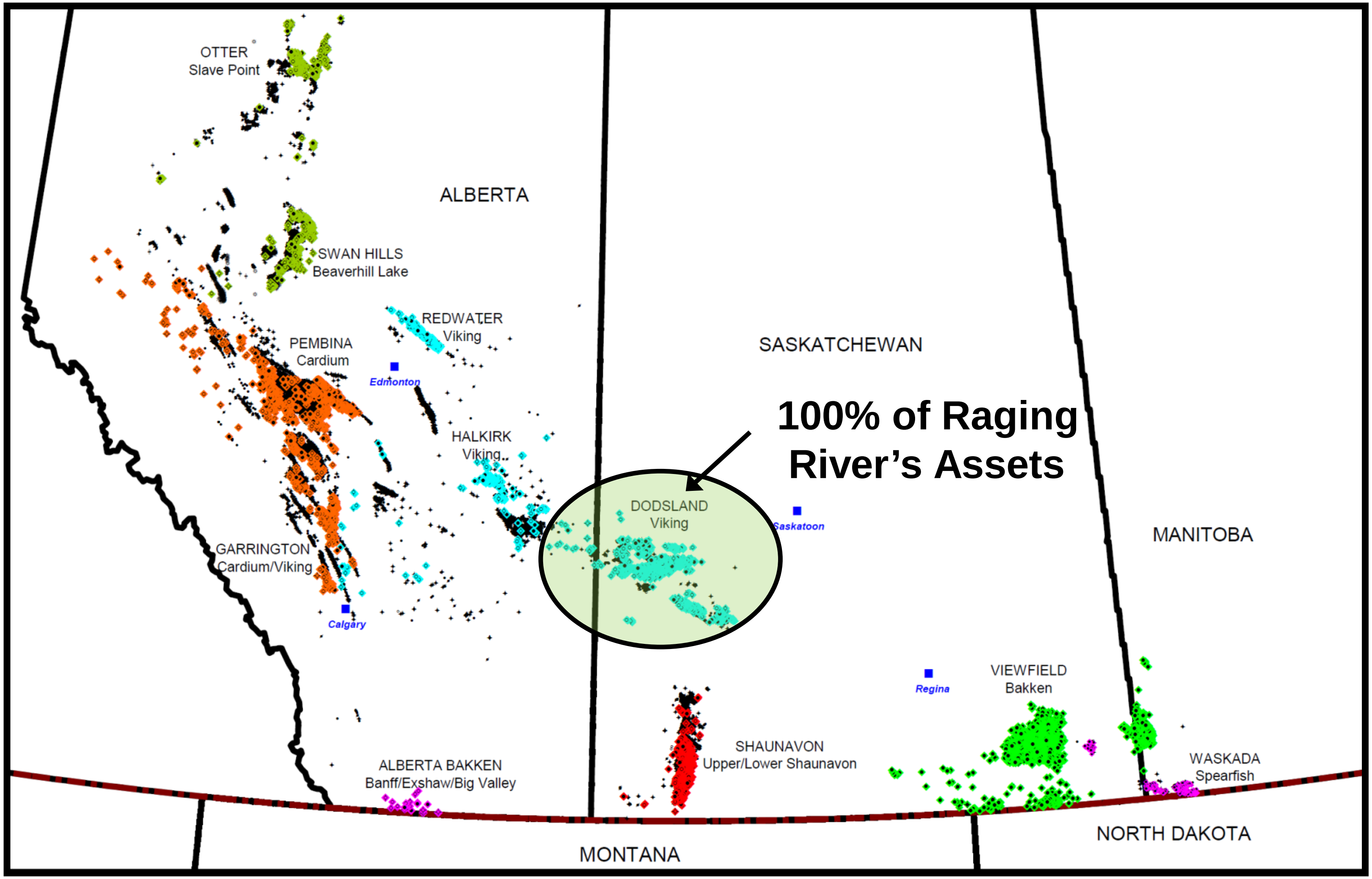
RRX

RAGING RIVER
EXPLORATION INC.

December 2016

Viking Light Oil

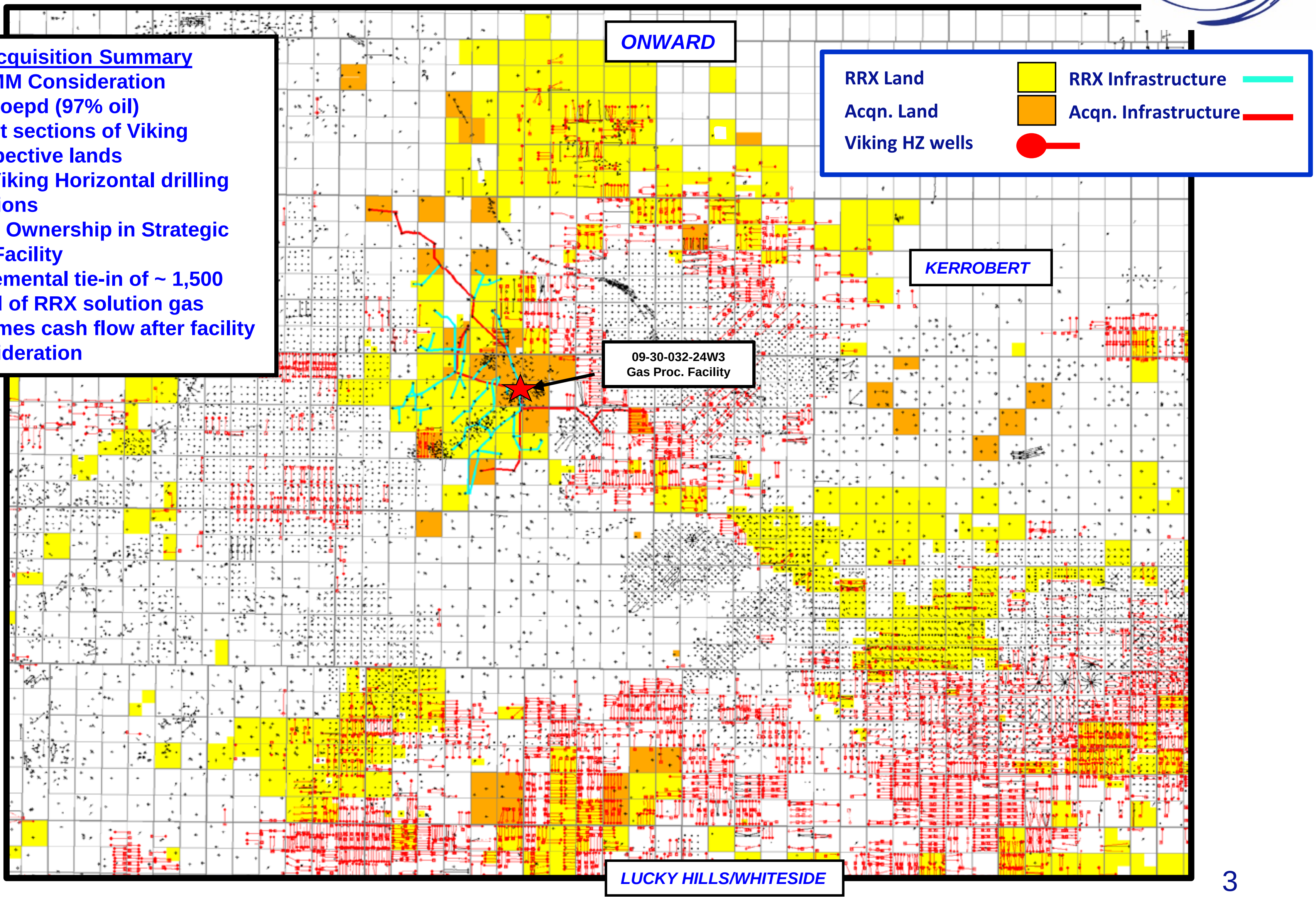


Viking Asset Acquisition

RRX
RAGING RIVER EXPLORATION INC.

<u>Asset Acquisition Summary</u>

- $58 MM Consideration
- 620 boepd (97% oil)
- 24 net sections of Viking prospective lands
- 100 Viking Horizontal drilling locations
- 100% Ownership in Strategic Gas Facility
- Incremental tie-in of ~ 1,500 mcf/d of RRX solution gas
- 6.1 times cash flow after facility consideration



TSX: RRX

Raging River Profile

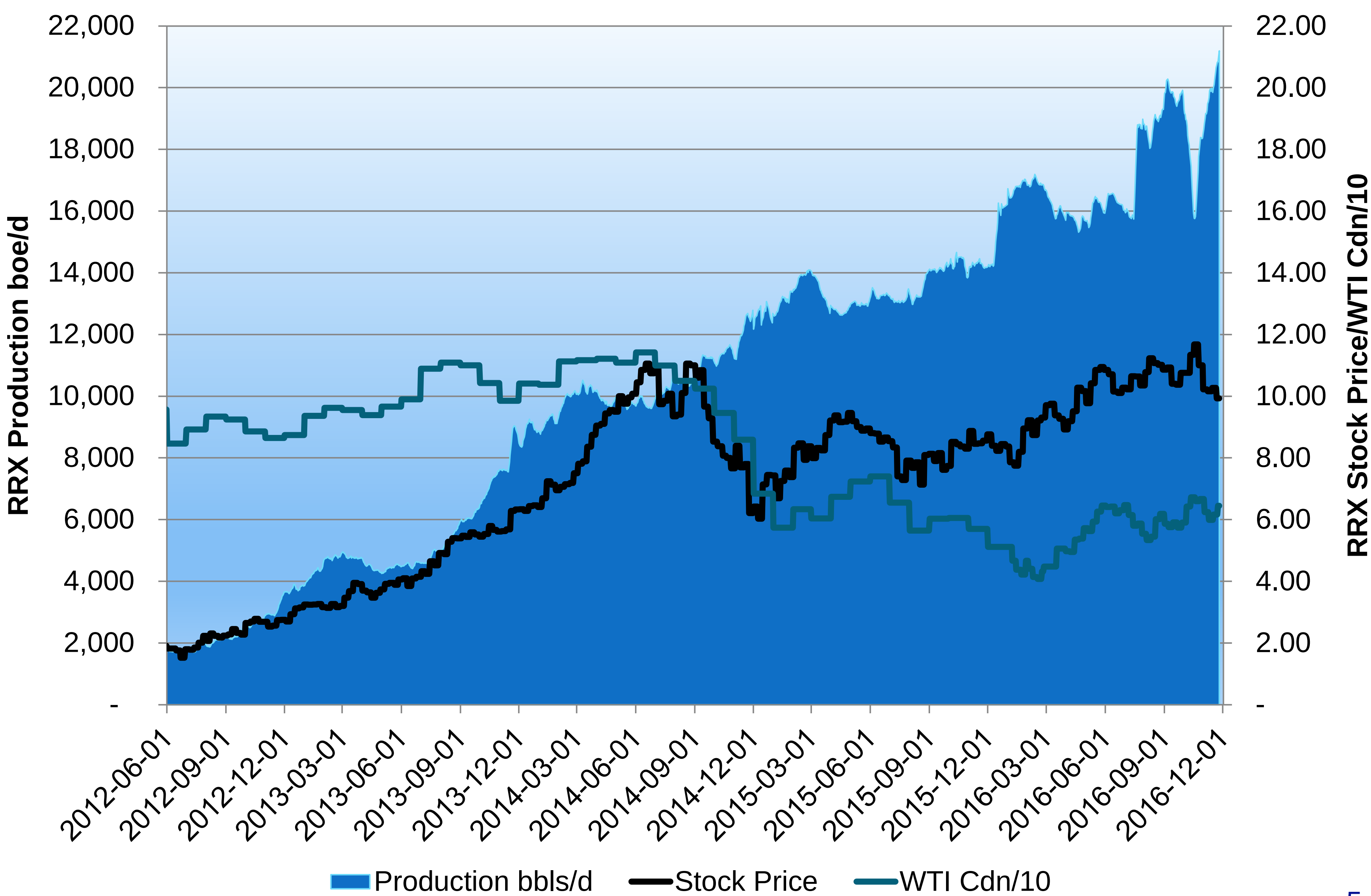
RRX
RAGING RIVER EXPLORATION INC.

Corporate Information	
Raging River Exploration	RRX.TO
Basic Shares Outstanding (mm)	231.1
Dilutives (@ Average $8.74/share) (mm)	9.6
FD Shares Outstanding	240.7
Insider Ownership Basic	8.9%
Insider Ownership	12.5%
Market Capital ($mm)	2,241.9
Q3 Net Debt ($mm)	140.2
EV ($mm)	2,391.5
Credit Facility ($mm)	300.0
Current Production (pre Acquisition)	21,000
% Oil	92%

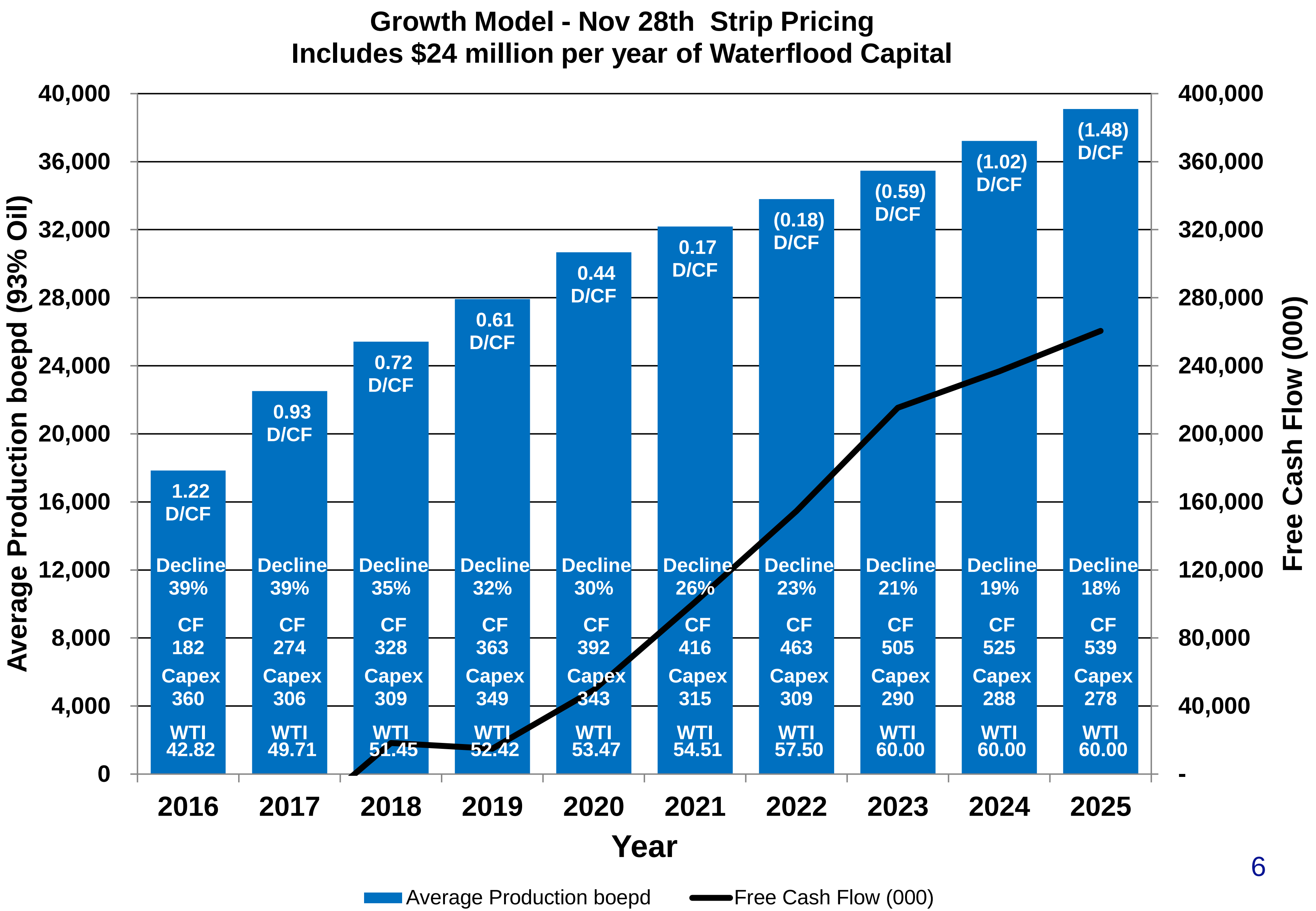
Trading Snapshot	
Closing Price November 28, 2016	9.70
YTD Return%	16%
1 Yr Return %	-1%
2 Yr Return %	56%
3 Yr Return %	53%
Average share volume (m)	600.0

Internal Estimates	2016e	2017e	2018e
EV/DACF	13.4	8.8	7.3
Production (boepd)	17,800	22,500	25,400
% Oil	93%	93%	93%
Cashflow ($mm)	182	274	328
Capex ($mm)		305	310
Cashflow per Share Basic	0.79	1.18	1.42
Exit Debt/CF	0.96	0.85	0.66
Production per mm shares	77.0	97.4	109.9
Production per share growth		26%	13%
WTI $(US/bbl)	42.82	49.71	51.45

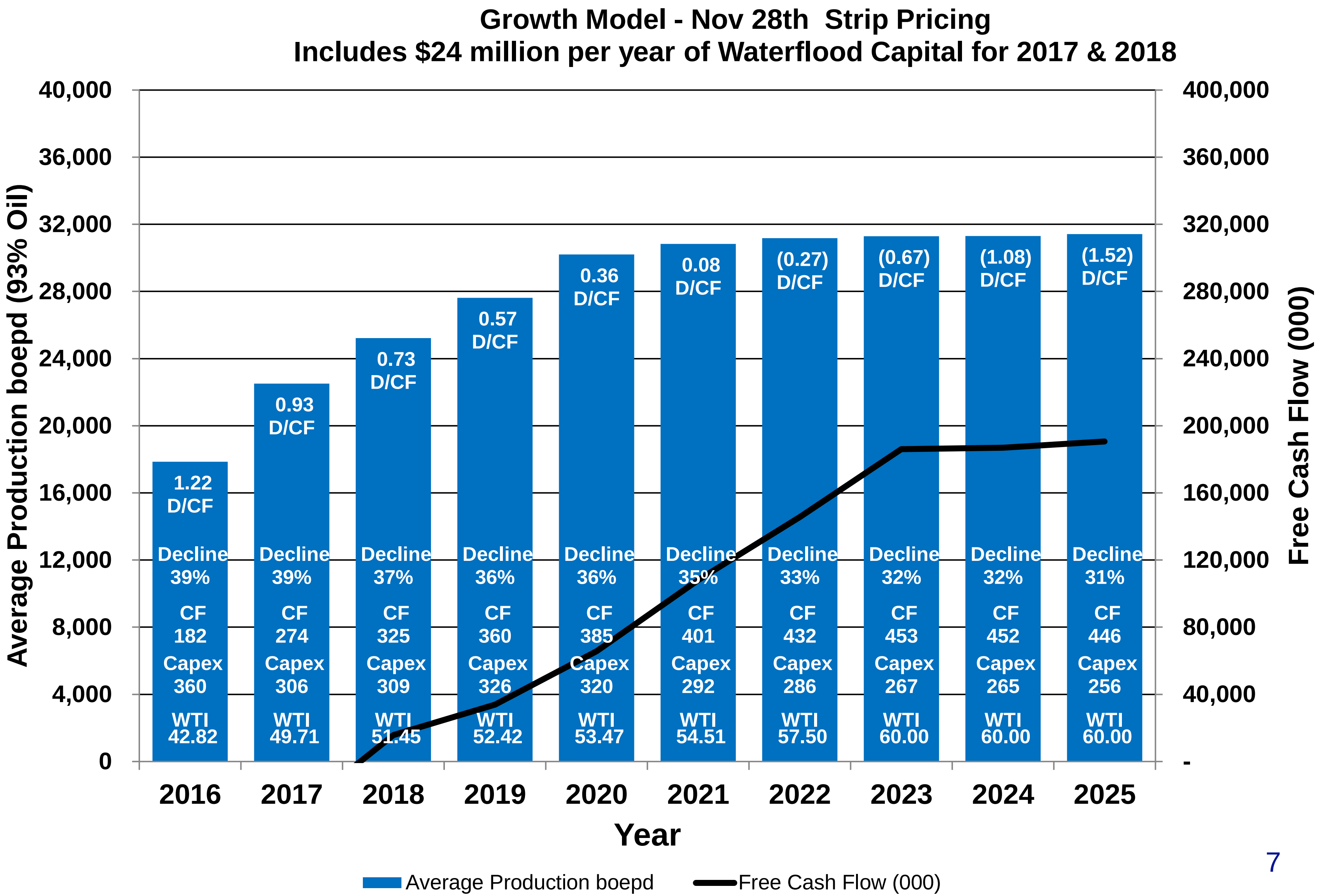
RRX an Organic Growth Story



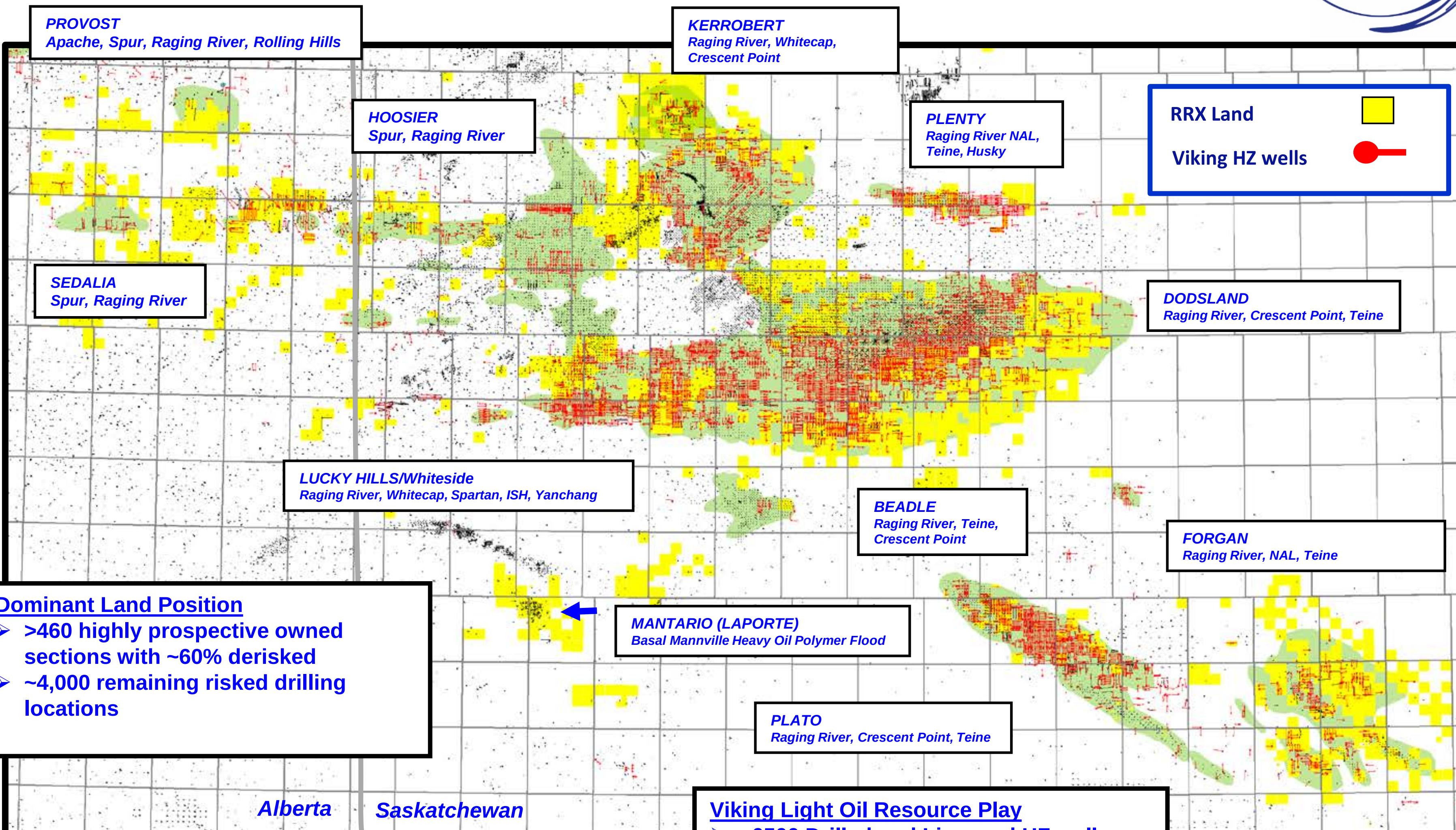
Sustainable Growth Model



Sustainable Model – Zero Waterflood Response Model



Raging River – Expands Dominant Viking Position



Dominant Land Position

- >460 highly prospective owned sections with ~60% derisked
- ~4,000 remaining risked drilling locations

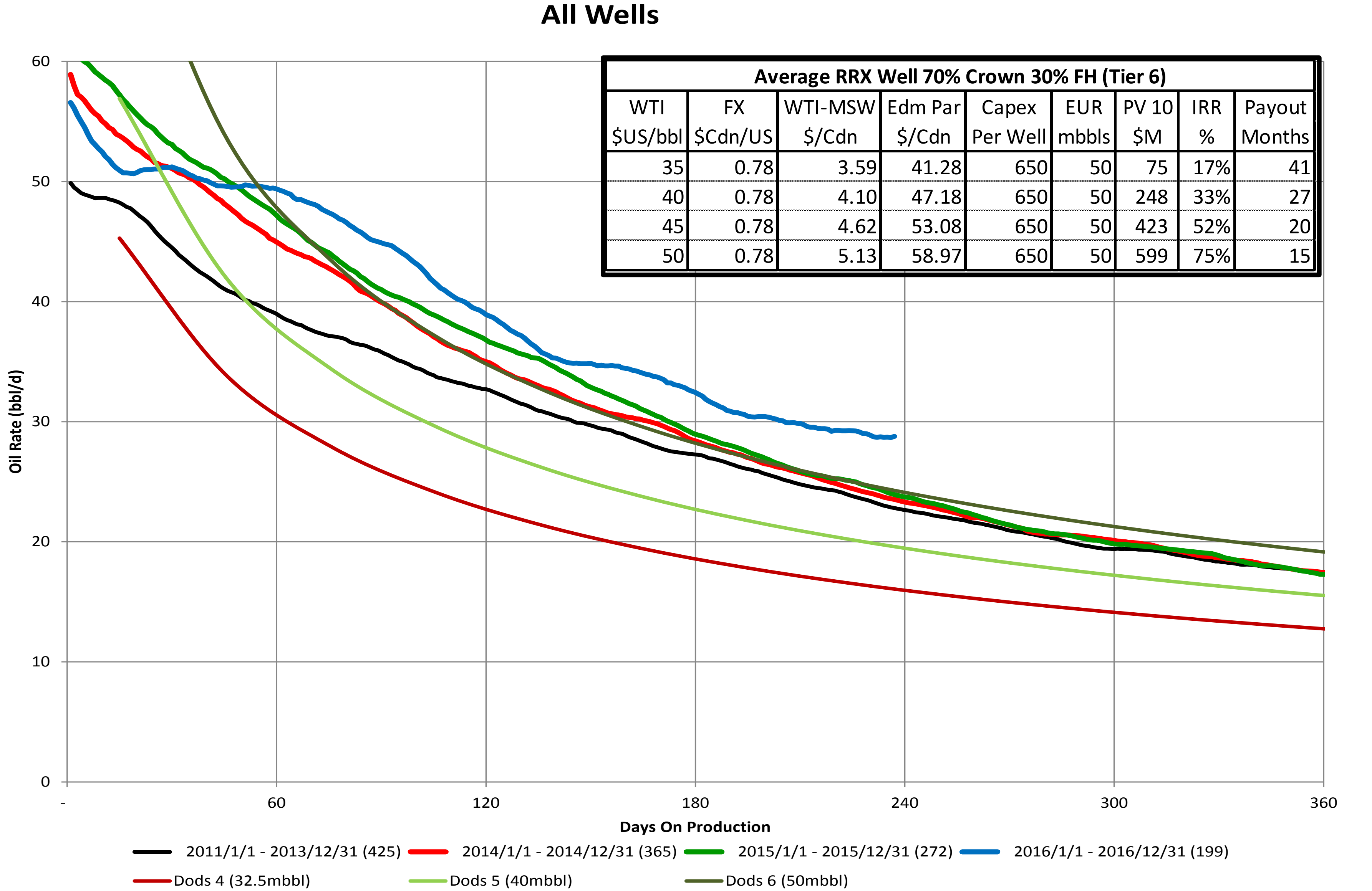
Viking Light Oil Resource Play

- >6500 Drilled and Licensed HZ wells
- >6000 With Public Domain Production

Defined Viking Oil Pools

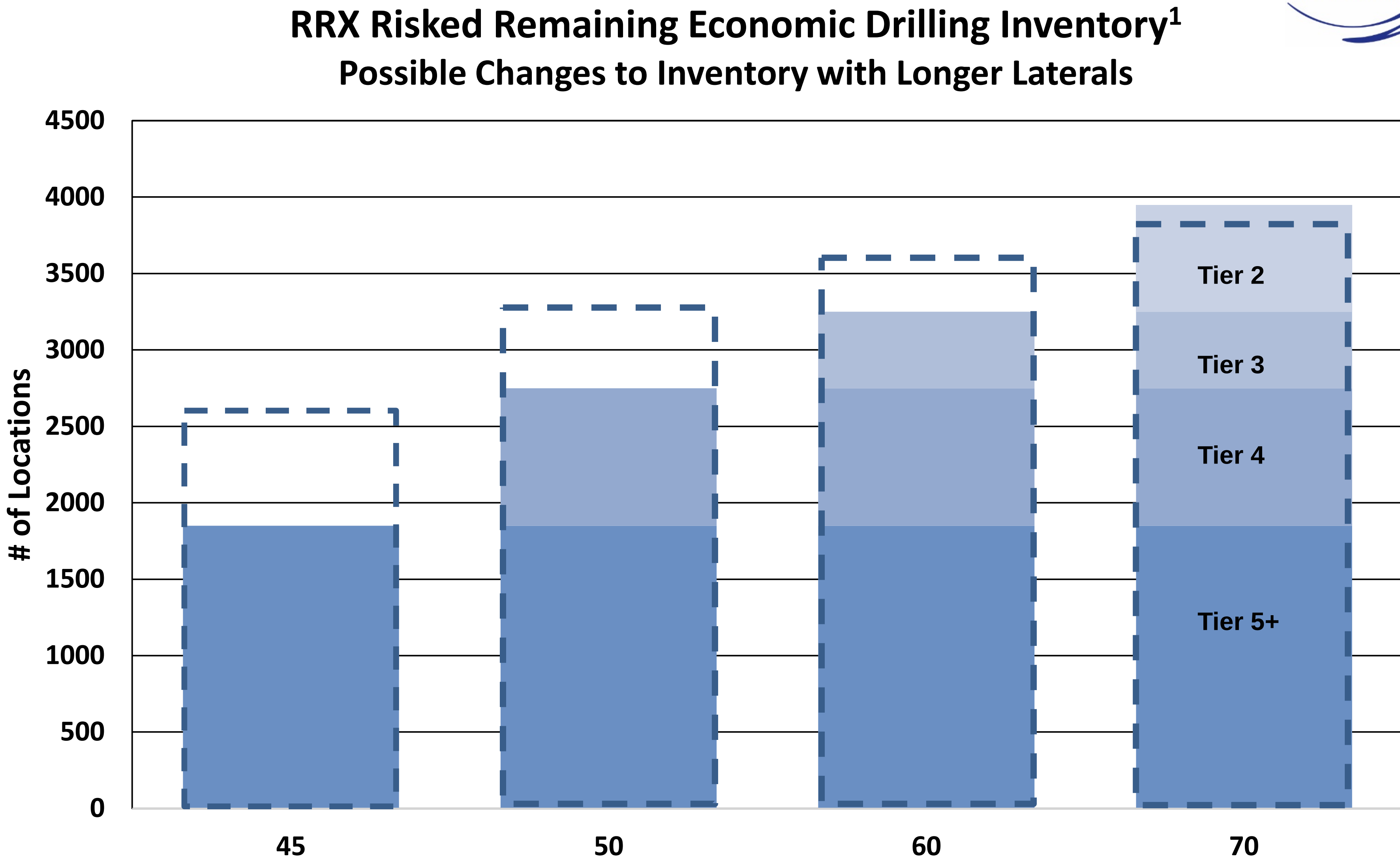
Raging River All Corporate Wells

Statistics Matter > 1,250 RRX Wells On-Stream



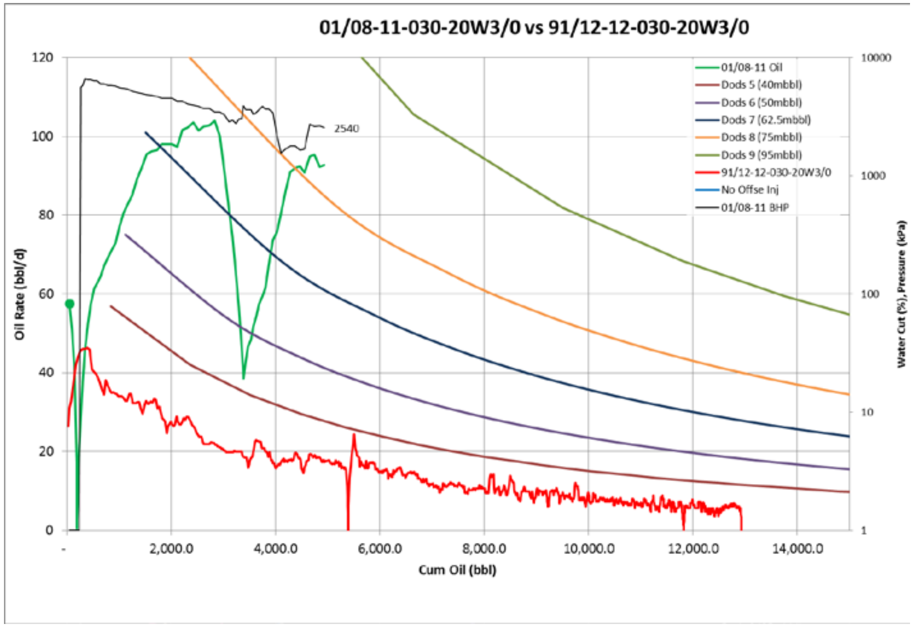
Average RRX Well 70% Crown 30% FH (Tier 6)								
WTI $US/bbl	FX $Cdn/US	WTI-MSW $/Cdn	Edm Par $/Cdn	Capex Per Well	EUR mbbls	PV 10 $M	IRR %	Payout Months
35	0.78	3.59	41.28	650	50	75	17%	41
40	0.78	4.10	47.18	650	50	248	33%	27
45	0.78	4.62	53.08	650	50	423	52%	20
50	0.78	5.13	58.97	650	50	599	75%	15

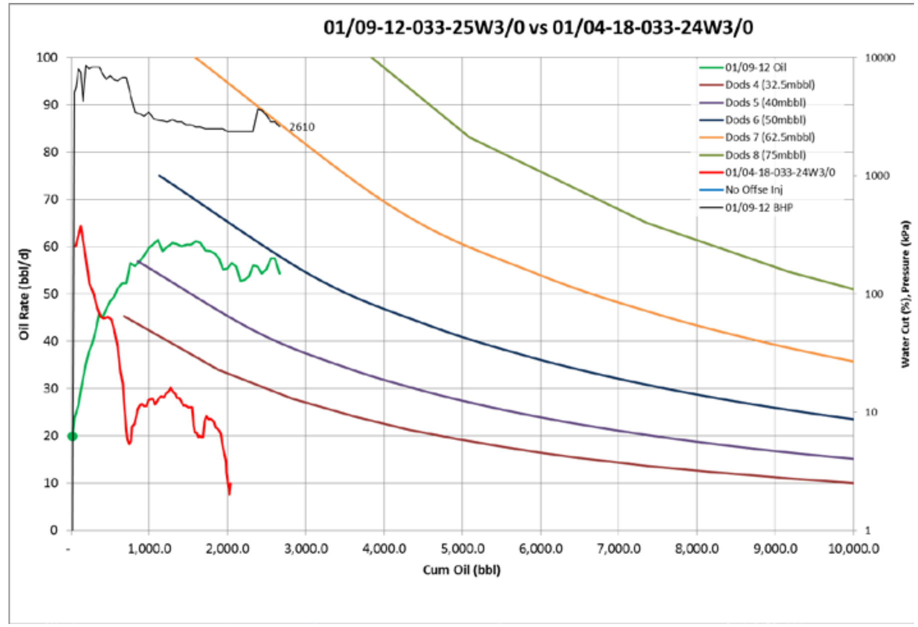
RRX Economic Drilling Inventory

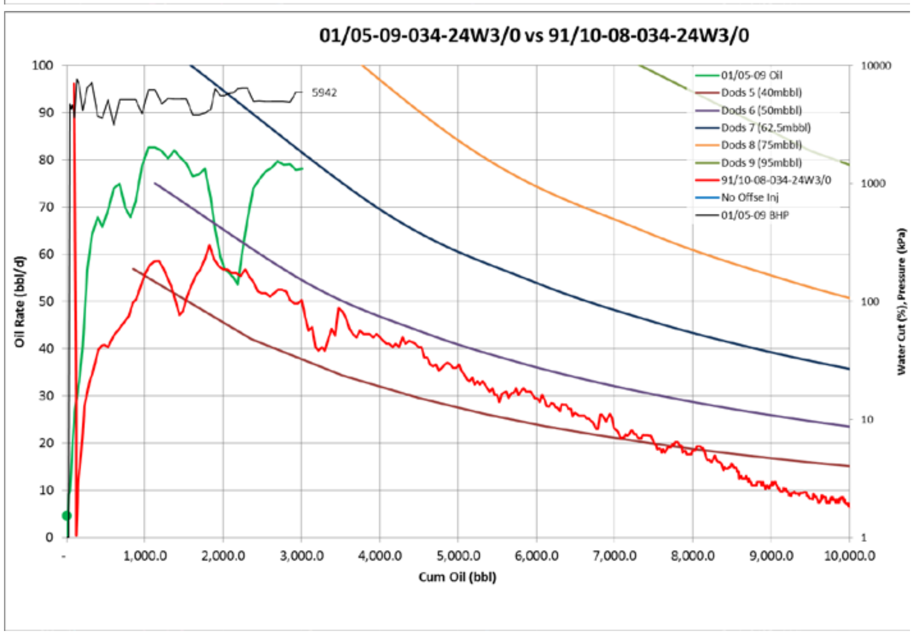


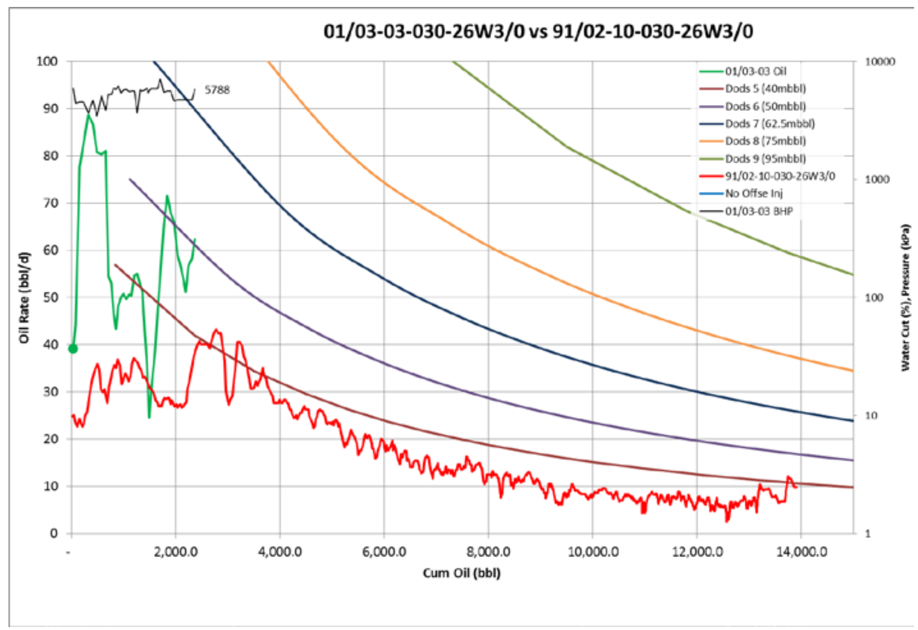
Based on 0.78 F/X (US$/CAD$), WTI/Ed Light Differential of 8%
On-stream Capital of $675,000 per well

“ERH” 0.75 mile Examples









Why Raging River

Management

- Proven execution throughout the commodity cycle

Business Model

- Per share growth is imperative
  - Debt and dividend adjusted per share growth of 350% since 2012
- 37%/yr. average production per share growth since inception

Balance Sheet

- Strict control and management of balance sheet
  - Debt has never exceeded 1x D/CF
  - Survive and thrive during adverse conditions

Sustainability

- Total per share returns (growth and FCF) of 10-15%/yr. at strip pricing over the next 10 years
- FCF above growth in 2018
- Drilling inventory through 2030
- Enhanced oil recovery optionality, water flood success is not imperative for continued success

RRX

RAGING RIVER EXPLORATION INC.

Office
1700, 605-5th Avenue SW
Calgary, Alberta
T2P 3H5
Main: (403) 387-2950
Fax: (403) 387-2951

Website
www.rrexploration.com

For further information
Please contact:

Mr. Neil Roszell, P.Eng.
Email: nroszell@rrexploration.com
Phone: (403) 767-1250

Mr. Jerry Sapieha, CA
Email: jsapieha@rrexploration.com
Phone: (403) 767-1265

Disclaimer

FORWARD LOOKING STATEMENTS: This presentation contains forward-looking statements. More particularly, this presentation contains statements concerning details of 2016 budget including amount to be spent on development expenditures, expected 2016 average and exit production, guidance for the full year and the fourth quarter of 2016, including production, commodity prices, operating cashflow, general and administrative expenses, financial charges, funds flow from operations, annualized funds flow from operations per share, 2016 exit net debt, 2016 exit net debt to funds flow from operations, oil and gas sales, royalties, operating expense, transportation expense, operating netback, and funds flow netback, the expected results from certain drilling space, longer lateral and waterflood initiatives, the Company's flexibility in changing its capital budget in response to changing commodity prices, the ability to grow without additional land capture, technology improvements or acquisitions and the intent to pursue acquisitions that add to shareholder value. In addition, the use of any of the words "guidance", "initial, "scheduled", "can", "will", "prior to", "estimate", "anticipate", "believe", "potential", "should", "unaudited", "forecast", "future", "continue", "may", "expect", "project", and similar expressions are intended to identify forward-looking statements. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct.

Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, that Raging River will not achieve the anticipated benefits of the Acquisition or other transactions, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses, and health, safety and environmental risks), commodity price and exchange rate fluctuations, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Additional information on these and other factors that could affect Raging River's operations and financial results are included in the Company's Annual Information Form and other reports on file with Canadian securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com). The Company has presented herein ten year growth plans based on certain commodity price assumptions. Such growth plans do not represent management's expectations of the Company's future performance but rather is intended to present management's belief in the economic viability of the Company's business based on such pricing scenarios. Readers should not use such ten year growth model as a presentation of the Company's future performance. The forward-looking statements contained in this presentation are made as of the date hereof and the Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

FUTURE ORIENTED FINANCIAL INFORMATION: Any financial outlook or future oriented financial information in this presentation, as defined by applicable securities legislation, has been approved by management of Raging River. Readers are cautioned that any such future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. The Company and its management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represent, to the best of management's knowledge and opinion, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results

NON-IFRS MEASURES: This document contains the terms "funds from operations" (or "cash flow"), "net debt", "field netback", "operating netback" and "funds flow netback", which do not have a standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable with the calculation of similar measures by other companies. Management uses funds from operations to analyze operating performance and leverage. Management believes "net debt" is a useful supplemental measure of the total amount of current and long-term debt of the Company. Mark-to-market risk management contracts are excluded from the net debt calculation. Management believes "field netback", "operating netback" and "funds flow netback" are useful supplemental measures of firstly, the amount of revenues received after royalties and operating and transportation costs, secondly, the amount of revenues received after royalties, operating, transportation costs and realized gain (loss) on derivatives, and thirdly, the amount of revenues received after royalties, operating, transportation costs, realized gain (loss) on derivatives, general and administrative costs, financial charges and asset retirement obligations. Additional information relating to certain of these non-IFRS measures, including the reconciliation between funds from operations and cash flow from operating activities, can be found in the Company's most recent management's discussion and analysis which is available on SEDAR at www.sedar.com.

ASSUMPTIONS RELATING TO RESULTS FROM LONGER LATERAL WELLS, WATERFLOOD AND WELL SPACING ECONOMICS: The Company has presented certain anticipated results from initiatives that the Company is currently undertaking relating to drilling longer lateral wells, decreasing well spacing and waterfloods. Such results have been based on historic performance and certain assumptions made by management relating to future performance. Such information has been presented so that readers can understand management's assumptions and modeling used for the purpose of determining to undertake such initiatives. The information presented relating to improved recovery factors, initial production rates, finding and development costs ("F&D"), estimated ultimate recovery ("EUR"), recycle ratios and reserves life index are not intended to provide an estimate of future performance of wells or an estimate of reserves. Readers should not use such information as an estimate or projection of the Company's future performance or the performance relating to any particular initiative to be undertaken by the Company.

Disclaimer

OIL AND GAS METRICS: This presentation contains a number of oil and gas metrics, including capital efficiency, initial production rates for the first 90 days ("IP 90"), internal rate of return ("IRR"), reserves life, F&D, recycle ratio, and payout, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods. Capital efficiency is based on the total capital invested in a period divided by the average daily production additions (over the period indicated) resulting from such activity. IP 90 is the expected initial production rate for the first 90 days of production of a well. Internal rate of return is calculated by taking the expected capital costs to drill, complete and equip wells and balancing them against the future net revenue expected using various commodity price forecasts and management estimates of operating costs, royalties, production rates and reserves. Reserves life is determined by dividing the reserves by the annual production of the Company. Finding and development costs are determined by dividing the expected reserves addition by the capital expected to be spent finding and developing such reserves. Recycle ratio is the ratio between netbacks and F&D on a per BOE basis. Payout is calculated by determining the number of years it will take the Company to earn back the capital invested in such well based on expected production and various price and cost inputs. The capital efficiencies, initial rates of production, rates of return and payouts associated with the wells or assets have been provided herein to give an indication of management's assumptions used for budgeting, planning and forecasting purposes. The capital efficiencies, initial rates of production, IRR, F&D, reserves life, recycle ratio and payouts associated with the wells or assets will most likely be different than projected. Any references in this presentation to capital efficiencies, initial rates of production, IRR, F&D, reserves life, recycle ratio and payouts associated with the wells or assets are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter and are not necessarily indicative of long term performance or long term economics of the relevant well or fields or of ultimate recovery of hydrocarbons. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production or performance for the Company.

DRILLING LOCATIONS: This presentation discloses drilling locations in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the Company's most recent independent reserves evaluation as prepared by Sproule as of December 31, 2015 and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on the Company's prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Of the 3,800 drilling locations identified herein, 892 were proved locations, 87 are probable locations at December 31, 2015 and the remainder are unbooked locations. In addition, 100 drilling locations associated with the assets acquired by the Company in the Forgan area of Saskatchewan represent unbooked locations. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

OOIP: Original Oil-In-Place ("OOIP") is equivalent to Total Petroleum Initially-In-Place ("TPIIP") and has been estimated as at December 31, 2015. TPIIP, as defined in the Canadian Oil and Gas Evaluations Handbook, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered.

RRX

RAGING RIVER EXPLORATION INC.

Appendix Information

Footnotes

Slide 4

1. Utilizing price of $9.70/share for RRX on November 28, 2016.

Slides 6,7

1. FX of 0.76 $US/$Cdn, Differential from WTI to Canadian Light of 8%.
2. WTI and Natural gas strip Pricing as at November 3, 2016.
3. Short well on-stream well costs assumed to be $620k in 2016, escalating by 5% per year for next two years.

Slide 10

1. Does not incorporate the Dodsland Viking property acquisition announce on November 28, 2016.

Management Team and Board of Directors

Management Team

Neil Roszell, P. Eng.
President, CEO & Director

Jason Jaskela, P. Eng.
VP Production & COO

Jerry Sapieha, CA
VP Finance & CFO

Bruce Beynon, P. Geol.
Executive Vice President

Scott Rideout
Vice President Land

Jesse Barlow, P. Eng.
Vice President Engineering

Terry Danku, P. Eng.
VP Business Development

Chad Lundberg, P. Eng.
Vice President Operations

Board of Directors

Neil Roszell
President & CEO
Raging River Exploration

Dave Pearce
Industry Partner
Azimuth Partners

Gary Bugeaud
Independent Businessman
Calgary, Alberta

George Fink
Chairman & CEO
Bonterra Oil & Gas Ltd.

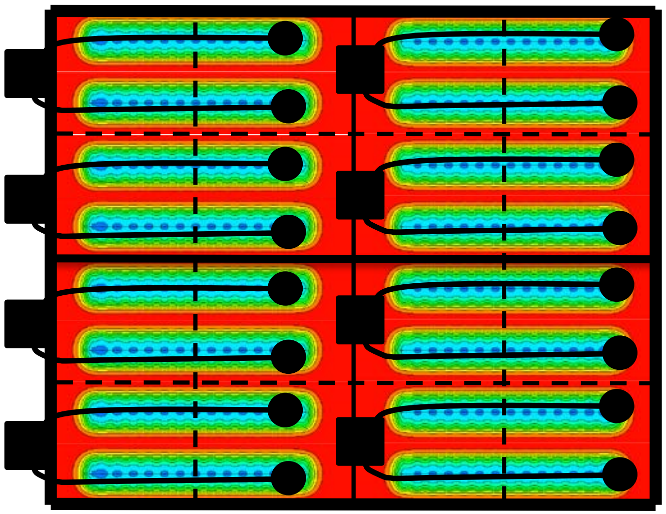
Kevin Olson
President Kyklopes
Capital Management

Raymond Mack
Partner: Kenway Mack
Slusarchuk Stewart LLP

Drilling Density

RRX RAGING RIVER EXPLORATION INC.

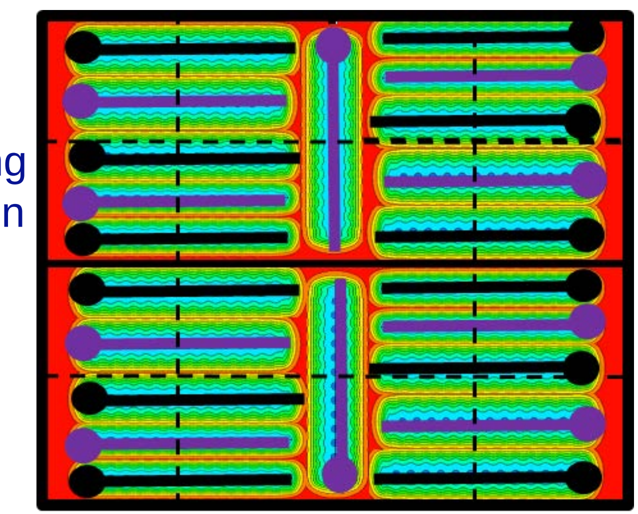
Drill Spacing at 16 wells per section



- OOIP(1) ~ 10MMbbls
- 16 Tier 5-6 HZ wells will recover 640-800 Mbbls (6.4%-8% Recovery)
- Reservoir modelling shows undrained areas (red on graphic) 20 years after production start-up

In high OOIP sections 16 HZ wells per section leaves significant unrecovered oil

Drill Spacing at 22 wells per section



Poor

Good

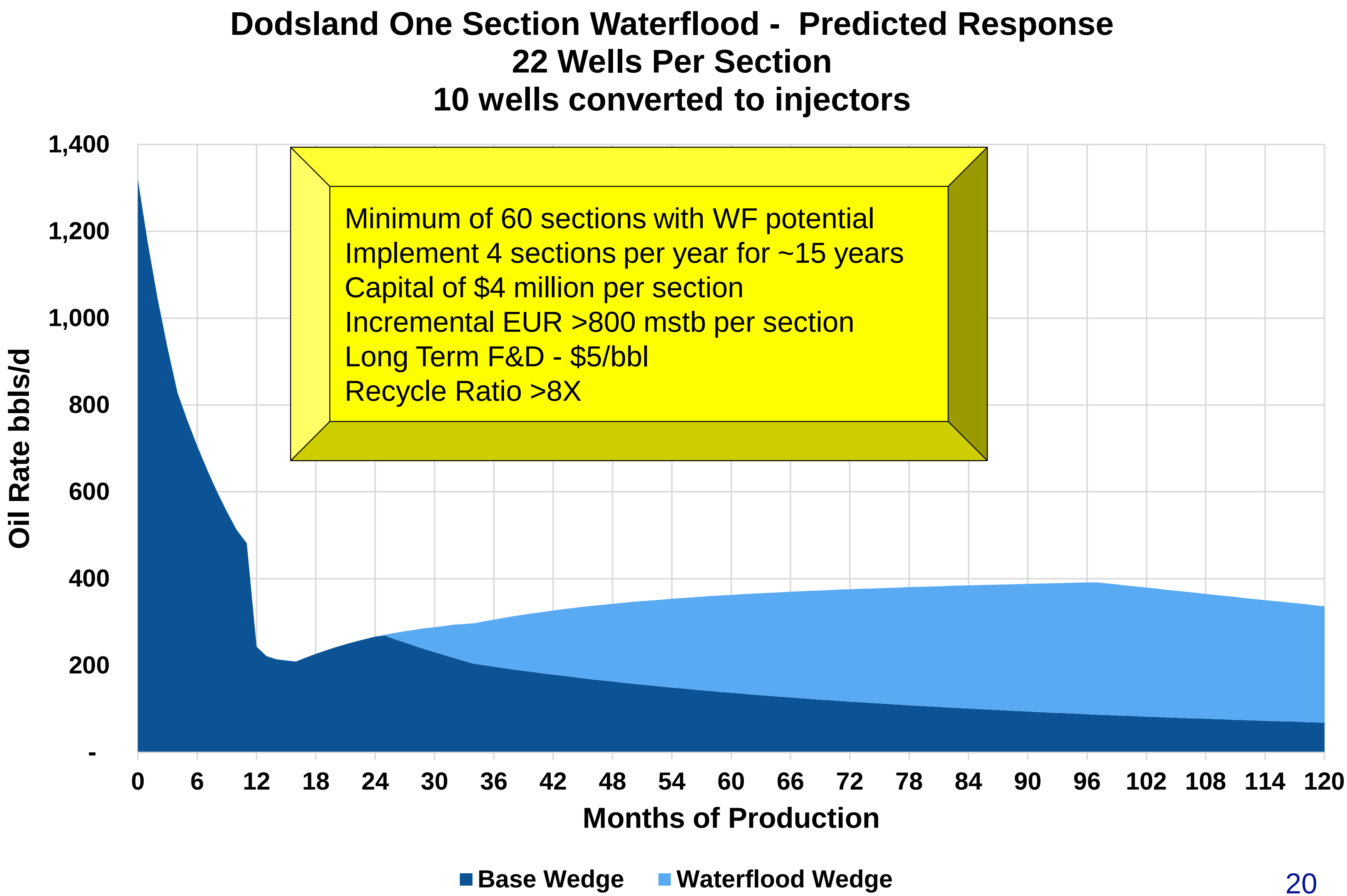
Relative Recovery

Optimal Well Density

- Significant improvement in oil recovery by increasing well density from 16 wells/section to 22 wells/section
  - 22 Tier 5-6 hz wells/section
    - 8.8-11.3% recovery factor

- RRX pilots are proving 22 well per section spacing to minimize interference and maximize recovery

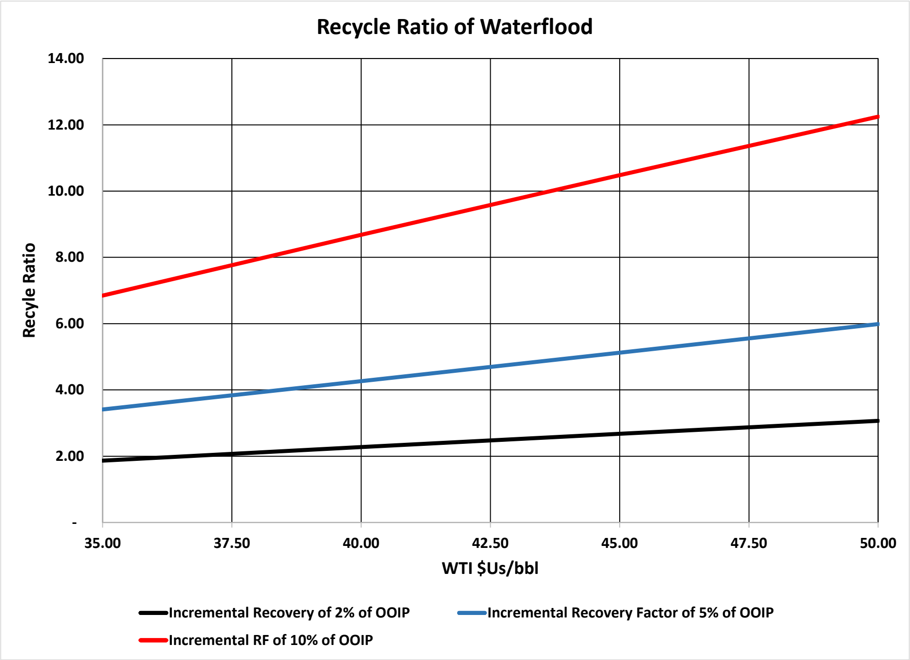
Waterflood – “A Long Term Strategy”



Waterflood Value

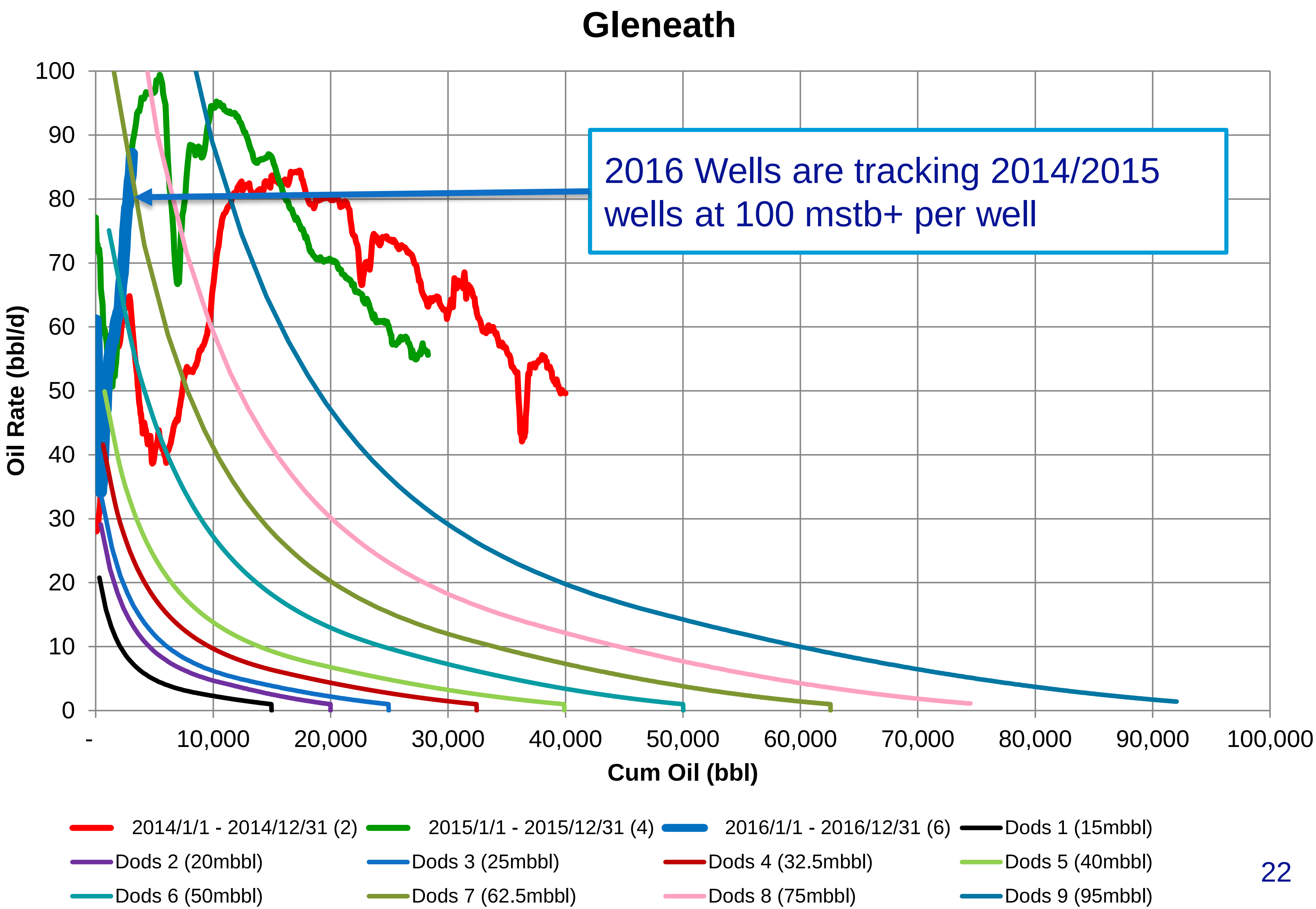
Why Waterflood

- Long term value creation
- Strong recycle ratios
- Double primary recovery
- Competitive payouts and IRR's
- Decline mitigation
- Capital efficiency enhancements

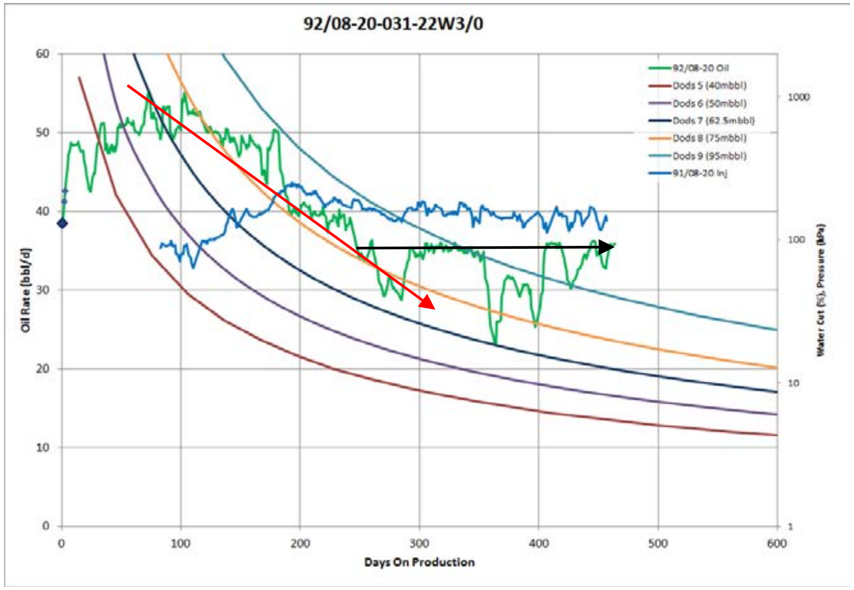


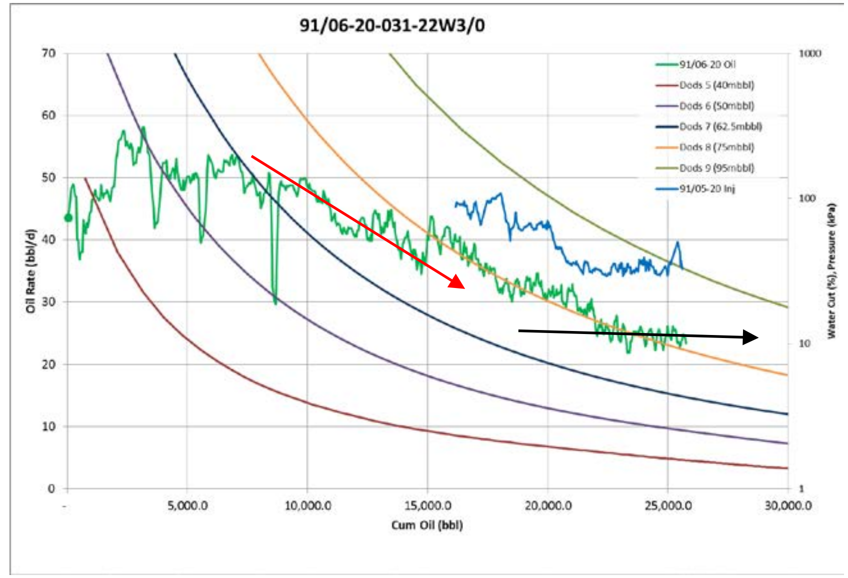
- Need to balance production/growth with waterflood value creation
  - Near term F&D and production efficiencies are negatively impacted by waterflood implementation.
- Because of the long RLI waterfloods are expected to take advantage of commodity price appreciation yielding **IRR's that improve with time**
- **The math at flat $50 WTI**
  - **Each successful section under waterflood is expected to cost ~$4 million**
  - **Each successful section is expected to return ~ $48 million in cashflow over it's life**

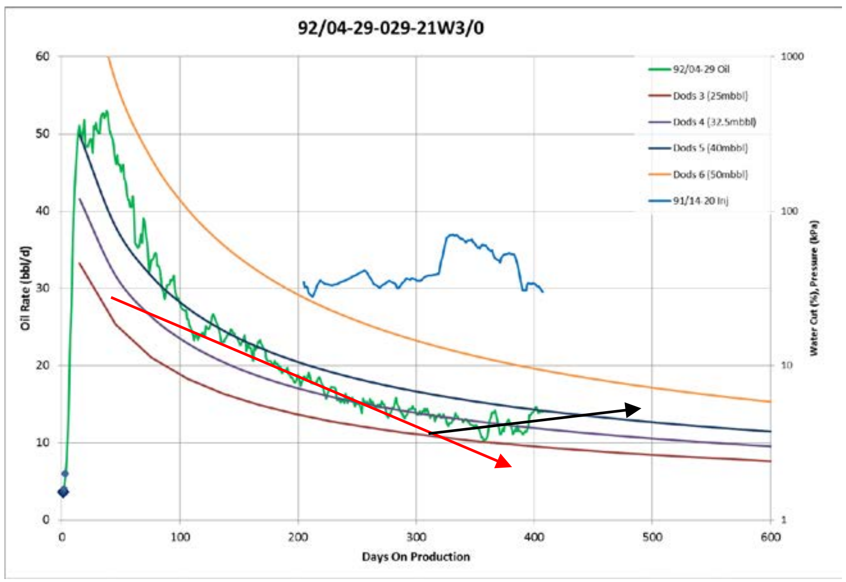
Waterflood Works



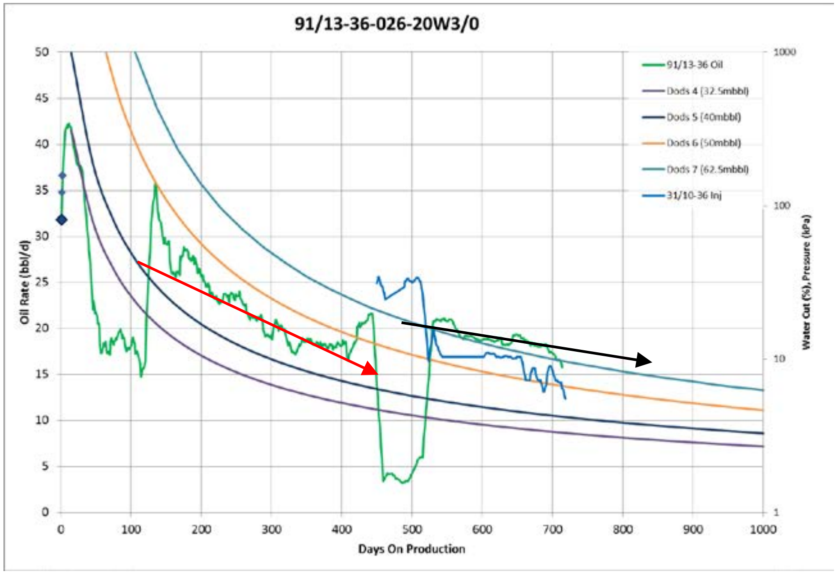
Pilot Response Examples

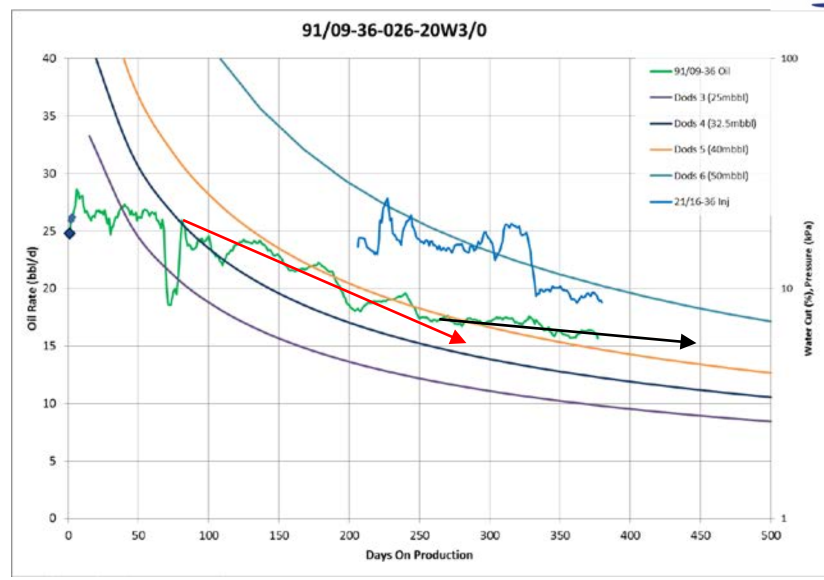


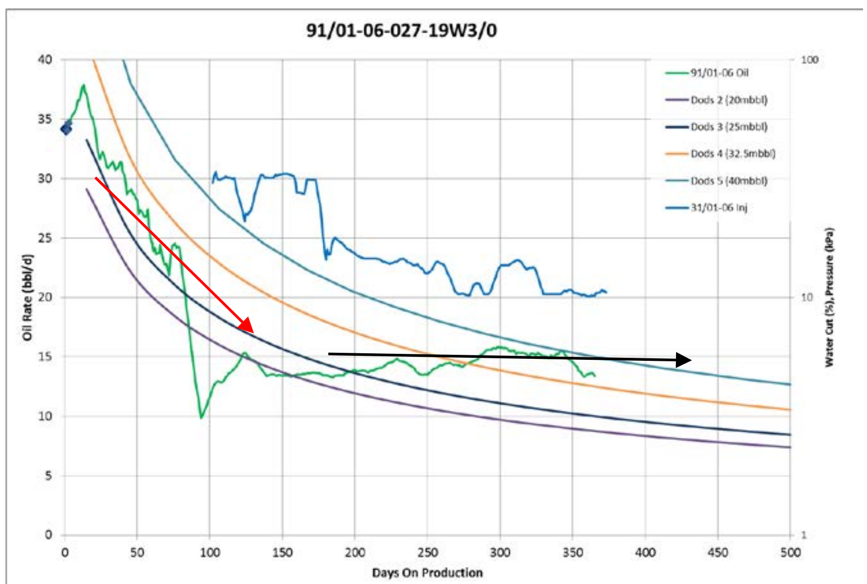




Pilot Response Examples







Independent Engineering per well Booking Structure Crown Royalties

Based on $50/bbl WTI pricing, 0.78 F/X (US$/CAD$), WTI/Ed Light Differential 8% of WTI
On-stream Capital of $650,000 per well

Tier	Well Spacing per Section*	90 Day Oil IP bbls/d	Months to Payout	Proved + Probable Reserves mstb	Proved + Probable NPV10 $M	ROR %
2.0	22	23	NA	20.0	(203)	-7%
3.0	22	27	97	25.0	(101)	2%
4.0	22	33	46	32.5	90	17%
5.0	22	40	30	40.0	284	32%
6.0	22	60	14	50.0	658	82%
7.0	22	77	10	62.5	1,006	150%
8.0	22	97	7	75.0	1,373	268%
9.0	22	124	5	95.0	1,872	554%

* PUD's booked only at 16 wells/section, only wells drilled and on production at 22 wells per section receive reserve assignments.

Independent Engineering per well Booking Structure
Freehold Royalties

RAGING RIVER EXPLORATION INC.

Based on $50/bbl WTI pricing, 0.78 F/X (US$/CAD$), WTI/Ed Light Differential 8% of WTI
On-stream Capital of $650,000 per well

Tier	Well Spacing per Section	90 Day Oil IP bbls/d	Months to Payout	Proved + Probable Reserves mstb	Proved + Probable NPV10 $M	ROR %
2.0	22	23	NA	20.0	(320)	-20%
3.0	22	27	NA	25.0	(241)	-10%
4.0	22	33	88	32.5	(86)	3%
5.0	22	40	47	40.0	71	15%
6.0	22	60	21	50.0	381	47%
7.0	22	77	14	62.5	667	88%
8.0	22	97	9	75.0	973	153%
9.0	22	124	6	95.0	1,409	297%

* PUD's booked only at 16 wells/section, only wells drilled and on production at 22 wells per section receive reserve assignments.

Historic Operational Excellence

	Q3/16	Q2/16	Q1/16	Q4/15	Q3/15	Q2/15	Q1/15	Q4/14	Q3/14	Q2/14	Q1/14	Q4/13
Financial *(thousands of dollars except share data)*												
Funds Flow from Operations	49,726	43,999	29,904	40,708	43,630	49,535	33,480	57,704	57,850	56,283	49,813	35,882
Basic Shares Outstanding End of Period	231,038	226,231	226,014	213,421	200,319	198,655	197,206	180,332	180,209	179,890	179,213	170,914
Annualized FFO/Share Basic	0.86	0.76	0.56	0.80	0.88	1.00	0.68	1.28	1.28	1.25	1.11	0.84
Quarterly CF/Share growth	13%	36%	-31%	-12%	-13%	47%	-47%	0%	3%	13%	32%	1%
Net Earnings	6,758	5,320	(7,852)	5,120	10,893	12,145	760	24,067	31,505	30,238	24,360	16,622
Annualized Quarterly Earnings per Basic Share	0.12	0.08	N/A	0.10	0.22	0.25	0.02	0.53	0.70	0.67	0.54	0.39
Quarterly Earnings Growth	50%	N/A	N/A	N/A	N/A	N/A	N/A	-24%	4%	24%	40%	30%
Average Daily Production	18,612	16,002	16,505	14,771	13,418	13,347	13,310	12,548	10,679	9,960	9,805	7,777
Operating Netback ($/boe)	30.88	31.57	20.04	32.21	37.22	42.92	29.97	54.05	67.68	72.16	66.82	54.89
Funds Flow Netback *($/boe)*	29.05	30.21	19.91	29.96	35.33	40.79	27.95	49.99	58.87	62.09	56.44	50.15

Per Share Matters!