Husky Energy

Investor Day

May 30, 2017

Agenda

How It Comes Together
Rob Peabody, CEO

Financial Framework
Jon McKenzie, CFO

Break

Integrated Corridor
Rob Symonds, COO
Thermal – **Andrew Dahlin**, SVP, Heavy Oil
Downstream – **Jeffrey Rinker**, VP Downstream Value Chain
Resource Plays – **Gerald Alexander**, SVP, Western Canada

Offshore
Asia Pacific – **Bob Hinkel**, COO Asia Pacific
Atlantic – **Malcolm Maclean**, SVP, Atlantic

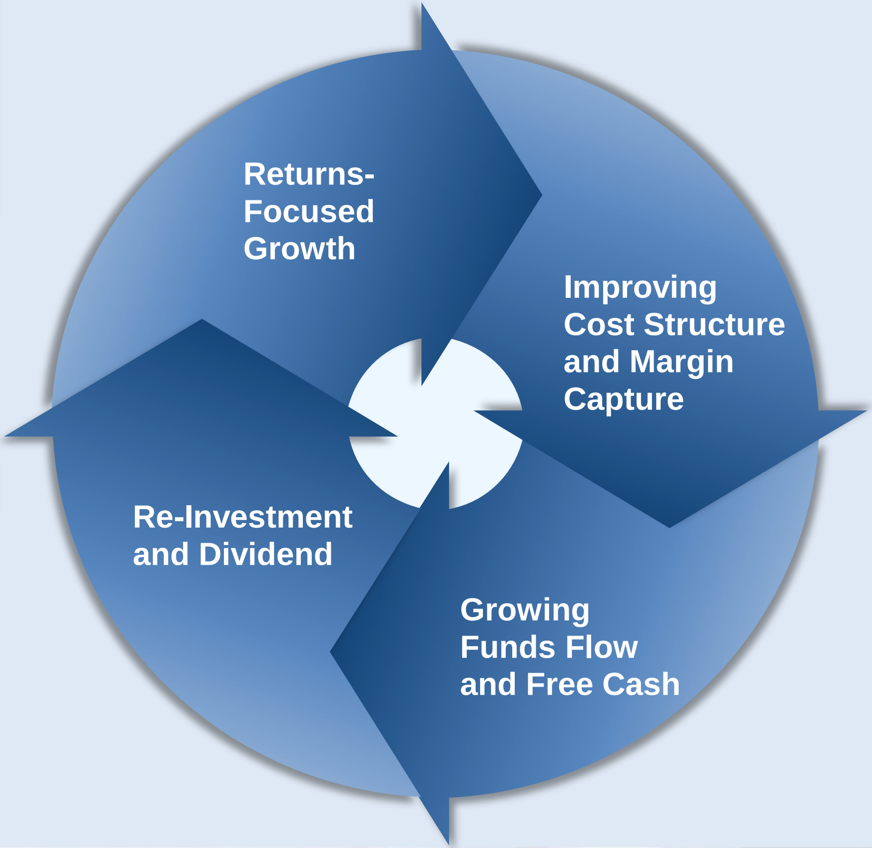
How It Comes Together

Rob Peabody
President & Chief Executive Officer

Five-Year Plan Highlights

Key Metrics	’17	’17-’21F CAGR	’21F
Production (mboe/day)	**320 – 335**	**4.8%**	**390 – 400**
Funds from operations (FFO)[1]	**$3.3B**	**9%**	**~$4.8B[2]**
Free cash flow (FCF)[1]	**$750M**	**12%**	**~$1.2B[2]**
Upstream operating cost/bbl	$14.25		<$12
Downstream realized refining margins/bbl (CAD)	$15.00		>$16
Earnings break-even oil price (US WTI)[3]	~$43.60		~$37
Cash break-even oil price (US WTI)[3]	~$33.50		~$32

Ranges and Targets	’17 - ’21F
Sustaining capital[4]	Avg. $1.9B
Capital spending[5]	Avg. $3.3B
Five-year average proved reserve replacement ratio	Target >130%
Net debt to FFO[6]	<2x



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

Two Businesses

Integrated Corridor	Offshore

Integrated Corridor

Five-Year Forecast ('17- '21)

- Production CAGR of 5.0%
- Funds from operations CAGR of 11%
- Free cash flow CAGR of 9%

Unique, Physically-Integrated Assets

- Mitigates location and product differentials
- Multiple options to maximize margins
- Secured access into U.S. markets

Integrated Corridor

Past 12 Months

Thermal Growth

- Ramped up three latest Lloyd thermal bitumen projects to ~30,000 bbls/day (17% above nameplate)
- Advanced construction of Rush Lake 2 (10,000 bbls/day thermal bitumen)
- Sanctioned 30,000 bbls/day of new Lloyd thermal bitumen capacity

Downstream Increasing Margin Capture

- Created Husky Midstream Partnership
- “Heavied-up” processing capacity at Lima/Toledo
- Advanced potential asphalt capacity expansion

Western Canada Repositioned

- Divestments targets achieved (net well-bore count reduced from 18,200 to ~8,000)
- Ansell well costs lowered 50% since ’14
- 150+ sections of Montney land acquired

Offshore

Asia Pacific – Next Five Years

- FFO of $5 billion and FCF of $4.2 billion
- 50% production growth to 60,000 boe/day in ’21

Atlantic

- 52.5 mbbls/day (net) West White Rose project

Value Drivers

- Extensive experience in both regions
- Leveraging existing infrastructure
- Access to global markets
- Strong track record for execution, reliability and exploration success

Offshore

Past 12 Months

Asia Pacific

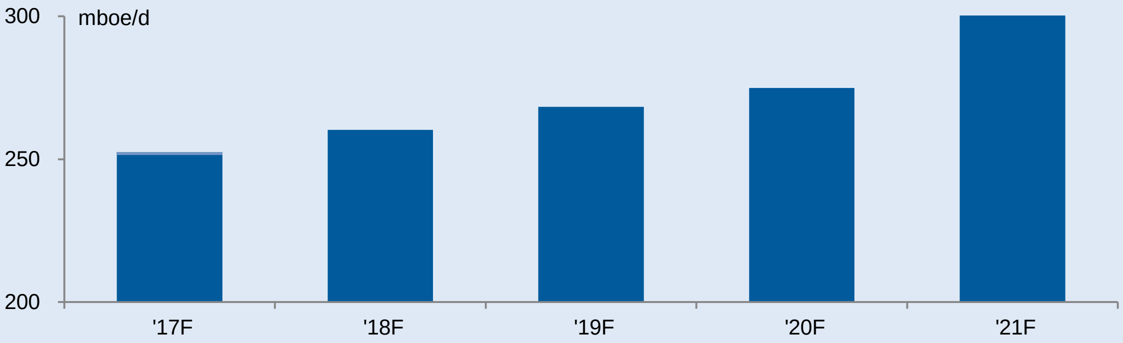
- Completion of 22” line at Liwan Gas Project, triggering next 20-year phase of gas sales contract
- Commissioning of BD Project in Indonesia
- Progressed four additional Madura Strait fields
- Acquired two exploration Blocks: 15/33, 16/25

Atlantic

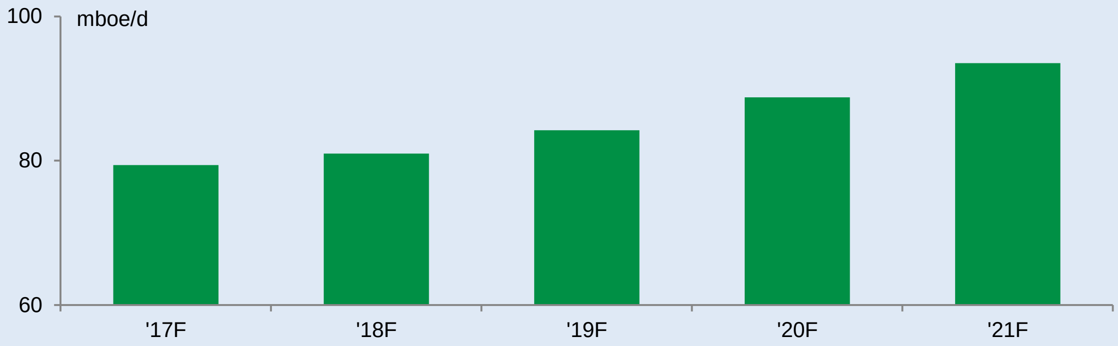
- First oil from North Amethyst Hibernia well
- Two new infill wells on stream
- Oil discovery at Northwest White Rose
- Two oil discoveries in Flemish Pass

Two Businesses . . .

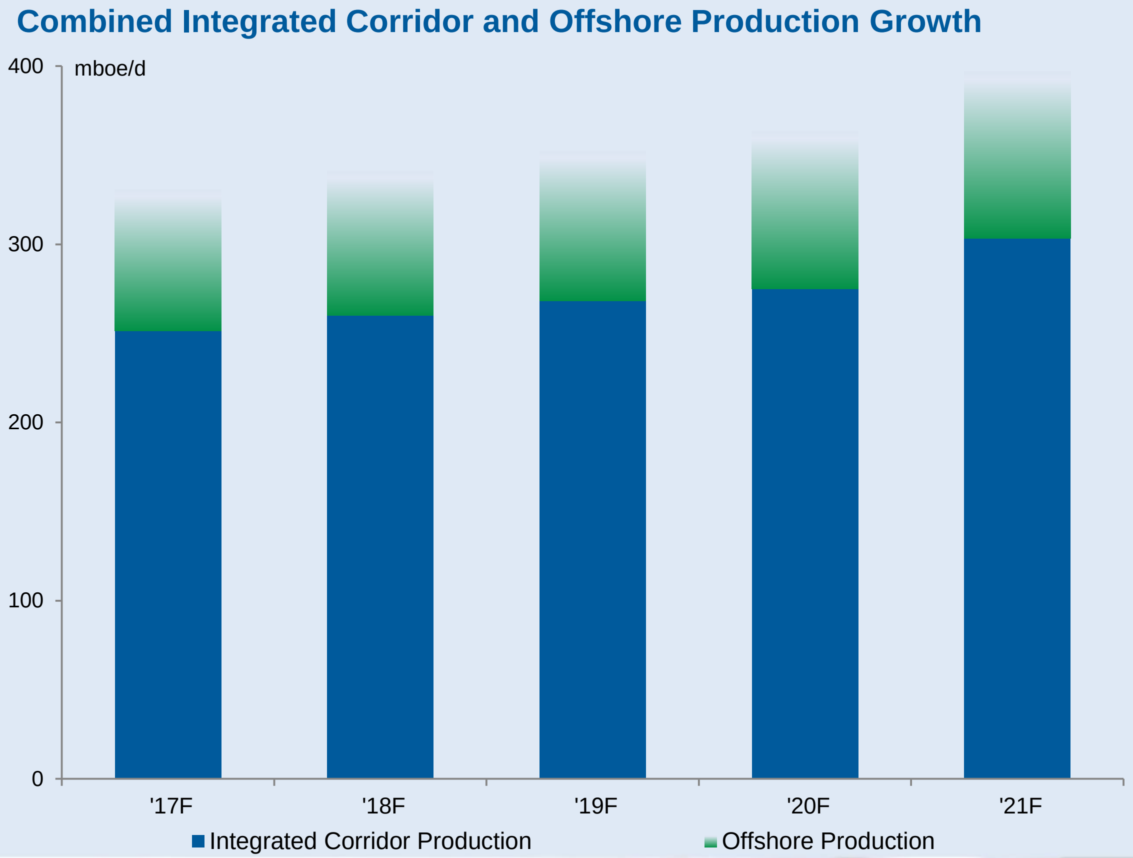
Integrated Corridor Upstream Production Growth



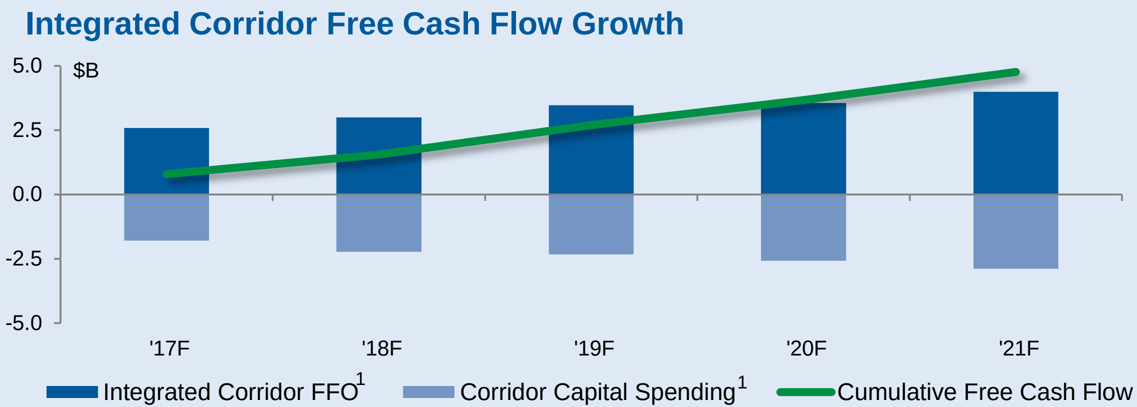
Offshore Production Growth

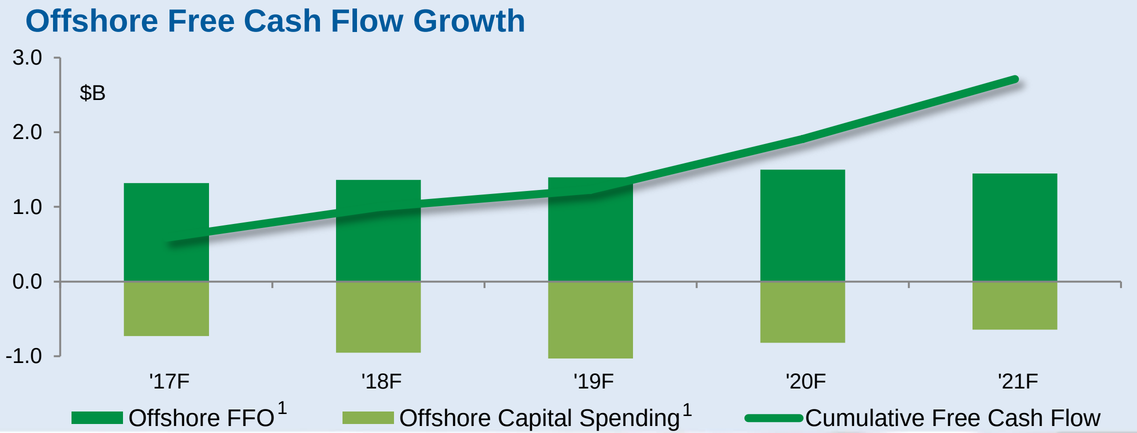


Combined Production Growth



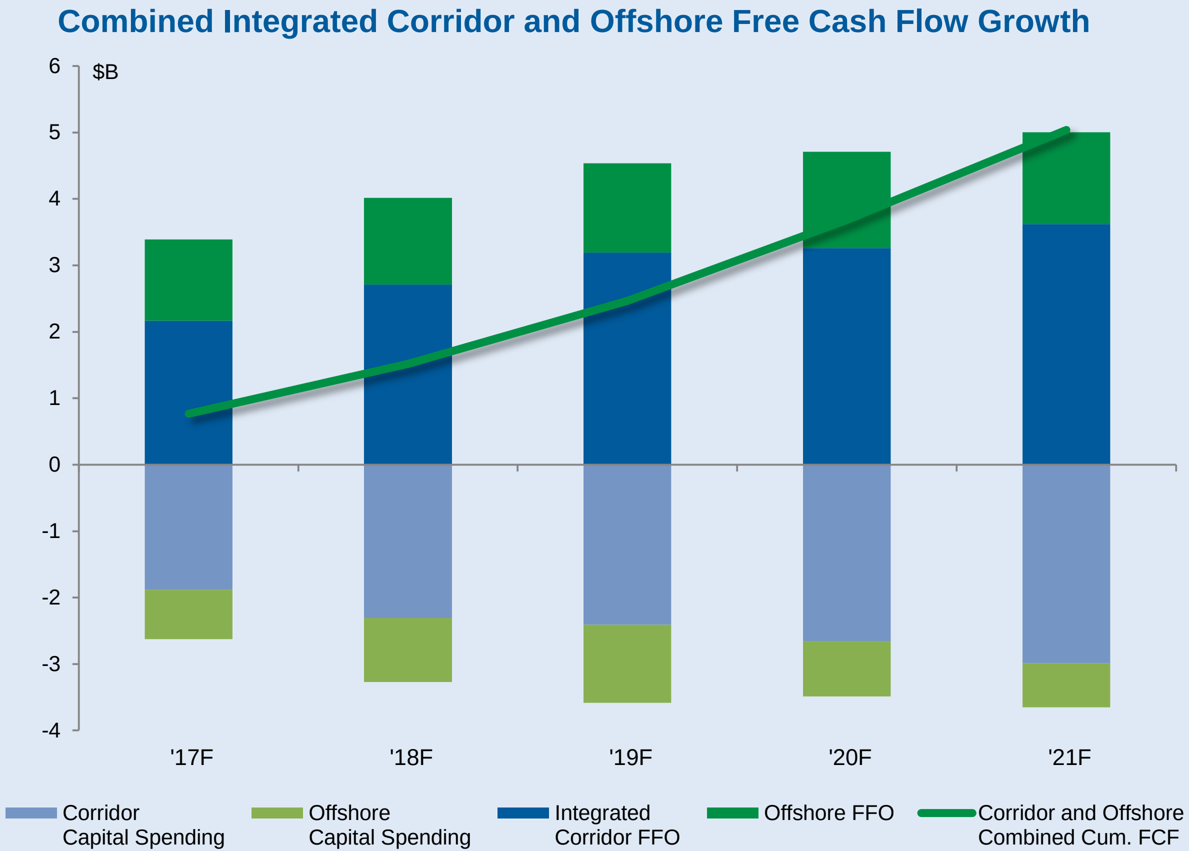
Two Businesses . . .





1 see *Slide Notes* and *Advisories*

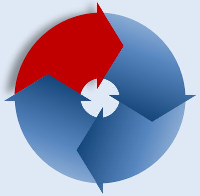
Combined Fund From Ops and Free Cash Flow



How it Comes Together

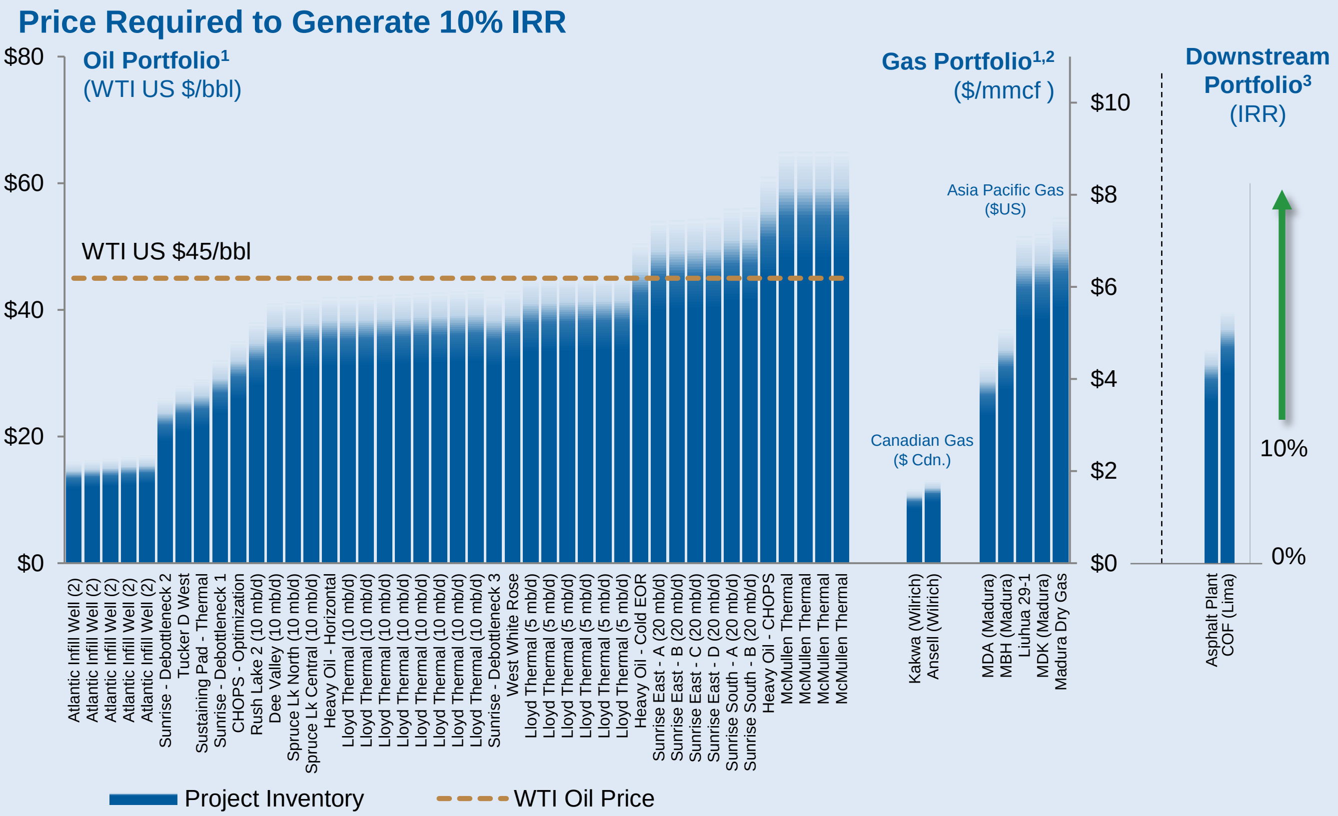
Returns-Focused Growth

New Project Hurdle of >10% IRR at $45 US WTI and/or $2.50 AECO



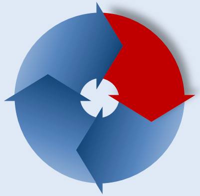
Capital Spending Over Plan Period **$16B**

Short to Medium-Cycle **2/3** **Of Planned Capital Spend**



1,2,3 see *Slide Notes* and *Advisories*

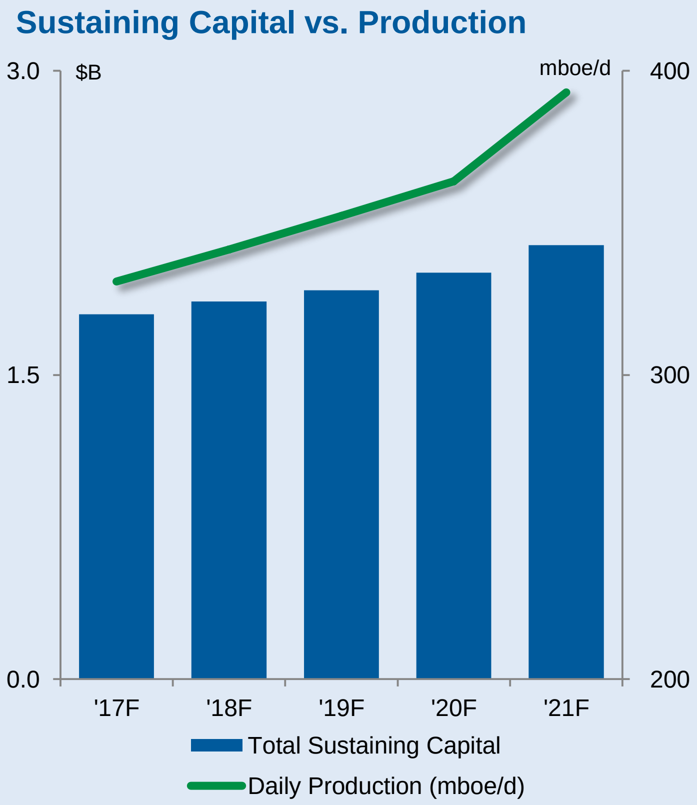
Improving Cost Structure



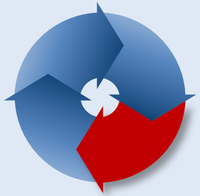
Sustaining Capital ’17-’21F | **~$1.9B** Annual Average

Upstream Sustaining Cost/Boe ’17-’21F | **~$11** Annual Average

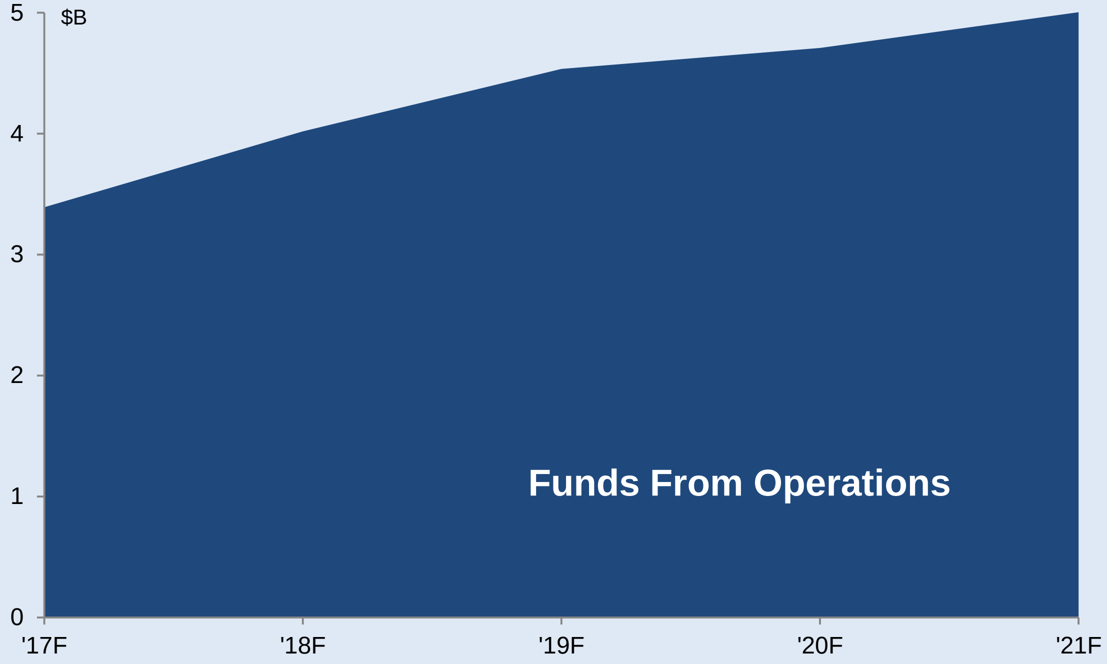
Cash Break-Even ’17-’21F | **~$32 (US WTI)** Annual Average



Expanding Funds From Ops and Free Cash Flow



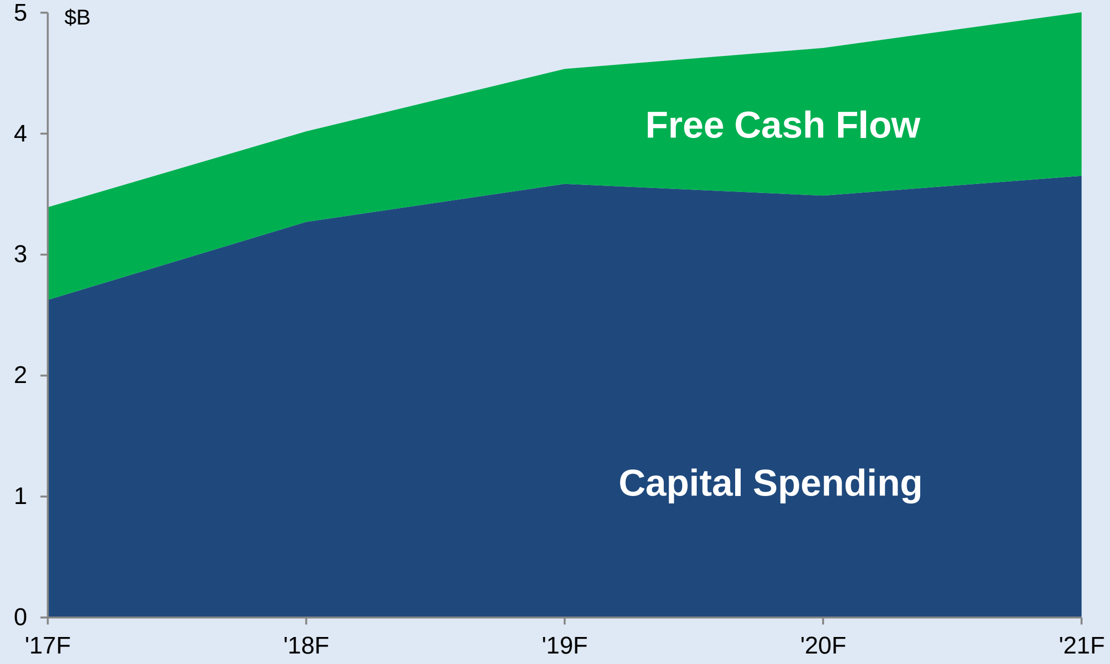
FFO CAGR ’17-’21F | **9%**



Expanding Funds From Ops and Free Cash Flow

FFO
CAGR
'17-'21F
9%

FCF
CAGR
'17-'21F
12%

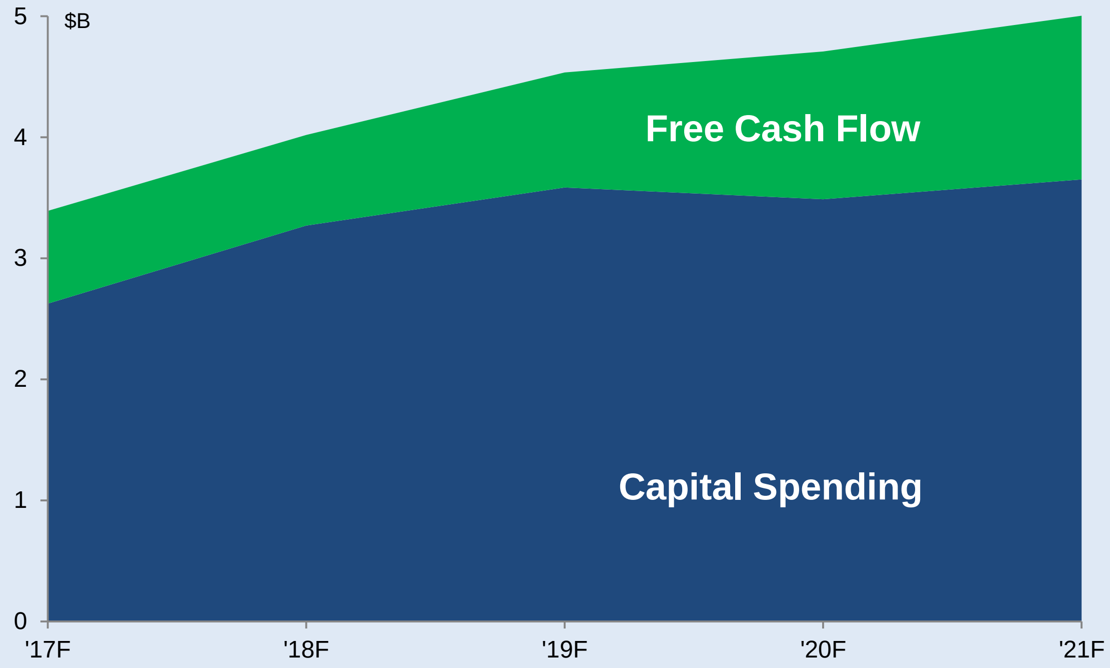


Re-Investment and Dividend

Excess FCF to Fund Strategic Growth Opportunities, Returns to Shareholders

Capital Spending Program ’17-’21F

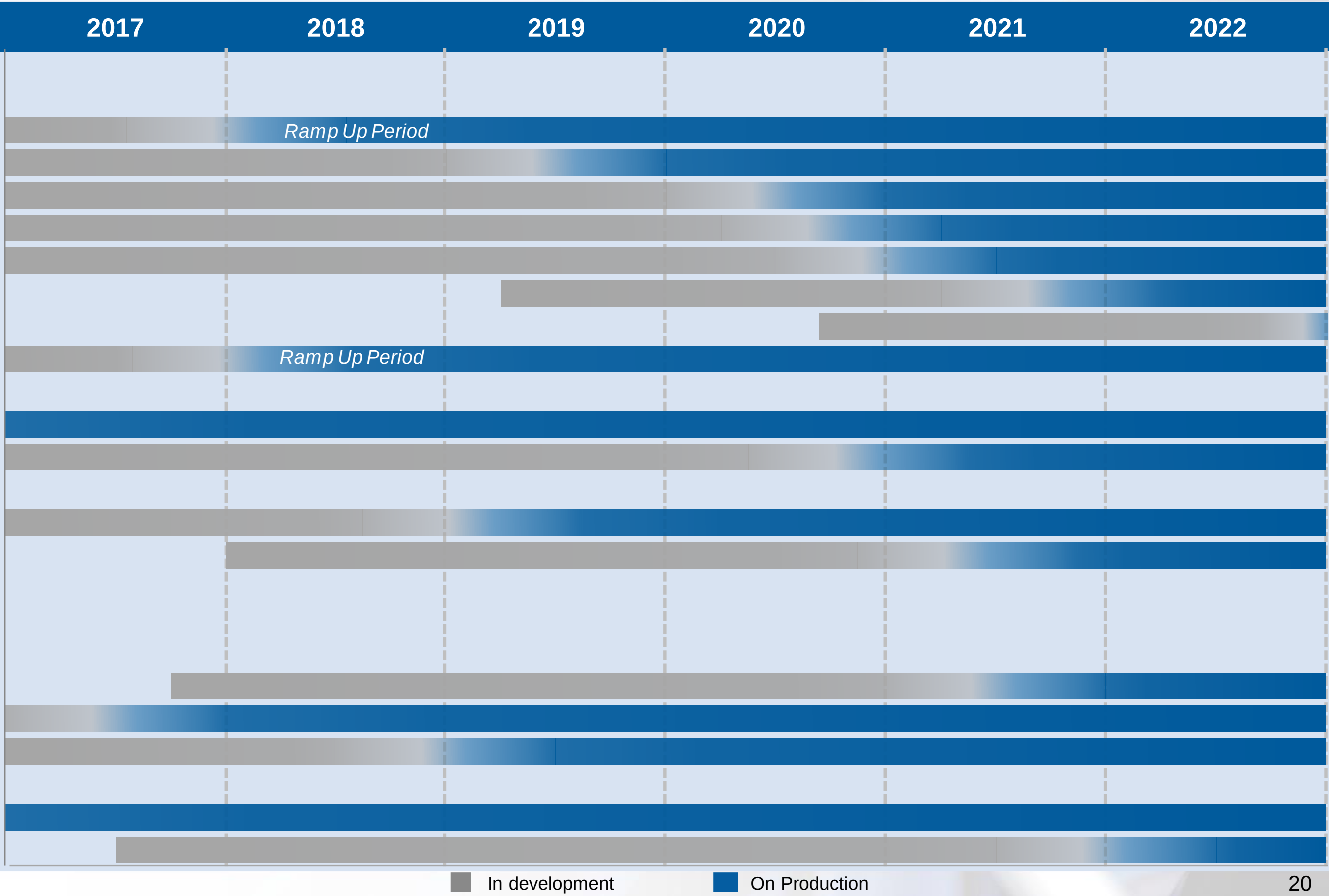
$3.3B
Annual Average



Five-Year Plan Milestones

Project Execution Focus

Major Projects	Production
INTEGRATED CORRIDOR	
Thermal	
Tucker Lake (to 30,000 bbls/d, YE 2018)	7,000 bbls/d
Rush Lake 2	10,000 bbls/d
Dee Valley	10,000 bbls/d
Spruce Lake North	10,000 bbls/d
Spruce Lake Central	10,000 bbls/d
Next Two Lloyd Thermal Projects	20,000 bbls/d
Future Lloyd Thermal Proejcts (x2)	20,000 bbls/d
Sunrise (14 wells)	11,500 bbls/d
Resource Plays	
Ansell-Kakwa drilling program	
Montney drilling program	
Downstream	Heavy Capacity Increase
Lima - Crude Oil Flexibility Project	30,000 bbls/d
Asphalt Capacity Expansion	30,000 bbls/d
OFFSHORE	
Asia Pacific	
China - Liuhua 29-1	30 mmcf/d
Indonesia - BD Field	9,000 boe/d
Indonesia - MDA-MBH, MDK	8,300 boe/d
Atlantic	
White Rose Development / Infill Wells	5-8,000 bbls/d
West White Rose (peak)	52,500 bbls/d



Husky Value Proposition

- Returns-focused growth
- Large inventory of low cost projects
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Resilient to volatile market conditions while preserving upside

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Ranges and Targets	’17 - ’21F
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.3B
Five-year avg. proved reserve replacement ratio	Target >130%
Net debt to FFO	<2x

Financial Framework

Jon McKenzie
Chief Financial Officer

Financial Priorities

- Invest in portfolio to generate returns and improve break-evens
- Generate free cash flow
- Maintain balance sheet strength
- Return cash to shareholders

Sustaining Capital

Corridor Sustaining Capital ’17-’21F

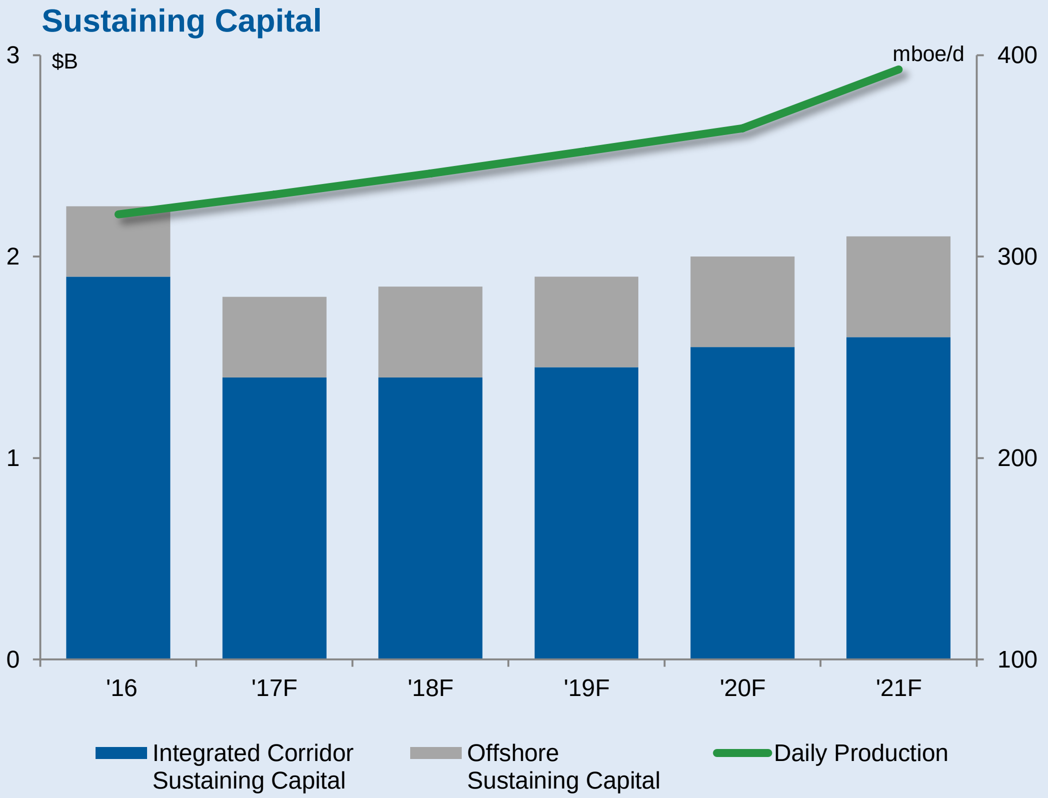
~$1.5B

Annual Average

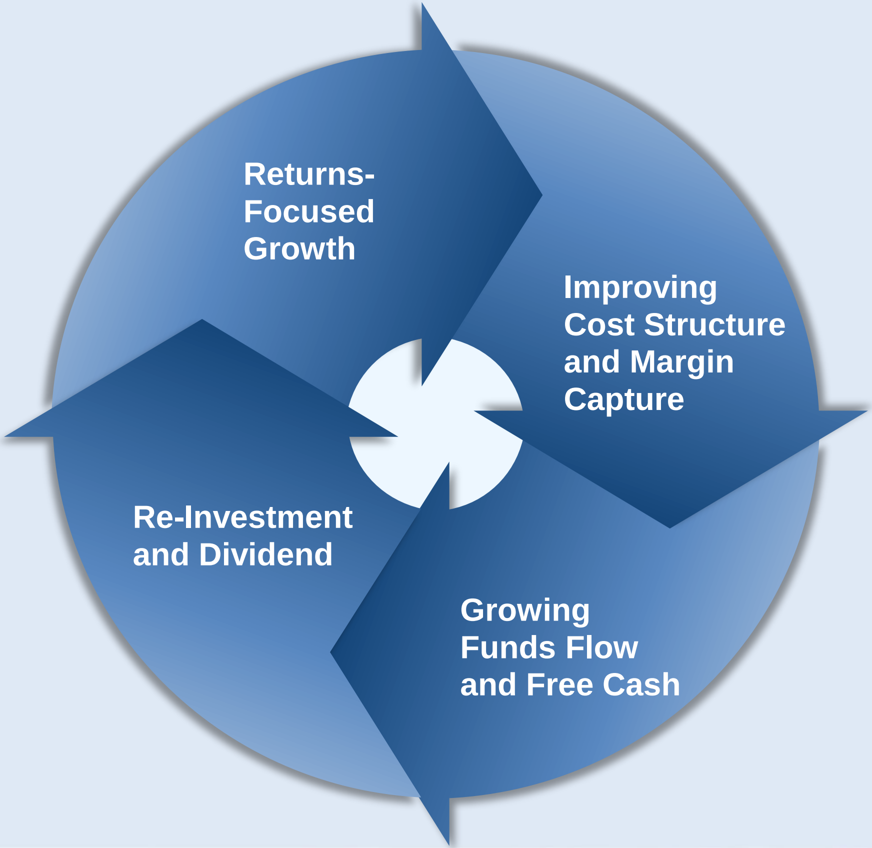
Offshore Sustaining Capital ’17-’21F

~$0.4B

Annual Average



Financial Framework



Returns-Focused Growth

New Project Hurdle of >10% IRR at $45 US WTI and/or $2.50 AECO

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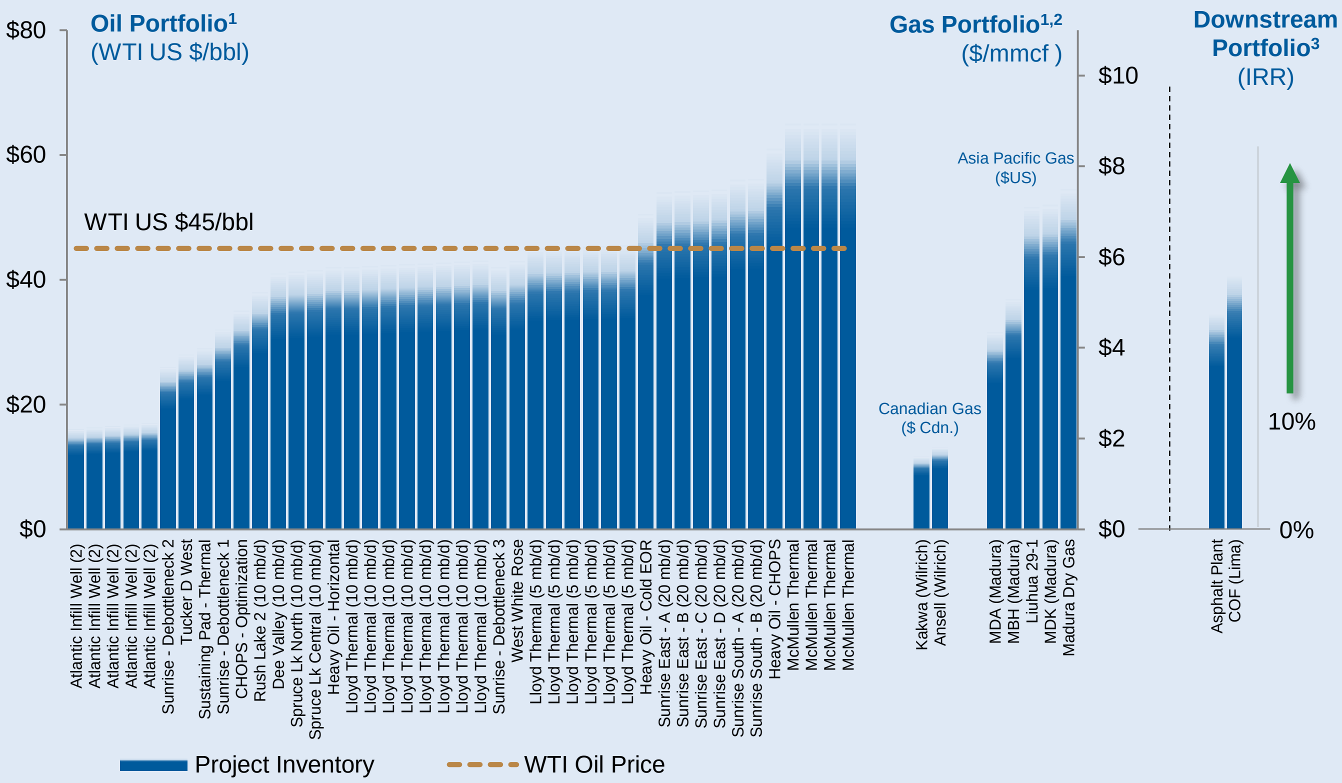
Price Required to Generate 10% IRR



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Returns-Focused Growth

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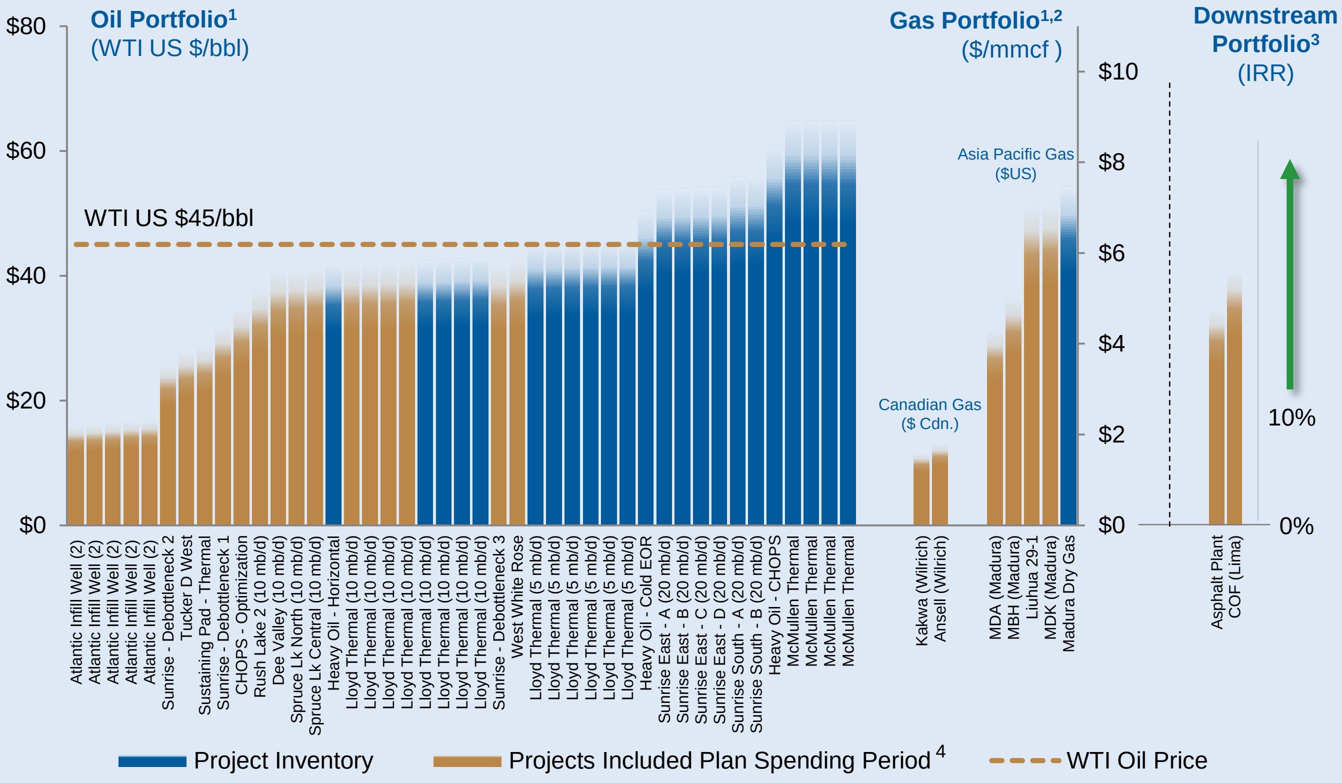

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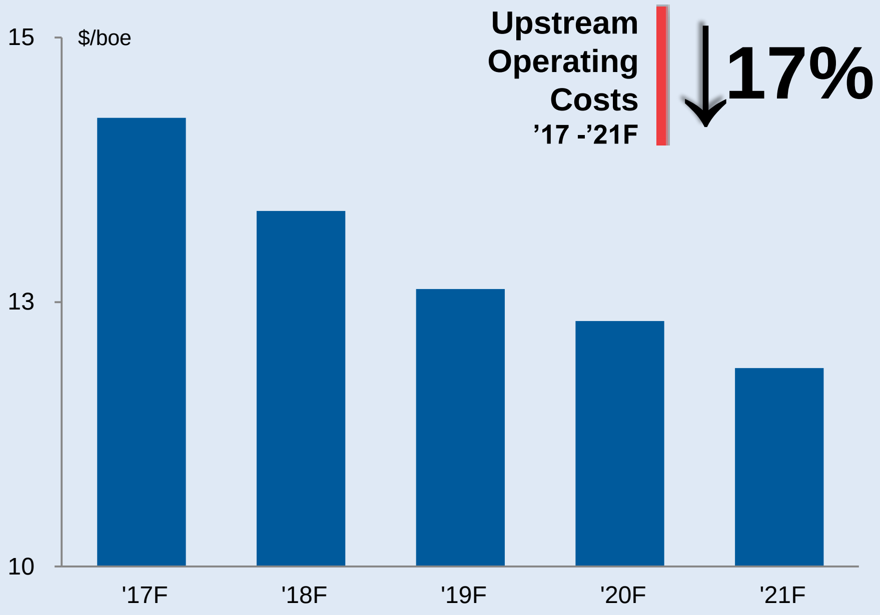
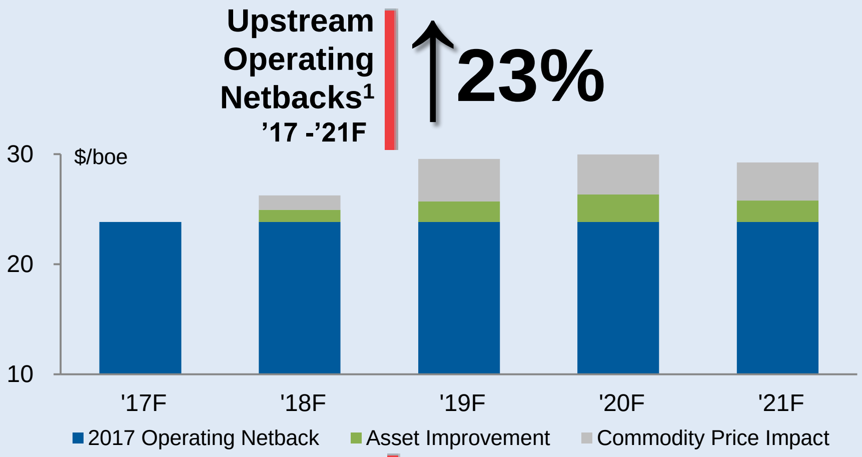
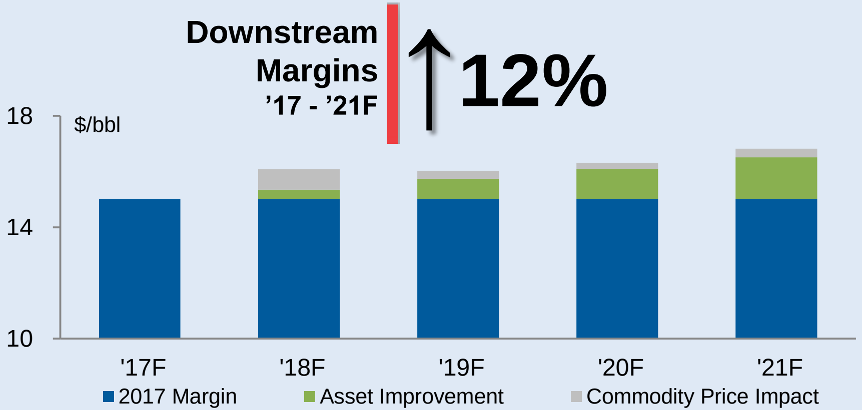
Capital Investment Lowers Cost Structure

Costs Down – Netbacks And Margins Up







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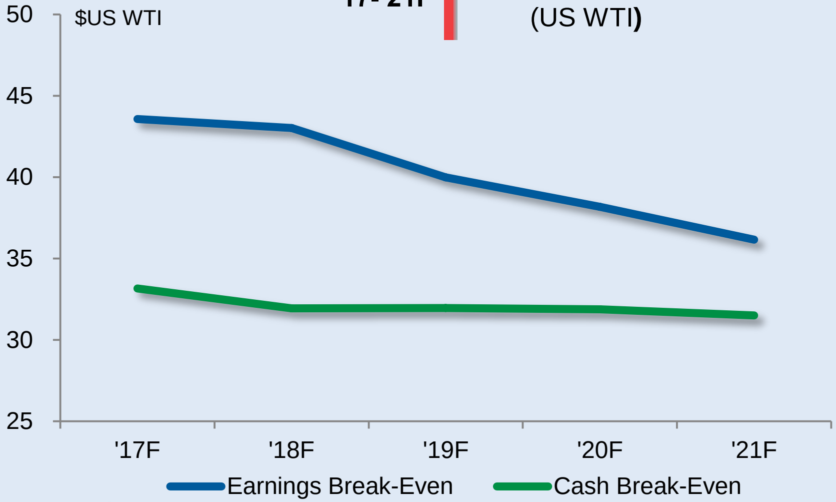
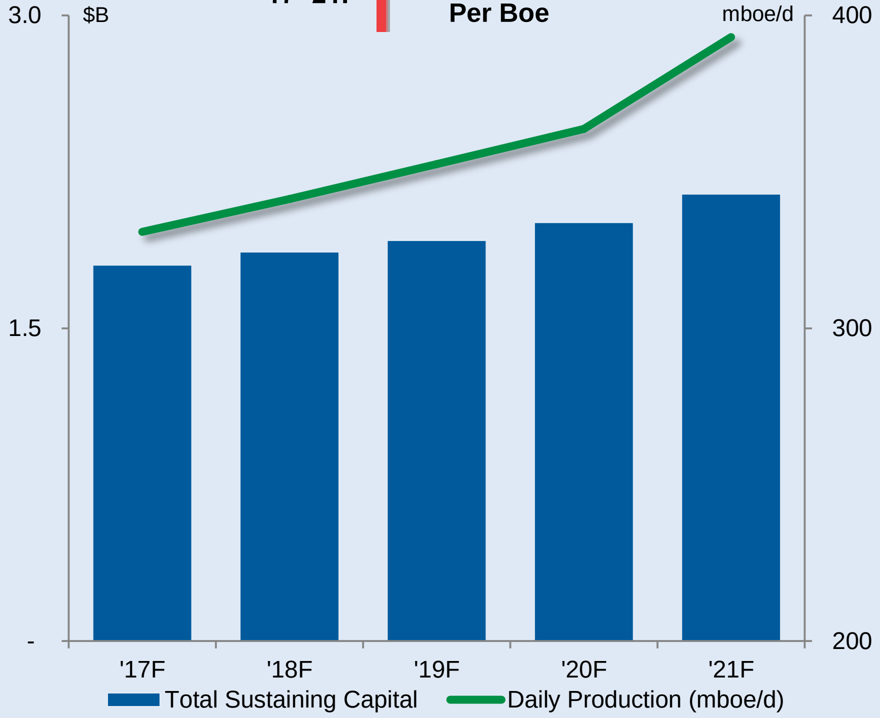
Capital Investment Lowers Cost Structure

Costs Down – Netbacks And Margins Up

Average Cash Break-Even ’17-’21F **~$32** (US WTI)



Average Upstream Sustaining Cost ’17-’21F **~$11** **Per Boe**



Building Our Financial Plan

Price Planning Assumptions

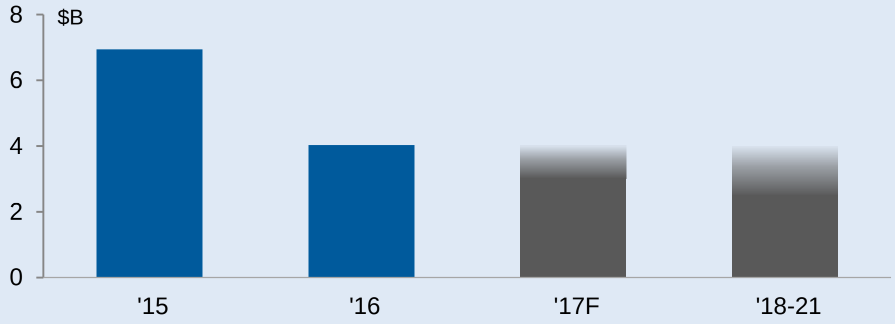
Benchmark Prices	2017	2018	2019	2020	2021
WTI ($bbl US)	50.00	55.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy crude differential ($/bbl US)	12.00	14.00	14.00	14.00	14.00
AECO ($/mmbtu Cdn)	2.50	3.00	3.00	3.00	3.00
USD/CAD exchange rate	0.76	0.78	0.80	0.80	0.80

Building Our Financial Plan

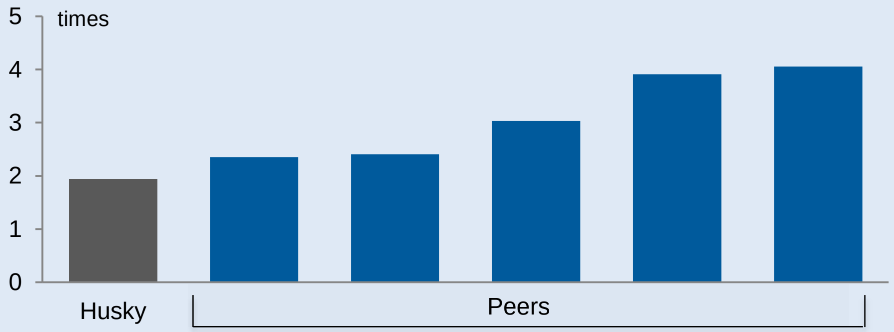
Growing Funds From Operations Covers All Spending Priorities

1. **Maintain balance sheet strength**
2. Cover sustaining capital requirements
3. Invest in portfolio and pay a dividend
4. Grow dividend and accelerate growth

Net Debt



Net Debt to Trailing FFO[1]



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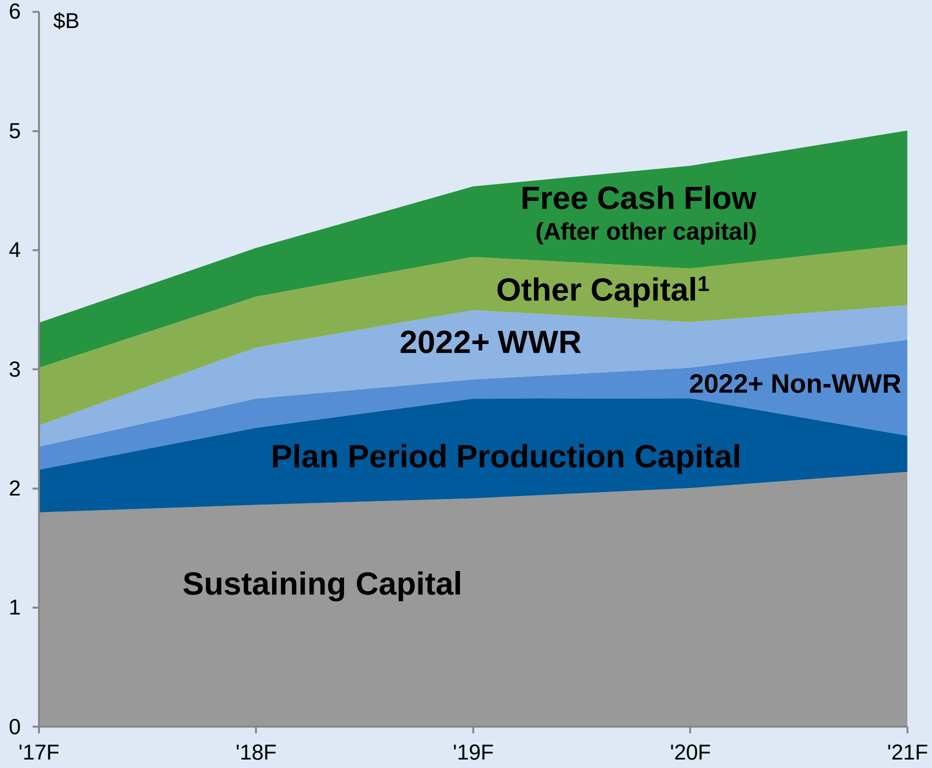
Building Our Financial Plan

Growing Funds From Operations Covers All Spending Priorities

1. **Maintain balance sheet strength**
2. **Cover sustaining capital requirements**
3. **Invest in portfolio and pay a dividend**
4. **Grow dividend and accelerate growth**

FFO and Cash Capital Spending



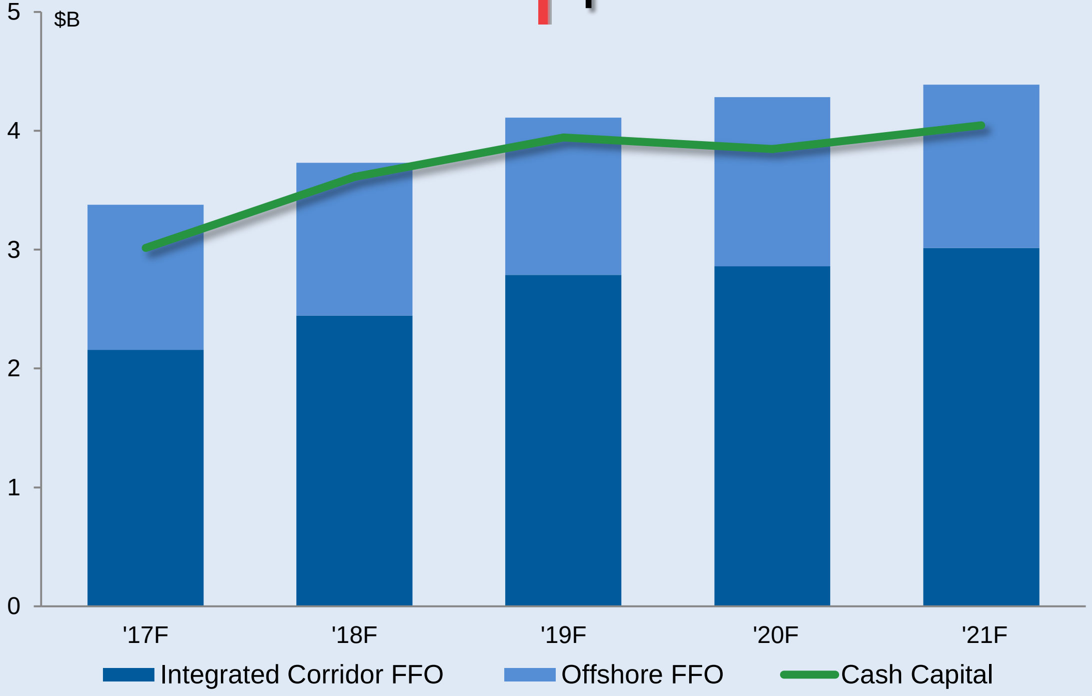
1 see *Slide Notes* and *Advisories*

Capital Plan Fully Funded At $50 US WTI Flat

Demonstrating Improving Asset Mix

FFO Generation at Flat $50 US WTI ’17-’21F

↑>30%



Today vs. 2021: What We Could Do at $35 US WTI

As Assets Improve, Earnings Profile and Debt Capacity Rise

Today's Portfolio

$35 US WTI
$12 US Chicago 3-2-1 Crack

$1.9B
FFO

<2x
Net Debt / FFO

$1.8B
Sustaining Capital

$0.1B
Discretionary

2021 Portfolio

$35 US WTI
$12 US Chicago 3-2-1 Crack

$3.1B
FFO

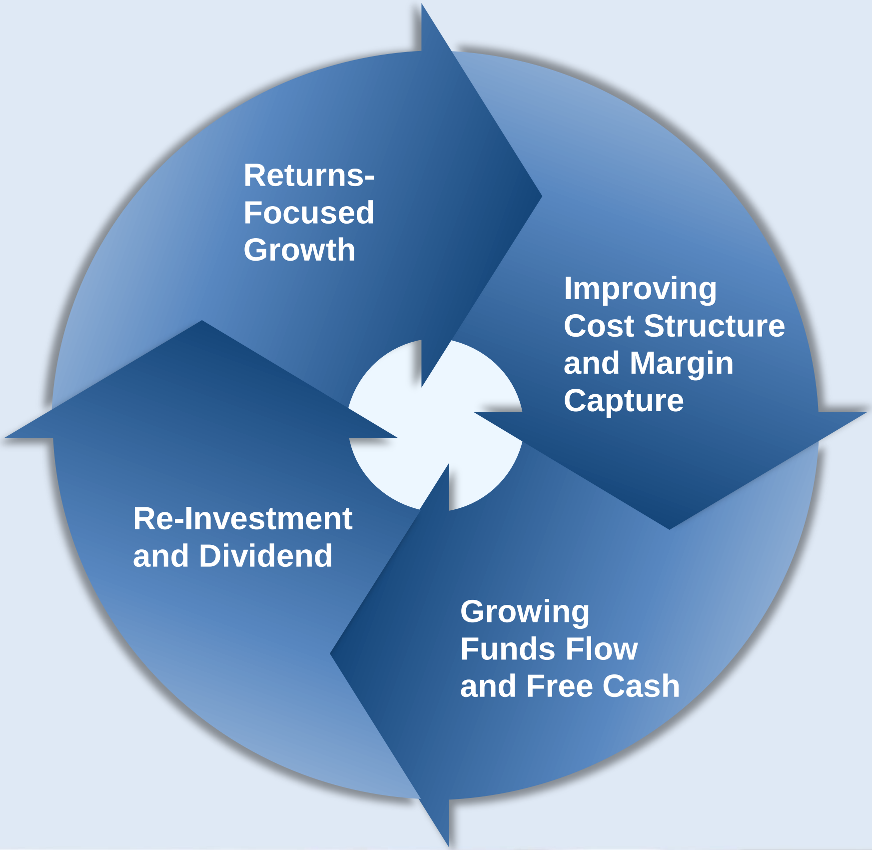
<2x
Net Debt / FFO

$2.1B
Sustaining Capital

$1.0B
Discretionary

Financial Framework Summary

- ’17-’21 Funds from operations CAGR of 9%
- ’17-’21 Free cash flow CAGR of 12%
- Invest in portfolio to generate returns and improve break-evens
    - Upstream op costs reduced by 17%
    - Upstream operating netback increased by 23%
    - Downstream margin improve by 12%
- Can cover growth spending program and generate free cash flow at $50 US WTI
- No need to increase net debt over plan



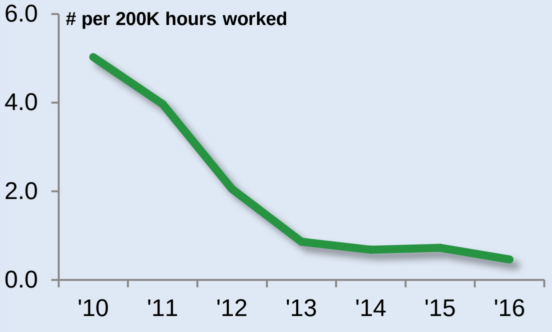
Husky Energy

Environmental
Social
Governance

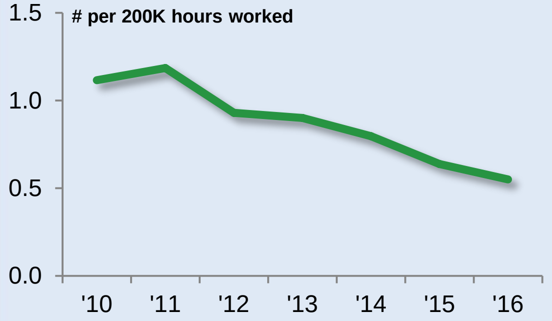
Strong Focus on Safety and ESG

Safety Performance

Critical & Serious Incidents



Total Recordable Incident Rate



ESG Performance and Ratings

JSI JANTZI SOCIAL INDEX

CDP DRIVING SUSTAINABLE ECONOMIES

SUSTAINALYTICS

Alberta Emerald Foundation

SHARE SHAREHOLDER ASSOCIATION for RESEARCH & EDUCATION

Results Disclosure

	Indicator	2015	2014	2013
Safety	Total Recordable Injury Rate *(recordable injuries per 200,000 exposure hours)*	**0.64**	0.80	0.90
	Lost-time Injury Frequency *(number of lost-time injuries per 200,000 exposure hours)*	**0.14**	0.14	0.14
	Fatalities	**0**	0	1
Environment	Total Energy Use *(gigajoules)*	**162,790,000**	133,590,000	128,200,000
	Scope 1 GHG Emissions[4] *(tonnes of CO_2e)*	**11,900,000**	11,260,000	11,270,000
	Scope 2 GHG Emissions *(tonnes of CO_2e)*	**2,430,000**	2,300,000	2,450,000
	Sulphur Dioxide (SO_2) Emissions[5] *(tonnes)*	**8,611**	7,795	6,197
	Nitrogen Oxides (NO_x expressed as NO_2) Emissions[5] *(tonnes)*	**9,546**	9,024	NPR[7]
	Volatile Organic Compounds (VOC) Emissions[5] *(tonnes)*	**3,703**	2,351	NPR[7]
	Fresh Water Withdrawal[6] *(million cubic metres)*	**24.2**	23.3	22.1
	Number of Spills	**291**	327	336
	Volume of Spills – Hydrocarbons *(cubic metres)*	**469**	644	624
	Volume of Hydrocarbons Recovered[8] *(percentage)*	**80**	NPR[7]	NPR[7]
	Volume of Spills – Other *(produced/process water, refined products, other) (cubic metres)*	**1,656**	1,634	5,161
People	Number of Employees *(permanent)*	**5,552**	5,774	5,479
	Employee Turnover *(percentage, voluntary and retirements)*	**4.0**	6.8	5.5
	Senior Executive Diversity *(percentage of women, Canada)*	**12.5**	17.65	13.3
Community	Community Contributions *($ millions)*	**3.0**	5.0	4.5
Governance	Independent Board Members *(percent)*	**60**	60	60
	Independent Audit Committee Members *(percent)*	**100**	100	100
	Board Diversity *(percentage of women)*	**13.3**	13.3	13.3

All data as of December 31, 2015, unless otherwise stated

- Rigorous emissions controls in all operations
- Leading developments of carbon capture and injection technology
- Supplying low CO_2 intensity natural gas for power generation in Asia, displacing coal

Integrated Corridor

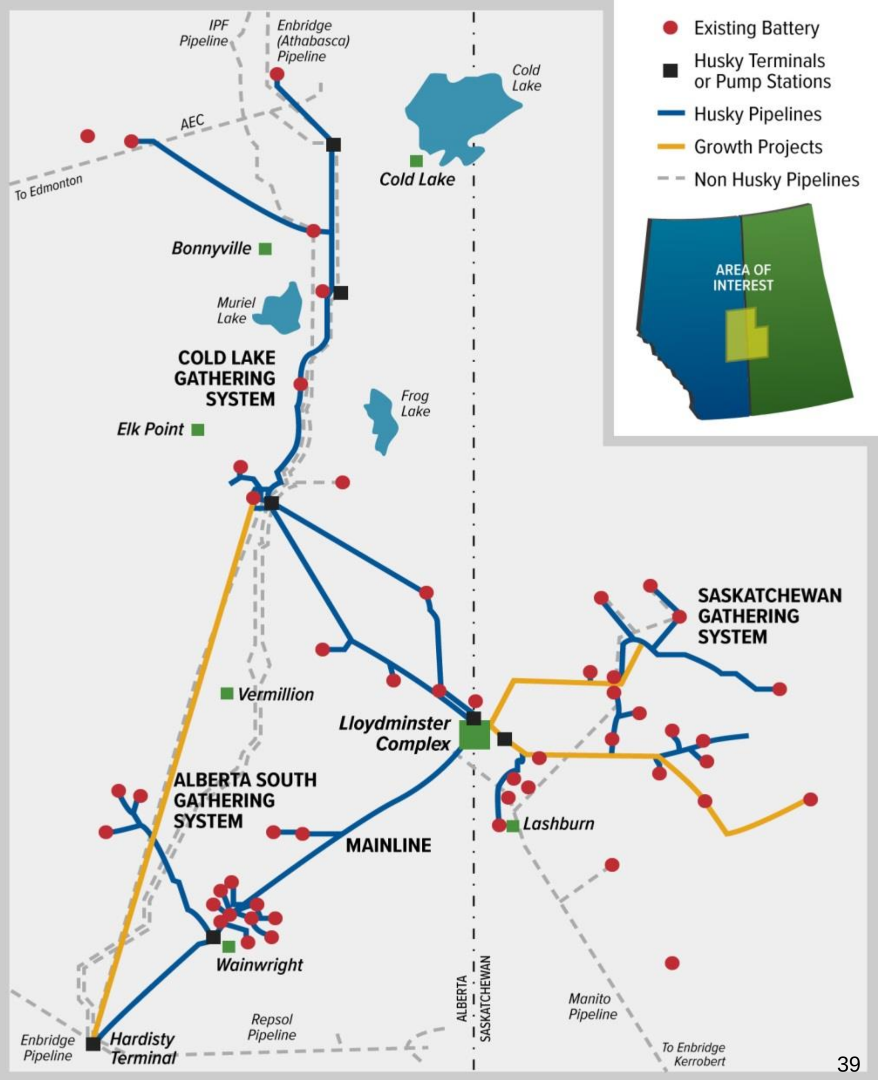
Rob Symonds
Chief Operating Officer

Midstream Momentum

A Growing Business

Husky Midstream Limited Partnership

- 35% working interest and operatorship
  - 1,900 kilometres of pipeline
    - Four gathering systems, one mainline
  - 4.1 million barrels storage capacity
- Secured funding and takeaway capacity for eight additional Lloyd thermal projects
  - Completing three new gathering systems:
    - South Saskatchewan
    - LLB Direct
    - North Saskatchewan
- Expanding third-party transportation business



Unique, Physically-Integrated Assets

Five-Year Forecast ('17- '21)

- Production CAGR of 5.0%
- Funds from operations CAGR of 11%
- Free cash flow CAGR of 9%

Upstream Production (Q1 '17)

- 259 mboe/day (121 mbbls/day thermal bitumen)

Downstream Heavy Oil Processing Capacity

- 160 mbbls/day

Finished Products (Q1 '17)

- 54 mbbls/day of sweet synthetic oil
- 15 mbbls/day of asphalt
- 101 mbbls/day of diesel and distillates
- 135 mbbls/day gasoline

Future Development (YE '16)

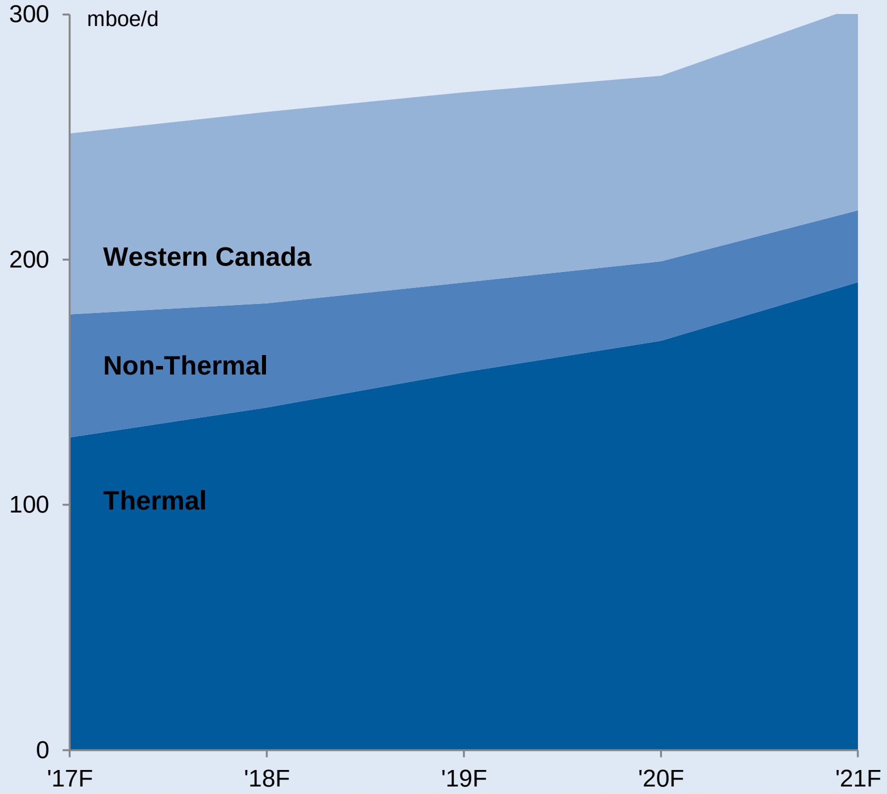
- 2.4 billion boe of proved and probable reserves
- 450+ resource play potential drilling opportunities

Opportunities Along the Corridor

Integrated Thermal Corridor Projects

Thermal Business	Net Peak Production (mboe/d)	Project Capital To First Production ($MM)	After-Tax IRR[1]
Rush Lake 2	14	350	25%
Dee Valley	12	350	21%
Spruce Lake North	13	350	19%
Spruce Lake Central	13	350	19%
8 X 10,000 bbls/d Lloyd thermal	80 capacity	2,800	~20%
6 X 5,000 bbls/d Lloyd thermal	30 capacity	1,500	~18%
Typical Lloyd sustaining pad	3	20	>30%
Typical Sunrise sustaining pad	4	40	>30%
Sunrise de-bottleneck 1	3	30	>30%
Sunrise de-bottleneck 2	6	140	>30%
Future Sunrise phases		Work Ongoing	
Gas Resource Plays	**Production ’21F (mboe/d)**	**Project Capex ($MM)**	**Full Cycle After-Tax IRR[1]**
Wilrich program	44	5/well	20%
Downstream	**Net Heavy Throughput (mbbls/d)**	**Remaining Project Capex First Production ($MM)**	**Full Cycle After-Tax IRR[1]**
Lima Crude Oil Flexibility Project	30	215 USD	16%
Asphalt expansion	30	Final Investment Decision Expected 2018	

Integrated Corridor Upstream Production Profile



1 see *Slide Notes* and *Advisories*

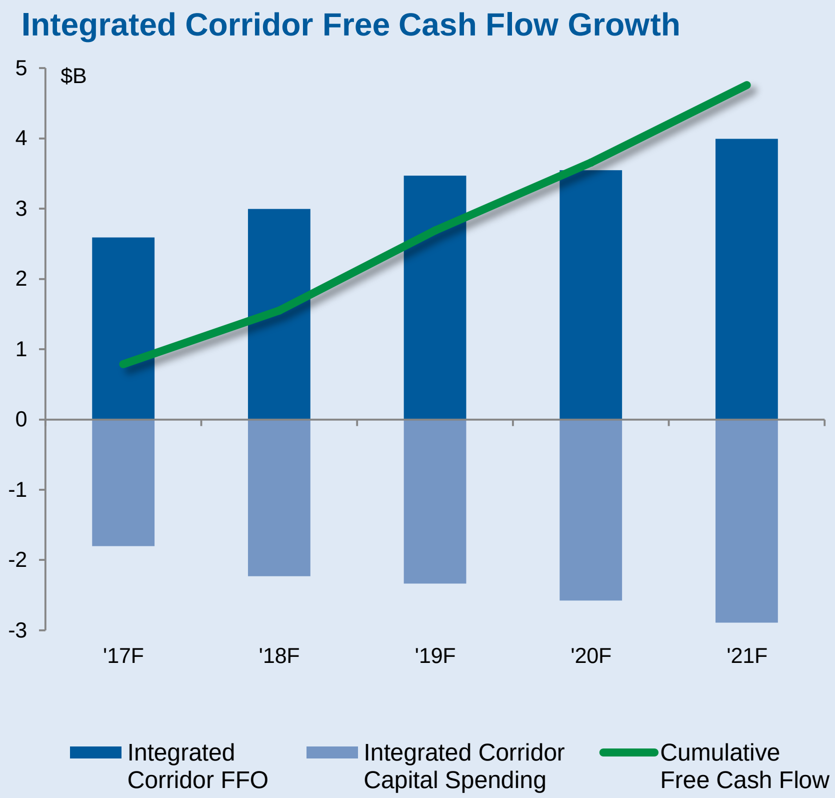
Cash Profile and Value Drivers

Next Five Years

- $16.5 billion FFO
- $12 billion capital spending
    - $0.5 billion/year average in Downstream
    - $1.0 billion/year average in Upstream
    - $0.9 billion/year average growth capital
- ~$4.5 billion free cash flow

Drivers of FFO Growth

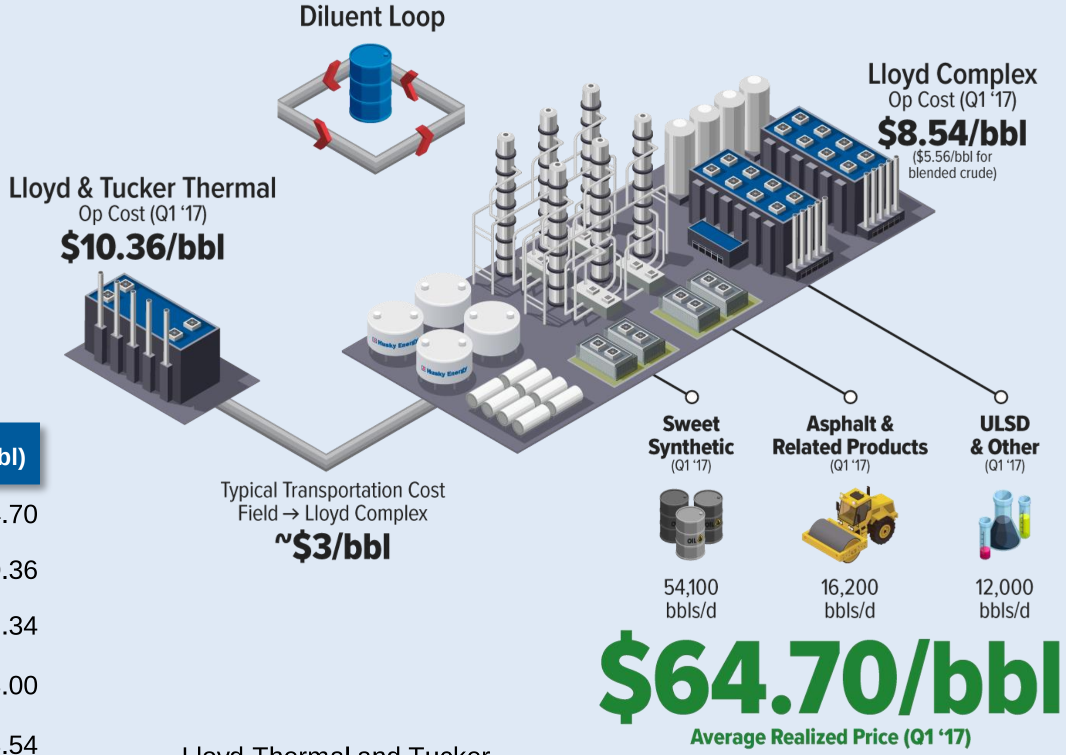
- Thermal production replacing non-thermal declines
- Increased heavy oil processing capacity
- Resource plays replacing conventional production declines and divestments



The Lloyd Advantage

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

Lloyd Value Chain Operating Netback Calculation (per bbl)	
Lloyd complex avg. realized price (Q1 '17)	$64.70
Lloyd Thermal and Tucker op costs (Q1 '17)	$10.36
Royalties (Q1 ’17)	$2.34
Typical transportation costs	~$3.00
Lloyd complex avg. processing op cost (Q1 '17)	$8.54
Est. Lloyd Value Chain Operating Netback (Q1 ’17)	**$40.46**



Lloyd Thermal and Tucker
Upstream Operating Netback (Q1 ’17)
$24.59

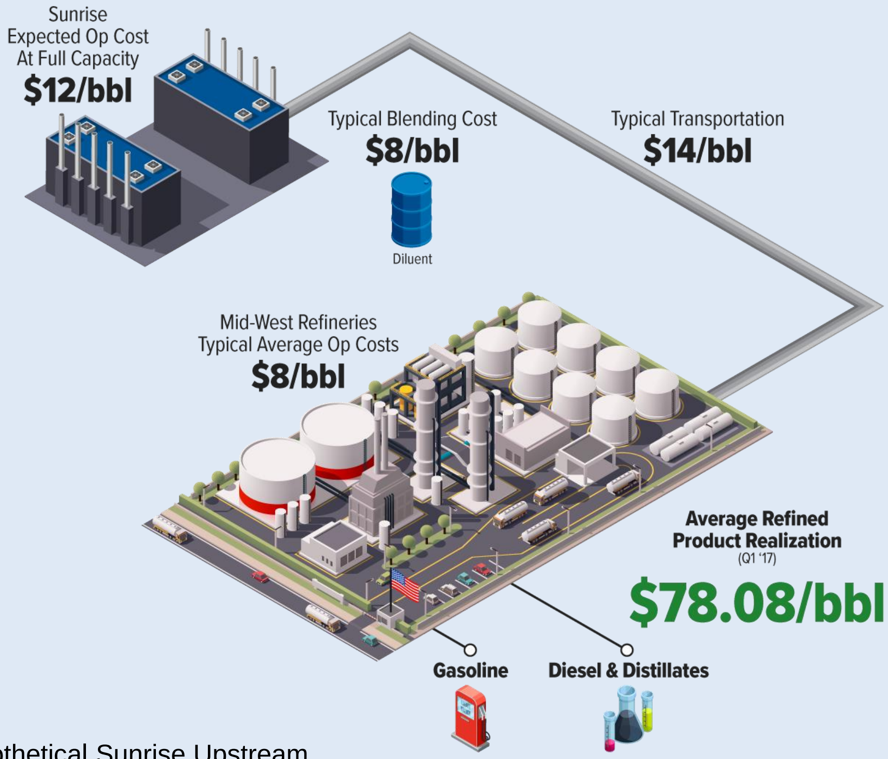
1,2 see *Slide Notes* and *Advisories*

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 (~104% in Q1 '17) [1,2]

Sunrise Value Chain Operating Netback Calculation (per bbl)	
Toledo realized product price (Q1 '17)	$78.08
Expected Sunrise op costs (at full capacity)	~$12.00
Royalties	$0.50
Typical blending cost	~$8.00
Typical transportation cost	~$14.00
Typical Midwest refining cost	~$8.00
Hypothetical Sunrise Value Chain Operating Netback (Sunrise plant capacity of 60,000 bbls/day)	**$35.58**



Hypothetical Sunrise Upstream Operating Netback (full capacity)
~$10.50

Strengthening the Corridor

Heavy Oil & Bitumen Production (boe/day)	Q1 '17	2021F
Lloyd thermal	80,400	125,000
Tucker	22,300	30,000
Sunrise	17,900	37,000
Non-thermal (heavy oil)	52,600	29,000
Total	**173,200**	**221,000**
Thermal bitumen as % of total	**70%**	**87%**

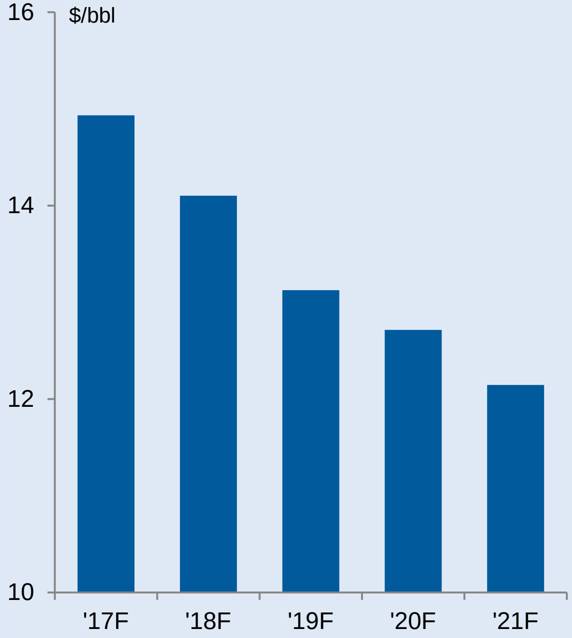
Western Canada Production (boe/day)	Q1 '17	2021F
Resource plays	30,000	50,000
Other W. Canada production	56,200	30,000
Total	**86,200**	**80,000**
Resource plays as % of total	**35%**	**63%**

Downstream Throughput Capacity (bbls/day)	Q1 '17	2021F
Heavy oil processing capacity	160,000	220,000
Light oil processing capacity	190,000	160,000
Total upgrading and refining capacity	**350,000**	**380,000**
Heavy capacity as % of total	**46%**	**58%**

Driving Down Costs and Improving Margins

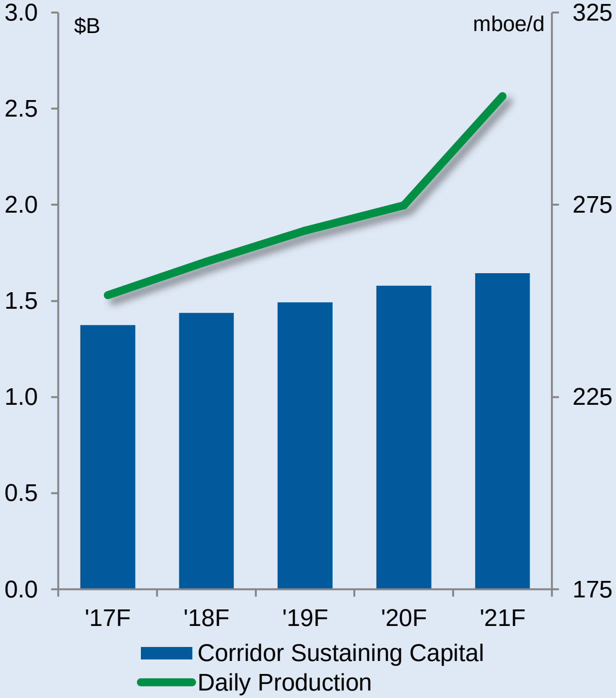
Upstream Corridor Operating Costs
’17 - ’21F

↓19%



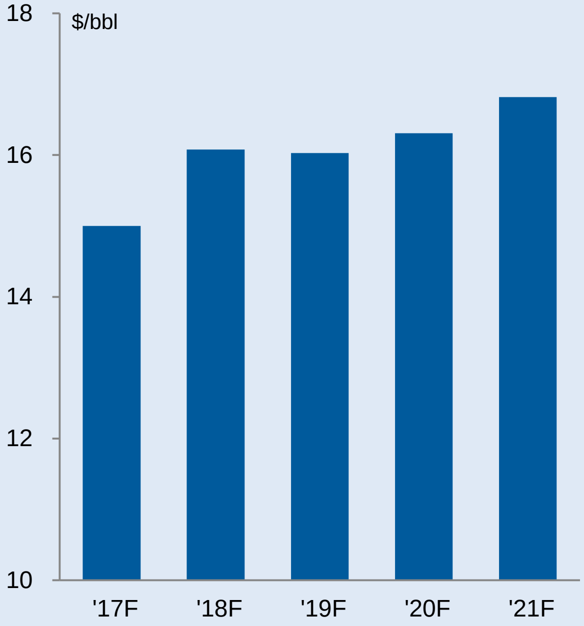
Average Upstream Corridor Sustaining Capital
’17 - ’21F

~$10
Per Boe



Downstream Margins
’17 - ’21F

↑12%



Integrated Corridor

Five-Year Forecast ('17- '21)

- Production CAGR of 5.0%
- FFO CAGR of 11%
- FCF CAGR of 9%

Upstream Production (Q1 '17)

- 259 mboe/day (121 mbbls/day thermal bitumen)

Downstream Heavy Oil Processing Capacity

- 160 mbbls/day

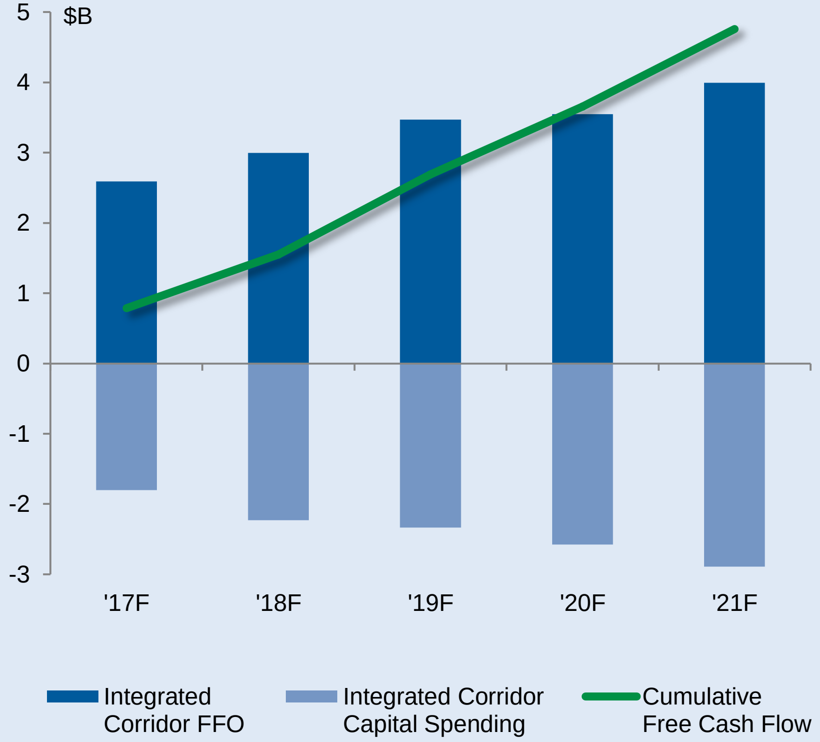
Finished Products (Q1 '17)

- 54 mbbls/day of sweet synthetic oil
- 15 mbbls/day of asphalt
- 101 mbbls/day of diesel and distillates
- 135 mbbls/day gasoline

Future Development (YE '16)

- 2.4 billion barrels of proven and probable reserves
- 450+ resource play potential drilling opportunities

Integrated Corridor Free Cash Flow Growth



Integrated Corridor
Thermal

Andrew Dahlin
SVP, Heavy Oil

Thermal Growth

- Current thermal bitumen production of 121,000 bbls/day
- 50% thermal bitumen production growth over plan
- Increasing margins driving free cash flow
- Modular, scalable designs
    - Low sustaining capital requirements
    - Long life, low operating costs
- Physically integrated assets
    - Lloyd and Tucker → Lloyd Complex → Lima
    - Sunrise → Toledo
- Technology application unlocking value, with more on the horizon

Thermal Growth

Sustained Low Cost Production

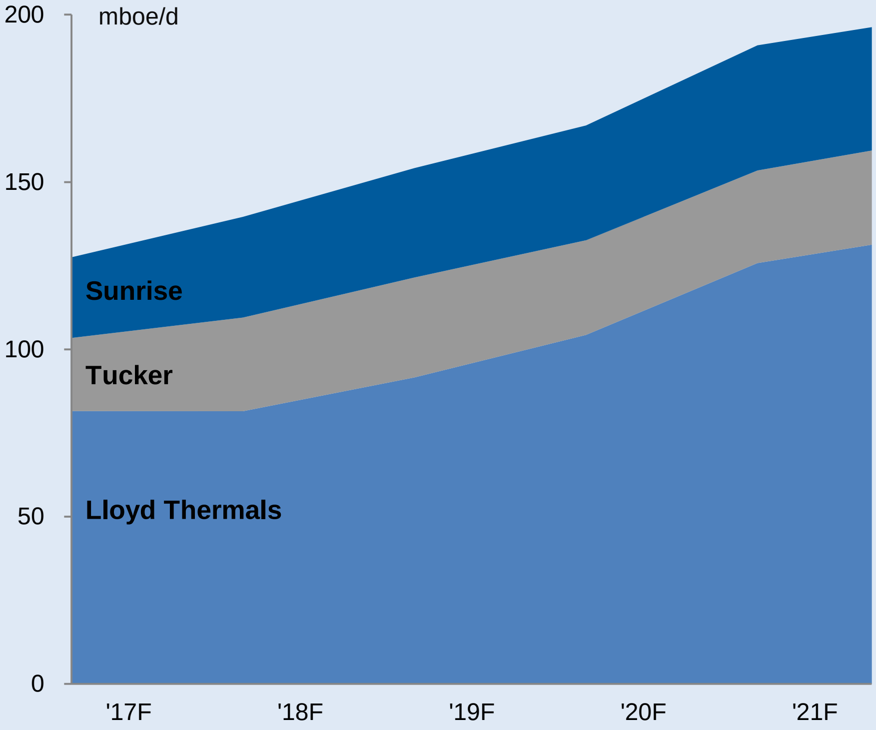
Integrated Corridor Thermal Projects

Thermal Business	Net Peak Production (mboe/d)	Project Capex First Production ($MM)	After-Tax IRR[1]
Rush Lake 2	14	350	25%
Dee Valley	12	350	21%
Spruce Lake North	13	350	19%
Spruce Lake Central	13	350	19%
8 X 10,000 bbls/d Lloyd thermal	80 capacity	2,800	~20%
6 X 5,000 bbls/d Lloyd thermal	30 capacity	1,500	~18%
Typical Lloyd sustaining pad	3	20	>30%
Typical Sunrise sustaining pad	4	40	>30%
Sunrise de-bottleneck 1	3	30	>30%
Sunrise de-bottleneck 2	6	140	>30%
Future Sunrise phases		Work Ongoing	

Thermal Bitumen Production Growth Over Five Years **50%**

Thermal Production CAGR **10%**

Thermal Bitumen Production Growth Profile

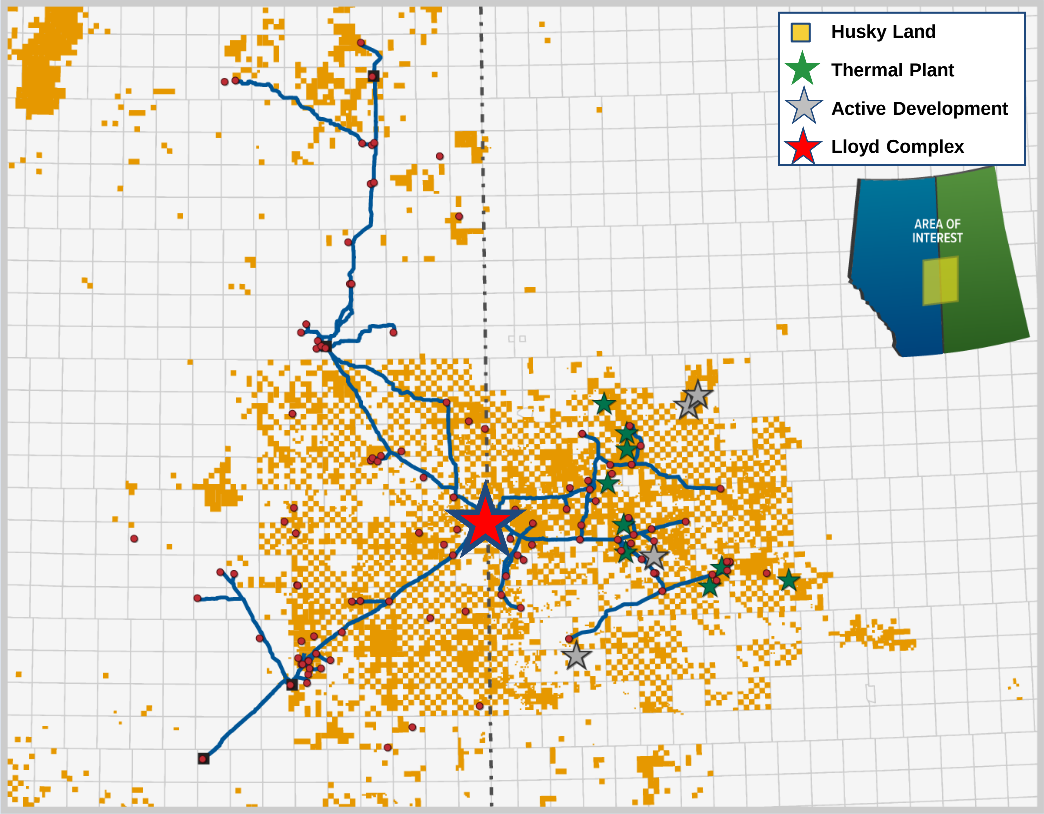


1 see *Slide Notes* and *Advisories*

Lloydminster Block

Unmatched Land and Infrastructure Position

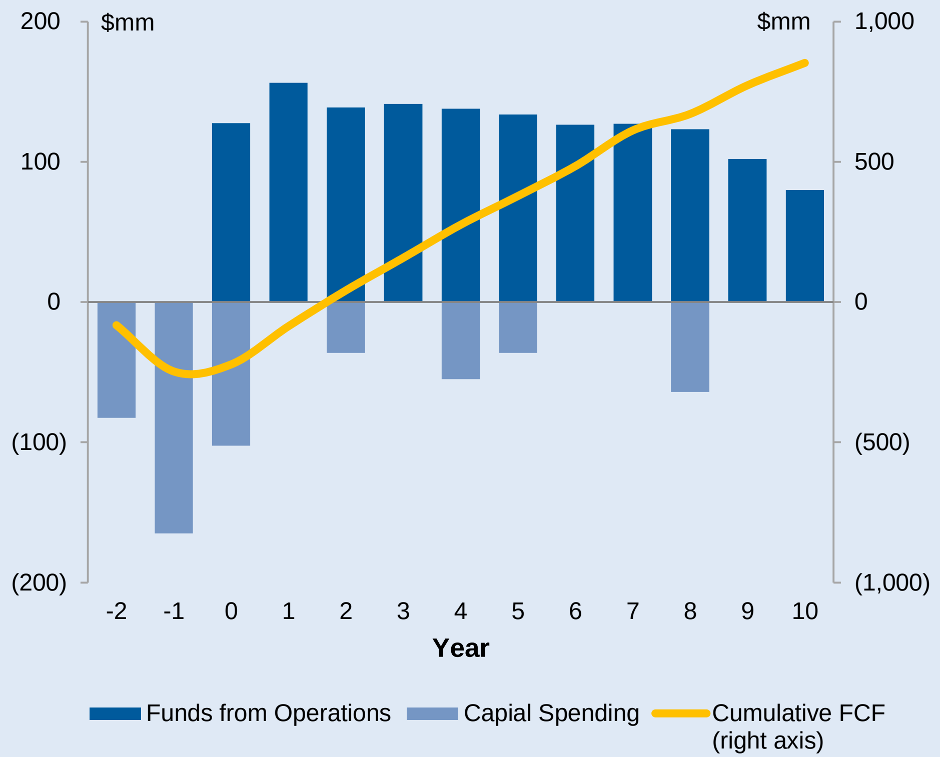
- 2.2 million net acres
- Combination of fee-simple and Crown lands enhance economics
- Detailed understanding of subsurface
  - 3D and 2D seismic over entire block
  - 65,000+ well logs analyzed
- Operatorship of 1,900 kilometres of gathering systems and pipelines
- Physical integration



Typical Lloyd Thermal Economics[1]

10,000 bbls/day Nameplate Project

Project Characteristics	
Peak production over nameplate	25-35%
Build costs ($Million)[2]	$350
Operating cost ($/bbl)[3]	$7-8
Royalty rate	7%
Crude quality	10^o-12^o
Differential to WCS ($/bbl)	~$4-5
Sustaining cost ($/bbl)	$5-7
Project life	>20 years
Reserve recoveries	>50%
Steam-Oil Ratio (first five years)	2.0 – 2.4
Steam-Oil Ratio (design capacity)	3.0
After-tax IRR[4]	~20%

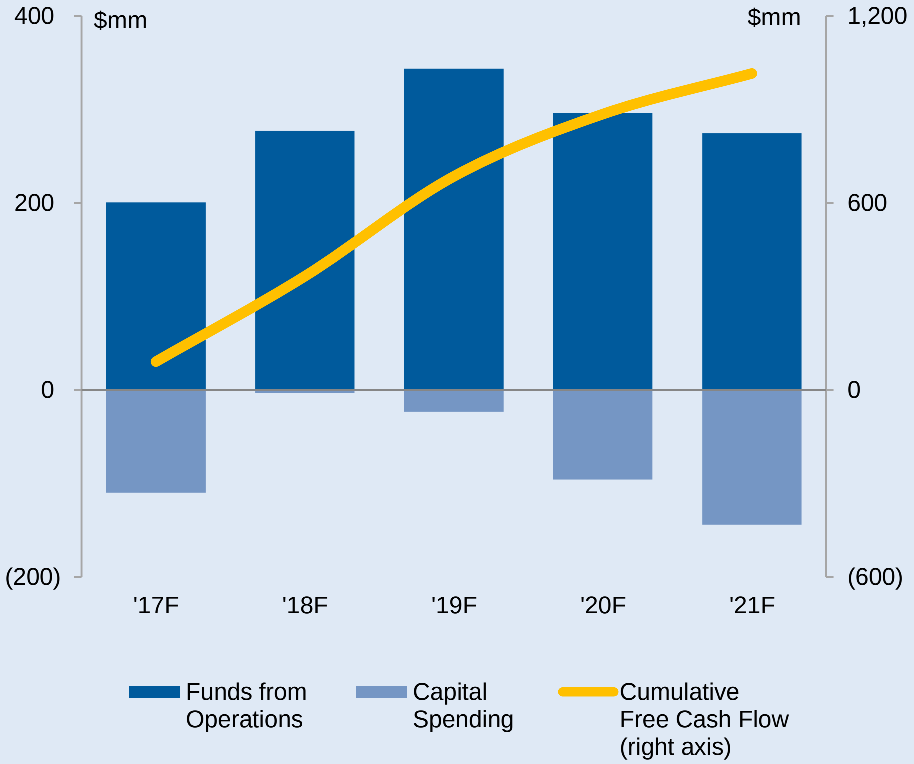


1,2,3,4 see *Slide Notes* and *Advisories*

Tucker Growth

Next Five Years

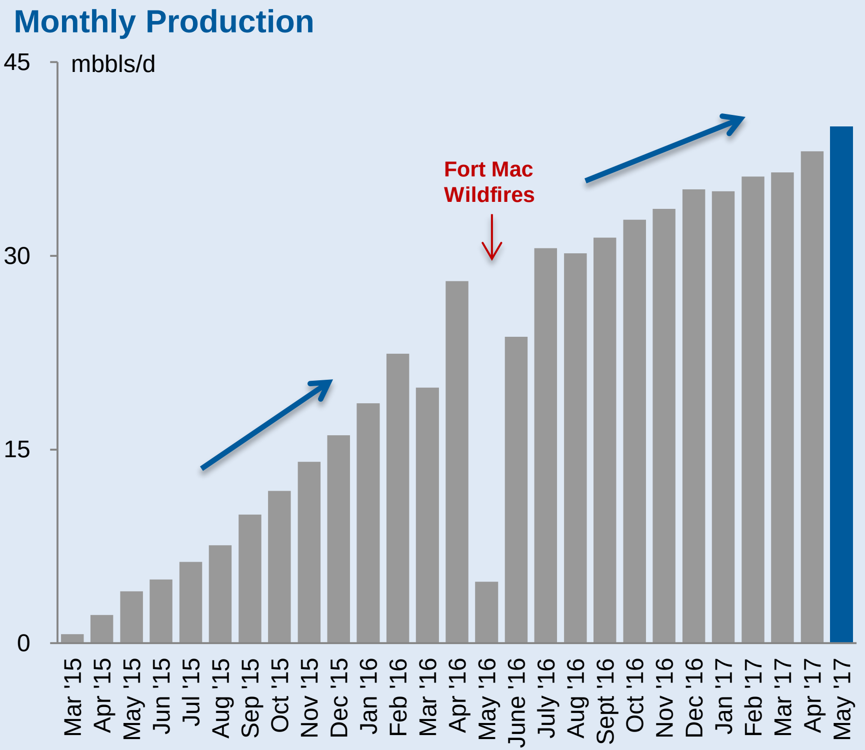
- Reaching capacity of 30,000 bbls/day in ’18
  - Op costs <$10 per barrel
  - Decades of productive life
- $1.3 billion in FFO over the plan
- $0.3 billion in capital spending
- $1.0 billion in free cash flow



Sunrise

Steady Ramp-up

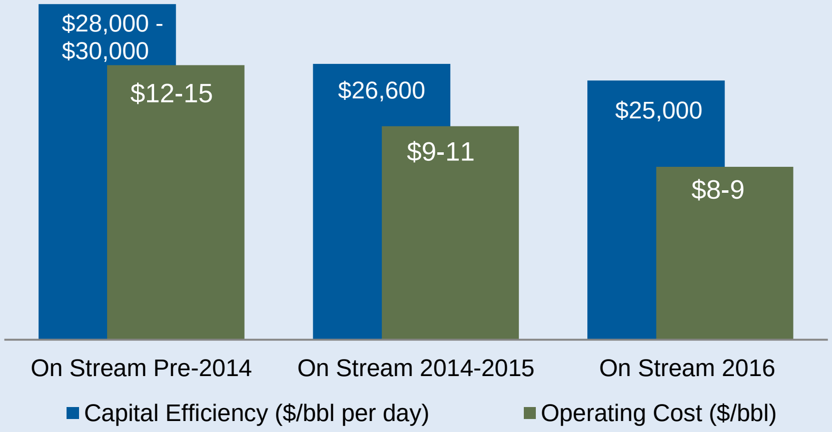
- Gross thermal bitumen production currently at 40,000 bbls/day
  - Production from original 55 well pairs averaging 725 /bbls/day, expected to achieve 800-900 bbls/day
  - Expected to reach 60,000 bbls/day in ’18
  - Target opex of $12 per barrel at full capacity
- Tie-in of additional 14 well pairs expected to be on production around end of ’17
  - Accelerated, not additional capital
  - Forecast EUR remains unchanged at 2.2 mmbbls per well pair



Structural Cost Savings

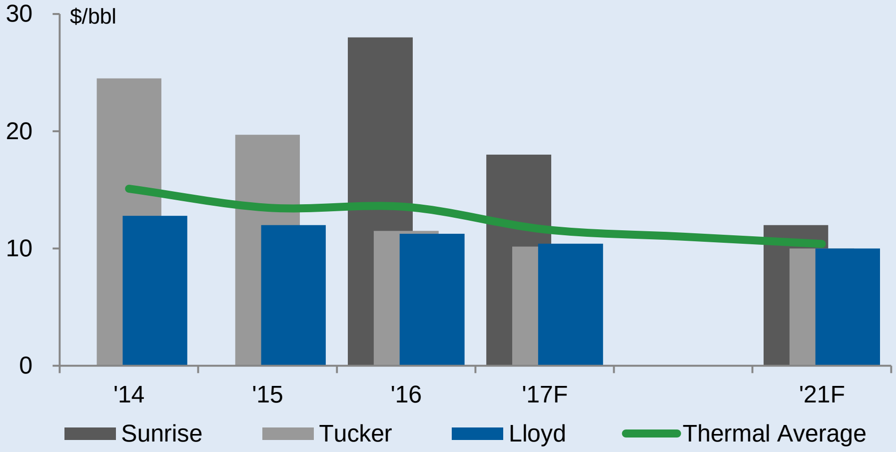
Capital Efficiency Improvements Driving Profitability

Lloyd Thermal Cost Improvements



- Streamlined construction of facilities leads to substantial cost savings
  - Repeatable, modular copy-and-paste approach
  - Sequential build allows for efficiencies

Thermal Operating Costs



- Higher production rates drive down costs
- Improving SOR profile over entire portfolio
  - Thermal average SOR of 2.8
  - New thermals coming on at 2.0-2.4 SOR
- Skilled local resident workforce at Lloydminster

Improving Capital Efficiency

Reducing Pad Footprint and Costs

Total costs reduced 40%

- Lowered well pad costs
- Reduced overall environmental footprint:
  - 49% smaller surface area
  - 30% reduced drilling time
  - Inline metering instead of separators
- Flanged modules eliminate site welding

Total Pad Size ↓ **49%**

Thermal Business Free Cash Flow

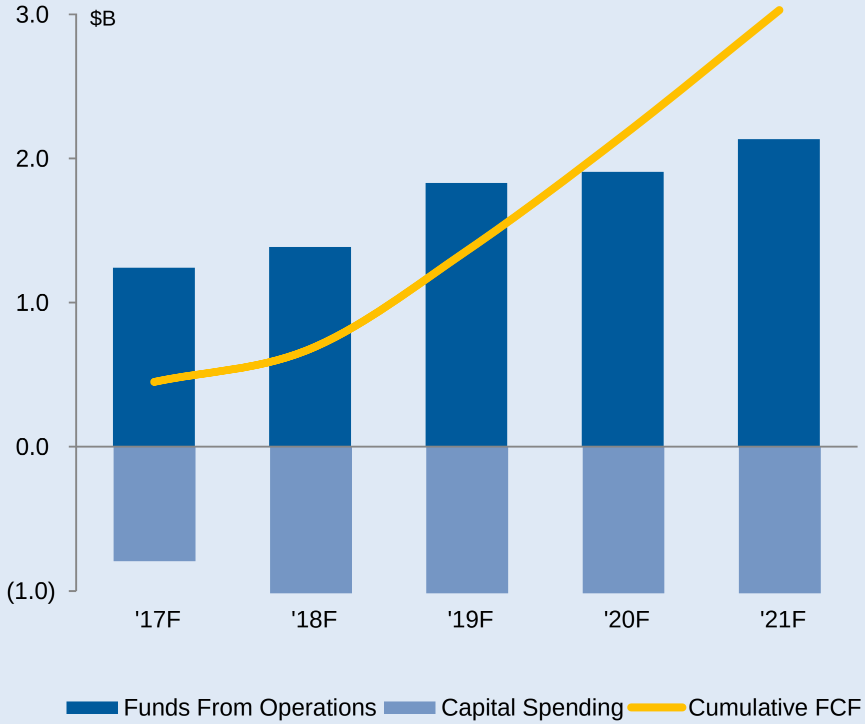
Next Five Years

- Annual FFO increases from $1.2 billion in ’17 to $2.1 billion in ’21
- $5.5 billion in capital spending over five years
    - Average $0.4 billion growth capital per year
    - $0.6 billion to $0.8 billion per year sustaining capital
- Cumulative FCF of ~$3 billion

Drivers of FFO Growth

- High-return thermal bitumen growth replacing legacy production
- Long life, low sustaining capital production

Thermal Business Free Cash Flow Growth



Heavy Oil/Thermal Technology

- Increases production and oil recovery
- Lowers cost
- Reduces environmental footprint

Technology	Cost Improvement	Improved Oil Recovery	Environmental Performance Improvement	Readiness
Diluent Reduction	✓	—	✓	Medium-term (Pilot 2019)
Infill Wells	✓	✓	✓	Near-term
CO_2 Capture	CO_2 policy dependent	—	✓	Pilot stage
CO_2 Injection	CO_2 policy dependent	✓	✓	Pilot stage
Solvent Injection	✓	✓	✓	Near-term (Pilot 2018)
Water Technology Development Centre (Joint venture)	✓	—	✓	Medium-term (Construction of pilot facility 2018-2019)
Inflow Control Devices	✓	✓	✓	Near-term (Pilot next 12 months)
Non-Condensable Gas Injection	✓	✓	✓	Medium-term (Pilot 2019+)

Thermal Technology Application

Implemented, Piloting and Developing

Husky Diluent Reduction (HDR)

- Synthetic crude oil is heated and mixed with bitumen and reacted, resulting in a pipeline-ready stable crude blend
- Potential to reduce condensate diluent requirements by 50%
  - Frees up pipeline space
- Better quality than dilbit, so receives better pricing
- Technology still in early stages
- Assessing 500 bbls/day pilot project at Sunrise

Husky's Thermal Evolution in Lloyd

- Four decades of experience has maximized reservoir knowledge:
  - Reservoir strategies increasing recovery factor for heavy oil SAGD) while reducing operating expenses
  - Smaller pools of 5-10,000 bbls/day projects now economic
- Multiple smaller scale project allows for low-risk experimentation
- Large resource with the potential to be unlocked with future technology

CO_2 Capture and Injection (Cold EOR)

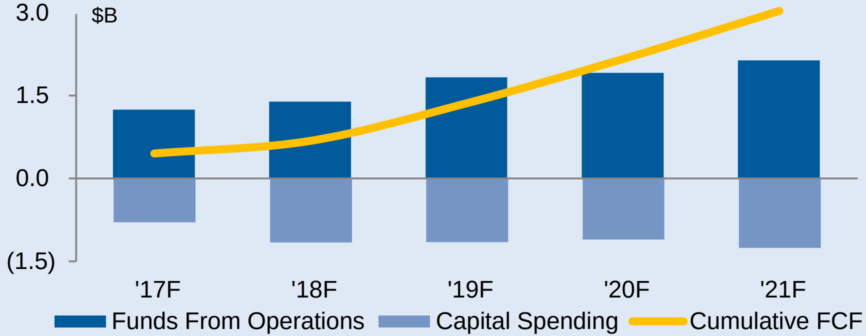
- Increases oil recovery to more than double to 20%+
- Potential to significantly reduce CO_2 capture costs from thermal plants
- Technology in development for 10+ years with government support
- Produced 2.7 million barrels to date
- Currently producing 2,000 barrels per day

Thermal Growth

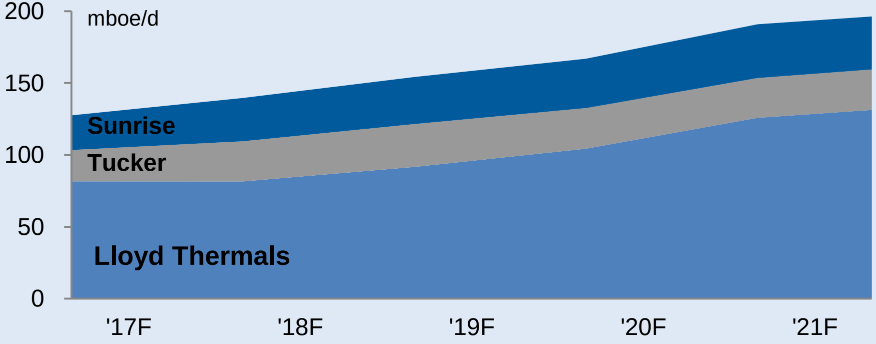
Deep Portfolio with Near and Long-Term Growth

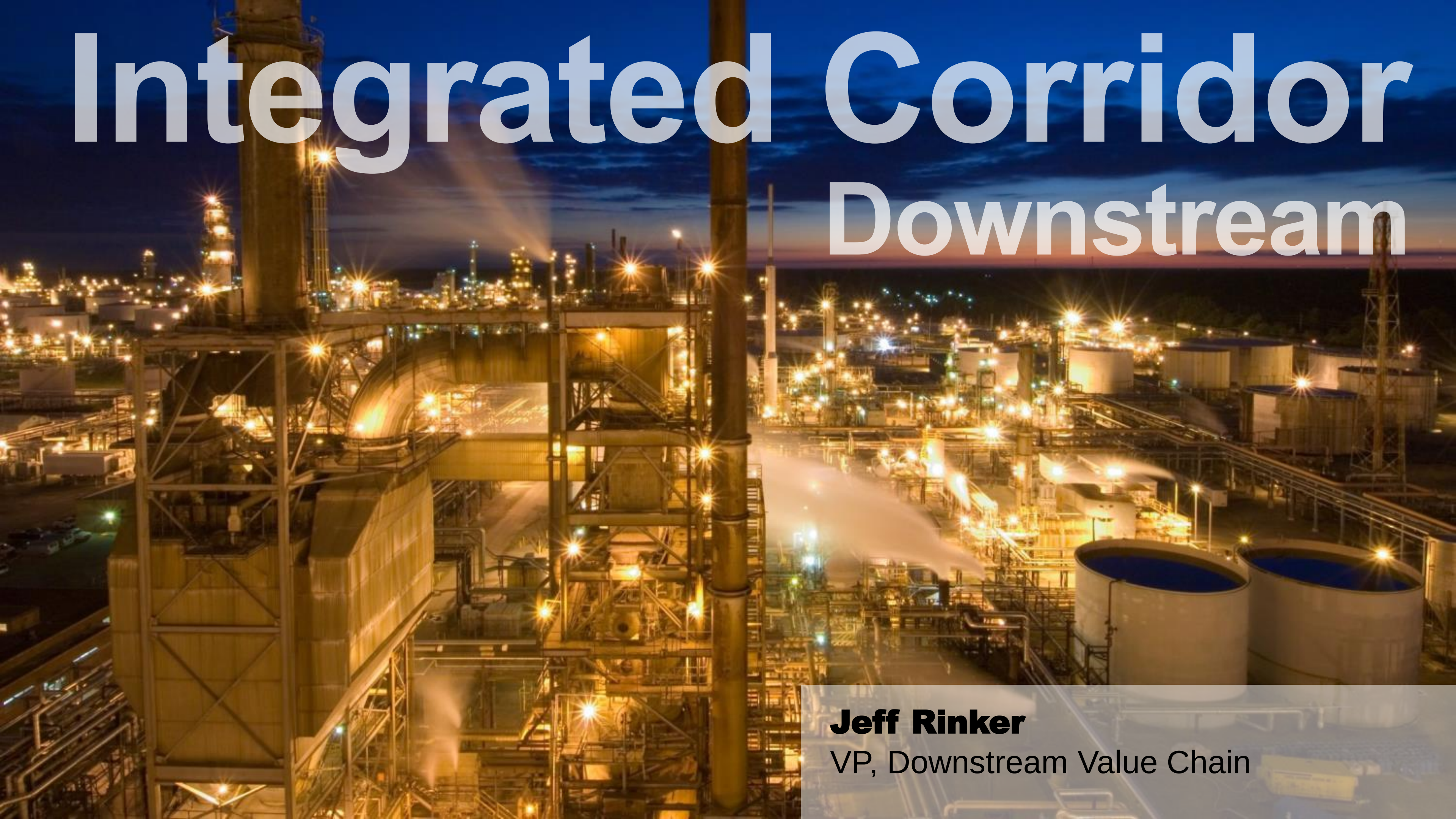
- Current thermal bitumen production of 121,000 bbls/day
- 50% thermal bitumen production growth over plan
- Increasing margins driving free cash flow
- Modular, scalable designs
  - Low sustaining capital requirements
  - Long life, low operating costs
- Physically integrated assets
  - Lloyd and Tucker → Lloyd Complex → Lima
  - Sunrise → Toledo
- Technology application unlocking value, with more on the horizon

Thermal Business Free Cash Flow Growth



Thermal Production Growth Profile





Integrated Corridor

Downstream

Jeff Rinker

VP, Downstream Value Chain

Downstream

Maximizing Value From Every Barrel of Production

- Physically integrated assets provide optionality
- Mitigation of light-heavy differential risk
- Total throughput capacity of 350,000 bbls/day, of which 160,000 bbls/day is available for heavy crude
- New investments increasing heavy oil processing capacity and reducing feedstock costs
- Additional margin capture “outside the fence-line”
- ~$3 billion cumulative FCF over the next five years

Downstream Assets

Lloyd Complex

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

Lloyd Upgrader

Capacity: 80 mbbls/d

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

Asphalt Refinery

Capacity: 30 mbbls/d

- Supplies ~4% of asphalt manufactured in North America
- Lloyd feedstock provides for premium quality
- Transportation by rail

U.S. Refining & Marketing

- 230,000 bbls/day processing capacity
- Product marketing footprint centered in Ohio

Lima Refinery

Capacity: 160 mbbls/d

- Light oil refinery
- Access to diverse crude supply

Toledo Refinery

Capacity: 70 mbbls/d[1]

- Configured to process high-TAN Sunrise crude
- Husky markets its products as well as secondary products on behalf of JV

Pipelines & Storage

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

Hardisty & Lloyd Storage Terminals

3.1 mmbbls at Hardisty
1.0 mmbbls at Lloyd

- Profitable blending business
- Increases flexibility in marketing crude

Gathering System

- Firm takeaway commitments
- Connections to several main pipelines ensure Husky crude can reach market

1 see *Slide Notes* and *Advisories*

Investments In Heavy Oil Capacity

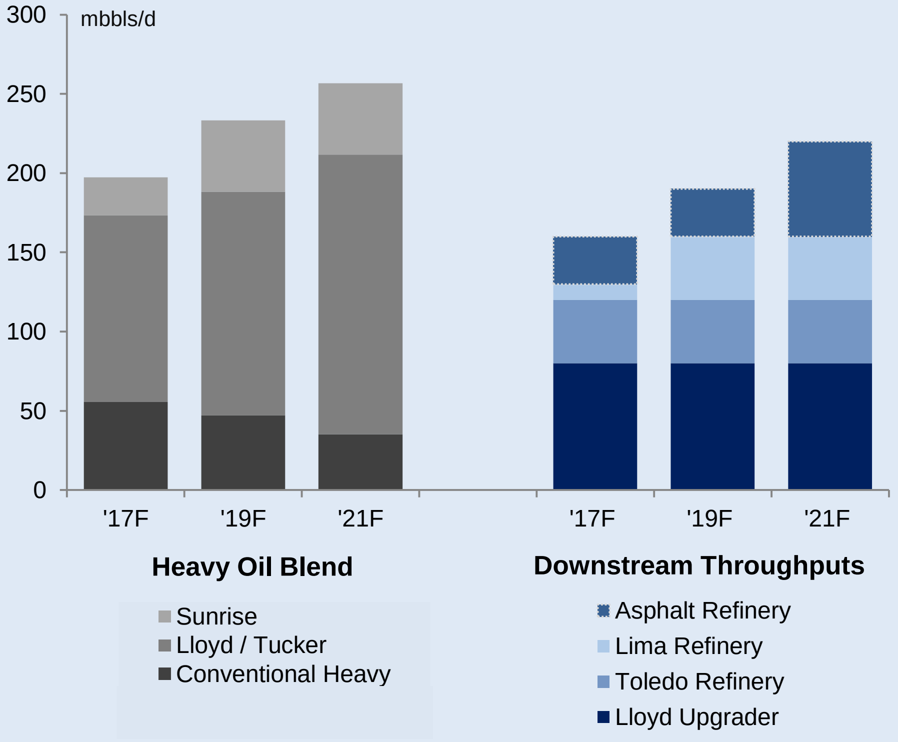
Growth in Processing Capacity Keeping Pace With Heavy Oil Production Growth

Project	Remaining Project Capital First Throughput ($MM)	Net Capacity	Full Cycle After-Tax IRR[1] Plan Pricing Assumptions
Crude Oil Flexibility Project	$215 US	40,000 bbls/day heavy capacity	16%
Asphalt Expansion (sanction pending)	FID ’18	30,000 bbls/day (throughput)	TBD

Heavy Oil & Bitumen Production Growth ’17-’21F **25%**

Heavy Crude Capacity Growth ’17-’21F **35%**

Bitumen and Heavy Oil Growth[2] **Heavy Oil Processing[3]**



1,2,3 see *Slide Notes* and *Advisories*

Brownfield Projects Deliver Solid Economics

Crude Oil Flexibility Project (Lima)

- Increases heavy processing capacity to 40,000 bbls/day by ’19
  - Total throughput remains at 160,000 bbls/day
- Capital costs: $215 million US (go forward)
- Increases feedstock flexibility
- Improves competitive position in PADD II

Asphalt Capacity Expansion

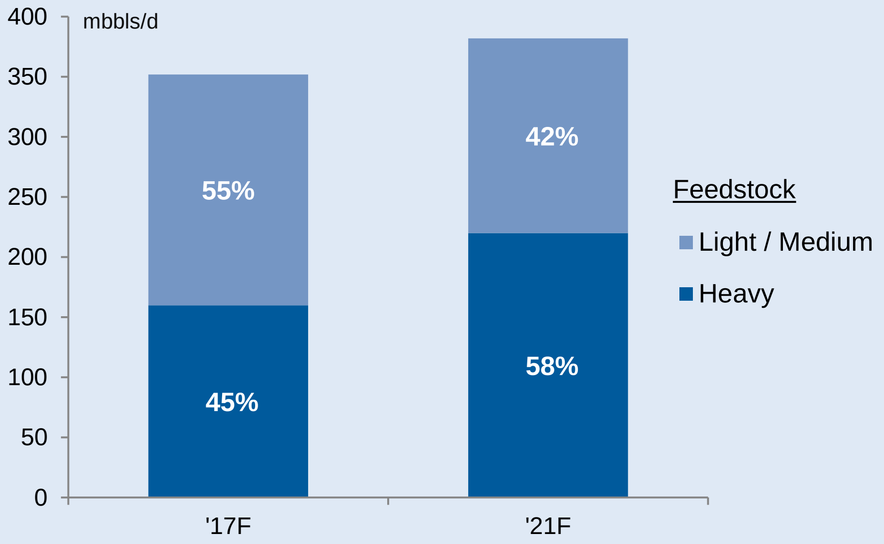
- Construction within the Lloyd Complex
- Expected capital cost of $700 - $900 million
- Throughput capacity: 30,000 bbls/day
- Final Investment Decision: ’18
- Commissioning stage: 1H ’20
- Full capacity: ’21
- Developing new markets in PADD V

Margin Economics

Improving Feedstock Options → Increased Margins

Heavier Feedstock Mix Margin Capture

- Heavy oil feedstock volume increase 35 percent
- ~$2 US per barrel lower feedstock costs



Increasing Margins and Free Cash Flow

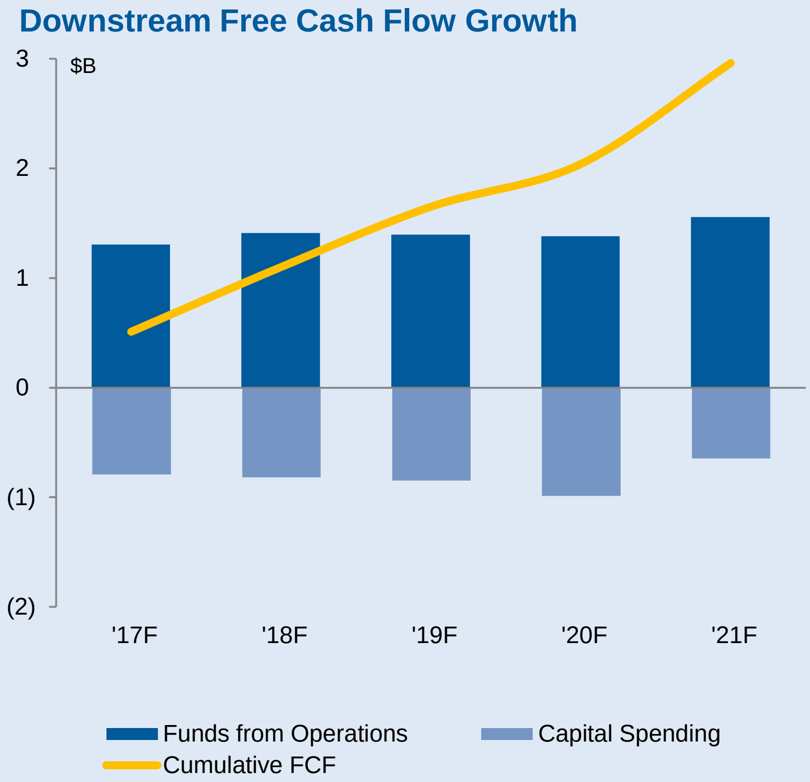
Focus on Feedstock Flexibility and Active Asset Management

Next Five Years

- $7 billion in FFO
- $4 billion in capital spending
- ~$3 billion in free cash flow

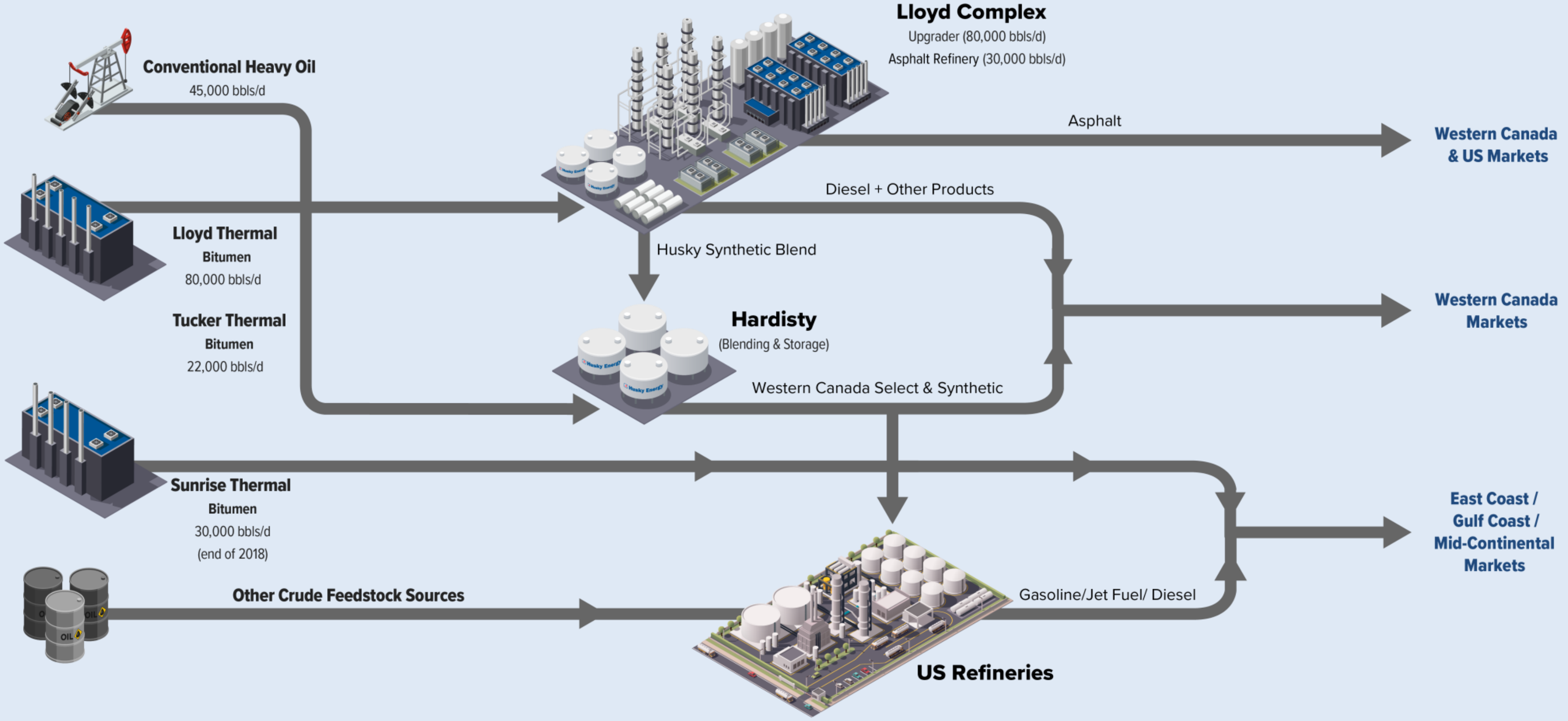
Drivers of Margin Growth

- Operational focus on utilization
- Increase heavy oil processing capacity
- Active asset management to capture optionality benefits



Downstream Connectivity

Reservoir to Refined Products



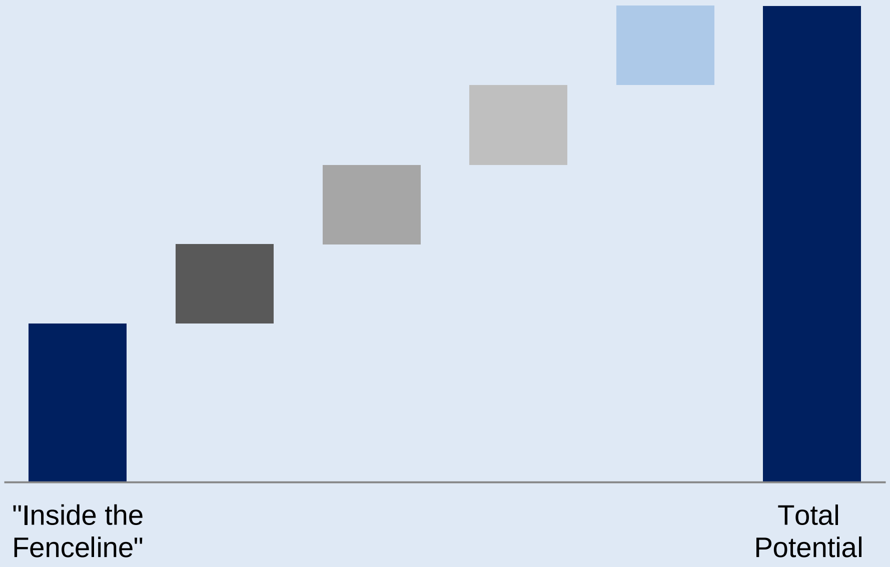
Margin Capture Outside the Fenceline

- Feedstock optionality
  - Crude selection
  - Customized feedstock quality
- Product optionality
  - Logistics flexibility between product markets
- Intermediate processing
  - Transfer of intermediate streams between refineries
  - Buy/sell of blending components
- Utilization of forward commodity markets
  - Trading the winter-summer gas storage spread
  - Pipeline location differentials
  - Refining and upgrading spreads

Potential Incremental Margin From Other Downstream Initiatives

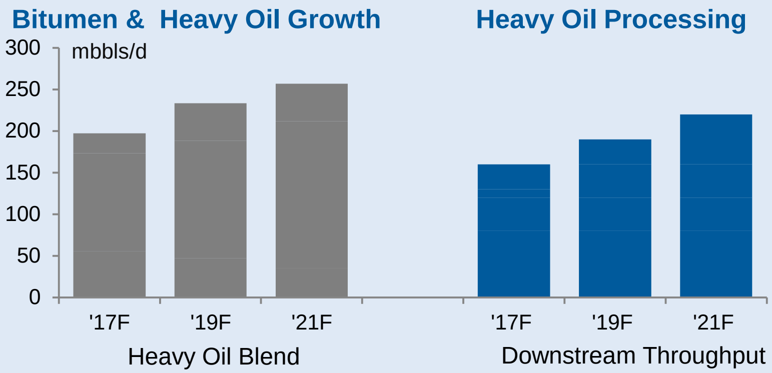
+$0.50-$1.00

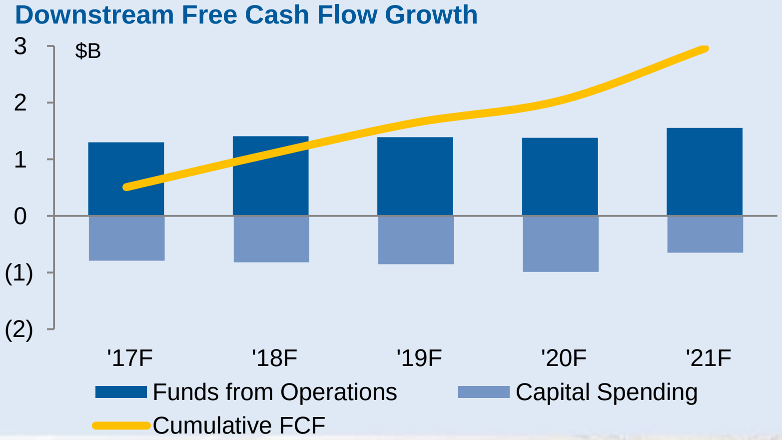
Per Barrel



Generating Value

- Physically integrated assets provide optionality
- Mitigation of light-heavy differential risk
- Total throughput capacity of 350,000 bbls/day, with 160,000 bbls/day available for heavy crude
- New investments increasing heavy oil processing capacity and reducing feedstock costs
- Additional margin capture “outside the fence-line”
- ~$3 billion cumulative FCF over the next five years





Integrated Corridor
Resource Plays

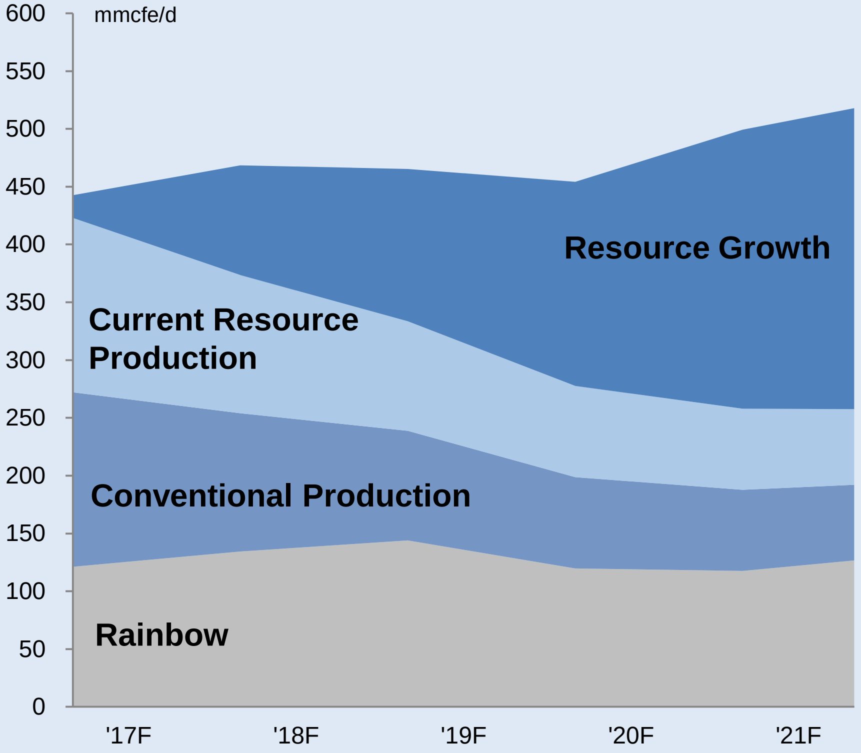
Gerald Alexander
SVP, Western Canada Production

Returning to Growth

Rejuvenated Asset Base

- Short-term investment cycle provides flexibility
- Land positions in right neighbourhood
- Running room with 450+ potential drilling opportunities (Wilrich)
- Emerging position in Montney
- Improving capital efficiencies
- Increasing type well recoveries
- Natural gas production provides internal hedge for thermal and refining energy needs

Production Growth Profile

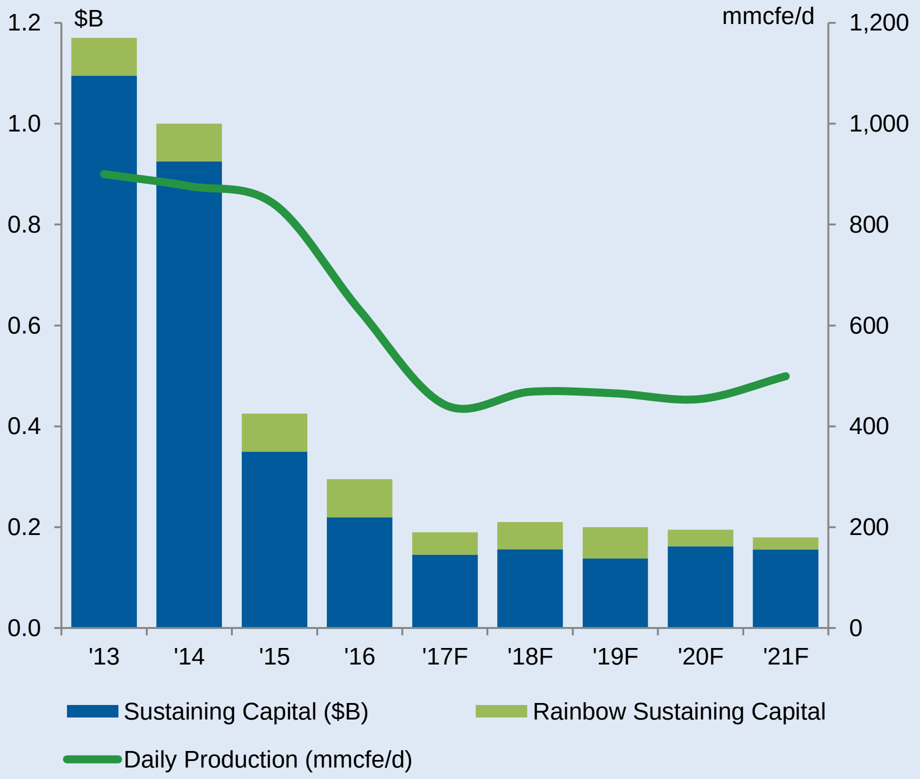


Reshaped Portfolio

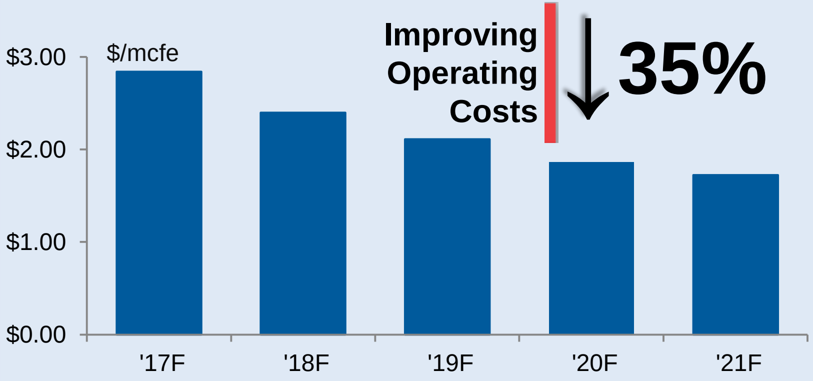
More Focused and Capital Efficient Business

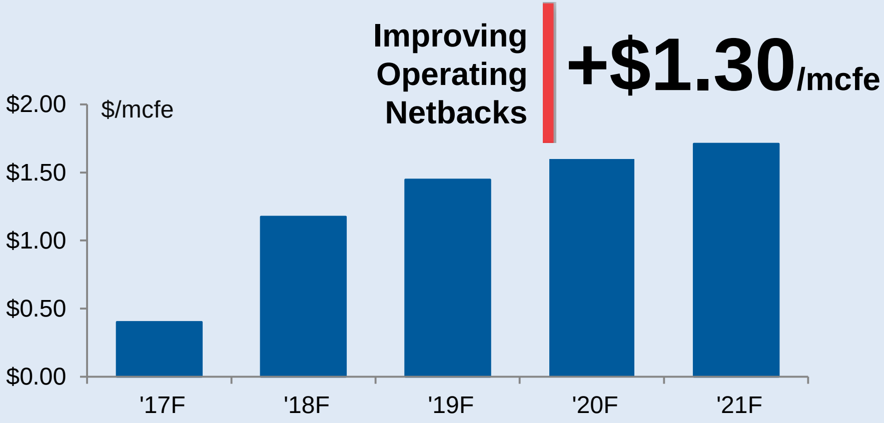
Western Canada Transformation	'15	Current	Change
Net wellbore count	18,200	~8,000	↓ **55%**
ARO provision - $ billions	$1.3	~$0.9	↓ **30%**
Unit operating cost - $/bbl (average per active well)	$16	<$12	↓ **25%**

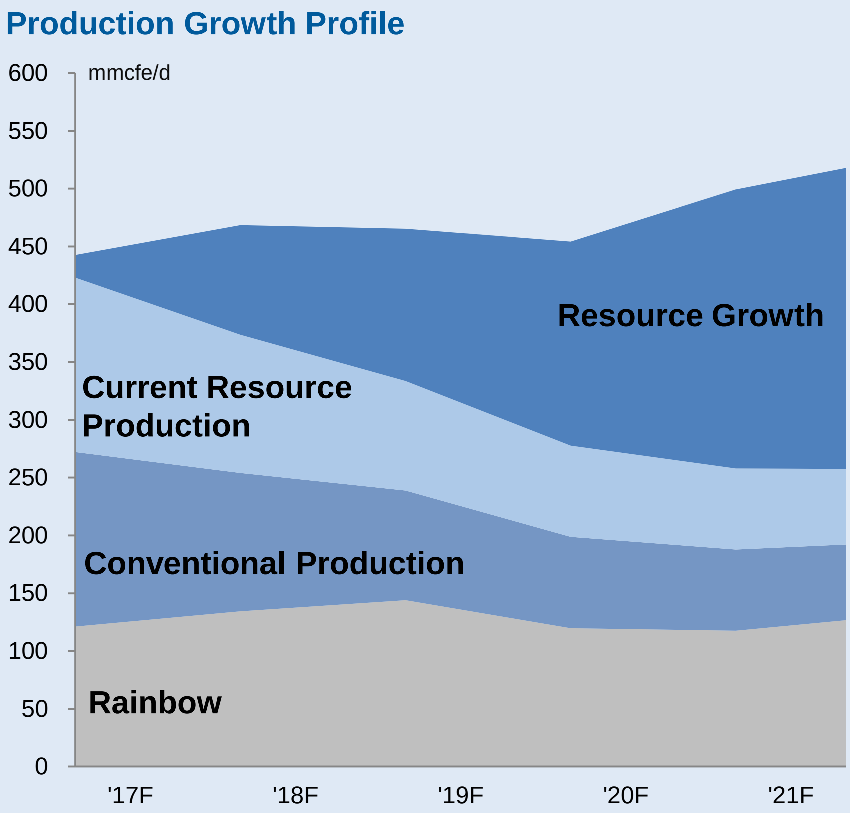
Annual Sustaining Capital Requirements



Low Cost Production Growth







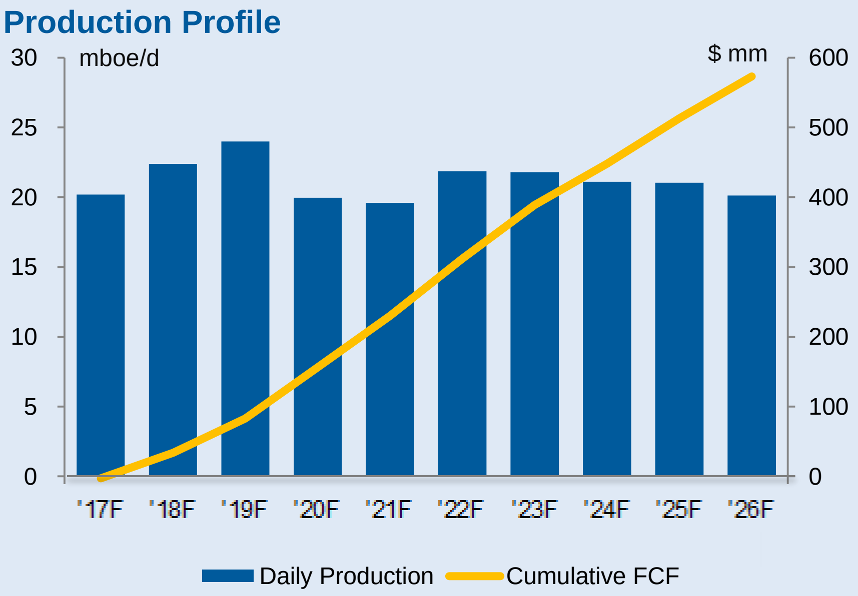
Rainbow Lake NGL

Low Sustaining Capital

- Legacy play to provide 15+ years of stable FFO and FCF
  - Minimal capital required
  - Operating costs to be reduced to $13/boe over plan period
  - Flat historical production profile of 10+ years
- Cumulative light oil production of ~700 mmboe since 1965
- Recovery of NGLs began in ’17
  - Original enhanced oil recovery play used injection of gas and NGLs to support production

FCF Over Next 10 Years **$570M**

Recoverable Reserves **128 mmboe**[1]



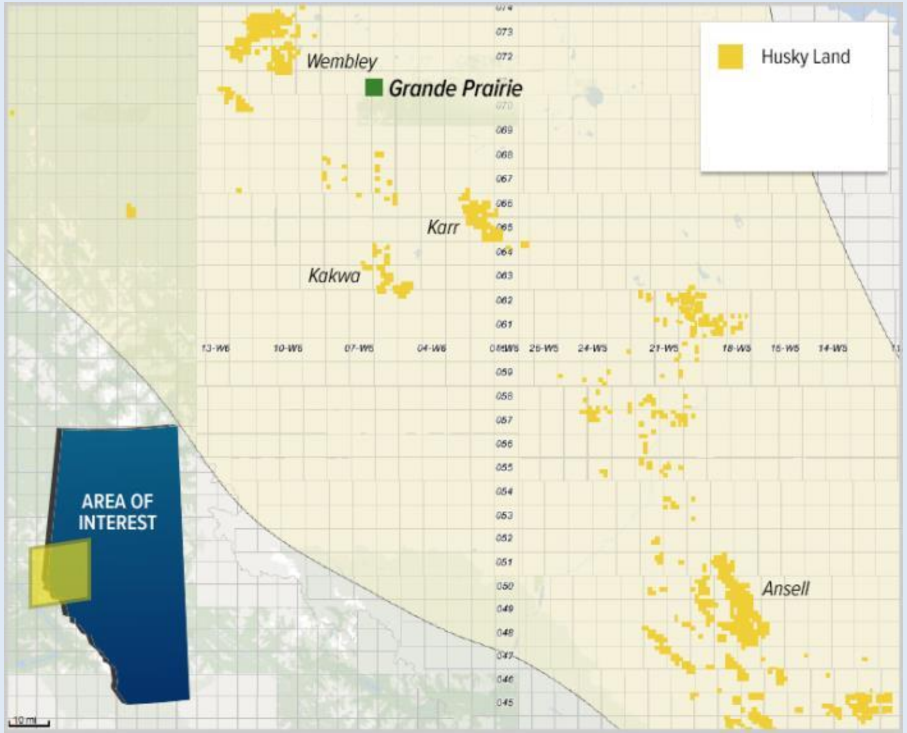
1 see *Slide Notes* and *Advisories*

Short-Cycle Investment Opportunities

Targeting High Impact Wells Across The Portfolio

Project	Capital (per well)	Type Well EUR (Bcf)	Type Well After-Tax IRR[1]
Ansell Wilrich (~160 net sections of land)	**$5M**	**6**	**25%**
Kakwa Wilrich (~30 net sections of land)	**$7M**	**6**	**>30%**
Karr Montney (~50 net sections of land)	Delineation program ongoing		
Wembley Montney (~100 net sections of land)	Delineation program ongoing		

Land Holdings

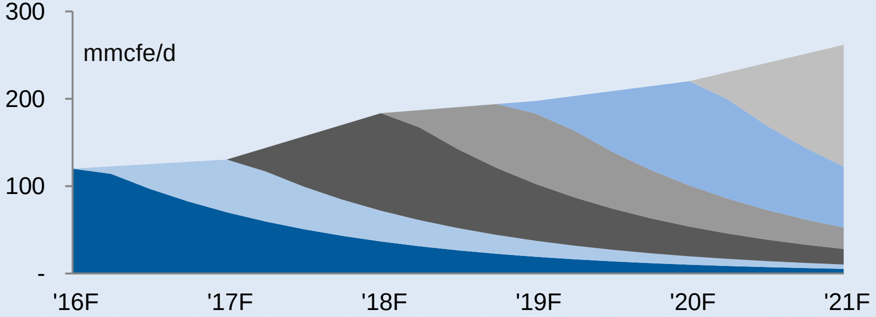


1 see *Slide Notes* and *Advisories*

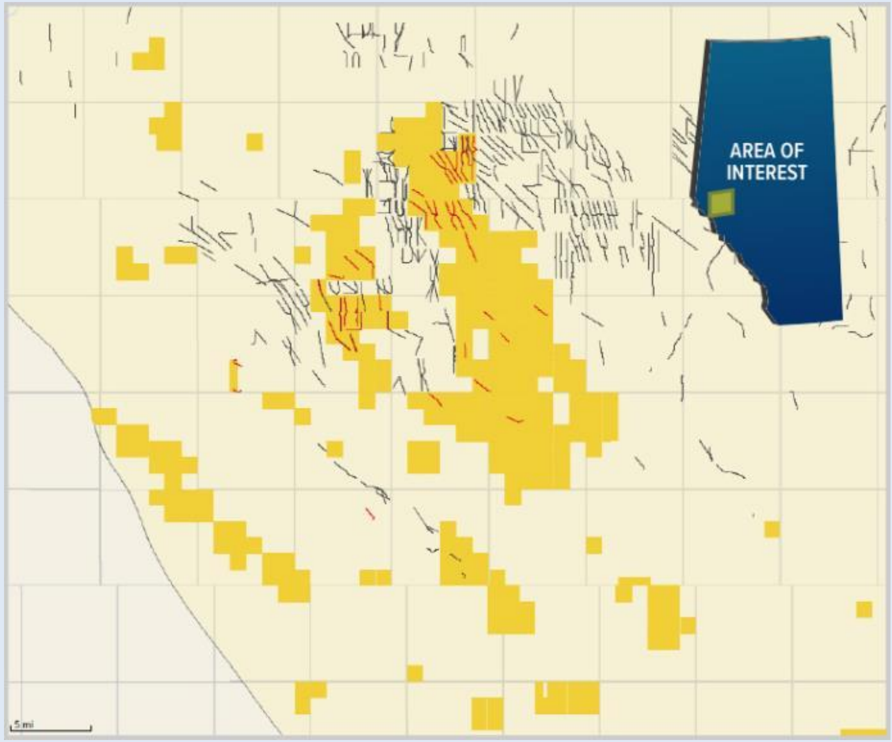
Wilrich Play

- Land holdings: 190+ sections
- Current production: ~20,000 boe/day
- Spirit River multi-formation stack
- Focus zone: Wilrich
  - Wilrich production (50% of base)
  - 16 net wells to be drilled in ’17
  - ~450+ potential drilling opportunities[1]

Five-Year Production Growth Profile



Wilrich Acreage



Source: CS Explorer

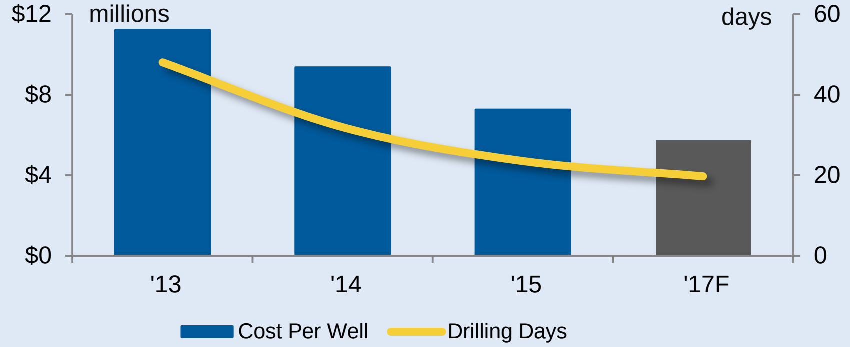
1 see *Slide Notes* and *Advisories*

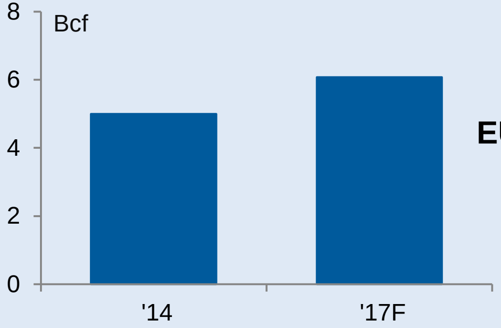
Ansell Drilling Efficiencies

Continued Cost Improvement and Well Deliverability

Well Costs ↓50%

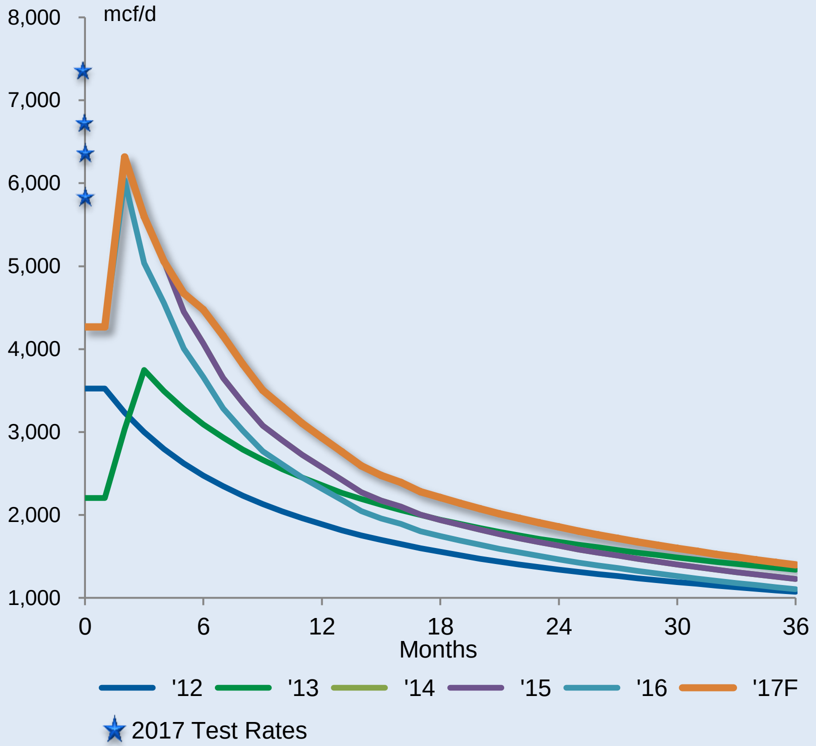
Drilling Days ↓60%





EUR[1,2] ↑20%

Ansell Wilrich-Type Well – Production Profile



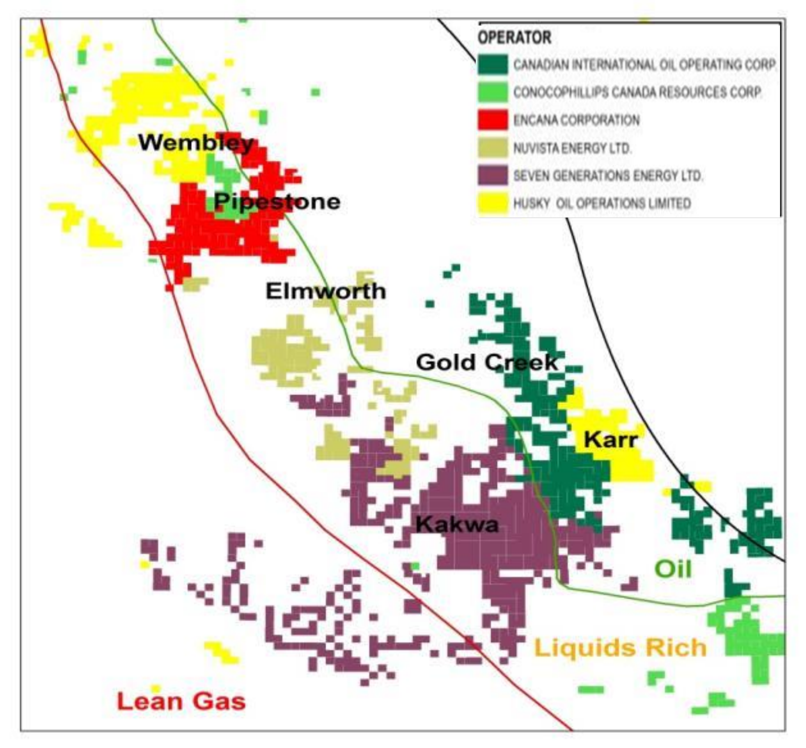
1, 2 see *Slide Notes* and *Advisories*

Montney Liquids-Rich and Oil Resource Play

Significant Alberta Position Next to Proven Success

- Two focus areas, 150+ net sections
- Wembley area:
  - ~100 net sections
  - Liquids-rich gas window
  - Adjacent to top-tier Montney production
- Karr area:
  - ~50 net sections
  - Volatile oil trend
  - Adjacent to top-tier Montney production
- Four net wells to be drilled in ’17
- Full development to be coordinated with pipeline access / infrastructure build

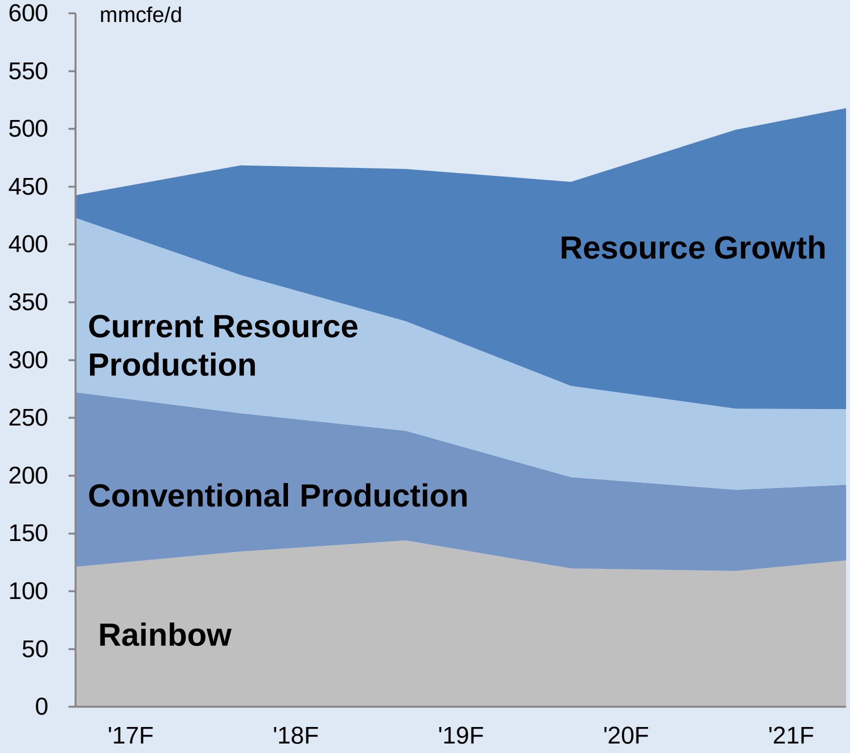
Montney Acreage



Reshaped Portfolio

- Short-term investment cycle provides flexibility
- Land positions in right neighbourhood
- Running room with 450+ potential drilling opportunities (Wilrich)
- Emerging position in Montney
- Improving capital efficiencies
- Increasing type well recoveries
- Natural gas production provides internal hedge for thermal and refining energy needs

Production Growth Profile




Offshore
WEST HERCULES

Offshore
Asia Pacific

Robert Hinkel
Chief Operating Officer, Asia Pacific

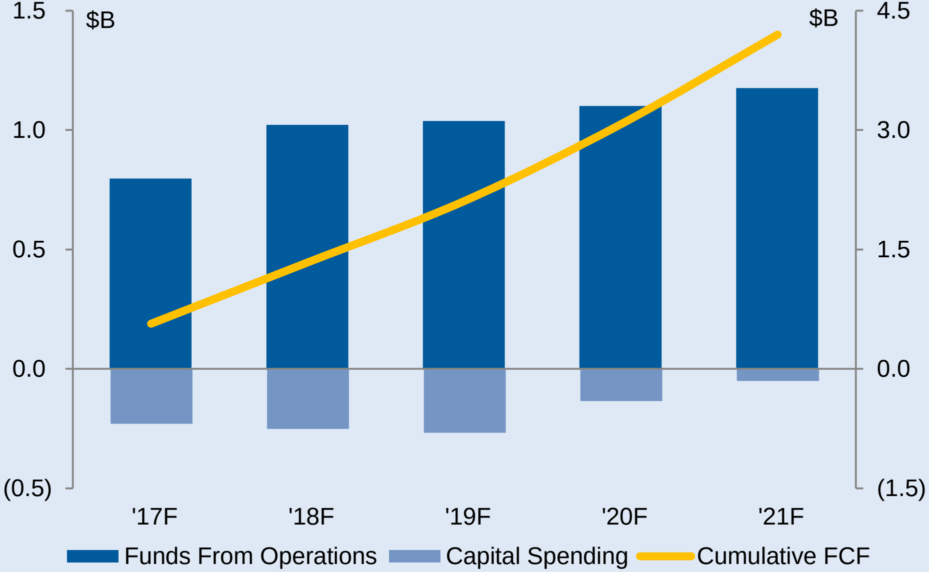
Asia Pacific

Established Operator in Region

- High operating netback production
  - $64.43 per boe operating netback (Q1 ’17)
  - Fixed-price contracts provides FFO stability
  - $0.9 billion of investment required for growth over the five-year plan
    - $0.6 growth capital
    - $0.3 sustaining requirements
- Defined growth
  - 240 mmcfe/day current production rising to over 360 mmcfe/day in ’21
  - Mix of near, mid and long-term development and exploration opportunities

Asia-Pac FCF ’17 - ’21F **$4.2B**

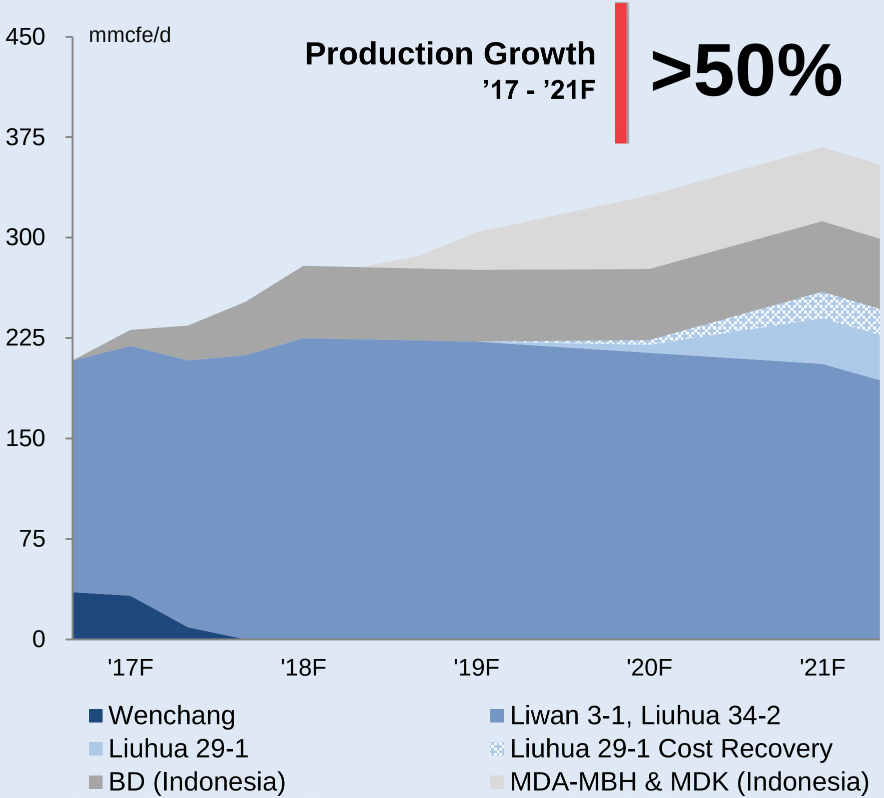
Free Cash Flow Growth



Low Volatility Growth

Project	Remaining Project Capital First Production ($US)	Net Peak Production	After-Tax IRR[1] Plan Pricing Assumptions
MDA-MBH, MDK	$160M	60 mmcf/day (combined fields)	16%
Liuhua 29-1	$370M	30 mmcf/day gas 1,200 bbls/day liquids	TBD

Five-Year Production Profile



1 see *Slide Notes* and *Advisories*

Liwan Gas Project

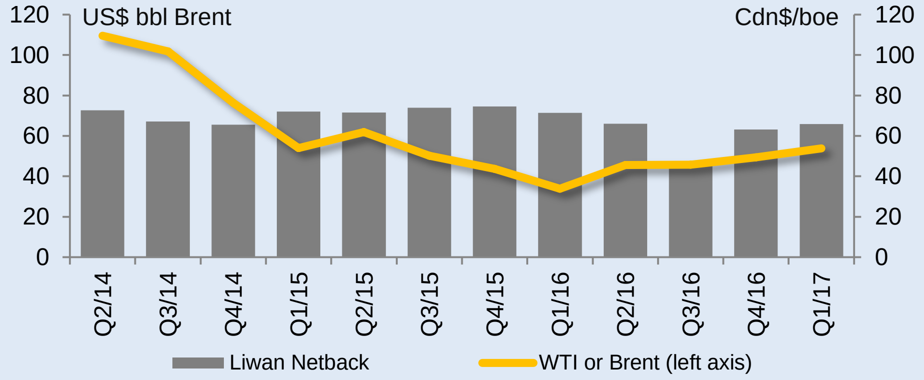
Liwan 3-1 and Liuhua 34-2

- Take-or-pay contract 150-165 mmcf/day (net)
  - $13.31 per mcf gas realized in Q1 ’17
- Full project payout forecast in ’18
- Delivered $2.4 billion EBITDA[1] since first gas in ’14

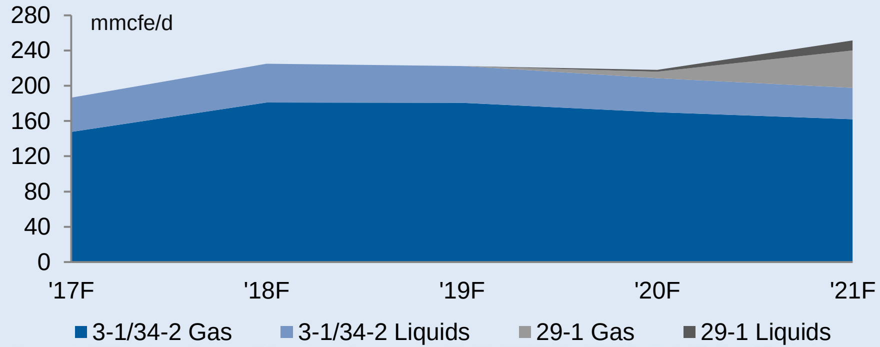
Liuhua 29-1

- Seven-well development plan to utilize subsea infrastructure
  - Gas sales contract negotiations in progress
- Exploration cost recovery

High Operating Netbacks Independent of Oil Price[2]



Liwan Production Profile



1, 2 see *Slide Notes* and *Advisories*

Madura Strait Growth Profile

Series of Stable, Fixed-Price Production

BD Project

↓

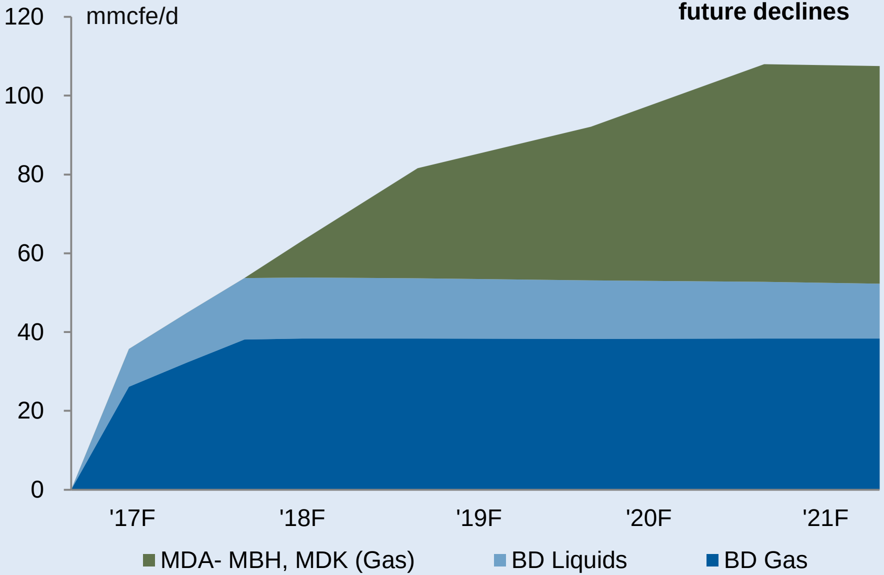
MDA-MBH, MDK

↓

MAC, MAX, MBF
(future potential - 2022 beyond)

Indonesia Production Profile

Potential projects at Madura to offset future declines



Indonesia FCF ’17 to ’21 | **C$600M**

BD Project

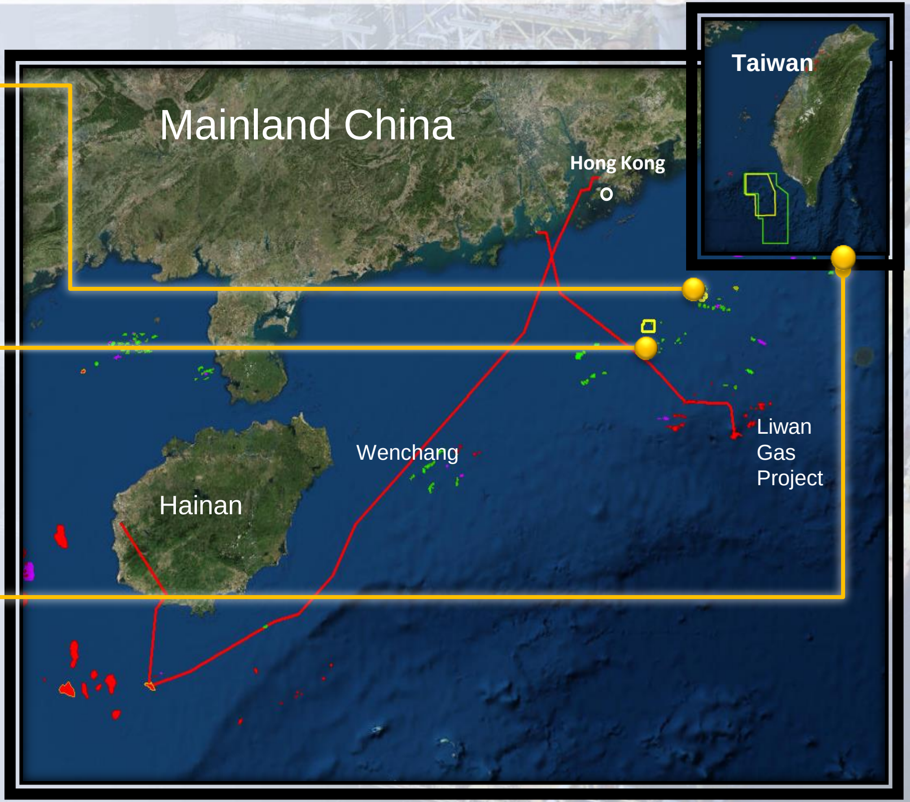
- Project currently being commissioned
- ~$7 US/mmbtu fixed-price gas contract in place
- 40 mmcf/day gas, 2,400 bbls/day liquids (net)
  - Direct subsea gas pipeline to shore
  - FPSO for liquids processing
- Husky-CNOOC Madura (HCML) is operator under Madura Strait PSC

Mid-Term Appraisal / Exploration Projects

Block 15/33
- Shallow water block
- Close proximity to FPSO
- Exploration well and appraisal well ('17-'18)

Block 16/25
- Shallow water block
- Close proximity to FPSO
- Exploration well and appraisal well ('18)

Taiwan Block DW-1
- Gas prone area of 7,700 km^2
- Major 3-D seismic acquisition program underway
- Proximity to large market



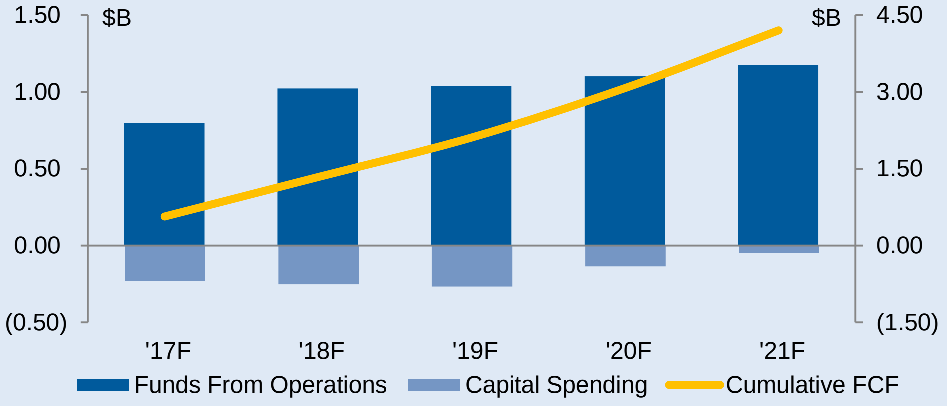
Generating Value

- $4.2 billion in FCF over five-year plan
- High operating netback production
  - Fixed price contracts provides FFO stability
  - $64.43 per boe operating netback (Q1 '17)
- Low level of investment required for growth
- Established operator in region

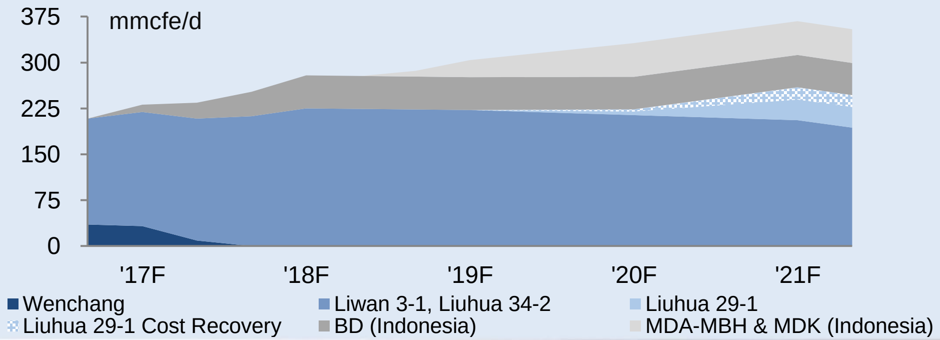
Defined growth:

- 240 mmcfe/day current production rising to over 360 mmcfe/day in '21
- Mix of near, mid and long-term developments and exploration opportunities

Free Cash Flow Growth



Five-Year Production Profile



Offshore
Atlantic

Malcolm Maclean
SVP, Atlantic Region

Proven Track Record

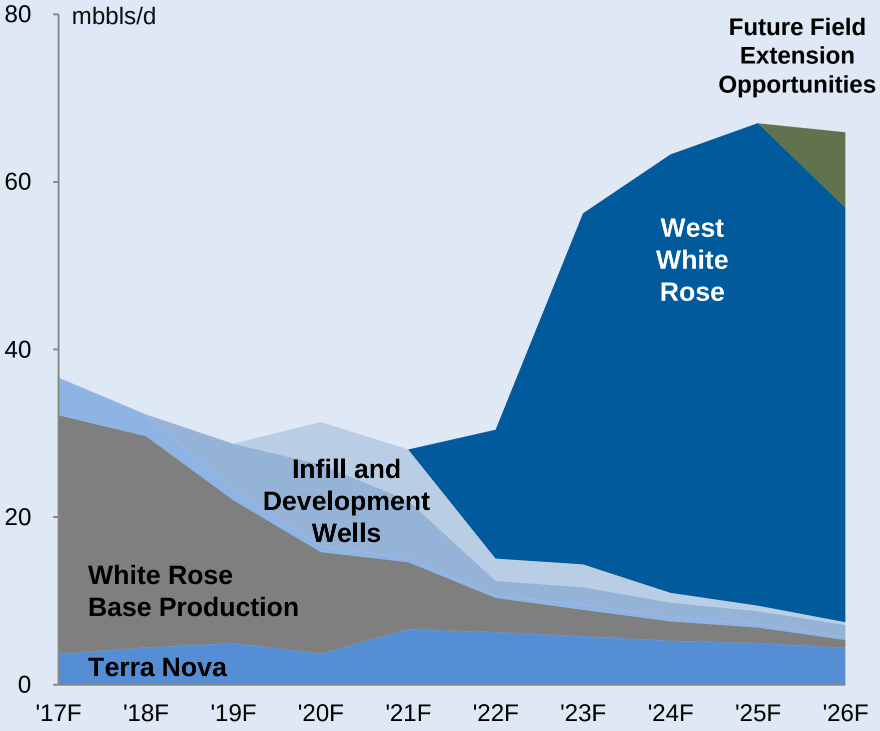
- Long history of successful operations in region
- High operating netback production
  - $44 per barrel operating netback (Q1 ’17)
- Production receives Brent+ pricing
  - <$15 per barrel operating costs (Q1 ’17)
- Investment economics enhanced through tiebacks to existing infrastructure
- Defined growth in next decade
- Exploration upside opportunities

Next Stage of Growth

Short, Mid and Long Cycle Projects

Project	Project Capital To First Production	Net Peak Production	After-Tax IRR[1] Plan Pricing Assumptions
SWRX and infill wells	~$70M per well	~4,500 bbls/day per well	>30%
West White Rose	~$2.2B	~52,500 bbls/day	~17%

Atlantic Production Profile



1 see *Slide Notes* and *Advisories*

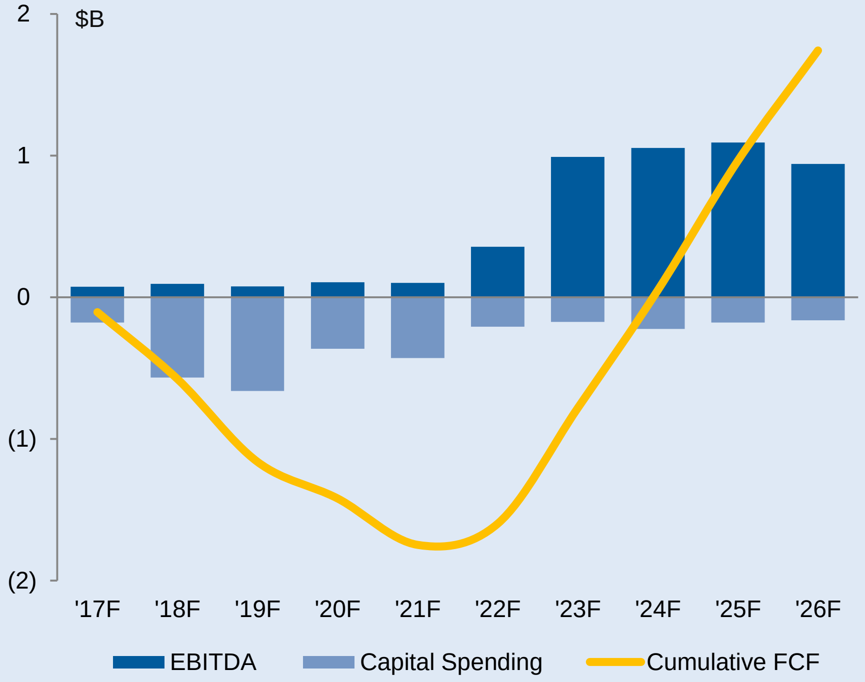
West White Rose

First Oil in ’22

- Improvement of capital efficiency by 30%
- Immediately earnings accretive
- Utilizes existing infrastructure

Economics	
Peak gross production	75,000 bbls/day
Capital spending to first oil (Husky W.I.)	$2.2 billion
Payback period	~3 years from first oil
IRR at price planning assumptions	17%
IRR at $45/bbl flat	12%
IRR at $35/bbl flat	7%

West White Rose Cash Flow Profile



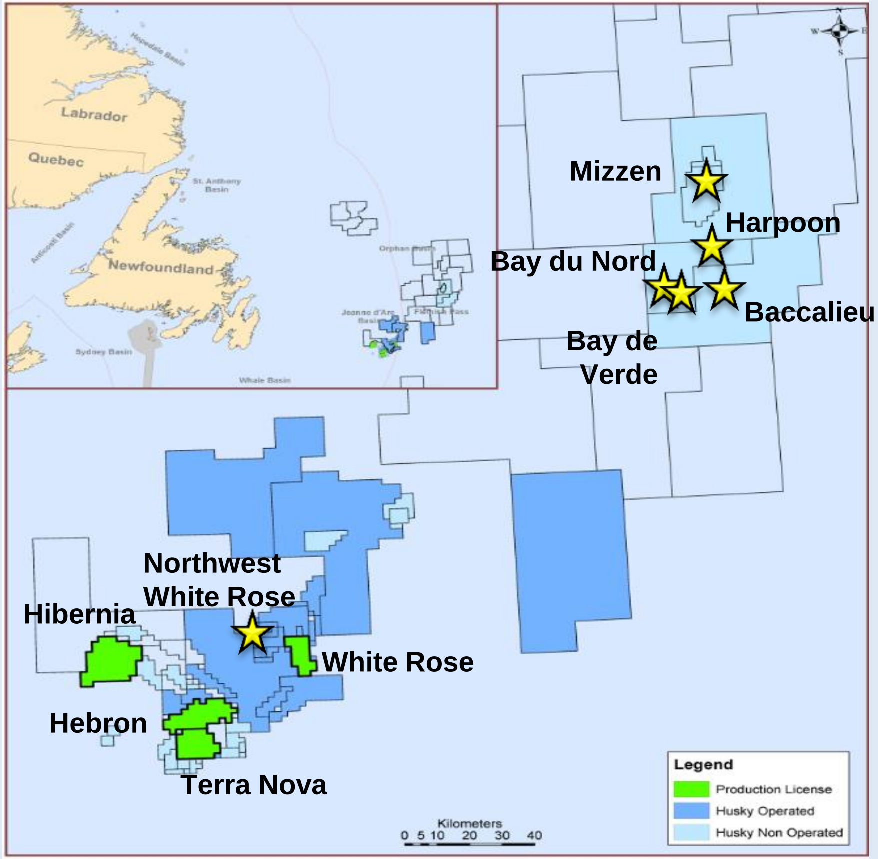
Exploration

Near-term: Near-Field Exploration

- Northwest White Rose discovery
    - Encountered 100+ metre light oil column
    - Potential tie-back to WWR WHP
- Newly acquired exploration acreage

Longer-term: Flemish Pass

- Original Mizzen discovery in ’09
- Light oil discoveries at Bay du Nord and Harpoon in ’13
- Discoveries at Bay de Verde, Baccalieu in ’16
    - Delineation program confirmed large resource potential
- Exploration program in ’17 (two wells)



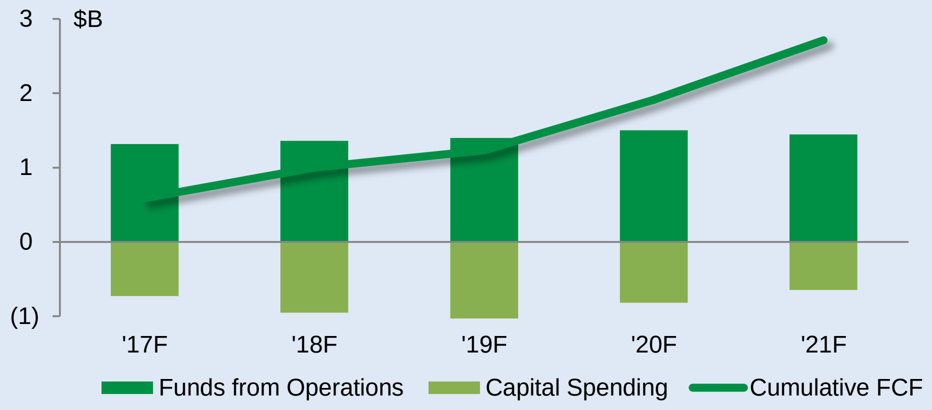
Offshore
Summary

Offshore Business Summary

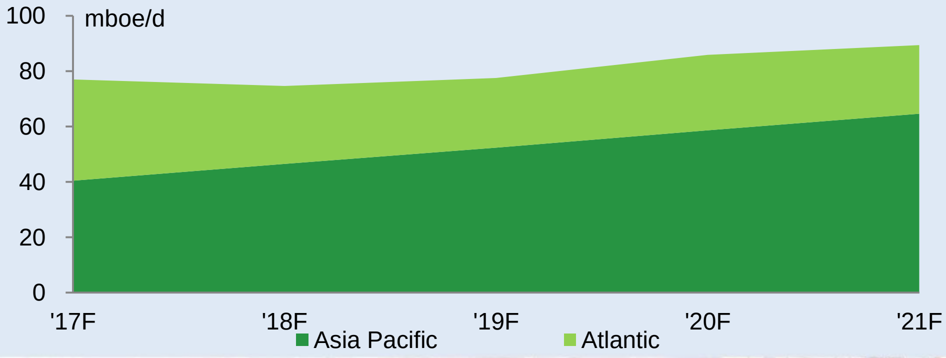
Asia Pacific and Atlantic

- 74,600 boe/day combined production (Q1 ’17)
- Average operating costs of $10.57/boe (Q1 ’17)
- Average operating netbacks of $53.79/boe (Q1 ’17)
- Free cash flow of $2.7 billion over plan
- Defined growth into next decade
- Exploration upside

Offshore Free Cash Flow Growth



Offshore Production Growth



Husky Energy

Q&A

Husky Value Proposition

- Returns-focused growth
- Large inventory of low cost projects
- Low and improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Resilient to volatile market conditions while preserving upside

Key Metrics	’17F	’17-’21F CAGR	’21F
Production (mboe/d)	**320 – 335**	**4.8%**	**390 – 400**
Funds from operations (FFO)	**$3.3B**	**9%**	**~$4.8B**
Free cash flow (FCF)	**$750M**	**12%**	**~$1.2B**
Upstream operating cost/bbl	$14.25		<$12
Downstream realized refining margins/bbl (CAD)	$15.00		>$16
Earnings break-even oil price (US WTI)	~$43.60		~$37
Cash break-even oil price (US WTI)	~$33.50		~$32

Ranges and Targets	’17 - ’21F
Sustaining capital	Avg. $1.9B
Capital spending	Avg. $3.3B
Five-year avg. proved reserve replacement ratio	Target >130%
Net debt to FFO	<2x

Husky Energy

Slide Notes & Advisories

Slide Notes

Slide 4

1. Funds from operations and free cash flow, as referred to throughout this presentation, are non-GAAP measures. Please see *Advisories* for further detail.
2. Funds from Operations and Free cash flow forecast for 2021 based on WTI price of $60 US per barrel, CAD$3.00/mmbtu gas price, 0.80 US/CAD exchange rate and US$16 Chicago 3-2-1 crack spread.
3. Earnings break-even and Cash break-even prices, as referred to throughout this presentation, are non-GAAP measures. Please see *Advisories* for further detail.
4. Sustaining capital, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
5. Capital spending, as referred to throughout this presentation, excludes asset retirement obligations and capitalized interest unless otherwise indicated.
6. Net debt and net debt to funds from operations, as referred to throughout this presentation, are non-GAAP measures. Please see *Advisories* for further detail.

Slide 12

1. Integrated Corridor FFO, Offshore FFO, Corridor Capital Spending and Offshore Capital Spending (in aggregate and on a project basis, as applicable), as referred to throughout this presentation, reflect funds from operations or capital spending, as applicable, from the respective businesses and do not include any corporate costs unless otherwise indicated.

Slide 15

1. Other than as indicated in the *Advisories*, 10% IRR calculations are based on proved and probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on a US$40 WTI price scenario.
3. Downstream portfolio IRR is not directly tied to oil or gas price. See *Advisories* for further detail

Slide 26

1. Other than as indicated in the *Advisories*, 10% IRR calculations are based on proved and probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on a US$40 WTI price scenario.
3. Downstream portfolio IRR is not directly tied to oil or gas price. See *Advisories* for further detail.

Slide 27

1. Other than as indicated in the *Advisories*, 10% IRR calculations are based on proved and probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on a US$40 WTI price scenario.
3. Downstream portfolio IRR is not directly tied to oil or gas price. See *Advisories* for further detail.
4. Projects Included in Plan Spending Period reflect projects that the Company will allocate capital spending to during the 2017-2021 timeframe.

Slide 28

1. Operating netback, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide Notes

Slide 31

1. Net debt to trailing funds from operations, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 32

1. Other Capital includes asset retirement obligation payments, capitalized interest and other corporate costs.

Slide 41

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and, other than as indicated in the *Advisories*, are based on proved and probable reserves.

Slide 43

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, Ultra Low Sulphur Diesel (ULSD) and other products.

Slide 44

1. Product variability can be influenced by several factors, including seasonal demand, access to feedstock, 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 50

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and other than as indicated in the *Advisories*, based on proved and probable reserves.

Slide 52

1. Lloyd economics represent the forecast economics of a generic 10,000 bbls/d thermal bitumen project.
2. Build costs represent sanctioning costs.
3. Operating costs include energy and non-energy costs.
4. After-Tax IRR is calculated using Price Planning Assumptions as shown on slide 30 and, other than as indicated in the *Advisories*, are based on proved and probable reserves.

Slide 63

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

Slide 64

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and, other than as indicated in the *Advisories*, are based on proved and probable reserves.
2. Production volumes represent blended volumes (bitumen, heavy oil and diluent).
3. Downstream throughputs represent 100% nameplate capacity except Toledo (50%).

Slide 75

1. Proven and probable reserves as at December 31, 2016.

Slide 76

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and, other than as indicated in the *Advisories*, are based on proved and probable reserves.

Slide 77

1. Drilling opportunities split: Proved Undeveloped (73), Probable (39), Unrisked Economic Best Estimate Development Pending Contingent Resource (260).

Slide Notes

Slide 78

1. Husky type curves and EUR reflect the unrisked, proven plus probable estimate.
2. Prepared by internal qualified reserves evaluators in accordance with COGEH.

Slide 84

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and other than as indicated in the *Advisories*, based on proved and probable reserves.

Slide 85

1. EBITDA, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
2. 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 the third quarter of 2016. The price adjustment under the HOA is effective as of November 2015 and a retroactive adjustment was recognized in the third quarter of 2016.

Slide 92

1. After-Tax IRRs are calculated using Price Planning Assumptions as shown on slide 30 and other than as indicated in the *Advisories*, based on proved and probable reserves.

Slide 114

1. Excludes mark to market accounting impacts.
2. Based on 1,005.5 million common shares outstanding as at March 31, 2017.
3. Does not include gains or losses on inventory.
4. Includes impacts related to Brent and Daqing based production.

Slide 114 con't

5. Includes impact of natural gas consumption.
6. Excludes impact on asphalt operations.
7. Assumes no foreign exchange gains or losses on U.S. dollar denominated long-term debt and other monetary items, including cash balances.

Slide 115

1. Other than as indicated in the *Advisories*, 10% IRR calculations are based on proved and probable reserves.
2. Gas portfolio break-even prices include assumed associated liquids prices based on a US$40 WTI price scenario.
3. Downstream portfolio IRR is not directly tied to oil or gas price. See *Advisories* for further detail.

Slide 116

1. Excludes additional working interest production allocated to Husky Energy from initial production until such time that Husky has recovered its complete exploration expense costs.

Slide 117

1. Capital expenditures include exploration capital in each business unit.
2. Lloyd and Tucker thermal capital expenditures includes Lloyd thermal heavy oil and Tucker Lake bitumen.
3. Asia Pacific Region oil & NGLs operating costs and capital expenditures reflected in Asia Pacific natural gas.
4. Downstream capital expenditure inlcude scheduled turnarounds.
5. Lloyd and Tucker thermal operating costs include energy and non-energy costs.
6. Includes ARO, capitalized interest and contribution payable.
7. Downstream operating costs exlude the impact of scheduled turnarounds in 2017.

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; forecasted production, FFO, FCF, upstream operating cost per barrel, downstream realized refining margins/bbl, earnings break-even oil price and cash break-even oil price by 2021 and range and targets for sustaining capital, capital spending, five-year average proved reserves replacement ratio and net debt to FFO from 2017 to 2021; forecast production, FFO and FCF compound annual growth rate from 2017 to 2021 (in total and for the Company's Integrated Corridor); forecast production growth, capital spending, FFO and FCF from the Company's Integrated Corridor and Offshore projects (individually and combined) from 2017 to 2021; forecast upstream (broken down into Integrated Corridor and Offshore and in aggregate), downstream and total sustaining capital, in aggregate and on a per boe basis for the years ending 2017 to 2021, including average upstream and downstream sustaining capital for such period; forecast net debt for the period from 2017 to 2021; five-year plan milestones in respect of the Company's Integrated Corridor projects and Offshore projects; plans to establish a sustainable cash dividend, which has room to grow over time; capital spending for the years 2017 to 2021 broken down for five-year plan production and 2022 and beyond including West White Rose and non-West White Rose expenditures and other capital for the years 2017 to 20121; forecast upstream operating costs, upstream operating netbacks and downstream margins for the years ending 2017 to 2021; Integrated Corridor FFO and FCF generation and cash capital at flat $50 US WTI for the years 2017 to 2021; forecast FFO, sustaining capital, discretionary capital and net debt to FFO assuming $35 US WTI for the years 2017 and 2021; forecast FFO, capital spending (broken down into downstream sustaining capital, upstream sustaining capital and growth capital) and FCF for the Company's Integrated Corridor for the years 2017 to 2021; forecast thermal, non-thermal and Western Canada production for the years 2017 and 2021, broken down by thermal project for 2021; forecast Integrated Corridor upstream operating costs, upstream sustaining capital per boe and downstream margins for the years 2017 to 2021; prices required to generate targeted IRR for the Company's listed in-flight and future projects; total spending for in-flight and future projects and percentage spent in short to mid-cycle; anticipation with respect to de-levering; forecast FCF, FFO and capital spending for the Offshore business over the next five years; decline rates, volumes to be replaced and capital efficiency for the years 2017 and 2021; major project economics; and costs and time frames to develop, and other factors affecting the development of, the Company's contingent resources;
- with respect to the Company's Thermal Developments: anticipated production growth from thermal projects over next five years and associated compound annual growth rate; strategic plans and growth strategy for the Company's Lloyd thermals; expected timing to bring Rush Lake 2 and three other thermal projects online; forecast net peak production, project capital spending and after-tax IRR for the Company's thermal business projects; forecast five-year production growth profile for Sunrise, Tucker and Lloyd thermals; project characteristics of a typical Lloyd thermal project; Tucker FFO, capital spending and FCF for the years 2017 to 2021; expected timing to reach capacity, operating costs and productive life at Tucker; expected timing to tie in an additional 14 well pairs at Sunrise; forecast production at Sunrise in 2018; nameplate capacities at thermal projects; plan to start de-bottlenecking work at Sunrise;

Advisories

forecast productive life at Sunrise; target operating costs per barrel at Sunrise once ramped up; forecast operating costs per barrel for Sunrise, Tucker and Lloyd for the period from 2017 to 2021; expected Sunrise capital costs at full capacity; total thermal FFO, FCF and capital spending (broken down into growth capital and sustaining capital) for the years 2017 to 2021; and expected timing and benefits of heavy oil/thermal technology;

- with respect to the Company's Western Canadian Resource Plays and other production: forecasted production from resource plays and other production for 2021; forecast sustaining capital requirements (broken down by Rainbow and non-Rainbow), operating costs per boe and operating netbacks for the years 2017 to 2021; 10-year production profile and FCF at Rainbow; five-year production profile at Rainbow, Ansell resource base, conventional production and resource growth; anticipated timeframe that legacy plays will provide stable FFO and FCF; forecast 2021 production, capital spending and after-tax IRR at Wilrich; forecast 2017 costs and drill time at Ansell; capital per well, type well EUR and after-tax IRR at Ansell Wilrich, Kakwa Wilrich, Karr Montney and Wembley Montney; and expected number of net wells to be drilled in 2017;

- with respect to the Company's Downstream operating segment: forecast FCF, FFO and capital spending for the Downstream operating segment over the next five years; forecast remaining project capital spending; capacity and after-tax IRR at the Lima Crude Oil Flexibility project; forecast throughput at Asphalt expansion; forecast heavy oil blend and downstream throughputs for 2019 and 2021 broken down by project and product types; forecast throughputs for 2021 for heavy oil processing; anticipated date for a final investment decision, commissioning stage and full capacity for the Asphalt expansion and anticipated annual margins from the expansion; forecast feedstock volumes broken down by product type for 2021; expected heavy and light oil processing capacity; expected capital costs for Crude Oil Flexibility Project and Asphalt Capacity expansion; and potential incremental margin from other downstream initiatives;

- with respect to the Company's Asia Pacific region: forecasted FFO, capital spending (broken down by growth capital and sustaining capital requirements) and FCF for the years 2017 to 2021; expected production in 2021; expected remaining project capital spending, net peak production and IRR for MDA-MBH, MDKA and Liuhua 29-1; five year production profile for Wenchang, Liwan 3-1 and Liuhua 34-2, Liuhua 29-1, Liuhua 29-1 Cost Recovery, BD (Indonesia, broken down by gas and liquids) and MDA-MBH & MDK (Indonesia); five-year production profiles at the Liwan Gas Project and Madura Strait; expected timing for full project payout for Liwan 3-1 and Liuhua 34-2; timing for first gas and cost recovery and amount of cost recovery at Liuhua 29-1; expected FCF at Indonesia for the five-year period; expectation that future projects at Madura will offset declines; gas rates for the BD project and expected timing for exploration well and appraisal well at Block 15/33 and Block 16/25; and

- with respect to the Company's Atlantic region: after-tax IRR, capital and peak production at the South White Rose and infill wells and West White Rose; 10-year production profile for the region broken down by project; expectation to be cash flow positive when West White Rose is online; timing for first oil from West White Rose and expected project economics, including peak gross production, lifetime gross production, capital spending to first oil, payback period, IRR and 10-year expected EBITDA, operating costs, capital spending and FCF; and the exploration program at Flemish Pass.

In addition, statements relating to "reserves" "and" "resources" 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 resources 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 reserve, resource and production estimates. In addition, with respect to the type curves and test rates, there is no certainty that future well will generate results to match type curves or test rates presented herein.

Advisories

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, 2016 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.

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 measurements are used to enhance the Company's reported financial performance or position. With the exception of funds from operations, EBITDA and free cash flow, 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. Funds from operations is presented in the Company’s financial reports to assist management and investors in analyzing

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operating performance by business in the stated period. Funds from operations equals cash flow – operating activities plus items not affecting cash, which include settlement of asset retirement obligations, deferred revenue, income taxes received (paid), interest received and 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. Free cash flow is presented in this presentation to assist management and investors in analyzing operating performance by business in the stated period. Free cash flow equals net earnings (loss) plus items not affecting cash which include accretion, depletion, depreciation, amortization and impairment, inventory write-downs to net realizable value, exploration and evaluation expenses, deferred income taxes (recoveries), foreign exchange (gain) loss, stock-based compensation, loss (gain) on sale of property, plant, and equipment, unrealized mark to market loss (gain), and other non-cash items less capital spending.

- "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.

- "Net debt to funds from operations" is a non-GAAP measure that equals net debt divided by funds from operations. Net debt to funds from operations 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" is a non-GAAP measure that equals net debt by the 12-month trailing funds from operations as at December 31, 2016. Net debt to trailing funds from operations is considered to be a useful measure in assisting management and investors to evaluate the Company's financial strength.

- "EBITDA" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "net earnings (loss)" as determined in accordance with IFRS, as an indicator of financial performance. EBITDA is presented in this presentation to assist management and investors in analyzing operating performance by business in the stated period. EBITDA equals net earnings (loss) plus finance expenses (income), provisions for (recovery of) income taxes, and depletion, depreciation and amortization.

- "Operating netback" is a common non-GAAP metric 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.

- "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, 2017. This assumption is based on holding several variables constant throughout the 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.

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- "Cash break-even" reflects the estimated WTI oil price per barrel priced in US dollars required in order to generate funds flow from operations equal to the Company's sustaining capital requirements in Canadian dollars over a 12-month period ending December 31. This assumption is based on holding several variables constant throughout the 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. Cash 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.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves 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, 2016 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, 2016. The Company has disclosed its total reserves in Canada and in Indonesia in its Annual Information Form for the year ended December 31, 2016, 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.

IRR calculations shown in this presentation are based on holding several variables constant throughout the period, including: estimated WTI oil price per barrel priced in US dollars, 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. This measure is used to assess potential return generated from investment opportunities and could impact future investment decisions. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers. IRR calculations in this presentation are based on proved and probable reserves, except for the IRR calculations for the projects described below, in which cases the IRR calculations are based on resources.

Husky's Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 268 million barrels of economic development pending, 164 million barrels of economic development unclarified and 554 million barrels of economic status undetermined development unclarified. The figures represent Husky's working interest volumes. The development pending category consists of 11 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 2019 through to 2040. The first three projects have a total capital cost to first production of $1.1 billion based upon the pre-development studies. The estimated total capital to fully develop these 12 development pending projects is approximately $8 billion.

The economic and economic status undetermined development unclarified projects require additional technical and commercial analysis of the conceptual SAGD or CSS studies. Of these, the first project requires $0.4 billion to achieve commercial production in 2030. The remaining projects are to be developed over more than 50 years in accordance with the conceptual studies for this large resource. In total, 311 million barrels of thermal bitumen are based upon pre-development studies while an additional 675 million barrels of thermal bitumen are based upon conceptual plans. This oil is reported as thermal bitumen and has viscosities ranging from 12,800 centipoise (cP) to as high as 600,000 cP with gravities between 9 and 12 degrees API.

Advisories

Specific contingencies preventing the classification of contingent resources at the Company's Lloydminster Heavy Oil thermal contingent resources as reserves include the need for further reservoir studies, delineation drilling, verification of sub-zone continuity and quality that would enable feasible implementation of a thermal scheme, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, the Company's capital commitment, development over a time frame much greater than the reserve timing window and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include potential reservoir heterogeneity in sub-zones which may limit the applicability of thermal schemes, a higher level of uncertainty in the estimates as a result of lower drilling density in some projects and current lack of development plans in the unclarified contingent resources. The main risks are the low well density and the associated geological uncertainties in certain projects, the production performance and recovery long term, future commodity prices and the capital costs associated with wells and facilities planned over an extended future period of time.

McMullen contains unrisked best estimate economic development pending contingent resources of 44 million barrels of bitumen for Phase 1 of the development with a further 1.3 billion barrels of bitumen of unrisked best estimate economic status undetermined development unclarified contingent resources. McMullen is a thermal play in the Wabiskaw formation covering over 130 sections southwest of Wabasca. Husky has a working interest of 100 percent. The cost to first production for Phase 1, based upon the pre-development study, is approximately $452 million for the initial commercial demonstration facility and horizontal cyclic steam stimulation (HCSS) wells in 2023. The results of the commercial demonstration will be utilized to refine the subsequent phases that are based upon a conceptual development plan at this time and each has the same capital estimate with initial production scheduled for 2028 for Phase 2. The total commercial facilities and wells will be developed over more than 50 years at an estimated total cost of $40 billion in accordance with the conceptual study for this large resource. The development of these projects depends on the results of the technical analysis, future bitumen prices and the Company's commitment to dedicate capital to this large inventory of projects. Specific contingencies preventing the classification of contingent resources at the McMullen thermal development project as reserves include the need for further reservoir studies, delineation drilling, facility design, preparation of firm development plans, regulatory applications and approvals and Company approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of uncertainty in the estimates as a result of lower core-hole drilling density. The main risks are the low well density and the associated geological uncertainties, the production performance and recovery long term and the capital costs associated with wells and facilities planned over an extended future period of time.

The Ansell liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, and Husky has an average 92 percent working interest. Husky is actively developing Ansell. This producing property contains unrisked best estimate economic development pending contingent resources of 248 million barrels of oil equivalent, consisting of 1.4 Tcf of natural gas and 14 million barrels of natural gas liquids (NGL). Ansell also includes unrisked best estimate economic development on hold contingent resources of 174 million barrels of oil equivalent from the Cardium formation, consisting of 0.8 Tcf of natural gas and 35 million barrels of NGL from approximately 300 potential drilling opportunities. The initial contingent resource fracture stimulated horizontal wells are scheduled to be drilled starting in 2024, following the development of the proved and probable reserves. The cost to achieve initial commercial production is the cost of the first well of $4.5 million. The remaining development pending drilling opportunities (259 working interest) will be drilled over the next 10 to 20 years in accordance with the pre-development study for the resource play. Specific contingencies preventing the classification of contingent resources in the Ansell liquids-rich resource play as reserves include the timing of development which is outside the timing allowed for booking as reserves and final Company approvals of capital expenditures. Positive and negative factors relevant to the estimate of Ansell contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. Key risks include the performance of future wells when the play is expanded and reducing costs to achieve optimal results in a low gas and NGL price environment.

Advisories

Liuhua 29-1, located in the South China Sea approximately 300 km southeast of the Hong Kong Special Administrative Region, contains unrisked best estimate economic development pending contingent resources of 28 million barrels of oil equivalent, consisting of 139 Bcf of natural gas and 5 million barrels of condensate. Husky has a working interest of 49 percent. The project uses conventional offshore gas wells and will be connected to the producing Liwan gas field. Based on the pre-development study, the cost to first production to complete and tie-in the well is approximately $650 million with an on-stream date in 2018. The development of this project depends on the Company's and its partners' commitment to dedicate capital to the project. Specific contingencies preventing the classification of contingent resources for Liuhua 29-1 are the signing of a gas sales agreement and regulatory approvals. Positive and negative factors relevant to the estimates of these resources include a higher level of certainty in the estimates as a result of extensive appraisal drilling and testing. The main risk is the production performance and recovery long term.

Husky's Lloydminster Heavy Oil cold heavy oil production with sand (CHOPs) and Horizontal well opportunity includes 189 million barrels (Husky's working interest) of unrisked economic best estimate contingent resources in the development pending sub-class and a further 593 million barrels (Husky's working interest) of unrisked best estimate contingent resources in the development unclarified sub-class with the economic status undetermined. A typical CHOPS well has a cost estimate to drill, complete and equip of $580,000, while a five-well horizontal pad has a cost estimate of $7.1 million with the first developments online in 2026 based on a pre-development study. This is a continuation of the CHOPs and horizontal well development programs which have been proven to be successful in the Lloydminster area. The timing of development and Company approvals are the main contingencies preventing the booking of these volumes as reserves. Positive and negative factors relevant to these contingent resources include a lower level of uncertainty in the estimates as a result of the large number of producing wells, extensive production history from the property, Husky's large contiguous land base and Husky's ownership of existing infrastructure in the area. The key risk is the execution of a multi-year program and reducing capital and operating costs in a low heavy oil price environment.

Heavy Oil Cold EOR, located in the Lloydminster area, contains 307 million barrels (Husky's working interest) of unrisked economic status undetermined best estimate contingent resources in the development unclarified sub-class. Cold EOR Solvent Injection is a cyclic process utilizing CO2 which has been demonstrated to be technically successful in the area. The wells and area have been identified in the conceptual development study, but more detailed development plans are required for each field. The first phase of the projects is planned for 2021 with a capital cost of $207 million to reach first oil production in one of the identified fields. The timing of development, regulatory and Company approvals are the specific contingencies preventing the booking of these volumes as reserves as well as the need for additional assessment for the area where the economic status is undetermined. Positive and negative factors include the extensive land base and infrastructure while the ultimate recovery for this technology is still being evaluated in the field. Key risks include the range of uncertainty in the ultimate recovery and accessing a long term supply of CO2 for the projects.

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.
The Company uses the term "operating costs per barrel", which is consistent with other oil and gas producers' disclosures, and is calculated by dividing total operating costs for the Company's Heavy Oil thermal bitumen or non-thermal production, as applicable, by the total barrels of such thermal or non-thermal production, as applicable. The term is used to express operating costs on a per barrel basis that can be used for comparisons.

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"Capital efficiency" 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.

"Sustaining cost per boe" is the additional development capital that is required by the business to maintain production and operations at existing levels on a per unit basis. It is calculated as sustaining capital divided by EUR. Sustaining cost per boe does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

"Steam-oil ratio" (or "SOR") measures the average volume of steam required to produce a barrel of oil. Water-oil ratio ("WOR") measures the average volume of water produced per a barrel of oil. These measures do not have any standardized meanings and should not be used to make comparisons to similar measures presented by other issuers.

The Company uses the term "reserve replacement ratio", which is consistent with other oil and gas companies' disclosures. Reserve replacement ratios for a given period are determined by taking the Company's incremental proved reserve additions for that period divided by the Company's upstream gross production for the same period. The reserve replacement ratio measures the amount of reserves added to a company's reserve base during a given period relative to the amount of oil and gas produced during that same period. A company's reserve replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserve replacement ratio only measures the amount of reserves added to a company's reserve base during a given period.

EUR (estimated ultimate recovery) estimates, type curves and test rates referred to in this presentation have been prepared by internal qualified reserves engineer and in accordance with COGEH. EUR reflects the unrisked proved plus profitable estimate.

The gas resource potential drilling opportunities include 73 proved undeveloped and 39 probable undeveloped locations and 260 unrisked economic best estimate development pending contingent resource opportunities in Ansell and Kakwa, mainly focused in the Wilrich formation. The remaining potential drilling opportunities identified in this presentation are un-booked locations. Un-booked locations are internal estimates based on prospective acreage and applicable geologic, seismic, engineering, production and reserves information. Un-booked locations do not have attributed reserves or resources. While certain of the un-booked drilling locations have been de-risked by drilling existing wells in relative close proximity to such un-booked drilling locations, the majority of un-booked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore, there is 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.

Note to U.S. Readers

The Company reports its reserves and resources 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 SEC. All currency is expressed in Canadian dollars unless otherwise directed.

Husky Energy

Appendix

Pricing Assumptions

Benchmark Prices – Base Case	2017	2018	2019	2020	2021
WTI (US $bbl)	50.00	55.00	60.00	60.00	60.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	12.00	14.00	14.00	14.00	14.00
AECO ($/mmbtu Cdn)	2.50	3.00	3.00	3.00	3.00
USD/CAD exchange rate	0.76	0.78	0.80	0.80	0.80

Benchmark Prices - $50 Flat Case	2017	2018	2019	2020	2021
WTI (US $bbl)	50.00	50.00	50.00	50.00	50.00
Chicago 3:2:1 ($/bbl US)	16.00	16.00	16.00	16.00	16.00
Heavy Crude Differential ($/bbl US)	12.00	12.00	12.00	12.00	12.00
AECO ($/mmbtu Cdn)	2.50	2.50	2.50	2.50	2.50
USD/CAD exchange rate	0.76	0.76	0.76	0.76	0.76

Benchmark Prices- $35 Stress Case	2017	2021
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
USD/CAD exchange rate	0.71	0.71

Sustaining Capital Calculations

Declines vs. Average Capital Efficiency of Replacement

	2017	2021
Target Production (mboe/day)	327	395
Estimated Average Annual Decline Rate (%)	15	15
Production Volumes to be Replaced (mboe/day)	49	59
Capital Efficiency ($ thousands/flowing barrel)	$27	$27
Annual Average Upstream Sustaining Capital ($Billions)	$1.3	$1.6
Annual Average Downstream Sustaining Capital ($Billions)	$0.5	$0.5
Annual Average Total Sustaining Capital ($Billions)	**$1.8**	**$2.1**

Sensitivity Table

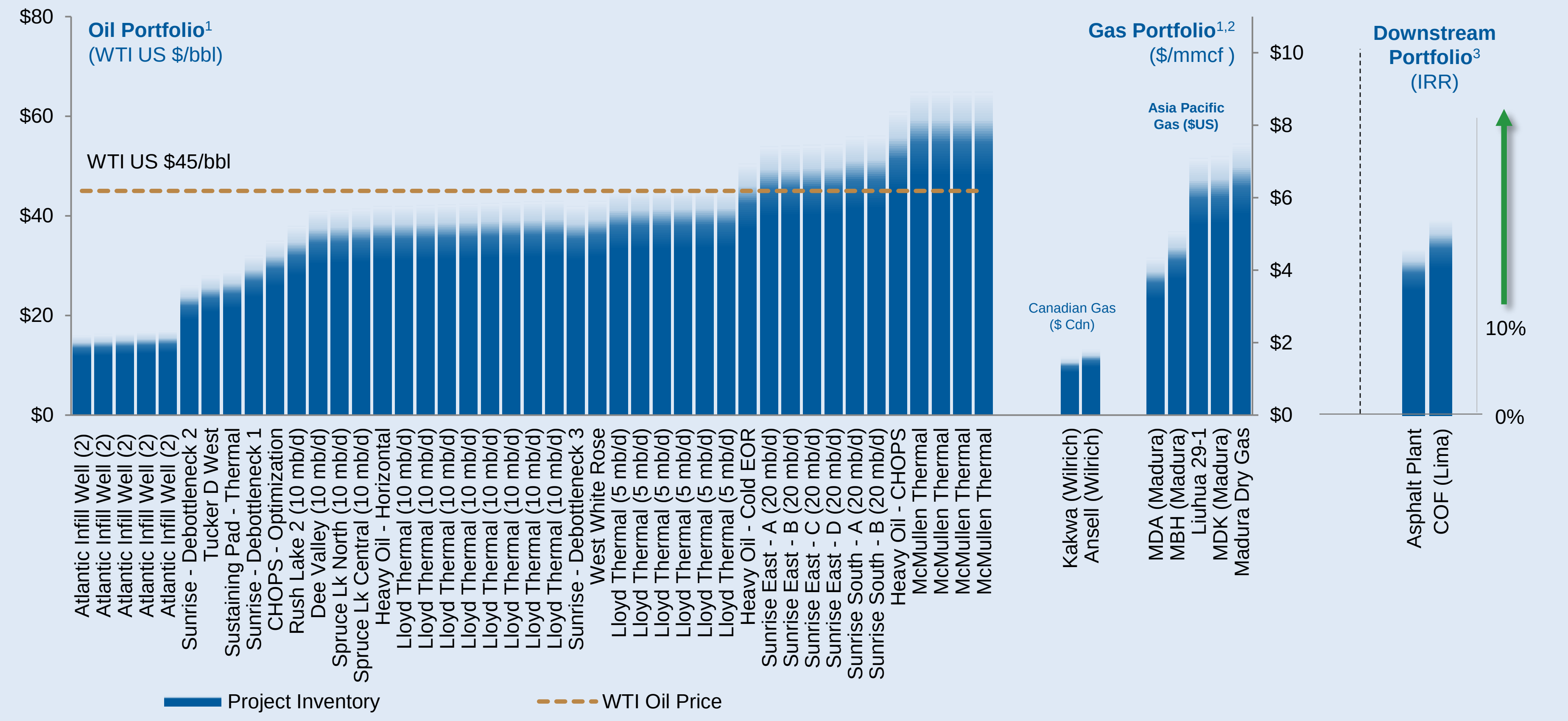
From Q1 2017 Management's Discussion and Analysis

Sensitivity Analysis	Q1 2017 Average	Increase	Effect on Earnings Before Income Taxes[1] ($ millions)	($/share)[2]	Effect on Net Earnings[1] ($ millions)	($/share)[2]
WTI benchmark crude oil price[3][4]	51.91	U.S. $1.00/bbl	105	0.10	76	0.08
NYMEX benchmark natural gas price[5]	3.32	U.S. $0.20/mmbtu	10	0.01	7	0.01
WTI/Lloyd crude blend differential[6]	14.32	U.S. $1.00/bbl	(48)	(0.05)	(36)	(0.04)
Canadian light oil margins	0.048	Cdn $0.005/litre	12	0.01	8	0.01
Asphalt margins	21.50	Cdn $1.00/bbl	8	0.01	5	0.01
Chicago 3:2:1 Crack Spread	11.22	U.S. $1.00/bbl	84	0.08	53	0.05
Exchange Rate (U.S. $ per Cdn $)[3][7]	0.756	U.S. $0.01	(60)	(0.06)	(44)	(0.04)

1,2,3,4,5,6,7 see *Slide Notes* and *Advisories*

Selected Project Inventory

Price Required to Generate 10% IRR



1,2,3 see *Slide Notes* and *Advisories*

Major Project Economics

Modelling Inputs

MAJOR PROJECT	Thermal	West White Rose	BD Gas (Indonesia)	Madura (Dry Gas)	Liuhua 29-1
	In Flight				*Pre-Sanction*
Peak Production / Throughput (bbls/d)	12,000 - 13,000	50,000 - 55,000	2,300 - 2,500	-	1,000 - 1,100[1]
(mmcf/d)	-	-	35 - 40	55 - 60	25 - 30[1]
Capital to First Production / Throughput ($ MM)	340 - 360	2,200 - 2,300	200 - 210	160 - 180	350 - 400
Benchmark Price	WCS	Brent	Fixed Price Contract (gas) Brent (Liquids)	Fixed Price Contract (gas)	Fixed Price Contract (gas) Brent (Liquids)
Relative to Benchmark ($/bbl - Oil, $/mmcf - gas)	Less: $4 - $5	Premium: $1-2/bbl	US$6.50 - US$7.50 Brent less $1.5/bbl (liquids)	US$6.50 - US$7.50	TBD TBD
Royalties (% of revenue)					
Start up	0 - 7	0 - 7	12 - 12	10 - 15	5% - 5%
Life of Field	10 - 12	10 - 12	30 - 32	30 - 35	5% - 5%
Operating Cost ($/boe)	7 - 9	10 - 20	5 - 7	6 - 8	6 - 7
Taxes / Gov't Take (%) (not Corporate Taxes)	11% - 12%	14% - 16%	40% - 40%	40% - 40%	30% - 30%
Production Profile					
Flat @ Peak Rate	Years 1-3	Years 1-3	Years 1-13	Years 1-5	Years 1-10
Decline Rate	15%	15% - 25%	20% - 25%	20% - 25%	20% - 25%
Operating netback / Margin @ $50 WTI ($/boe)	20 - 25	25 - 46	35 - 40	20 - 25	TBD
Booked 2P Reserves / Contingent Resources	~50 mmbbls at sanction	2P: 124 mmbbls	2P: 43 mmbbls	2P: 26 mmbbls	Contingent: 28 mmbbls
IRR @ Price Planning Assumptions	19%	17%	17% (Full Cycle)	17% (Full Cycle)	

1 see *Slide Notes* and *Advisories*

2017 Guidance Planning Assumptions

Upstream

Oil and Liquids	Capital Expenditures[1] ($ millions)	Production (mbbls/day)
Lloyd & Tucker thermal[2]	575 - 605	103 - 105
Oil Sands thermal	90 - 100	20 - 22
Lloyd Non-Thermal	85 - 90	44 - 46
Atlantic Region light	440 - 470	35 - 37
W. Canada Light, medium, heavy & NGLs	60 - 65	19 - 20
Asia Pacific light & NGLs[3]		13 - 15
Total Crude Oil and Liquids	**1,250 - 1,330**	**234 - 245**

Natural Gas	($ millions)	(mmcf/day)
Canada	150 - 160	345 - 353
Asia Pacific Region	230 - 240	171 - 182
Total Natural Gas	**380 - 400**	**516 - 535**

	($ millions)	(mboe/day)
Total Upstream	**1,630 - 1,730**	**320 - 335**

Downstream	Capital Expenditures ($ millions)
Canada downstream	325 - 350
US downstream	400 - 415
Downstream Total[4]	**725 - 765**

Corporate Costs

Unallocated Capital ($ millions)	15 - 50
Corporate Capital ($ millions)	95 - 105
Total Capital Budget	**2,465 - 2,650**
Other Capital Items ($ millions)[6]	350 - 400
Corporate SG&A ($ millions)	200 - 300

Sustaining Capital ($ millions)	
Upstream	1,300 - 1,350
Downstream	450 - 500
Total Sustaining Capital	**1,750 - 1,850**

2017 Price Planning Assumptions	
WTI, Cushing ($US/bbl)	50.00
3-2-1 Chicago Crack ($US/bbl)	16.00
Natural Gas, AECO ($Cdn/mcf)	2.50
Exchange Rate ($US/$Cdn)	0.76

Operating Costs

Upstream	($/bbl)
Lloyd and Tucker thermal[5]	9.25 - 10.25
Atlantic Region light oil	17.00 - 19.00

	($/mcfe)
Resource Play Natural Gas	1.00 - 1.30
Asia Pacific Region Gas	1.10 - 1.40

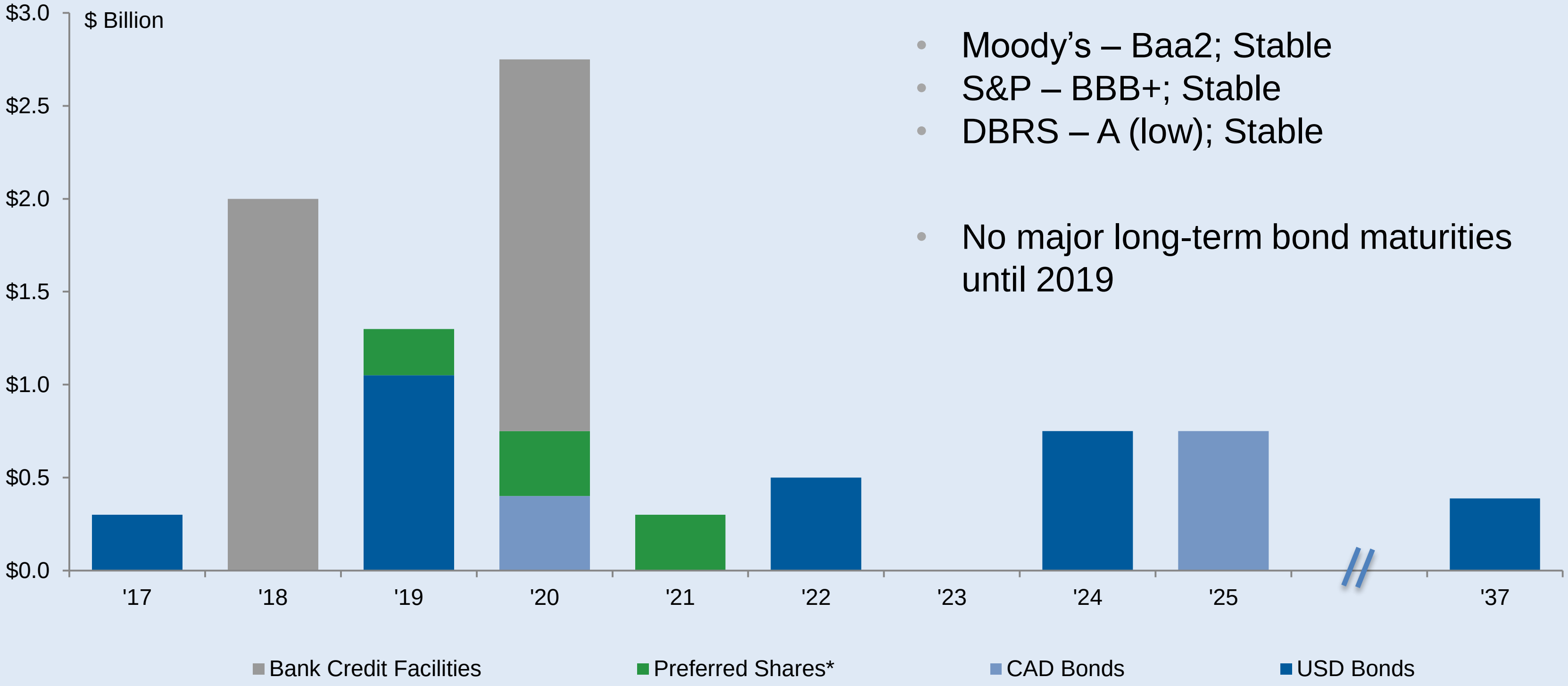
	($/boe)
Total Upstream Operating Cost	**14.00 - 15.00**

Downstream[7]	($/boe)
Lloyd Upgrader	6.50 - 7.50
US Refineries	6.00 - 7.00

1,2,3,4,5,6,7 see *Slide Notes* and *Advisories*

Debt Ratings and Maturity Schedule

Debt Maturity Schedule



* Husky has redemption option.

Strong investment grade credit rating

- Moody's – Baa2; Stable
- S&P – BBB+; Stable
- DBRS – A (low); Stable

- No major long-term bond maturities until 2019

Executive Management

Robert J. Peabody

President & Chief Executive Officer

Mr. Peabody was appointed as Husky Energy's President and Chief Executive Officer and member of the Board of Directors in December, 2016.

He joined Husky as Chief Operating Officer in 2006, and has played a key role in the transformation of the Company.

Mr. Peabody has extensive oil, gas, and chemicals experience, and started his career in Canada, where he worked on early in-situ oil sands development.

Previous positions included President, BP Global Polymers, and Upstream business unit leader in the North Sea. Other leadership roles included senior positions in exploration and production, natural gas marketing, oil trading and project management.

Mr. Peabody holds a Master of Science in Management from Stanford University (Sloan Fellow) and a Bachelor of Science in Mechanical Engineering from the University of British Columbia.

Mr. Peabody is a member of the Foothills Hospital Development Council, Calgary, Alberta. He is also a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

He enjoys skiing, golfing and cycling. He is married to Patricia and has two sons, David and James.

Executive Management

Jonathan McKenzie

Chief Financial Officer

Responsible for the financial management of Husky, including Controllers, Planning, Investment Analysis, Treasury, Tax, Credit, Internal Audit and Business Development.

Career History and Key Accomplishments

Appointed as Chief Financial Officer in April 2015, Mr. McKenzie is an experienced financial executive with extensive energy and utilities sector experience.

Before joining Husky, Mr. McKenzie was Chief Commercial Officer with Irving Oil Ltd. in Saint John, New Brunswick. Prior to Irving Oil, he worked at Suncor Energy Inc. in Calgary as Vice President and Controller. He also worked with Crestar Energy Inc. as Treasury Manager; Manager, Oil and Gas Marketing and, Business Development Manager, South America. He worked with Arthur Andersen & Co. as a Senior Accountant.

Education

Mr. McKenzie has a Bachelor of Commerce degree and a Bachelor of Arts degree from the University of Alberta.

Professional Memberships, Associations and Designations

Mr. McKenzie is a Chartered Accountant.

Executive Management

Rob Symonds

Chief Operating Officer

Responsible for leading Husky's Upstream (excluding Asia Pacific and the Atlantic Region) and Downstream businesses, Mr. Symonds will also have responsibility for Exploration, Safety, Engineering and Procurement.

Career History and Key Accomplishments

Mr. Symonds was appointed Chief Operating Officer in February 2017. Previously, he held the role of Senior Vice President, Western Canada Production. Prior to joining Husky in 2011, he was Vice President, Canadian Operations with Enerplus Resources Fund in Calgary.

Mr. Symonds started his career with Shell where he held a number of engineering and production/ development-related roles in Western Canada, the North Sea, off Canada's East Coast and Calgary. His senior level assignments included Vice President, Foothills Business Unit; Director of Corporate Strategies; and Vice President, Frontier Business Unit.

Education

Mr. Symonds holds a Master of Science in Petroleum Engineering from the University of Alberta and a Bachelor of Science (Chemical Engineering) from the University of Edinburgh.

Professional Memberships, Associations and Designations

Mr. Symonds holds a Professional Engineer designation and is a member of the Society of Petroleum Engineers.

Executive Management

Janet Annesley

Senior Vice President, Corporate Affairs

Responsible for the development of Husky's strategies and engagement approach with internal and external business stakeholders on sensitive or high profile issues having potential for significant strategic business and reputation impact.

Career History and Key Accomplishments
Ms. Annesley is Senior Vice President of Corporate Affairs for Husky Energy. Janet joined Husky from the Government of Canada where she was Chief of Staff to the Minister of Natural Resources.

Prior to serving in government, Janet worked at Queen’s University, as a Vice President at the Canadian Association of Petroleum Producers. She spent 10 years at Shell Canada working in a variety of government relations, communications and stakeholder relations roles.

Education
Ms. Annesley holds a degree in Applied Communications from Mount Royal College, and Masters of Business Administration degrees from Queen’s University and Cornell University.

Professional Memberships, Associations and Designations
Ms. Annesley is also a fellow of the Royal Canadian Geographical Society.

Executive Management

Andrew Dahlin

Senior Vice President, Heavy Oil

Responsible for growing the management and expansion of Husky's heavy oil portfolio.

Career History and Key Accomplishments

Mr. Dahlin was appointed Senior Vice President of Heavy Oil in 2017. Prior to this appointment, he was Vice President of Operations & Projects in Western Canada where he was a core contributor to delivering the transformation of Husky's Western Canada business.

Prior to joining Husky in 2011, Mr. Dahlin had a 19-year career with Shell (Europe, Middle East, Canada) in progressively senior technical, operational, commercial and management roles in their Upstream business.

Education

Mr. Dahlin holds a Master of Science in Petroleum Engineering from Imperial College in London, U.K., and a Bachelor of Engineering in Civil Engineering from the University of Surrey, U.K.

Originally from Norway, he is married to Nicola and has three children. He enjoys skiing, mountain-biking and golfing.

Executive Management

Jeff Rinker

Vice President, Downstream Value Chain

Career History and Key Accomplishments

Jeffrey Rinker joined Husky in February 2017 as VP Downstream Value Chain with responsibility for crude oil and gas marketing, hydrocarbon supply chain planning and optimization, refinery feedstock supply, and US refined product sales.

A Chemical Engineer by training, Jeff graduated from Carnegie Mellon University in 1989. He came to Husky from the Austrian integrated oil company OMV, where he was a Senior Vice President for 11 years including assignments as director of Romanian Refining & Petrochemicals, manager of Integrated Value Chain, and most recently as the head of M&A.

Earlier, Jeff worked at BP for 16 years in various technical and management roles, including as the Optimization manager for the Toledo refinery of which Husky now owns half. He has also held several board positions in the industry, including as a director of PARCO, the largest oil refinery in Pakistan.

Jeff and his wife Andrea enjoy travel and hiking in the mountains.

Executive Management

Gerald Alexander

Senior Vice President, Western Canada Production

Responsible for the leadership and management of Husky's Upstream business in Western Canada, excluding Heavy Oil and Oil Sands. Focus is on growing Husky's production from oil and gas resource plays while achieving finding and development and operation cost targets.

Career History and Key Accomplishments

Mr. Alexander was appointed Senior Vice President, Western Canada Production in February 2017. Prior to his appointment, he was Vice President, Western Canada Development.

Mr. Alexander started his oil and gas career with Mobil Oil and Amerada Hess where he held a number of production/operations related roles in Western Canada. He joined Husky in 2000, after Husky acquired Renaissance Energy where Mr. Alexander was Chief Production Engineer. Throughout his tenure at Husky, he has held progressively senior positions in production and development including Manager of Ram River operations and General Manager of the Southern Alberta, South Saskatchewan business unit.

Education

Mr. Alexander holds a Bachelor of Science in Petroleum Engineering from the University of Montana and a diploma in Petroleum Technology from the Southern Alberta Institute of Technology.

Professional Memberships, Associations and Designations

Mr. Alexander is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and the Professional Engineers and Geoscientists of Saskatchewan (APEGS).

Executive Management

Robert Hinkel

Chief Operating Officer, Asia Pacific Region

Responsible for managing Husky's South East Asia assets including China and Indonesia operations, Asia Pacific exploration, new business development, commercial activity and the Liwan and Madura projects.

Career History and Key Accomplishments

With more than 30 years experience in the energy and mining industries, Mr. Hinkel joined Husky in 2010 as Chief Operating Officer, Asia Pacific. Immediately prior to joining Husky, he held the position of Senior Vice President - Operations for Asia Pacific Exploration Company, a private exploration and production company. From 2003 until 2007, he was the President and CEO of Enventure Global Technology, a subsidiary of the Shell Group.

A frequent public speaker in the industry, Mr. Hinkel has also published articles and technical papers on the topics of Arctic drilling, commercialization of new technology, contractor safety management, and continuous operational Improvement.

Education

Mr. Hinkel graduated magna cum laude from the University of Texas at Austin with a Bachelor of Science Degree in Petroleum Engineering. He subsequently earned an MBA in International Management from Thunderbird University in Phoenix, Arizona.

Executive Management

Malcolm Maclean

Senior Vice President, Atlantic Region

Responsible for Husky's Atlantic Region operations.

Career History and Key Accomplishments

With more than 30 years of international operational and project experience in the upstream sector, Mr. Maclean joined Husky as Vice President, Developments for the Atlantic Region in 2011. In October 2012, he was appointed Senior Vice President, Atlantic Region.

Prior to joining Husky, Mr. Maclean was Vice President, Developments for Petrofac. From 2000 until 2010, he held several senior positions with the Hess Corporation. As Vice President, South East Asia he successfully led the organization through a period of rapid expansion. Other assignments included Country Manager, Algeria where he led a major field redevelopment project and Vice President, Business Development.

Education

Mr. Maclean holds a Bachelor of Science in Mechanical Engineering from Dundee College of Technology, Scotland, and a Postgraduate Diploma in Offshore Engineering from Robert Gordon's Institute of Technology, Aberdeen, Scotland.

Professional Memberships, Associations and Designations

Mr. Maclean is a member of the Institution of Mechanical Engineers, Energy Institute and Society of Petroleum Engineers.

Executive Management

Brad Allison

Senior Vice President, Exploration

Responsible for the leadership of Husky's exploration related business including geological and geophysical services.

Career History and Key Accomplishments

Mr. Allison was appointed Vice President, Exploration in June 2010 with responsibilities for resource capture and appraisal within the Western Canada Basin, Canadian Frontier and International regions, as well as geological and geophysical services and business development. Prior to his appointment, he was General Manager, Canadian / International Exploration. Mr. Allison joined Husky in 2002 as Deep Basin Exploration Manager. In 2012, he was made Senior Vice President.

Prior to joining Husky, Mr. Allison was Vice President and Chief Geoscientist with Advantage Energy Services Ltd. focusing on asset optimization and M & A evaluations. Mr. Allison started his career with Imperial Oil Limited where he held a number of technical and management related roles involving Western Canada exploration, Canadian Frontiers and Oil Sands. He also worked on an assignment with Esso UK working in the Central North Sea on both exploration and development projects.

Education

Mr. Allison holds a Bachelor of Science (Honours) in Geology from Mount Allison University.

Professional Memberships, Associations and Designations

Mr. Allison holds a Professional Geologist designation and is a member of the CSPG and AAPG.

Executive Management

Bob I. Baird

Senior Vice President, Downstream

Responsible for all of Husky Energy's integrated Downstream including pipelines, upgrading, refining, transportation, marketing and retail operations.

Career History and Key Accomplishments

Mr. Baird was appointed Senior Vice President, Downstream in April 2012. Previously he had been Vice President, Downstream and Vice President, Upgrading and Refining for Canada. He is responsible for overseeing five business units including Canadian Downstream, U.S. Refining, Retail & Canadian Product Marketing, Commodity Supply & Marketing and Downstream Commercial. Prior to Husky, Mr. Baird worked in several senior roles including refining, strategy, and consulting for Royal Dutch Shell in Canada and Europe.

Education

Mr. Baird graduated from Concordia University with a Bachelor of Engineering, Mechanical in 1982. He also has a Management Certificate from IMD in Lausanne, Switzerland.

Professional Memberships, Associations and Designations

Mr. Baird is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).

Executive Management

Nancy Foster

Senior Vice President, Human & Corporate Resources

Responsible for Human Resources, Diversity, Real Estate, Corporate Services, Information Services and Corporate Responsibility.

Career History and Key Accomplishments

Appointed as Vice President, Human & Corporate Resources in 2011, Ms. Foster is an experienced human resources practitioner with extensive oil and gas experience, both domestically and internationally. In 2012, she was made Senior Vice President.

Prior to that, she was the Senior Vice President, Human Resources and Corporate Services at Nexen, responsible for strategic oversight and operation of all human resources functions for a global employee base of 4,000. She also provided oversight of the supply management and corporate administration functions.

Education

Ms. Foster holds a Bachelor of Arts degree from McMaster University and is a graduate of the Harvard Advanced Management Program.

Professional Memberships, Associations and Designations

Ms. Foster has served on a number of industry related committees, including the Alberta Economic Development Authority, CAPP and the Conference Board of Canada. She has worked on numerous charitable committees, including the Alberta Children's Hospital Foundation, Child & Youth Friendly Calgary, Hospice Calgary, the United Way of Calgary & Area, and the YWCA of Calgary.

Executive Management

David A. Gardner

Senior Vice President, Business Development

Reporting to the Chief Financial Officer, Mr. Gardner is responsible for leading business development activities across Husky Energy and for building the Company’s capability and capacity in this strategic area.

Career History and Key Accomplishments
Mr. Gardner was appointed Senior Vice President, Business Development at Husky in December 2014. Before coming to Husky, he had a nearly 17– year career with BP, most recently as Director of Upstream Business Development, Europe & Africa, in London, United Kingdom.

Prior to that he was Vice President Business Development, Exploration Access, in London.

Previous BP roles included Mergers & Acquisitions Project Manager in Houston, Texas; Commercial Manager in Cairo, Egypt; and Strategy, Planning & Performance Manager in the Group Business Centre in London.

Education
Mr. Gardner has a Bachelor of Science with a Geology major and a German minor from The College of William and Mary in Virginia; a Masters in Geology from the University of Wisconsin — Madison; and an MBA, Finance & Entrepreneurship, from University of California, Los Angeles — The Anderson Graduate School of Management.

Professional Memberships, Associations and Designations
Mr. Gardner is a member of the Association of International Petroleum Negotiators.

Executive Management

Terry Manning

Senior Vice President, Safety, Engineering & Procurement

Responsible for safety, procurement, project management services and technical services. .

Career History and Key Accomplishments

Mr. Manning was appointed Vice President, Safety, Engineering & Procurement in January 2012 with responsibilities for process and occupational safety, project management and technical services, and procurement. Prior to this appointment, he was Vice President, Engineering & Procurement Management. And previously he was Vice President, Engineering & Project Management.

Prior to joining Husky, Mr. Manning was Vice President, Capital Projects for Barrick Gold Corporation where he had accountability for Barrick's portfolio of megaprojects and development of project business systems. From 2002 to 2006, Mr. Manning was General Manager, Project Management Office with Suncor Energy Inc.

Mr. Manning has worked for Agrium, where he was Director of Projects, focused primarily on international project development.

Education

Mr. Manning holds a Bachelor of Applied Science in Mechanical Engineering from the University of Toronto.

Professional Memberships, Associations and Designations

Mr. Manning is a member of Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Professional Engineers and Geoscientists of British Columbia (APEGBC).

Executive Management

Jerry P. Miller

Vice President, U.S. Refining

Career History and Key Accomplishments

Mr. Miller was appointed Vice President, U.S. Refining in October 2015. As Vice President and General Manager of the Lima Refining Company, he is responsible for refining operations in the United States, including the Lima Refinery. Mr. Miller was previously Husky's General Manager of the Lloydminster Upgrader in Alberta/ Saskatchewan, Canada.

Mr. Miller joined Husky in 2008 as General Manager of U.S. Refined Products and New Ventures at the Husky Marketing and Supply business unit located in Columbus, Ohio.

Before joining Husky, Mr. Miller was the General Manager of Asphalt and Energy Operations with Oldcastle Materials Group in Columbus, Ohio.

Mr. Miller retired from the United States Army National Guard as a Lieutenant Colonel. He served as an active duty infantry officer, airborne ranger and an instructor at the elite ranger school. Throughout his military career, Mr. Miller led several overseas deployments. In addition to earning the elite U.S. Army Ranger tab, he also received the Bronze Star and the Combat Infantry Badge.

Education

Mr. Miller holds a Master of Business Administration from Penn State University and a Bachelor of Science in Accounting from the University of Pittsburgh.

Professional Memberships, Associations and Designations

Mr. Miller is certified as a Six-Sigma Green Belt and partial Black Belt (non-ASQ Certified).

Executive Management

John Myer

Senior Vice President, Oil Sands

Responsible for the Oil Sands Business Unit.

Career History and Key Accomplishments

Mr. Myer was appointed Vice President, Oil Sands, in November 2010 with responsibilities to develop and operate the Sunrise SAGD asset and advance Husky's portfolio of emerging properties in the oil sands region. In 2012, he was made Senior Vice President.

Prior to his appointment at Husky, he was with Suncor Energy for 20 years in such roles as Vice President InSitu, Vice President Exploration and Development and Vice President Production. Before moving to the executive level he held management positions in Acquisitions and Divestments, Reservoir Exploitation and Exploration. Mr. Myer started his career with Home Oil, where he held technical and supervisory positions in facility design and construction, production, operations, and reservoir engineering for the 12 years he was with the organization.

Education

Mr. Myer holds a Bachelor of Science in Engineering, a Masters degree in Petroleum Engineering, and a Masters in Business Administration, all from the University of Calgary.

Professional Memberships, Associations and Designations

Mr. Myer is a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, Society of Petroleum Engineers and Canadian Heavy Oil Association.