02/17/15 PRESENTATION STATEWIDE OIL & GAS TAX CREDITS

<TARGET><BILL></BILL><SUBJECT>02-17-15 PRESENTATION STATEWIDE OIL and GAS TAX CREDITS</SUBJECT><COMM>HFIN29</COMM></TARGET>

ALASKA STATE LEGISLATURE

HOUSE FINANCE COMMITTEE

State Capitol, Room 519

Rep. Mark Neuman, Co-Chair   Rep. Steve Thompson, Co-Chair

Tuesday, February 17, 2015
9:00 AM

Rep. Thompson will chair for Rep. Neuman

Agenda:

Statewide Oil and Gas Production Tax Credits
Presentation by Enalytica

Presenting in Person:
JM Janak Mayer, Partner, Enalytica
NT Nikos Tsafos, Partner, Enalytica

P. 01

TRANSACTION REPORT

FEB-17-2015 TUE 11:18 AM

FOR: house finance 4656813

SEND

DATE	START	RECEIVER	TX TIME	PAGES	TYPE	NOTE	M#	DP
FEB-17	11:17 AM	4655334	43"	1	FAX TX	OK	190	

TOTAL : 43S PAGES: 1

COMMITTEE ACTION ON LEGISLATION

Fax to Chief Clerk's Office 5334

HOUSE FINANCE SECRETARY: Jodie McDonnell

PAGE 1 OF 1

DATE: 2.17.2015

SHORT TITLE	ACTION TAKEN ON LEGISLATION
STATEWide OIL & GAS PRODUCTION TAX CREdits - PRESENTATION BY ENalytica	____ Moved Out of Committee ____ Moved CS (____) Out of Committee ____ Moved HCS (____) Out of Committee ____ Heard and Held ____ Heard and Held Assigned to Subcommittee ____ Bill Postponed to ____ ____ Scheduled but not Heard ____ Failed to Move Out of Committee P/A
SHORT TITLE	ACTION TAKEN ON LEGISLATION
	____ Moved Out of Committee ____ Moved CS (____) Out of Committee ____ Moved HCS (____) Out of Committee ____ Heard and Held ____ Heard and Held Assigned to Subcommittee ____ Bill Postponed to ____ ____ Scheduled but not Heard ____ Failed to Move Out of Committee
SHORT TITLE	ACTION TAKEN ON LEGISLATION
	____ Moved Out of Committee ____ Moved CS (____) Out of Committee ____ Moved HCS (____) Out of Committee ____ Heard and Held ____ Heard and Held Assigned to Subcommittee ____ Bill Postponed to ____ ____ Scheduled but not Heard ____ Failed to Move Out of Committee
SHORT TITLE	ACTION TAKEN ON LEGISLATION
	____ Moved Out of Committee ____ Moved CS (____) Out of Committee ____ Moved HCS (____) Out of Committee ____ Heard and Held ____ Heard and Held Assigned to Subcommittee ____ Bill Postponed to ____ ____ Scheduled but not Heard ____ Failed to Move Out of Committee

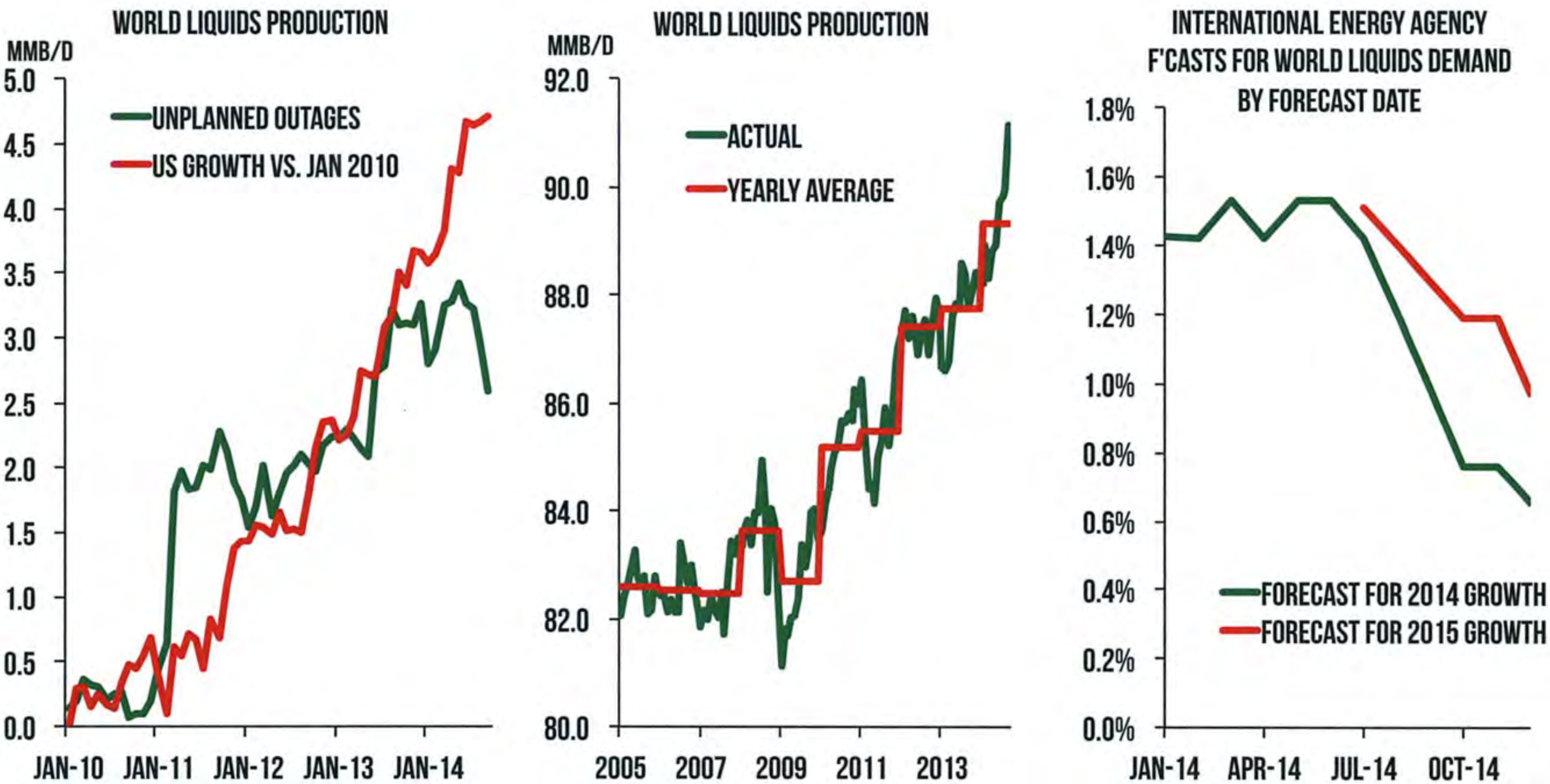
IMPACT OF OIL & GAS PRODUCTION TAX CREDITS AT LOW OIL PRICES

Presentation to House Finance Committee
Juneau, Alaska › Tuesday, February 17, 2015

Janak Mayer, Partner › janak.mayer@enalytica.com
Nikos Tsafos, Partner › nikos.tsafos@enalytica.com

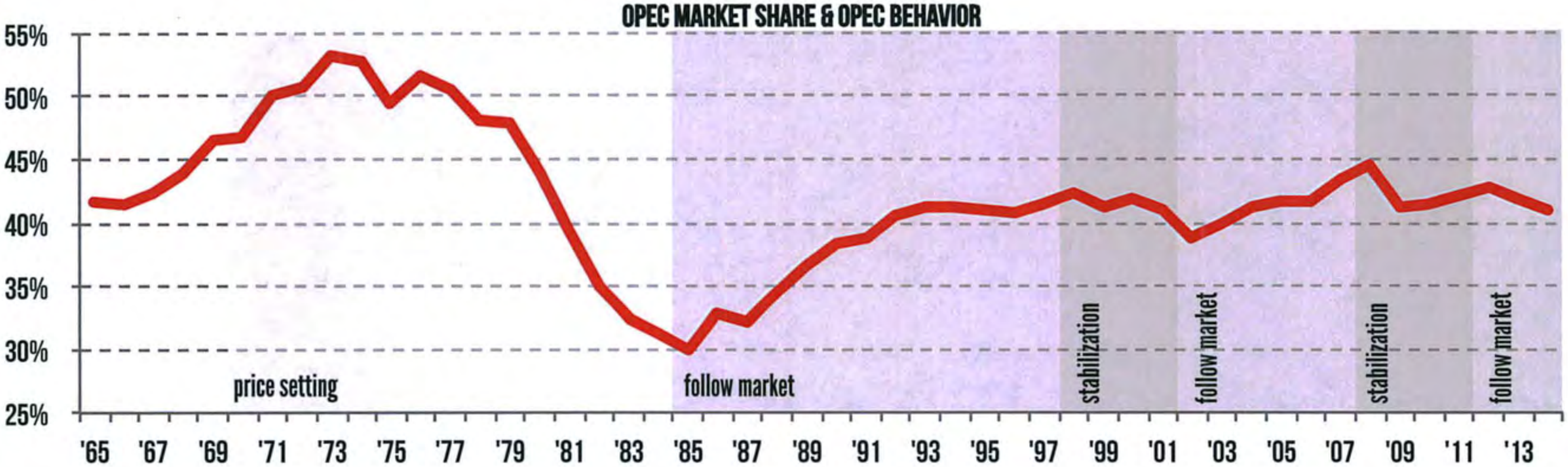
http://enalytica.com

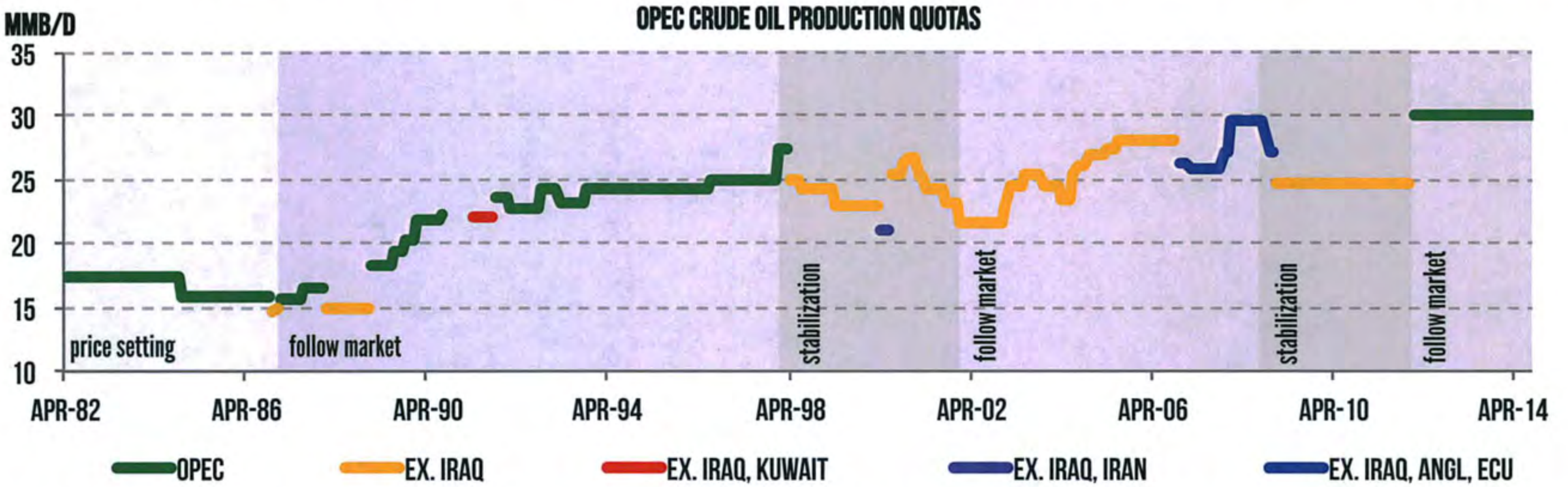
OIL PRICE DROP: HIGHER SUPPLY AND WEAKER DEMAND



SOURCE: ENALYTICA BASED ON ENERGY INFORMATION ADMINISTRATION AND INTERNATIONAL ENERGY AGENCY

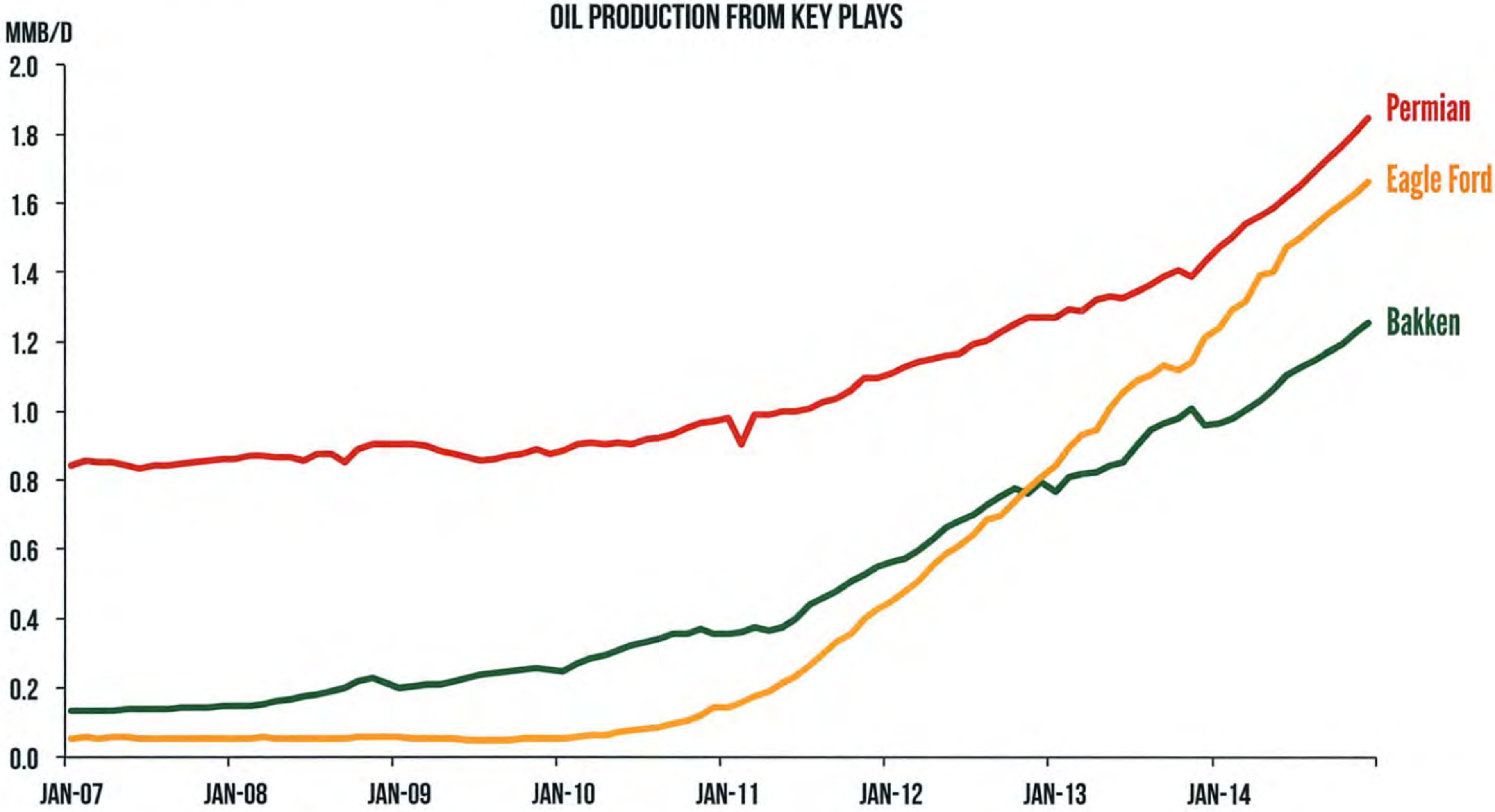
OPEC BEHAVIOR NOT A NOVELTY





SOURCE: BP STATISTICAL REVIEW OF WORLD ENERGY; US DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION; ORGANIZATION OF PETROLEUM EXPORTING COUNTRIES (OPEC)

US PRODUCTION: SCALABLE, DIFFUSE, VARIABLE



SOURCE: US DEPARTMENT OF ENERGY, ENERGY INFORMATION ADMINISTRATION

NET CREDIT BALANCE DUE TO TWO FLOWS

. Revenues net of credits used against tax liability (big producers)–no cash outflow

. Credits paid out in cash to companies that do not have a liability

	HISTORY	FORECAST	
	FY 2014	FY 2015	FY 2016
PRODUCTION TAX REVENUE BEFORE CREDITS	3,486.2	1,273.6	818.4
CREDITS USED AGAINST TAX LIABILITY	888.0	750.0	510.0
PRODUCTION TAX REVENUE	2,598.2	523.6	308.4
CREDITS FOR POTENTIAL PURCHASE	593.0	625.0	700.0

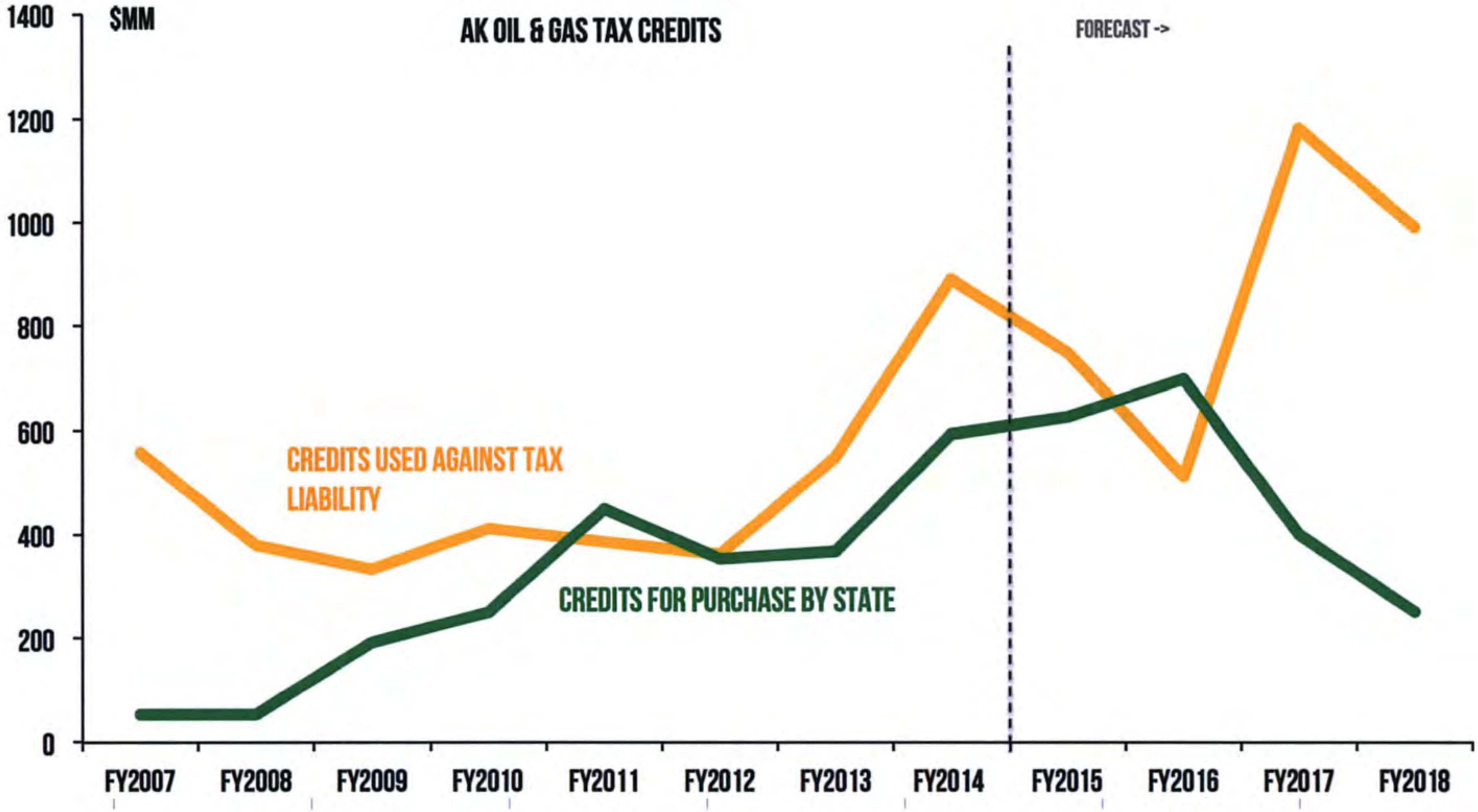
Source: AK DOR Fall 2014 Revenue Sources Book, p27 (all figures in $mm)

Under RSB assumptions for oil price and production, SB 21 brings more revenue than ACES would have in both FY 2015 and FY 2016; in fact, in FY 2016, under ACES producers would pay no tax and carry a credit forward.

Main differences are binding gross minimum and elimination of capital credits.

North Slope production and tax	FY2015				FY2016			
	$/bbl	Mbbls	Value ($mm)		$/bbl	Mbbls	Value ($mm)	
Price & Daily Production	$76.31	510	$38.9		$66.03	524	$34.6	
Annual Production								
Total		185,980	$14,192.1			191,294	$12,631.1	
Royalty, Federal bbls		(23,565)	($1,798.2)			(24,291)	($1,603.9)	
Taxable bbls		162,415	$12,393.9			167,003	$11,027.2	
Transportation Costs	($9.31)	162,415	($1,511.3)		($9.17)	167,003	($1,531.8)	
Lease Expenditures	($43.40)	162,415	($7,048.9)		($43.55)	167,003	($7,272.8)	
Production Tax			SB21	ACES			SB21	ACES
Gross Value Reduction			($47.3)				($3.0)	
Prod. Tax Value (PTV)	$23.31		$3,785.6	$3,785.6	$13.29		$2,219.6	$2,219.6
SB21 (35%*PTV)			$1,325.0				$776.9	
ACES (25%*PTV)				$946.4				$554.9
1) Total Tax before credits			$1,325.0	$946.4			$776.9	$554.9
2) $8 /bbl * Taxable bbls			($1,299.3)				($1,336.0)	
3) Max credits (4% floor)			($889.7)				($397.0)	
4) RSB F'cast Credits			($720.0)				($490.0)	
5) ACES 20% Cap Credits				($722)				($797.3)
6) Total Tax after credits			$605.0	$224.4			$286.9	($242.4)

Source: AK DOR Fall 2014 Revenue Sources Book, p99–100 (all figures in $mm; figures in grey are enalytica estimates)


1400
1200
1000
800
600
400
200
0
$MM
AK OIL & GAS TAX CREDITS
FORECAST ->
CREDITS USED AGAINST TAX LIABILITY
CREDITS FOR PURCHASE BY STATE
FY2007
FY2008
FY2009
FY2010
FY2011
FY2012
FY2013
FY2014
FY2015
FY2016
FY2017
FY2018

SUNSET FOR SMALL PRODUCER-FOCUSED CREDITS

Alternative Credit for Exploration

Frontier Basin Credit

Small Producer Credit

- Collectively cost $113 million in FY2014

IMPACT OF TRANSITIONAL ARRANGEMENTS

Support for small producer spending at 45% until January 2016 (same as ACES)

Reduced to 35% thereafter

COOK INLET REMAINS HEAVILY SUBSIDIZED

Production tax essentially a continuation of 'ELF':

- Low, fixed rate on gas, and generally no tax on most oil production

But significant credits to Cook Inlet producers:

- 20% capital credit
- 40% well expenditure credit
- 25% carried-forward annual loss credit

With no profit-based production tax, credits are not, as on North Slope, an investment in future production tax revenue - but have played important role in turning around Cook Inlet production

Full analysis of costs and benefits of program warranted; Oil & Gas Competitiveness Review Board is required to make recommendations to the legislature before January 15 2017

Oil price drop due to excess supply and bearish demand—and OPEC acknowledging reality

Big producers still paying large sums but not enough to offset credits paid to small companies

SB 21 placed a more secure floor under state revenues when oil prices fall and eliminated many credits

Cook Inlet production still receives substantial state support—is the policy mix right?

http://enalytica.com

enalytica

IMPACT OF ALASKA OIL & GAS PRODUCTION TAX CREDITS AT LOW OIL PRICES

JANUARY 2015

Contents

EXECUTIVE SUMMARY

Alaska has for some time now offered a range of tax credits to incentivize new oil and gas production. Credits to large producers can only be used to reduce their tax liability, while credits to small producers without a tax liability can be directly paid out by the state, and are counted as spending. Until this year, revenue from the oil and gas production tax has dwarfed the state's spending on credits paid to small producers; but the recent plunge in oil and gas prices has created a situation where, for the first time, it is forecast that in FY2015 and FY2016, the state will outlay more on credits to small producers than it will take in production tax revenue.

Given ongoing debates about oil tax reform in Alaska, it is important to understand how SB21 has impacted this situation. The credit programs that create this flow of cash to small producers are a legacy that precedes SB21 by many years. In the current low price and high investment environment, Alaska's finances are in fact substantially sounder as a result of SB21 than they might have been otherwise. This is because SB21 deliberately included important measures to better protect the state's revenue stream in low price environments, while also taking steps to reduce the credits the state pays out. The impact of some SB21 measures to reduce credit outlays, however, will not take effect for another 12 months.

There remain, however, a number of areas of spending on credits that SB21 did not seek to reform. Principal among these are credits paid to Cook Inlet producers, which in FY2015 are estimated to account for around half of the state's spending on credits paid out to producers. Since the state does not levy a profit-based production tax in Cook Inlet, these essentially constitute a subsidy to Cook Inlet producers rather than an investment in future tax revenue. While these subsidies have played an important role in turning around investment and production in Cook Inlet, it may now be an opportune time to reconsider the future of these credits. In particular, it may be worth examining whether financing solutions that leverage the strength of the state's balance sheet to assist these companies in gaining access to reasonably-priced capital might present an alternative to credits that makes more efficient use of the state's resources, at a lower cost to the state.

TWO TYPES OF OIL AND GAS TAX CREDIT

The Alaska Department of Revenue (DOR) accounts for two broad types of oil and gas tax credits. Credit payments are categorized according to the status of the tax payer that claims the credits.

Credits claimed by producers with a current tax liability are accounted for on the **revenue** side of the state's ledger, as '**credits used against tax liability**', and serve to reduce the final amount of oil and gas production tax paid to the state by these companies. All credits claimed by Alaska's large oil and gas producers fall into this category. Such credits cannot reduce producers tax liabilities below zero, and in most cases also cannot reduce their liabilities below a set floor that is a percentage of their gross revenue.

By contrast, credits claimed by small producers or companies that have not yet commenced production, which exceed any production tax liability such companies may have, and which are potentially reimbursable by the state through the oil and gas tax credit fund (AS 43.55.028), are accounted for as **spending** items, representing state spending on '**credits for potential purchase**'.

	HISTORY	FORECAST	
	FY 2014	FY 2015	FY 2016
PRODUCTION TAX REVENUE BEFORE CREDITS	3,486.2	1,273.6	818.4
CREDITS USED AGAINST TAX LIABILITY	888.0	750.0	510.0
PRODUCTION TAX REVENUE	2,598.2	523.6	308.4
CREDITS FOR POTENTIAL PURCHASE	593.0	625.0	700.0

Source: AK DOR Fall 2014 Revenue Sources Book, p27 (all figures in $mm)

In FY2015, the state is forecast to generate **$524 million in tax revenue** from the oil and gas production tax, consisting of $1.274 billion of revenue before credits from producers with a liability, less an estimated $750 million in credits against those liabilities. The major component of the credits claimed against the tax is the variable dollar-per-barrel credit, introduced under SB21, which ranges from $8/bbl at wellhead oil prices below $80/bbl, and tapers to zero at wellhead prices above $150/bbl. The purpose of this payment is to provide an element of progressivity to the 35% 'flat' tax rate of SB21, and is a deliberate means of reducing the effective tax rate below that relatively high headline amount at lower price levels. The $524 million in revenue is net of these credits, and this positive figure represents primarily the forecast production tax revenue received from current major producers.

Thus while the state's overall revenue, and in particular revenue from the oil and gas production tax, will be significantly reduced in FY2015 as a result of current low prices, Alaska's major producers continue to contribute substantially to the state's treasury. Indeed, as we will see shortly, major producers will pay substantially more in oil and gas production tax in FY2015 and FY2016 under current tax arrangements than they would in this oil price environment had SB21 not passed.

At the same time, the state is forecast to pay out **$625 million in credits** to small producers. This refers to forecast spending on 'credits for potential purchase' by the treasury - the amount that is forecast to be demanded of the state by small producers with little to no tax liability claiming refundable credits. Since this figure is larger than the $524 million in revenue, it is correct to conclude that, in net, the state will, for the first time in 2015, reimburse more in credits than it collects in revenue through the oil and gas production tax (although of course other components of the fiscal system, such as royalties and corporate income tax continue to generate revenue for the state).

Forecast production tax revenue received from major producers is significantly positive ($524 million), but is exceeded by the $625 million of credits being paid to small producers that have no tax liability.

Equally important to understand, however, is from whom revenues are being received and to whom payments are being made. **Production tax revenues** are, broadly speaking, being **received from major producers,** and then being used to **pay tax credits to smaller companies**. For the first time in FY2015, because of the low oil price, production tax revenues (net of all credits) from major producers are suddenly forecast to be smaller than tax credit payments to small ones.

POSITIVE IMPACT OF SB21 ON PRODUCTION TAX REVENUES FROM LARGE PRODUCERS

Detailed analysis of the impact of fiscal system changes on revenues requires access to confidential taxpayer records, which only the administration can provide. This is because differences in the specific positions of individual taxpayers influences the fine detail of overall tax liabilities. These differences are the cause of the deviations between the 'income statement' example tax calculations provided in Table E-1 of the appendix to the Revenue Sources Book (pp. 98-99), which treat the tax system as a monolithic block, and the actual revenue forecast numbers (shown above), which are prepared on the basis of individual taxpayer modeling.

Nonetheless, the high-level approximation of Table E-1 can be very useful in illustrating how Alaska's oil & gas production tax functions overall, and how changes in price or tax structure can impact the rough amounts of revenue received through the system. To demonstrate how the passage of SB21 has impacted Alaska's production tax collection at times of low oil prices and high investment, it is useful to look at how this calculation is done under SB21, and what it might have looked like under ACES.

In the below table, figures in black are those presented in tables E-1b and c in the Fall 2014 Revenue Sources Book appendix. Figures in grey represent indicative calculations to demonstrate the mechanics of the production tax system under SB21, and compare that to what might have been the case under ACES. The focus of the below analysis will be on the final 6 numbered lines of the tax calculation.

Roughly in line with the actual RSB forecast figures shown earlier, in FY2015 the high-level Table E-1 'income statement' working shows that the production tax system will generate some $1.3 billion in pre-credit revenue *(see line marked as 1)*. Against this, $720 million *(line 4)* in North Slope credits (slightly below the $750 million state-wide) are applied by producers with a liability. This credit figure, however, is far less than it might be were it not for the minimum floor level of taxation. We can see this by multiplying the 162 million taxable barrels forecast to be produced on the North Slope by $8 (the amount of the per-barrel credit at current prices), reaching a total of approximately $1.3 billion *(line 2)* - almost as much as the entire pre-credit tax.

The fact that, rather than this startling amount, only $720 million in credits are actually forecast to be claimed against liabilities, is due to the "gross minimum" tax, established under AS 43.55.011, which is set at four percent of gross wellhead value. Note that four percent of wellhead value is $890 million *(line 3)*; the fact that the $720 million in credits forecasted are even further below this is likely due to the intricacies of individual taxpayer liabilities.

	FY2015				FY2016			
	$/bbl	Mbbls	Value ($mm)		$/bbl	Mbbls	Value ($mm)	
Price & Daily Production	$76.31	510	$38.9		$66.03	524	$34.6	
Annual Production								
Total		185,980	$14,192.1			191,294	$12,631.1	
Royalty, Federal bbls		(23,565)	($1,798.2)			(24,291)	($1,603.9)	
Taxable bbls		162,415	$12,393.9			167,003	$11,027.2	
Transportation Costs								
ANS Marine Trans	($3.44)				($3.41)			
TAPS Tariff	($5.80)				($5.72)			
Other	($0.06)				($0.05)			
Total Trans. Costs	($9.31)	162,415	($1,511.3)		($9.17)	167,003	($1,531.8)	
Lease Expenditures								
Deductible Opex	($19.62)		($3,186.2)		($18.94)		($3,163.0)	
Deductible Capex	($23.78)		($3,862.7)		($24.61)		($4,109.8)	
Total Lease Exp.	($43.40)	162,415	($7,048.9)		($43.55)	167,003	($7,272.8)	
Production Tax			SB21	ACES			SB21	ACES
Gross Value Reduction			($47.3)				($3.0)	
Prod. Tax Value (PTV)	$23.31		$3,785.6	$3,785.6	$13.29		$2,219.6	$2,219.6
SB21 (35%*PTV)			$1,325.0				$776.9	
ACES (25%*PTV)				$946.4				$554.9
1) Total Tax before credits			$1,325.0	$946.4			$776.9	$554.9
2) $8 /bbl * Taxable bbls			($1,299.3)				($1,336.0)	
3) Max credits (4% floor)			($889.7)				($397.0)	
4) RSB F'cast Credits			($720.0)				($490.0)	
5) ACES 20% Cap Credits				($722)				($797.3)
6) Total Tax after credits			$605.0	$224.4			$286.9	($242.4)

Source: AK DOR Fall 2014 Revenue Sources Book, p. 99-100 (all figures in $mm; figures in grey are enalytica estimates)

What is vital to understand here is the fact that, while the gross minimum existed in statute long before the passage of SB21, it was only with the passage of SB21 that it actually became in any way a binding, meaningful, minimum level of tax that must be paid by large producers.[1] Before SB21, the minimum existed in statute, but would almost never have applied in practice, as the below will show.

Prior to SB21, while dollar-per-barrel credits did not exist, ACES capital credits did. These credits, which were paid as a percentage of a producer's capital spending for the year, were capable of reducing a producer's tax liability below the 4% minimum, since the minimum applied to the total tax before credits *(line 1)*, not after. As a result, with the high levels of capital investment currently occurring on the North Slope, the capital credit under ACES would have largely offset the $946 million in revenue *(line 1)* that would have been generated under the lower 25% base tax rate under ACES at current prices (note that ACES progressivity does not apply at these price and spending levels). Capital credits that could have been claimed in FY2015 were ACES still in place can be estimated by summing half of FY2015 and half of FY2014 deductible capex figures, then multiplying by 20%. This gives us $722 million in capital credits *(line 5)*, leaving only $224 million in revenue after credits under ACES *(line 6)* in this scenario - this is barely over a third of the revenue generated at these prices by SB21.

By making the 4% gross minimum floor effectively binding for the first time, SB21 significantly improved the state's revenue position in the current low-price, high-investment environment.

The contrast between SB21 and estimated ACES numbers are even more startling if we look at FY2016. Had ACES remained in place in the current price and investment environment, capital credits in FY2016 would have been greater (calculated under the indicative, broad-brush methodology of Table E-1) than the pre-credit revenue generated by ACES. Thus, based on current forecasts, **in FY2016 under ACES the production tax system would likely not have generated any tax revenue at all, even before spending on reimbursable credits to companies without a liability**.

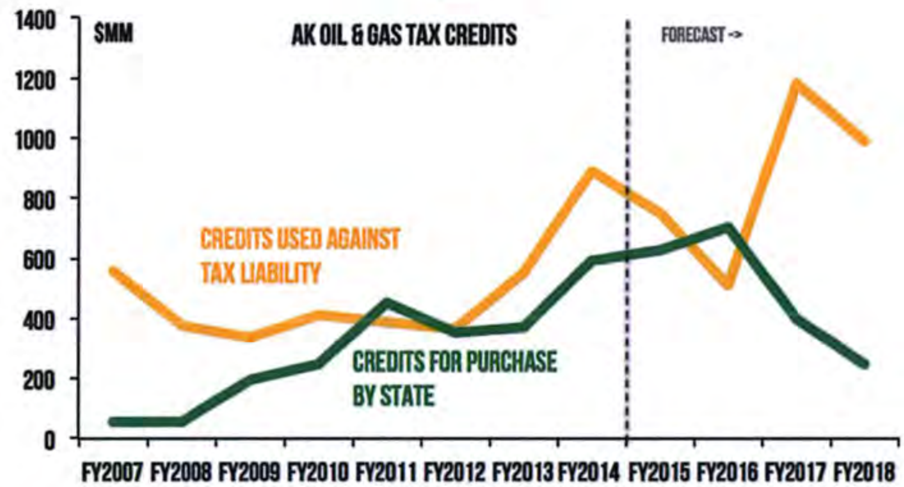
While ACES did not permit taxpayer liabilities to go below zero, in such a scenario producers would have been issued transferable credit certificates to account for the approximately $242 million in unused capital credits *(line 6)* that exceeded the amount of their pre-credit liabilities. While producers with more than 50,000 b/d production would not have been able claim reimbursement by the state through the oil and gas tax credit fund for these certificates as small producers could, they would have been able to apply them against future years' liabilities, even further reducing future years' revenue for the state.

The impact of the binding 4% gross minimum floor that SB21 introduced in limiting the state's credit liabilities at low oil prices can be seen quite dramatically in Chart 1. The precipitous fall in credits against tax liabilities forecast for FY2015 and FY2016 is a result of that floor kicking in at the low oil prices forecast for these two years, substantially improving the state's fiscal position.

---

[1] Technically, the 4% gross minimum is a binding floor level of taxation on a large North Slope producer that is cash positive. Were a large producer to be cash-negative in a given year, such a producer would be eligible for the carried-forward annual loss credit, that could reduce their liability below the 4% floor (but not below zero); this, however, would require prices below $50/bbl for a sustained period of time.

Chart 1



Source: AK DOR Fall 2014 Revenue Sources Book

SB21 was designed as a deliberate rebalancing of Alaska's tax system, better protecting the state at low oil prices, while in return splitting income more evenly with companies in times of plenty. This rebalancing is providing a significant benefit in the current spending and oil price environment.

EFFORTS UNDER SB21 TO LIMIT CREDITS TO SMALL PRODUCERS

In addition to making the 4% floor effectively binding for large producers, SB21 also took a number of steps to limit the credits paid out to small producers. The biggest of these steps were taken not through direct legislative action in SB21 but rather through deliberate inaction - in passing SB21 the legislature decided not to extend a series of credits that are reimbursable to companies without a tax liability, that were otherwise due to sunset on January 1, 2016.

SB21 allowed tax credits to sunset that collectively cost the treasury $113 million in 2014. The impact of this will be felt from January 1 2016 onward.

Tax credits that will expire on January 1, 2016 as a result of this decision include the Alternative Credit for Exploration, the Frontier Basin Credit, and the Small Producer Credit (although the latter will continue for nine years after a producer that was eligible for the credit first commenced commercial production). Allowing these credits to sunset were part of a deliberate attempt to limit the credits provided to small producers, precisely because of the threat to state revenues that could be posed by such credits in a time of low oil prices.

Collectively, these credits cost the state $113 million in 2014 (see RSB p67). Because these credits do not sunset until January 1 2016, however, the impact of their elimination will only be felt partially in FY2016, and fully for the first time in FY2017. FY2015 still includes the full cost of these ongoing credit programs.

SB21 TRANSITIONAL ARRANGEMENTS

In addition to the fact that these efforts to reduce credit payments to companies without a tax liability have not yet "kicked in", transitional treatment of the carried-forward annual loss credit under SB21 also means that the total reduction in state support for investment by small producers remains at ACES-levels, and will also only be reduced commencing in January 2016.

SB21 raised the carried-forward annual loss credit from 25% to 35%. There was sound rationale for this shift, since this credit is designed to be set at the same rate as the base production tax, which SB21 also raised to 35%. The reason for this is that the carried-forward annual loss credit is intended to make the impact of the tax system the same on small producers without a tax liability as it is on large ones with a liability.

A large producer that makes capital investments in new production facilities is able to reduce the value of its tax liability to the state by the value of that investment multiplied by the tax rate - which under SB21 is 35%. By setting the carried-forward annual loss credit to the same rate, a new producer without a liability gets the same tax benefit as a large incumbent from investment - in the form of a reimbursable credit from the state.

In addition, however, SB21 further raised the carried-forward annual loss credit to 45% as a 'transitional arrangement', with the elevated level of the credit applying for a limited period of two years, from January 1 2014 to January 1 2016. The purpose of this change was to ease the transition to SB21 for small, capital constrained producers. These companies have historically relied on capital credits under ACES to make projects outside of their natural capital constraints financeable; the elimination of North Slope capital credits under SB21 will, in many cases, likely require them to find other financing solutions, such as the participation of other partners. The elevated level of the carried-forward annual loss credit for two years was intended to ease this transition for these companies; at the 45% level, this credit provides exactly the same level of government support for capital spending as was available to these companies under ACES, which had a 25% carried-forward annual loss credit combined with a 20% capital credit.

The impact of this is being somewhat exacerbated at a time when oil prices have fallen as low as they have, and when capital spending on the North Slope is at unprecedented levels, as Chart 2 below shows. Within 12 months, however, this transitional treatment will cease. At that point, government support for capital spending for small, cash-negative producers will go from 45%, the same level it was at under ACES, to 35%. With the state forecast to spend some $300 million on North Slope carried forward annual loss credits in 2015 (a function of the high level of capital investment by small producers on the slope), it is useful to note that around $60 million of that figure is the result of the temporarily elevated level of the carried-forward annual loss credit that will be reduced in 12 months time.

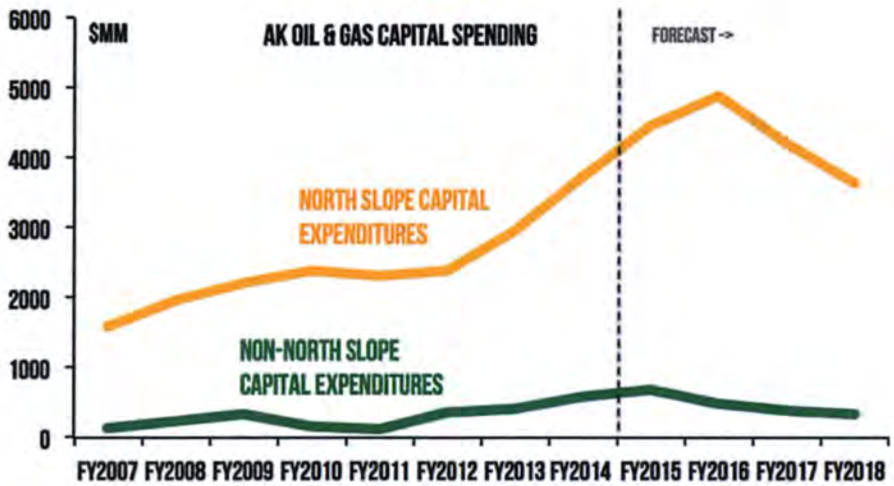
SB21 transition arrangements continue levels of government support for capital spending by cash-negative producers at ACES levels until January 1 2016, before reductions apply.

MATTERS NOT ADDRESSED BY SB21

Government support for spending in Cook Inlet remains very high, and is not offset by profit-based taxation.

Finally, SB21 also left a number of areas of credits, inherited from previous tax regimes, unchanged. In Cook Inlet, in particular, the State of Alaska has for some time paid out significantly more in credits than it has received in tax revenues. Since the pre-2006 ELF tax regime largely still holds in Cook Inlet, producers there by and large pay no production taxes on oil production, and only a very low, fixed rate on gas production.

Chart 2



Source: AK DOR Fall 2014 Revenue Sources Book

At the same time, they receive substantial credits through the production tax system. In particular, the 20% capital credit applicable under ACES continues to apply in Cook Inlet, despite having been abolished on the North Slope under SB21. In addition, Cook Inlet producers are eligible for credits of 40% applying to well lease expenditures - an elevated level that has never applied on the North Slope. Cook Inlet producers that are currently cash-negative are also eligible for a 25% carried-forward annual loss credit. Together, these credits add up to very high levels of government support for capital investment in Cook Inlet.

On the North Slope, the existence of the profit-based production tax makes credits a form of state investment in the upfront capital costs of oil and gas production, which is correspondingly recouped later in the cashflow cycle through the production tax. The absence of a profit-based production tax makes these credits a subsidy for Cook Inlet producers.

As Chart 2 shows, along with the North Slope, capital investment in Cook Inlet is also currently at previously unprecedented levels - DOR forecasts $684 million of total capital spending by companies outside the North Slope in FY2015, compared with just $123 million in FY2011. At the same time, it is estimated that the state will spend around $300 million on refundable tax credits to Cook Inlet producers in 2015 - close to half the amount of total capital spending occurring, reflecting the very high degree of government subsidy (and also reflecting around half the total the state will spend on all refundable oil & gas tax credits in FY2015).

Low taxes and generous credits have undoubtedly played a major role in the turnaround of previously declining Cook Inlet production that has occurred in recent years. The high level of current capital spending in Cook Inlet, like the high level of spending on the North Slope, is in general very positive, since much of this is investment in future production capacity, contributing significantly to energy security for Anchorage and other communities that have historically relied on Cook Inlet gas.

Alternative methods for providing competitive access to capital by small producers may be worth investigating.

Given the current strain on state finances, however, it may be wise to ask whether some of the same benefit that these credits provide to companies might not be provided through other means that do not require a cash subsidy to these companies. Financing solutions that leverage the strength of the state's balance sheet to assist these companies in gaining access to reasonably-priced capital might present one such means, and may, as a result, be worth examining further.

CONCLUSIONS

SB21 made significant contributions both to limiting the loss of production tax revenue by the state in low oil price environments, and to limiting the pay-out of refundable tax credits to producers with no tax liability. Many of these are already providing much-needed protection to the state in the current low-price but high-investment environment. In other areas, transitional arrangements under SB21 mean that further efforts to curtail outlays on credits for purchase by the state will apply automatically within the next 12 months.

There remain, however, a number of areas that have been untouched by tax reform, where major government support for capital spending continues to exist, and be made in the form of direct cash outlays by the state. The Cook Inlet capital, well lease expenditure and carried-forward-annual loss credits are the most significant of these, and are worth examining further in some detail.

ABOUT US

Janak Mayer. Before co-founding enalytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds a BA with first-class honors from the University of Adelaide, Australia and an MA with distinction in international relations and economics from the Johns Hopkins School of Advanced International Studies (SAIS).

Nikos Tsafos. Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at enalytica. He previously spent 7 ½ years at PFC Energy, where he advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

enalytica

enalytica

OIL IN 2015: UNDERSTANDING THE MARKET

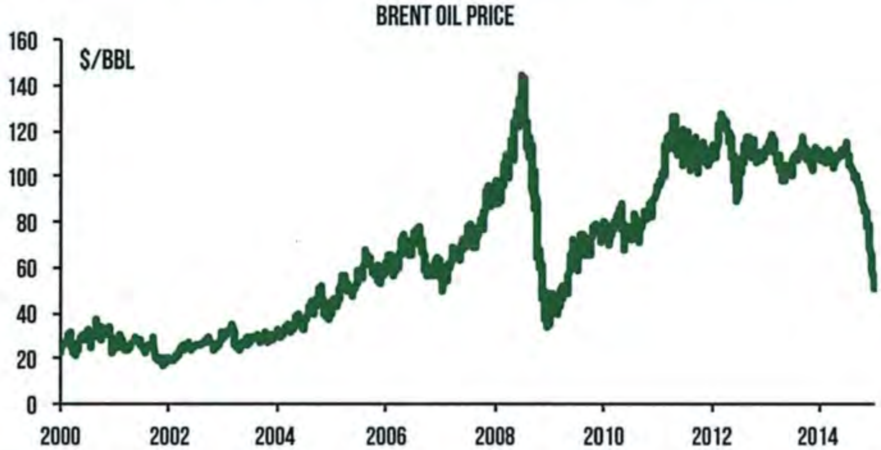
JANUARY 2015

Contents

POINT OF DEPARTURE

Crude oil closed 2014 at just $55/bbl (Brent), a 50% decline from its yearly high of $115/bbl in June. The sharp drop is due to market fundamentals—increased supply and weaker expectations about demand. But the price drop also underscores deep changes in the oil market which make forecasting even harder than before.

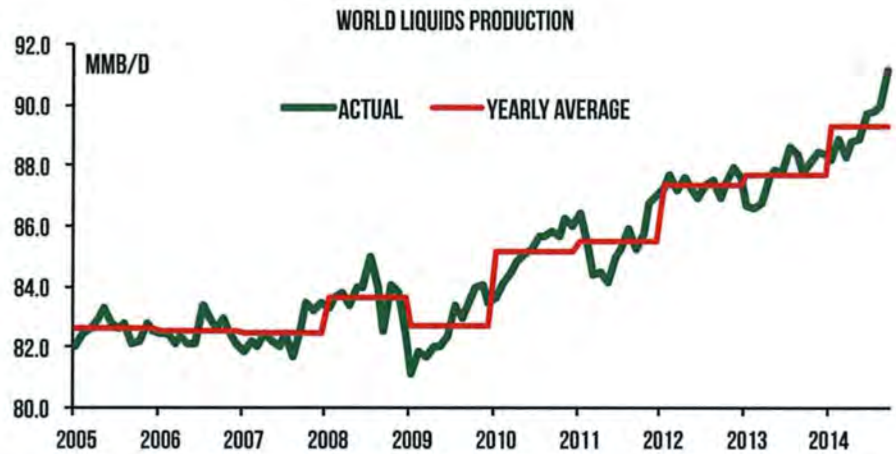
BRENT OIL PRICE



Source: Department of Energy, Energy Information Administration

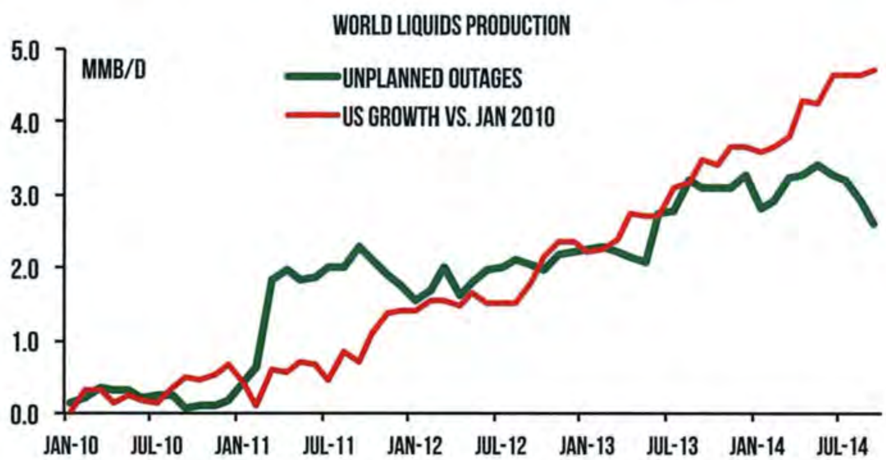
INCREASED SUPPLY

Oil production has risen in the past decade, but the increases have been irregular: some years, production has grown significantly; other years, it has declined; and many years, it has stayed flat. These fluctuations reflect decisions made by many companies and the Organization of Petroleum Exporting Countries (OPEC), and they also reflect physical disruptions caused by weather (e.g. hurricanes), strife (e.g. civil wars) or policy (e.g. sanctions). In other words, despite a secular upward trend, production has many ups and downs, and the past few years have been no exception: in 2014, oil production likely grew by 1.8%, which is robust but not unheard of, but it followed a year of meager growth (+0.4%).



Source: Department of Energy, Energy Information Administration

The growth in world oil supply has been driven largely by the United States, which has grown production by almost 5 million barrels a day (mmb/d) versus 2010. Yet, the impact of this growth was muted by physical disruptions to supply elsewhere, mostly due to war (Libya, Syria) and tightening sanctions against Iran. In other words, the United States was pumping more oil, but this just replaced oil lost from elsewhere. These "unplanned outages" peaked in April 2014 and started to fall, largely due to Libya, whose output rose from 0.2 mmb/d in June to 1 mmb/d in October 2014. The supply picture changed dramatically in these short months.



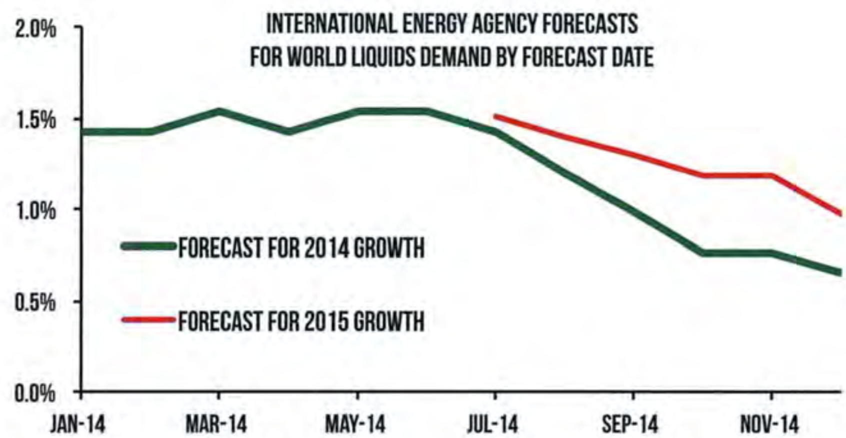
Source: Department of Energy, Energy Information Administration

BEARISH DEMAND

Just as supply has (finally) started to grow, the outlook on demand has become bleaker, largely on the back of more bearish expectations for the global economy. In January 2014, the International Monetary Fund (IMF) forecast that world gross

domestic product (GDP) would increase by 3.7% in 2014 and 3.9% in 2015. In its latest forecast, in January 2015, it estimated that GDP grew by 3.3% in 2014, and that it would grow by 3.5% in 2015. More importantly, the IMF has revised down its expectations for the Chinese economy, which is a locomotive for commodities and, through trade, for other economies in the world.

The weaker economy soon translated into more bearish expectations for the oil market, as seen by the progressive reduction in growth expectations. In July 2014, the International Energy Agency (IEA) expected that oil demand would grow by 1.4% in 2014 and 1.5% in 2015. Within six months, it had revised both forecasts down: it now expected oil demand to grow by just 0.7% in 2014 and only 1% in 2015. In other words, from a place where it expected growth of ~3% over two years, it now saw growth being roughly half (1.7%) that rate. Given the growth in supply, which also came this summer, the market turned on its head: supply was growing faster and demand was growing more slowly than expected. Prices started to plummet.

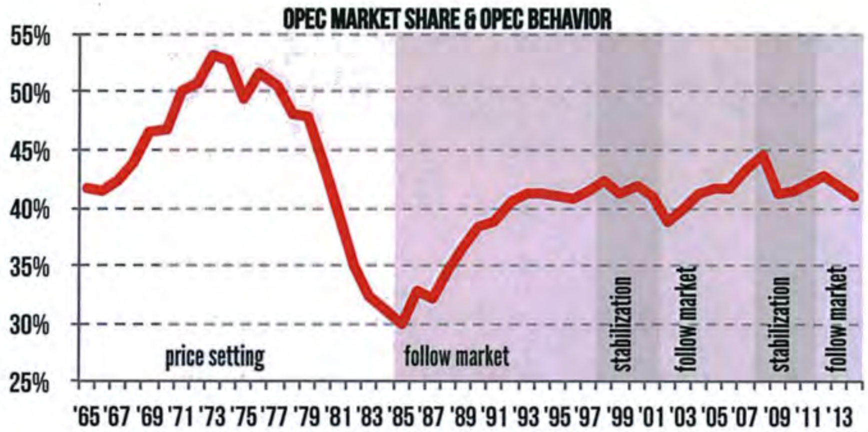


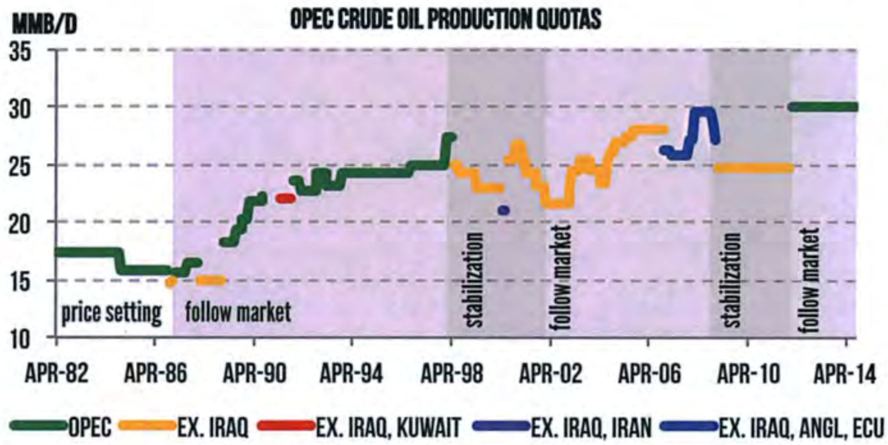
Source: International Energy Agency, Oil Market Reports

OPEC'S ROLE

Given these market fundamentals, we should expect prices to fall. But prices have fallen more precipitously than anyone expected, in large part because OPEC (mostly Saudi Arabia) made it very clear that it has no intention to cut production in an effort to prop up prices.

Inevitably, such declaration prompted many analysts to talk about a "sharp reversal" in OPEC's role or, even, of OPEC's death. In reality, OPEC has never been able to set prices—the one time it tried, it only managed to cut production so much that its market share collapsed (from 1973 to 1986). Twice, OPEC tried to stabilize markets—once successfully (2008—09) and once unsuccessfully (1998—2001). Mostly, OPEC has followed markets—providing additional oil when needed, and cutting back slightly to prevent excessive price volatility.





Source: BP Statistical Review of World Energy; US Department of Energy, Energy Information Administration; Organization of Petroleum Exporting Countries (OPEC)

OPEC has few good options: if it cuts back production to prop up prices, it will merely send a signal to US producers to keep drilling and keep growing production. Defending prices is thus merely a recipe for losing market share. Instead, OPEC is basically letting the market play itself out: let prices drop to the point that new supply becomes uneconomic and comes off the market. Rather than try to estimate that price point, it is letting markets tell it what it is.

FLOORS AND CEILINGS

Such a response from OPEC is neither revolutionary, nor shocking (although the emphasis with which OPEC declares that it will not defend prices is). But it does pose a challenge for forecasters. Broadly speaking, observers in the oil market predict long-term prices based on supply, rather than demand. Mostly, this is due to simplicity: demand is more diffuse and affected by myriad choices, policies and technologies. Mapping the elasticity of demand at different prices is a daunting

task that requires insights into driving patterns, fuel substitution, technology, and fiscal policies (subsidies, taxes) across many countries.

Instead, supply is simpler to forecast because it has effectively boiled down to two numbers: the break-even price for new, marginal projects and the fiscal break-even price for OPEC countries. The former tells us the price at which new supply does or does not come to the market; this has generally meant Canadian oil sands or deepwater projects because those have been at the edge of the supply curve (representing the most expensive barrels of oil that come to market only when prices are high enough to make the major projects to produce them viable). The latter is a proxy for the price that OPEC countries need "to run their economies", in particular to maintain a sustainable budget deficit and to finance imports, and is meant to tell us when OPEC will feel pain and thus step in to prevent prices from falling further. Both are crude estimates with several problems, but they are both simple enough that they work.

In today's market, however, it is clear that neither estimate is very helpful. OPEC is unwilling to step in and prop prices artificially high, even though oil prices are below what countries need to "run their economies", for fear of repeating the mistakes of the 1970s and 1980s, when its cuts to maintain prices allowed new developments like Alaska's North Slope and the UK and Norwegian North Sea to take much of its market share. Similarly, the marginal barrel is no longer easy to model by focusing on a handful of mega projects (oil sands or deepwater). Rather, the marginal barrel is scattered around thousands of wells across the United States, controlled by many companies making decisions independently from each other, and responding to different incentives and market signals (including a willingness to accept sub-optimal returns, and thus drill even when a project may not "break even"). This difficulty in understanding the true break-even price might explain OPEC's reticence —it too wants to know that pricing point and it can only find out by letting the market follow its course.

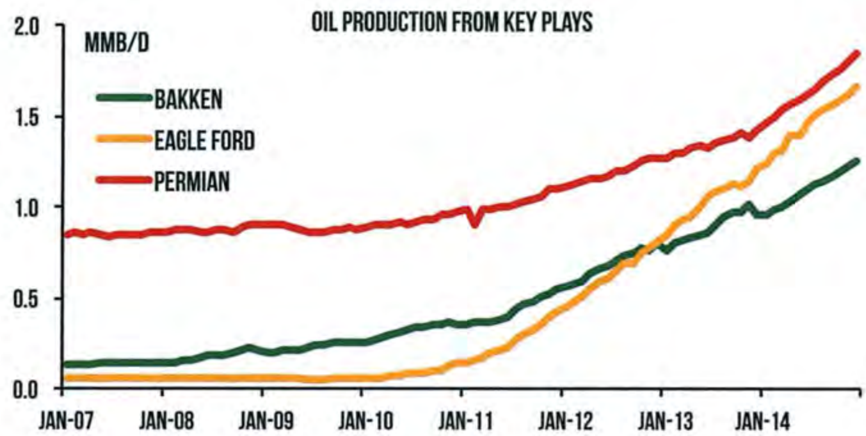
OIL IN THE LOWER 48

Oil in the Lower 48 will drive oil prices over the next few years. Making sense of oil in the Lower 48 depends on understanding three central facts:

Scale. Three regions have produced the bulk of the new oil in the United States: the Bakken (North Dakota and Montana), the Eagle Ford (Texas) and the Permian (Texas and New Mexico). The Bakken was marginal in 2007, the Eagle Ford was marginal until 2010, and the Permian produced mostly conventional oil. Since 2010, each region has increased production by more than 1 mmb/d, with the Eagle Ford showing the sharpest increase. Such dynamism illustrates how quickly the market can respond and deploy resources to produce additional oil.

Diffusion. Unlike other places in the world, oil in the United States is decentralized. Of course, there are bigger companies in each play, but overall activity is driven by dozens of actors. In Texas, for instance, the top 32 producers only accounted for two-thirds of the state's oil production in 2013. As such, production reflects the

choices of dozens of players with diverse incentives, financial positions, and strategies, which makes forecasting much harder to do.



Source: US Department of Energy, Energy Information Administration, Drilling Productivity Report

Variation. The flip side to diffusion is variation: while it is fairly common to look at average numbers (production per rig), these figures become less meaningful when the spread between top and bottom performers is very large, as is the case in the Lower 48. The best producing wells can be 20 to 30 times better than the worst performers. This also means that scaling back activity can have a trivial impact on output if operators cut the worst performers—this is precisely what happened a few years ago with natural gas in the Lower 48 where the rig count was cut in half while production stated flat.

These facts complicate the forecasting exercise of the link between oil prices and production in the Lower 48. For one, the market can respond quickly and deploy tremendous resources in response to a price signal. Moreover, the response will be decentralized, and some companies may appear to behave uneconomically but quite rationally given their incentives and constraints (need to cover debt, for instance, making them accept lower returns). And the variation means that activity may have to be scaled back significantly before production falls. This is why, despite an overall consensus that production will be hurt at $40 to $50/bbl, there is considerable uncertainty around this point forecast.

In short, the drop in oil prices represents a perfect storm: increased supply and weaker (actual and expected demand). But the drop underscores the inapplicability of old forecasting models that looked at a few mega projects and OPEC budgets. As long as US oil supply is the marginal barrel, forecasting prices will be even more difficult and imprecise given how diffuse the oil supply picture is in the Lower 48.

ABOUT US

Janak Mayer. Before co-founding enalytica, Janak led the Upstream Analytics team at PFC Energy, focusing on fiscal terms analysis and project economic and financial evaluation, data management and data visualization.

Janak has modeled upstream fiscal terms in all of the world's major hydrocarbon regions, and has built economic and financial models to value prospective acquisition targets and develop strategic portfolio options for a wide range of international and national oil company clients. He has advised Alaska State Legislature for multiple years on reform of oil and gas taxation, providing many hours of expert testimony to Alaska's Senate and House Finance and Resources Committees.

Prior to his work as an energy consultant, Janak advised major minerals industry clients on a range of controversial environmental and social risk issues, from uranium mining through to human rights and climate change. He has advised bankers at Citigroup and policy-makers at the US Treasury Department on the management and mitigation of environmental and social impacts in major projects around the world, and has undertaken macroeconomic research with senior development economists at the World Bank and the Peterson Institute for International Economics.

Janak holds a BA with first-class honors from the University of Adelaide, Australia and an MA with distinction in international relations and economics from the Johns Hopkins School of Advanced International Studies (SAIS).

Nikos Tsafos. Nikos Tsafos has a diverse background in the private, public and non-profit sectors. He is currently a founding partner at enalytica. He previously spent 7 ½ years at PFC Energy, where he advised the world's largest oil and gas companies on some of their most complex and challenging projects; he also played a pivotal role in turning the firm into one of the top natural gas consultancies in the world, with responsibilities that included product design, business development, consulting oversight and research direction.

Prior to PFC Energy, Nikos was at the Center for Strategic and International Studies (CSIS) in Washington, DC where he covered political, economic, and military issues in the Gulf, focused on oil wealth, regime stability and foreign affairs. Before CSIS, he was in the Greek Air Force, and prior to his military service, Nikos worked on channeling investment from Greek ship-owners to Chinese shipyards.

Nikos has also written extensively on the domestic and international dimensions of the Greek debt crisis. His blog (Greek Default Watch) was listed as one of "Europe's Top Economic Blogs" by the Social Europe Journal, and his book "Beyond Debt: The Greek Crisis in Context" was published in March 2013.

Nikos holds a BA with distinction in international relations and economics from Boston University and an MA with distinction in international relations from the Johns Hopkins School of Advanced International Studies (SAIS).

enalytica