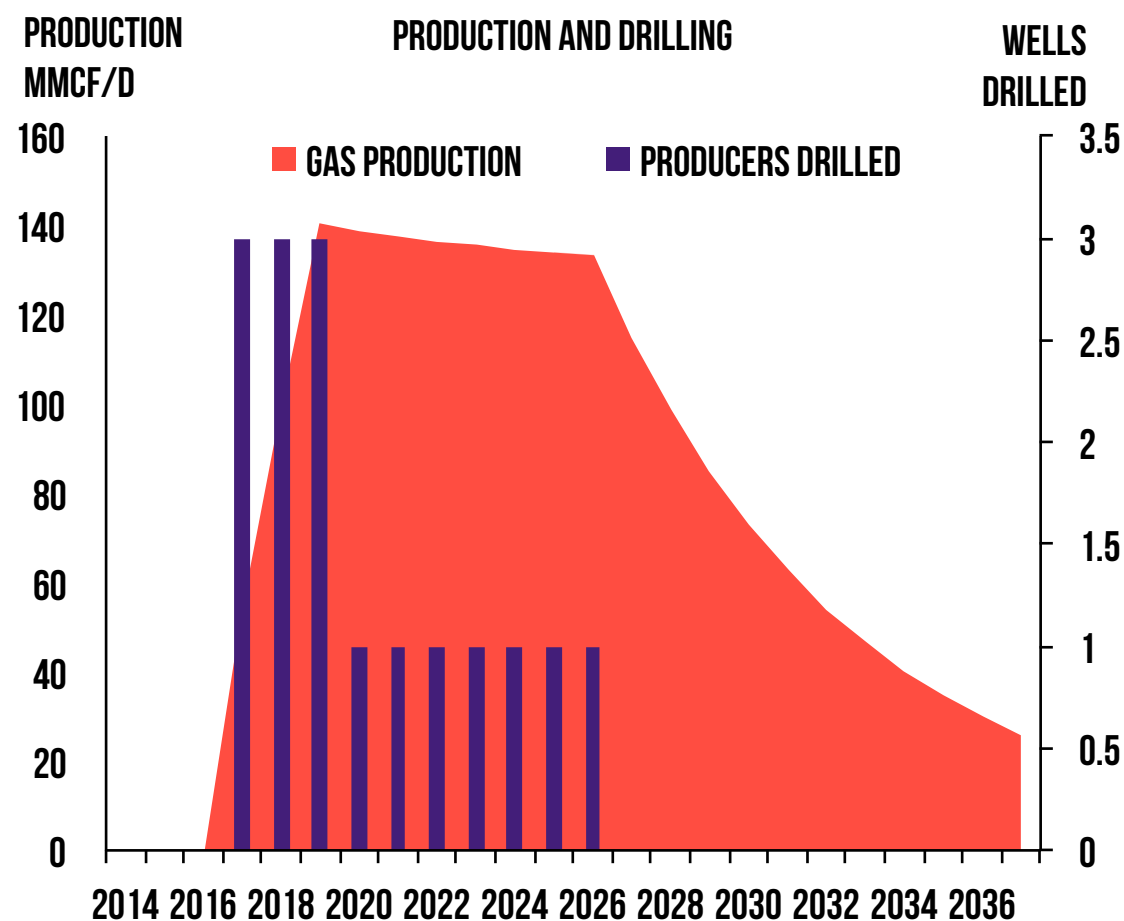


# PROJECT #2: MARKET UN-CONSTRAINED (ASSUMPTIONS)

Large upfront investment but un-constrained gas market

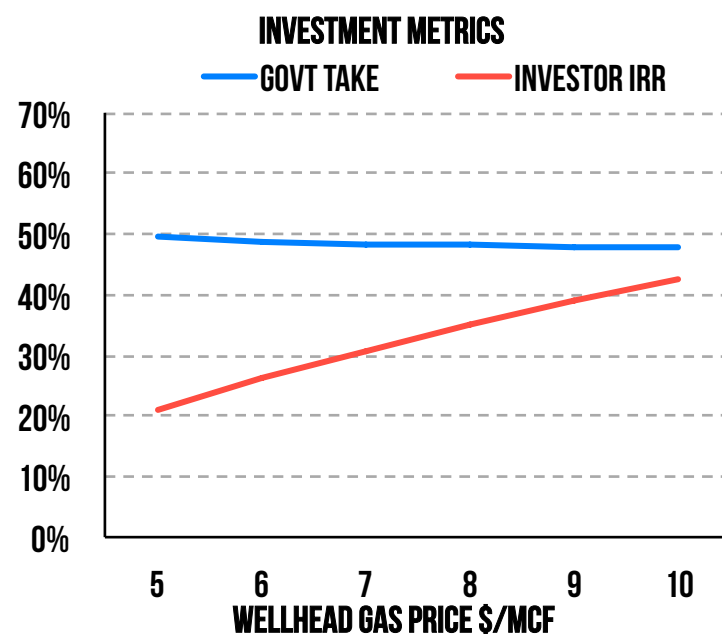
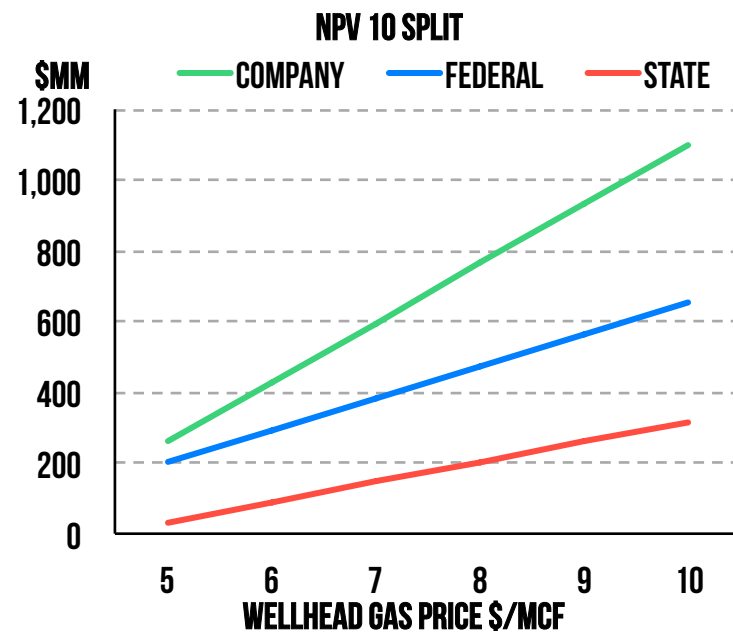
Continued drilling lead to a plateau of 130 mmcf/d

Scenario would require a step change in existing supply-demand dynamics in Cook Inlet

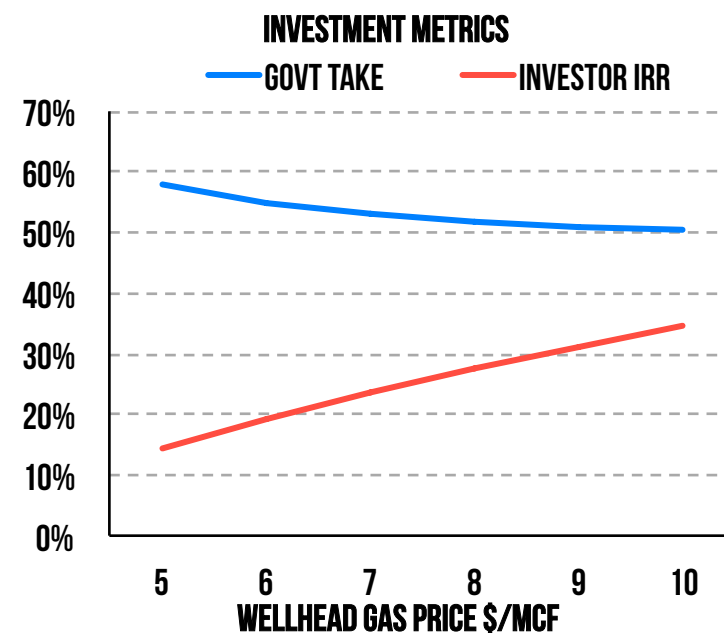
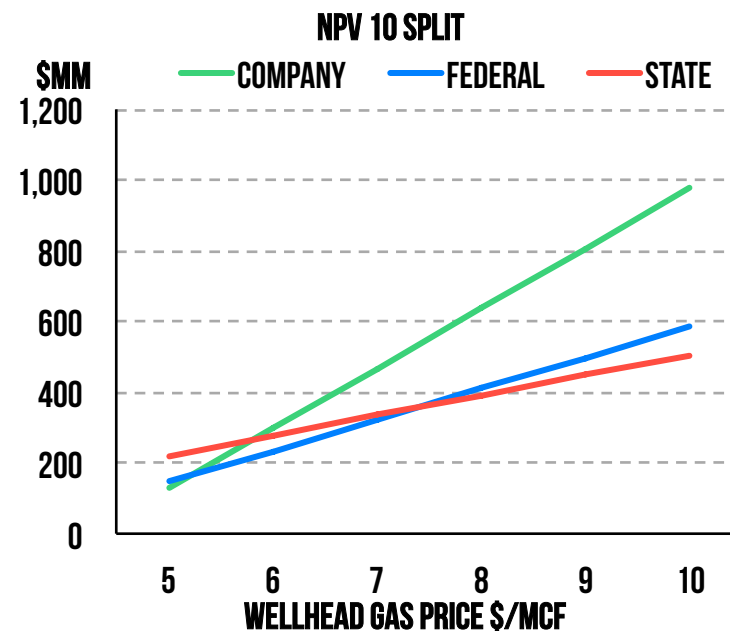


# PROJECT #2: UN-CONSTRAINED (RESULTS)

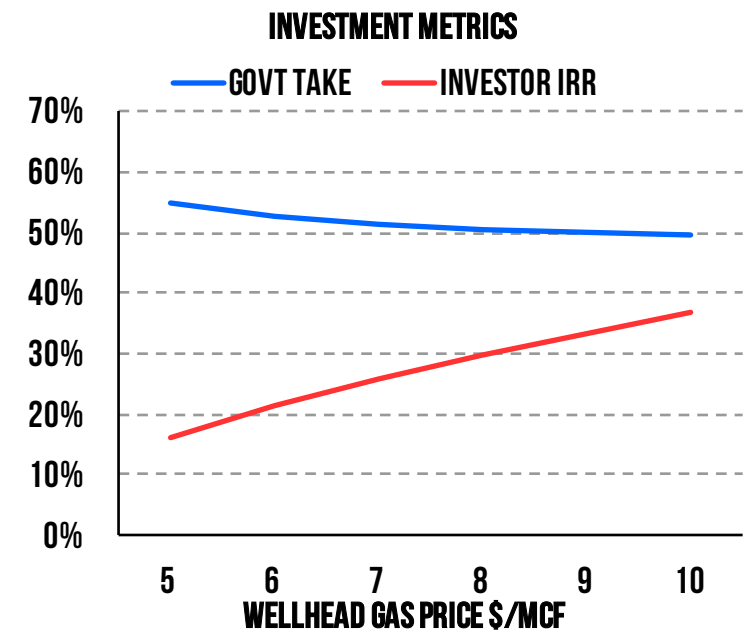
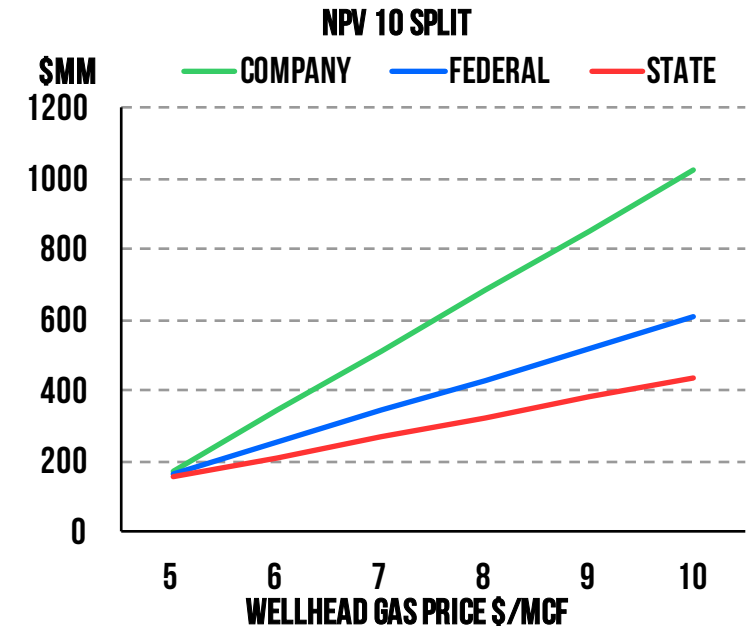
## STATUS QUO



## HB 247: NOL ONLY



## CS HB247: 10% NOL. 20% CAP

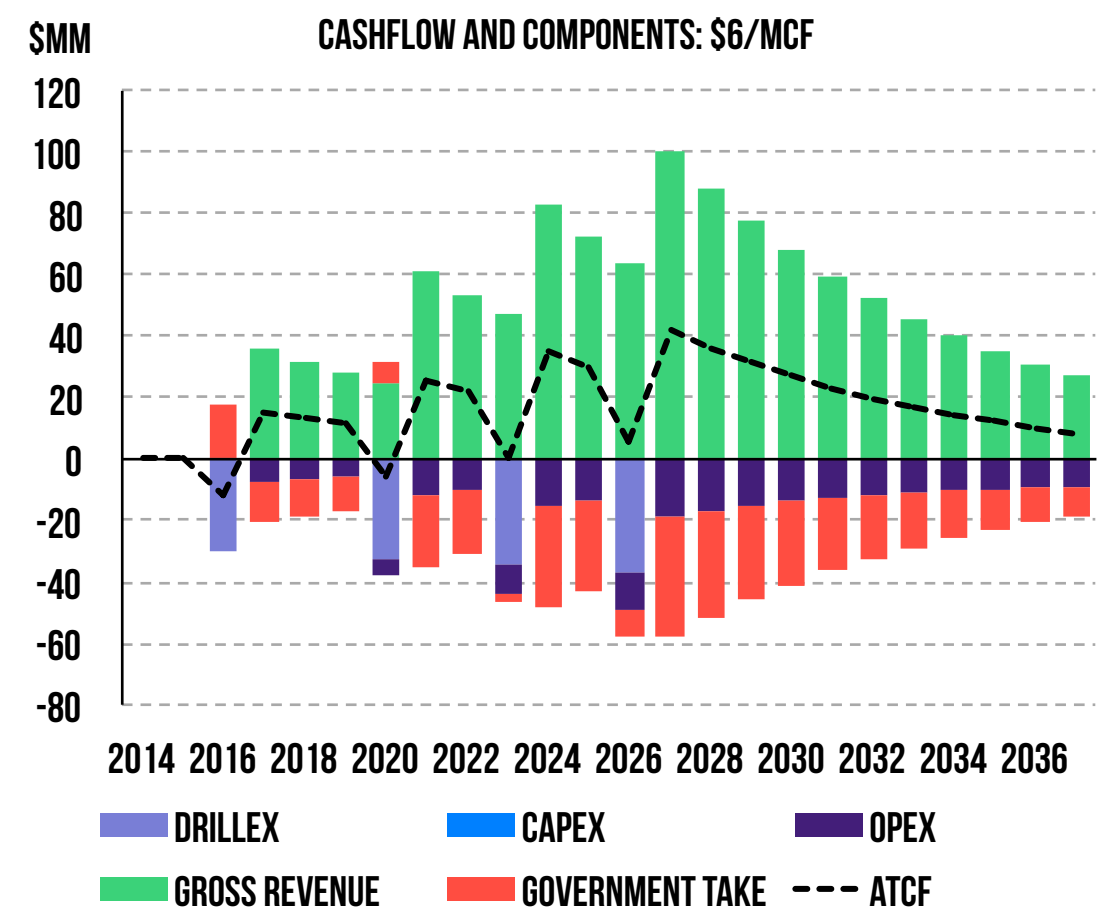
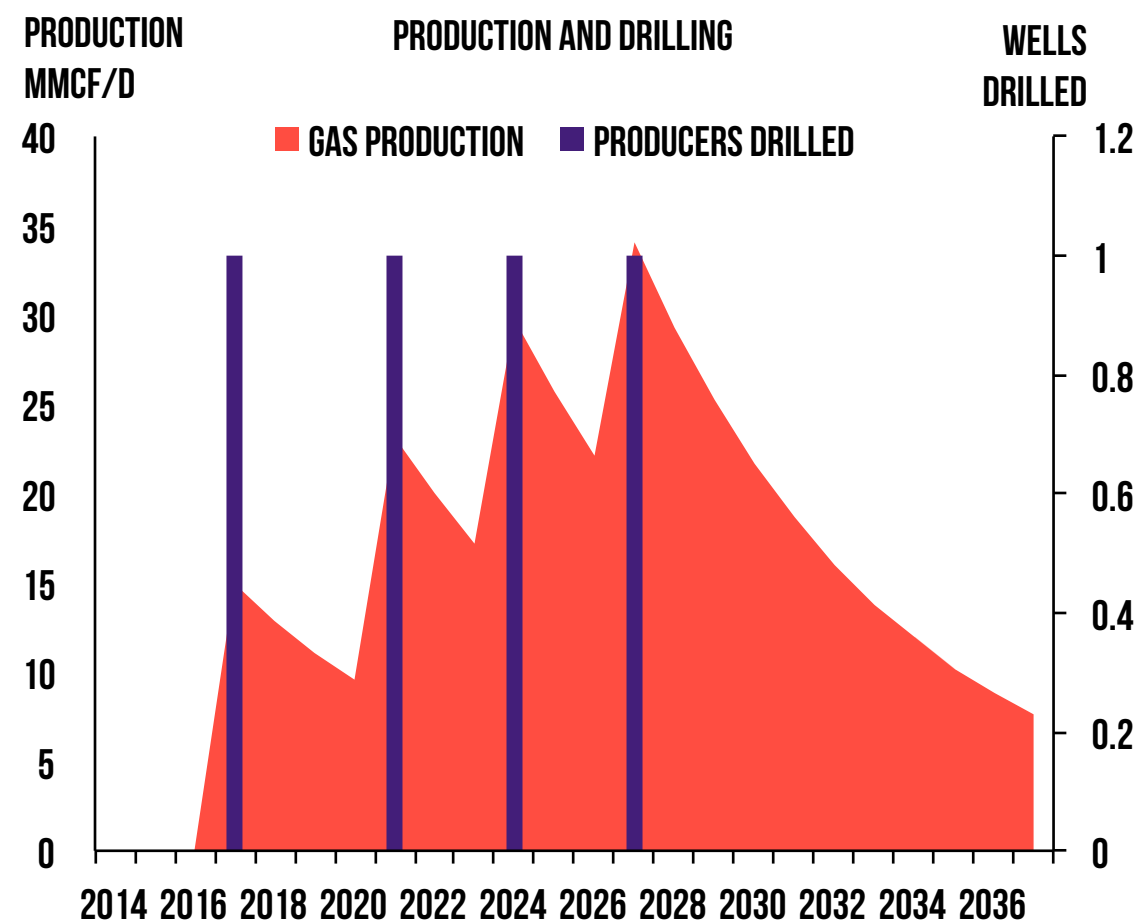


# PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)

Drilling expenditures at existing production—smaller upfront investment

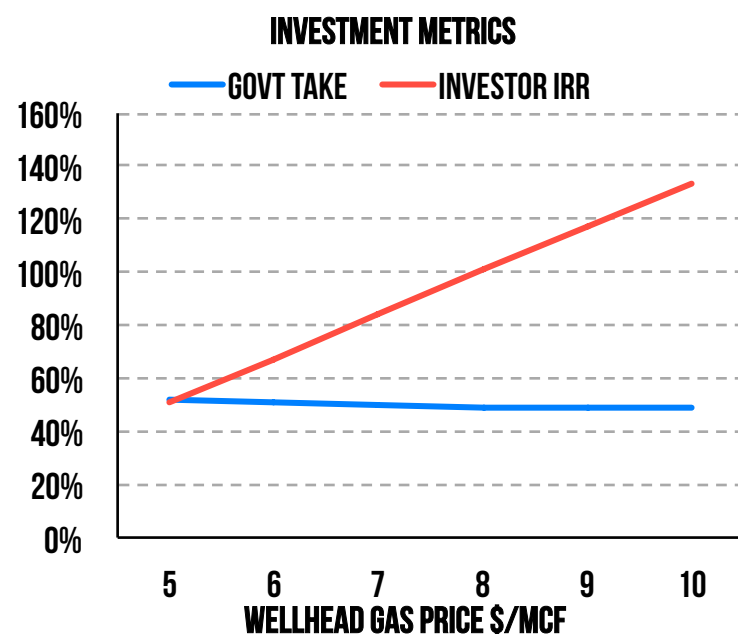
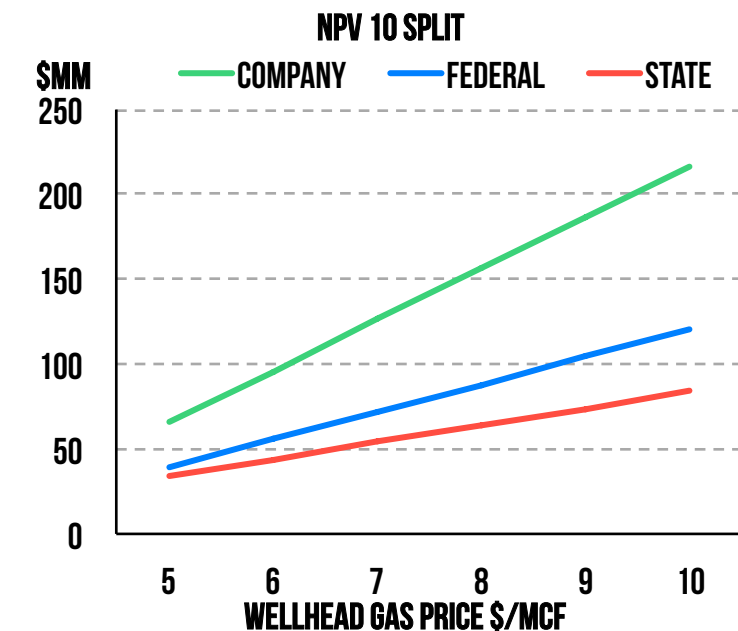
No market constraints assumed

This is a point-forward analysis—it ignores sunk, entry or acquisition costs

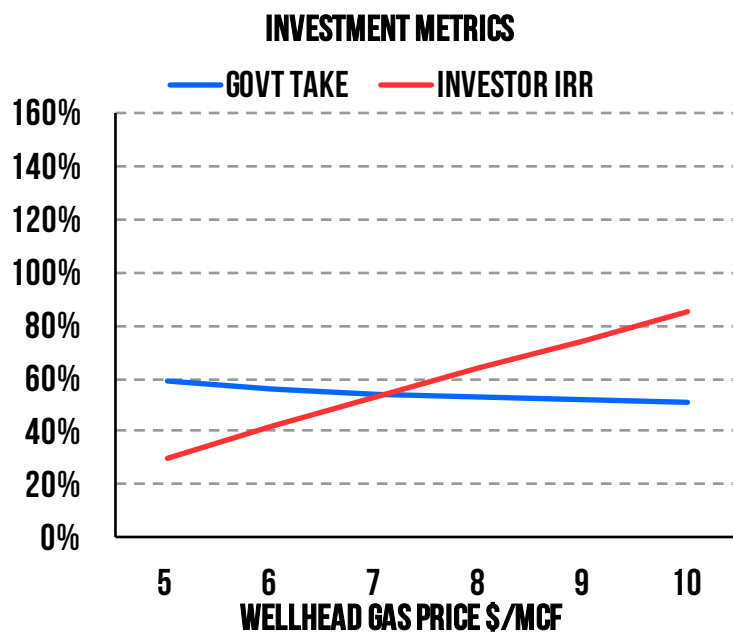
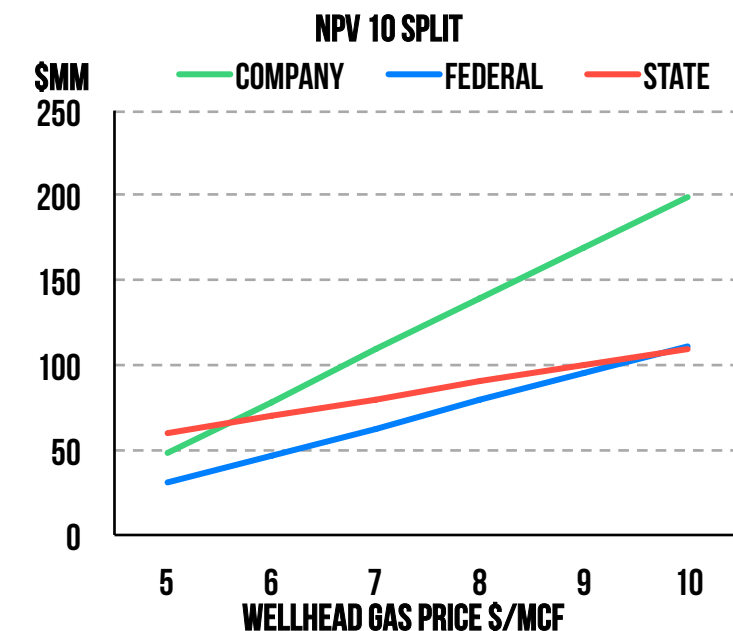


# PROJECT #3: DRILLING EXISTING FIELD (RESULTS)

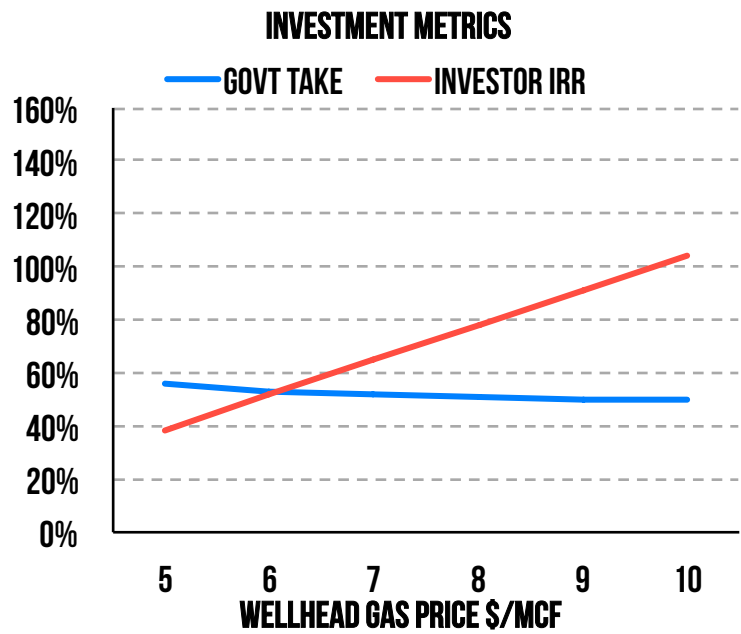
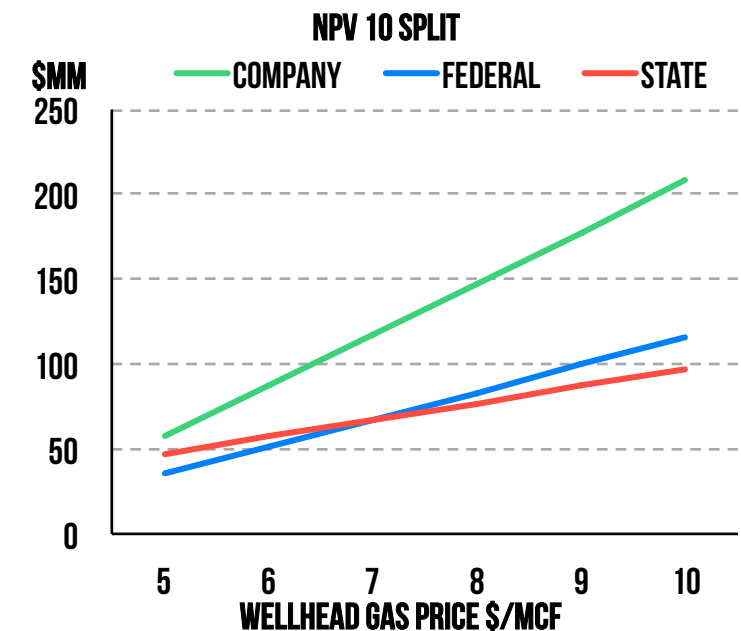
## STATUS QUO



## HB 247: NO CREDITS



## CS HB247: 20% CAP



# AGENDA

**HB 247: SUMMARY OF KEY ISSUES**

**NORTH SLOPE: FISCAL REGIME OVERVIEW**

**NORTH SLOPE: CHANGES PROPOSED UNDER HB 247**

**COOK INLET: KEY ISSUES AND PROPOSED CHANGES**

**HB 247: SUMMARY OF KEY ISSUES**

**APPENDIX**



<b>Fiscal System Feature</b>	<b>Status Quo</b>	<b>HB 247 Proposed Change</b>	<b>Impact</b>	<b>HRES CS HB247</b>
<b>Per-Barrel Credit and Gross Minimum Tax</b>	Tax liabilities assessed annually, smoothing impact of price volatility.	Calculate \$/bbl credit and Gross Minimum Tax interaction monthly.	State would have netted additional ~\$100mm in 2014 under this system.	Maintain status quo - tax liabilities assessed annually
<b>Gross Value Reduction and Net Operating Loss Credit</b>	Gross Value Reduction artificially reduces Production Tax Value, and NOL credit is based on PTV, so 35% NOL credit can be given on loss greater than actual loss - effectively more than 35% support for spending.	Assess NOL credit on actual loss (not including GVR), so NOL is for 35% of actual loss, and all producers have 35% support for spending.	Net impact is to reduce state support for all spending to 35%. Questions exist about whether >35% spending support for GVR oil was deliberate incentive or unintended consequence under SB21.	Adopt proposed fix to NOL calculation for GVR-eligible production
<b>Gross Minimum Tax</b>	4% rate, binding for legacy output if net value is positive. If net value is negative, NOL can reduce taxes below floor. "New," GVR-eligible production can take to zero due to \$5/bbl and small producer credit	Harden floor for all production: NOL credits can't take below floor for legacy, and NOL, small Producer and \$5/bbl can't take below floor for GVR-eligible production. Increase rate from 4% to 5%	State revenues rise at low oil prices. For many new fields, taxes rise from 0 to 5% at current prices. For legacy production, taxes rise at time when value is negative.	Maintain status quo - no further floor hardening

<b>Fiscal System Feature</b>	<b>Status Quo</b>	<b>HB 247 Proposed Change</b>	<b>Impact</b>	<b>HRES CS HB247</b>
<b>Net Operating Loss credit reimbursement</b>	Producers with >50 mb/d production must carry NOL forward, others can be reimbursed by the state	\$25mm per company annual limit on reimbursement. Companies with annual revenues > \$10bn must carry forward, regardless of production level.	Limit substantially increases capital needs for new developments; and if effective July 2016 would have major negative impact on developments underway. Raises hurdle/break-even price for projects by \$5 to \$15/bbl.	\$200mm per company annual limit on reimbursement.
<b>Gross Value at Point of Production calculation</b>	GVPP is calculated by subtracting transportation costs from sale price. If transportation costs for some production exceed price, GVPP is negative	GVPP cannot go below zero	Could limit deductibility of some transport costs. Particularly likely to be an issue at current prices if applied on a per-unit or per field basis.	Maintain status quo
<b>Cook Inlet Tax Credits</b>	25% Net Operating Loss credit, 20% Qualified Capital Expenditure credit, 40% Well Lease Expenditure credit; up to 65% gov't support for spending and minimal production tax	Repeal QCE and WLE credits effective July 1 2016, leaving only 25% NOL credit	Cook Inlet credit regime is clearly unsustainable in current environment; repeal in present year may have major impacts on capital commitments already made, and the viability of producers who have made those commitments	Reduce NOL credit to 10%, keep 20% QCE credit, reduce WLE credit to 20% by 2018

# AGENDA

**HB 247: SUMMARY OF KEY ISSUES**

**NORTH SLOPE: FISCAL REGIME OVERVIEW**

**NORTH SLOPE: CHANGES PROPOSED UNDER HB 247**

**COOK INLET: KEY ISSUES AND PROPOSED CHANGES**

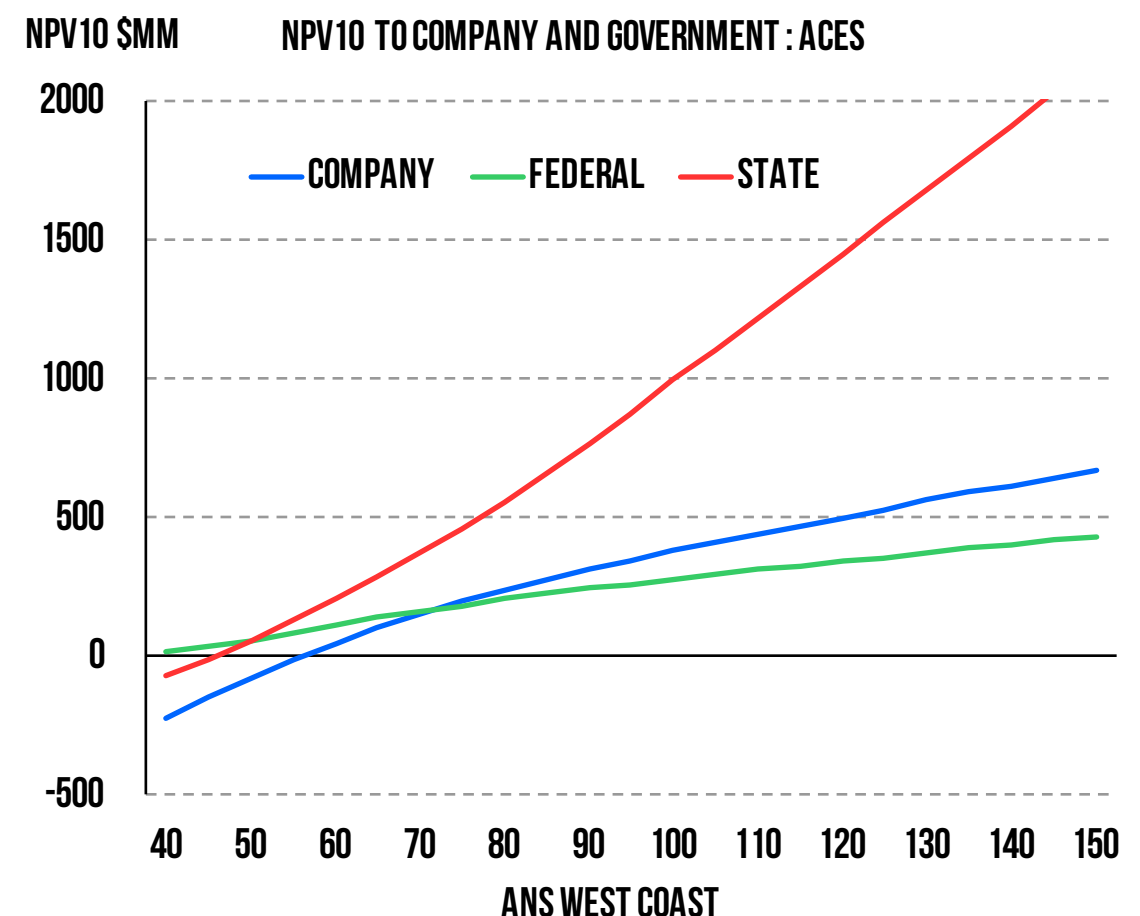
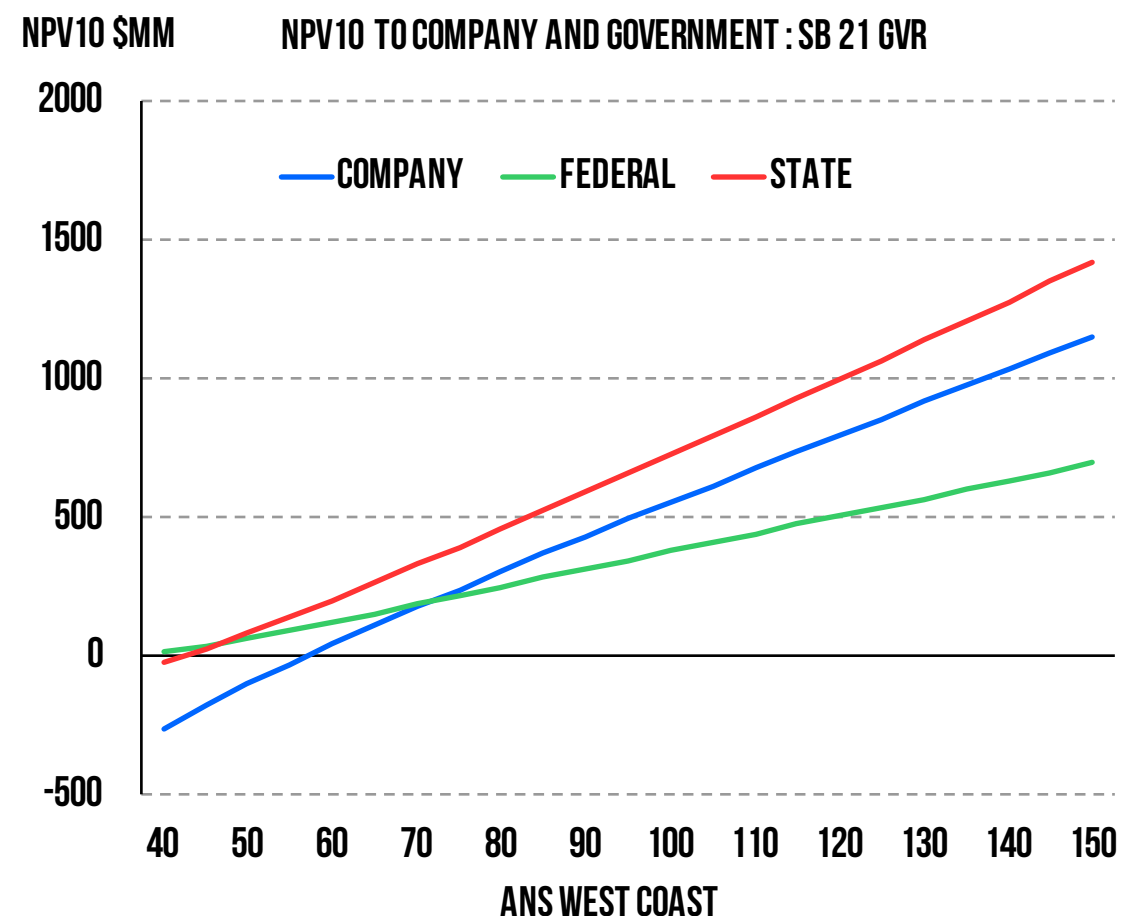
**HB 247: SUMMARY OF KEY ISSUES**

## APPENDIX

# SB21 WITH GVR MORE PROTECTIVE AT LOWER PRICES

Using sample NS investment, examining total value over lifecycle to all stakeholders at range of prices:

- SB21 GVR Split of total value between state and company relatively even over a wide range of prices
- SB21 GVR state NPV10 higher than that for company at all prices, and at low prices, higher than ACES



# COOK INLET GAS HAS GONE THROUGH **MAJOR TRANSITION**

## Old Cook Inlet Gas Market

Surplus gas exported (via LNG and Agrium)

Low wellhead prices

Market view is that gas is long

Gas produced by large, international players

Secure local supply via long-term contracts

Producers offered high seasonal flex

Seasonal flex coming largely from supply

## New Cook Inlet Gas Market

Limited surplus; gas absorbed in local market

High wellhead prices

Market view is that gas is short

Gas produced by smaller, focused players

Shorter term sales contracts b/w producers, utilities

Mature fields have much more limited seasonal flex

Seasonal flex largely from storage and demand

# **GAS SUPPLY AND DEMAND DYNAMICS IN COOK INLET**

## **Supply and resources**

2015 production: 103 bcf

Estimated 2P reserves: 1,600 bcf (DNR, 2015)

Legacy fields: 1,183 bcf

Kitchen Lights/Cosmo: 417 bcf (ballpark)

Yet to find estimates are much higher

**Existing + new fields should be enough for current demand 10+ years; demand upside needs more gas**

## **Demand**

2015 consumption around 100 bcf

In-state demand: 80-85 bcf/yr

Exports: 13–16 bcf (2014–2015)

AGDC 2030 forecast: 115 to 130 bcf/yr (ex. nitrogen)

Nitrogen demand upside: 28 bcf/yr per train (2 trains)

State support due to gas “shortage,” yet developers say they lack markets to develop new fields; why?

Maybe issue is timing (market covered by existing contracts, window opens later)

Or a natural negotiation process (buyers and sellers looking for the “right” pricing point)

Or different views about resource certainty, especially for developing new demand (Agrium)

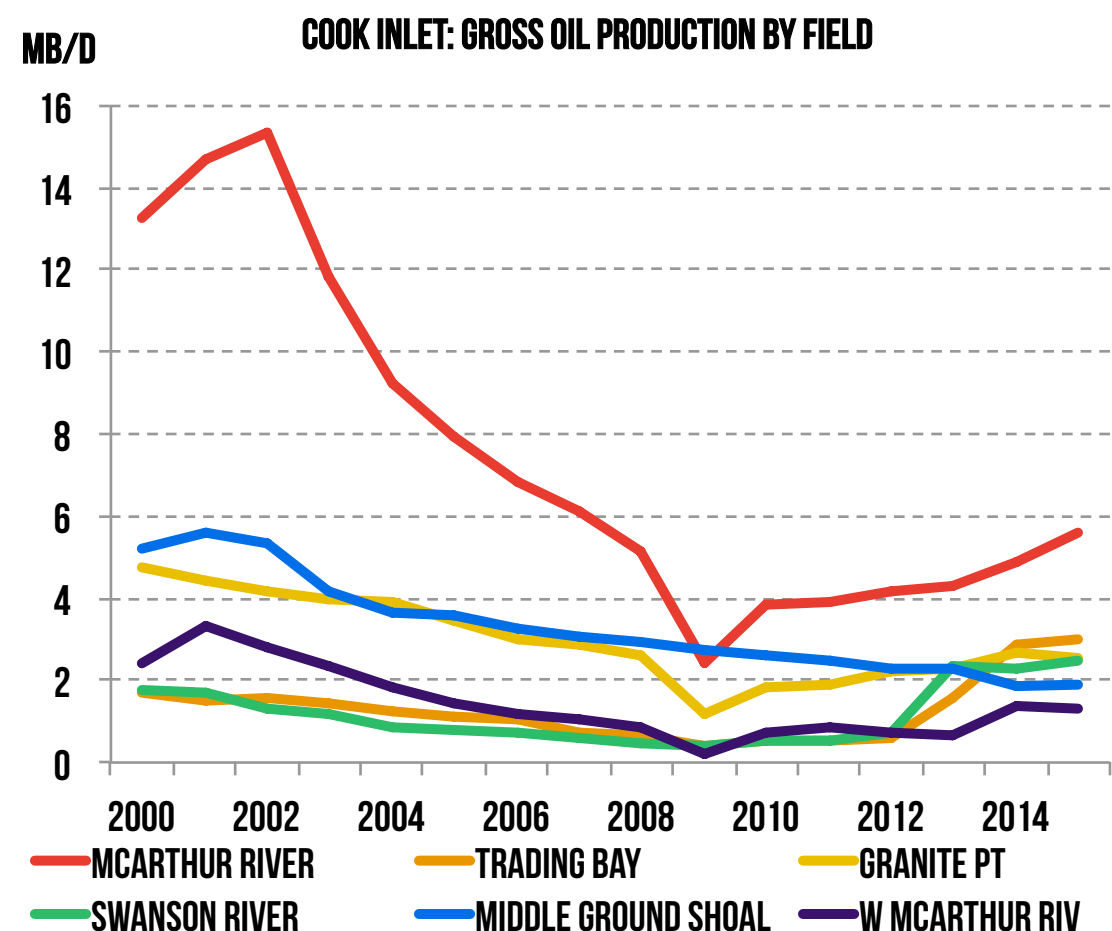
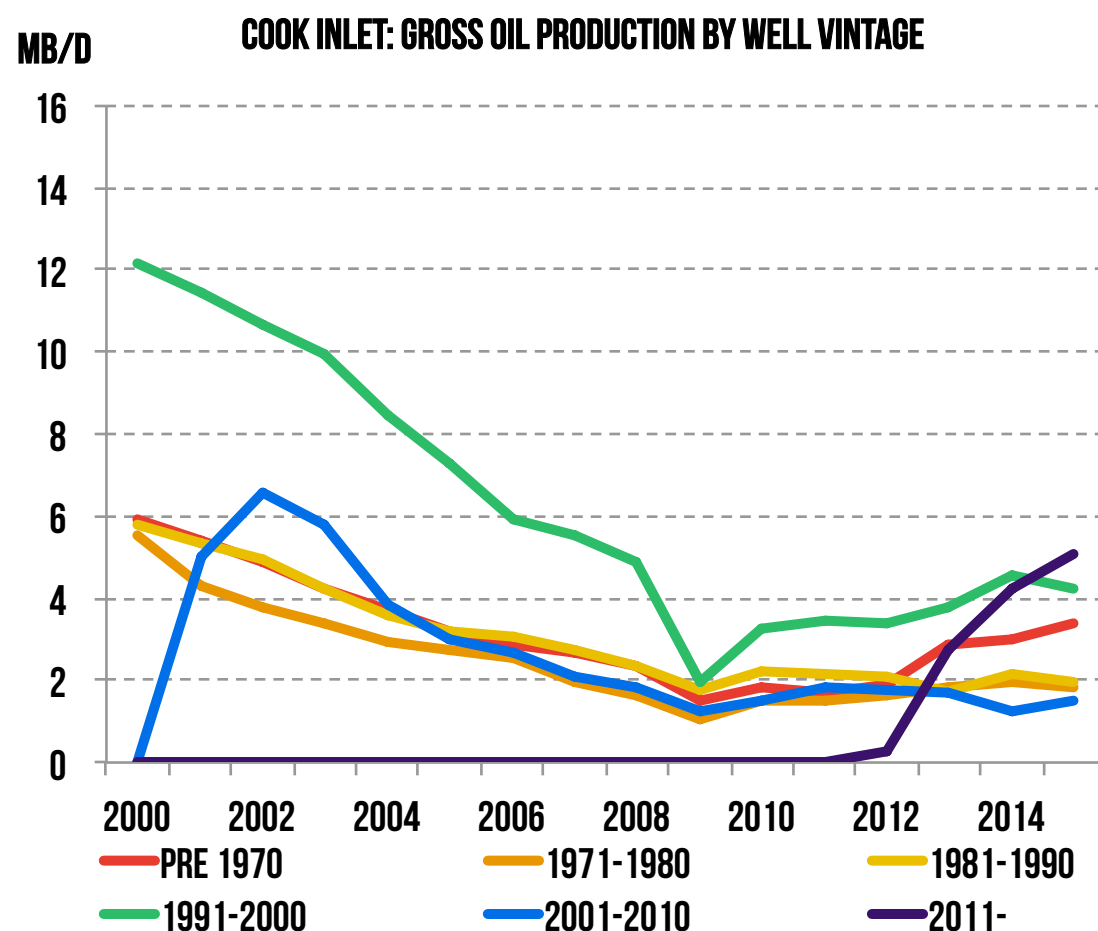
SOURCE: DEPARTMENT OF NATURAL RESOURCES; ALASKA OIL AND GAS CONSERVATION COMMISSION; ALASKA GASLINE DEVELOPMENT CORPORATION; MCDOWELL GROUP (NITROGEN DEMAND)

# OIL UP FROM WORKOVERS, NEW WELLS IN EXISTING FIELDS

Production from old wells has risen, especially from wells drilled before 1970 and in 1990s

New wells drilled after 2011 have also added about 5 mb/d of production

Production is up in most fields; biggest gains from McArthur River field



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

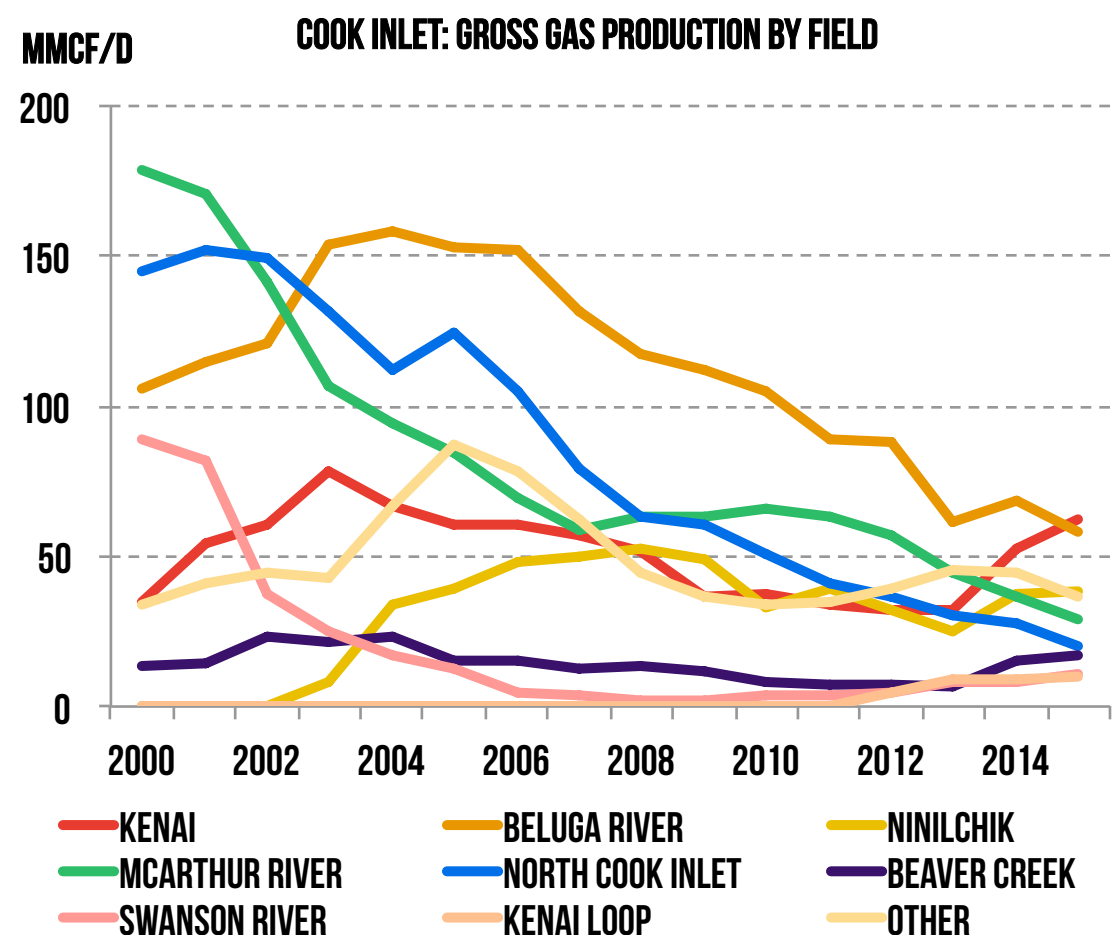
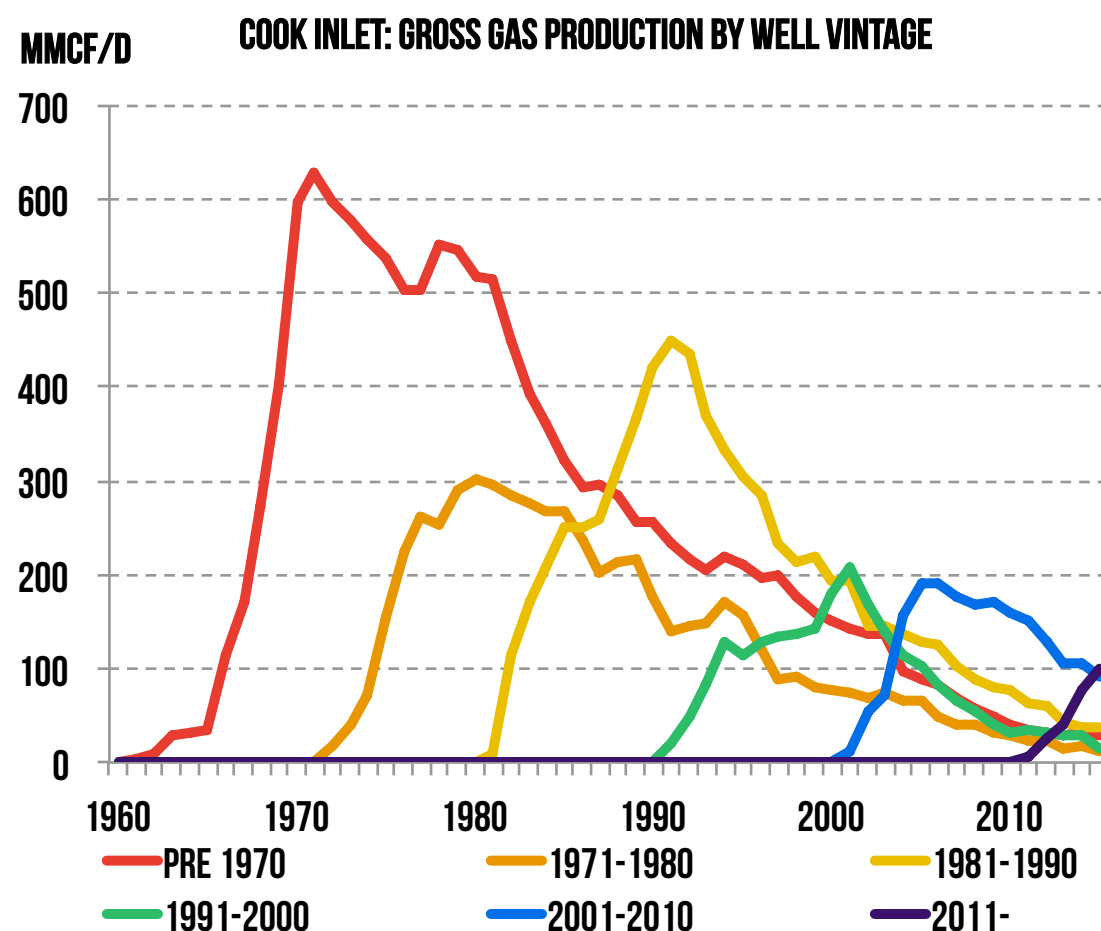
# **GAS** FLATTENING FROM NEW WELLS IN EXISTING FIELDS

Wells drilled after 2011 have added about 100 mmcf/d of new production

Production from Beluga River, Ninilchik, and North Cook Inlet declined by 85.7 mmcf/d in 2011–2015

Growth from Kenai (+28 mmcf/d), Beaver Creek (+10), Kenai Loop (+9.7), and Swanson River (+7.3)

Only Kenai Loop is (major) new field (first gas in 2012); other growth from workovers and new wells



SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

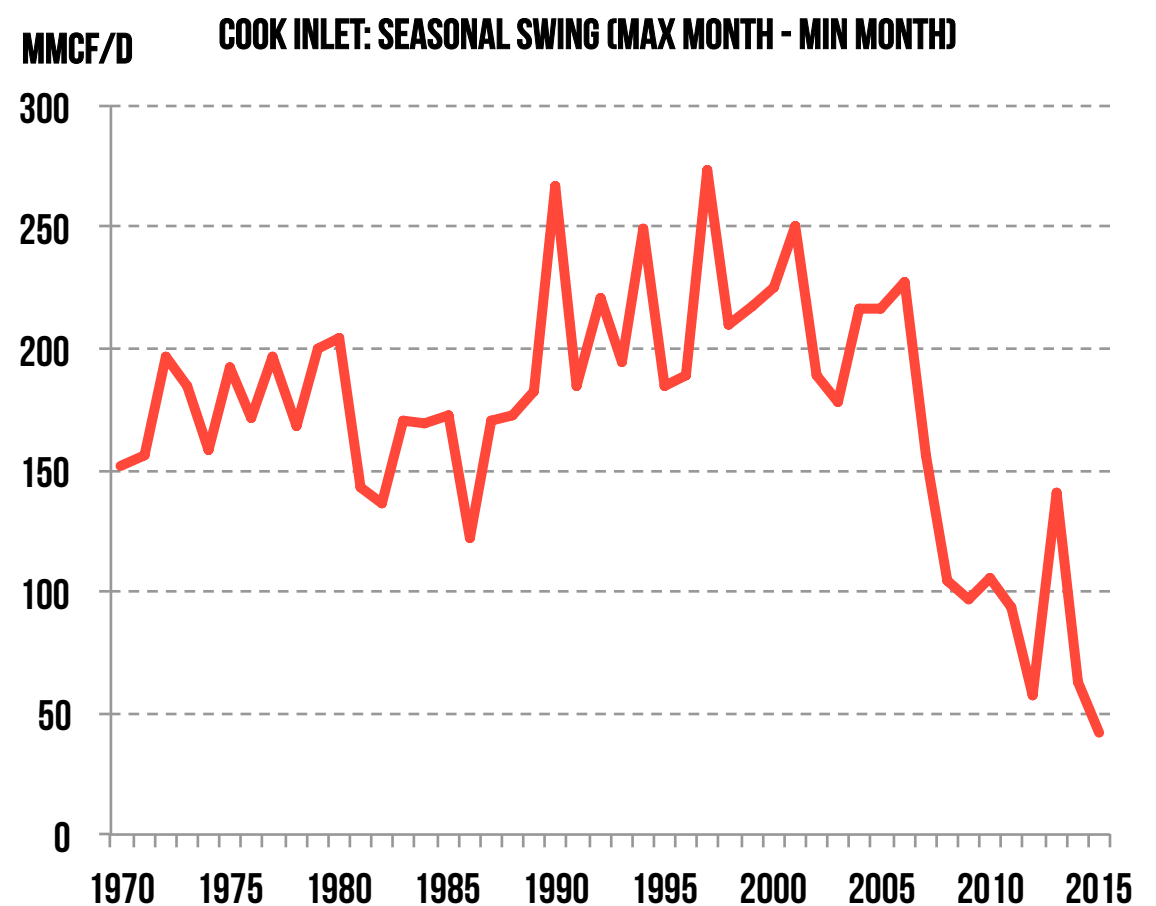
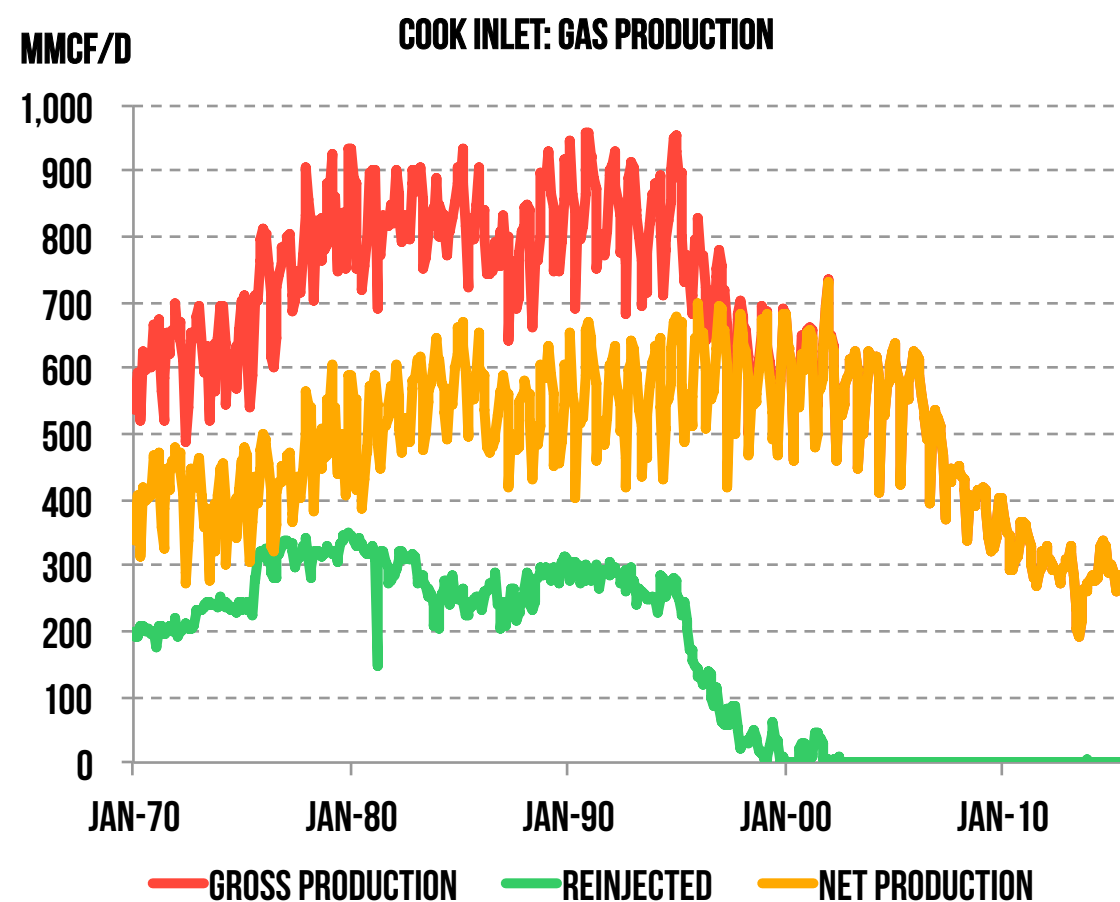


# MATURE BASIN HAS **LIMITED SEASONAL** PRODUCTION FLEX

Historically, gas production in Cook Inlet has provided seasonal flex

As production has matured, that seasonality has gone away

Since 2006, we have seen the seasonal swing (max-min month) drop to below 100 mmcf/d



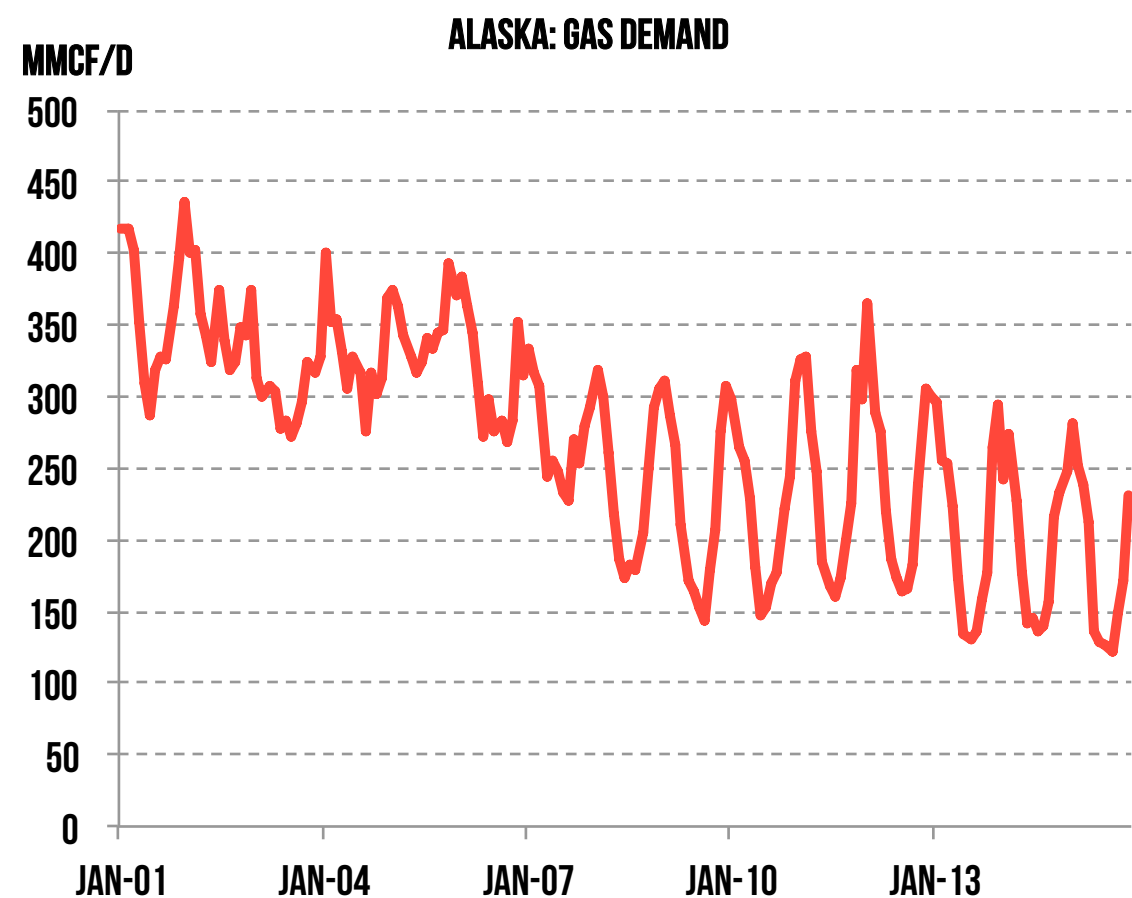
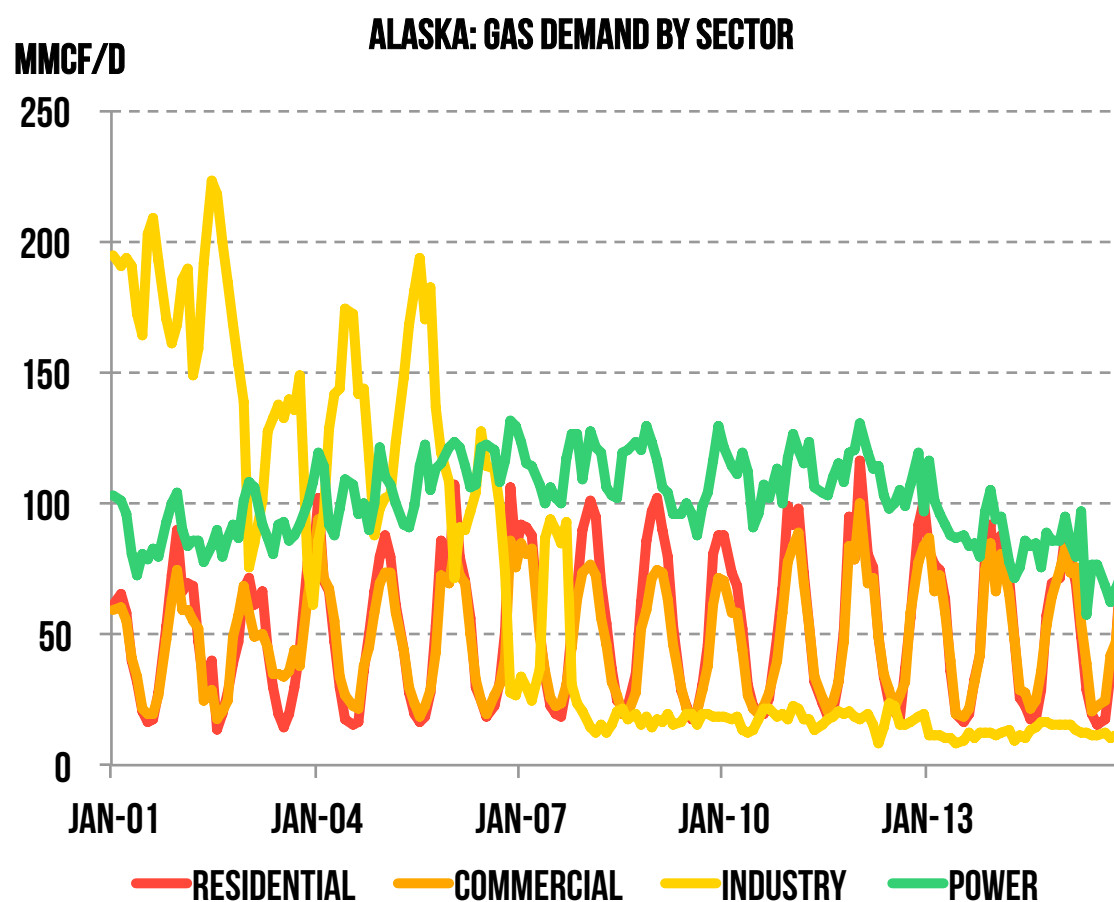
SOURCE: ALASKA OIL AND GAS CONSERVATION COMMISSION, OIL AND GAS DATA WEB APPLICATION (DATA THROUGH DECEMBER 2015)

## DEMAND HAS, MEANWHILE, BECOME MORE SEASONAL

Historically, gas production was either exported or consumed in industry (nitrogen)

Lower consumption in industry has made the demand profile more seasonal (lack of “base-load” demand)

In 2003–2005, industry consumption was flexible enough to serve a seasonal purpose



SOURCE: ENERGY INFORMATION ADMINISTRATION, ALASKA NATURAL GAS CONSUMPTION BY END USE

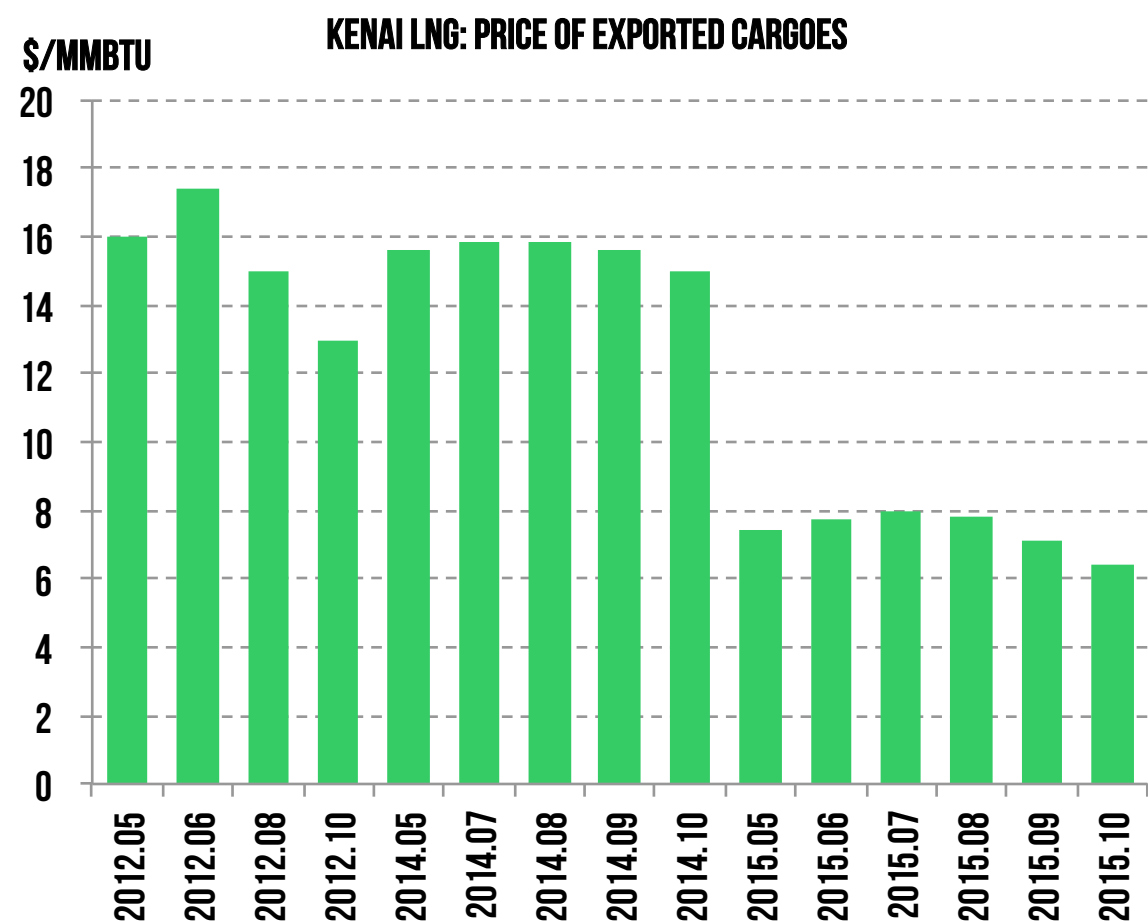
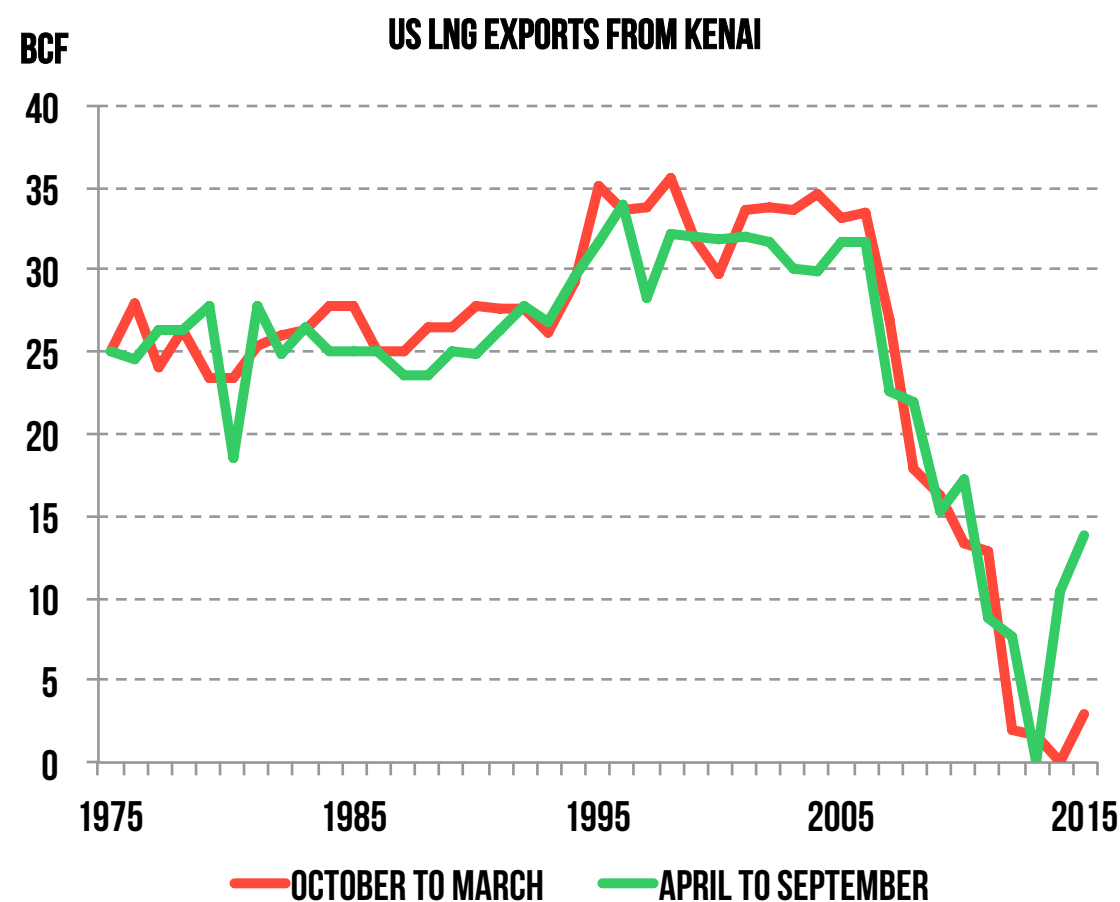
# RECENTLY, **EXPORTS** HAVE OFFERED A SEASONAL OUTLET

Historically, LNG exports were not particularly seasonal: exports in winter and summer were similar

Since 2012, LNG exports have taken place largely in the summer

In 2014 and 2015, Kenai exported 13 and 16 bcf respectively, helping to support seasonal flexibility

How will lower prices and ConocoPhillips' divestment of upstream in Cook Inlet impact this outlet?



SOURCE: ENERGY INFORMATION ADMINISTRATION

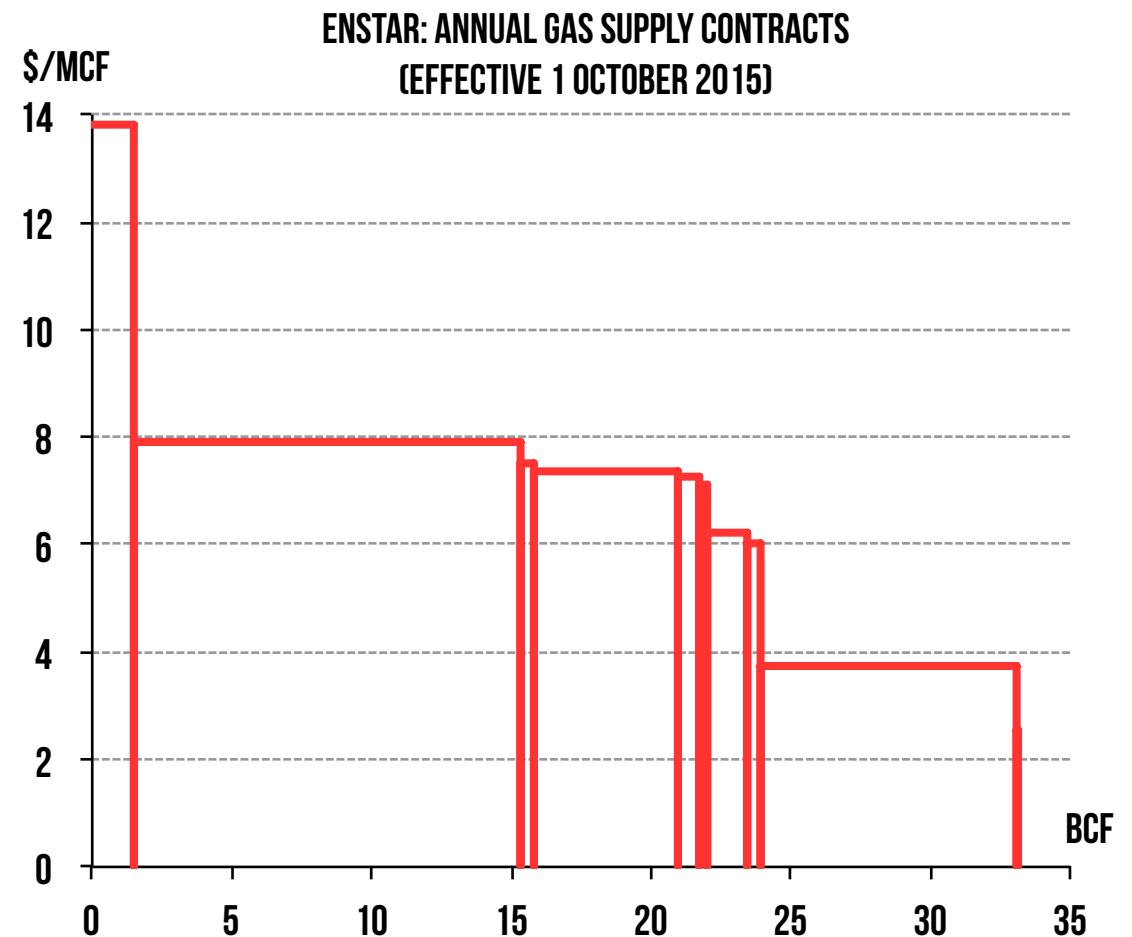
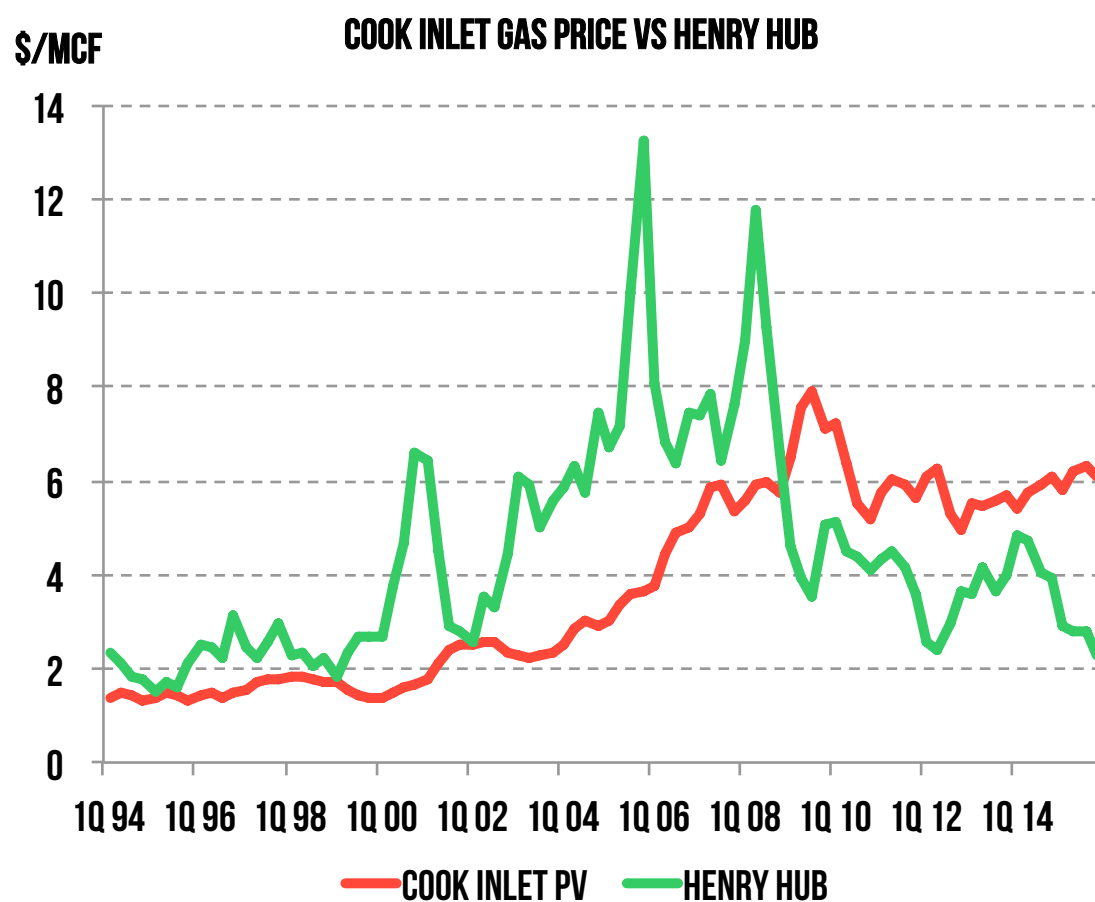
# GAS PRICES HAVE RISEN CONSIDERABLY POST 2004

Historically, gas prices in Cook Inlet have been equal to or (more often) below Henry Hub

Since 2004, there has been a steady rise in gas prices; since 2010, prices were between \$5 and \$6/mcf

But there is considerable supply trading above this level, at \$8+ (and rising depending on contract)

Other jurisdictions have found \$5-\$7/mcf is sufficient to produce most expensive gas (shale, deepwater)



SOURCE: ALASKA DEPARTMENT OF REVENUE, TAX DIVISION (COOK INLET PV); ENERGY INFORMATION ADMINISTRATION (HENRY HUB); ENSTAR, DETERMINATION OF GAS COST ADJUSTMENT