Husky Energy

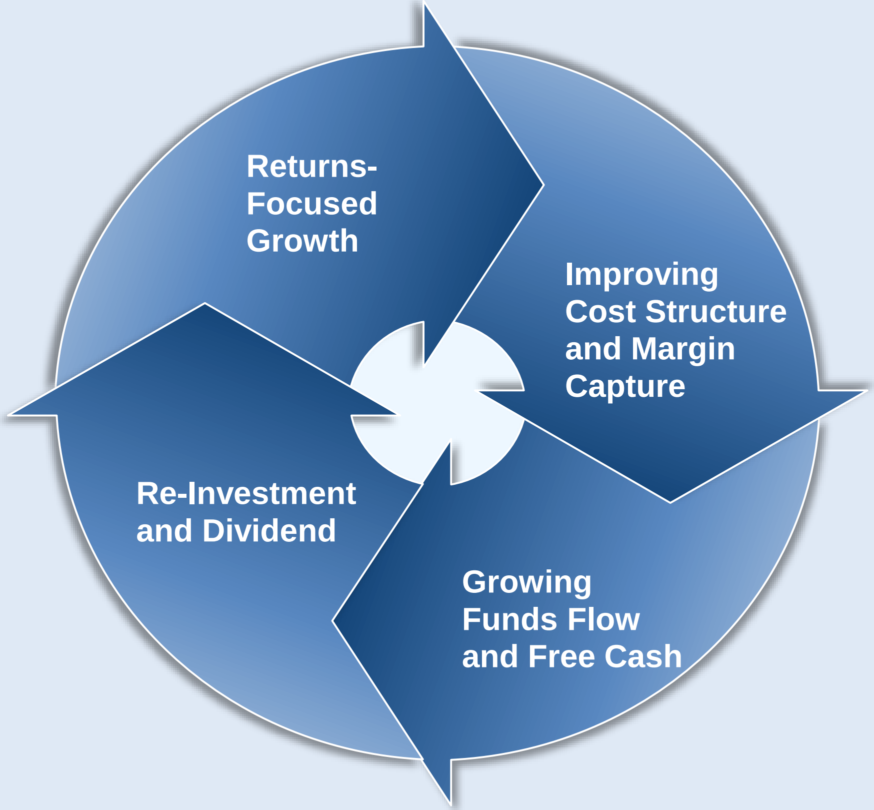
Corporate Presentation

Updated August 14, 2018

Value Proposition

Resilient and Well Positioned to Capture Upside

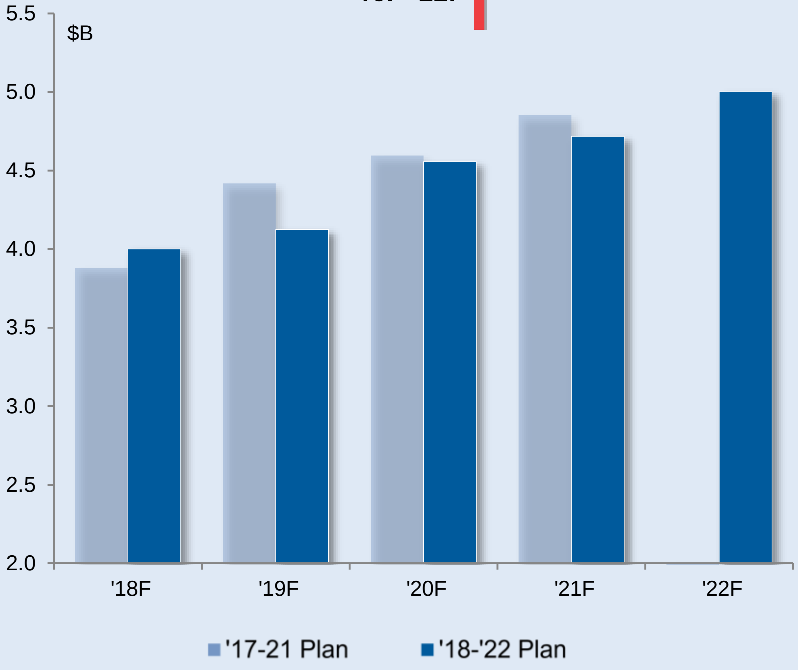
- Production and throughput growth from a large inventory of low cost projects = returns-focused growth
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Increasing cash returns to shareholders
- Integration and fixed-price Asia Pacific sales provide resilience to volatile market conditions while preserving upside



Updated Five-Year Plan (2018-2022)

Plan Remains On Track, Using Flat $60 US WTI

Funds From Operations CAGR '18F-'22F **6%**



Key Metrics	'18F	'22F	'18F-22F CAGR[1]
Funds from operations (FFO)[2,3]	**$4B**	**$5B**	**6%**
Free cash flow (FCF)[4]	**$1B**	**$1.4B**	**9%**
Upstream production (mboe/day)	**310-320**	**410-420**	**7%**
Downstream throughputs (mbbls/day)	**360-370**	**360-370**	
Thermal bitumen production (mbbls/day)	126-130	200	12%
Heavy processing capacity (mbbls/day)	190	220	
Upstream operating cost/bbl	$13-13.50	$11-12	
Downstream operating costs/bbl (CAD)	$7-8	$7-8	
Earnings break-even oil price (US WTI)[5]	$42	$37	

Ranges and Targets	2018F - 2022F
Annual base dividend	$500MM
Sustaining capital[6]	Avg. $1.9B
Capital spending[7,8]	Avg. $3.5B
5-yr avg. proved reserves replacement ratio	Target >130%
Net debt to FFO[9] at $35 US WTI	<2x

1,2,3,4,5,6,7,8,9 See Slide Notes and Advisories

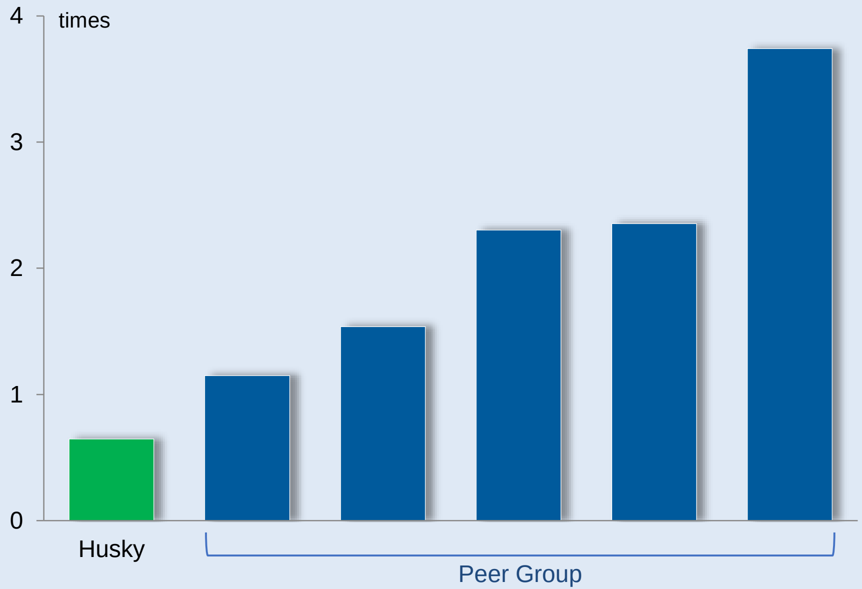
Resilience to Unpredictable Commodity Prices

Setting Husky Apart

Resilience through:

- Strong balance sheet
- Integrated model
- Growing high netback, fixed-price business in Asia
- High weighting of low sustaining capital assets and projects
- Low earnings break-evens

Net Debt to Trailing FFO[1] (Q2 '18)



Source: Factset, Company Documents
Peer group: CNRL, Cenovus, Encana, Imperial and Suncor

1 See Slide Notes and Advisories

Tight Integration Largely Eliminates Differentials

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Growing High Netback Business in Asia

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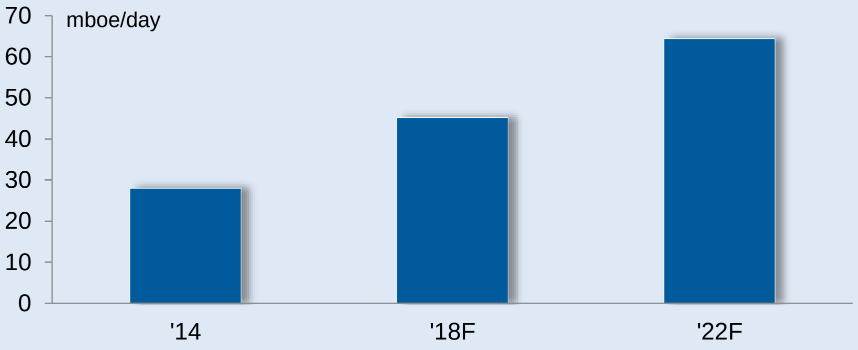
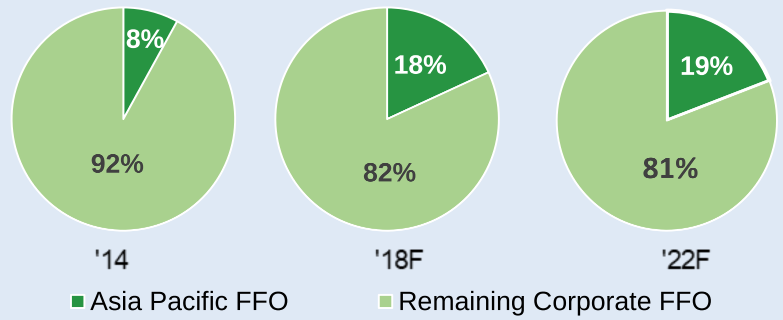
Asia Pacific Production Growth



Asia Pacific Funds From Operations as Percentage of Total



Growing Proportion of Low Sustaining Capital Projects

Setting Husky Apart

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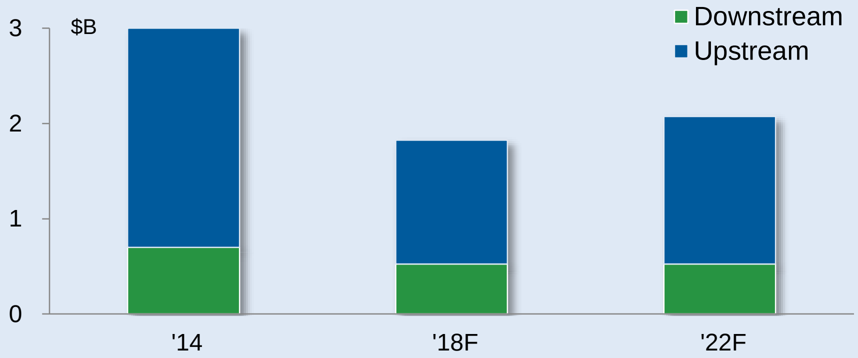
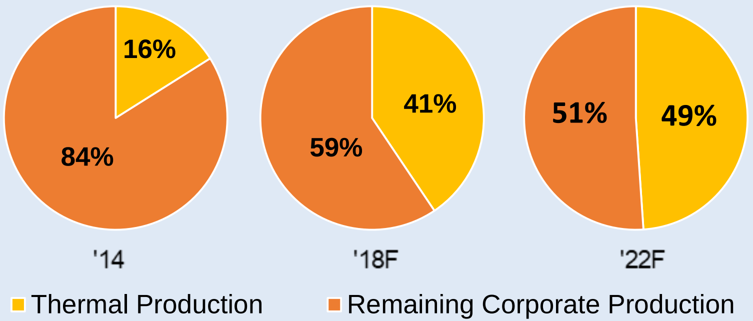
- Low earnings break-evens

Total Sustaining Capital



Thermal Bitumen Production as a Percentage of Total



Low Break Evens, And Going Lower

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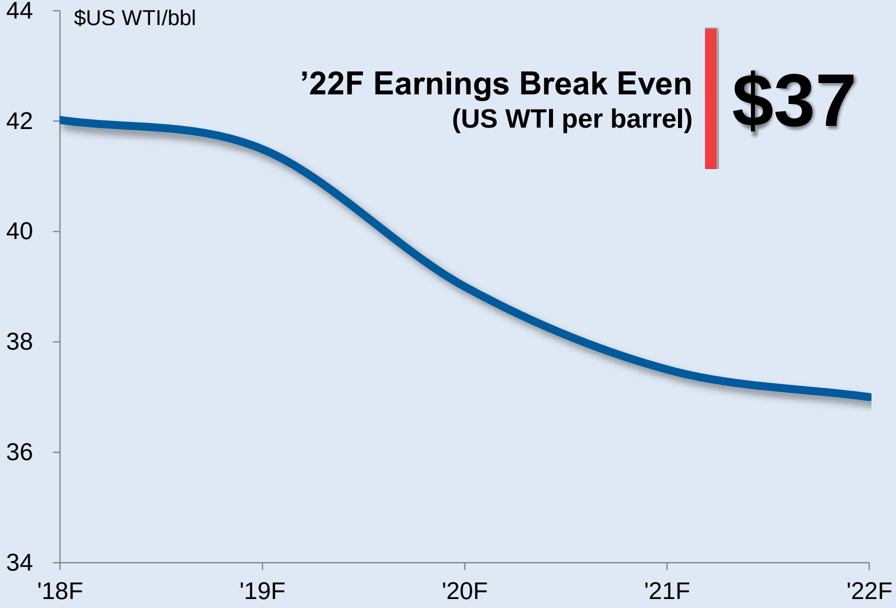
- Low earnings break-evens

Earnings Break-Even Oil Price



Setting Husky Apart

Resilience through:

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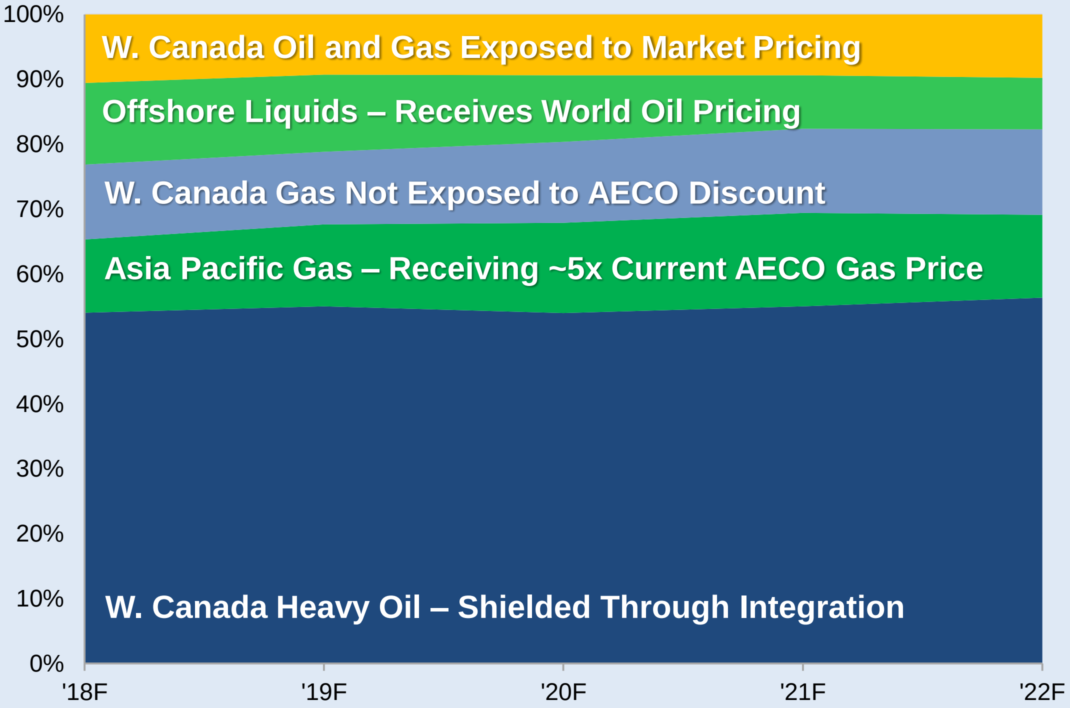
Production Mix and Commodity Price Exposure



ESG Performance and Reporting

Measuring Performance and Improving Disclosures

Economic

Business resilience

Innovation and advanced technology

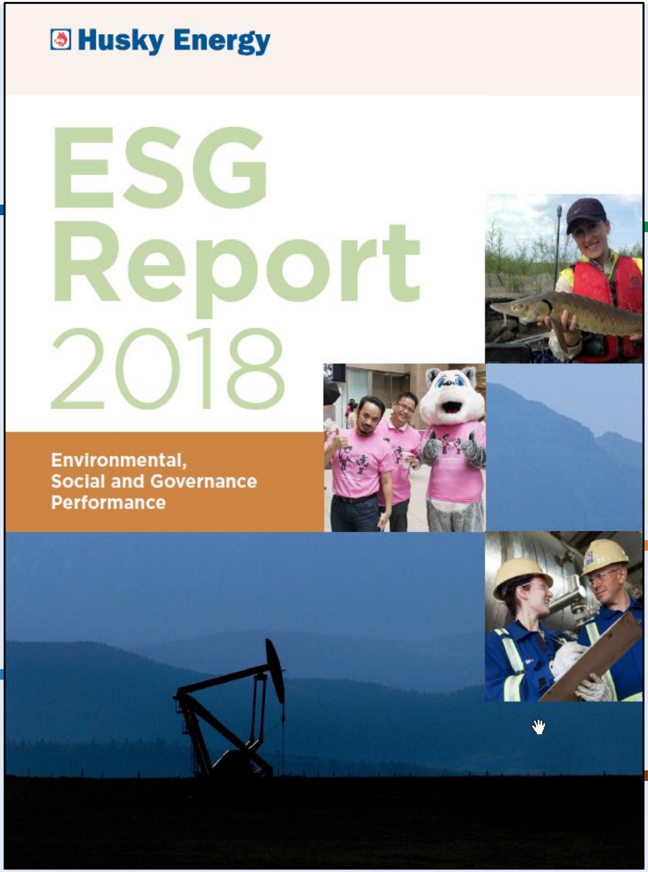
Energy use

Safety & Reliability

Asset integrity and reliability

Occupational health and safety

Emergency preparedness and response



Environment

Water use and availability

Air emissions management, including carbon

Land use and reclamation

Social

Talent management and culture of inclusion

Community & Indigenous People's Engagement

Governance

Business ethics and transparency

Two Businesses

Each Has Built-in Sustainable Competitive Advantages

Integrated Corridor	Offshore

Five-Year Plan Milestones

Project Execution in the Integrated Corridor and Offshore

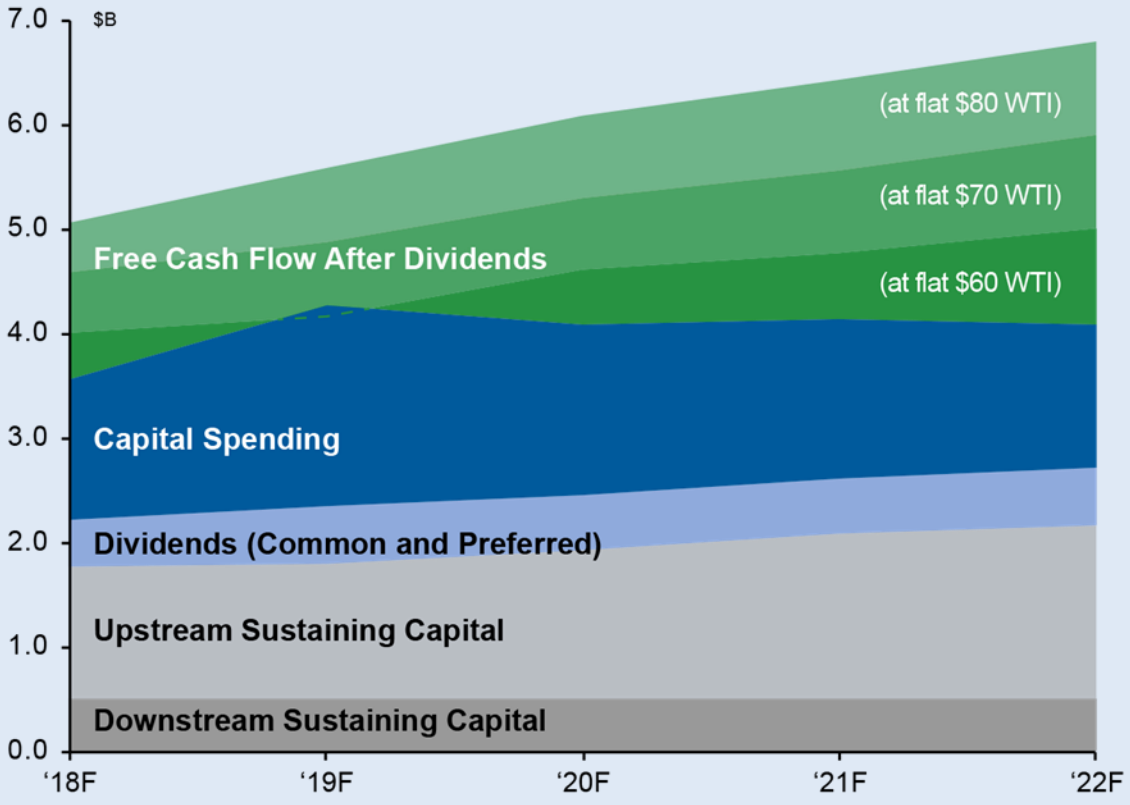
Major Projects	Net Production	2017	2018	2019	2020	2021	2022
INTEGRATED CORRIDOR							
Thermal Bitumen							
Tucker	7,000 bbls/d	On Schedule	Ramp Up Period				
Rush Lake 2	10,000 bbls/d	Accelerated to Q4 2018 from 1H 2019					
Dee Valley	10,000 bbls/d	On Schedule					
Spruce Lake Central	10,000 bbls/d	On Schedule					
Spruce Lake North	10,000 bbls/d	On Schedule					
Edam Central	10,000 bbls/d	Sanctioned Q4/17					
Westhazel	10,000 bbls/d	Sanctioned Q4/17					
Future Lloyd Thermal Projects (x2)	20,000 bbls/d						
Sunrise - 14 wells	11,500 bbls/d	Completed	Ramp Up Period				
Resource Plays							
Spirit River drilling program (Ansell-Kakwa)		17 Net wells planned for 2018					
Montney drilling program (Wembley-Karr)		Up to 8 Net wells planned for 2018					
Downstream	<u>Heavy Capacity Increase</u>						
Lima - Crude Oil Flexibility Project	30,000 bbls/d	On Schedule					
Asphalt Capacity Expansion	30,000 bbls/d		Acquired Superior Refinery				
OFFSHORE							
Asia Pacific							
China - Liuhua 29-1	45 mmcf/d, 1,800 bbls/d	Sanctioned Q4/17					
Indonesia - BD Field	9,000 boe/d	Completed	Ramp Up Period				
Indonesia - MDA-MBH, MDK	10,000 boe/d	On Schedule					
Atlantic							
White Rose Development / Infill Wells	5-8,000 bbls/d	2 Wells accelerated to Q4 2017					
West White Rose	52,500 bbls/d	On Schedule					

Spending Priorities

1. Maintain <2X net debt to FFO
2. Sustaining capital requirements
3. Maintain base dividend
4. Invest for margin and FFO growth
5. Allocate discretionary free cash flow
   - Return to shareholders
   - Organic/inorganic growth

Cumulative Free Cash Flow After Dividends at $60 US WTI '18-'22F

$2.3B

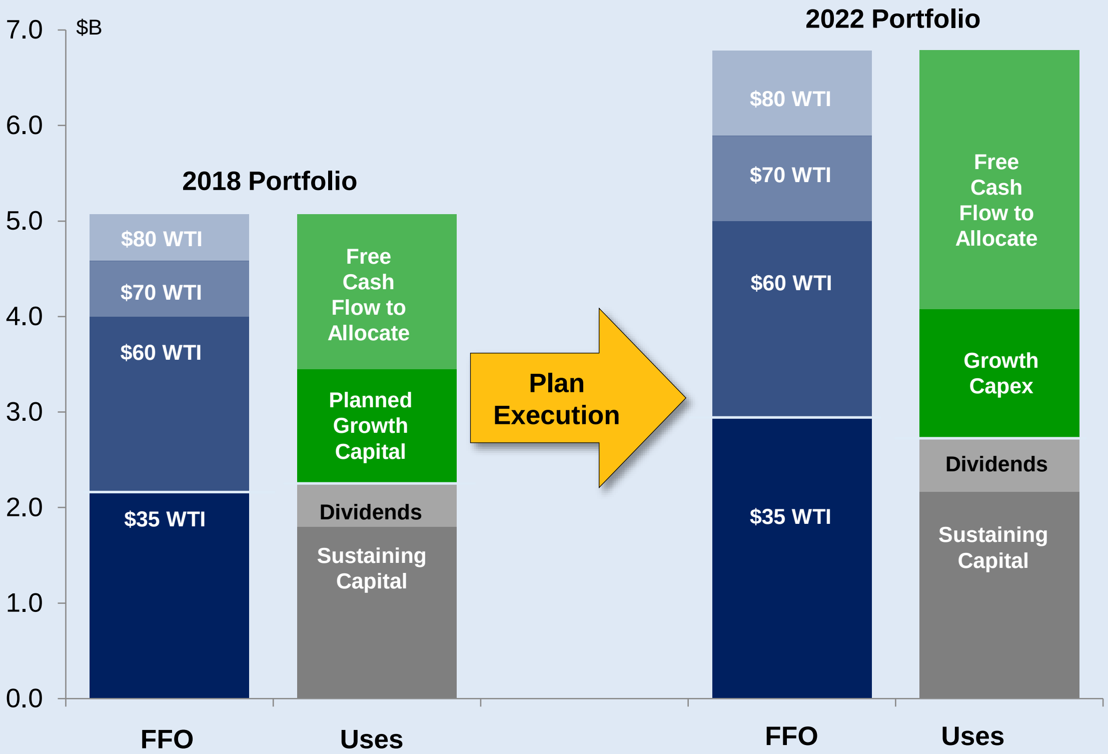


Financial Framework

Sustainable Model Through the Cycles With Free Cash Flow Upside

- Maintain balance sheet strength
- Invest in portfolio to:
  - Generate returns
  - Lower cost structure
  - Grow funds from operations and free cash flow
- Return cash to shareholders
- Optimize deployment of discretionary free cash flow

FFO Sources and Uses at Various Oil Prices (US WTI)[1]



1 See Slide Notes and Advisories

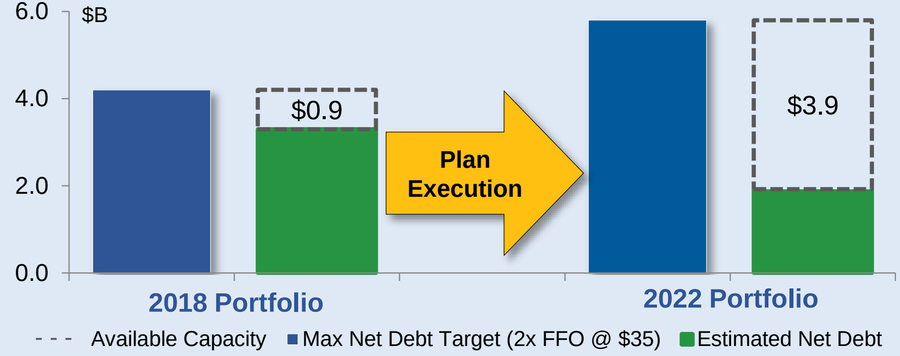
Balance Sheet

Low Leverage, Ample Liquidity

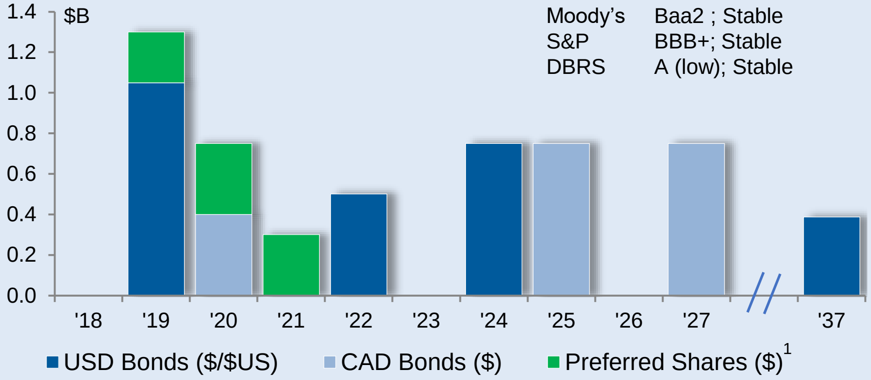
- Net debt $3.0 billion, including $2.6 billion in cash
- $4.2 billion in unused credit facilities
- Total debt to capitalization: 23.2% (Q2 ‘18)
- Debt target: <2x net debt to FFO at bottom of cycle
- Investment grade credit rating

All figures as at end Q2 ’18

Illustrative 2x Net Debt to FFO Debt Capacity at US$35 WTI



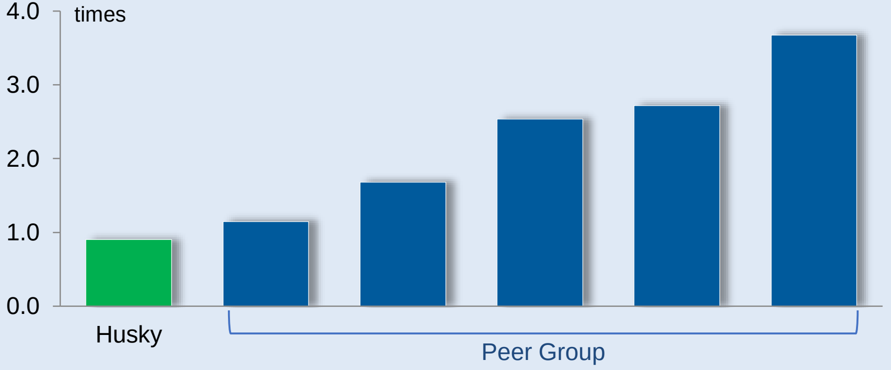
Debt Maturity Schedule



Credit Ratings

Moody’s	Baa2 ; Stable
S&P	BBB+; Stable
DBRS	A (low); Stable

Net Debt to Trailing FFO



Peer Group: Cenovus, CNRL, Encana, Imperial, Suncor

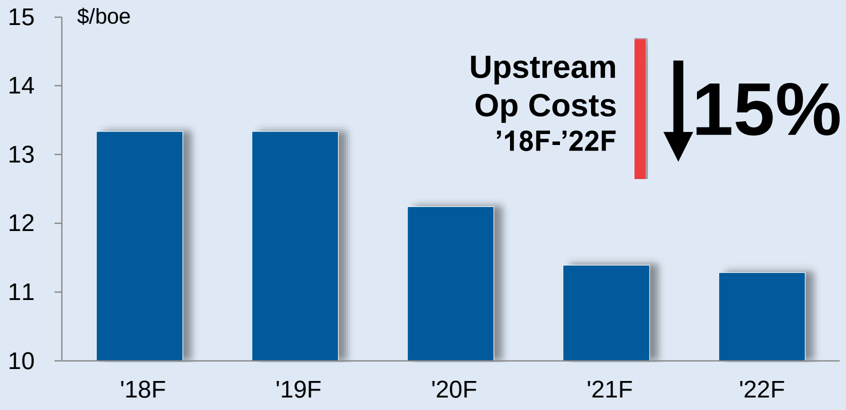
1 see *Slide Notes and Advisories*

Capex Program Drives Improving Cost Structure

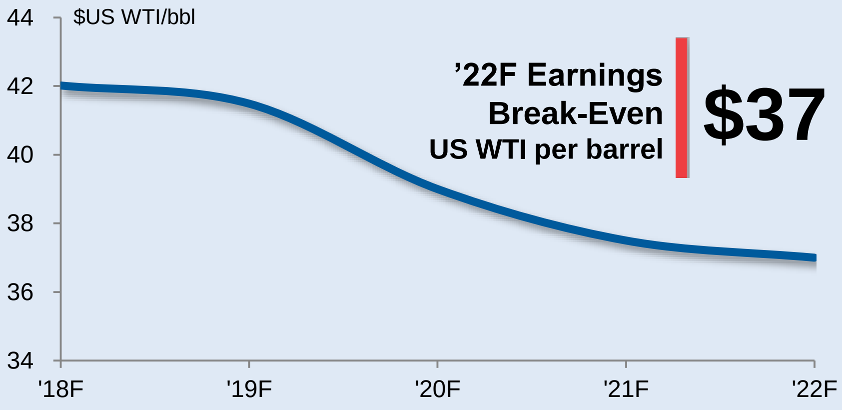
Lowering Operating Costs and Break-Even Oil Price

- New investment hurdle rate of 10% IRR at $45 US WTI and/or $2.00 per mcf AECO
- Investment options in both the Integrated Corridor and Offshore
- Approximately two-thirds of capital plan to be directed to short and mid-cycle projects

Upstream Operating Costs



Earnings Break-Even Oil Price




Integrated Corridor

Integrated Corridor

Optimizing the Entire Value Chain

Reserves base (YE '17)

- 2.0 billion boe of proved & probable reserves

Production of 233 mboe/day (Q2 '18)

- 123 mbbls/day thermal bitumen
- 63 mbbls/day non-thermal oil and liquic
- 285 mmcf/day gas

Refining and upgrading capacity[1]

- Total processing capacity – 400 mbbls/day
- Heavy processing capacity – 190 mbbls/day

Finished products (Q2 '18)

- 47 mbbls/day of sweet synthetic oil
- 25 mbbls/day of asphalt
- 104 mbbls/day of diesel / jet fuel
- 145 mbbls/day of gasoline

1 See Slide Notes and Advisories

Integrated Corridor

Growing Higher Quality Production and Increasing Downstream Flexibility

Heavy Oil & Bitumen Production (bbls/day)

	2018F	2022F
Lloyd Thermal	77,000	135,000
Tucker	24,000	30,000
Sunrise	26,000	38,000
Cold & EOR	43,000	40,000
Total	**170,000**	**243,000**
Thermal as % of total	75%	84%

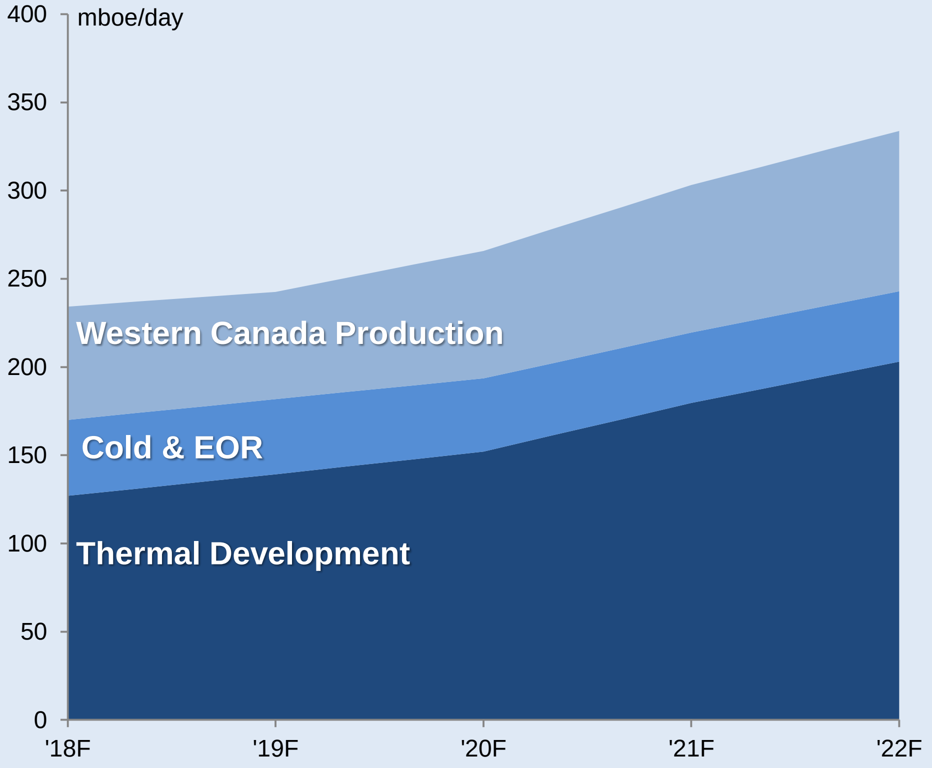
Western Canada Production (boe/day)

	2018F	2022F
Resource plays	30,000	70,000
Other W. Canada production	34,000	20,000
Total	**64,000**	**90,000**
Resource plays as % of total	47%	78%

Downstream Throughputs Capacity (bbls/day)

	2018F	2022F
Heavy oil processing capacity[1]	190,000	220,000
Light oil processing capacity[1]	210,000	180,000
Total refining and upgrading capacity[1]	**400,000**	**400,000**
Heavy oil capacity as % of total	48%	55%

Integrated Corridor Upstream Production Profile



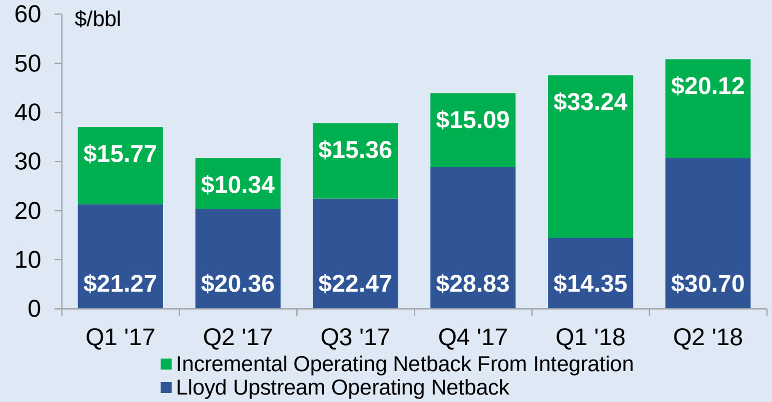
1 See Slide Notes and Advisories

Lloyd Advantage

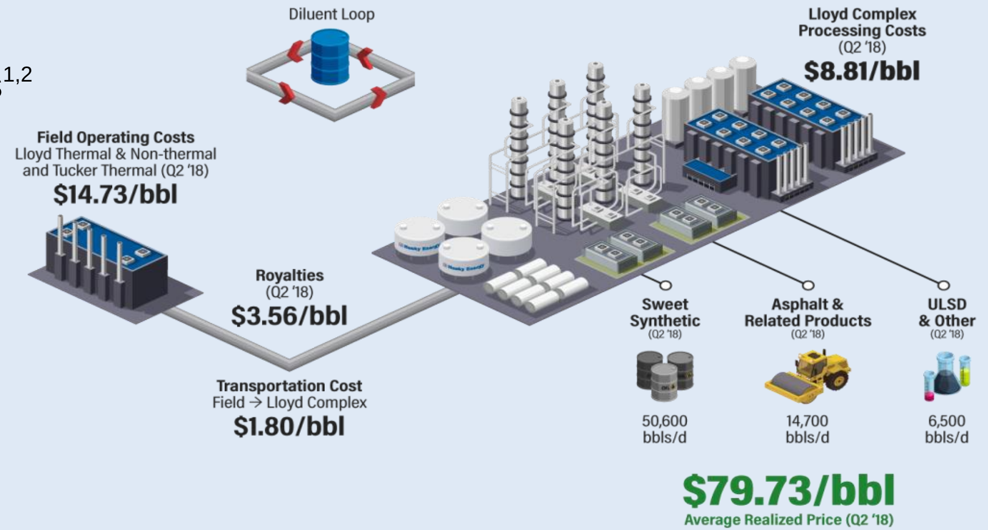
Full Value Chain Netbacks

- Low cost thermal production
- Low cost refining and upgrading
- Higher value, diverse basket of finished products[1,2]
- Higher finished product yield (98%)
- Extensive local market demand

Lloyd Value Chain Operating Netback[3]



Lloyd Value Chain (Q2 '18)



Estimated Lloyd Value Chain Operating Netback
($ per barrel, Q2 2018)

$50.83

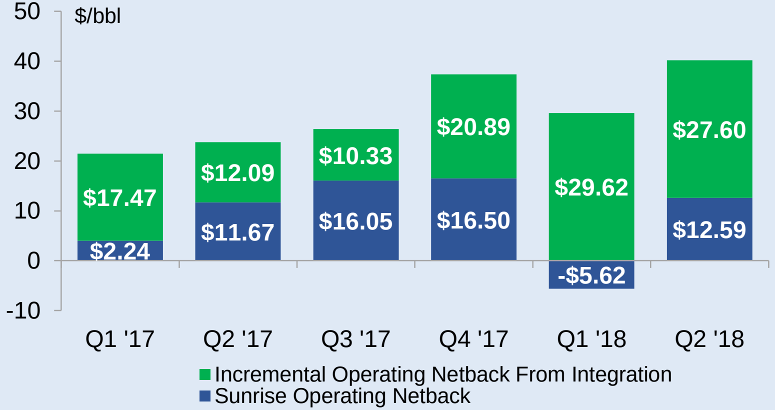
1,2,3 See Slide Notes and Advisories

Sunrise to Toledo

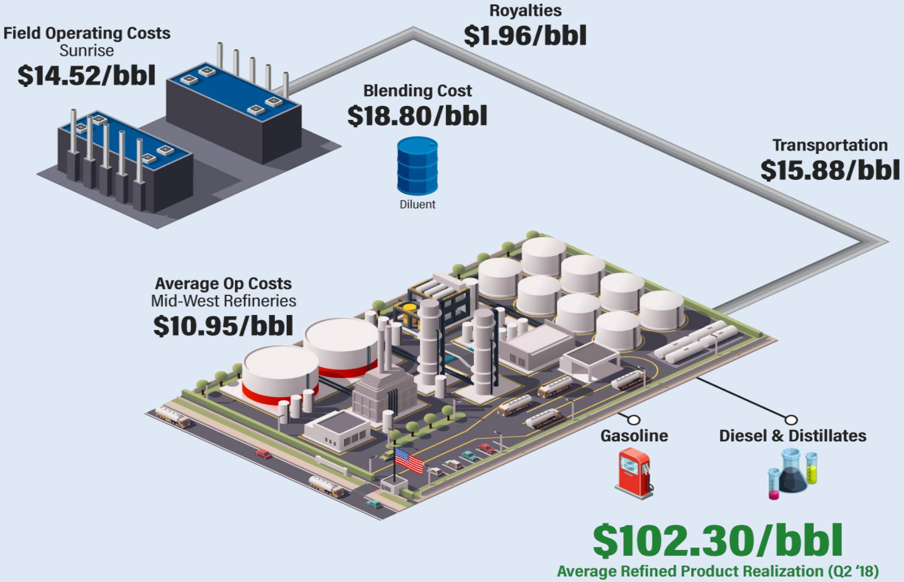
“One-Step” Refining, No Upgrading Required

- Toledo high-TAN project added processing capacity for all Sunrise crude
- Dilbit delivered directly to Toledo
  - No upgrading cost, no volume lost
- High finished product yield[1,2]

Sunrise Value Chain Operating Netback



Sunrise Value Chain (Q2 ‘18)



Estimated Sunrise Value Chain Operating Netback
($ per barrel, Q2 2018)

$40.19

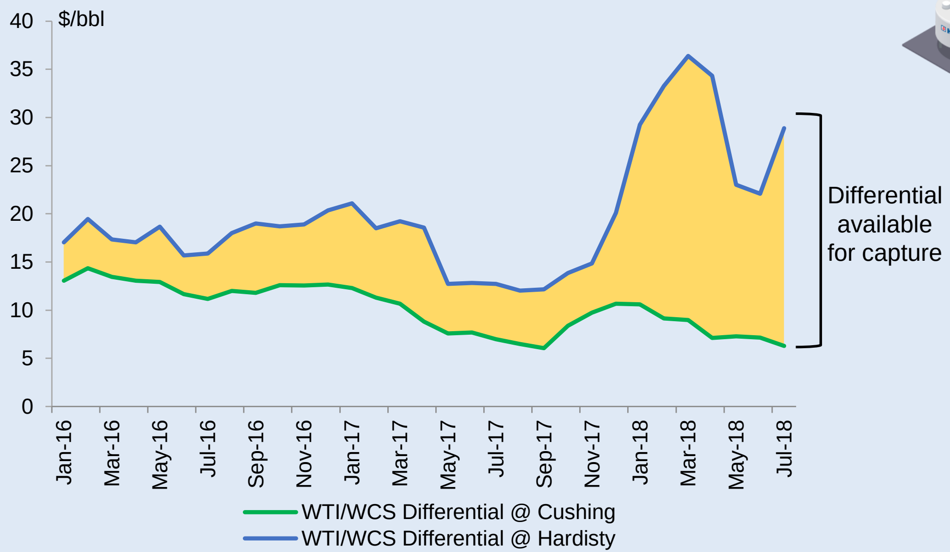
1,2 See Slide Notes and Advisories

Midstream Value Chain

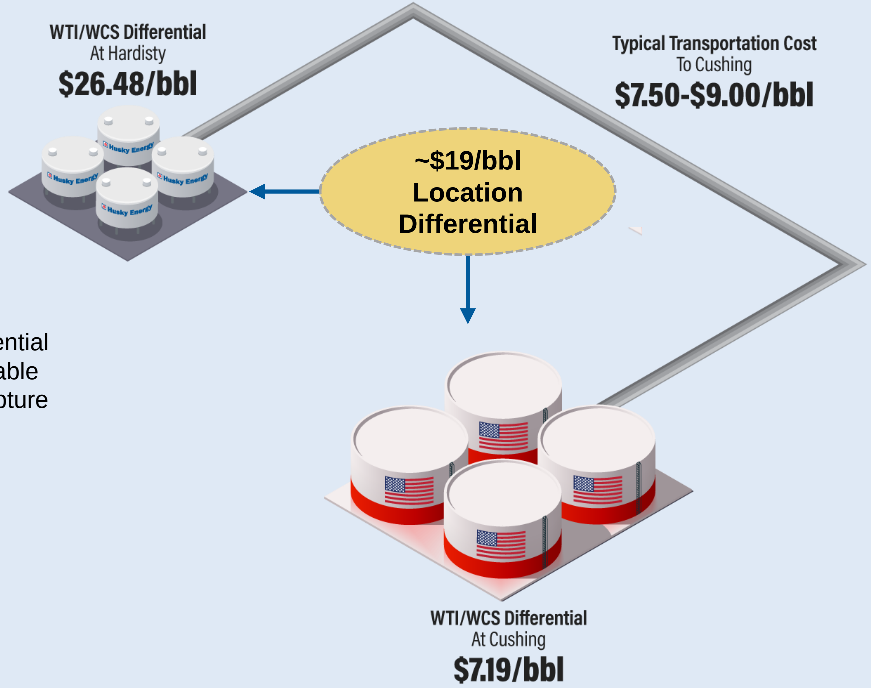
Crude Storage and Export Pipeline Capacity to U.S. Capturing Location Differentials

- 75,000 bbls/day capacity on existing Keystone
- 3.1 million barrels of storage at Hardisty

Heavy Oil Differentials



Midstream Value Chain (Q2 '18)



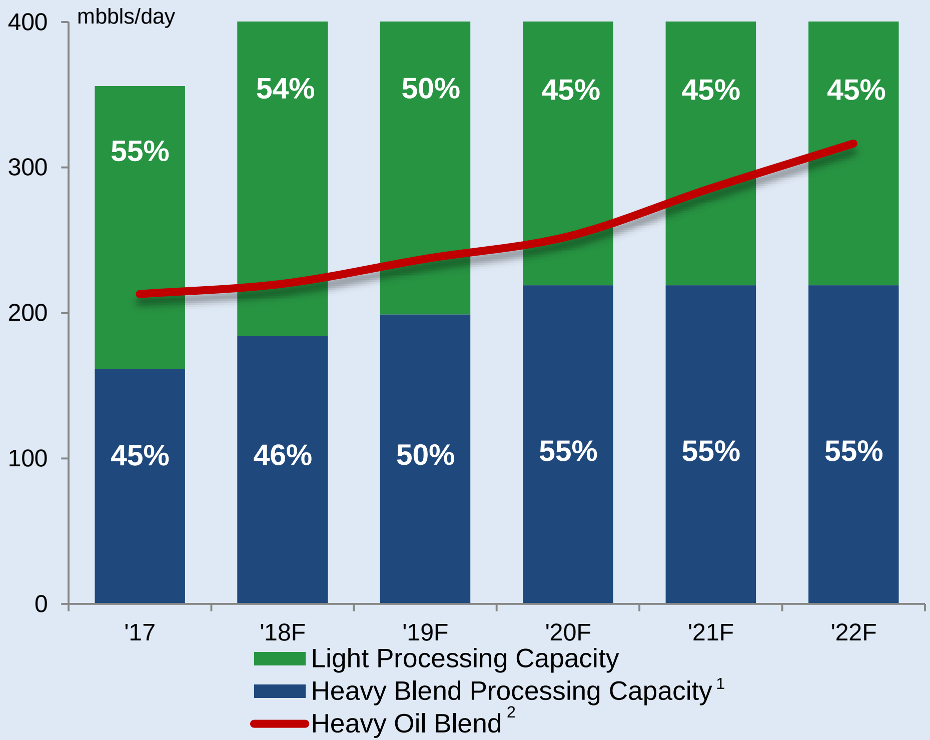

Downstream

Maximizing Value From Every Barrel

Downstream

- Maintain Downstream integration with Upstream production
- Insulation from both location and quality differentials
- Ongoing investments to increase heavy oil processing capacity
- Increasing optionality of feedstocks, products and finished product markets
- Continual optimization of value chain

Downstream Processing Capacity (2017-2022F)

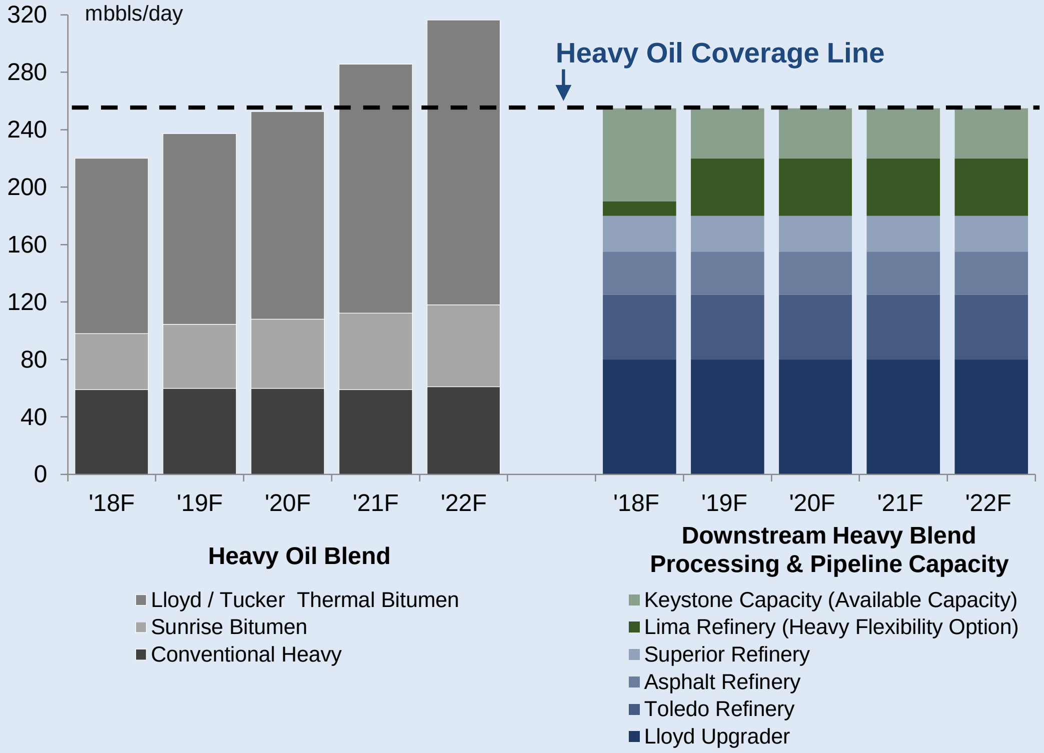


1,2 See Slide Notes and Advisories

Matching Heavy Processing to Upstream Production

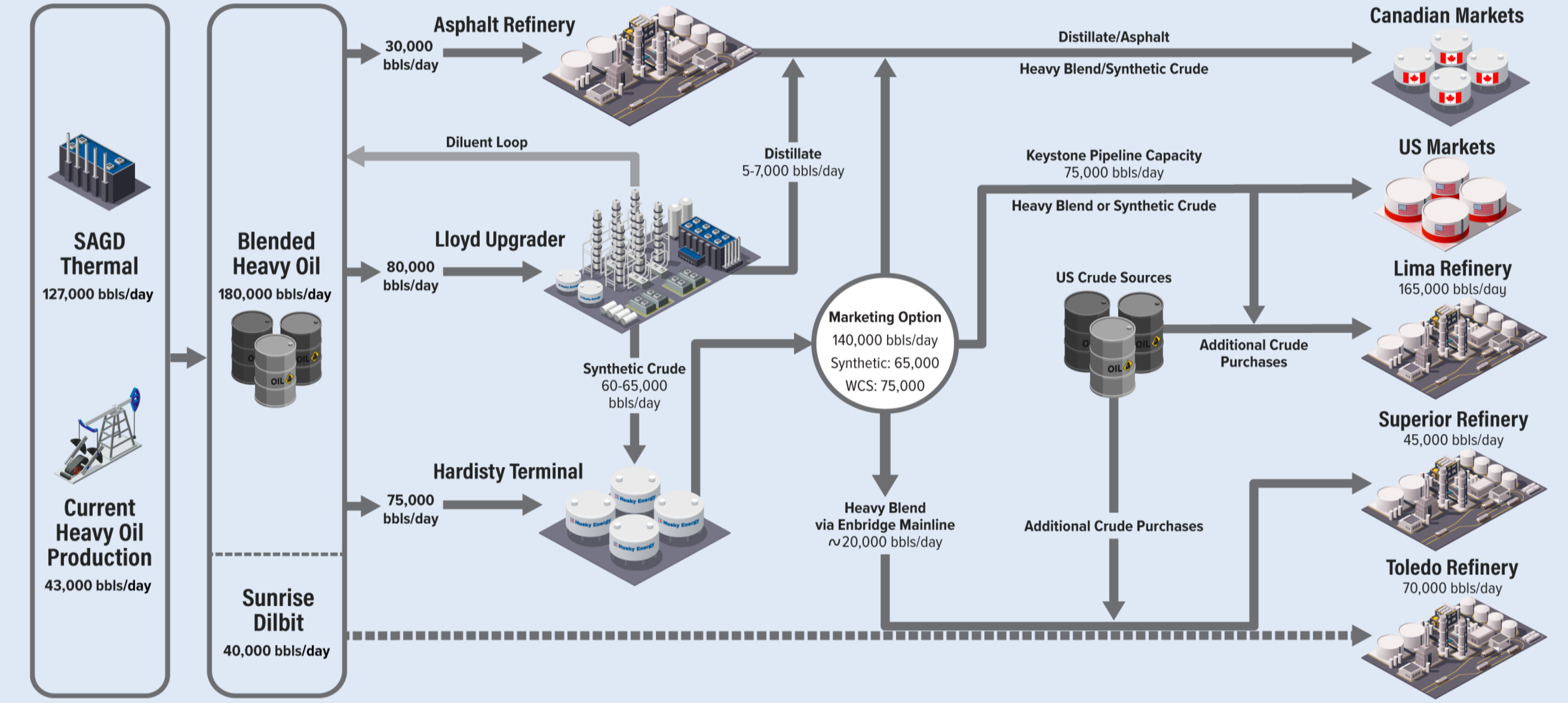
- Heavy oil blend matched to Downstream heavy processing and pipeline takeaway capacity through 2020
- Lima crude oil flexibility project
  - To add 30,000 bbls/day of heavy oil processing capacity in 2019
- Future heavy oil outlet options:
  - Export pipeline access
  - Lloyd asphalt plant expansion
    - Additional 30,000 bbls/day

Heavy Oil Blend vs Downstream Processing & Pipeline Capacity



Flexibility of Feedstock, Product Mix and Markets

Downstream Connectivity

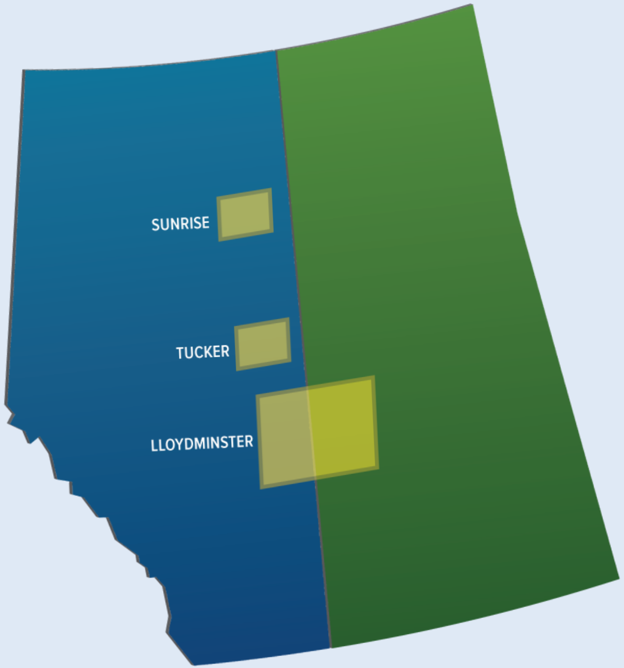


Heavy Oil & Oil Sands

Tightly Integrated Growth Engine

Heavy Oil and Oil Sands

- 170,000 bbls/day today, growing ~40% to ~240,000 bbls/day by 2022
- Modular, scalable designs lowering operating costs and sustaining capital requirements
- Physically integrated with Midstream and Downstream
- **Lloydminster**
  - 10 thermal projects producing ~75,000 bbls/day
  - 60,000 bbls/day of new projects under development
  - Plan to sanction two 10,000 bbls/day projects every year
  - 43,000 bbls/day of CHOPs and EOR oil production
- **Cold Lake**
  - Tucker ramping up to 30,000 bbls/day
- **Fort McMurray**
  - Sunrise ramping to 30,000 bbls/day (net); approved for 100,000 bbls/day (net)



Large Inventory of Low Cost Production

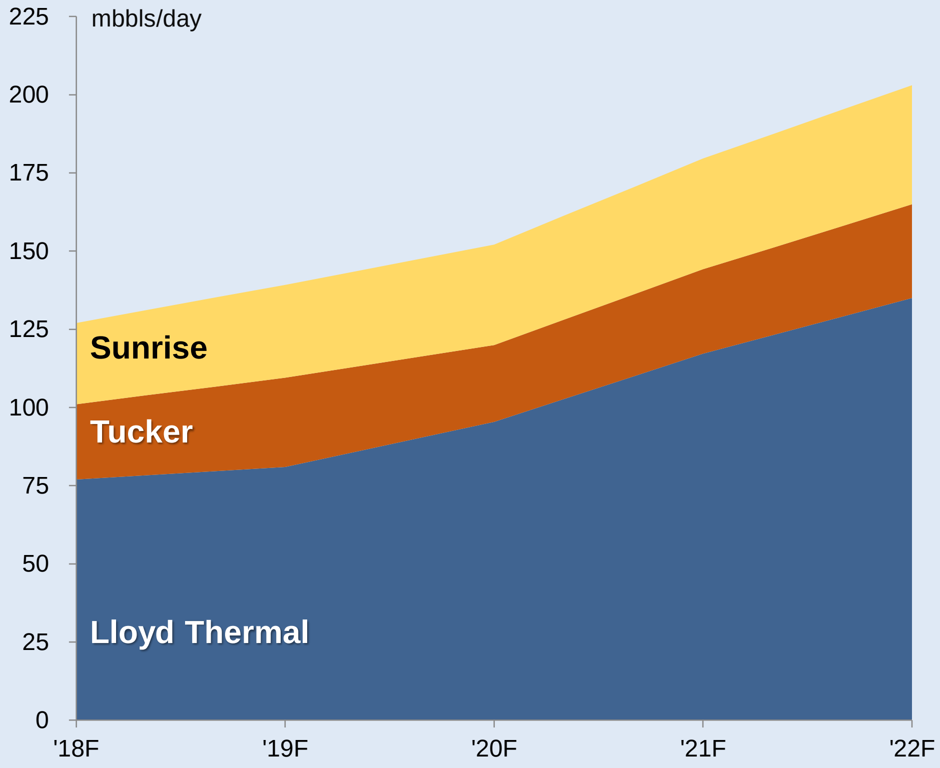
Thermal Business

Project	Production Capacity (boe/day)	Timing of First Oil
Rush Lake 2	10,000	2018
Sunrise Phase 1, de-bottleneck 1	3,000	2019
Dee Valley	10,000	2020
Spruce Lake Central	10,000	2020
Spruce Lake North	10,000	2020
Edam Central	10,000	2021
Westhazel	10,000	2021
Sunrise Phase 1, de-bottleneck 2	6,000	2021+
Future Lloyd Thermals 1-6	60,000	2022-2024
Future Phases of Sunrise	60,000	2024+

Thermal Bitumen Production '18F -'22F — **50+%**

Thermal Production CAGR '18F -'22F — **12%**

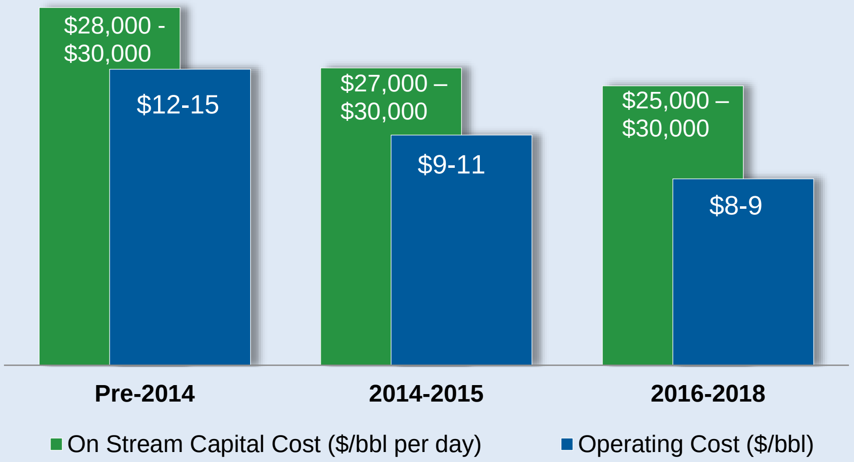
Thermal Bitumen Production Growth (2018F-2022F)



Improving Capital Efficiency & Operating Costs

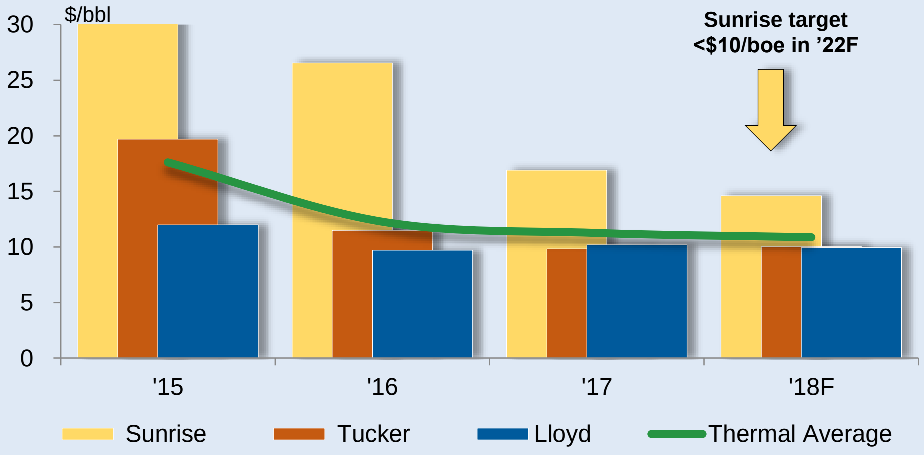
Thermal Business

Lloyd Thermal Project Capital Efficiency Improvements



Capital Efficiencies ’14 –’18F ↑20%

Thermal Production Operating Costs

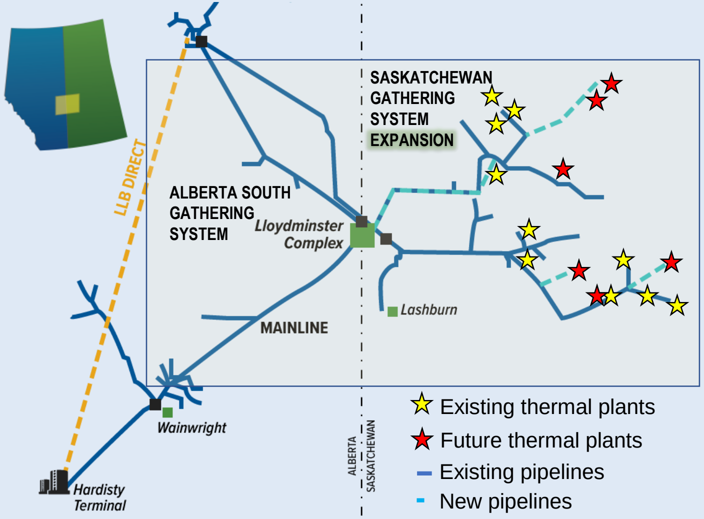


Overall Thermal Operating Costs ’15 –’18F ↓40%

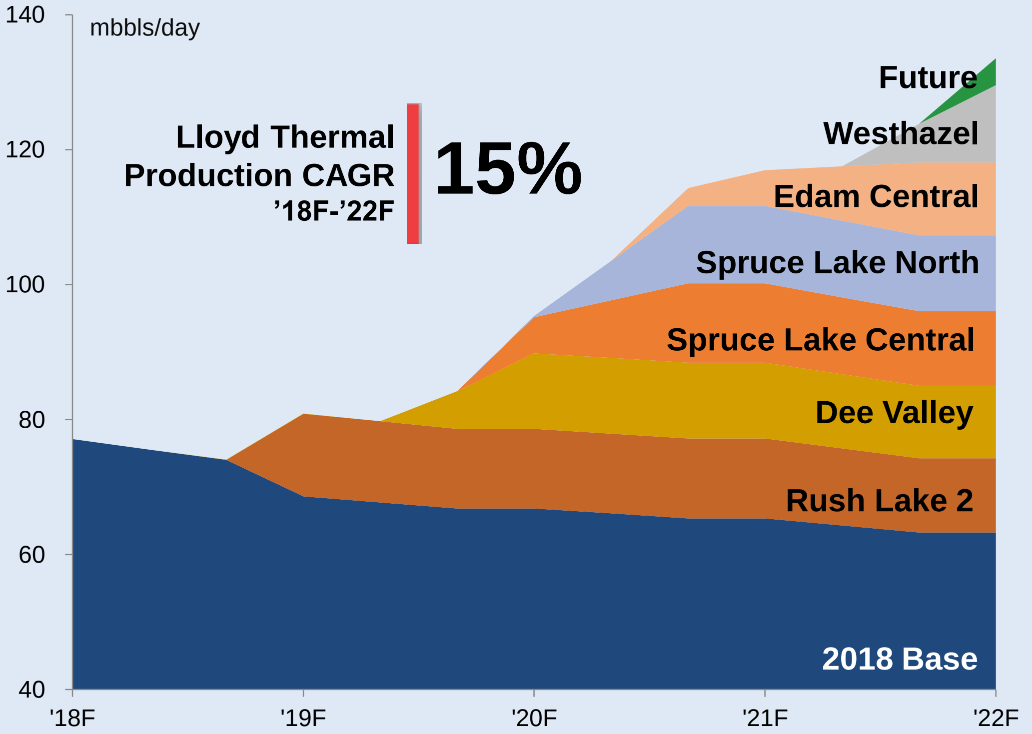
Deep Inventory of Projects

Lloyd Thermal Growth

- Plan to sanction two new projects every year
- Average capital efficiency of $25,000-$30,000 per flowing barrel
- Midstream capacity to match Upstream growth
- Operating costs of $8-$9 per barrel



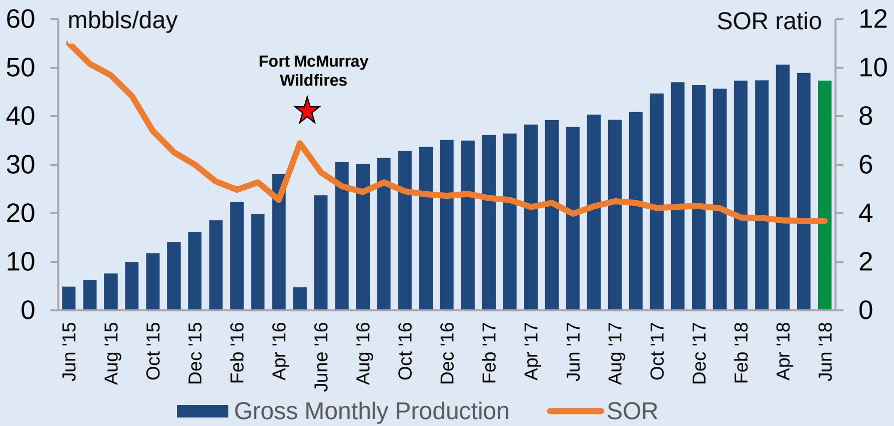
Future Lloyd Thermal Production



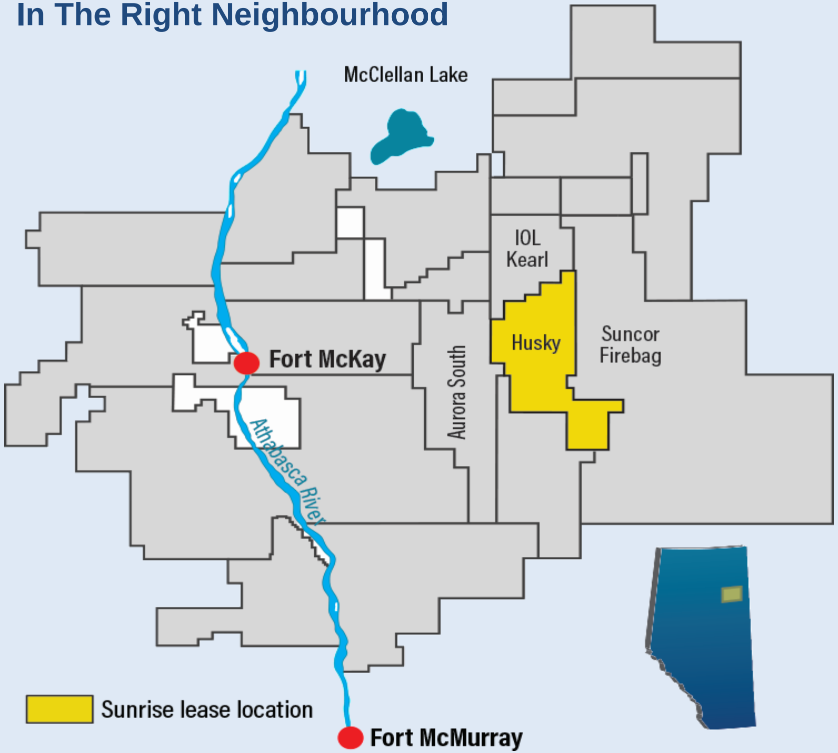
50,000 Barrels Per Day . . . And Growing

Sunrise Energy Project

- 2018 year-end target of 60,000 bbls/day (gross)
- Target production per well pair: 800-900 bbls/day
  - 55 well pairs in Initial Development Area now at 815 bbls per well pair
  - 14 new well pairs from Development Area 2 now at 395 bbls/day, expected to ramp to 800-900 bbls/day



In The Right Neighbourhood



Unlocking Further Potential At Sunrise

Next Steps

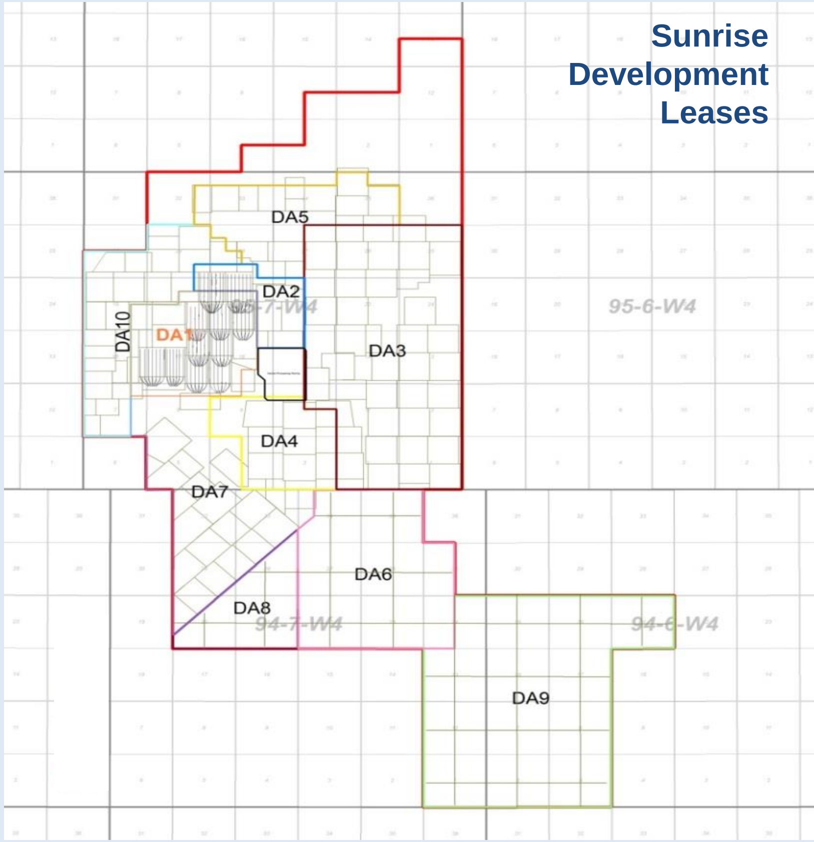
- De-bottlenecking initiatives to create future capacity
- Regulatory approvals in place for 200,000 bbls/day (gross)
- Targeting increased returns with modular approach and cost-effective technologies

Modular Development

- 20,000 bbls/day repeatable, cookie-cutter designs
- Builds on Lloyd thermal expertise and design
- Leverages existing development

Technology Advancements

- Husky Diluent Reduction (HDR) pilot under way
- Potential to reduce condensate diluent requirements by 50%
- Co-generation



Resource Plays

Transformation Complete – Positioned for Growth

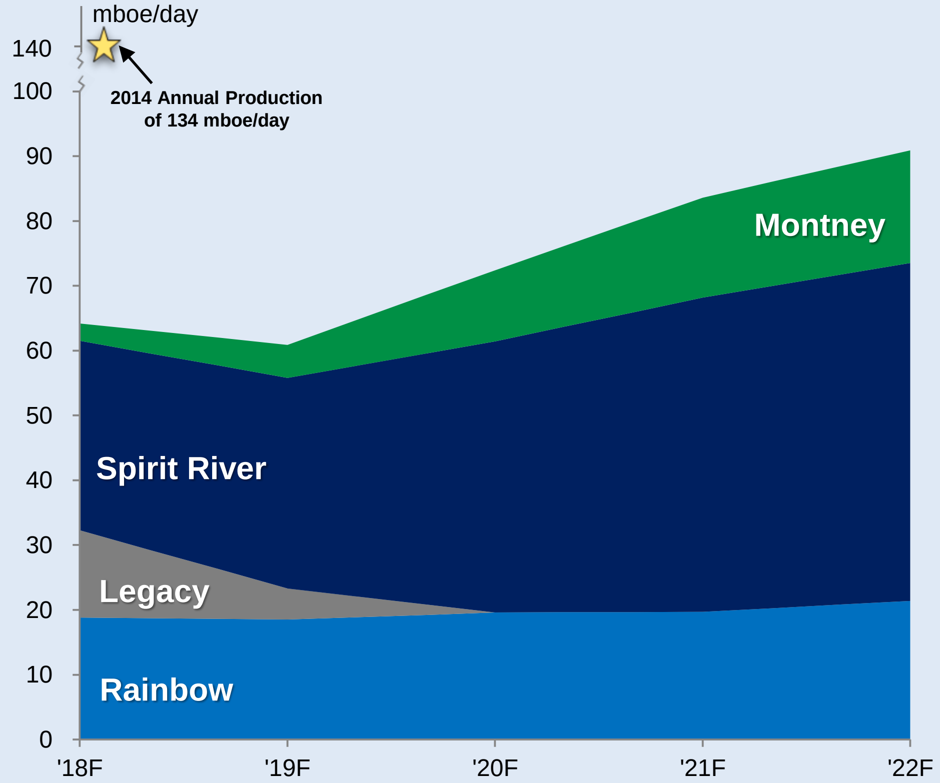
Western Canada Resource Plays

- Competitive stand-alone business
- Flexible short-cycle capital spending profile
- Minimal AECO exposure
- Pivoting to liquids
- Multiple egress options enable growth
- Room to run

Western Canada Production ’18F - ’22F **>40%**

Western Canada Production CAGR ’18-’22F **9%**

Production Growth Profile



Wembley-Montney

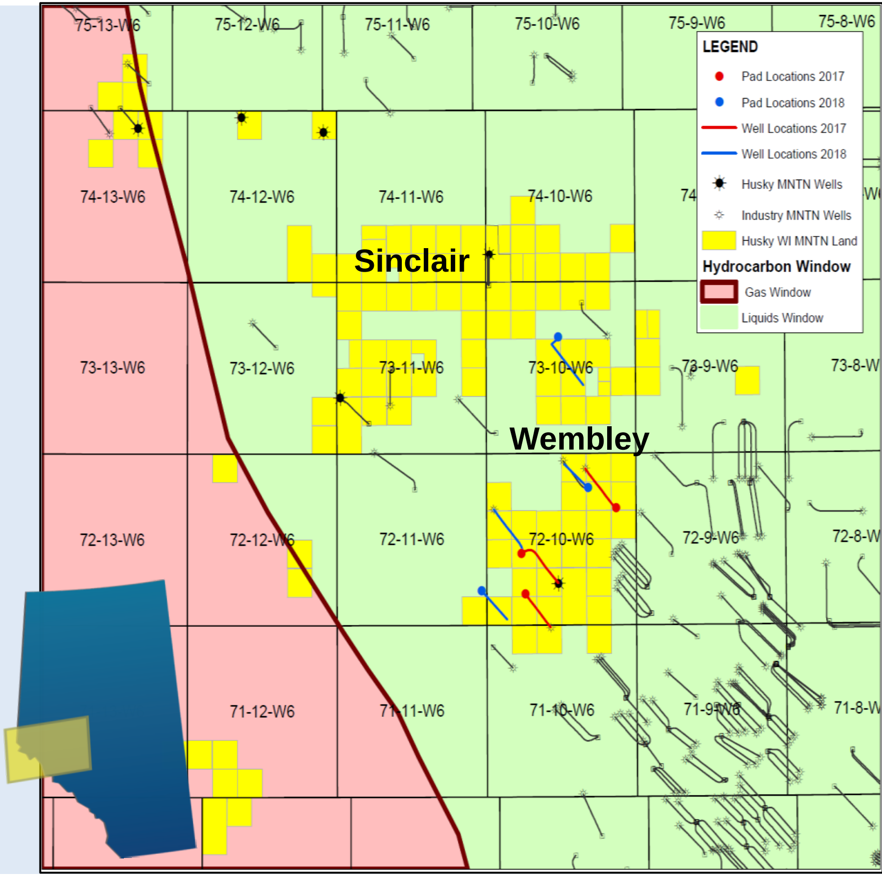
Appraisal Complete, Moving to Development

Wembley position within an established fairway

- 50 net developable sections in liquids-rich gas window
- Multi-layer pad development potential
- First well currently producing at a restricted rate capable of up to 7 mmcf/day
- Seven wells drilled, completed, and tested by the end of 2018
- Future development opportunities identified

Appraisal activity moving to Sinclair

- 50+ net sections



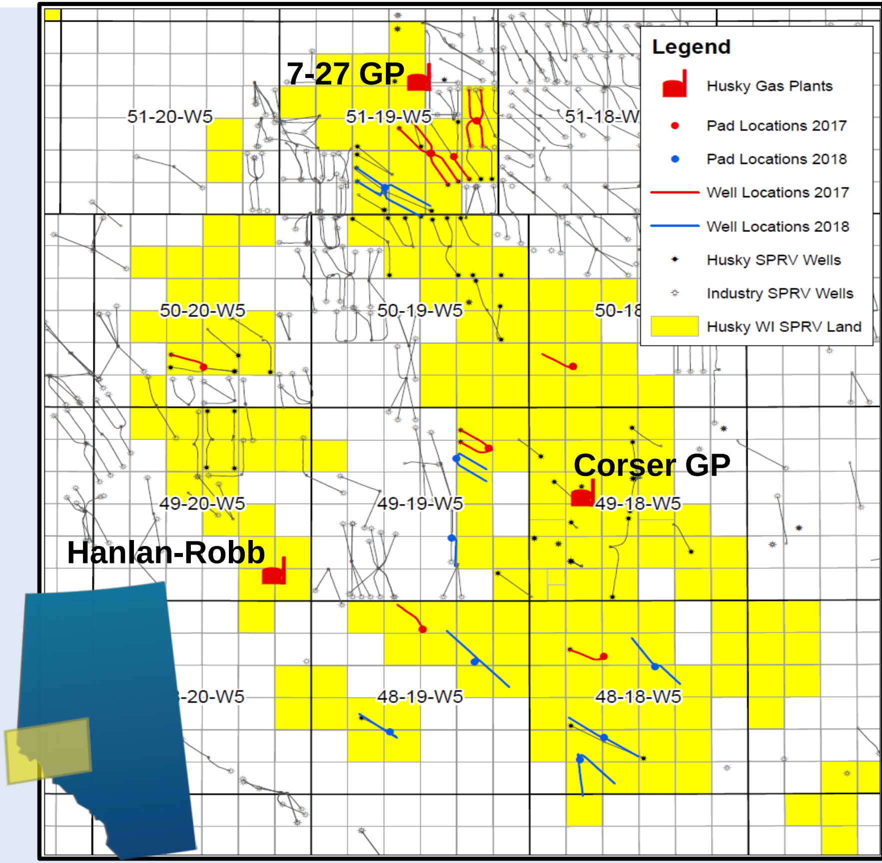
Ansell Spirit River

Building Towards Full Field Development

- Development moving from Wilrich to full Spirit River
- Drilling to keep pace with capacity and egress
- 360 Spirit River potential drilling opportunities[1,2]
- Cardium locations will add liquids to the development
  - Liquids yield of 60 barrels per mmcf
- Ansell: ~170 net sections
- Kaybob: ~30 net sections

Technology and data integration improving results

- Leveraging 3D seismic in target identification and drills
- Utilizing data analytics to improve rig performance
- Optimizing frac and production facility design



1,2 See Slide Notes and Advisories

Minimal Exposure To AECO

Market Optionality

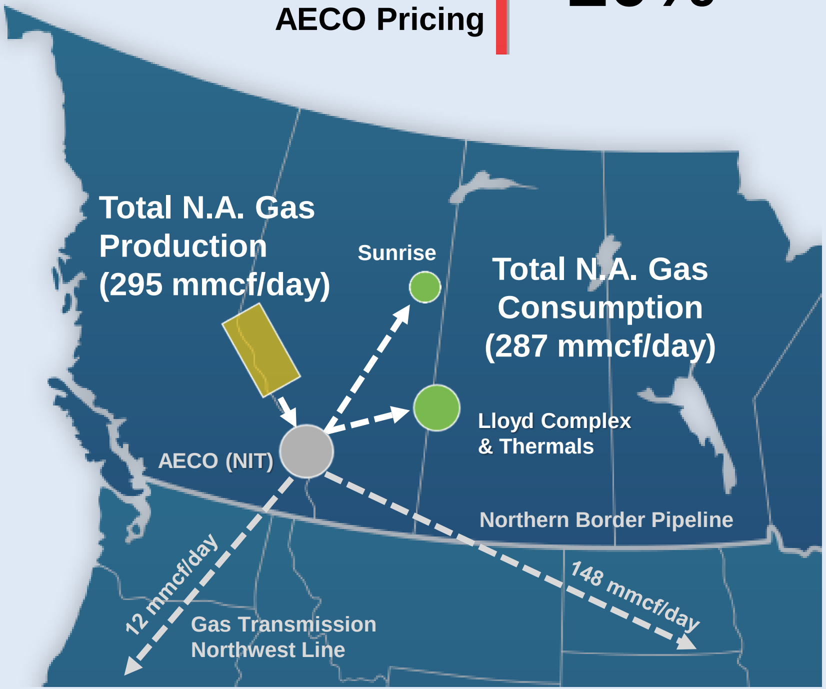
Integration delivers value

- Production offsets gas consumption
- 160 mmcf/day export capacity to U.S. markets
- Forward sales of gas volumes
- Gas storage for seasonal sales

Positioned for growth

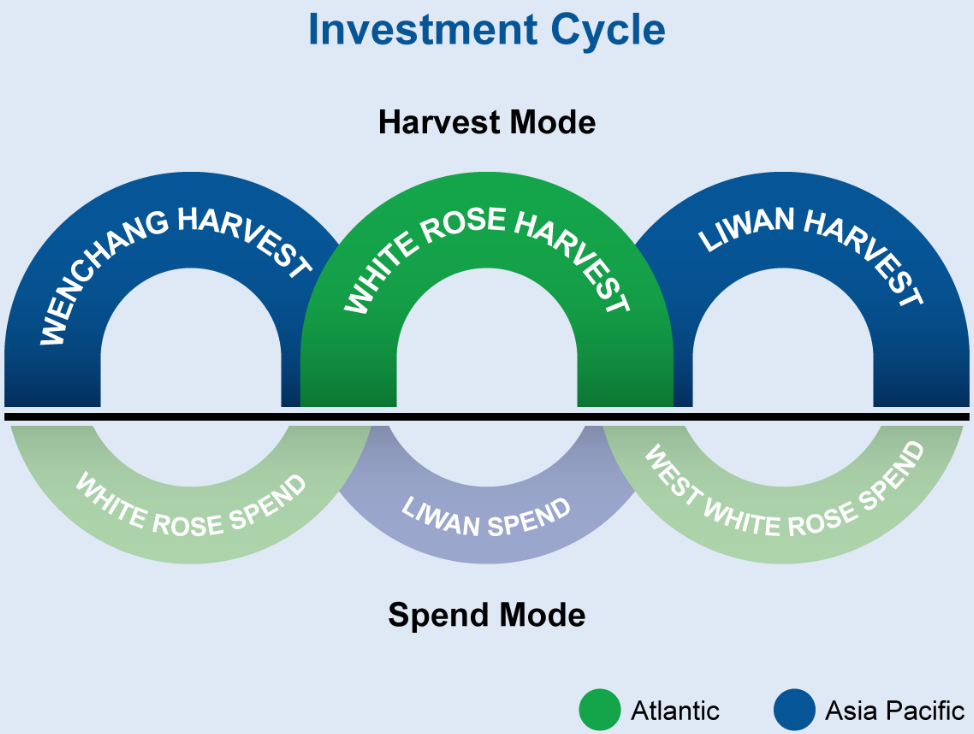
- Current gas production growth plan supports thermal projects
- Capacity available to U.S. market can support more aggressive growth plan
- Flexibility for liquids in each core hub

Gas Production Exposed to AECO Pricing | ~20%



Offshore

Self-Funding, Synchronized Build-Harvest Cycles



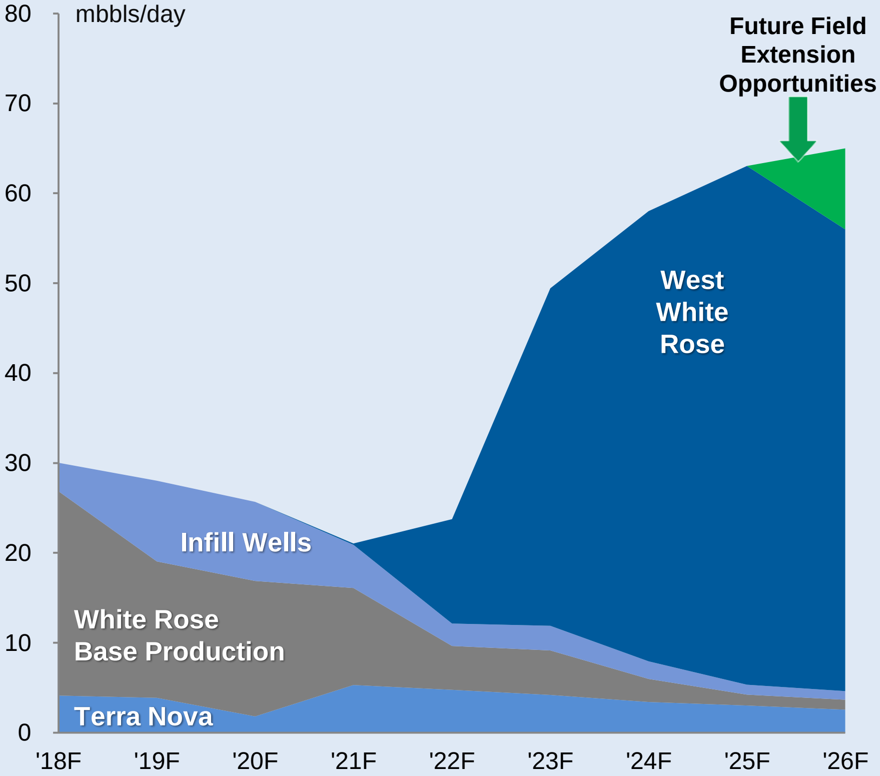

Atlantic
Region

Infill Wells Bridging to West White Rose

Active Development Program

- ~75,000 bbls/day peak production (52,500 bbls/day net to Husky) in 2025
- Low incremental operating costs
- Construction of Concrete Gravity Structure and topsides progressing

Atlantic Production Profile



Exploration

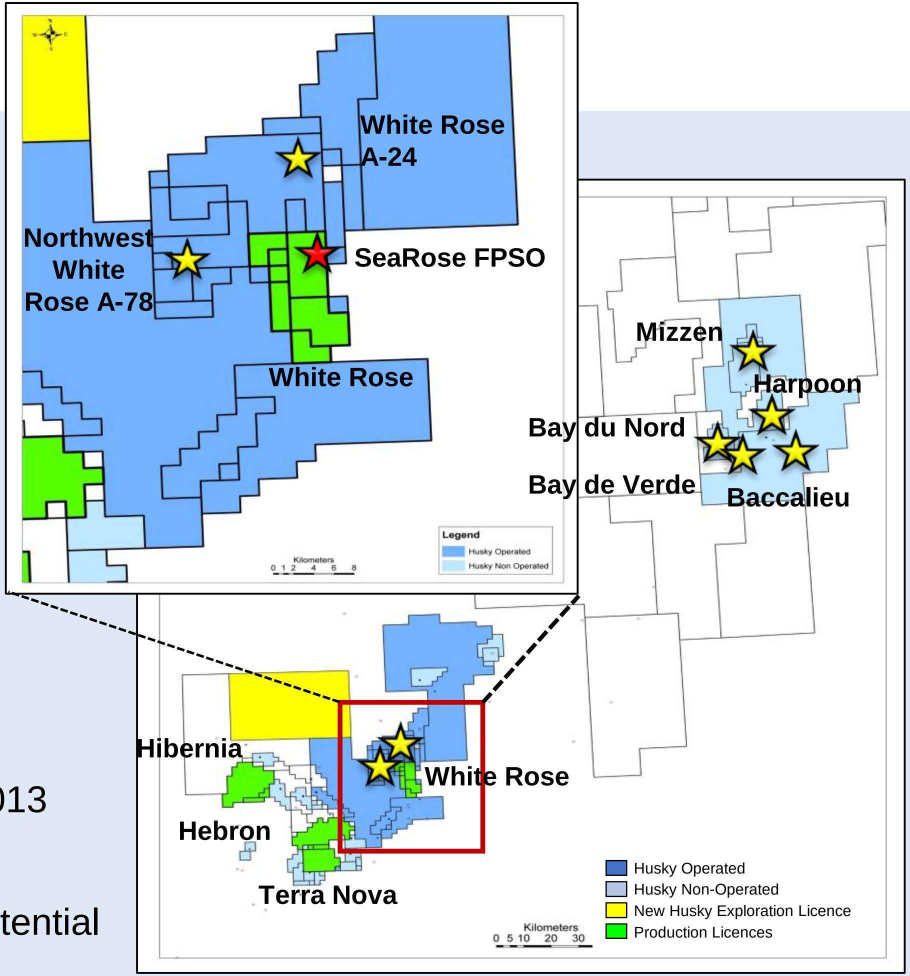
Short, Mid and Long Cycle Projects

Near-term: Near-Field Exploration Success

- White Rose A-24 discovery in 2018
  - Encountered 85+ metre net pay thickness oil-bearing sandstones
- Northwest White Rose A-78 in 2017
  - Encountered 100+ metre net pay thickness light oil column
- Newly acquired exploration acreage

Longer-term: Flemish Pass

- Original Mizzen discovery in 2009
- Light oil discoveries at Bay du Nord and Harpoon in 2013
- Discoveries at Bay de Verde, Baccalieu in 2016
  - Delineation program confirmed large resource potential

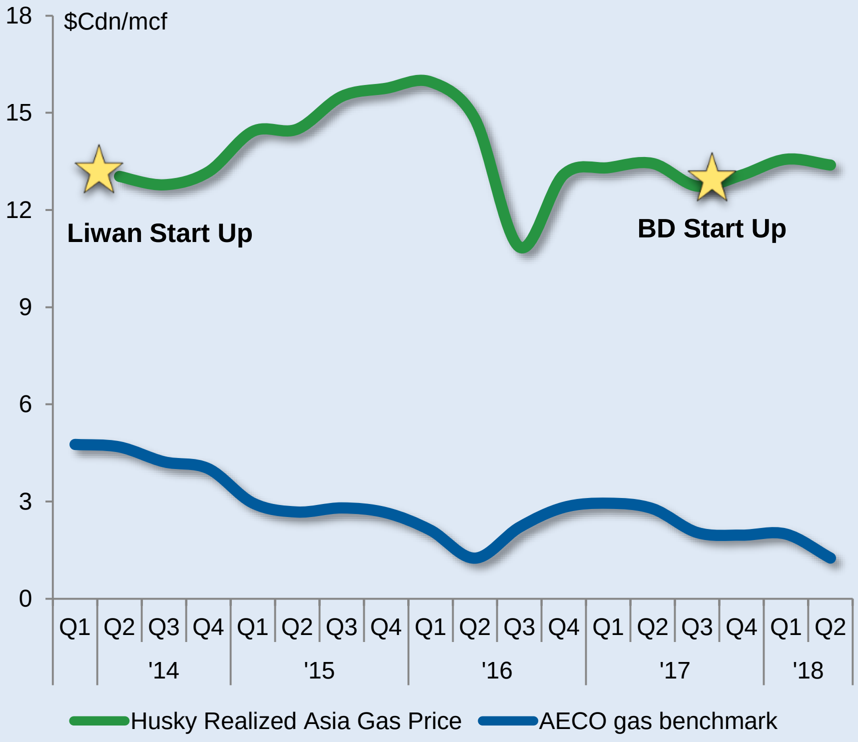


Asia Pacific

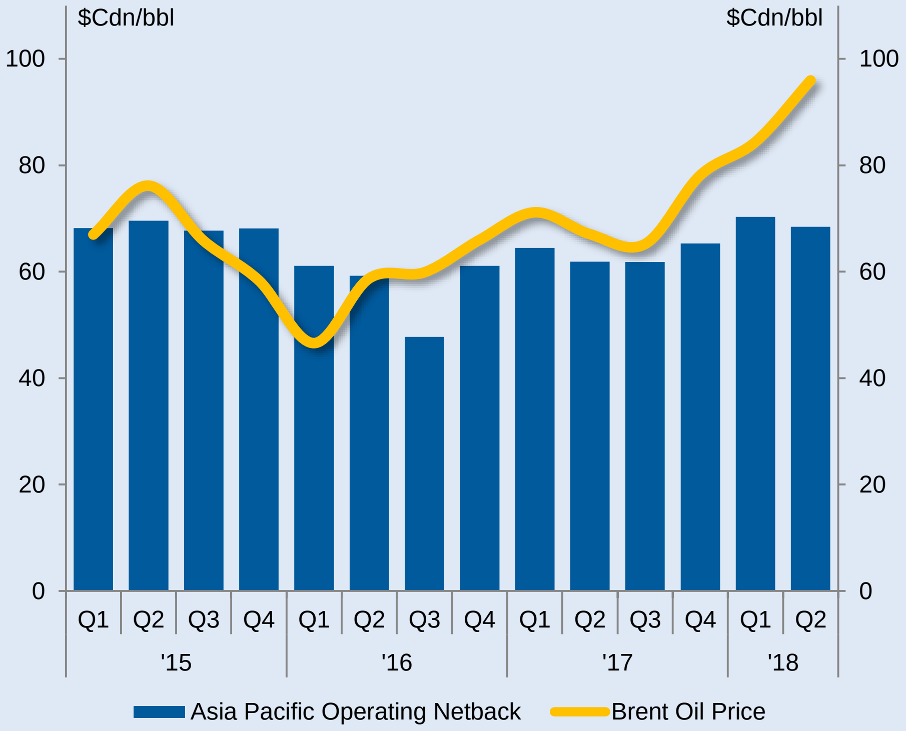
High Netback Production and FFO Stability

Asia Pacific Business Delivering >$60 per boe Operating Netbacks

Asia Pacific Realized Gas Price



High Operating Netback[1]



1 See Slide Notes and Advisories

Production Growth Profile

Capital Efficient Developments

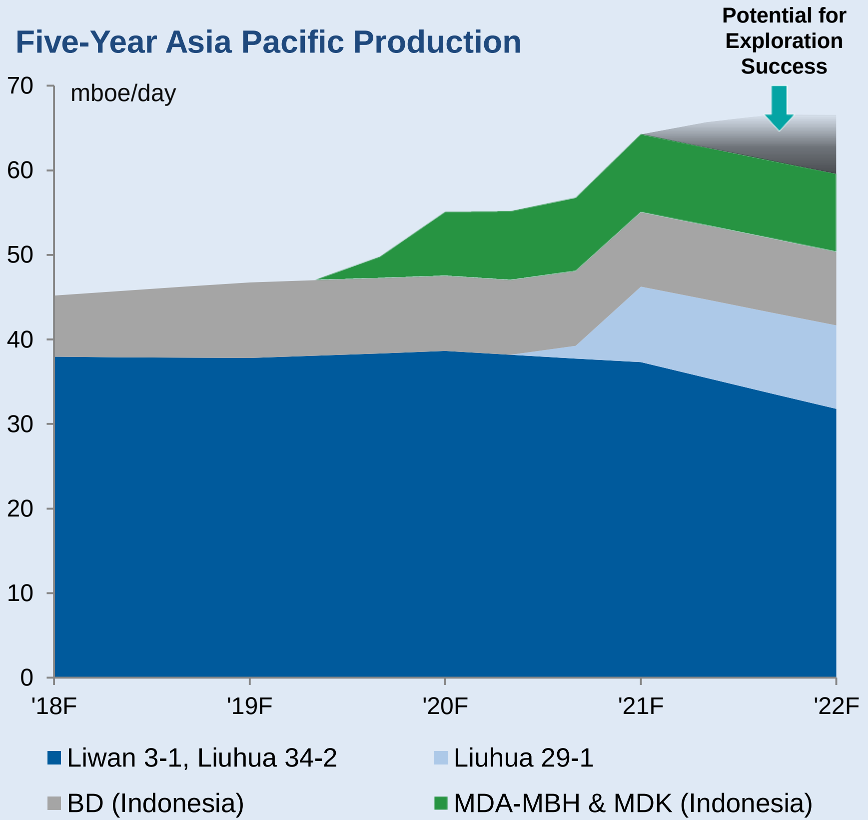
China (Liwan 3-1, Liuhua 34-2 & 29-1)

- Q2 2018 production of ~180 mmcf/day (3-1 & 34-2)
- Take-or-pay contract 165 mmcf/day (net)
- 29-1 field sanctioned, first gas expected in 2020
  - $250M US in exploration cost recovery

Indonesia (BD Project, MDA-MBH, MDK fields)

- BD Project on production; first gas sales in July 2017
- MDA-MBH, MDK fields in development; first gas anticipated in 2019-2020
- Combined production target ~20,000 boe/day (100 mmcf/day of gas plus 2,400 bbls/day of liquids)
- Three additional discoveries for future growth

Five-Year Asia Pacific Production



Mid-Term Appraisal / Exploration Projects

Ongoing Exploration Throughout the Region

Blocks 15/33 & 16/25

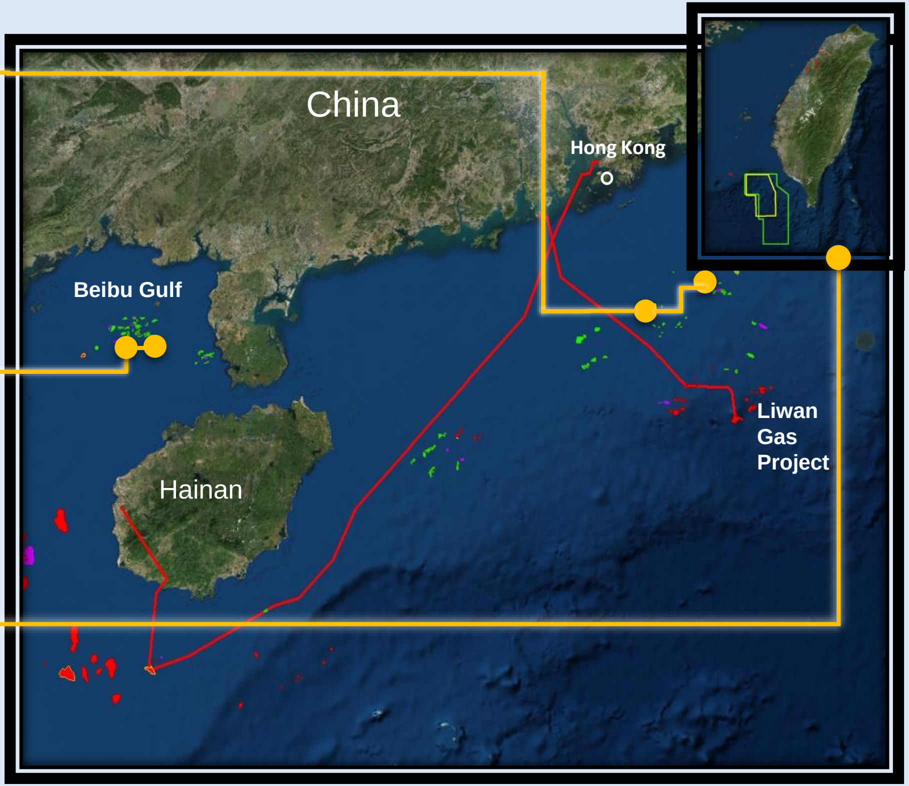
- New discovery on 15/33
- Shallow water
- Close proximity to FPSO
- Exploration and appraisal wells 2H 2018

Blocks 22/11 & 2307 (Beibu Gulf)

- Shallow water
- Proven basin
- Close to infrastructure

Taiwan Block DW-1

- Gas prone area of 7,700 sq. km.
- 3-D seismic acquisition program completed
- Proximity to large market



Updated Five-Year Plan (2018-2022)

On Track, Using Flat $60 US WTI Prices

- Production and throughput growth from a large inventory of low cost projects = returns-focused growth
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Increasing cash returns to shareholders
- Integration and fixed-price Asia Pacific sales provide resilience to volatile market conditions while preserving upside

Key Metrics	’18F	’22F	’18F-22F CAGR
Funds from operations (FFO)	**$4B**	**$5B**	**6%**
Free cash flow (FCF)	**$1B**	**$1.4B**	**9%**
Upstream production (mboe/day)	**310-320**	**410-420**	**7%**
Downstream throughputs (mbbls/day)	**360-370**	**360-370**	
Thermal bitumen production (mbbls/day)	126-130	200	12%
Heavy processing capacity (mbbls/day)	190	220	
Upstream operating cost/bbl	$13-13.50	$11-12	
Downstream operating costs/bbl (CAD)	$7-8	$7-8	
Earnings break-even oil price (US WTI)	$42	$37	

Ranges and Targets	2018F - 2022F
Annual base dividend	$500MM
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.5B
5-yr avg. proved reserves replacement ratio	Target >130%
Net debt to FFO at $35 US WTI	<2x

Husky Energy

Appendix

2018 Guidance Summary

Last Updated April 26, 2018

Upstream Oil and Liquids	Capital Expenditures[1] ($ millions)	Production (mbbls/day)
Lloyd & Tucker thermal bitumen	835 - 860	101 - 103
Sunrise thermal bitumen	60 - 70	25 - 27
Lloyd Non-Thermal	85 - 90	42 - 44
Atlantic light	750 - 775	29 - 31
W. Canada Light, medium, heavy & NGLs	55 - 60	21 - 22
Asia Pacific light & NGLs[2,3]	- -	10 - 11
Total Crude Oil and Liquids	**1,785 - 1,855**	**230 - 237**
Natural Gas	**($ millions)**	**(mmcf/day)**
Canada	215 - 225	280 - 290
Asia Pacific[3]	130 - 150	200 - 210
Total Natural Gas	**345 - 375**	**480 - 500**
	($ millions)	**(mboe/day)**
Total Upstream	**2,130 - 2,230**	**310 - 320**
Downstream	**($ millions)**	**Throughput[4] (mbbls/day)**
Canada downstream	130 - 160	110 - 115
U.S. downstream	580 - 625	250 - 255
Downstream Total	**710 - 785**	**360 - 370**

Corporate Costs	($ millions)
Total Capital	100 - 110
Total Capital Budget	**100 - 110**
Other	**($ millions)**
Capitalized Interest	110 - 120
Corporate SG&A	175 - 225
Sustaining Capital	**($ millions)**
Upstream	1,275 - 1,325
Downstream	500 - 550
Total Sustaining Capital	**1,775 - 1,875**

Upstream Operating Costs	($/bbl)
Lloyd and Tucker thermal[5]	9.50 - 10.50
Atlantic Region light oil	18.50 - 19.50
	($/mcfe)
Resource Play Natural Gas	1.00 - 1.30
Asia Pacific Region Gas	1.00 - 1.25
	($/boe)
Total Upstream Operating Costs	**13.00 - 13.50**
Downstream Operating Costs[6]	**($/boe)**
Lloyd Upgrader	6.50 - 7.50
US Refineries	6.00 - 7.00

1,2,3,4,5,6 see Slide Notes and Advisories

Price Planning Assumptions

2017 vs. 2018 Five-Year Plan / Stress Case

Benchmark Prices – 2017 Base Case	2018	2019	2020	2021
WTI (US $bbl)	55.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	14.00	14.00	14.00	14.00
AECO ($/mmbtu Cdn)	3.00	3.00	3.00	3.00
US/CAD exchange rate	0.78	0.80	0.80	0.80

Benchmark Prices – 2018 Base Case	2018	2019	2020	2021	2022
WTI (US $bbl)	60.00	60.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
US/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

Benchmark Prices – $35 Stress Case	2018	2022
WTI (US $bbl)	35.00	35.00
Chicago 3:2:1 ($/bbl US)	12.00	12.00
Heavy crude differential ($/bbl US)	11.00	11.00
AECO ($/mmbtu Cdn)	2.25	2.25
US/CAD exchange rate	0.71	0.71

Price Planning Assumptions

Other Cases

Benchmark Prices – $70 Flat Case	2018	2019	2020	2021	2022
WTI (US $bbl)	70.00	70.00	70.00	70.00	70.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
USD/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

Benchmark Prices - $80 Flat Case	2018	2019	2020	2021	2022
WTI (US $bbl)	80.00	80.00	80.00	80.00	80.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	18.00	18.00	18.00	18.00	18.00
AECO ($/mmbtu Cdn)	2.00	2.00	2.00	2.00	2.00
USD/CAD exchange rate	0.80	0.80	0.80	0.80	0.80

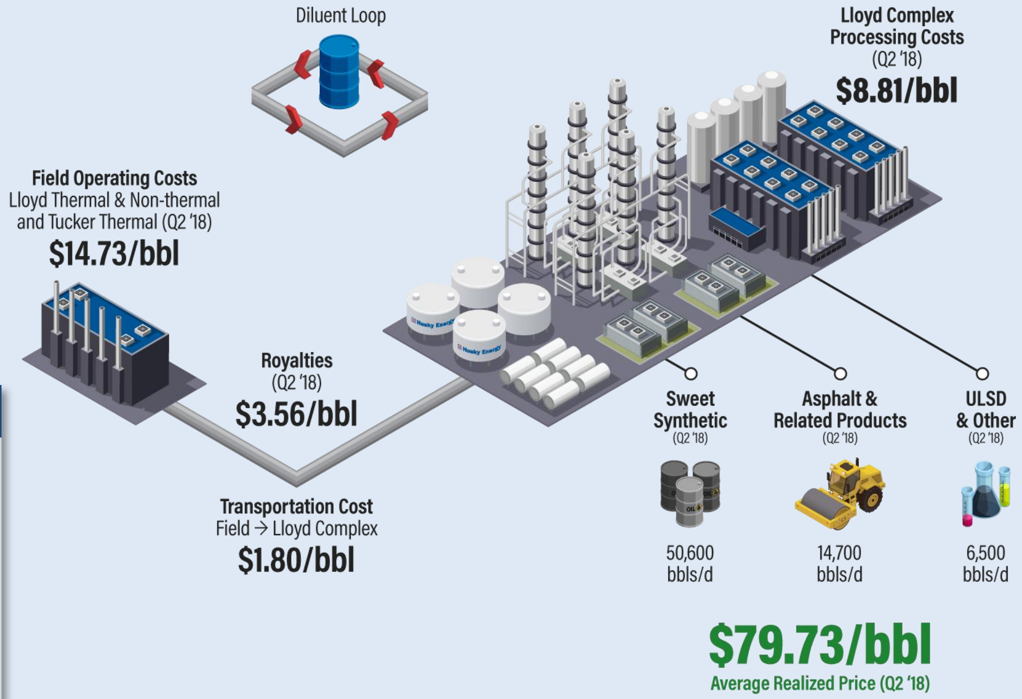
Lloyd Advantage

Full Value Chain Netback

- Low cost thermal production
- Low cost refining and upgrading
- Higher value, more diverse basket of finished products
- Higher finished product yield (98%)
- Extensive local market demand

Lloyd Value Chain Operating Netback (per bbl)	
Lloyd Complex average realized product price	$79.93
Upstream operating costs	$14.73
Royalties	$3.56
Transportation cost	$1.80
Avg. Lloyd Complex processing cost	$8.81
Estimated Lloyd Value Chain Operating Netback	**$50.83**
Actual Lloyd Upstream Operating Netback	**$30.70**

** All figures as Q2 2018.*



$20.12 (per bbl) | **Incremental Netback From Integrated Operations**

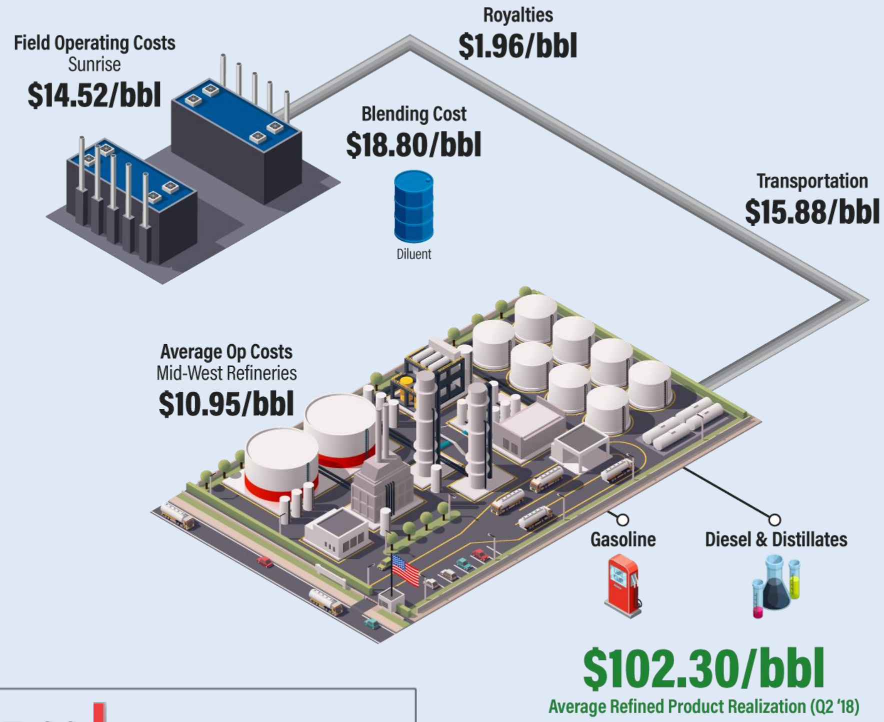
Sunrise to Toledo

"One-Step" Refining, No Upgrading Required

- Toledo high-TAN project added processing capacity for all Sunrise crude
- Dilbit delivered directly to Toledo
    - no upgrading cost, no volume lost
- High finished product yield

Sunrise Value Chain Operating Netback (per bbl)	
Toledo realized product price	$102.3
Sunrise operating costs	$14.52
Royalties	$1.96
Blending cost	$18.80
Transportation cost	$15.88
Midwest refining cost	$10.95
Estimated Sunrise Value Chain Operating Netback	**$40.19**
Sunrise Upstream Operating Netback	**$12.59**

** All figures as Q2 2018.*



$27.60 (per bbl) | **Incremental Netback From Integrated Operations**

Physically Connected Assets Across N. America

400,000 barrels per day Upgrading and Refining Capacity

Lloyd Complex

- 110,000 bbls/day processing capacity
- Physically connected to Lloyd and Tucker


Lloyd Upgrader

Capacity: 80 mbbls/day

- Produces Husky Synthetic Crude (HSB)
- Low operating costs


Asphalt Refinery

Capacity: 30 mbbls/day

- Supplies ~4% of asphalt manufactured in North America
- Transportation by rail

Prince George Refinery


Asphalt Refinery

Capacity: 12 mbbls/day

- Light oil refinery
- Supplies B.C. market

U.S. Refining & Marketing

- ~280,000 bbls/day processing capacity
- Product marketing centered in Ohio


Lima

Capacity: 165 mbbls/day

- Lima, Ohio
- Light oil refinery
- Access to diverse crude supply


Toledo

Capacity: 70 mbbls/day[1]

- Toledo, Ohio
- Configured to process high-TAN Sunrise crude


Superior

Capacity: 45 mbbls/day

- Superior, Wisconsin
- Light / Heavy oil refinery
- Asphalt, diesel, gasoline

Pipelines & Storage

- Five million barrels tank storage
- 75,000+ bbls/day takeaway capacity


Storage Terminals


Gathering System

Crude storage capacity:

- **3.1M bbls at Hardisty**
- **1.0M bbls at Lloyd**
- **1.3M bbls at Patoka**
- **0.9M bbls at Superior**
- Blending business
- Increases flexibility in marketing crude
- 35% interest in Midstream partnership
- Connections to several main pipelines ensure Husky crude can reach market

Retail


Retail Outlets

- 550+ retail outlets across Canada
- Branded, dealer-operated
- Cardlock JV with Imperial

1 See Slide Notes and Advisories

Configured to Benefit From IMO 2020 Rule

Flexibility to Adjust to Market Conditions

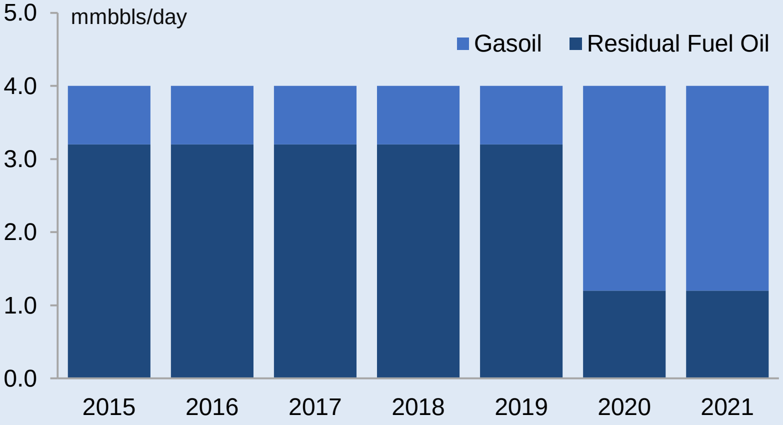
Market Impact

- Decrease in global demand for bunker fuel
- Increase in global demand for diesel and distillates
- Pressure on global heavy oil pricing

Husky Ability to Respond

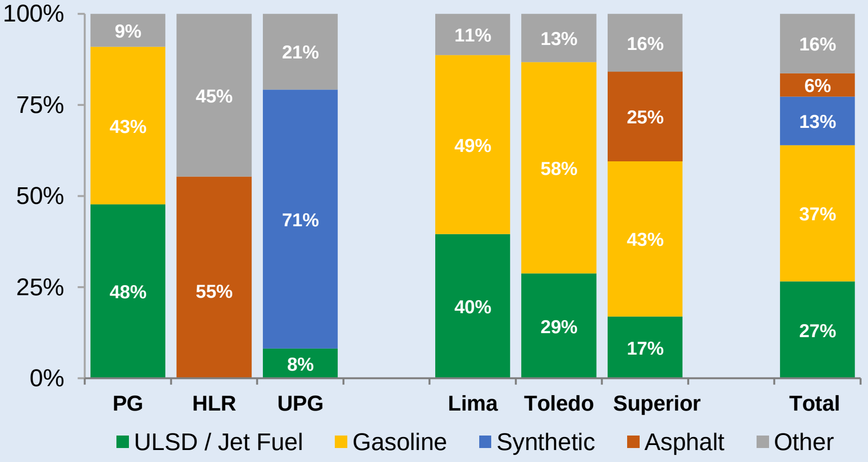
- Refining assets produce a high percentage of diesel and distillate versus other refiners
- Projects underway to grow heavy oil processing capacity to capture potential heavy oil differentials

Oil-Based Marine Fuel Consumption



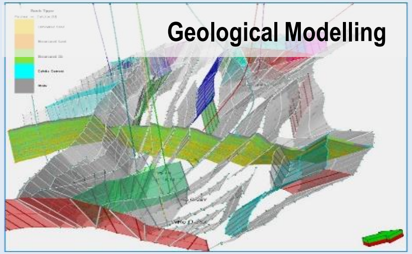
Source: IEA, Medium-Term Oil Market Report 2016

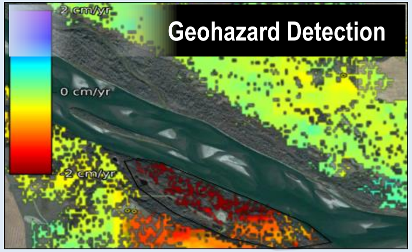
Refined Products By Facility (Percentage of Throughput)



Innovation and Technology

Unlocking Further Potential





Production Optimization

- Diluent reduction module for lower costs, GHG emissions at Sunrise *(pilot under construction)*
- Improved steam utilization and process safety using Machine Learning for SAGD *(active)*
- Low cost wellsite monitoring devices to reduce WCP site visits / operating costs *(active)*

Subsurface

- Reduce geological core description time using AI for pattern recognition *(active proof of concept)*
- Accelerate subsurface interpretation with Cloud computing *(pilot completed)*
- Shorten decision process for Heavy Oil well re-completion with Machine Learning *(active proof of concept)*

Remote Analysis

- Drones for visual pipeline right-of-way inspections *(completed pilot)*
- Geohazard identification at pipelines and facilities using satellite image analysis *(proof of concept complete)*
- Safer flare stack and equipment inspections at plant sites using drones *(active)*

Machine Learning

- Initial trials have yielded encouraging results for improved confidence in wave height prediction
- Work is ongoing to advance predictive capability for other metocean conditions, including sea-ice trajectory prediction to provide for more effective intervention

Husky Energy

Slide Notes & Advisories

Slide Notes

Slide 3

1. Compound annual growth rates (CAGR), as referred to throughout this presentation, are calculated using 2018 forecasted production, FFO and FCF and 2022 forecasted production, FFO and FCF, as applicable.
2. Funds from operations ("FFO"), as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
3. FFO and FCF forecasts for 2018 and 2022 are calculated using the Benchmark Prices – 2018 Base Case Pricing Assumptions on Slide 51.
4. Free cash flow ("FCF"), as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
5. Earnings break-even, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
6. Sustaining capital, as referred to throughout this presentation, is a non-GAAP measure. Please see Advisories for further detail.
7. Capital spending, as referred to throughout this presentation does not include capitalized interest unless otherwise indicated.
8. Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
9. Net debt to funds from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 4

1. Net debt and net debt to trailing funds from operations, as referred to throughout this presentation, are non-GAAP measures. Please see *Advisories* for further detail. All figures are as of June 30, 2018.

Slide 14

1. FFO in US$35 WTI Stress Case are calculated using Pricing Assumptions on Slide 51.

Slide 15

1. Husky has a redemption option on Preferred Shares.

Slide 18

1. Includes the acquisition of the Superior Refinery, which closed in Q4 2017.

Slide 19

1. Includes the acquisition of the Superior Refinery, which closed in Q4 2017.

Slide 20

1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock and distribution system interruptions, among others.
2. Products include Husky Synthetic Blend, asphalt and Ultra Low Sulphur Diesel (ULSD), among others.
3. Value chain operating netback and operating netback, as referred to throughout this presentation, are non-GAAP measures. Please see Advisories for further detail.

Slide 21

1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock and distribution system interruptions, among others.
2. Products include gasoline, distillate, Ultra Low Sulphur Diesel (ULSD), propane, benzene, Sulfur, LPG, LVGO, HVGO, heavy fuels, petro-chemicals and various other by-products.

Slide 25

1. Throughput represents Husky's 100% interest in the heavy oil processing capacity at the Prince George Refinery, Lloydminster Refinery, Lloydminster Upgrader, Lima Refinery and Superior Refinery and 50% interest in the Toledo Refinery.
2. Production volumes represent blended heavy oil volumes (bitumen, heavy oil and diluent).

Slide 37

1. Prepared by internal qualified reserves evaluators in accordance with COGEH.
2. Drilling opportunities split: Proved Undeveloped (76), Probable (47), Unrisked Economic Best Estimate Development Pending Contingent Resource (242).

Slide 45

1. Q3 2016 Operating Netback reflects the impact of a price adjustment for natural gas from the Liwan 3-1 and Liuhua 34-2 fields, per the Heads of Agreement ("HOA") signed by the Company with CNOOC Limited in Q3 2016. The price adjustment under the HOA is effective as of November 2015 and a retroactive adjustment was recognized in Q3 2016.

Slide 50

1. Capital expenditures include exploration capital in each business unit.
2. Asia Pacific oil & NGLs operating costs and capital expenditures are reflected in Asia Pacific natural gas.
3. Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
4. Downstream capital expenditures include scheduled turnarounds.
5. Lloyd and Tucker thermal operating costs include energy and non-energy costs.
6. Downstream operating costs exclude the impact of scheduled turnarounds in 2018.

Slide 55

1. Husky has a 50% working interest in the Toledo Refinery.

Advisories

Forward-Looking Statements and Information

Certain statements in this presentation, including "financial outlook", are forward-looking statements and information (collectively "forward-looking statements"), within the meaning of the applicable Canadian securities legislation, Section 21E of the United States Securities Exchange Act of 1934, as amended, and Section 27A of the United States Securities Act of 1933, as amended. The forward-looking statements contained in this presentation are forward-looking and not historical facts.

Some of the forward-looking statements may be identified by statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events or performance (often, but not always, through the use of words or phrases such as "will likely result", "are expected to", "will continue", "is anticipated", "is targeting", "estimated", "intend", "plan", "projection", "could", "aim", "vision", "goals", "objective", "target", "schedules" and "outlook"). In particular, forward-looking statements in this presentation include, but are not limited to, references to:

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies and the results thereof; the Company's capital plan for 2018 to 2022; forecast sustaining capital and thermal production (as a percentage of total corporate production) for 2018 and 2022; forecast FFO, FCF, upstream production, downstream throughputs, thermal production, heavy processing capacity, upstream operating costs per barrel, downstream operating costs per barrel and earnings break-even oil price for 2018 and 2022; forecast production (as a percentage of total corporate production) for 2018 to 2022 by region, product type and business segment production mix and commodity price exposure for 2018 to 2022; ranges and targets for annual base dividend, sustaining capital, capital spending, target five-year average proved reserves replacement ratio and net debt to FFO for 2018 to 2022; forecast FFO, production growth and FCF compound annual growth rate for 2018 to 2022; forecast upstream operating costs, heavy oil processing capacity, average annual capital spending and average sustaining capital for 2018 to 2022; potential FFO sources and uses at various oil prices in 2022; FFO growth in 2018 as compared to 2017 and factors expected to affect FFO growth in 2018; forecast FFO for 2018 to 2022; forecast net debt to FFO for 2018 to 2022; estimated net debt and target net debt to FFO in 2018 and 2022; forecast FFO, total sustaining capital (broken down into Upstream and Downstream), annual base dividend, annual average growth capital, upstream operating costs, earnings break-even oil price and cumulative after dividends FCF for 2018 to 2022; the Company's potential allocation of free cash flow for the 2018 to 2022 period, including any return of free cash flow to shareholders; forecast FFO, capital spending and cumulative FCF for each of the Integrated Corridor business and the Offshore business for 2018 to 2022; anticipated benefits from the Company's innovation and technology projects; anticipated timing for execution of the Company's major projects in each of the Integrated Corridor business and the Offshore business for 2018 to 2022 and forecast production or capacity thereof, as applicable, and; operating costs guidance ranges for 2018 broken down by business segment; and oil prices required to generate targeted IRR for the Company's listed in-flight and future projects;

Advisories

- with respect to the Company's Downstream operating segment: forecast throughput capacity (total and broken down into heavy oil processing and light oil processing) for 2018 and 2022; forecast light oil processing capacity, heavy oil blend processing capacity and heavy oil blend for 2018 to 2022; plans to add 30,000 bbls/day of heavy oil processing capacity in 2019; potential future heavy oil outlet options; forecast heavy oil blend and downstream processing and pipeline capacity for 2018 to 2022 broken down by product type and project, as applicable; forecast global oil-based marine fuel consumption from 2018 to 2021 and the Company's ability to respond to related market changes;; and forecast Downstream FFO, capital spending and cumulative FCF for 2018 to 2022;

- with respect to the Company's heavy oil and thermal production in the Integrated Corridor: forecast production (in total and broken down by project) for 2018 and 2022; forecast production growth for 2018 to 2022; expected timing to bring Rush Lake 2, Dee Valley, Spruce Lake Central, Spruce Lake North, Edam Central and Westhazel online; anticipated production growth from thermal projects for 2018 to 2022 and associated compound annual growth rate; anticipated timing of first oil from thermal projects; 2018 forecast thermal production operating costs broken down by project and 2018 forecast average thermal operating costs; forecast Lloyd thermal production for 2018 to 2022; strategic plans and growth strategy for the Lloyd thermal projects; expected timing to reach nameplate capacity at Tucker and Sunrise; capital efficiencies and operating costs; 2018 year-end gross production target at Sunrise (in total and per well pair); strategic plans and growth strategy for Sunrise; and forecast capital spending, FFO and cumulative FCF for the thermal business for 2018 to 2022;

- with respect to the Company's resource plays and other production in the Integrated Corridor; forecast production growth from resource plays for 2018 to 2022 and associated compound annual growth rate; drilling plans for 2018 at Ansell-Kakwa and Montney; expected testing of seven wells at Wembley by the end of 2018; and strategic plans and growth strategy for the Company's resource plays;

- with respect to the Company's Offshore business in the Atlantic: forecast production growth from 2018 to 2026; and

- with respect to the Company's Offshore business in Asia Pacific: forecast production growth; forecast production growth from 2018 to 2026; forecast gas production growth for 2018 to 2022 for Liwan 3-1 and Liuhua 34-2, Liuhua 29-1, the BD Project and the MDA-MBH and MDK fields; expected timing of first gas from Liuhua 29-1; target production at the BD Project and the MDA-MBH and MDK fields broken down into gas and liquids; expected timing of first gas, and expected net peak production, at the MDA-MBH and MDK fields; drilling plans at Block 16/25 in 2018; and forecast FFO for 2018 and 2022 as a percent of corporate FFO.

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In addition, statements relating to “reserves” are deemed to be forward-looking statements as they involve the implied assessment based on certain estimates and assumptions that the reserves or resources described can be profitably produced in the future. There are numerous uncertainties inherent in estimating quantities of reserves and in projecting future rates of production and the timing of development expenditures. The total amount or timing of actual future production may vary from reserves and production estimates. In addition, with respect to the test rates, there is no certainty that future wells will generate results to match test rates presented herein.

Certain of the information in this presentation is “financial outlook” within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company’s reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this presentation are reasonable, the Company’s forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources including third-party consultants, suppliers, regulators and other sources.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky.

The Company’s Annual Information Form for the year ended December 31, 2017 and other documents filed with securities regulatory authorities (accessible through the SEDAR website www.sedar.com and the EDGAR website www.sec.gov) describe risks, material assumptions and other factors that could influence actual results and are incorporated herein by reference.

New factors emerge from time to time and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on the Company’s business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are dependent upon other factors, and the Company's course of action would depend upon management’s assessment of the future considering all information available to it at the relevant time. Any forward-looking statement speaks only as of the date on which such statement is made and, except as required by applicable securities laws, the Company undertakes no obligation to update any forward-looking statement to reflect events or circumstances after the date on which such statement is made or to reflect the occurrence of unanticipated events.

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Non-GAAP Measures

This presentation contains certain terms which do not have any standardized meanings prescribed by IFRS and are therefore unlikely to be comparable to similar measures presented by other issuers. None of these measures is used to enhance the Company's reported financial performance or position. With the exception of funds from operations, free cash flow and net debt, there are no comparable measures to these non-GAAP measures in accordance with IFRS. The following non-GAAP measures are considered to be useful as complementary measures in assessing Husky's financial performance, efficiency and liquidity:

- "Funds from operations" or "FFO" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "cash flow – operating activities" as determined in accordance with IFRS, as an indicator of financial performance. FFO is presented to assist management and investors in analyzing operating performance of the Company in the stated period. FFO equals cash flow – operating activities plus change in non-cash working capital.

- "Free cash flow" or "FCF" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, cash flow – operating activities as determined in accordance with IFRS, as an indicator of financial performance. FCF is presented to assist management and investors in analyzing operating performance by the business in the stated period. FCF equals funds from operations less capital expenditures and investment in joint ventures. FCF has been restated in the first quarter of 2018 in order to be more comparable to similar non-GAAP measures presented by other companies. Changes from prior period presentation include the addition of investment in joint ventures. Prior periods have not been restated.

The following table shows the reconciliation of net earnings to FFO and FCF for the periods indicated:

	Three Months Ended	6 Months Ended	
($ millions)	June 30, 2018	June 30, 2018	June 30, 2017
Net earnings (loss)	448	696	(22)
Items not affecting cash:			
Accretion	25	49	57
Depletion, depreciation, amortization and impairment	639	1,257	1,562
Exploration and evaluation expenses	7	7	5
Deferred income taxes	138	215	(51)
Foreign exchange loss (gain)	(2)	(1)	(2)
Stock-based compensation	33	54	9
Loss (gain) on sale of assets	-	(4)	(31)
Unrealized mark to market loss (gain)	(26)	(112)	(32)
Share of equity investment gain	(26)	(35)	(48)
Other	19	21	(1)
Settlement of asset retirement obligations	(22)	(71)	(68)
Deferred revenue	(25)	(45)	(2)
Distribution from joint ventures	-	72	25
Change in non-cash working capital	(199)	(565)	58
Cash flow - operating activities	1,009	1,538	1,459
Change in non-cash working capital	199	565	(58)
Funds from operations	1,208	2,103	1,401
Capital expenditures	(708)	(1,345)	(964)
Investment in joint venture	-	(40)	(60)
Free cash flow	500	718	377

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- “Net debt” is a non-GAAP measure that equals total debt less cash and cash equivalents. Total debt is calculated as long-term debt, long-term debt due within one year and short-term debt. Net debt is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

The following table shows the reconciliation of total debt to net debt as at the periods indicated:

($ millions)	**June 30, 2018**	**December 31, 2017**
Short-term debt	200	200
Long-term debt due within one year	394	-
Long-term debt	5,015	5,240
Total debt	5,215	5,440
Cash and cash equivalents	(2,583)	(2,513)
Net debt	3,026	2,927

- “Net debt to funds from operations” or “net debt to FFO” or “net debt to FFO ratio” is a non-GAAP measure that equals net debt divided by FFO. Net debt to FFO is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- “Net debt to trailing funds from operations” or “net debt to trailing FFO” is a non-GAAP measure that equals net debt divided by the 12-month trailing FFO as at June 30, 2018 and December 31, 2017. Net debt to trailing FFO is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- “Upstream operating netback” or “operating netback” is a common non-GAAP measure used in the oil and gas industry. This measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as realized price less royalties, operating costs and transportation costs on a per unit basis.

- “Value chain operating netback” is a non-GAAP measure used in the oil and gas industry. This measure assists investors to evaluate the operating performance of the Integrated Corridor. Value chain operating netback is calculated as an average realized price of synthetic crude and other refined products less royalties, operating costs, transportation costs and processing costs on a per unit basis.

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- “Sustaining capital” is the additional development capital that is required by the business to maintain production and operations at existing levels. Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

- “Earnings break-even” reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate a net income of Cdn$0 in the 12-month period ending December 31 of the indicated year. This assumption is based on holding several variables constant throughout the applicable 12-month period, including foreign exchange rate, light-heavy oil differentials, realized refining margins, forecast utilization of downstream facilities, estimated production levels and other factors consistent with normal oil and gas company operations. Earnings break-even is used to assess the impact of changes in WTI oil prices on the net earnings of the Company and could impact future investment decisions. Earnings break-even does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves and resources estimates and potential drilling opportunities in this presentation have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, have an effective date of December 31, 2017 and represent the Company's working interest share; (ii) projected and historical production volumes provided represent the Company’s working interest share before royalties; and (iii) historical production volumes provided are for the year ended December 31, 2017. The Company has disclosed its total reserves in Canada, Indonesia and China in its Annual Information Form for the year ended December 31, 2017, which reserves disclosure is incorporated by reference in this presentation.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Husky’s Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 186 million barrels of economic development pending, 150 million barrels of economic development unclarified and 589 million barrels of economic status undetermined development unclarified. The figures represent Husky’s working interest volumes. The development pending category consists of 8 steam assisted gravity drainage (SAGD) projects and one combined SAGD and cyclic steam stimulation (CSS) project that have been scheduled for initial production starting in 2021 through to 2040. The first three projects have a total capital cost to first production of $0.9 billion based upon the pre-development studies. The estimated total capital to fully develop these 9 development pending projects is approximately $3 billion.

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The Company uses the term “barrels of oil equivalent” (or “boe”) and “thousand cubic feet of gas equivalent” (or “mcfe”), which are consistent with other oil and gas companies’ disclosures. Boe amounts have been calculated by using the conversion ratio of 6 mcf of natural gas to 1 bbl of oil and mcfe amounts have been calculated by using the conversion ratio of 1 bbl of oil or NGL to 6 mcf of natural gas. A boe conversion ratio of 6 mcf: 1 bbl and an mcfe conversion ratio of 1 bbl: 6 mcf are based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent value equivalency at the wellhead. Readers are cautioned that the terms boe and mcfe may be misleading, particularly if used in isolation.

This news release includes estimates of net pay thickness at Block 15/33 in the South China Sea and at White Rose A-24, which estimates may be considered to be anticipated results under National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities. The estimates were prepared internally. The risks and uncertainties associated with recovery of resources from Block 15/33 and A-24 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

References in this news release to production test rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which wells will commence production and decline after testing and are not indicative of long term performance or of ultimate recovery. Additionally, such rates may also include recovered “load oil” fluids used in well completion stimulation. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered to be preliminary.

The Company uses the term “capital efficiency”, which is calculated by dividing the development capital per well by the well's initial production rate ($ per flowing barrel, mcf or boe). Development capital includes the cost to drill, complete, equip and tie-in wells to existing infrastructure. As capacity becomes available within facilities, new wells are added to replace the volume. The number of wells required to replace such volume is a function of capital efficiency. Capital efficiency does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

The Company uses the term “reserves replacement ratio”, which is consistent with other oil and gas companies’ disclosures. Reserves replacement ratios for a given period are determined by taking the Company's incremental proved reserves additions for that period divided by the Company's upstream gross production for the same period. The reserves replacement ratio measures the amount of reserves added to a company's reserves base during a given period relative to the amount of oil and gas produced during that same period. A company's reserves replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserves replacement ratio only measures the amount of reserves added to a company's reserves base during a given period. Reserves replacement ratios presented as excluding economic factors exclude the impact that changing oil and gas prices have on reserves amounts.

The Spirit River gas resource potential drilling opportunities include 76 proved undeveloped and 47 probable undeveloped locations and 242 unrisked economic best estimate development pending contingent resource opportunities in Ansell and Kakwa, mainly focused in the Wilrich formation.

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Note to U.S. Readers

The Company reports its reserves information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources information in accordance with Canadian disclosure requirements, it may use certain terms in that disclosure that U.S. oil and gas companies generally do not include or may be prohibited from including in their filings with the U.S. Securities and Exchange Commission.

All currency is expressed in Canadian dollars unless otherwise indicated.