Husky

Investor Day

May 28, 2019

Agenda

- **Overview**
  Rob Peabody, CEO
- **Safety and Reliability**
  Peter Rosenthal, SVP Safety & Operations Integrity
- **ESG Priorities**
  Janet Annesley, SVP, Corporate Affairs
- **Financial Framework**
  Jeff Hart, CFO
- **Plan Delivery, Innovation & Technology**
  Rob Symonds, COO

Integrated Corridor

- **Downstream**
  Jeffrey Rinker, SVP, Downstream
- **Thermal / Sunrise Update**
  Andrew Dahlin, SVP, Heavy Oil & Oil Sands
- **Resource Plays**
  Gerald Alexander, SVP, Western Canada

Offshore

- **Atlantic**
  Jonathan Brown, VP Operations, Atlantic
- **Asia Pacific**
  Bob Hinkel, COO, Asia Pacific

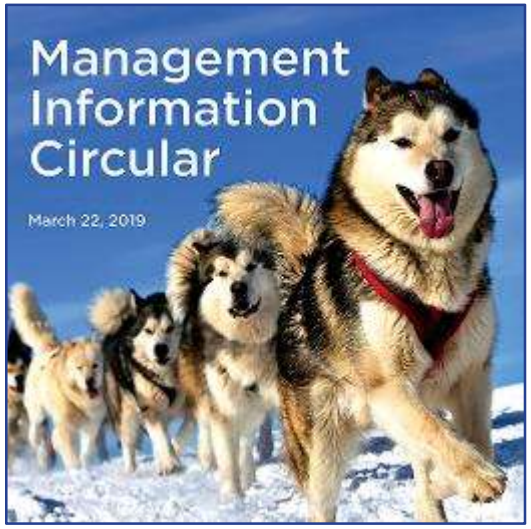
- **Wrap-up & Q&A**
  Rob Peabody

Overview

Rob Peabody, President & CEO

Our Top Priority: Safe & Reliable Operations

Safety Aligned With Compensation



New SVP of Safety & Operations Integrity

Five Principles of a High Reliability Organization

- Knowledge & learning
- Standards & procedure compliance
- Questioning attitude
- Team backup
- Integrity

Competitively Advantaged Business Model

Built To Mitigate Risks In A Cyclical Industry, While Preserving Upside

Integrated Corridor
(~70% Contribution)

Upstream (2018)

Production	Netback[2]
231 mboe/day	$12 /boe

Downstream (2018)

Throughput	Gross Margin[3]
347 mboe/day	$20 /bbl

Thermal & Heavy Oil

- Large supply of low-cost, reliable feedstock

Western Canada

- Supplies gas to Corridor
- Competitive, standalone business

Downstream

- Captures full value for all Corridor production

Offshore
(~30% Contribution)[1]

Production (2018)	Operating Costs (2018)	Netback[2] (2018)
68 mboe/day	$12 /boe	$65 /boe

Asia Pacific

- Attractive, long-term contracts
- Fast-growing market

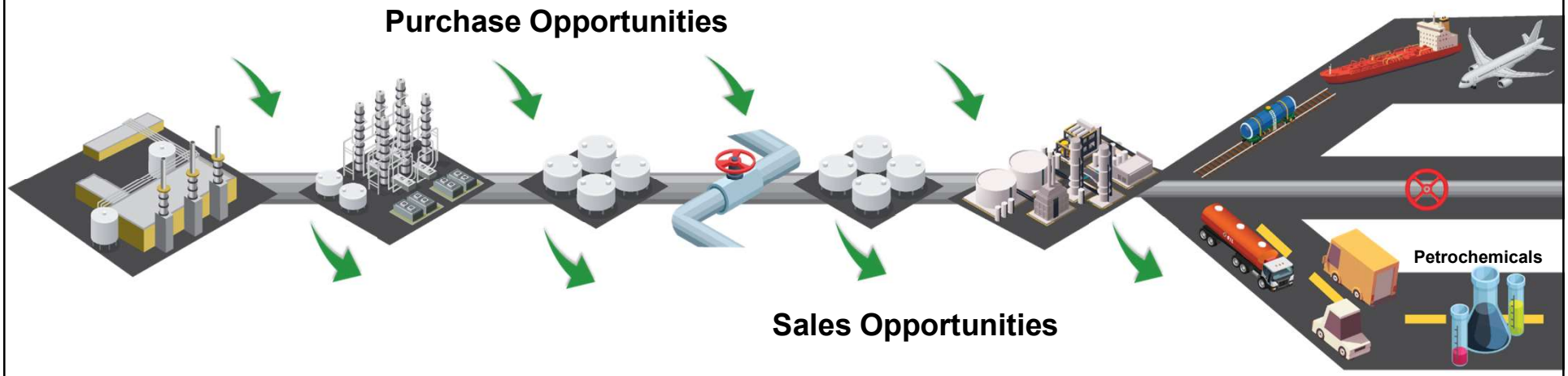
Atlantic

- High-netback production
- Global pricing
- Production growth

1, 2, 3) See Slide Notes and Advisories

Maximizing Full Value Chain Margin Capture

Integrated Corridor – Manufacturing Process

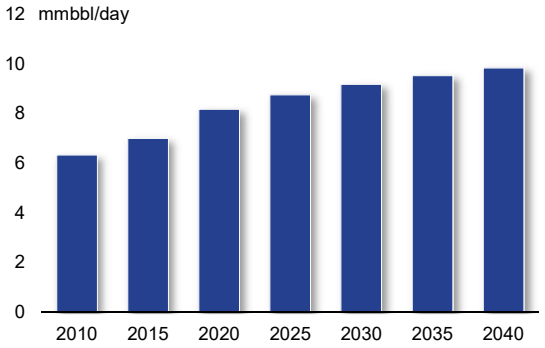


Growing Demand For Integrated Corridor Products

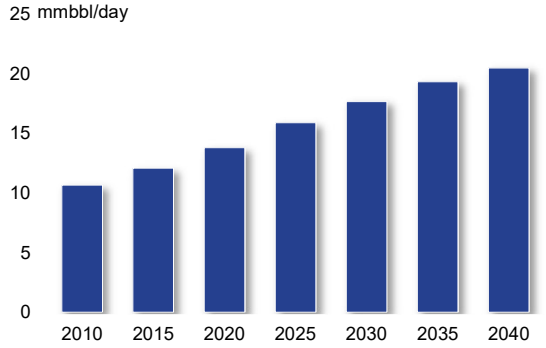
Supplying Refined Products To Meet Forecast Global Demand

- Husky is well-positioned as a growth business in a growing market
- Demand[1] is being led by aviation, petrochemicals, global population and GDP growth in the developing world

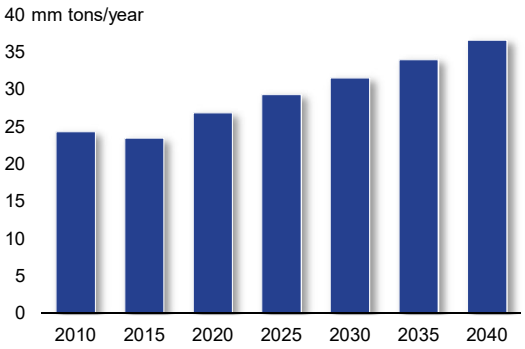
Global Jet Fuel Demand



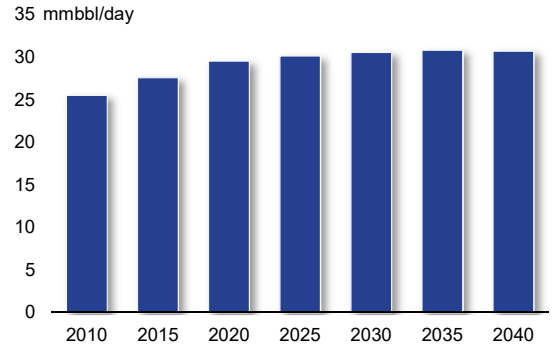
Global Petrochemical Feedstocks Demand



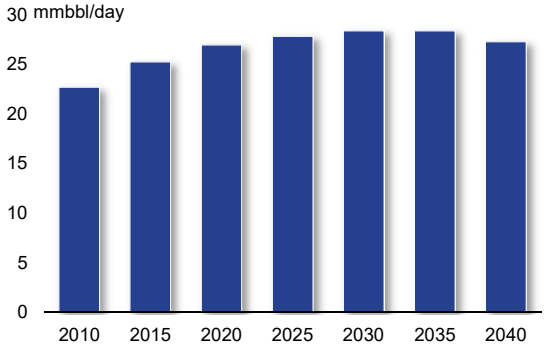
Asphalt Demand



Global Diesel and Distillates Demand



Global Gasoline Demand



1) See Slide Notes and Advisories

Maximizing Full Value Chain Margin Capture

Integrated Corridor – Manufacturing Process

Increasing Revenue

- Improving uptime and reliability
- Upstream production growth
- Refining throughput capacity growth with increased heavy oil processing
- Expanding end-user markets for our asphalt

Reducing Costs

- Growth of lower cost Upstream production
- Use of existing infrastructure
- Cluster approach for Lloyd thermal projects
- Use of regional operational hubs in Western Canada
- Multiple technologies

Improving Optionality

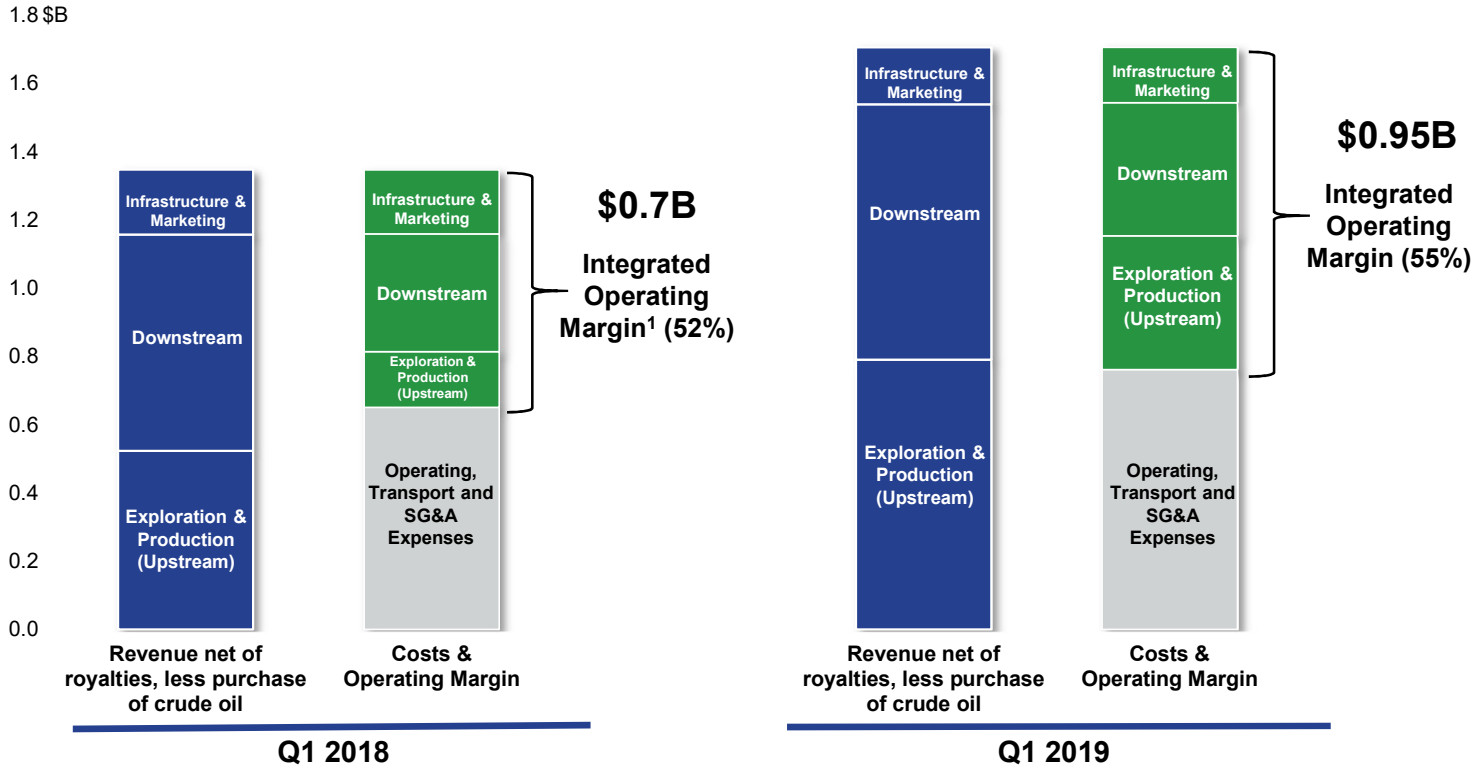
- Increasing flexibility of refineries and Upgrader
- Optimizing use of storage and pipeline assets
- Increasing feedstock options
- Developing more connectivity to refined product markets

Improving Quality & Speed of Commercial Decisions

- Clear separation of manufacturing; trading, supply and logistics; marketing; and optimization teams
- Optimization team creates the plan, responds in real time to maximize performance
- Use of technology (enhanced optimization models)

Maximizing Full Value Chain Margin Capture: Example

Integrated Corridor – Manufacturing Process



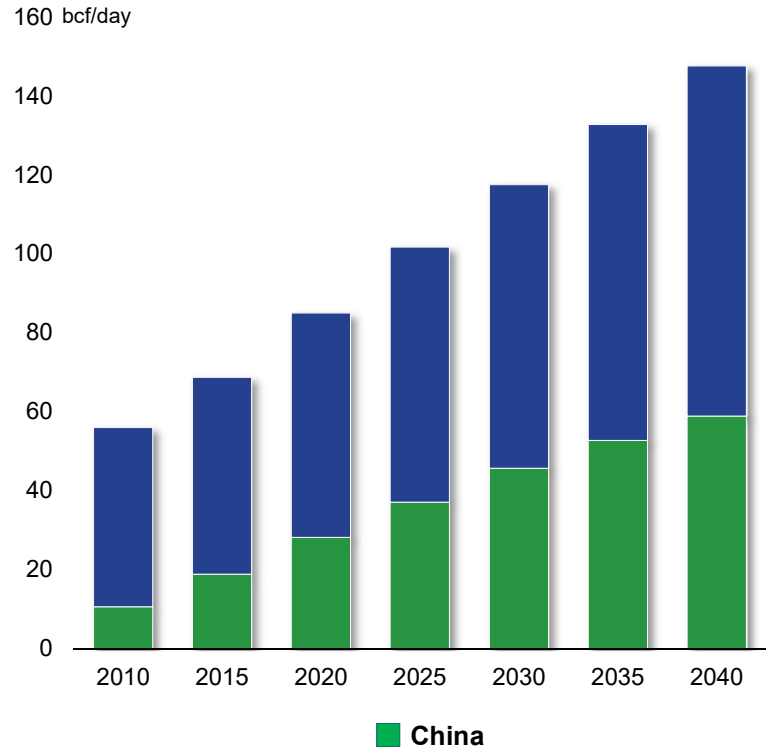
In Both Cases: ~$84 CAD Brent Prices

1) See Slide Notes and Advisories

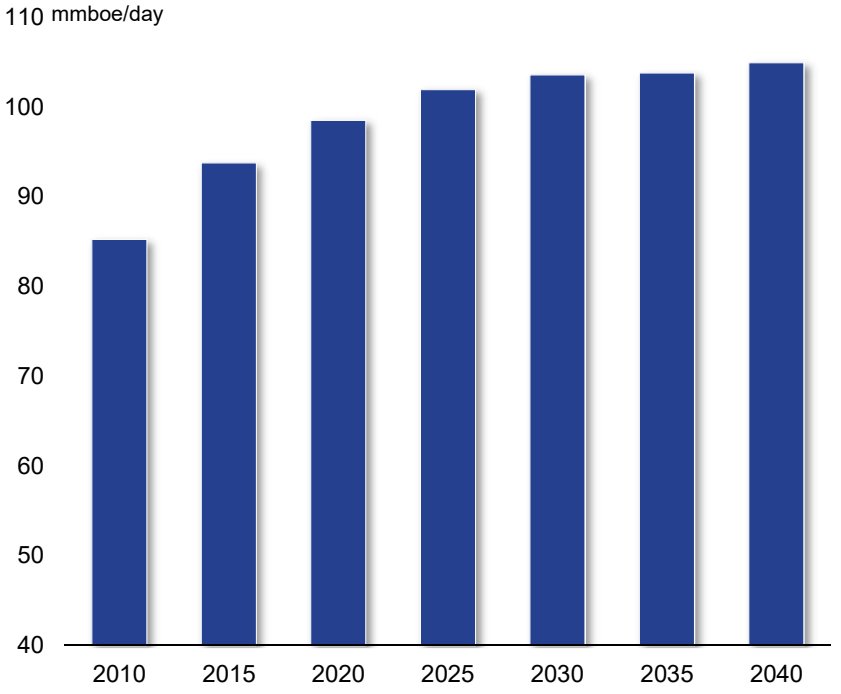
Offshore Business Forecast Demand

Supplying Products To Meet Growing Demand

Asia Gas Demand[1]



Global Oil Demand[2]

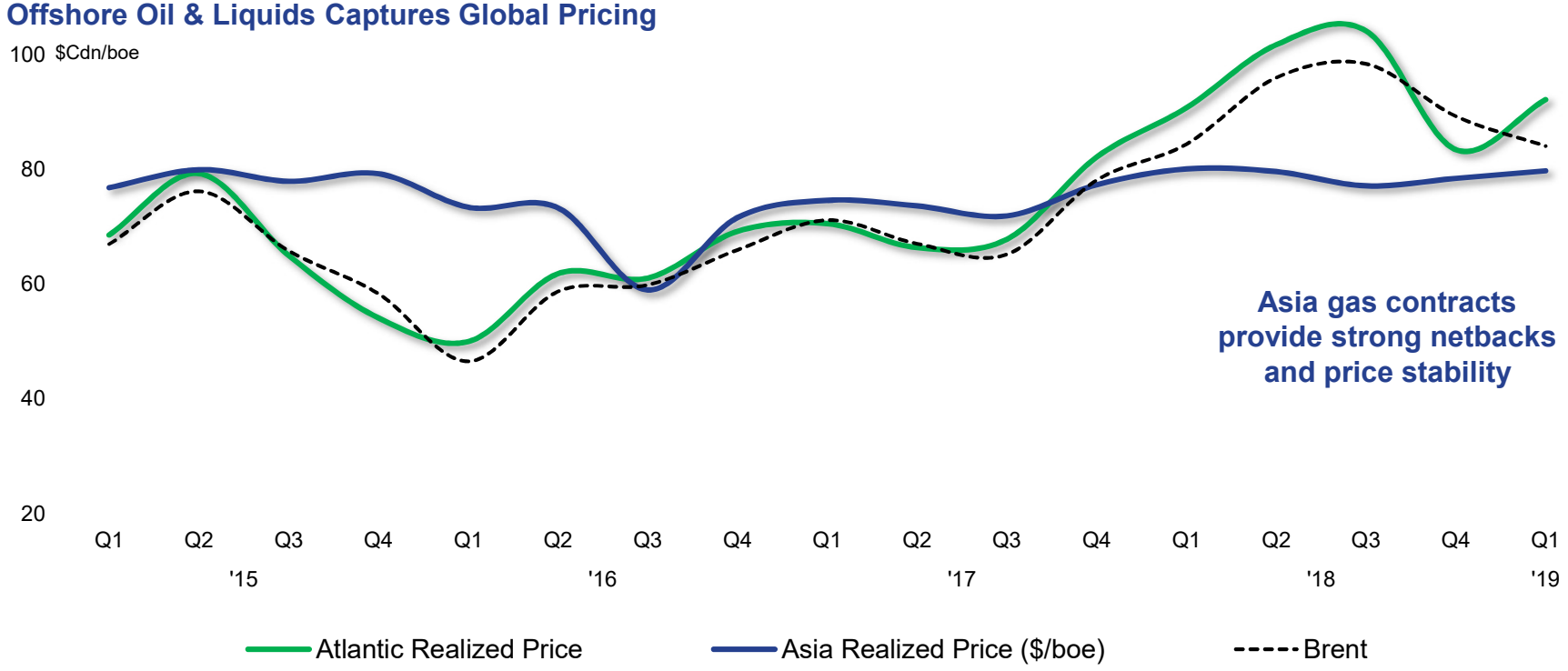


1, 2) See Slide Notes and Advisories

Fixed-Price Asia Gas Complemented By Oil Price Torque

Offshore Business

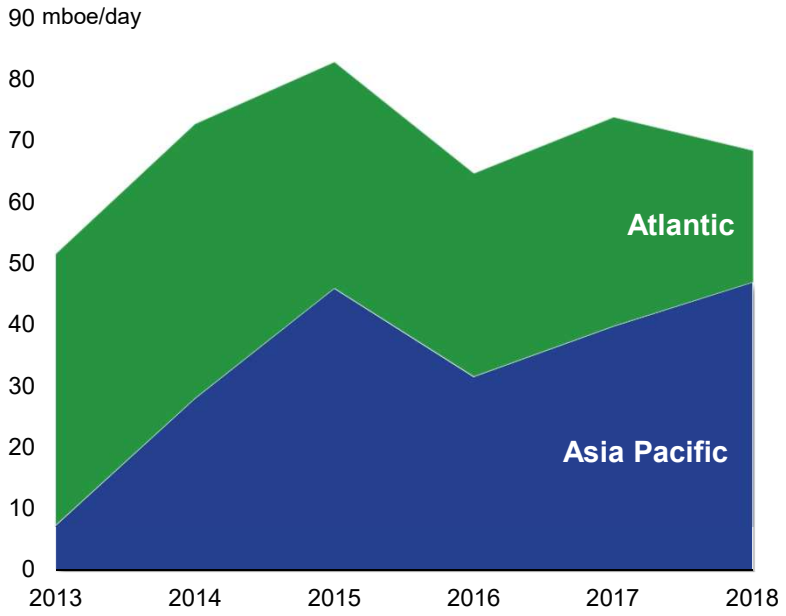
Offshore Oil & Liquids Captures Global Pricing



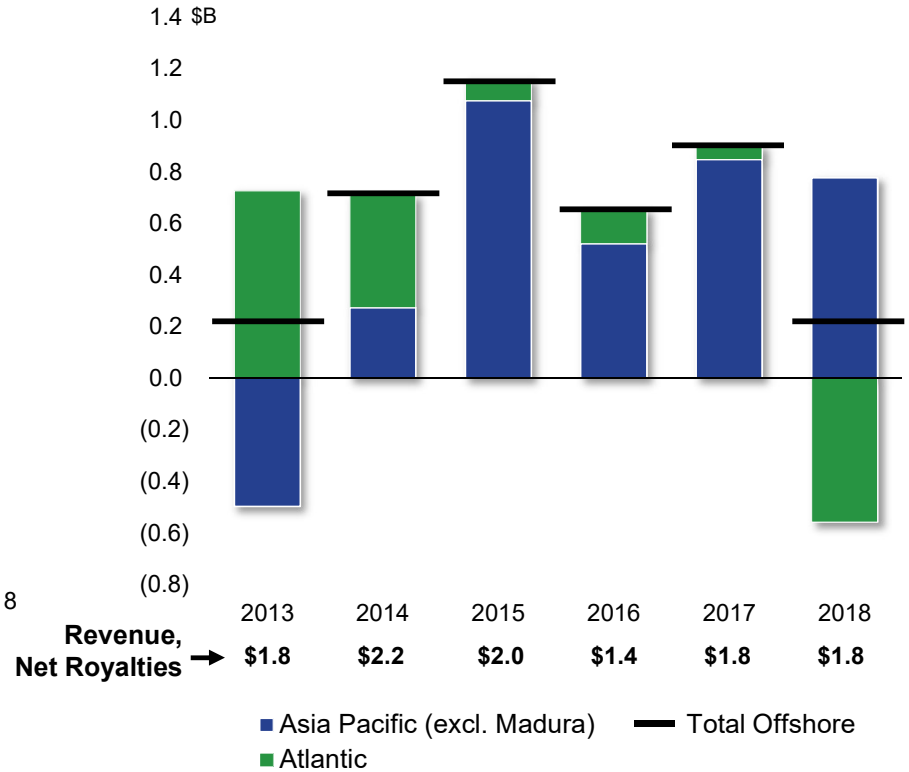
Strong Operating Margin Generator

Offshore Business

Offshore Production



Offshore Operating Margin Less Capital[1,2]

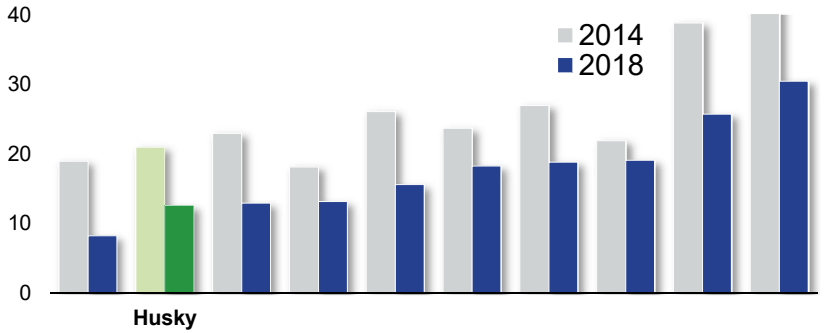


1, 2) See Slide Notes and Advisories

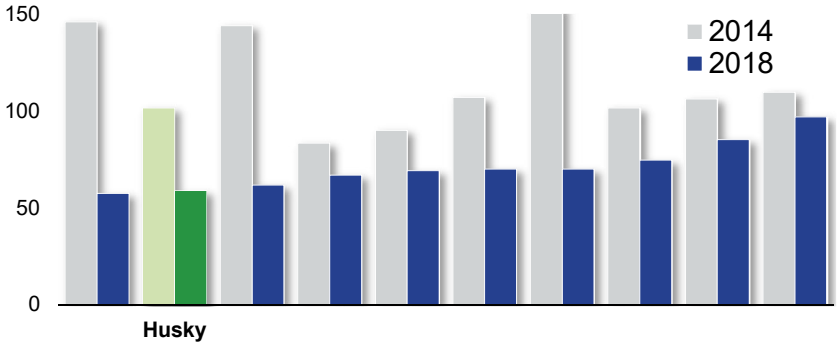
Improving Performance

How Husky Stacks Up

Upstream Operating Costs (US$/boe)



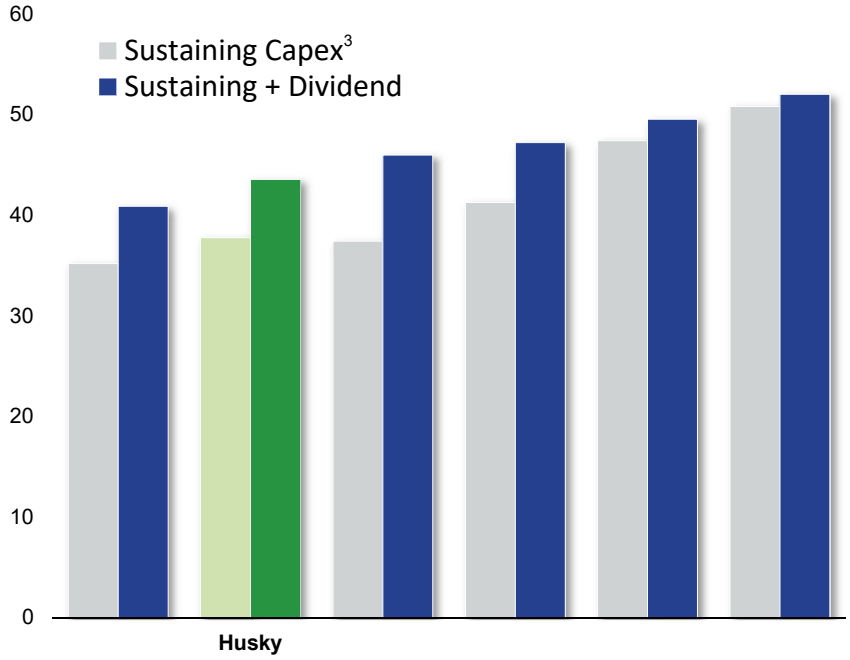
Oil-Weighted Supply Cost Rankings[1] (US$/boe, Brent)



Source: BMO Capital Markets research.
Peers: BP, Cenovus, Chevron, ConocoPhillips, CNRL, Exxon, Imperial, Occidental, Suncor.

Cash Flow Break-Even[2]

WTI Required to Fund Sustaining Capex and Dividend (2019F, US$/boe)



Source: Scotia Capital research.
Peers: Cenovus, CNRL, Encana, Imperial, Suncor.

1, 2, 3) See Slide Notes and Advisories

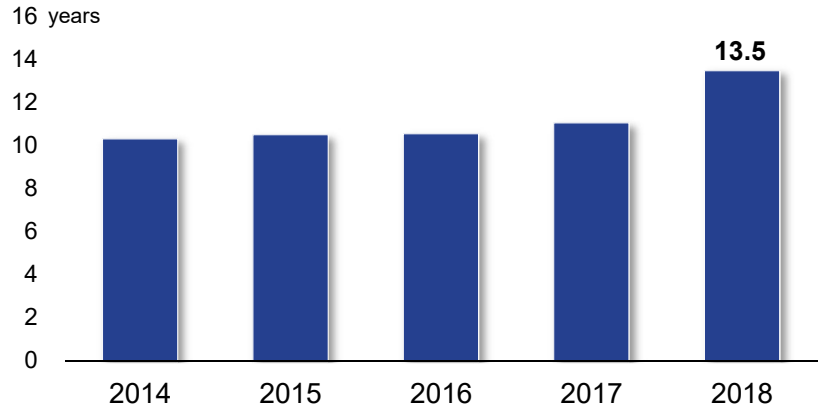
Deep Portfolio

Ramping Up Higher Margin Feedstock Production While Growing Reserves

Project Portfolio	Capacity*	Startup
Thermal Bitumen (bbls/day)		
Dee Valley	10,000	2019
Spruce Lake Central	10,000	2020
Spruce Lake North	10,000	2020
Spruce Lake East	10,000	2021
Edam Central	10,000	2022
Dee Valley 2	10,000	2023
Sunrise Phase 1 debottleneck	4,000	2024+
Future Lloyd thermals 1-5	50,000	2024+
Future Sunrise phases	60,000	2024+
Downstream (bbls/day)		
Lima Crude Oil Flexibility Project (Ability to switch to heavy oil feedstock)	10,000 → 40,000	2019
Lloyd Upgrader capacity increase - Diesel debottleneck	80,000 → 81,500 6,000 → 9,800	2020
Superior enhancements	40,000 → 45,000	2021
Asia Pacific (boe/day)		
Liuhua 29-1	9,300	2020
MDA-MBH & MDK	10,000	2021+
Atlantic (bbls/day)		
West White Rose Project	52,500	2022
Total Upstream Project Volumes*	**~250,000**	

- Added 279 mmboe of proved reserves in 2018
- 260% proved reserves replacement ratio[1]
- Proved reserves of 1.5 mmboe (before royalties)
- Probable reserves of 1.1 mmboe (before royalties)

Proved Reserves Life Index (RLI)



* Husky Working Interest (at peak)

1) See Slide Notes and Advisories

Business Plan Update – What's New?

Strategic

- Implementation of High Reliability Organization principles
- Canadian retail and commercial fuels business sale process
- Prince George Refinery sale process
- Downstream business reorganized

Financial

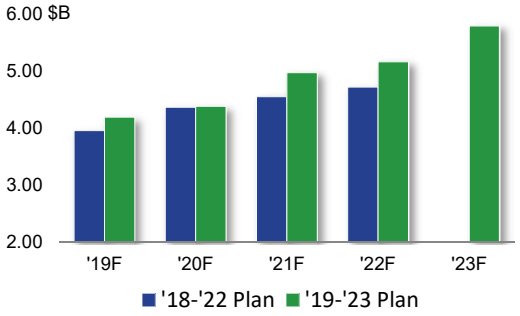
- Increased free cash flow profile
- Reduced average annual capital spending to $3.15 billion (previously $3.5 billion) for total of over $1.7 billion over the plan
- Using $40 US WTI for bottom of the cycle planning (previously $35 US WTI)
- Pricing assumption unchanged at a flat $60 US WTI
- Canada-U.S. exchange to $0.75 from $0.80
- Superior rebuild timing incorporated; robust insurance policy in place

Projects / Operations

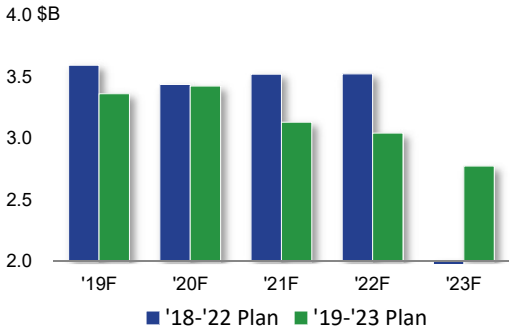
- Dee Valley first oil in Q3 '19 ahead of schedule
- Alberta production quotas
- Focus on margin capture vs. growth at Sunrise and Tucker
- Future Lloyd thermal projects paced to three every two years, given pipeline outlook
- Slowed growth in W. Canada resource plays
- West White Rose Project paced to focus on capital efficiency (startup still planned for 2022)
- Downstream margin improvements:
  - Lima capacity enhancement
  - Lloyd Upgrader/diesel debottleneck
  - Superior Refinery rebuild enhancements (post-startup)
- Madura fields deferred by one year

Free Cash Flow Of $8.7 Billion Over Next Five Years

Funds from Operations[1,2] / Cash Flow from Operating Activities

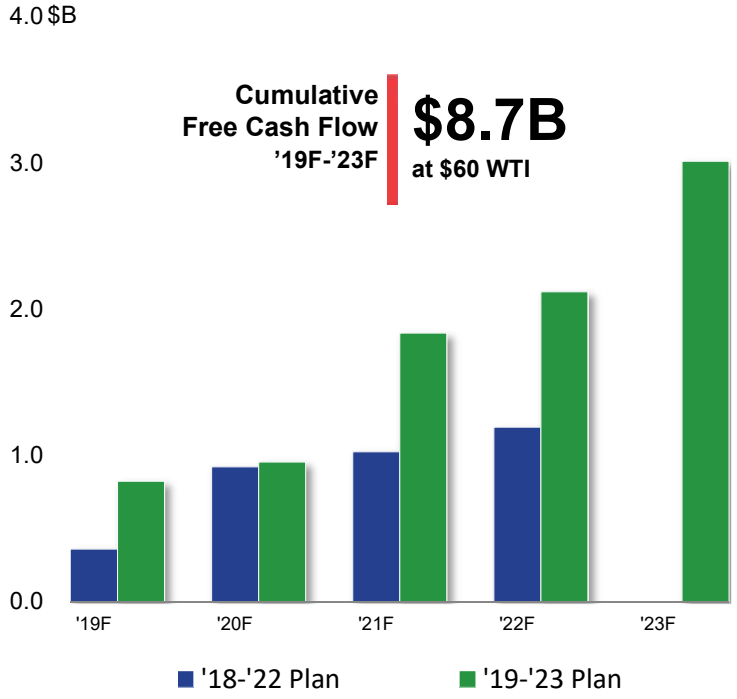


Reduced Capital Expenditures[3]

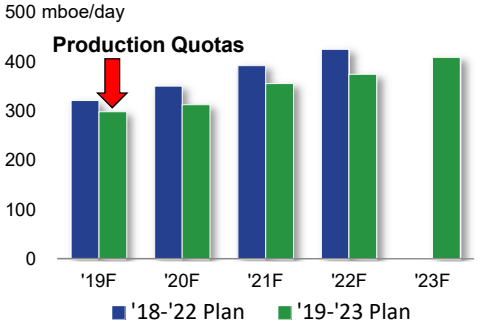


Free Cash Flow[4]

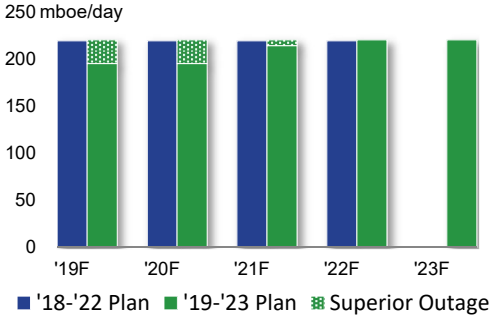
(FFO Less Capital Expenditures)



Paced Production[5]



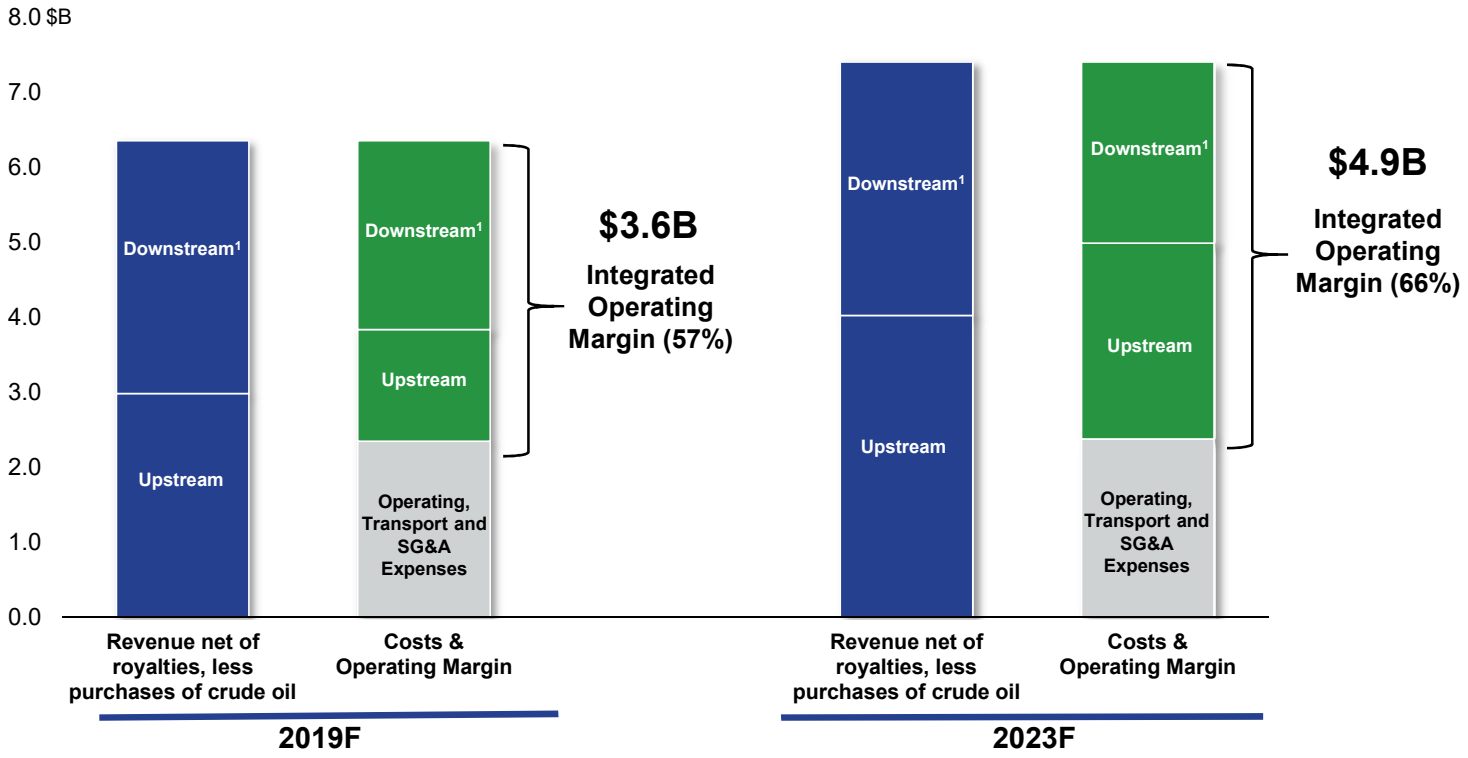
Heavy Oil Processing Capacity



1, 2, 3, 4, 5) See Slide Notes and Advisories

Integrated Corridor Outlook

Increasing Operating Margins



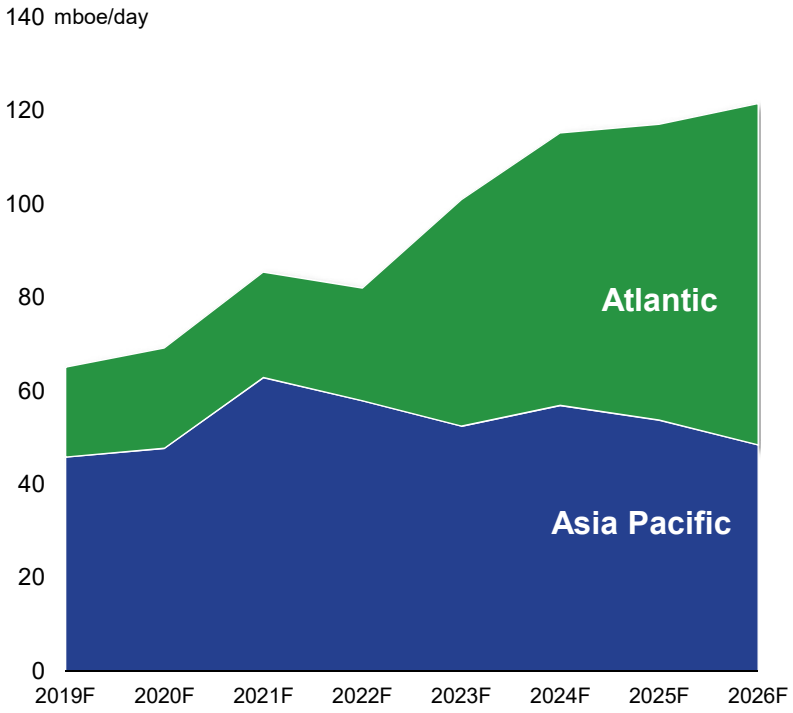
Flat $60 US WTI & Chicago 3-2-1 of $18 US in ’19 and $16 US in ’23

1) Infrastructure and Marketing segment included in Downstream

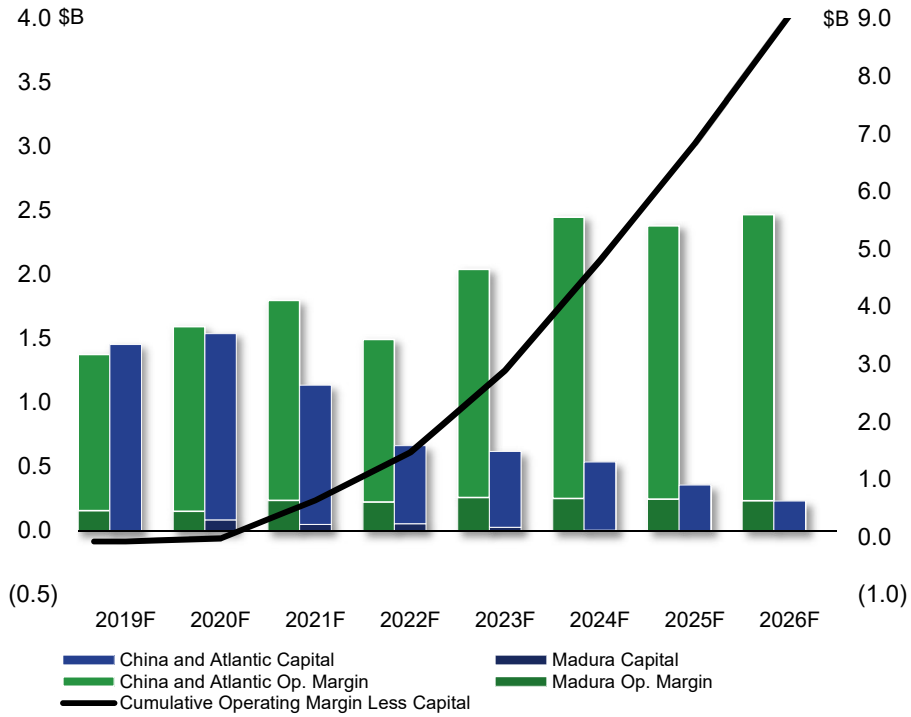
Offshore Business Outlook

Ramp-ups Of West White Rose And Liuhua 29-1 Make Strong Contribution

Production



Offshore
Operating Margin Less Capital[1]

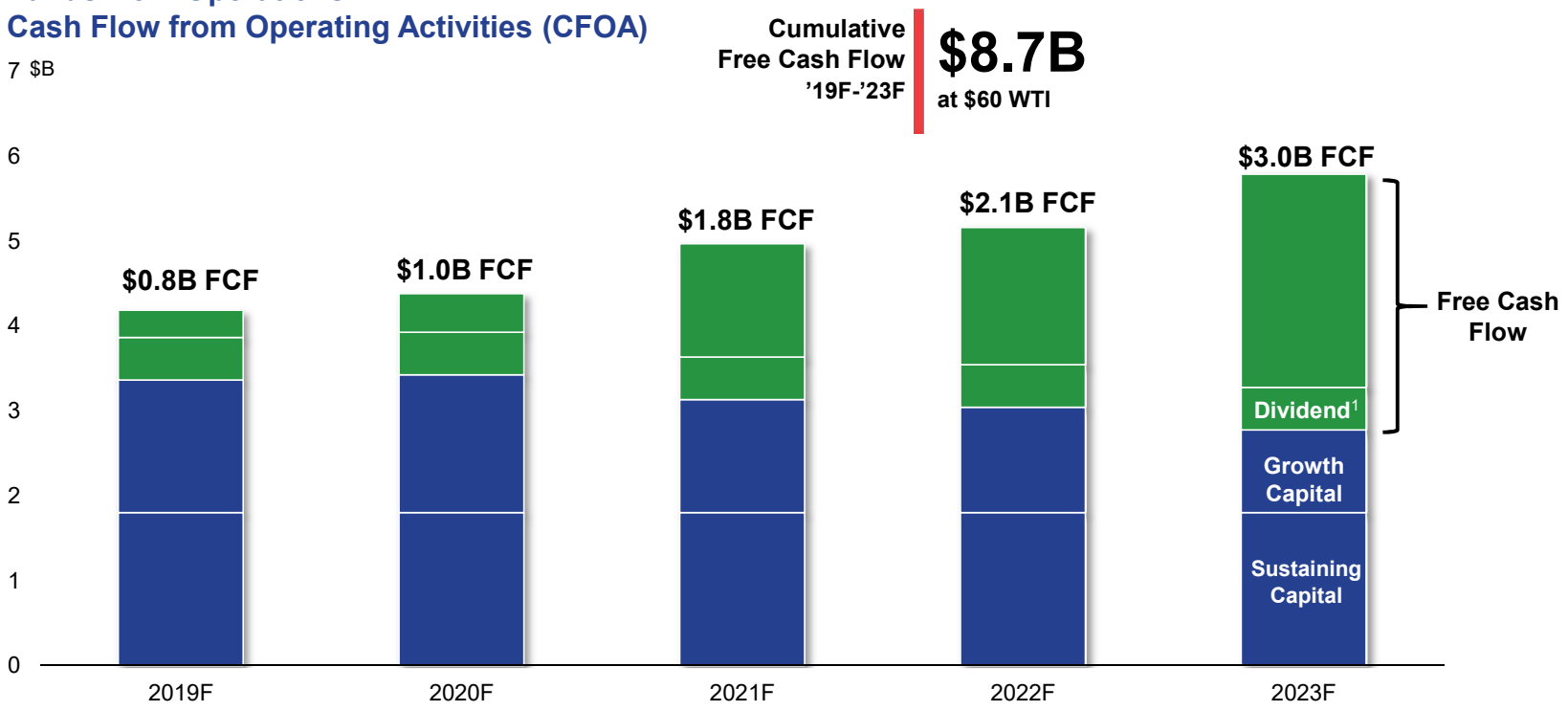


1) See Slide Notes and Advisories

Strong Free Cash Flow Growth

Increasing Ability To Return Cash To Shareholders

Funds from Operations / Cash Flow from Operating Activities (CFOA)



1) See Slide Notes and Advisories

Delivering Our Plan

Husky's Value Proposition

- Safe and reliable operations
- Production and throughput growth from a large inventory of higher margin projects = returns-focused growth
- Improving earnings and cash break-evens
- Strong growth in funds from operations and free cash flow
- Ability to increase cash returns to shareholders
- Strong balance sheet, integration and fixed-price gas sales in Asia provide resilience to volatile market conditions while preserving upside

Safety & Operations Integrity

Peter Rosenthal, SVP, Safety & Operations Integrity

Lloydminster Upgrader

What Good Looks Like

Safety & Operations Integrity

We are systematic and in control when operational and technical requirements:

- Are documented, correct, well understood and practiced
- Have clear accountabilities
- Have defined competencies that can be documented
- Verified over time

Building A High Reliability Organization (HRO)

Safety & Operations Integrity

HRO Principles & Safety Culture

- Knowledge and learning
- Standards and procedure compliance
- Questioning attitude
- Team backup
- Integrity

Atlantic Region

Western Canada

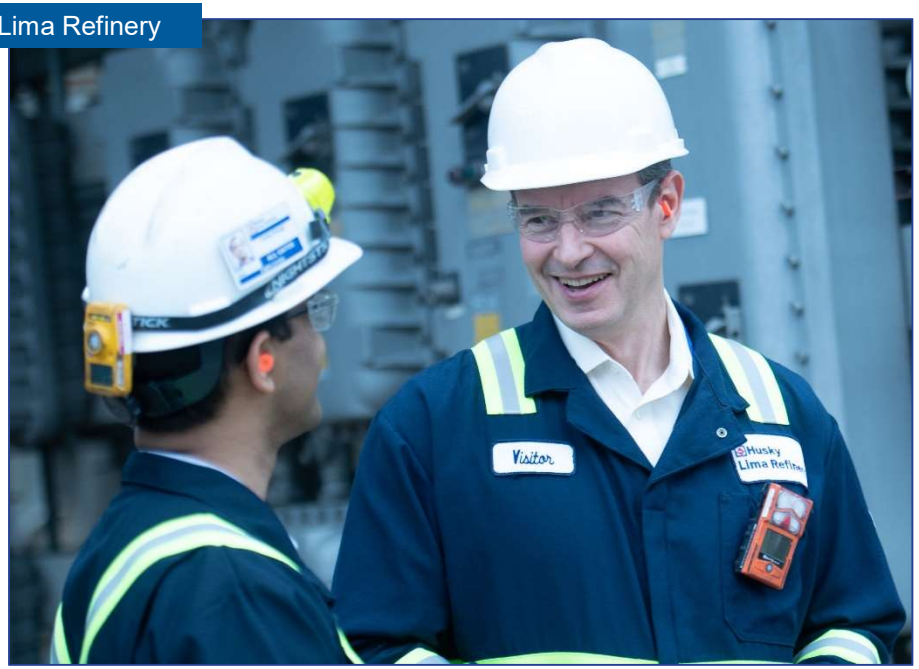
High Reliability Group

Actions Since Joining Husky

Safety & Operations Integrity

- Discussions with Board and senior management
- Familiarization with team and internal stakeholders
- Review of Husky's previous incidents
- Review of safety organization and current programs
- Visits to Lima Refinery, Lloydminster area . . . and now onwards to China

Lima Refinery



What I've Learned

Safety & Operations Integrity

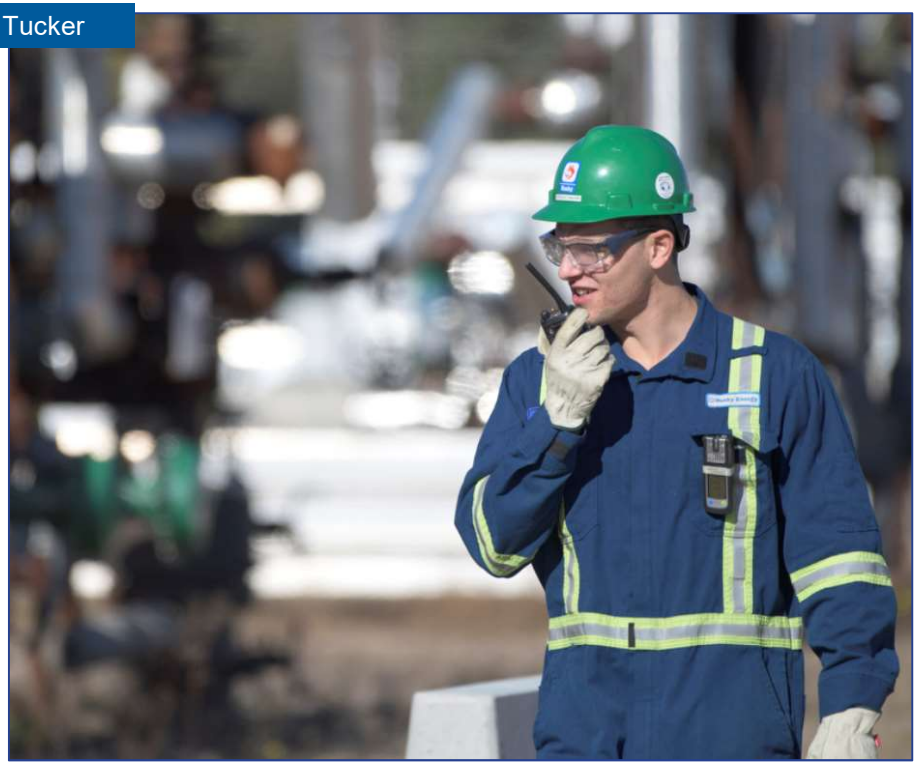
- Board and senior management:
  - Truly understand process safety and are fully dedicated to getting this right – becoming a worldwide top-quartile safety performer
  - Believe that excellence in process safety leads to general operational excellence and hence sustainable, predictable business results
- Many great people in the organization, taking deep pride and ownership of Husky and its assets
- The High Reliability Organization (HRO) principles are starting to take hold at the front line – already making an impact
- Opportunities to further strengthen operational discipline, quality of standards and procedures and applying consistent operational approaches – leading to excellence

Priorities For The Next Three Months

Safety & Operations Integrity

- Visit the remaining assets to deepen my understanding of Husky's existing safety culture and to prioritize opportunities for improvement in operational excellence
- Support the HRO implementation and transition ownership to my group – working closely with the High Reliability Group
- Focus on supporting key areas with higher risk exposure

Tucker

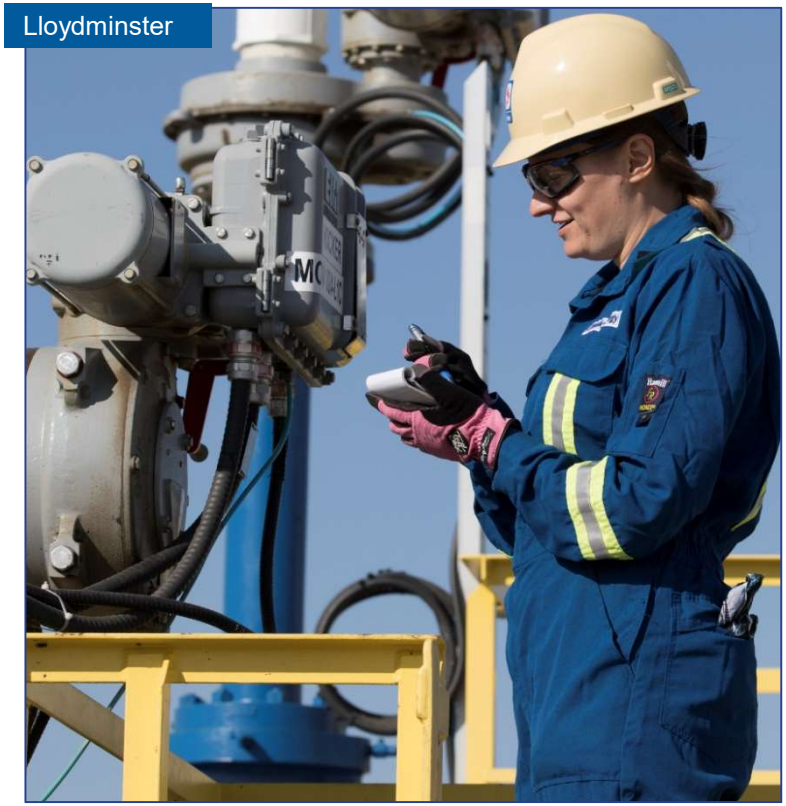


Plan For The Next 12-18 Months

Driving Towards World-Class Performance

- Shift towards leading rather than lagging process safety indicators
- Make the HRO principles the backbone of our operations, including a strong culture of continuous improvement – and implement targeted operational excellence programs
- Strengthen the Husky Operational Integrity Management System (HOIMS) and its frontline impact – combining it with HRO principles to achieve world-class:
  - Operations leaders
  - Process safety and operations excellence competence
  - Safety culture
  - Systems and processes – standardized across our operations

. . . All leading to world-class performance



Environmental, Social & Governance

Janet Annesley
SVP Corporate Affairs

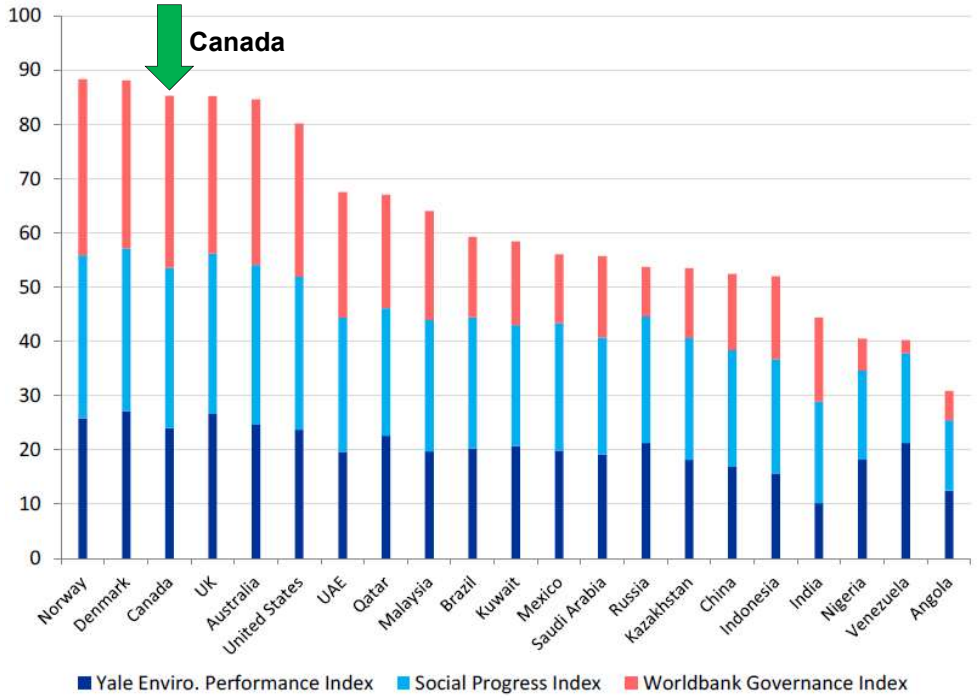
Sandhill Cranes on Sunrise Lease

Responsible Energy Production

Leadership In ESG Performance

- Canada is a leader amongst major oil producing nations in terms of:
  - Environment performance
  - Social progress
  - Governance
- The majority of Husky's operations are located within Canada
- Husky adheres to the same high standards of performance when operating in other jurisdictions

ESG Ratings by Major Oil-Producing Country



Source: BMO Capital Markets, Yale Environmental Performance Index (EPI); Social Progress Imperative; World Bank Worldwide Governance Indicators
Notes: Equal weighting applied to all three indices

Priority Topics

ESG Performance & Reporting

- Process Safety & Asset Integrity
- Air Emissions Management, including GHGs
- Water Use & Availability
- Land Use & Reclamation
- Business Ethics and Transparency

- Business Resilience
- Innovation & Advanced Technology
- Talent Management & Culture of Inclusion
- Community & Indigenous People's Engagement

Air & Water

ESG Performance & Reporting

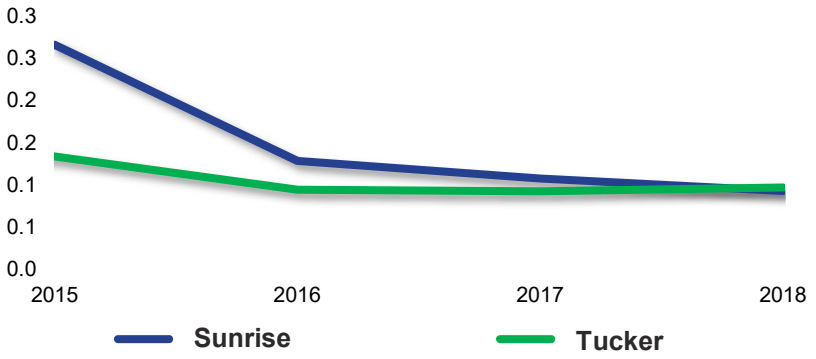
Emissions

- Lowering energy intensity at Sunrise and Tucker
- Gas re-injection in the Atlantic region
- Supplying cleaner-burning natural gas from Liwan to growing markets in Asia

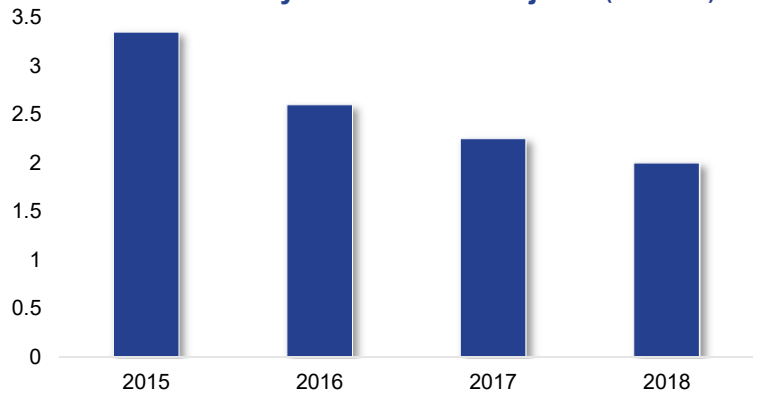
Water Use

- Recycling 88% of water at Sunrise and 82% at Tucker
- Water re-use at Lima

Heavy Oil & Oil Sands Scope 1 GHG Intensity[1] (tonnes CO_{2e} per boe)



Freshwater Intensity For Thermal Projects (m^3/m^3oe)



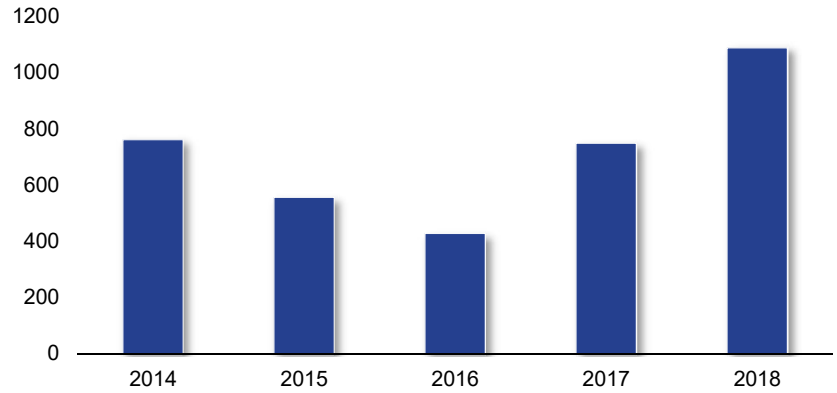
1) See Slide Notes and Advisories

Asset Retirement Leadership: Area-Based Closure

ESG Performance & Reporting

- Timely and effective retirement of active sites that have no future production potential
- Husky pioneered the ABC initiative, which includes a coordinated approach to well abandonment, pipeline and facility decommissioning, and site remediation and reclamation

Well Abandonments



Proactive Asset Retirement

Social & Governance

ESG Performance & Reporting

Social

- Diverse and inclusive workplace
- Indigenous economic inclusion
- More than 230 employee-earned grants awarded to community organizations
- Employees volunteered 12,000+ hours

Governance

- Executive compensation more tightly aligned with safety performance
- Enterprise Risk Management System
- Evaluate suppliers against safety and environmental goals
- Confidential Ethics Help Line

$30 million
with Indigenous vendors

5,100
employees participate in mandatory Code of Conduct training

How We Rate

Improving Performance & Disclosure

MSCI | MSCI ESG RESEARCH LLC

ESG RATING **BBB**

CDP
DISCLOSURE INSIGHT ACTION

2018 CLIMATE SCORE: B

SECTOR AVERAGE: C

2018 WATER SCORE: B-

SECTOR AVERAGE: C

SUSTAINALYTICS

40 out of 129

Relative Position

Average Performer

Corporate Knights

Best 50 Corporate Citizens in Canada

Financial Framework

Jeff Hart
Chief Financial Officer

Lower Capex, Higher FCF: Bias Toward Dividend Growth

Financial Plan

Pricing Premise

- Pricing assumption unchanged at flat $60 US WTI
- Chicago crack $18 in 2019, $16 in 2020 and forward
- $0.75 Canadian-U.S. exchange

Financial Metrics

- Cumulative free cash flow of $8.7 billion vs. $4.8 billion previously
  - Funds from operations grows at a CAGR[1] of 8% to $5.8 billion in 2023
  - Average annual capital spending reduced to $3.15 billion vs. $3.5 billion previously
- Using $40 US WTI for bottom of the cycle planning (previously $35 US WTI)
- Debt limit of 2x FFO at $40 US WTI
- Sustaining capital remains at $1.8 billion

Free Cash Flow Allocation

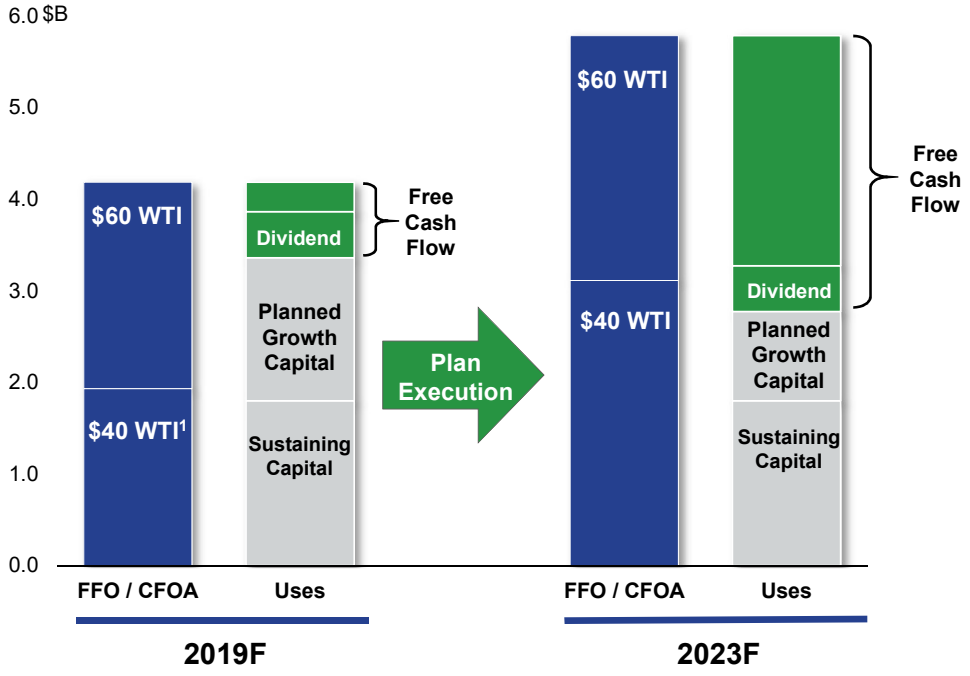
- More free cash flow to allocate
- Bias towards increasing shareholder returns
- No need to pay down debt

1) See Slide Notes and Advisories

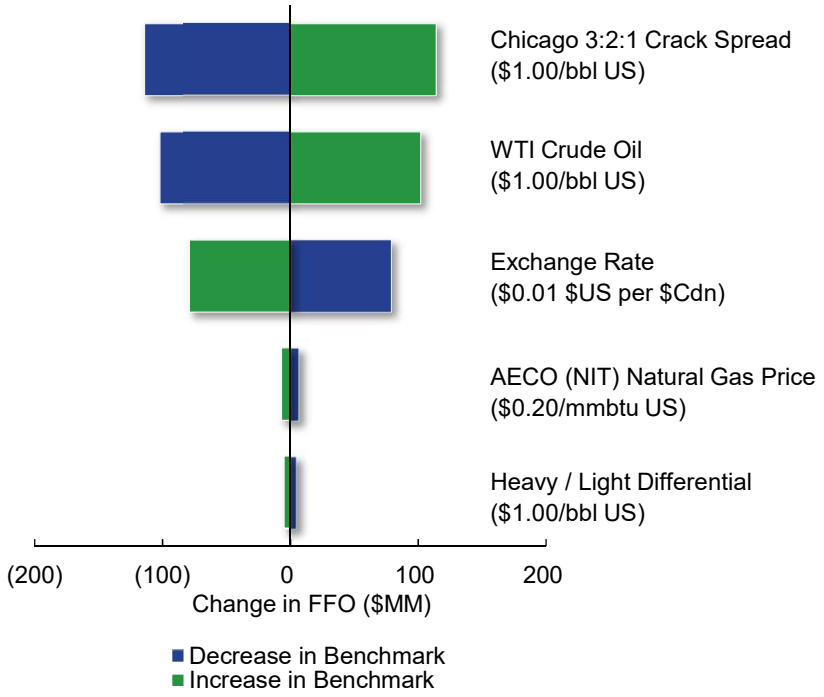
Mid-Cycle Financial Framework

$60 US WTI Base Assumption

Funds from Operations / Cash Flow From Operating Activities ($MM)



Cash Flow Sensitivity[2] ($MM)



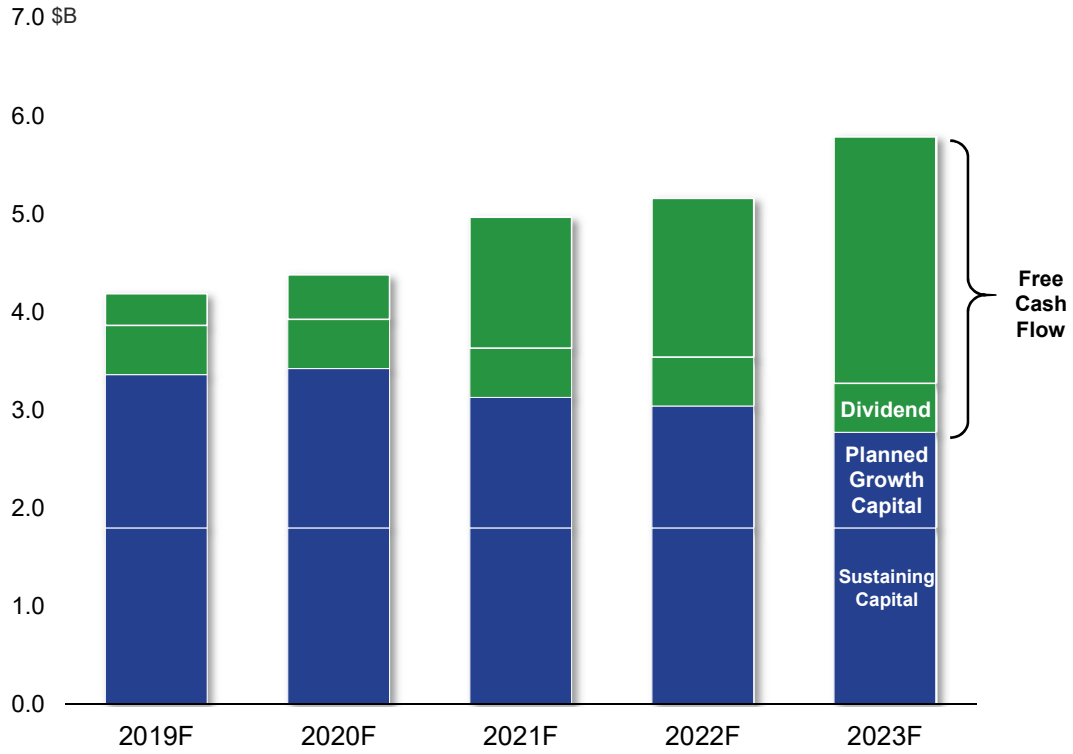
1,2) See Slide Notes and Advisories

Funding Priorities

2019-2023

1. Balance sheet strength
2. Sustaining capital
3. Dividend
4. Growth capital
5. Allocate discretionary free cash flow
    - Bias towards shareholder returns

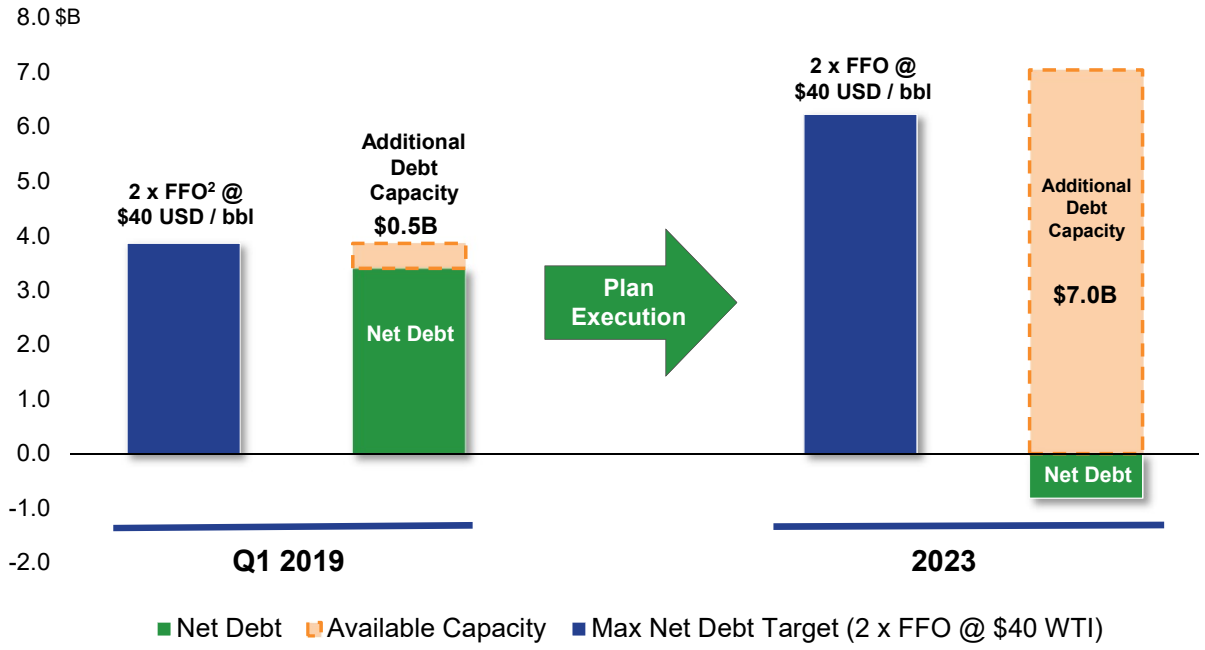
Funds From Operations / Cash From Operating Activities



Maintain Balance Sheet Strength

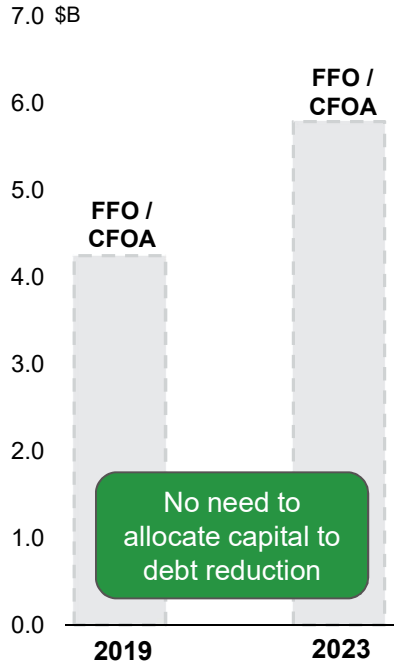
Funding Priorities

Illustrative 2x Net Debt to FFO[1] Debt Capacity at US$40 WTI



< 2x Net Debt to FFO at $40 US WTI

Cash Generation and Uses at $60 WTI

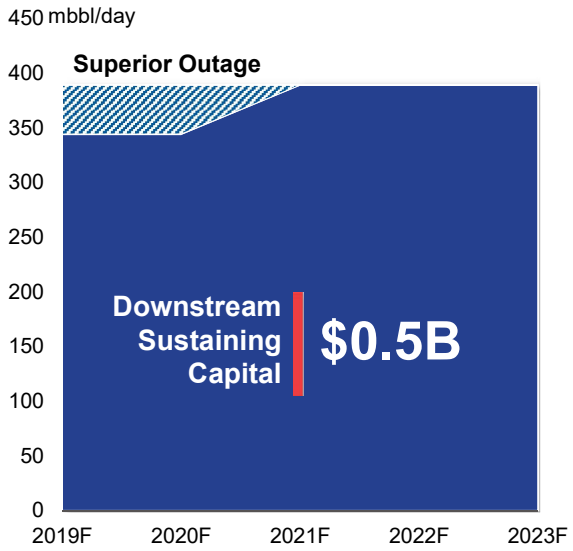


1, 2) See Slide Notes and Advisories

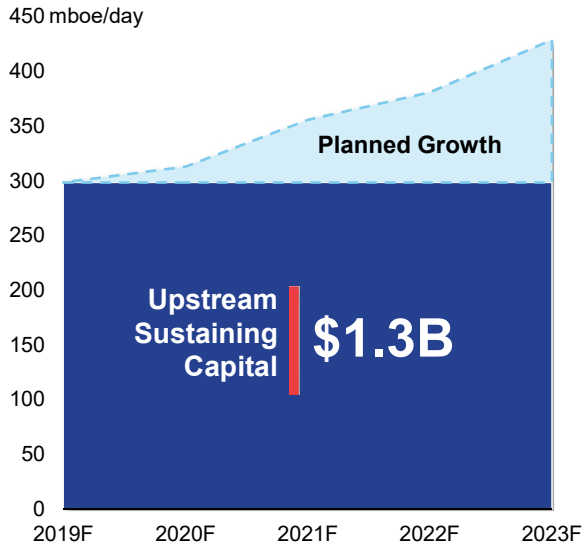
Fund Sustaining Capital

Funding Priorities

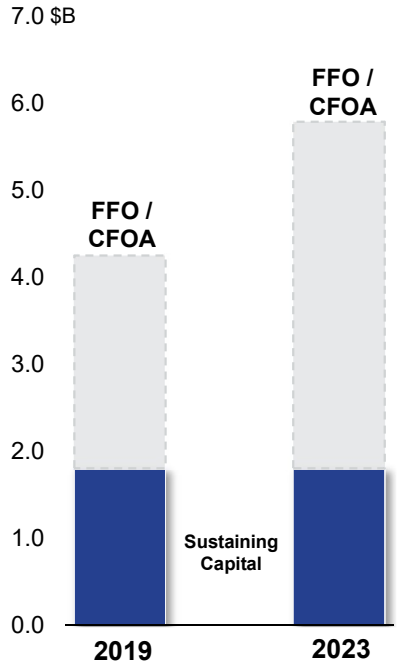
Throughput



Production



Cash Generation and Uses at $60 WTI

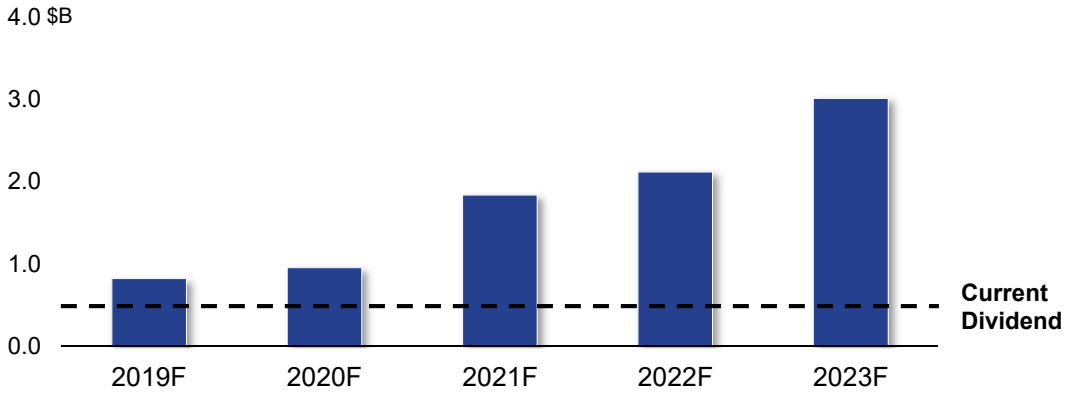


Keep Upstream Production Flat / Run Operations Safely & Reliably

Maintain Strong Dividend

Funding Priorities

Free Cash Flow

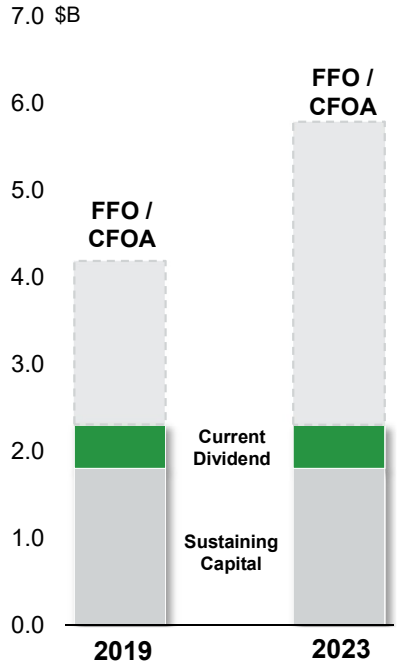


Free Cash Flow Coverage (FCF divided by Current Dividend)

2019	2020	2021	2022	2023
164%	**191%**	**367%**	**423%**	**602%**

Room to Grow Dividend

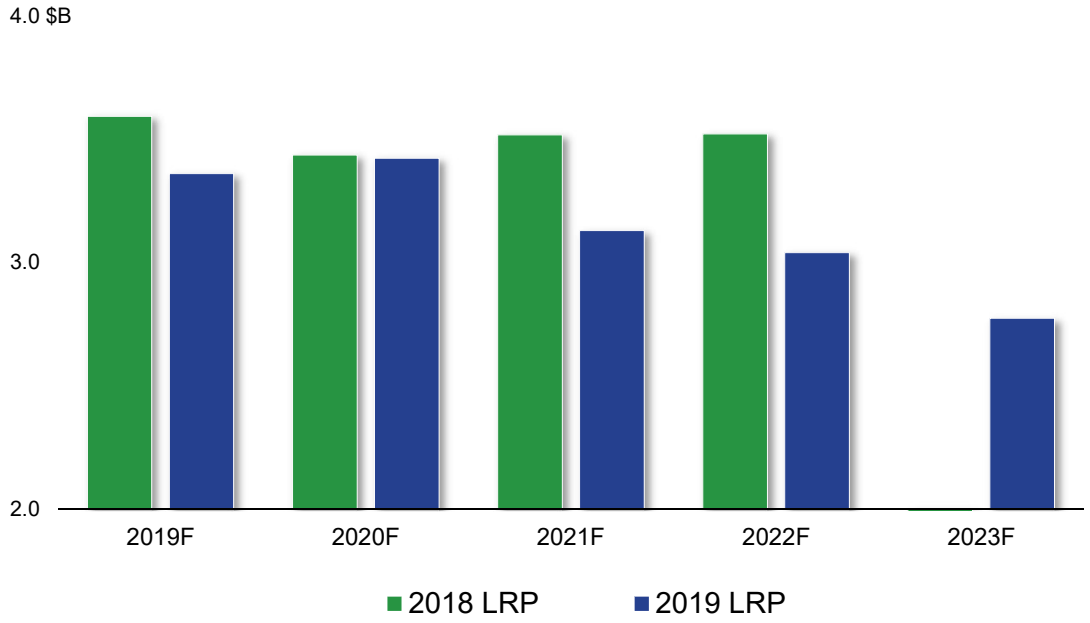
Cash Generation and Uses at $60 WTI



Growth Capital

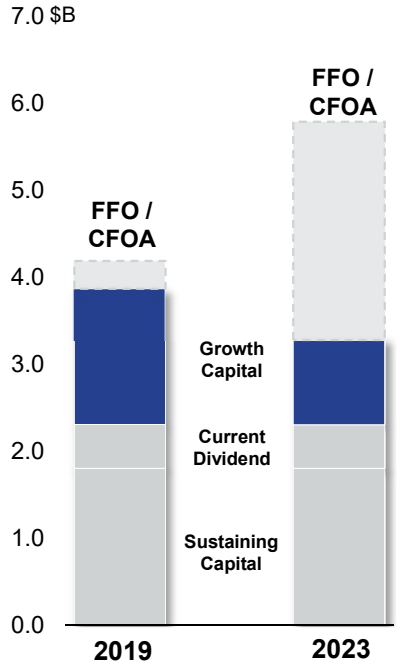
Funding Priorities

Total Capital Expenditures



Average Annual Capex Reduced by $350M to $3.15B

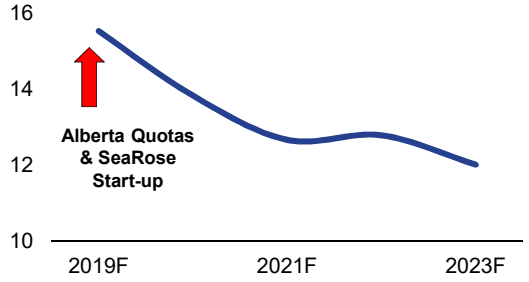
Cash Generation and Uses at $60 WTI



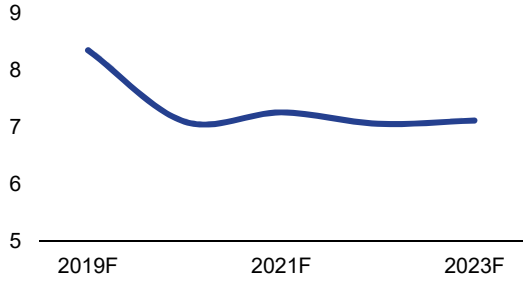
Growth Capital Drives Down Costs; Improves Break-Even

Funding Priorities

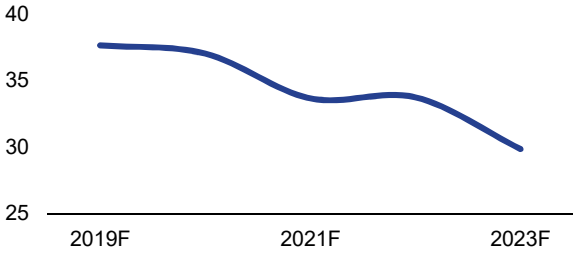
Upstream Operating Costs ($Cdn/bbl)



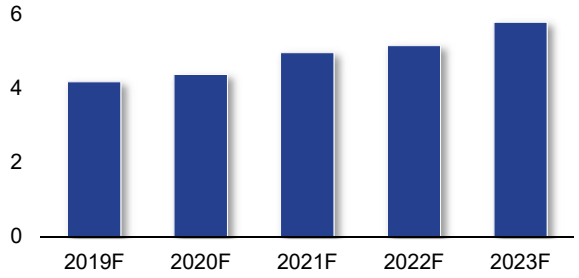
Downstream Operating Costs ($Cdn/bbl)



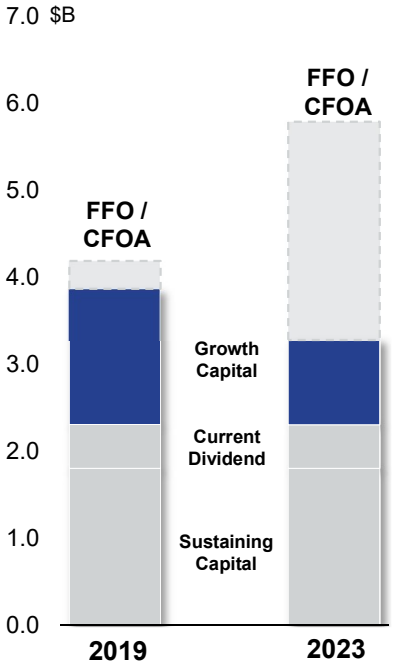
Cash Flow Break-Even Price (US/bbl Brent)



FFO / Cash Flow – Operating Activities ($B)



Cash Generation and Uses at $60 WTI



Capex Program Driving Down Cost Structure, Growing Margins

Allocation Of Discretionary Free Cash Flow

Funding Priorities

Maintain Balance Sheet Strength

- Already strong, no need to de-lever
- Aim to stay below 2x net debt to FFO at $40 US WTI

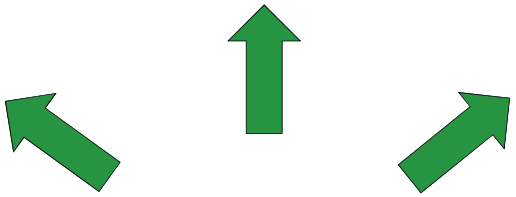
Return to Shareholders

Dividend Growth

- Option to grow with continued strengthening of asset base

Share Buybacks

- Buybacks remain an option



Cumulative Free Cash Flow ’19F-’23F **$8.7B**

Growth

Organic Growth

- Limited acceleration of current portfolio investment without compromising capital efficiency
- Will maintain capital discipline

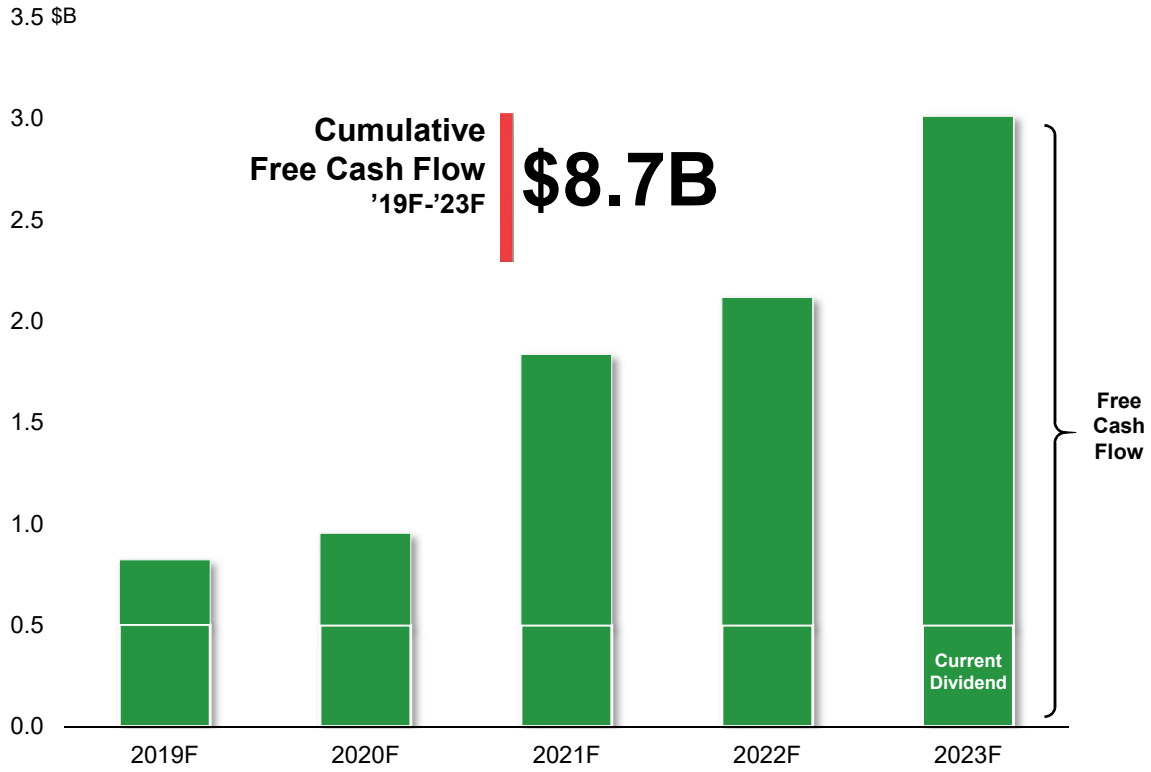
Inorganic Growth

- Needs to be on-strategy
- Need to fit within financial framework
- Must be accretive on key metrics
- Must enhance ability to increase dividend

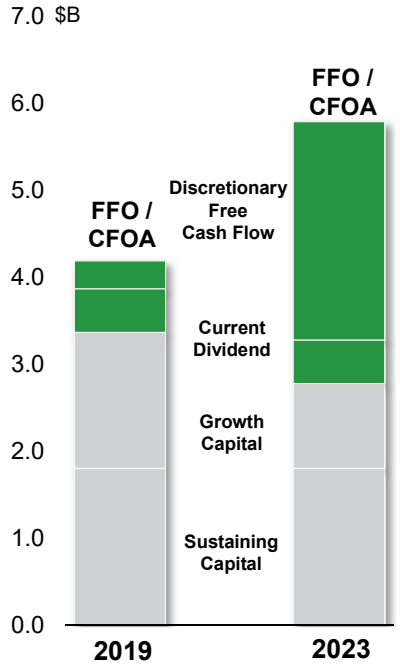
Bias Towards Accelerating Shareholder Returns

Funding Priorities

Free Cash Flow



Cash Generation and Uses at $60 WTI



Rigorous Criteria For Any Additional Growth Capex

Funding Priorities

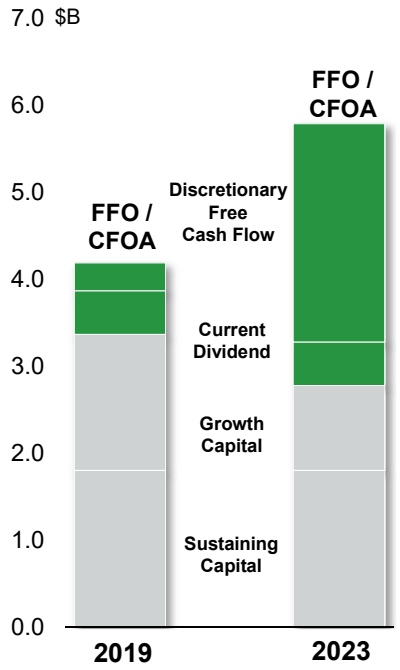
Organic Growth

- Satisfied with current growth profile
- Will not accelerate in order to preserve capital efficiency

Inorganic Growth

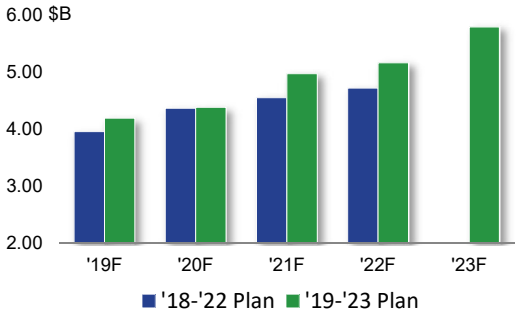
- M&A criteria:
  1. Fit within Husky's strategy
  2. Maintain balance sheet strength and investment grade credit ratings
  3. Accretive to:
     - Funds from operations
     - Free cash flow
     - Earnings
     - Enhanced ability to fund dividend

Cash Generation and Uses at $60 WTI

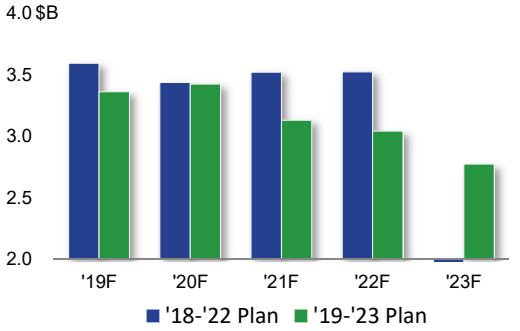


2019-2023 Plan Update

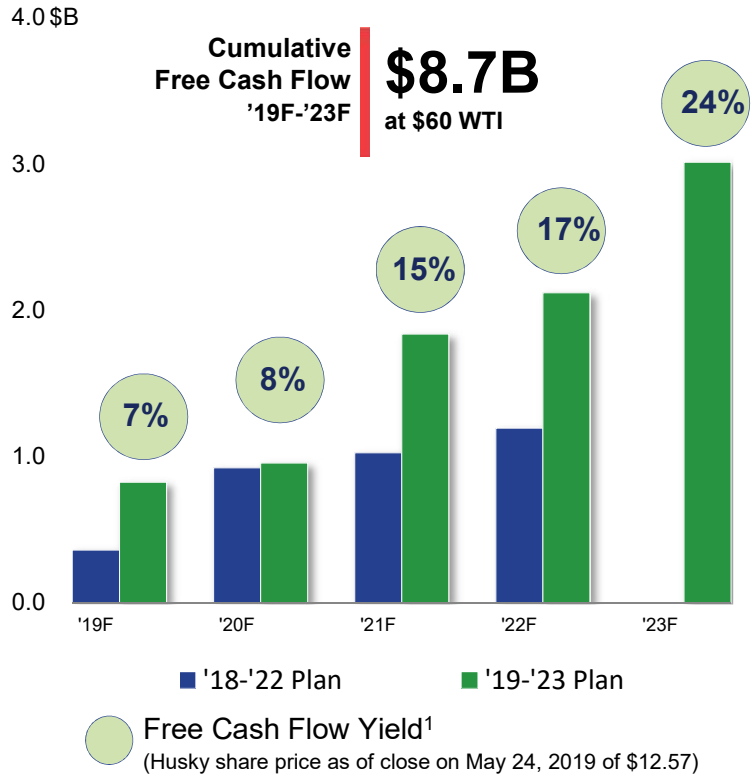
Funds from Operations / Cash Flow from Operating Activities



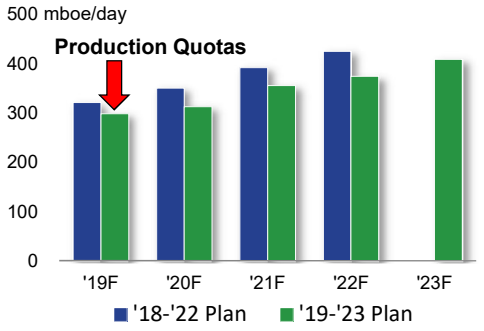
Reduced Capital Expenditures



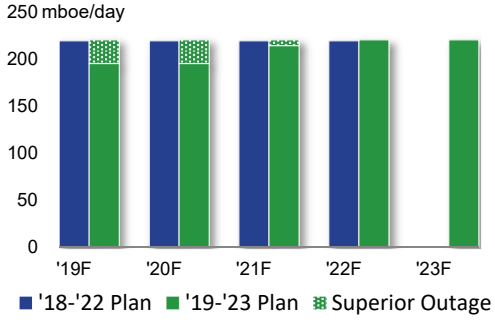
Free Cash Flow



Paced Production



Heavy Oil Processing Capacity



1) See Slide Notes and Advisories

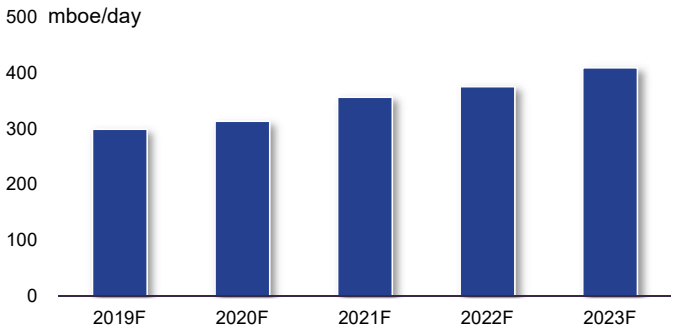
Plan Delivery
Innovation & Technology

Rob Symonds, Chief Operating Officer

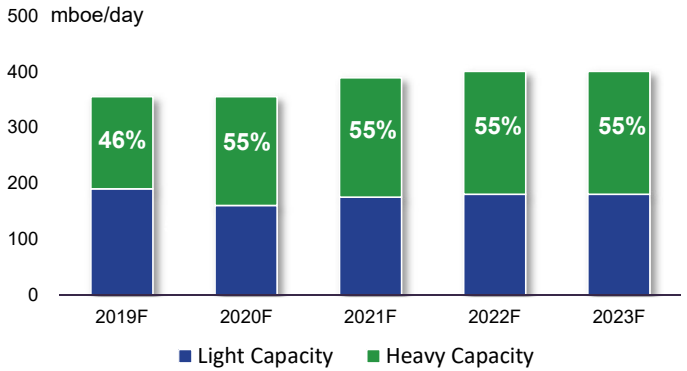
Safety & Operational Reliability

Top Priority In Five-Year Plan

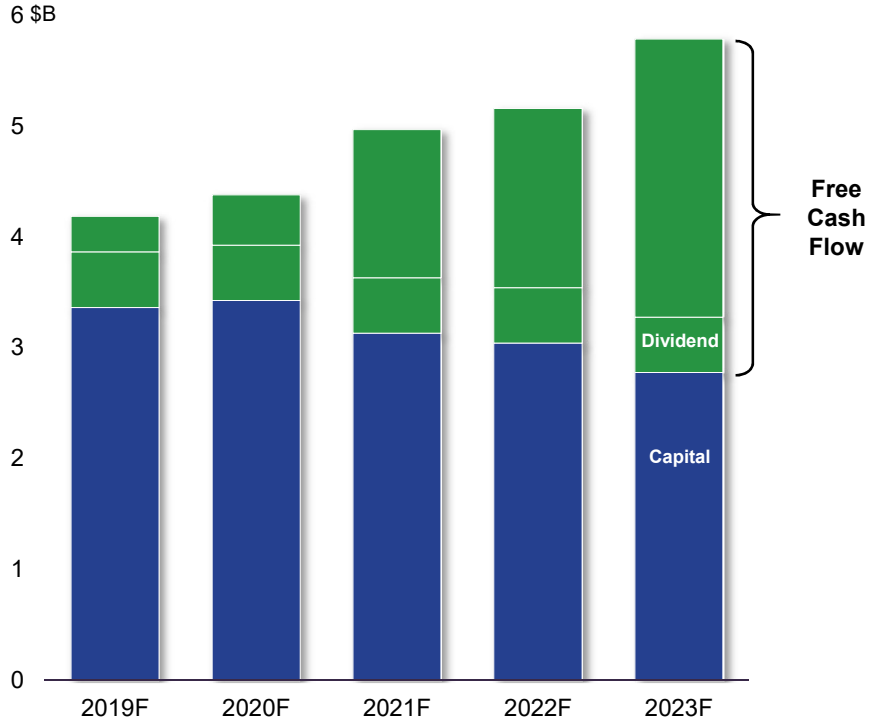
Production



Upgrading and Refining Capacity[1]



Funds From Operations / Cash Flow From Operating Activities



1) Does not include Prince George Refinery.

Becoming A High Reliability Organization

Committed To Incorporating HRO Principles Across Business Units

Integrated Corridor

Thermal

Downstream

Western Canada

- Building on High Reliability Group safety assessment
- Improving safety and reliability across business segments
- Single Downstream manufacturing organization
- Focus on standards and procedure compliance

Offshore

Asia Pacific

Atlantic

Project And Operations Update – What's New?

Paced Growth, Incremental Changes

Integrated Corridor

- Implementation of HRO principles
- Alberta production quotas
- Focus on margin capture vs. growth at Sunrise and Tucker
- Dee Valley first oil in Q3 '19 ahead of schedule
- Future Lloyd thermal projects paced to three every two years given pipeline outlook
- Slowed growth in Western Canada resource plays
- Downstream business reorganized
    - Lima capacity enhancement
    - Lloyd Upgrader/diesel debottleneck
    - Superior Refinery rebuild enhancements

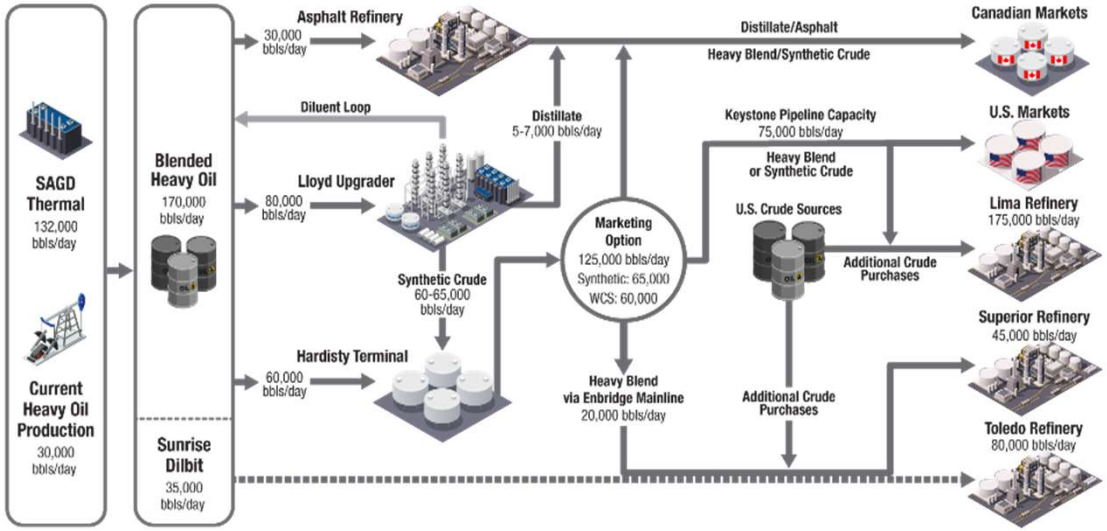
Offshore

- Implementation of HRO principles
- Ramp-up of SeaRose FPSO
- West White Rose Project paced to focus on capital efficiency
    - Startup still planned for 2022
- Madura fields deferred by one year

Integrated Corridor Strategy

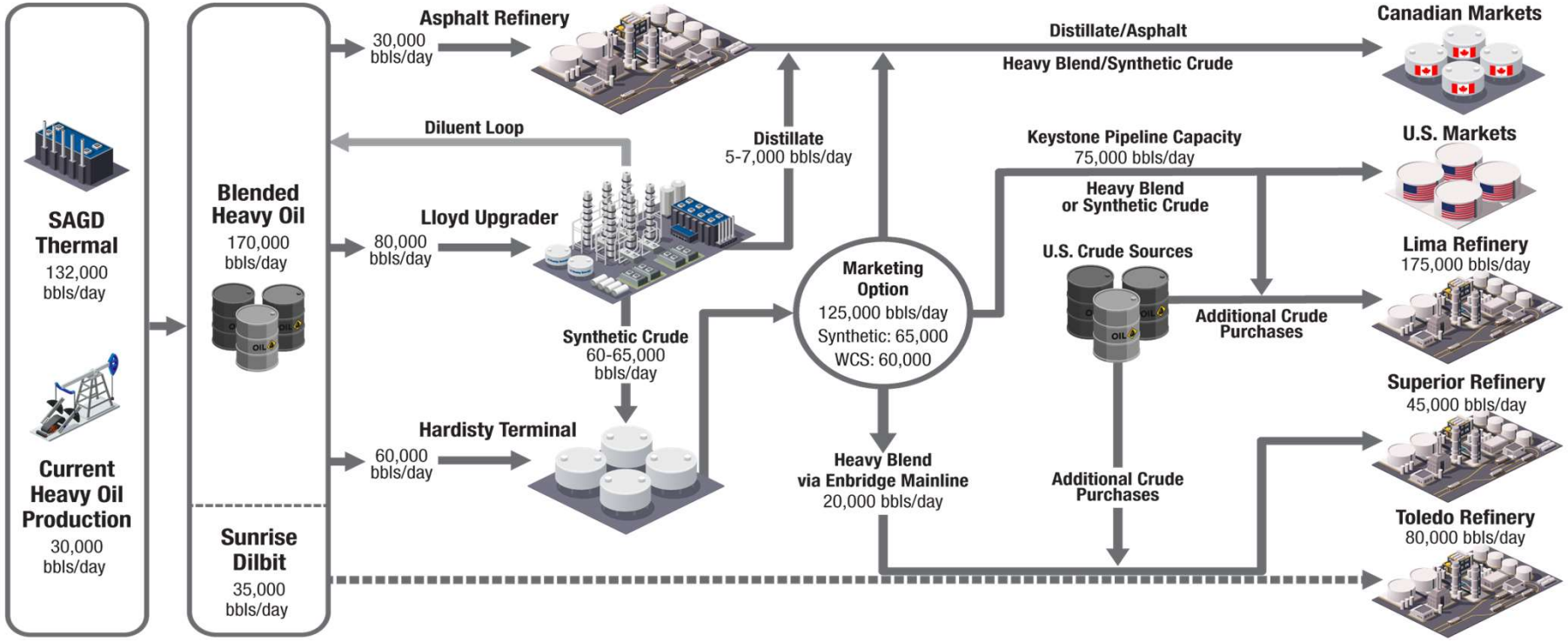
Capturing Global Pricing For Upstream Production

- Includes upgrading and refining, ample storage and committed pipeline capacity to our U.S. refineries.
- Eliminates exposure to heavy-light and location differentials
- Physical integration provides the most optionality to maximize margins
- Matches Upstream production with Downstream processing and takeaway capacity



Manufacturing Process Maximizes Margins

Integrated Corridor Strategy

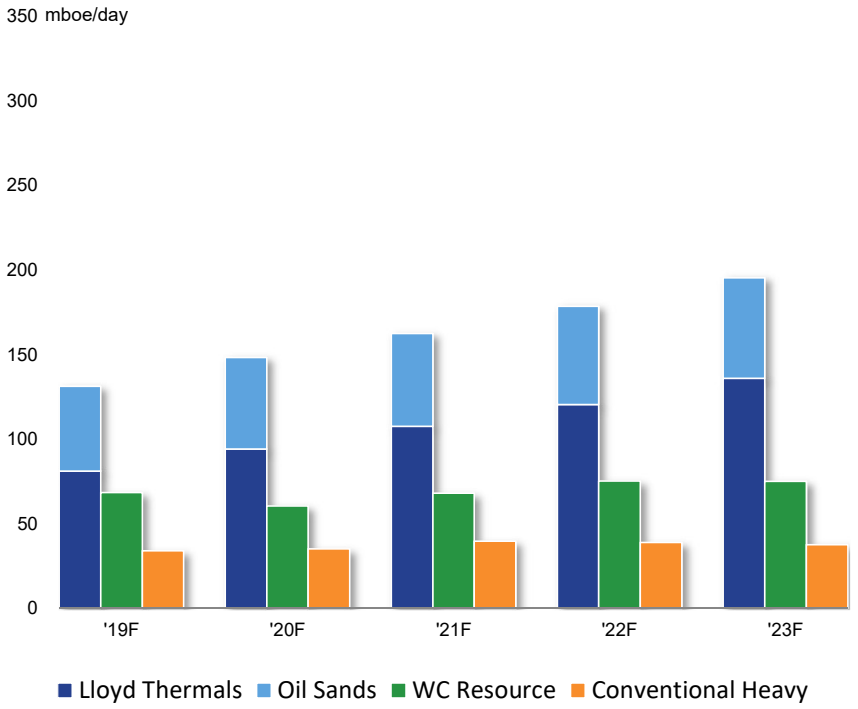


Increasing Revenue | **Reducing Costs** | **Improving Optionality**

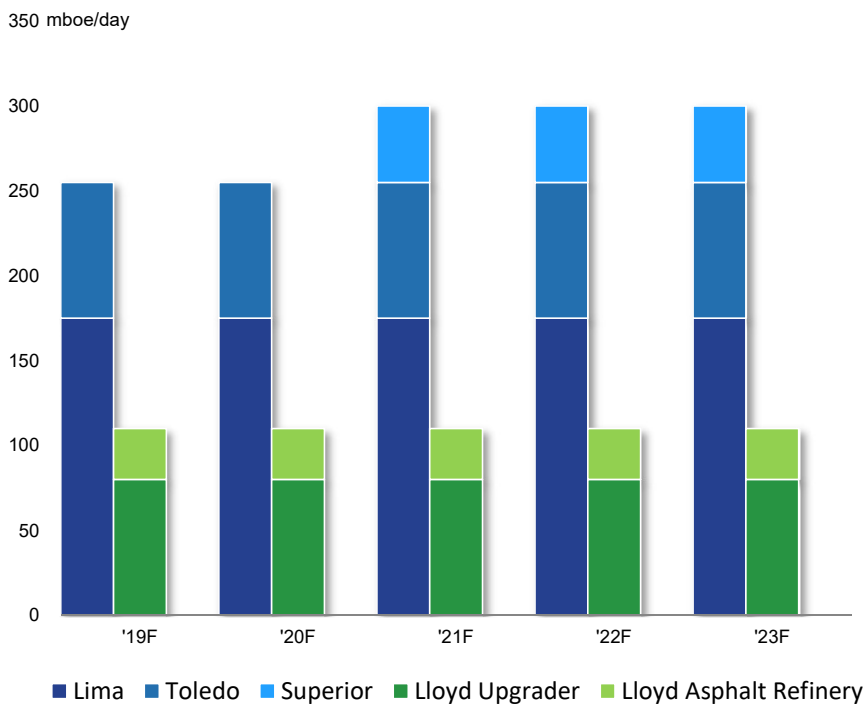
Updated Production And Throughput Forecasts

Integrated Corridor (2019-2023)

Production



Throughput Capacity[1]



1) Does not include Prince George Refinery

Maximizing Full Value Chain Margin Capture

Integrated Corridor

Lloyd Thermals & Oil Sands

- Long-life assets with a large resource
- Modular, scalable designs
- Low and improving operating costs and sustaining capital costs

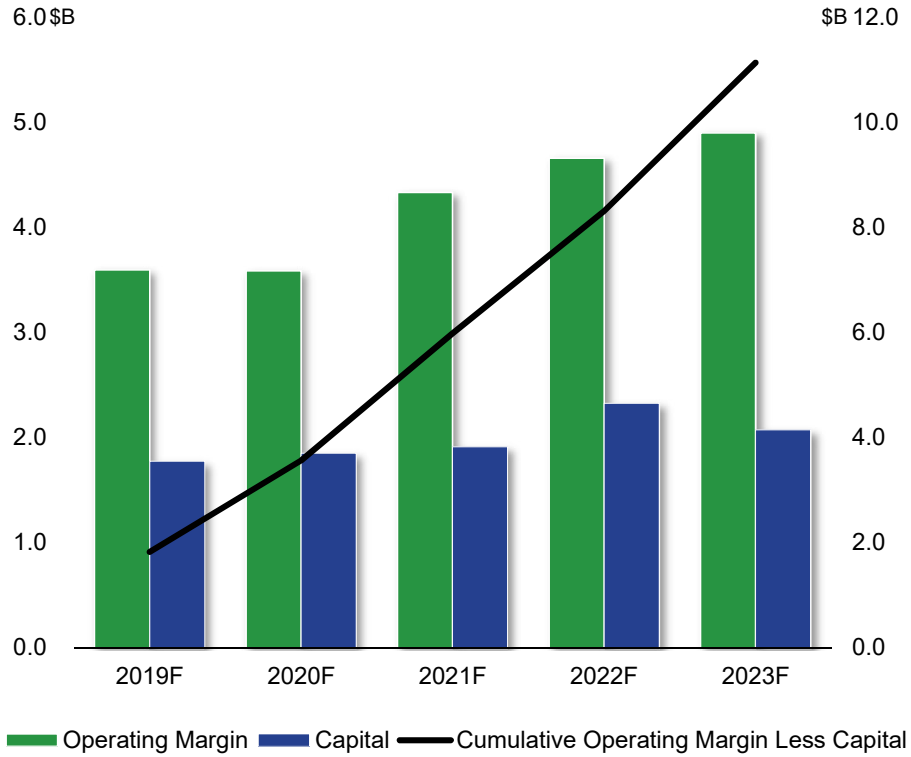
Downstream

- Increasing speed of action to opportunity
- Leaner, integrated organization
- Capturing value outside the refinery gate

Western Canada

- Competitive, integrated business
- Pivoting to liquids
- Gas production fuels thermal growth and Canadian Downstream facilities

Integrated Corridor
Operating Margin Less Capital



Synchronized Build-Benefit Cycles

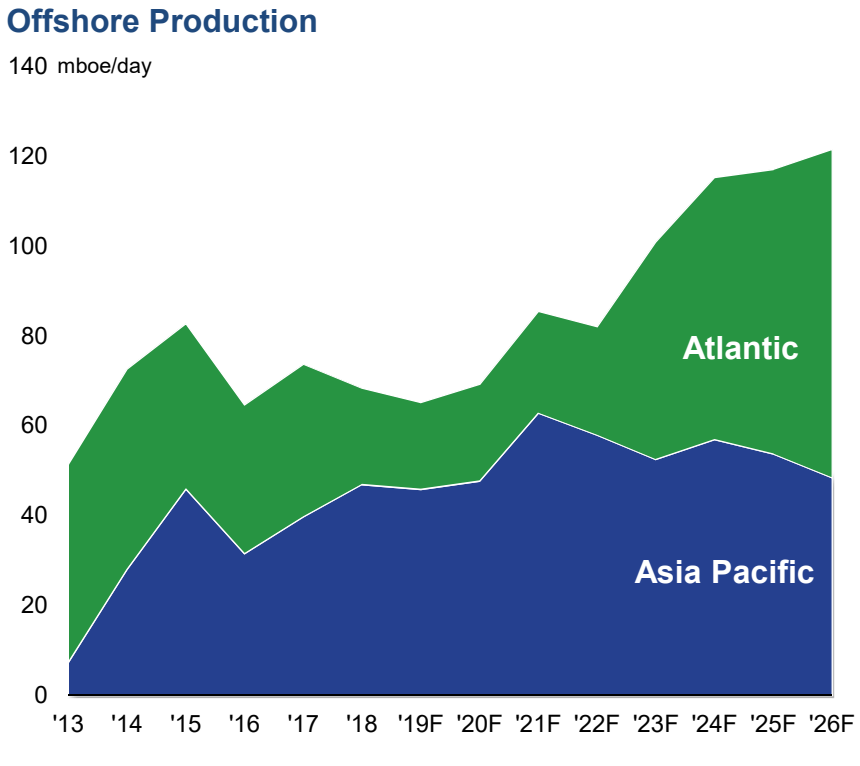
Offshore Strategy

White Rose Field

Liwan

BD Project

West White Rose

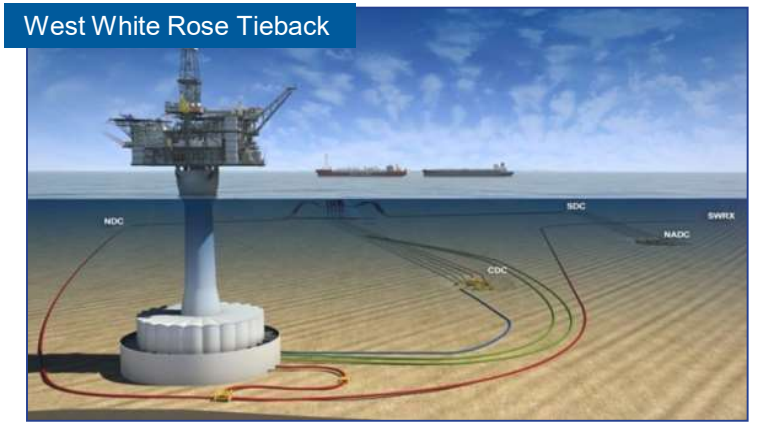


Leveraging Existing Infrastructure Drives Efficiencies

Offshore Strategy

- West White Rose tieback to SeaRose FPSO
- 29-1 tieback to Liwan platform
- Madura Strait fields offshore Indonesia linked by existing East Java pipeline
- Shallow water exploration fields offshore China close to existing infrastructure

West White Rose Tieback



Liwan Onshore Infrastructure

Fixed-Price Asia Gas Complemented By Oil Price Torque

Offshore Business

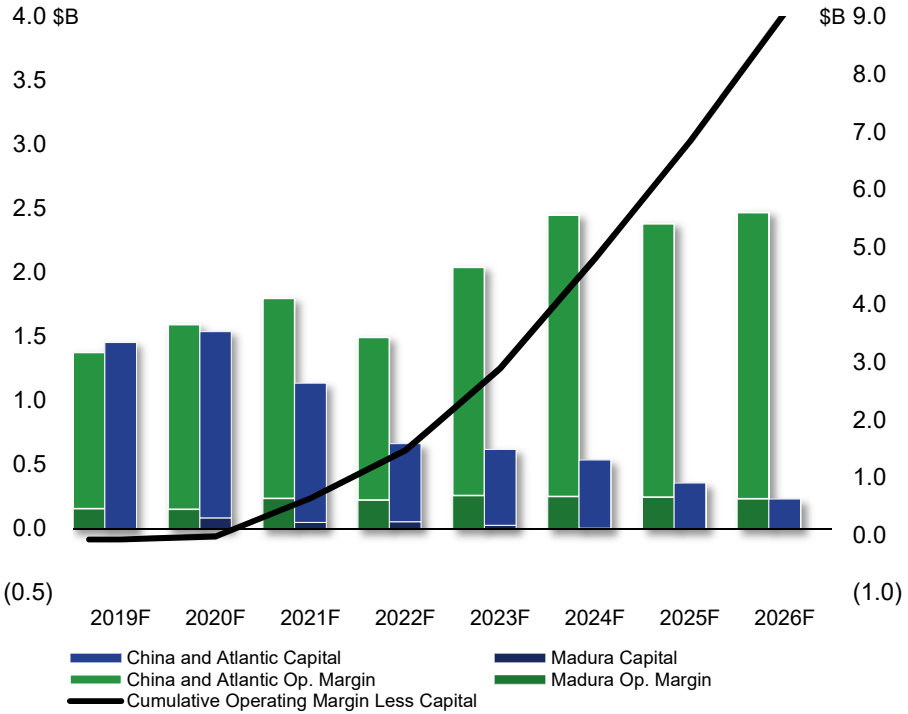
Atlantic

- High netbacks with global oil pricing
- Direct access to tidewater
- Leveraging existing infrastructure
- Defined growth into next decade
- Exploration opportunities

Asia Pacific

- High netback long-term contracts
- Established partnerships
- Leveraging existing infrastructure
- Exploration opportunities

Offshore
Operating Margin Less Capital



1) See Slide Notes and Advisories

Innovation Gateway Driving New Technology Adoption

Innovation & Technology

Husky Diluent Reduction Program

Fibre Optic Leak Detection

Remote Well Monitoring

Well Optimizations

Iceberg Management

CO_2 Carbon Capture

Improving Safety, Lowering Costs & Increasing Capital Efficiency

Husky Diluent Reduction Program (HDR)

Innovation & Technology

- Diluent reduction module pilot program at Sunrise
  - Partial upgrading solution
  - Creates pipeline-ready, stable crude
  - Lowers costs
  - Reduces GHG emissions
- Pilot commissioned Q4 2018; testing ongoing

HDR at Sunrise Energy Project

Leveraging Artificial Intelligence For Remote Wells

Innovation & Technology

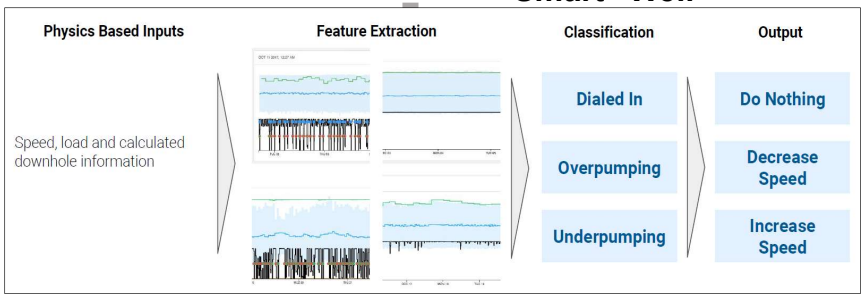
Connected Well (iIoT) → **Data Gathering** → **Machine Learning** → **Artificial Intelligence**

Well On/Off Visibility

Performance Diagnostics

Performance Optimization

Automated "Smart" Well



Where we are today . . .

. . . and where we are going

- ✓ Improved operator safety
- ✓ Reduced downtime
- ✓ Reduced well servicing expense
- ✓ Well performance optimization

Reducing Our Carbon Footprint

Innovation & Technology

- Historically trialed different CO_2 capture technologies at Pikes Peak South
- New novel technology pilot successfully captured 0.5 tonnes/day in 2018 and is now being evaluated for commercial potential
- CO_2 captured at Husky's Lloydminster Ethanol Plant and from the Pikes Peak South pilots is used for enhanced oil recovery – benefitting the businesses and reducing carbon impact

CO_2 Capture at Pikes Peak South

Reducing Risk & Costs In The Atlantic

Innovation & Technology

Improving Safety

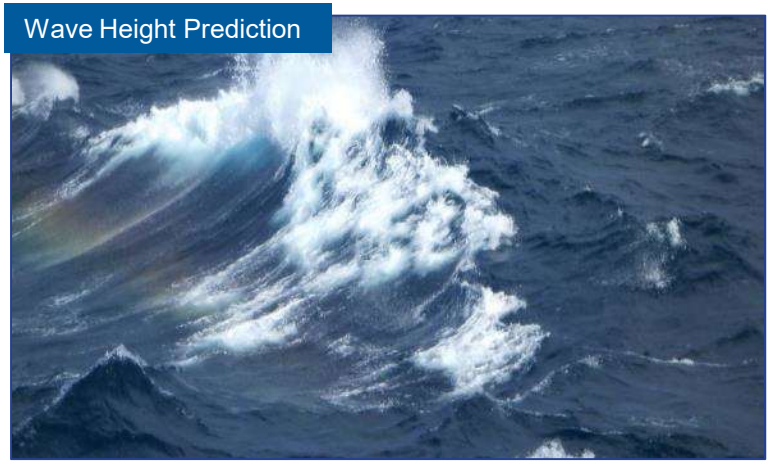
- Iceberg drift prediction
- Wave height prediction

Peer Collaboration

- Petroleum Research Newfoundland & Labrador (PRNL)
- Joint industry partnerships

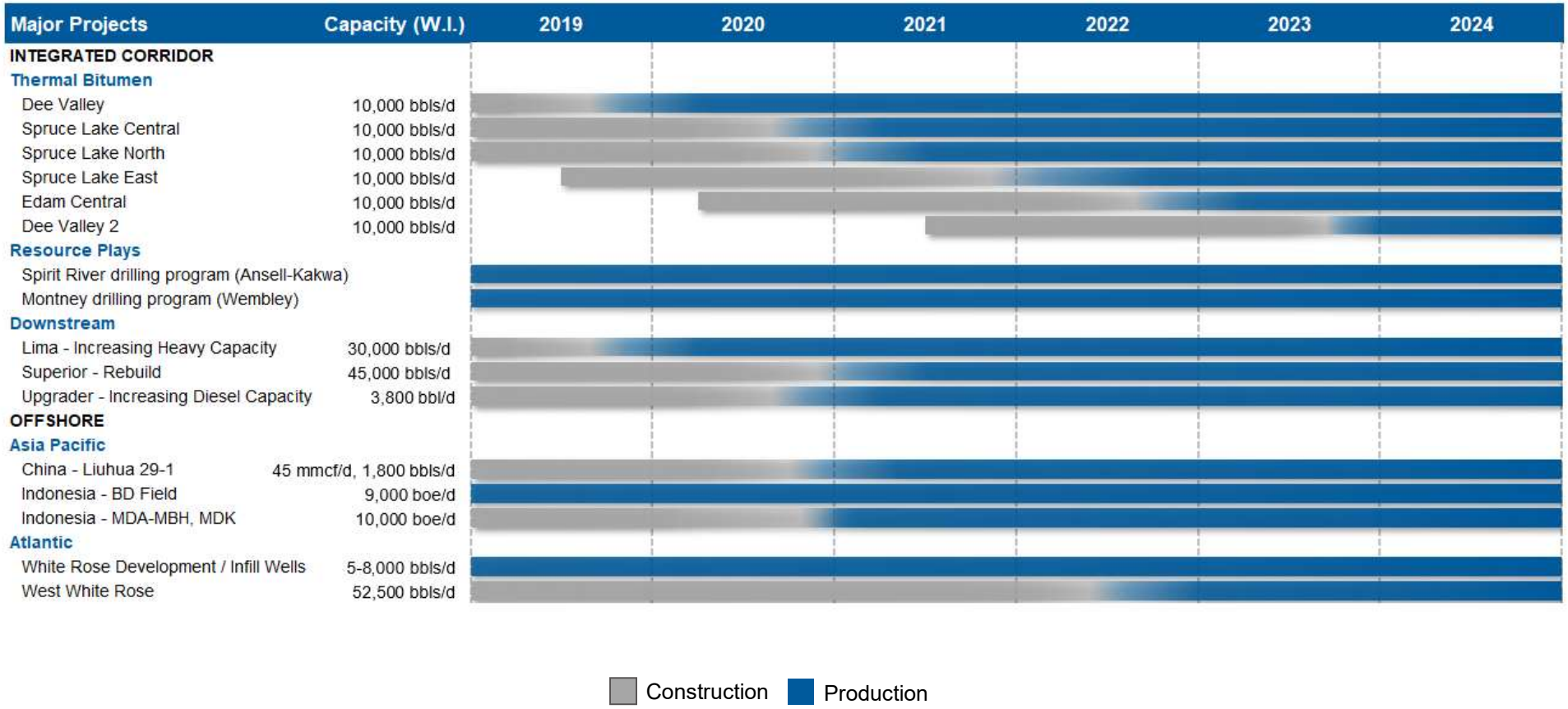
Sea Ice Management

Wave Height Prediction



Major Project Execution: Integrated Corridor & Offshore

Five-Year Plan Milestones

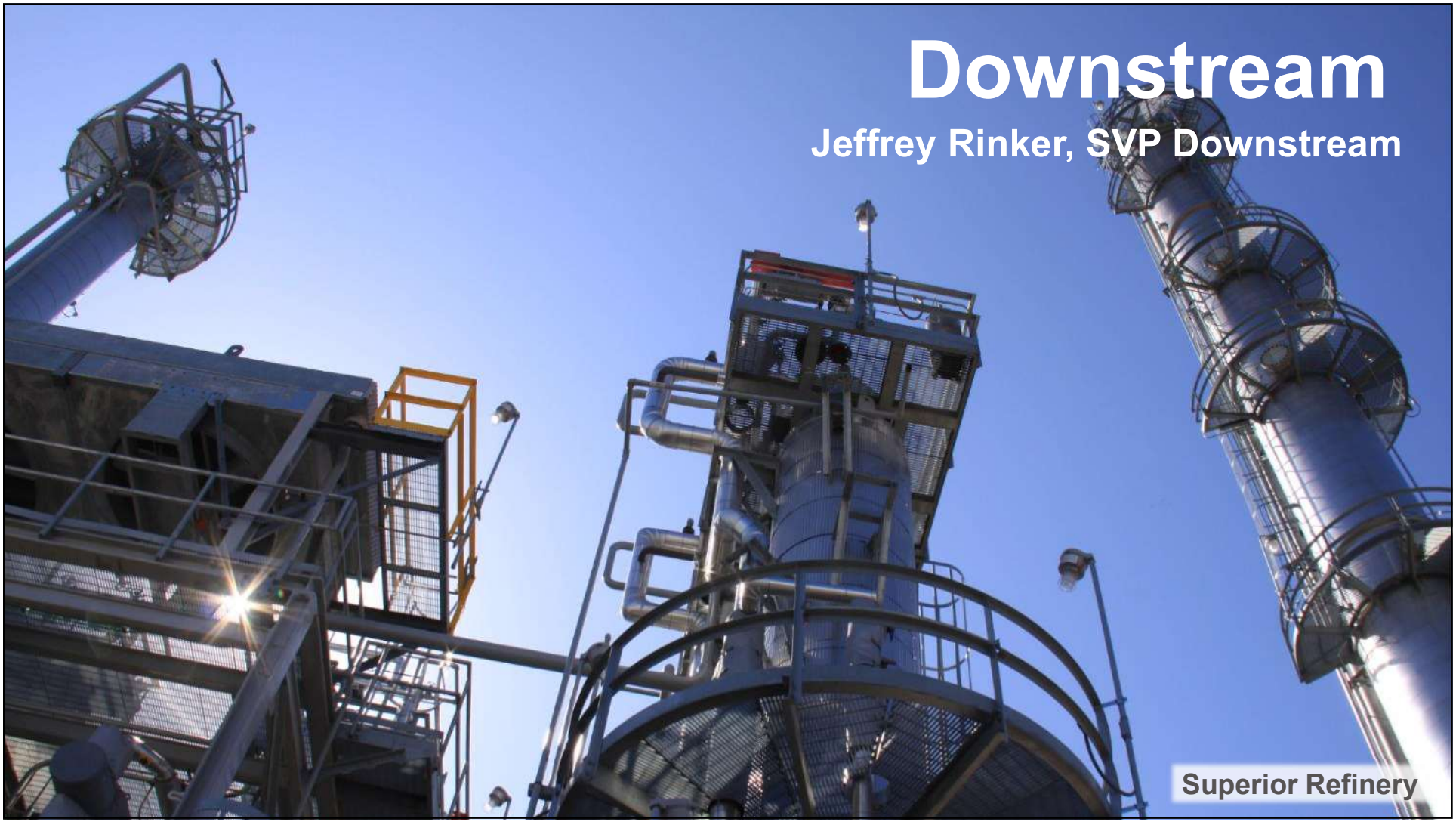


Husky

Break

Downstream

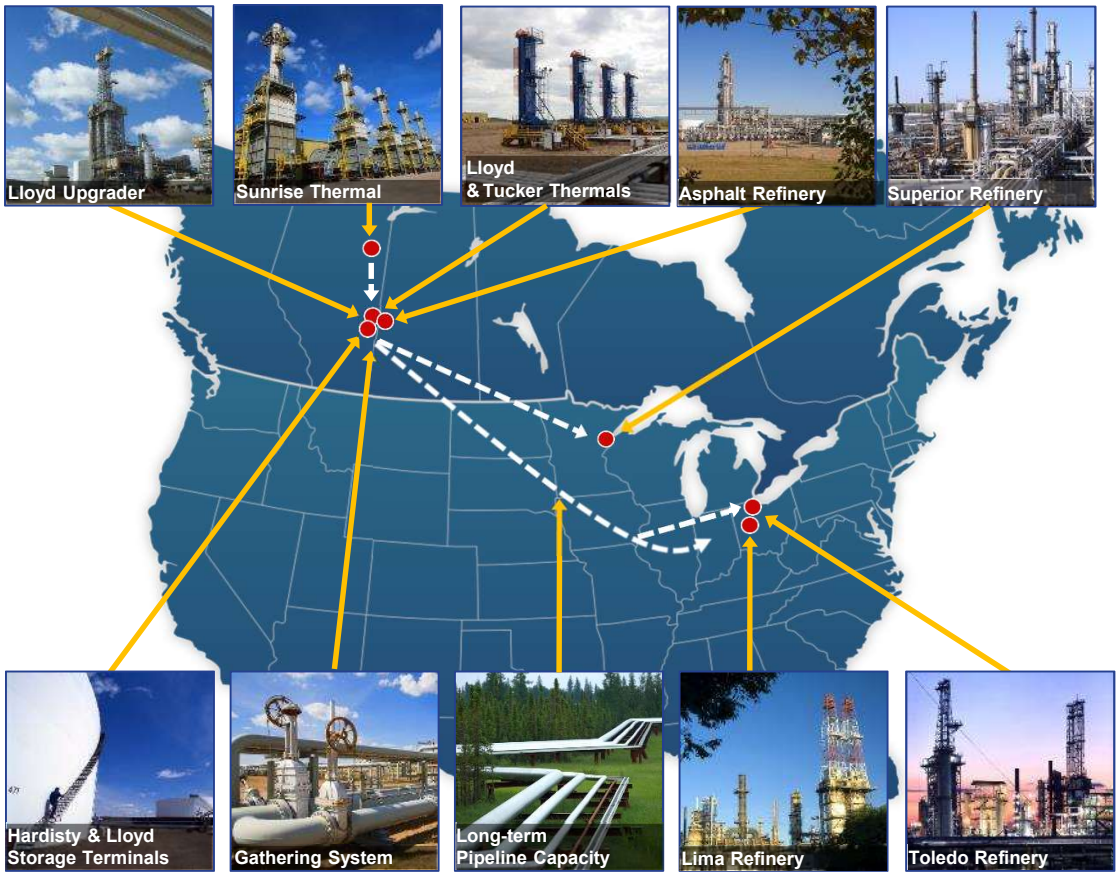
Jeffrey Rinker, SVP Downstream



Four Strategic Cornerstones

Basis For Downstream Excellence

- Safe and reliable operations
- Balancing production, processing and logistics
- Physical integration with optionality
- Substantial positive cash flow



Physically Connected Assets Across North America

Integrated Corridor – Downstream

Lloyd Complex

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

Lloyd Upgrader

- Capacity: 80 mbbls/day
- Produces Husky Synthetic Crude (HSB)
- Low operating costs

Asphalt Refinery

- Capacity: 30 mbbls/day
- Supplies ~4% of asphalt manufactured in N. America
- Transportation by rail

Prince George Refinery

- Capacity: 12 mbbls/day
- Light oil refinery
- Supplies B.C. market

U.S. Refining & Marketing

- 300,000 bbls/day processing capacity
- Product marketing centered in Ohio

Lima, Ohio

- Capacity: 175 mbbls/day
- Hydrocracker/FCC/coker configuration
- Access to diverse crude supply

Toledo, Ohio

- Capacity: 160 mbbls/day gross 80mbbls/day (Husky WI)
- Configured to process high-TAN Sunrise crude

Superior, Wisconsin

- Capacity: 45 mbbls/day
- Light / Heavy oil refinery
- Asphalt, diesel, gasoline production

Pipelines & Storage

- More than six million barrels of tank storage
- 75,000+ bbls/day long distance crude pipeline

Crude storage capacity:

- **3.4M bbls at Hardisty**
- **1.0M bbls at Lloyd**
- **1.3M bbls at Patoka**
- **0.9M bbls at Superior**
- Blending capability
- 35% interest in Midstream partnership
- Connections to several main pipelines to ensure Husky crude can reach market
- Export gas pipeline and gas storage

Retail

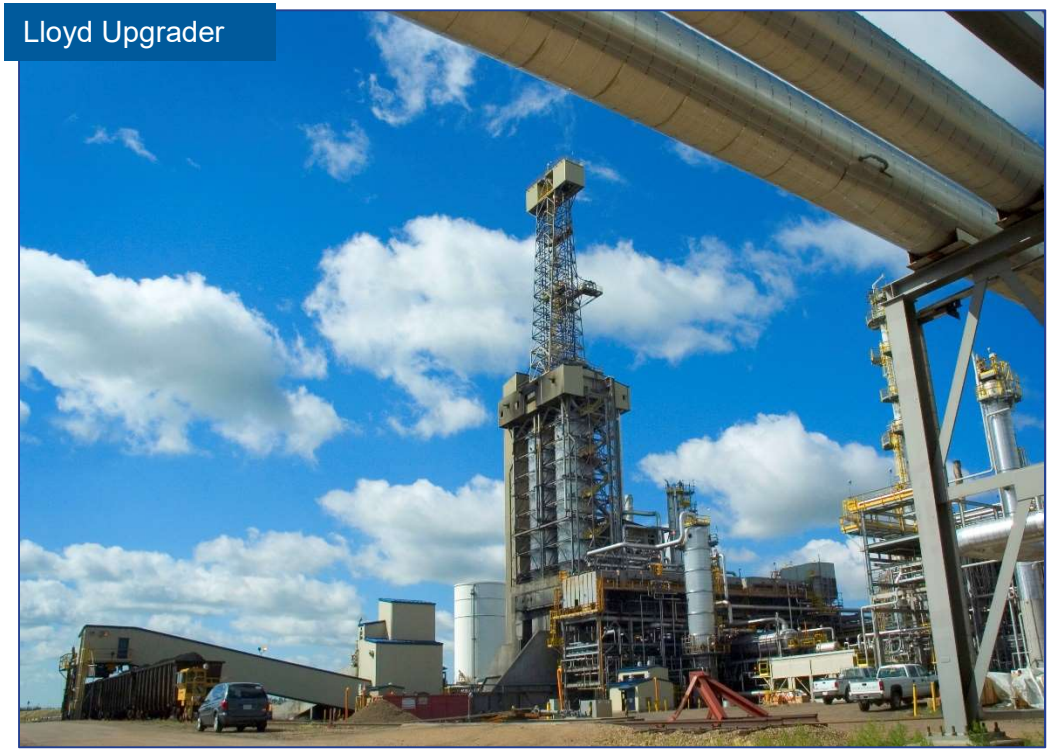
- 550+ retail outlets across Canada
- Branded, dealer-operated
- Cardlock JV with Imperial

Lloydminster Upgrader

Engine Of The Integrated Corridor

- Heavy crude capacity 80,000 bbls/day (2018 throughput of 74,200 bbls/day including the turnaround)
- Operating cost of $7.21/bbl (2018)
- Expansion in mid-2020 to 81,500 bbls/day
- Diesel production increasing from 6,000 bbls/day to 9,800 bbls/day
- Capture of intermediates from Husky Lloydminster Refinery

Lloyd Upgrader



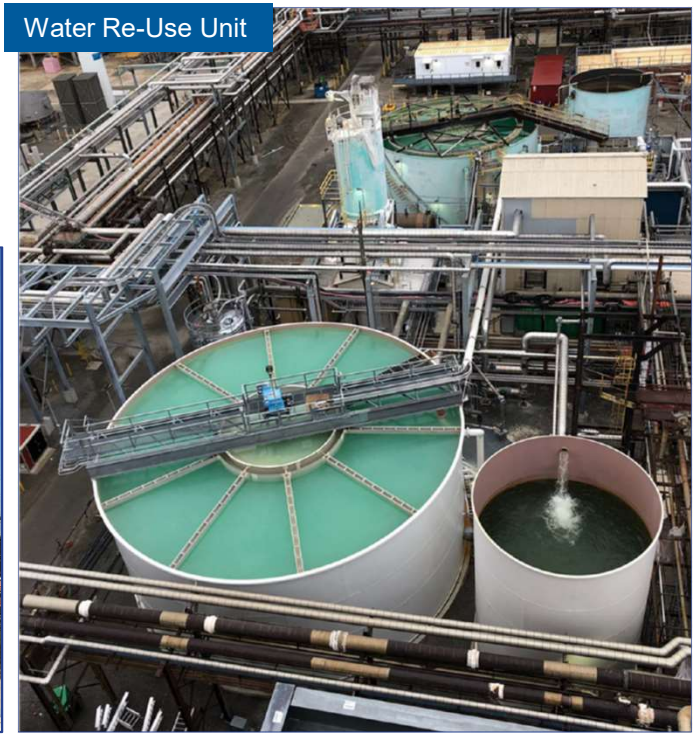
Lima Crude Oil Flexibility Project

Positioned To Process Up To 40,000 bbls/day Of Heavy Oil

- 2018 major turnaround scope completed; peak capacity increased to 175,000 bbls/day
- Project to be completed at end of 2019
  - 80% complete
  - 20% commissioned
  - Ahead of schedule and on budget
- Major final tie-ins planned for Q4 2019
- Over 20% of Lima's crude feedstock can be shifted between light and heavy grades
- Increased water recycling to reduce water withdrawals

Site Construction

Water Re-Use Unit



Superior Refinery Rebuild

Back Online In 2021

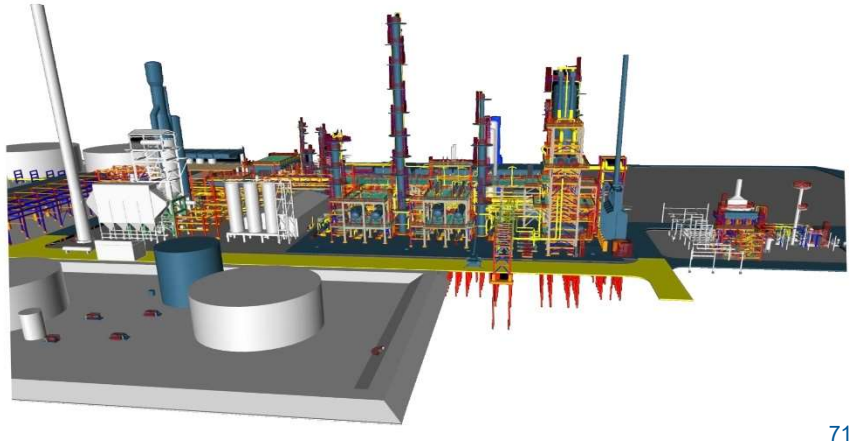
- Same design and capacity
- Modernizations and safety enhancements
- Main areas of rebuilding:
  - Crude unit
  - Fluid Catalytic Cracking Unit (FCCU)
  - Asphalt tanks
- Latest and most advanced emissions control technology to be applied

Design advantages:

- Continuous operation on heavy/light crude blend
- Improved asphalt blending
- Higher energy efficiency
- Greater product flexibility

Rebuild Next Steps:

- Demolition: Now through Fall 2019
- Construction begins: Fall 2019, subject to permitting
- Full operations: 2021
- Estimated cost: Over $400 million US, largely funded by insurance

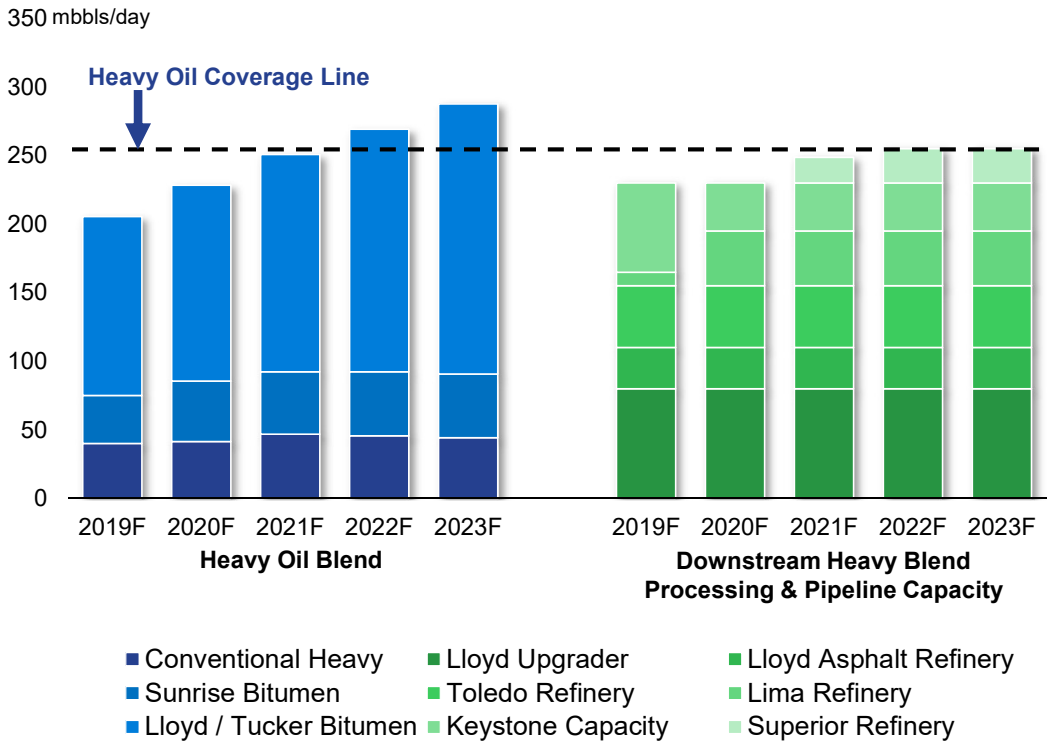


Matching Heavy Processing To Upstream Production

Removing Exposure To The Heavy-Light Differential

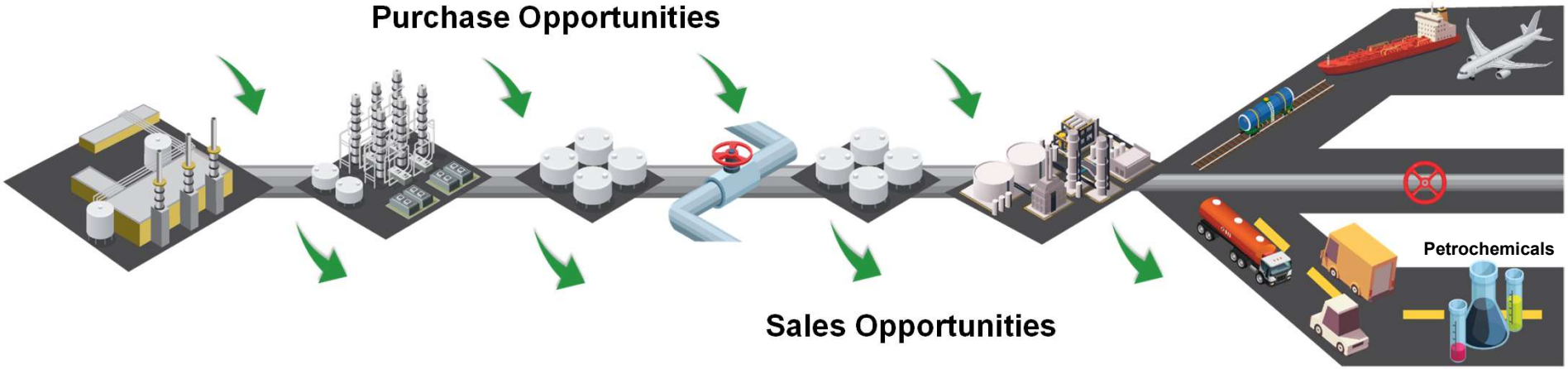
- Heavy oil bitumen blend matched to Downstream heavy processing and pipeline takeaway capacity through 2021
- Lima crude oil flexibility project
  - To add 30,000 bbls/day of heavy oil processing capacity in 2019
- Return of Superior Refinery in 2021
- Future heavy oil outlet options:
  - Export pipeline access
  - Lloyd asphalt plant expansion
    - Additional 30,000 bbls/day

Heavy Oil Blend vs. Downstream Processing & Pipeline Capacity



Physically Integrated Corridor

Optimizing Buy/Sell Decisions At Each Step



- **Production**
  - Oil sands
  - Heavy oil
  - Light oil
  - Natural gas
- **Market Hubs**
  - Edmonton
  - Hardisty
  - Patoka
  - Cushing
- **Logistics**
  - Crude pipelines
  - Gas pipelines
  - Product pipelines
  - Railcars
  - Barge
  - Trucks
- **Storage**
  - Hardisty
  - Superior
  - Patoka
  - Lima
  - Lloydminster
- **Refineries**
  - Lloydminster
  - Superior
  - Lima
  - Toledo
- **Products**
  - Gasoline
  - Diesel
  - Jet fuel
  - Asphalt
  - NGLs
  - Petrochemicals
- **Markets**
  - Canada
  - U.S. Midwest
  - U.S. Gulf Coast
  - U.S. West Coast

Downstream Operating Model

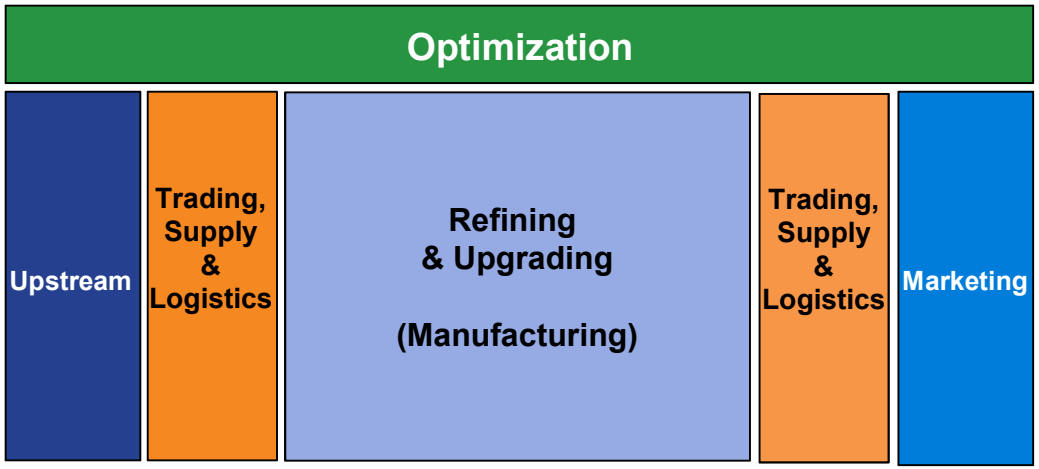
Purpose-Built To Capture Integration Value

Optimization

Determines the plan on behalf of the total Downstream

Trading, Supply & Logistics

Captures market opportunities, manages all logistics operations and supports operations with price-risk protection



Marketing

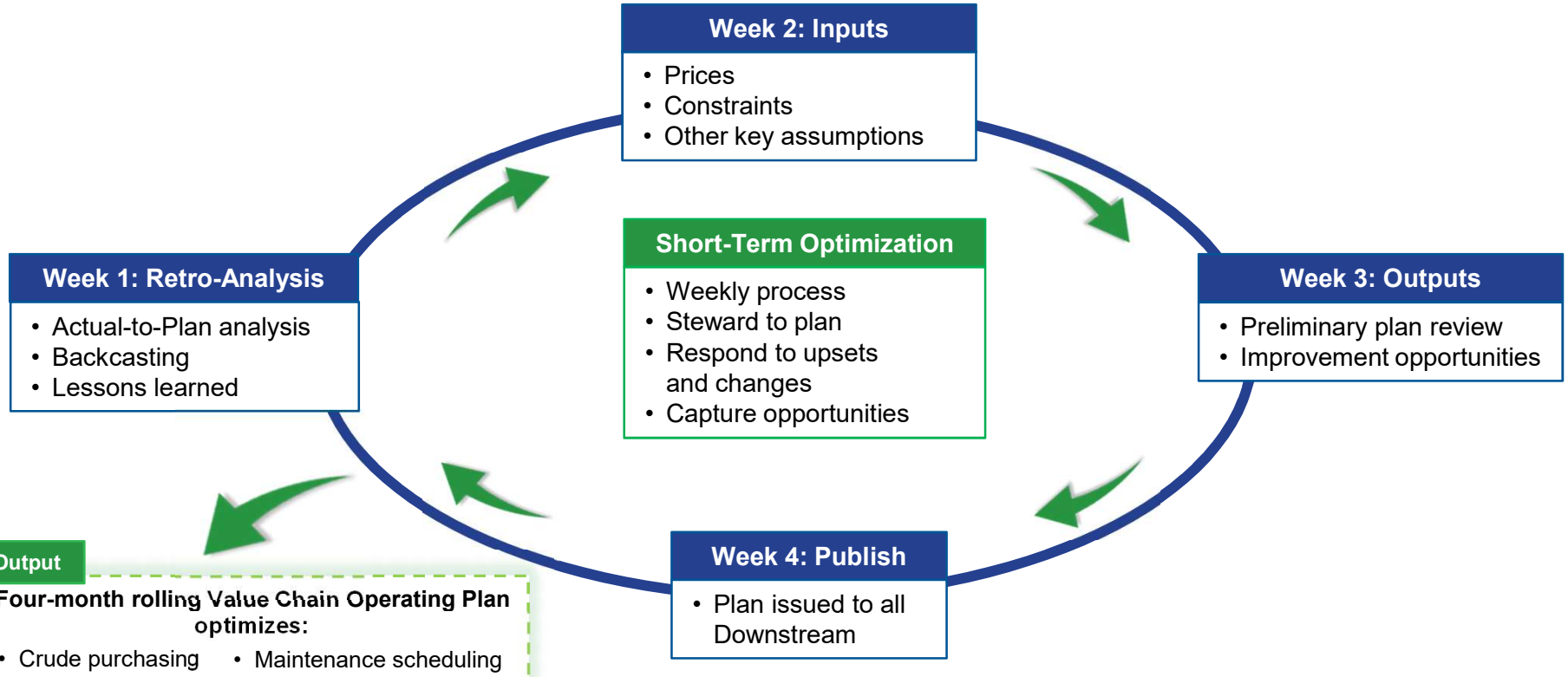
Manages customer-facing businesses

Manufacturing

Safe, reliable, efficient operations

Downstream Optimization

Responsible For Integrated Plan



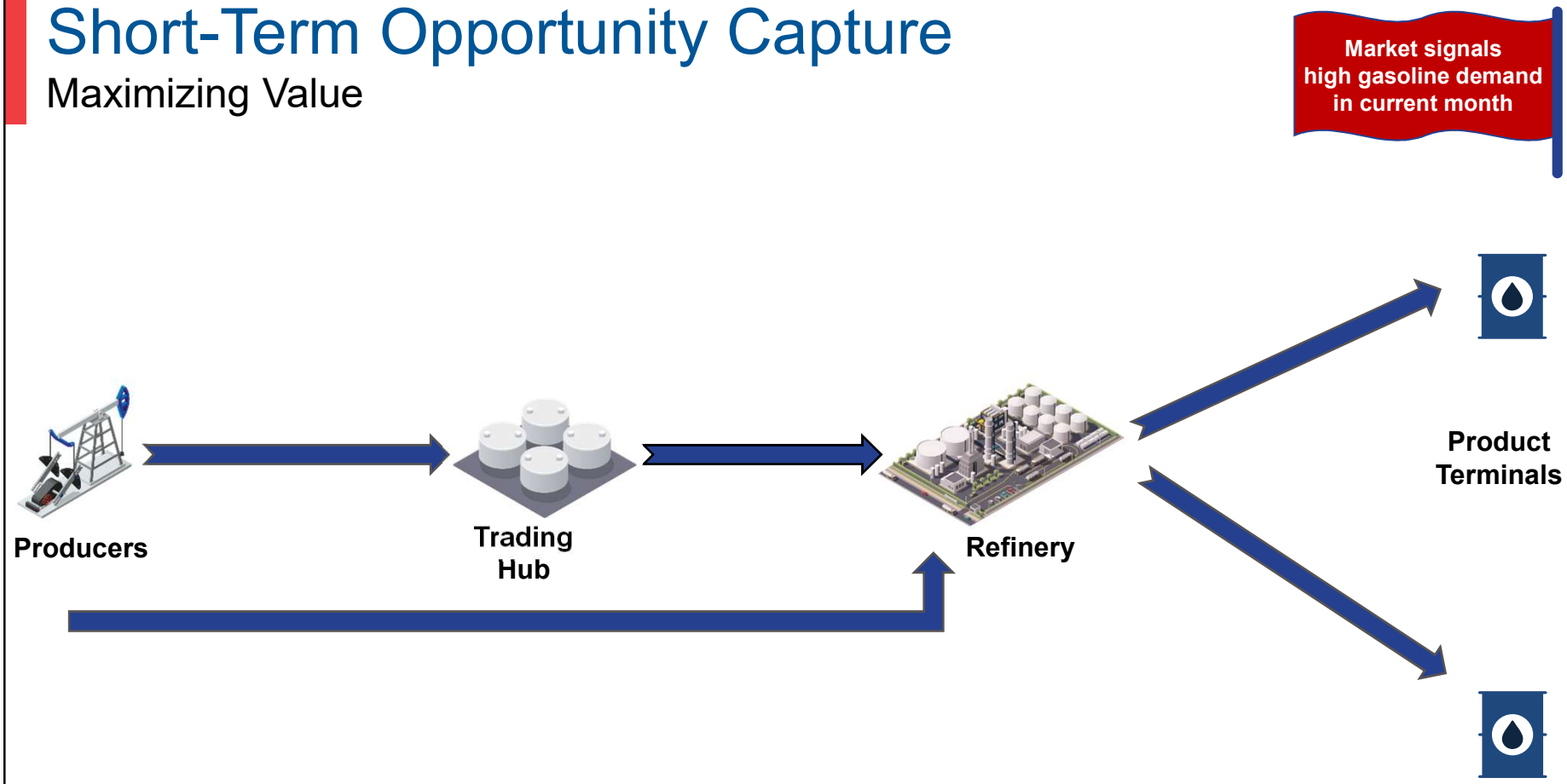
Output

Four-month rolling Value Chain Operating Plan optimizes:

- Crude purchasing
- Inventory planning
- Refinery operations
- Maintenance scheduling
- Logistics operations
- Product sales

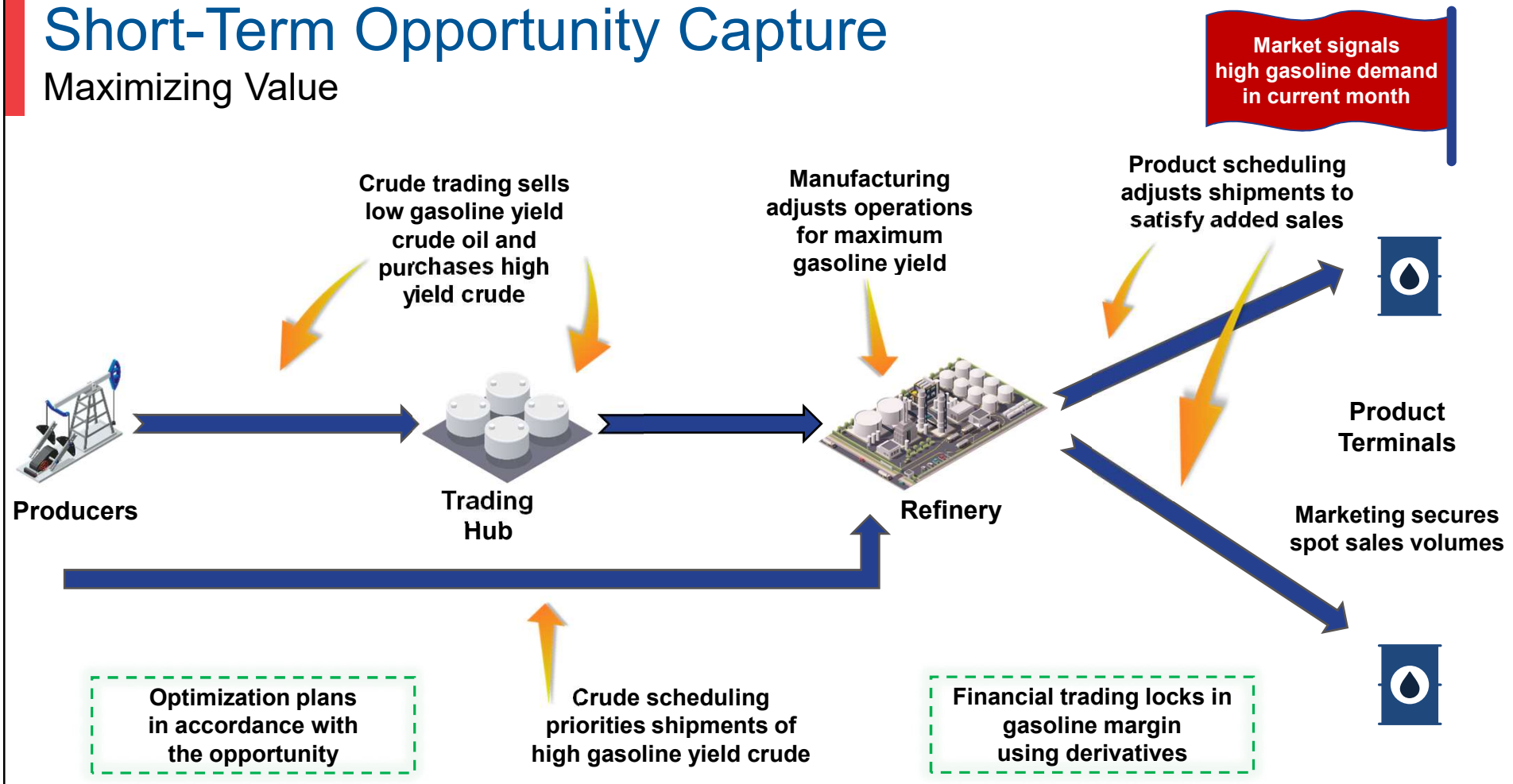
Short-Term Opportunity Capture

Maximizing Value



Short-Term Opportunity Capture

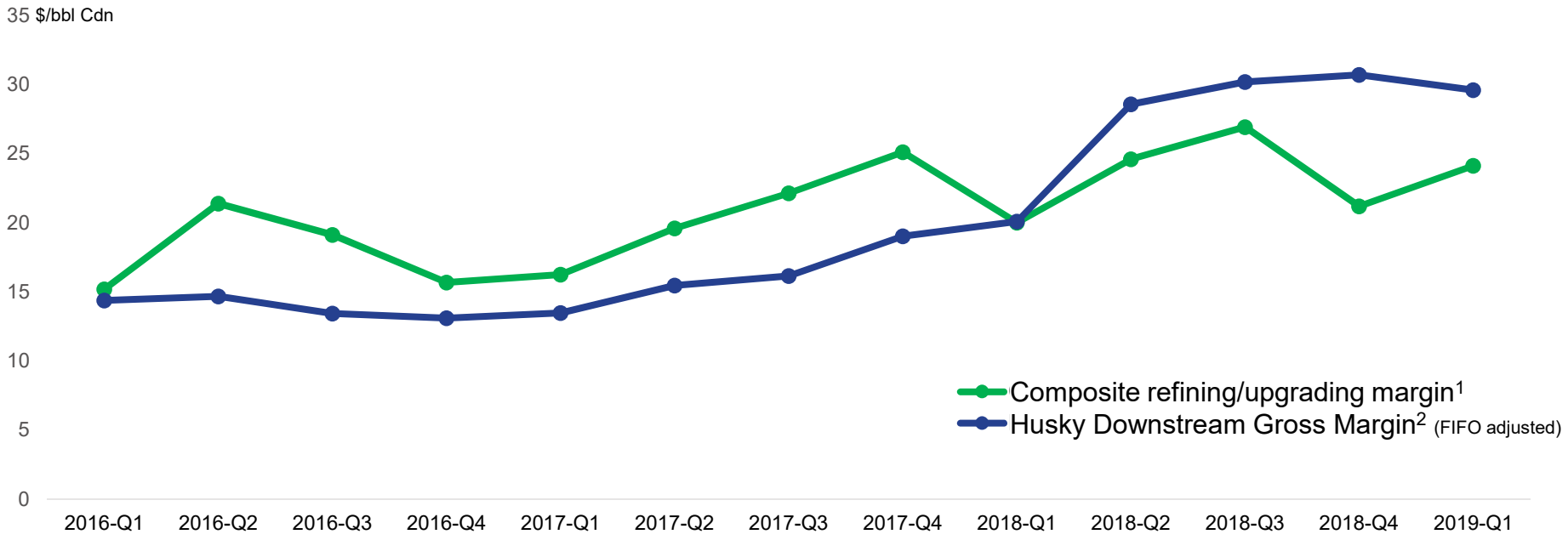
Maximizing Value



Growing Downstream Margins

Growing Fraction Generated 'Outside The Refinery Gate'

Historical Gross Margin Analysis ($/bbl Cdn)



1) Composite calculated using a Husky asset sales volume weighted average of Chicago 3-2-1, HLU differential and Edmonton 2-1-1 prices. 2) Husky Downstream excludes Canadian product sales volume and margin, and includes allocation of profits from the Upstream segment.

Husky Downstream

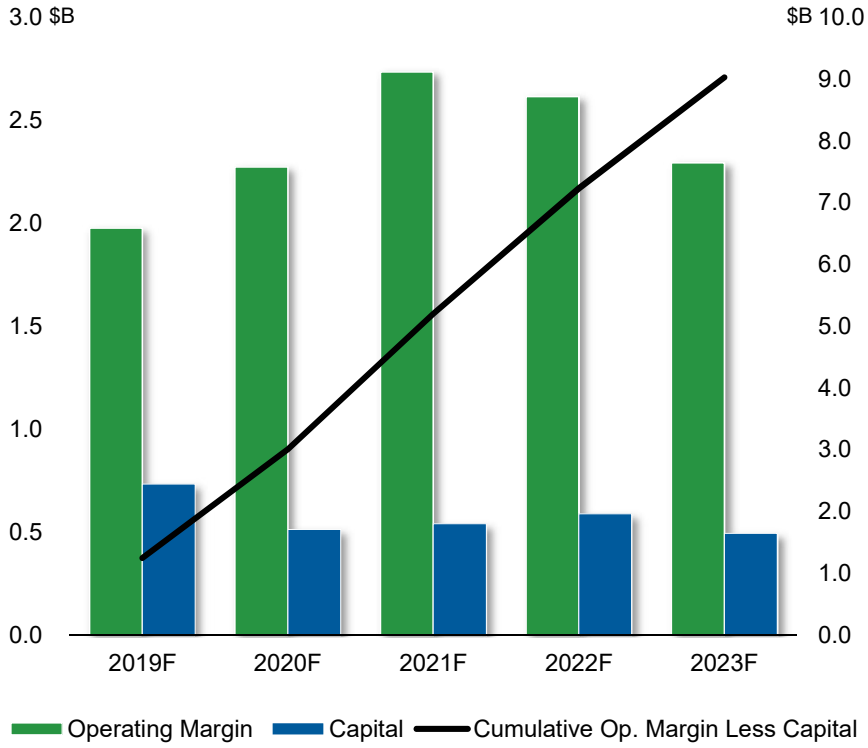
Purpose-Built To Capture Integrated Value

We are transforming Downstream through a new operating model

- Renewed focus on safe, reliable operations
- A leaner, integrated Downstream focused on the Integrated Corridor
- Increasing our speed of action to opportunity
- Capturing more value outside the refinery gate

Annual Average Operating Margin Less Capital '19-'23F **~$1.8B**

Downstream
Operating Margin Less Capital



Maximizing Full Value Chain Margin Capture

Integrated Corridor – Downstream

Downstream

- Increasing speed of action to opportunity
- Leaner, integrated organization
- Capturing value outside the refinery gate

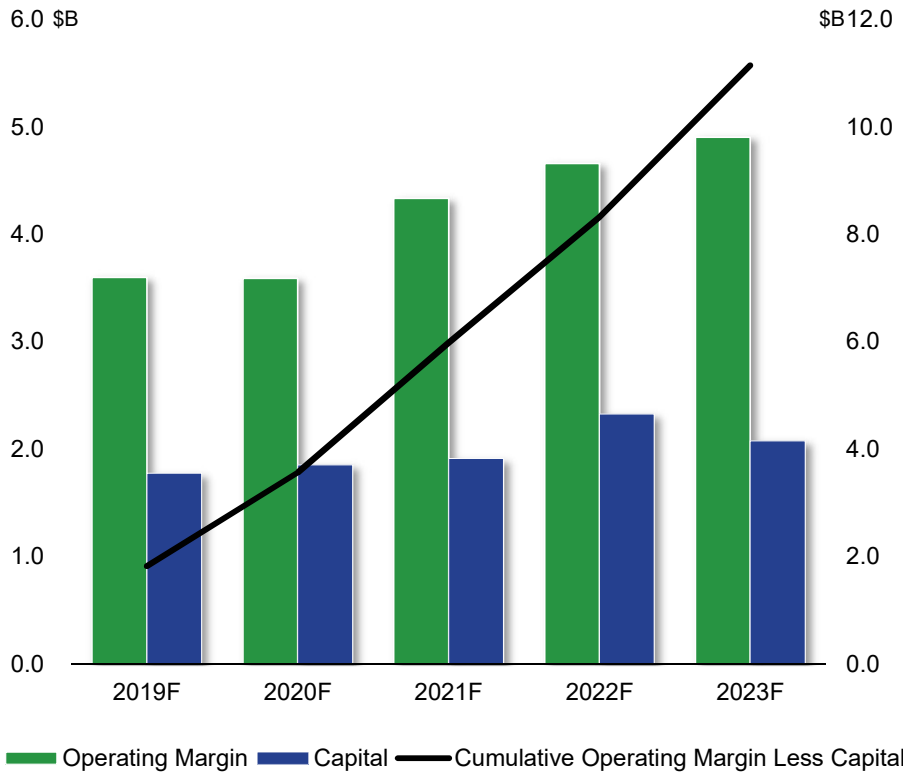
Lloyd Thermals & Oil Sands

- Long-life assets with a large resource
- Modular, scalable designs
- Low and improving operating costs and sustaining capital costs

Western Canada

- Competitive, integrated business
- Pivoting to liquids
- Gas production fuels thermal growth and Canadian Downstream facilities

Integrated Corridor
Operating Margin Less Capital

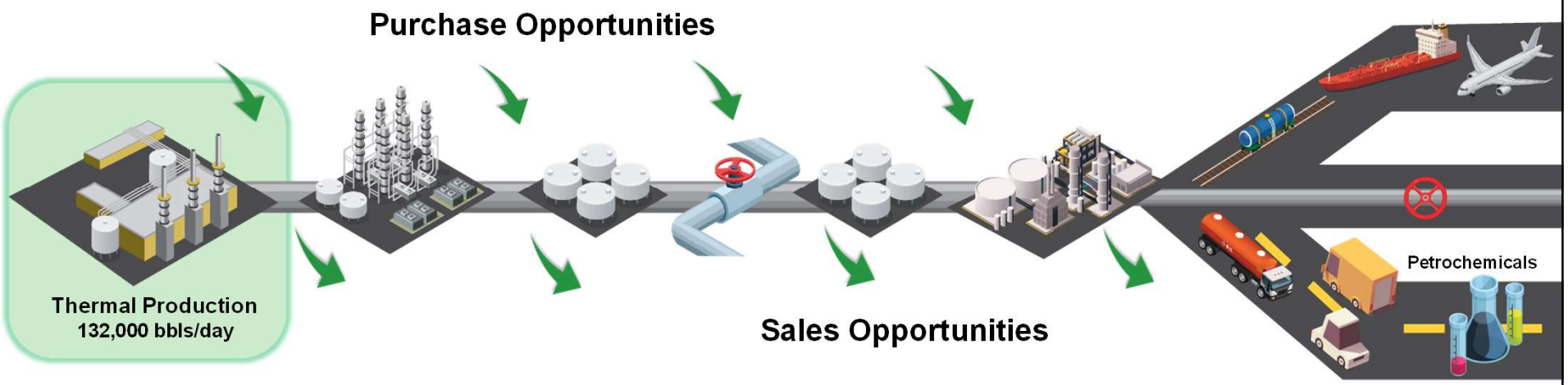


Andrew Dahlin

SVP, Heavy Oil & Oil Sands

Supplying Low Cost, Reliable Feedstock

Integrated Corridor – Thermal Production



Supplying Low Cost, Reliable Feedstock

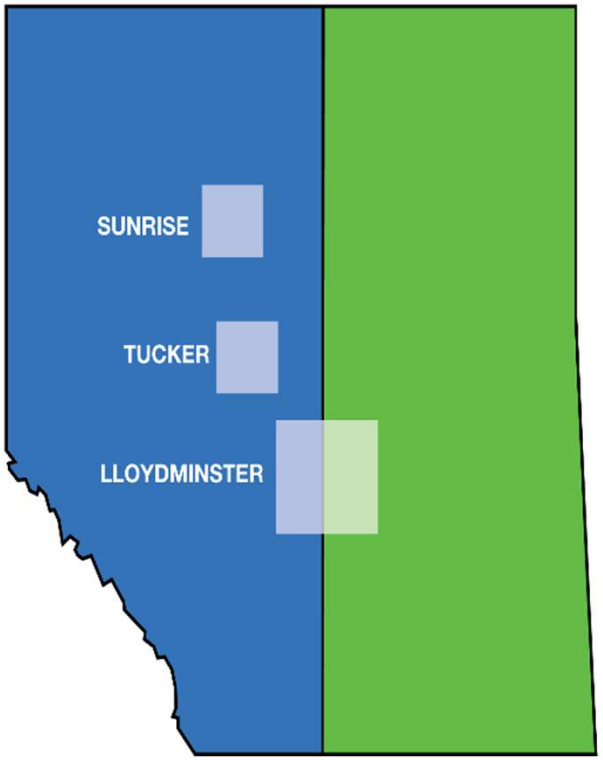
Integrated Corridor – Thermal Production

What's New

- Implementing HRO principles
- Pacing of Lloyd thermal projects
- Focus on Sunrise & Tucker margin capture vs. growth
- Investing in technologies to improve efficiency

Top Priorities

- Continuing safe, reliable operations
- Further progressing the adoption of HRO principles
- Measured growth of our large resource base
- Continue to improve capital intensities and operating costs



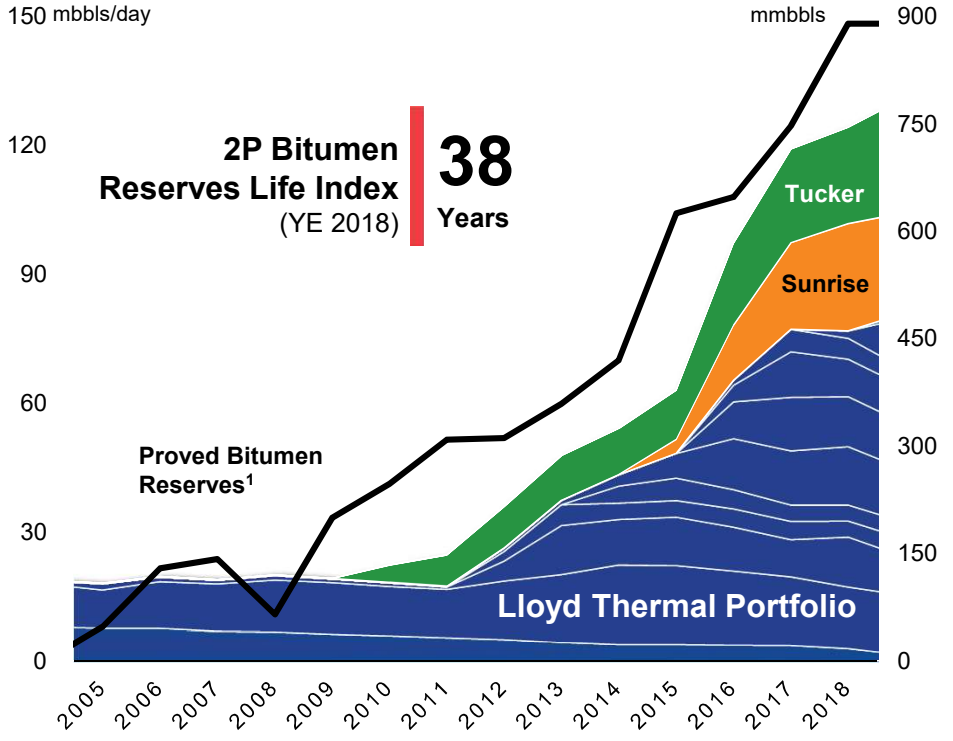
High Quality Resource Base

Low Cost, Low Decline, Long Life Projects

Producing Assets	Production	Startup
Thermal Bitumen (bbls/day)		
✓ Pikes Peak	9,100	1980
✓ Bolney/Celtic	18,400	2001
✓ Tucker	30,000	2006
✓ Pikes Peak South	11,600	2012
✓ Paradise Hill	4,900	2012
✓ Sandall	5,200	2014
✓ Rush Lake	13,600	2014
✓ Sunrise	30,000	2015
✓ Edam East	12,400	2016
✓ Vawn	10,600	2016
✓ Edam West	5,200	2016
✓ Rush Lake 2	11,500	2018

In-Flight & Future Projects	Capacity	Startup
Thermal Bitumen (bbls/day)		
Dee Valley	10,000	2019
Spruce Lake Central	10,000	2020
Spruce Lake North	10,000	2020
Spruce Lake East	10,000	2021
Edam Central	10,000	2022
Dee Valley 2	10,000	2023
Sunrise Phase 1 de-bottleneck 2	4,000	2024+
Future Lloyd thermals 1-5	50,000	2024+
Future Sunrise phases	60,000	2024+

Production and Reserves History



1) See Slide Notes and Advisories

Lloyd Thermals

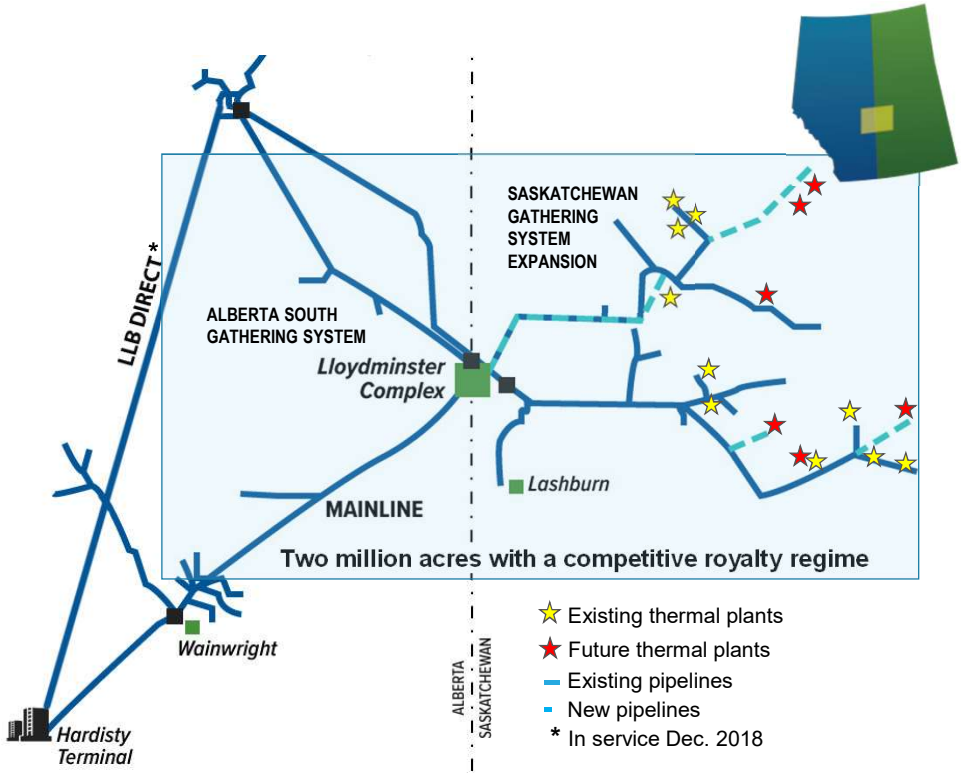
History Of Successful Project Execution And Capital Discipline

10 thermal projects producing 82,500 bbls/day

- Modular, scalable designs with standardized engineering & construction
- Rush Lake 2 continues to perform above nameplate
- Project break-evens of $30/bbl WTI
- Not impacted by Alberta government production quotas

Growth projects update:

- Paced development: Three projects every two years
- Focus on hub centralization and shared infrastructure
- Dee Valley on stream for Q3, ahead of original plan
- Spruce Lake Central and Spruce Lake North on track for start-up in 2020 start-up, adding approximately 20,000 boe/day of capacity



Sunrise Energy Project

Design Capacity Reached; Focus On Reducing Cost Structure

60,000+ bbls/day in Dec. 2018 (30,000 bbls/day Husky WI)

- Potential to increase steam capacity by 123%
- Cost reduction target of $10/bbl in ~2021
- Currently impacted by Alberta production quotas

Target production per well pair: 800-900 bbls/day

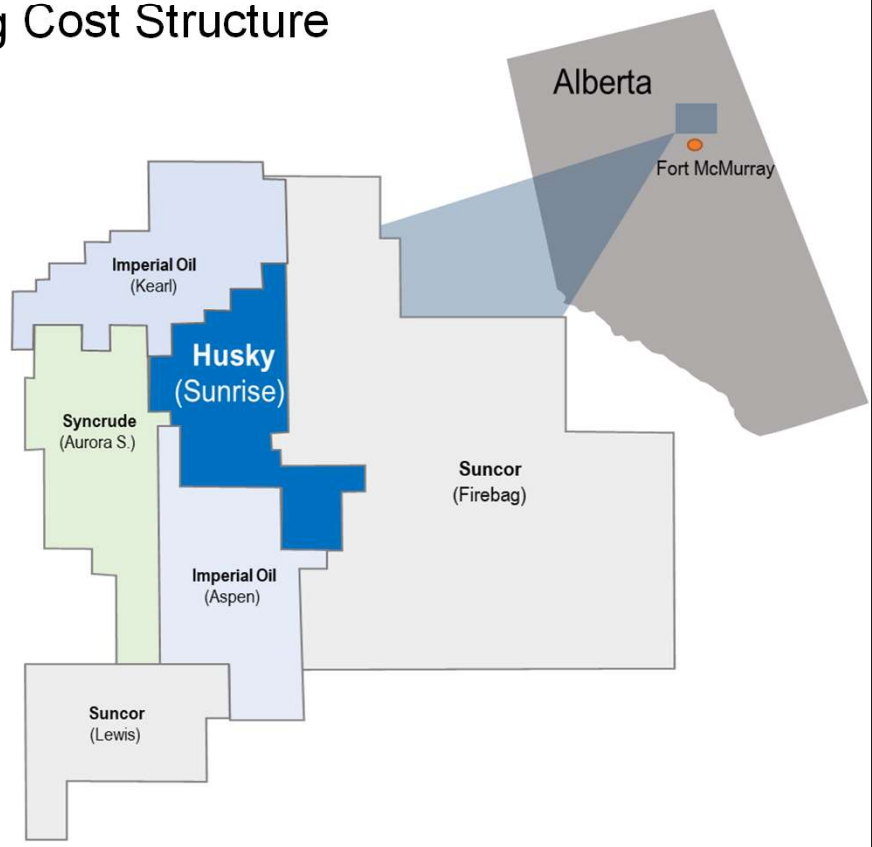
- 55 Initial Development Area well pairs (855 bbls/day)
- 14 Development Area 2 well pairs (442 bbls/day – will ramp up post-production quotas) and 12 infill wells

Reducing sustaining capital costs:

- Pad and well spacing optimization
- Modular design for sustaining pads

Future phases of growth and debottlenecking potential

- 20,000 bbls/day modularized design concept with potential to add co-gen



Tucker Thermal Project

Design Capacity Reached; Debottlenecking And Optimization To Drive Margins

Surpassed 30,000 bbls/day (October 2018)

- Exceeded design capacity after overcoming tough reservoir
- Operating costs of $12.64/boe; operating netback of $33.50/boe in Q1/19
- Focus on cost reduction with $10 per boe goal in ~2021

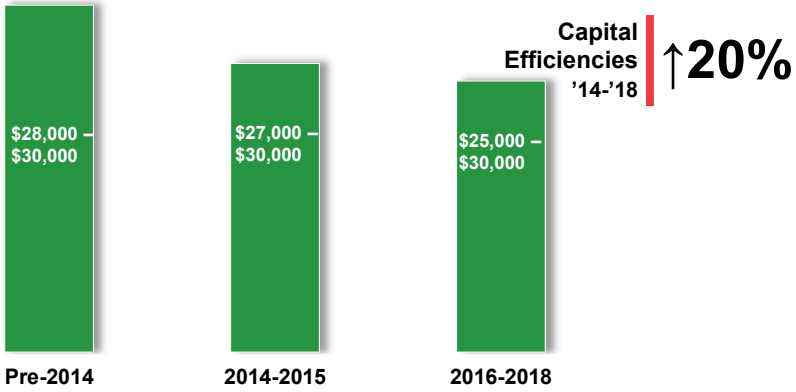
Production of 25,000 bbls/day (Q1 2019)

- Impacted by Alberta government production quotas
- Committed to reducing sustaining capital costs through pad and well spacing optimization and modular design for sustaining production
- Future debottleneck opportunities identified; re-rating on steam generation capacity

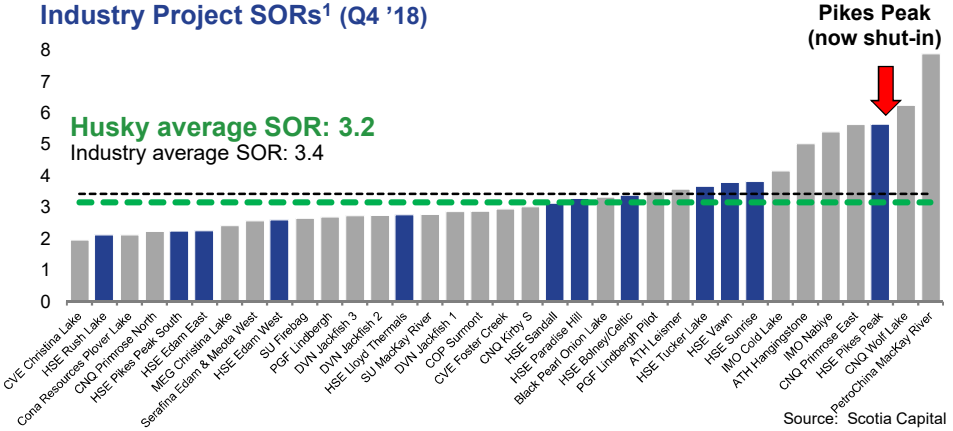
Competitive Capital Efficiency & Operating Costs

Continuous Improvement Generating Value

On-Stream Capital Cost ($/bbl per day)

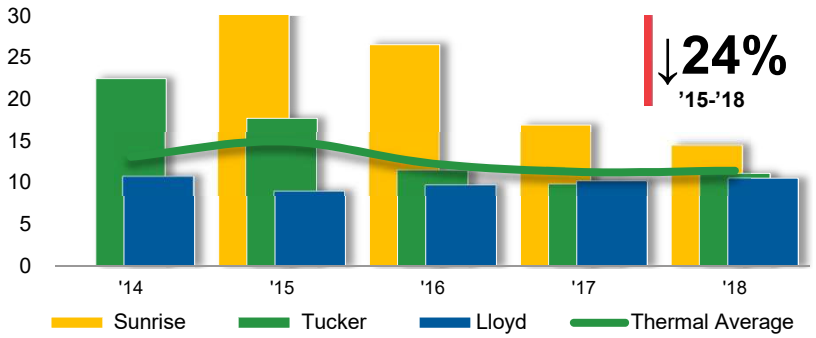


Industry Project SORs[1] (Q4 '18)

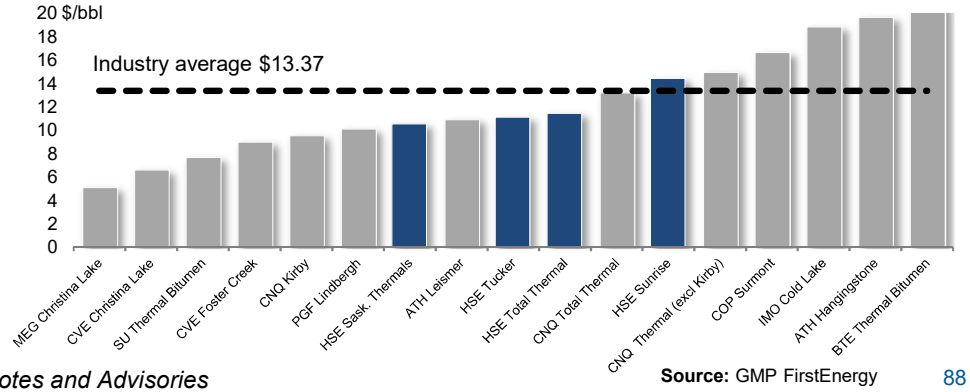


Source: Scotia Capital

Thermal Operating Costs ($/bbl per day)



Industry Operating Costs Per Barrel (2018)



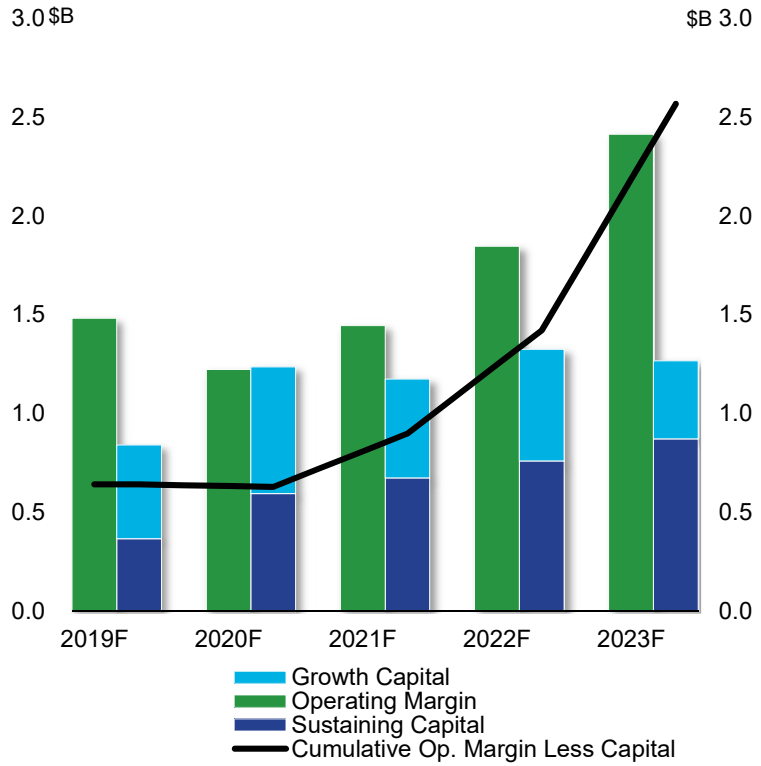
Source: GMP FirstEnergy

1) See Slide Notes and Advisories

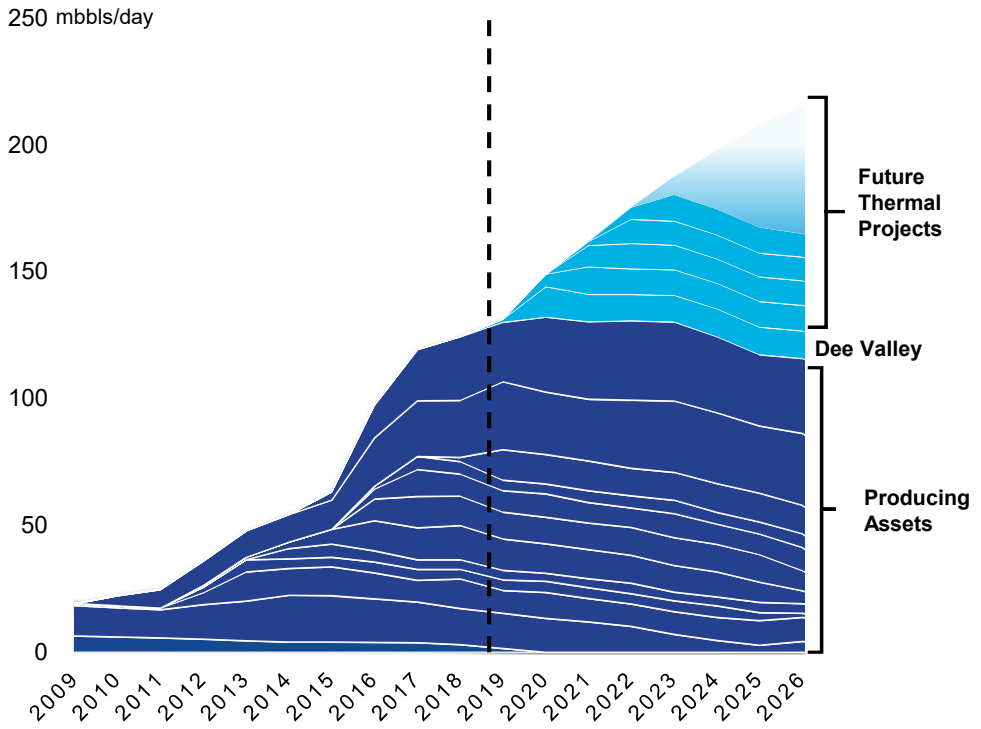
Repeatable Growth With High Certainty of Success

Growth Capital Focused On Lloyd Thermals

Heavy Oil & Oil Sands
Operating Margin Less Capital



Thermal Production Forecast

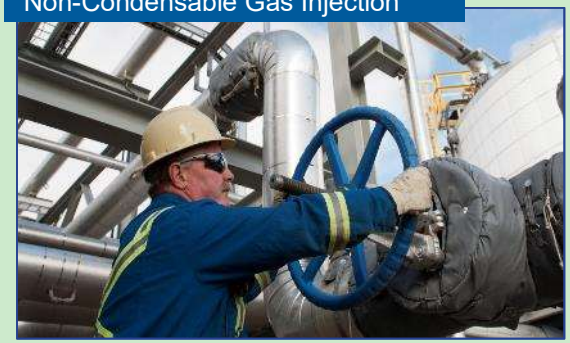


Applying Technology To Heavy Oil & Oil Sands

Increasing Recoverable Resource And Improving Cost Structure

Near Term/Commercialization Stage

Non-Condensable Gas Injection



Artificial Intelligence

CO2 Capture

Debottlenecking

Up and Coming

HDR at Sunrise

Improved Pad Designs

Maximizing Full Value Chain Margin Capture

Integrated Corridor – Thermal Production

Downstream

- Increasing speed of action to opportunity
- Leaner, integrated organization
- Capturing value outside the refinery gate

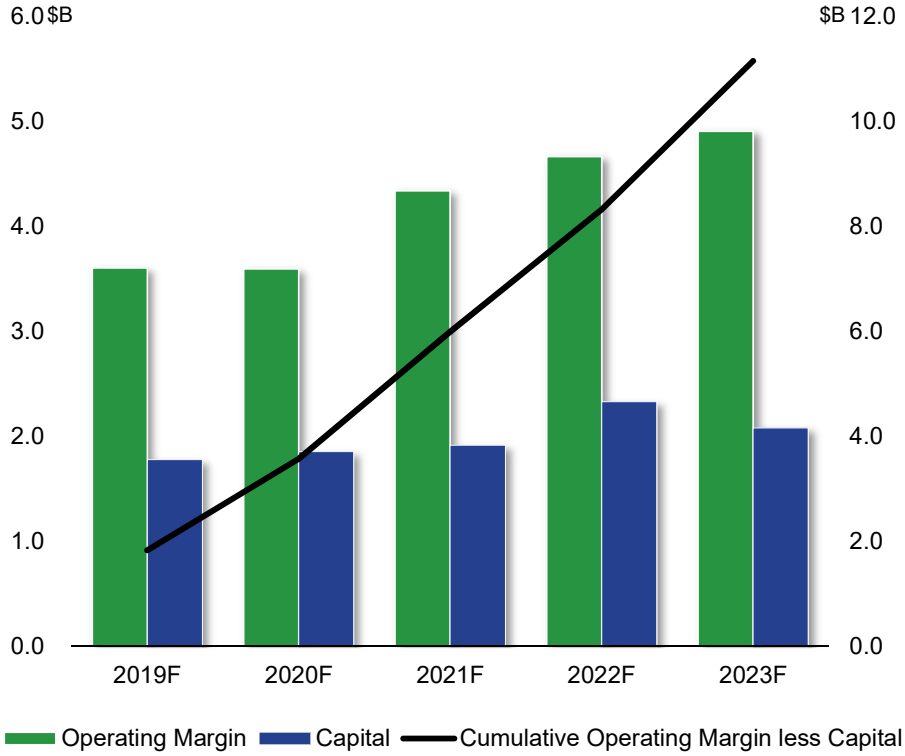
Lloyd Thermals & Oil Sands

- Long-life assets with a large resource
- Modular, scalable designs
- Low and improving operating costs and sustaining capital costs

Western Canada

- Competitive, integrated business
- Pivoting to liquids
- Gas production fuels thermal growth and Canadian Downstream facilities

Integrated Corridor
Operating Margin Less Capital



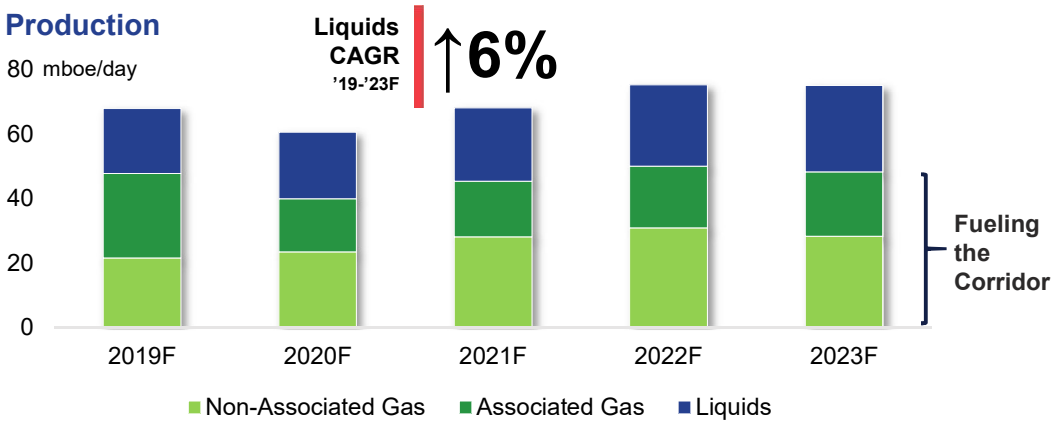

Western Canada
Resource Plays
Gerald Alexander
SVP Western Canada Production
Ansell Gas Plant

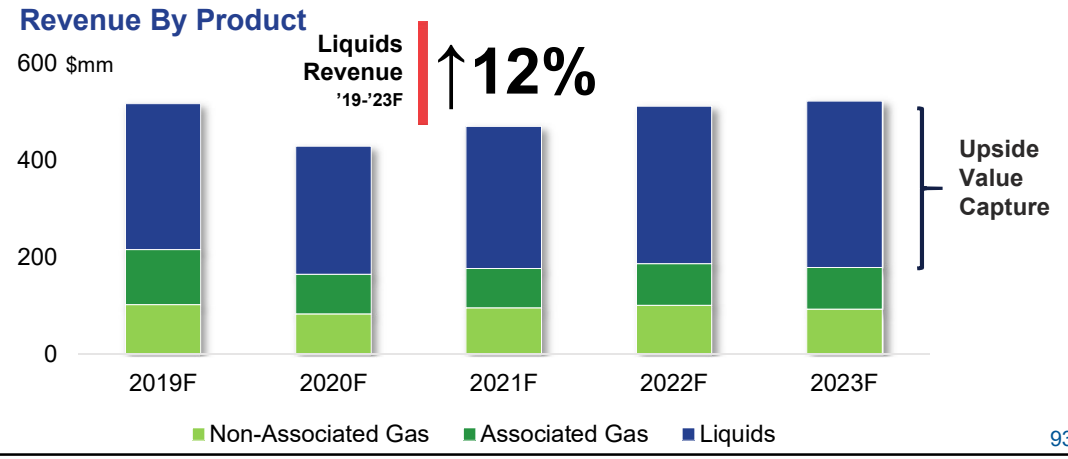
Competitive, Integrated Business

Supplies Gas To Integrated Corridor

Highlights

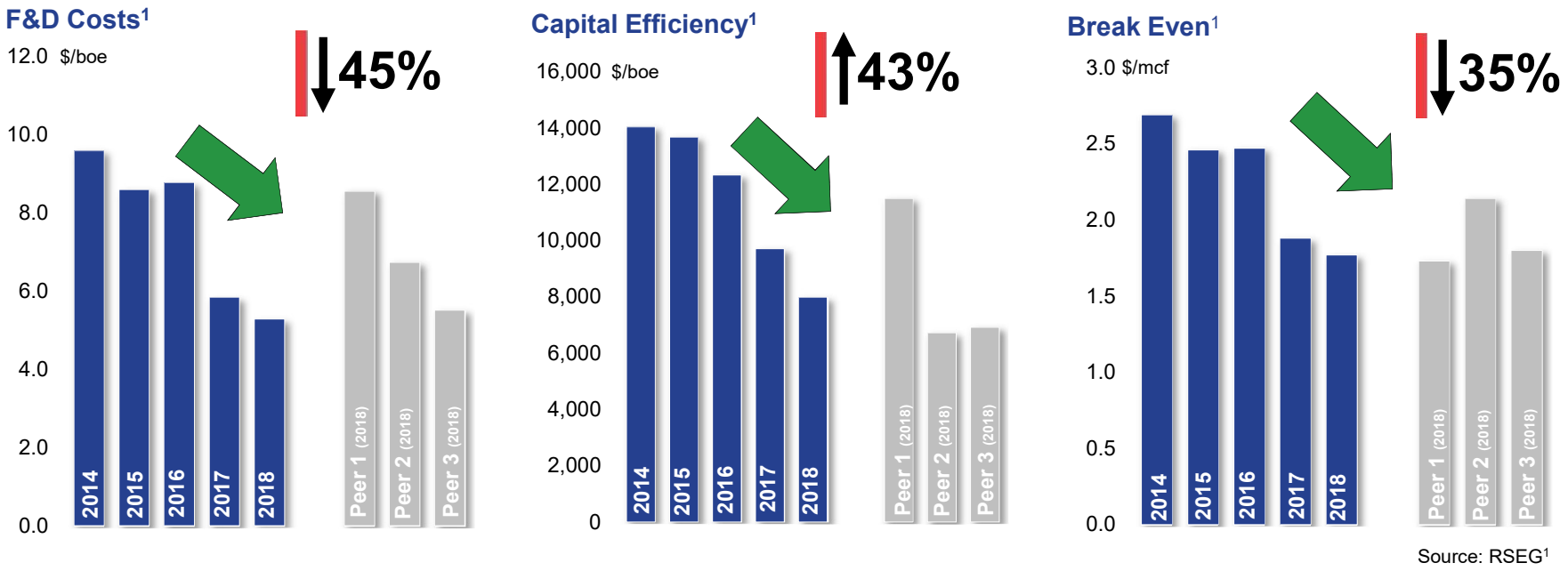
- Implementing HRO principles; top-tier safety results in 2018
- Large resource base with optionality for liquids or gas growth
- Significantly improved costs and well performance
- Wembley key to margin growth
- Markets for products add value capture; no egress issues
- Balanced growth mirrors thermal development while providing strong economics with liquids upside





Ansell: Increasing Value Through Focused Execution

Demonstrated Ability To Deliver Top-Tier Performance

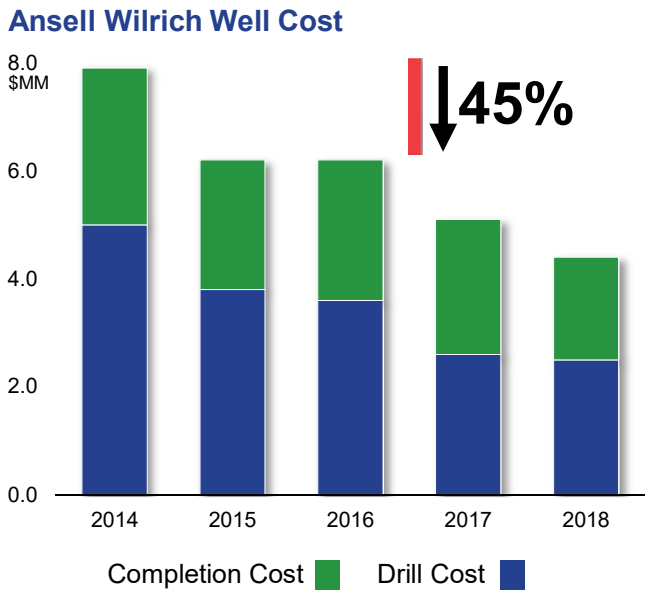


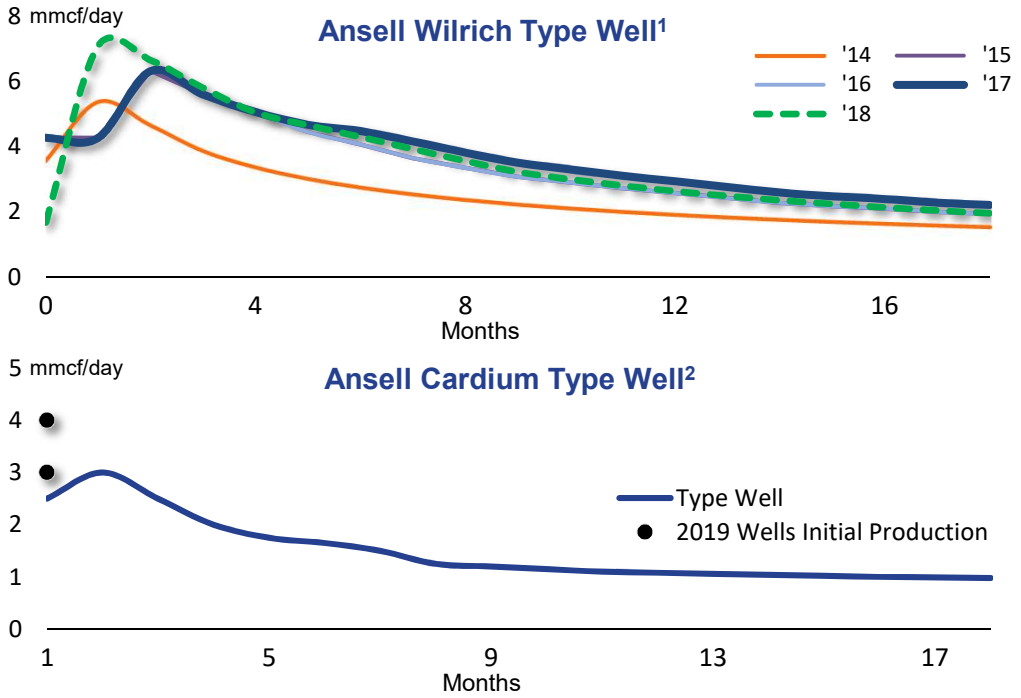
Source: RSEG[1]

1) See Slide Notes and Advisories

Technology Delivering Results

Knowledge Transferred Across All Resource Plays





- Continuous multi-well pad development
- Drilling analytics and new technology

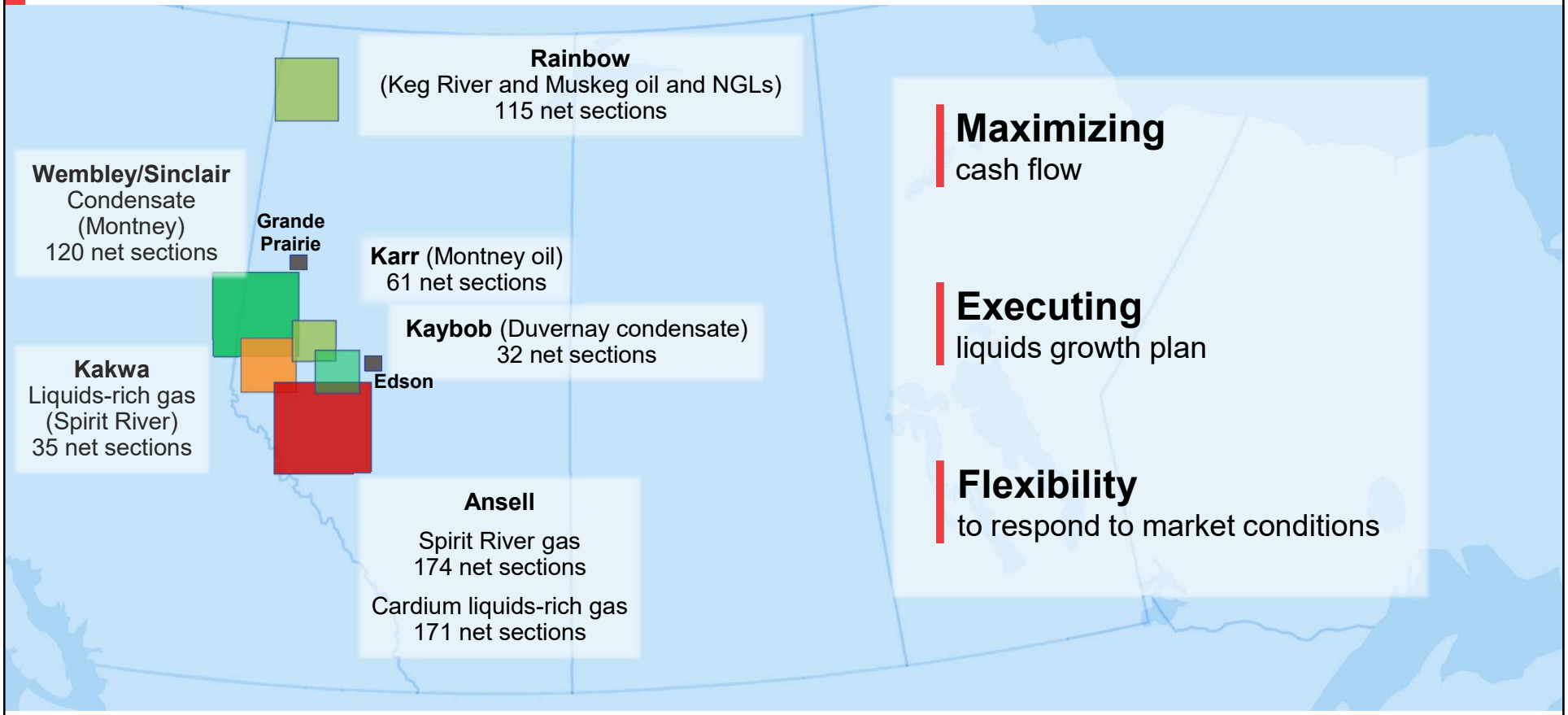
- Subsurface well design placement
- Higher proppant and fluid intensities

- Enhanced flowback and optimized design
- Driving efficiencies

1, 2) See Slide Notes and Advisories

Western Canada Core Growth Areas

Deep Portfolio Of Resource Play Projects Provide Optionality



Maximizing
cash flow

Executing
liquids growth plan

Flexibility
to respond to market conditions

Wembley – Sinclair

Condensate Growth Driving Significant Value

Liquids-rich Montney:

- **Materiality:** Three stacked horizons; 120 sections
- **Liquids yield:** Up to 150 bbl/mmcf total NGL (deep cut)
- **Egress:** 2019 secured, long-term plan in progress
- **Production:** Six wells planned for Q4 tie-in
- **Resilience:** Liquids 10% IRR at $29.20/bbl US WTI

Liquids Production[1] **51%**

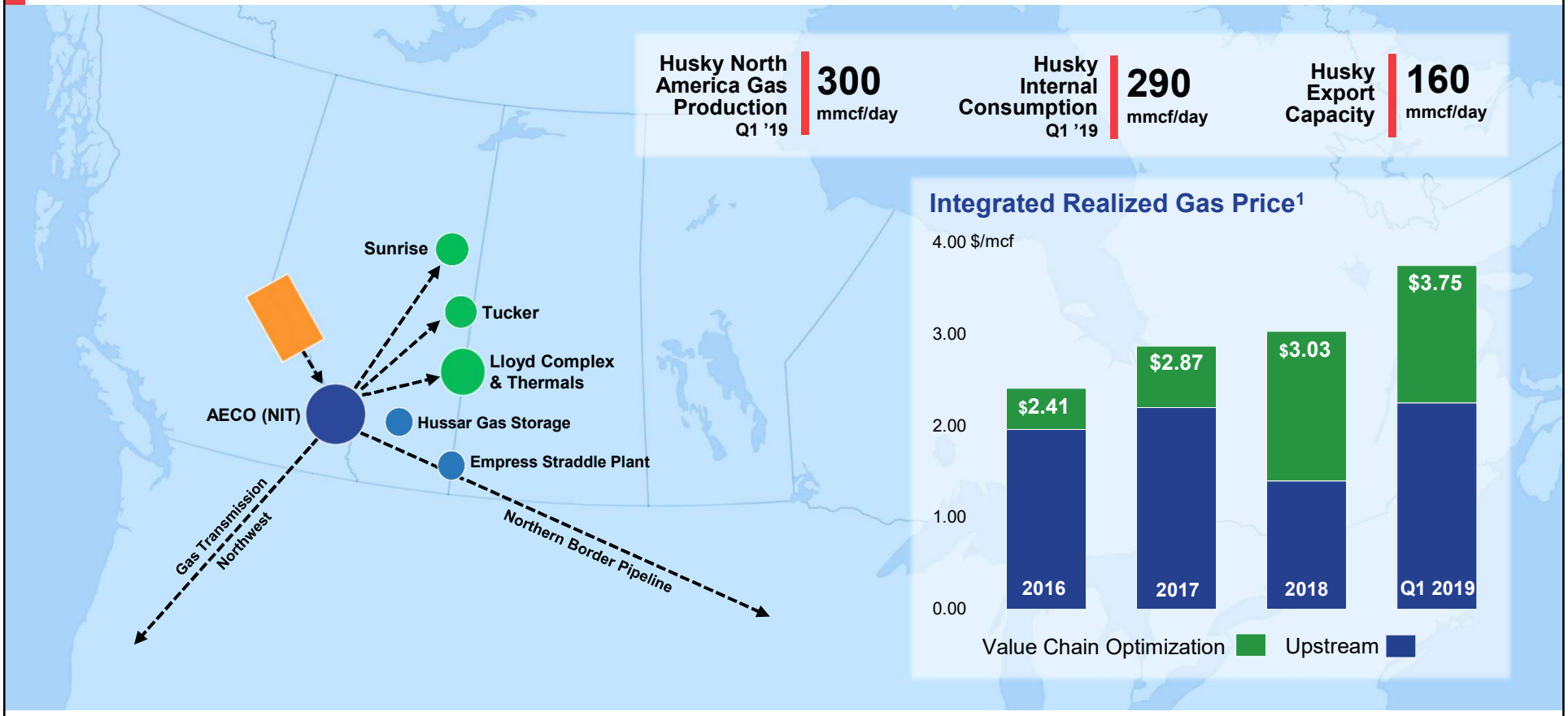
Liquids Revenue[2] **82%**

Drilling 13-26 Pad at Wembley

1, 2) See Slide Notes and Advisories

Marketing Strategy Yields Strong Realized Pricing

Realized Gas Prices Much Higher Than AECO



1) See Slide Notes and Advisories

Maximizing Full Value Chain Margin Capture

Integrated Corridor

Downstream

- Increasing speed of action to opportunity
- Leaner, integrated organization
- Capturing value outside the refinery gate

Lloyd Thermals & Oil Sands

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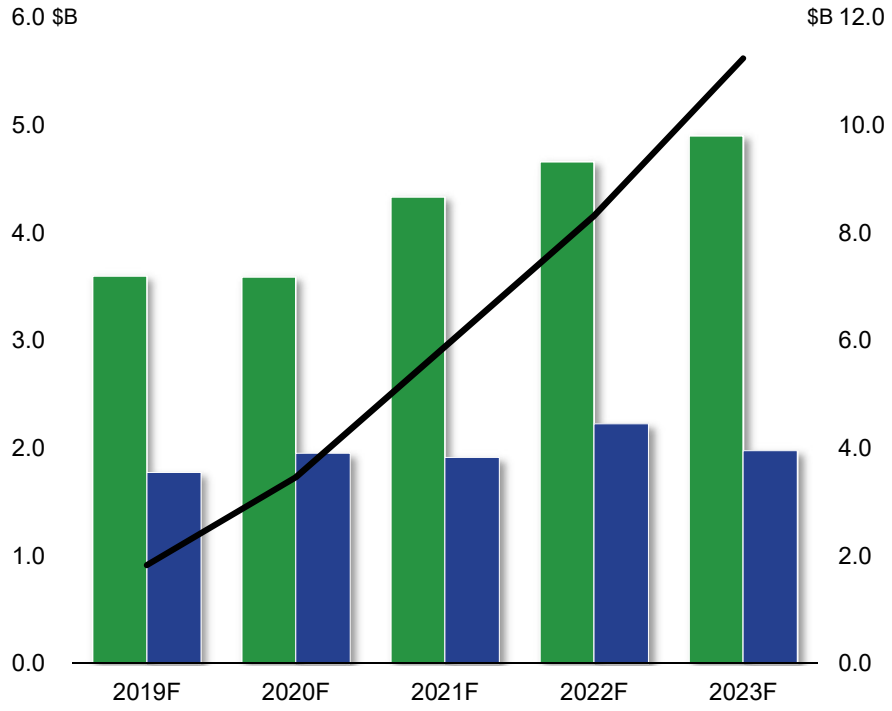
Integrated Corridor
Operating Margin Less Capital



Offshore

Jonathan Brown, VP Operations Atlantic
Bob Hinkel, COO Asia Pacific

West White Rose Project Construction

Offshore Business

Oil Price Torque Complemented By Fixed-Price Stability

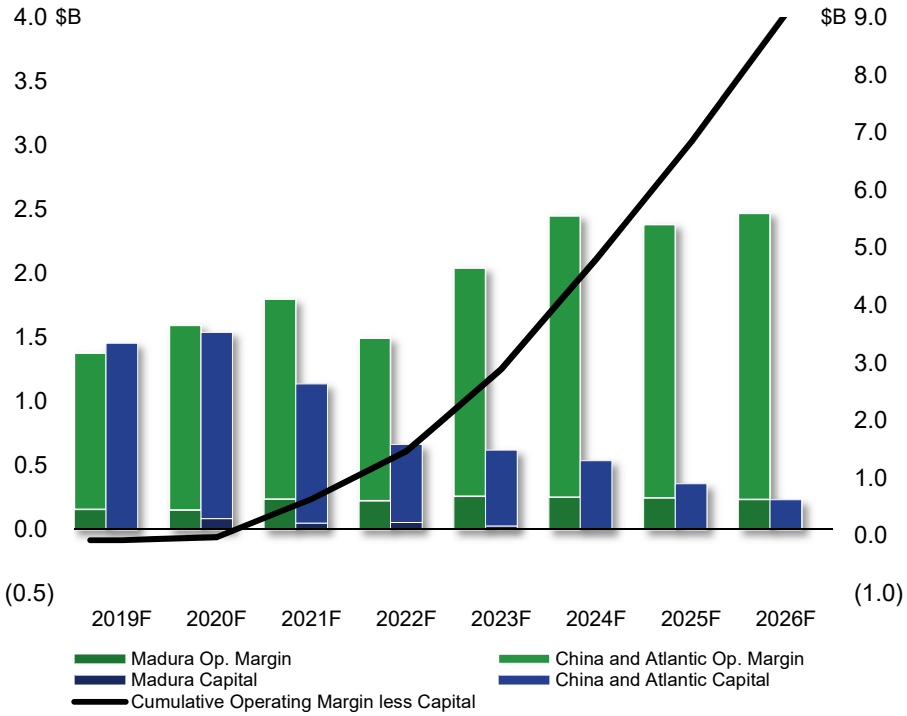
Atlantic

- High netbacks with global oil pricing
- Direct access to tidewater
- Leveraging existing infrastructure
- Defined growth into next decade
- Exploration opportunities

Asia Pacific

- High netback long-term contracts
- Established partnerships
- Leveraging existing infrastructure
- Exploration opportunities

Offshore
Operating Margin Less Capital



Atlantic Canada

Applying HRO Principles In Operations And New Developments

Top Priorities

- Safe and reliable operations
- SeaRose FPSO production ramp up
- West White Rose construction progress

What's New

- Implementation of High Reliability Organization (HRO) principles
- West White Rose paced development

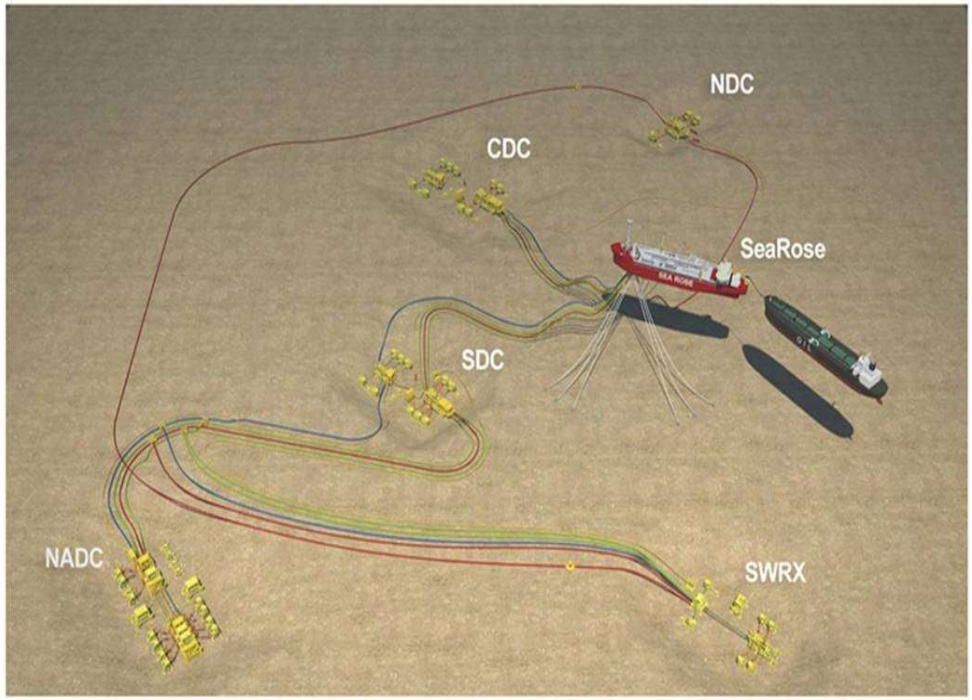
SeaRose FPSO

SeaRose Ramp-Up

Staged Startup Focused On Asset Integrity; Full Ramp-Up In 2H 2019

Key milestones achieved

- Central Drill Centre Jan 2019 (completed)
- Two infill wells in production (May 2019)
- Southern Drill Centre May 2019 (on track)
- North Amethyst July 2019 (on track)
- South White Rose Extension July 2019 (on track)



High-Netback Production

Brent-Based Pricing Provides Global Exposure

Economics enhanced through tiebacks to existing infrastructure

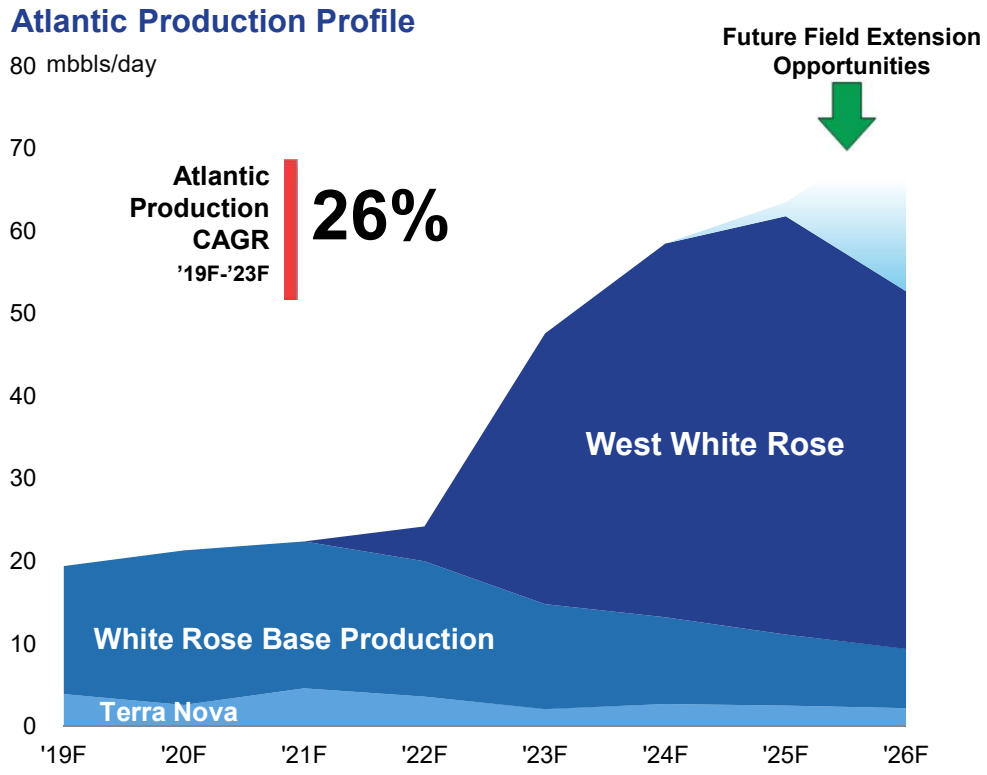
- Defined growth for the next decade
- Exploration upside opportunities

White Rose Field

- 290+ million barrels produced (gross, as of March 31, 2019)
- Integrity work on four water injection wells
- No maintenance turnaround in 2019

West White Rose

- 52,500 bbls/day of light oil production (Husky W.I.)
- Significant free cash flow in second half of decade



West White Rose

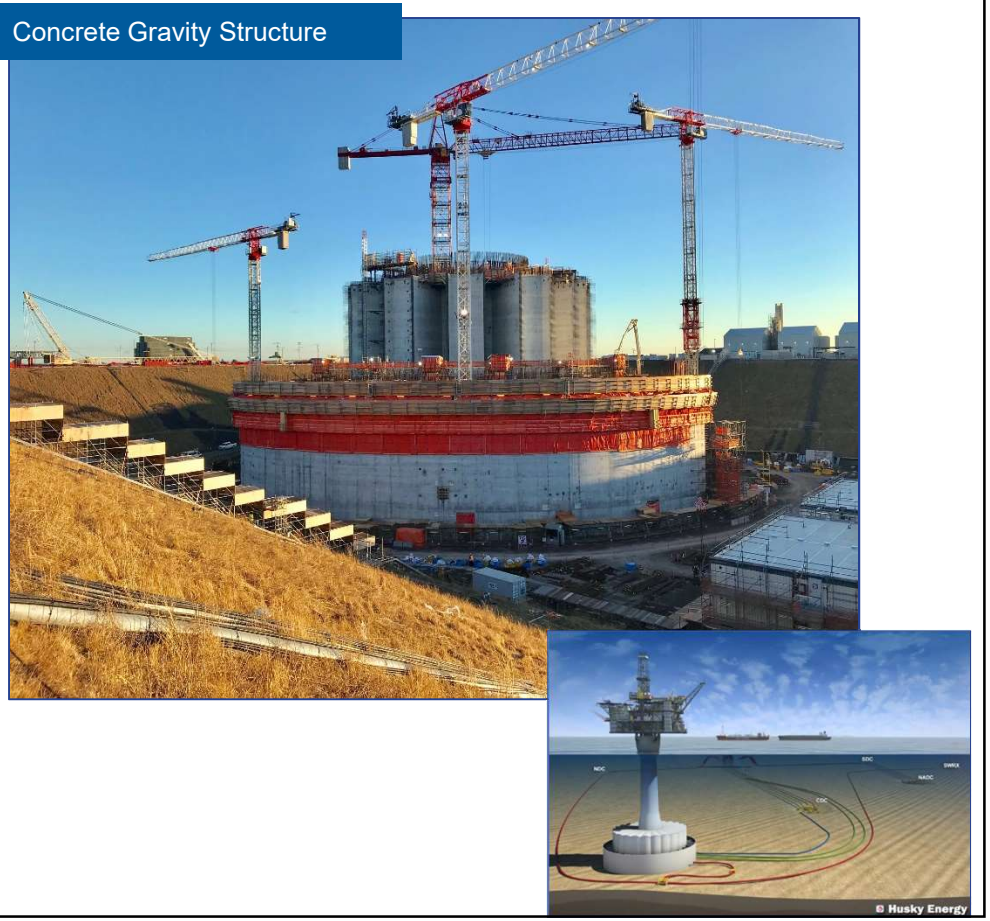
Adding High-Margin Production

- Tow out and installation anticipated in 2022
- Good safety performance
- Low incremental operating costs due to tie-in opportunities with existing infrastructure

2019 key milestones:

- Project ~40% complete
- Topsides engineering completed
- Three slipforms on the Concrete Gravity Structure in Argentia (first is complete)
- Construction ongoing and has been realigned with updated schedule

Concrete Gravity Structure



West White Rose – Large Cash Generator

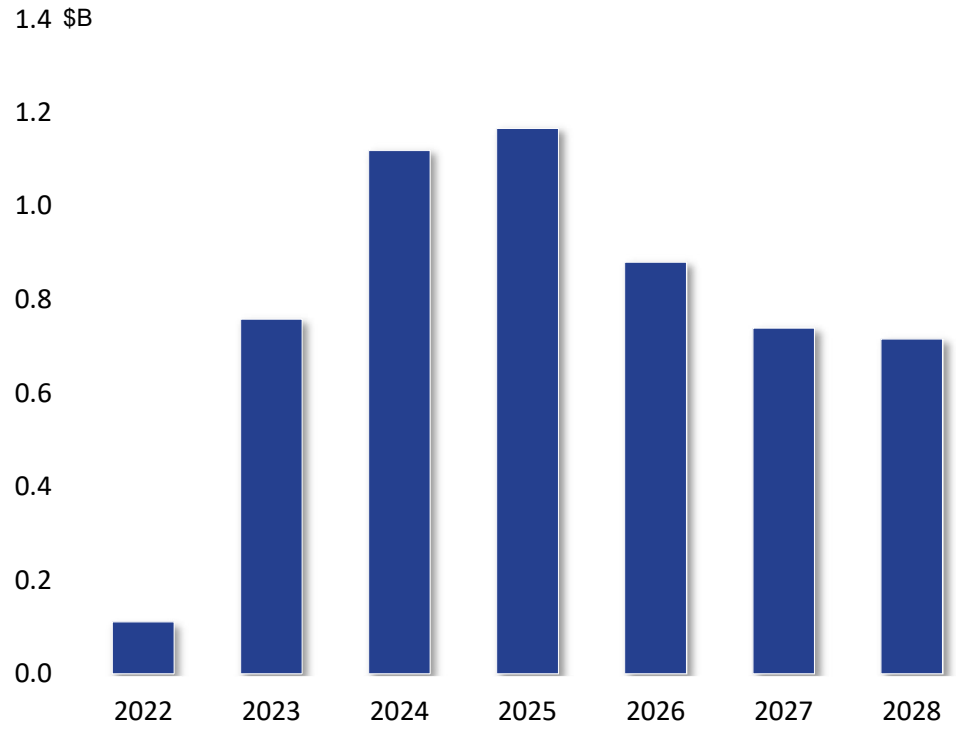
Over $1 Billion Per Year (Peak Years)

Once West White Rose is on stream:

- Provides for improved drilling efficiency
- Tie-backs of new discoveries to existing infrastructure
- Reduced drilling costs
- Low incremental operating costs of ~$5 per barrel

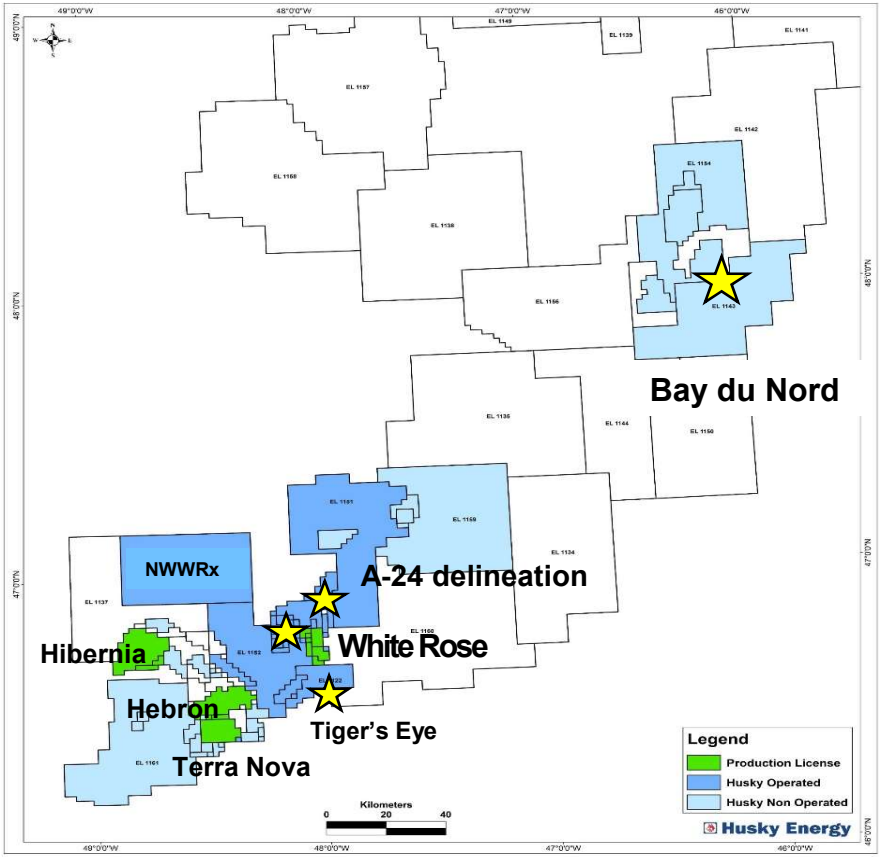
Peak Production Husky WI **52.5K** **bbls/day**

West White Rose
Operating Margin Less Capital



Further Potential: East Coast Exploration

A Balanced Approach



FPSO Concept

Courtesy Equinor

- Bay du Nord (35% W.I.)
- Actively managing portfolio of exploration licences

Offshore Business

Oil Price Torque Complemented By Fixed-Price Stability

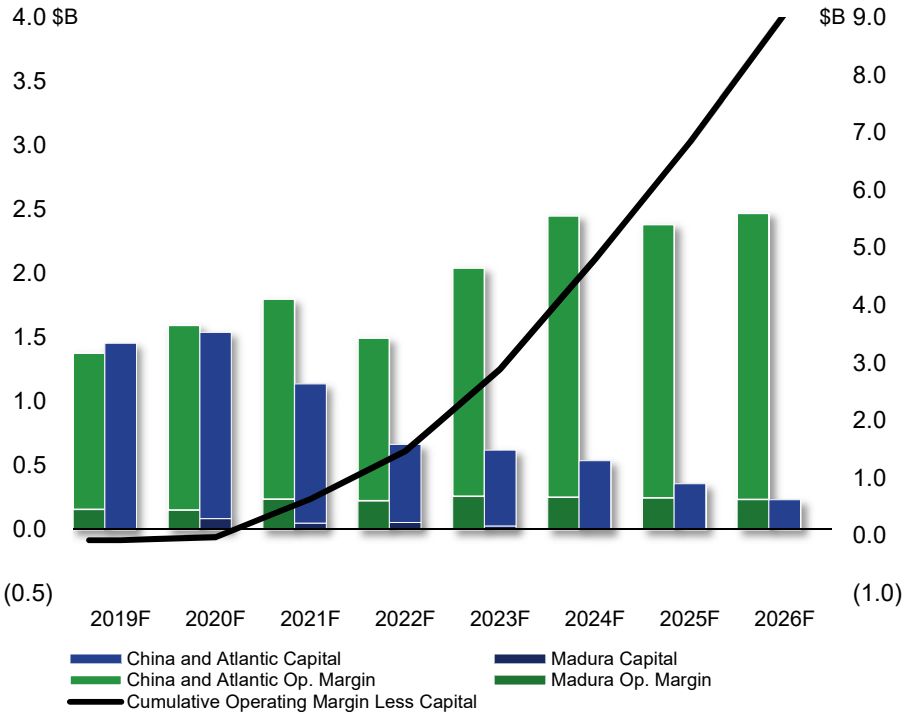
Atlantic

- High netbacks with global oil pricing
- Direct access to tidewater
- Leveraging existing infrastructure
- Defined growth into next decade
- Exploration opportunities

Asia Pacific

- High netback long-term contracts
- Established partnerships
- Leveraging existing infrastructure
- Exploration opportunities

Offshore
Operating Margin Less Capital



Asia Pacific

Bob Hinkel, COO Asia Pacific

Liwan Offshore Platform

A Growing Business In A Fast-Growing Market

Asia Pacific

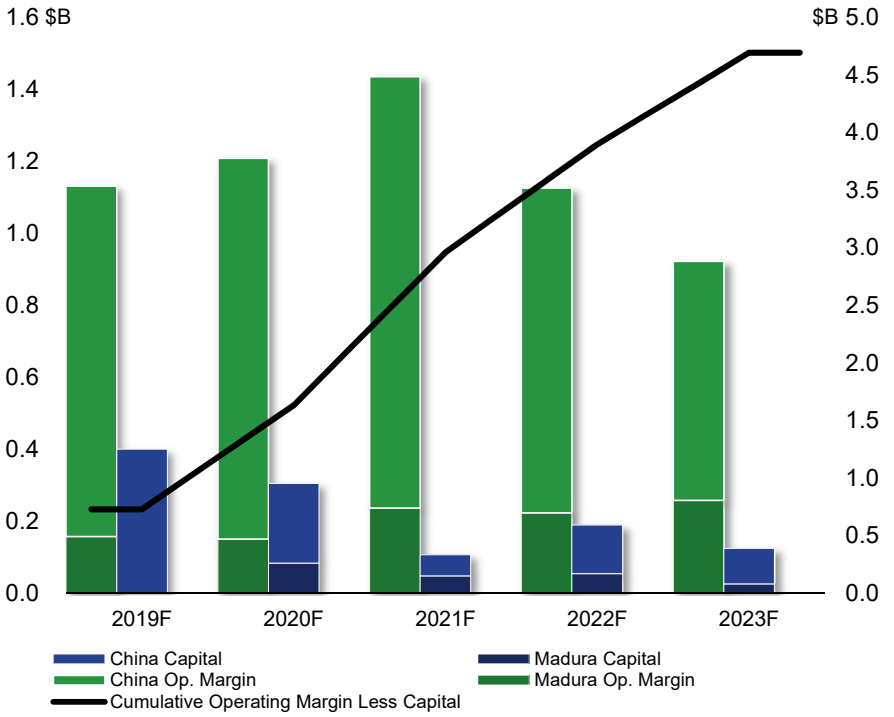
Highlights

- Commitment to High Reliability Organization principles
- Strong, stable revenue and free cash flow generation
- Minimal investment required to grow production and margins over five-year plan
- Balance of mid- and long-term development and exploration opportunities
- Cleaner burning natural gas helping meet growing energy demand

What's New

- Liuhua 29-1 development on track for start up within 18 months
- Indonesia Madura fields deferred by one year
- Block 15/33 discovery expansion and development plan
- New exploration acreage

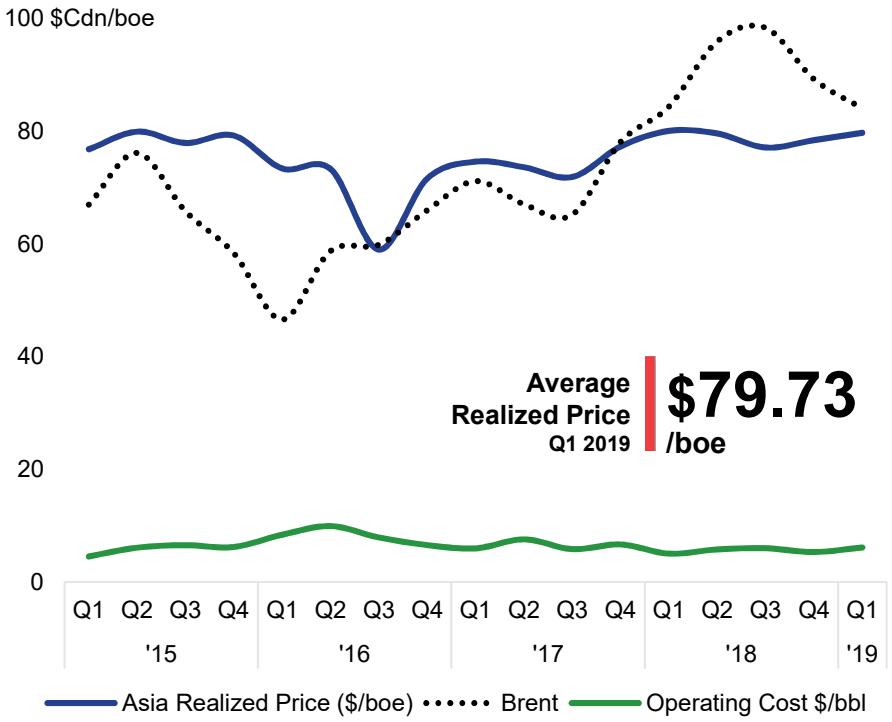
Asia Pacific
Operating Margin Less Capital



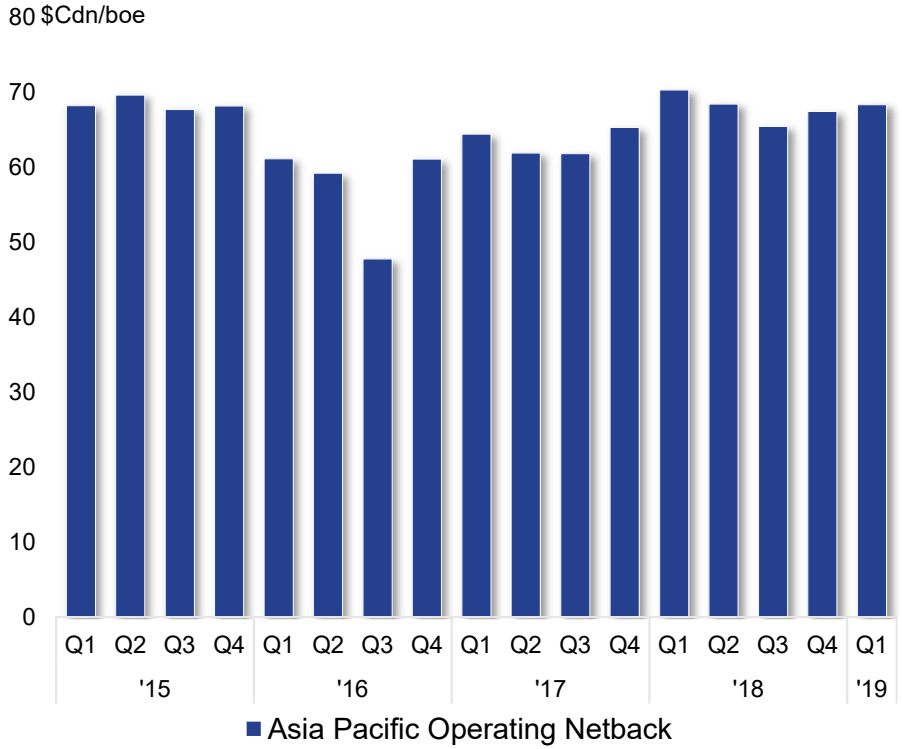
High-Netback Production With Global Pricing

>$60/boe Operating Netbacks, Attractive Long-Term Gas Contracts

Strong Global Pricing



High Operating Netback[1]



Near-Term Growth

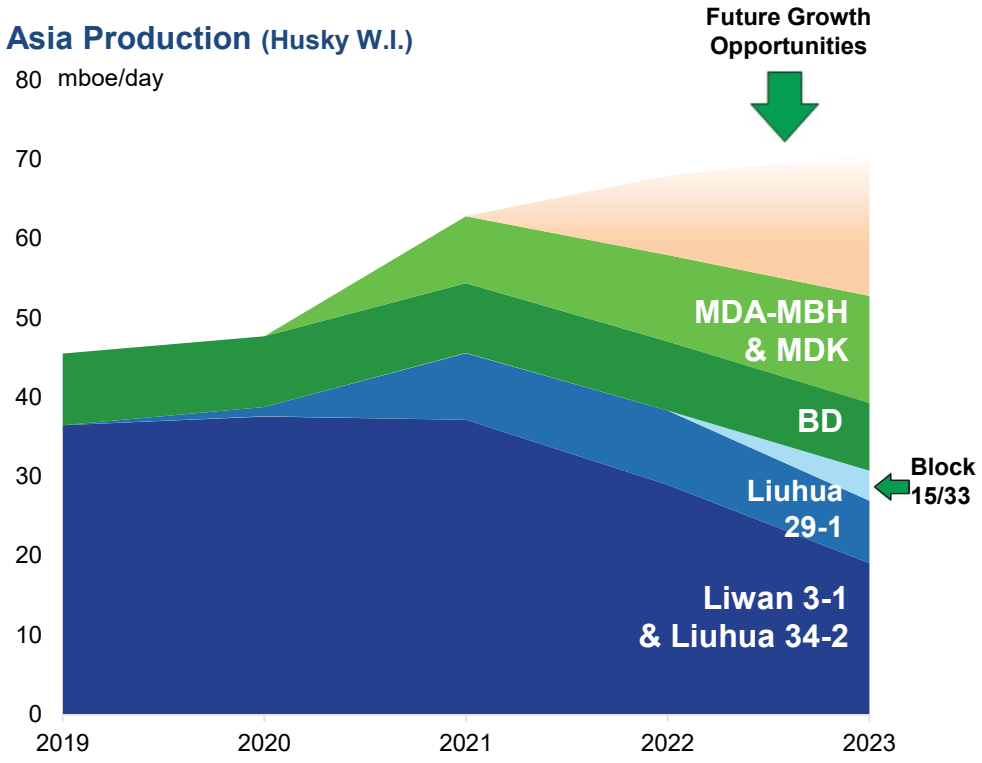
Providing Further Stability To Funds From Operations

China

- Liuhua 29-1 field sanctioned, under construction
- First gas late 2020
- Successful exploration well drilled on Block 15/33 in 2018
  - Well flow tested at >9,000 bbls/day
  - Two additional exploration wells to be drilled on the block in 2020

Indonesia

- MDA-MBH, MDK fields in development
  - First gas anticipated in 2021

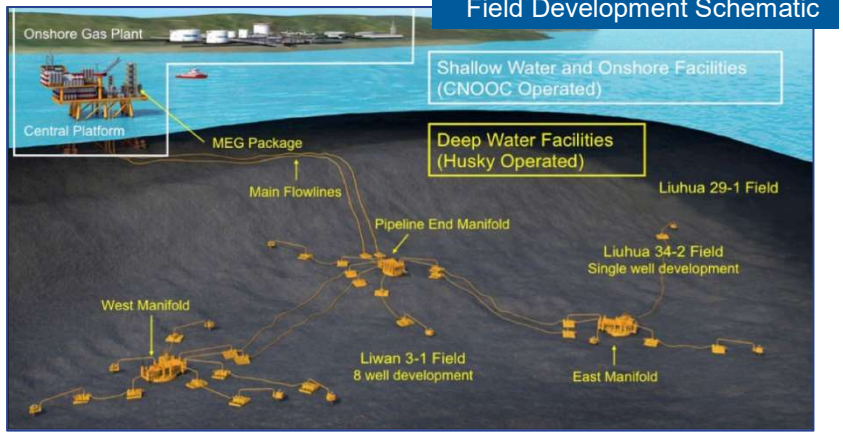


Liuhua 29-1

On Time And On Budget

- First gas around end of 2020
- Gas sales agreement in place:
  - 15+ year contract term
  - ~$9-10/mcf US floating price mechanism based on oil price planning assumptions post-2020 (tied to JCC)
- 45 mmcf/day gas and 1,800 bbls/day liquids once ramped up
  - 75% Husky W.I.
- Uses existing subsea infrastructure
- Husky W.I. reserves (Proved + Probable): 231 bcf + 8 mmbbls liquids; 47 mmboe

Field Development Schematic



Gaolan Gas Plant

Madura Strait Growth Profile

Series Of Stable, Fixed-Price Production Projects

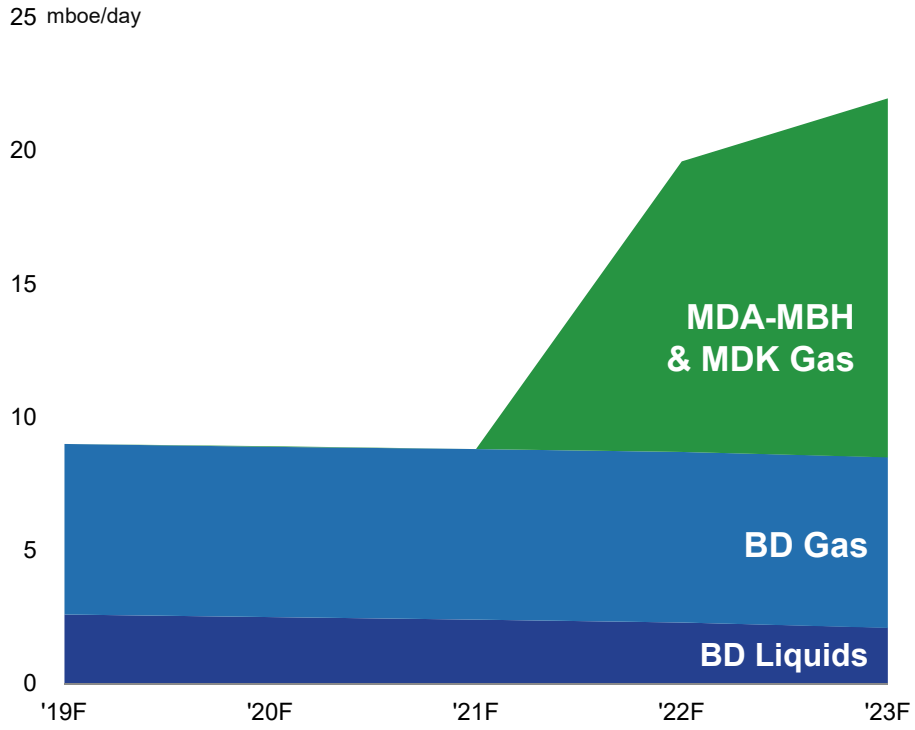
BD Project generating reliable, high margin production

- Production commenced July 2017, currently at ~105 mmcf/d (gross) plus 8,800 bbls/day of liquids
- $7.0 US per MMBtu fixed price with 2% escalation commencing from the fifth year

MDA-MBH/MDK fields in development

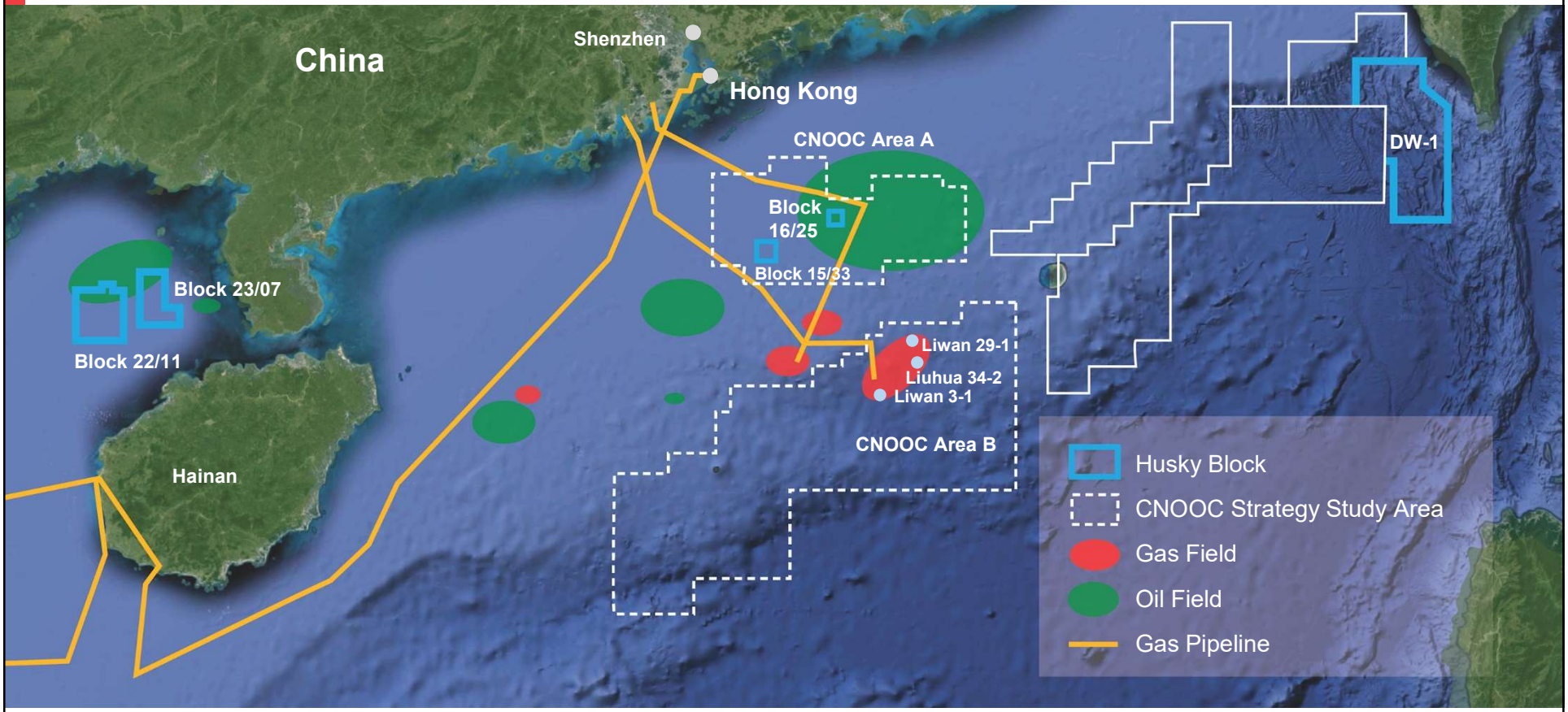
- 120 mmcf/day combined sales rate (gross)
- $6.5 US per MMBtu fixed price with 3% escalation commencing from the second year
- Anticipating first gas end of 2021

Indonesia Production Profile



South China Sea Exploration Areas – 2019

New Offshore Development With Strong Economics



Offshore Business

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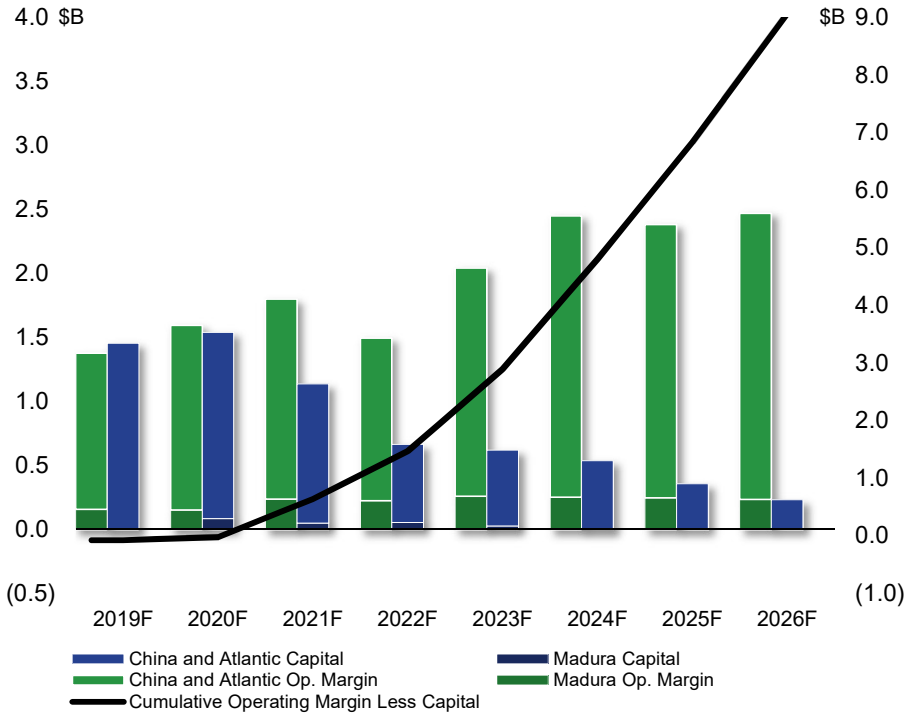
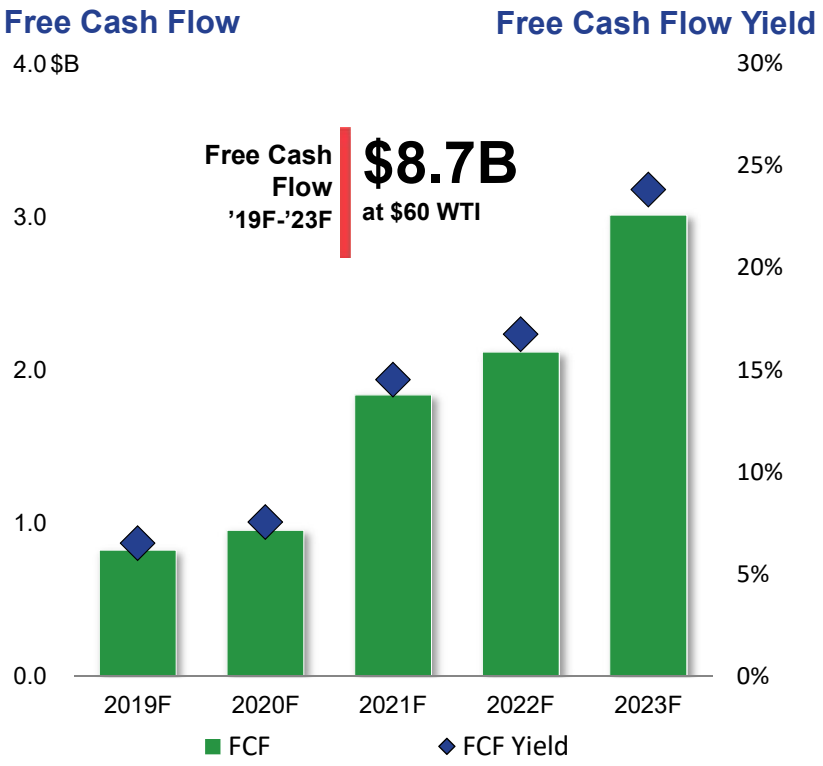
Offshore
Operating Margin Less Capital



Husky

Closing Remarks

Growing Free Cash Flow



FCF yield based on Husky share price as of close on May 24, 2019 of $12.57

Upcoming Catalysts

2019

- Atlantic ramp up to 25,000 bbls/day
- Dee Valley start up in Q3 – 10,000 bbls/day
- Lima Crude Oil Flexibility project start up in Q4 (40,000 bbls/day)
- Potential sale of commercial fuels business and Prince George Refinery

2020

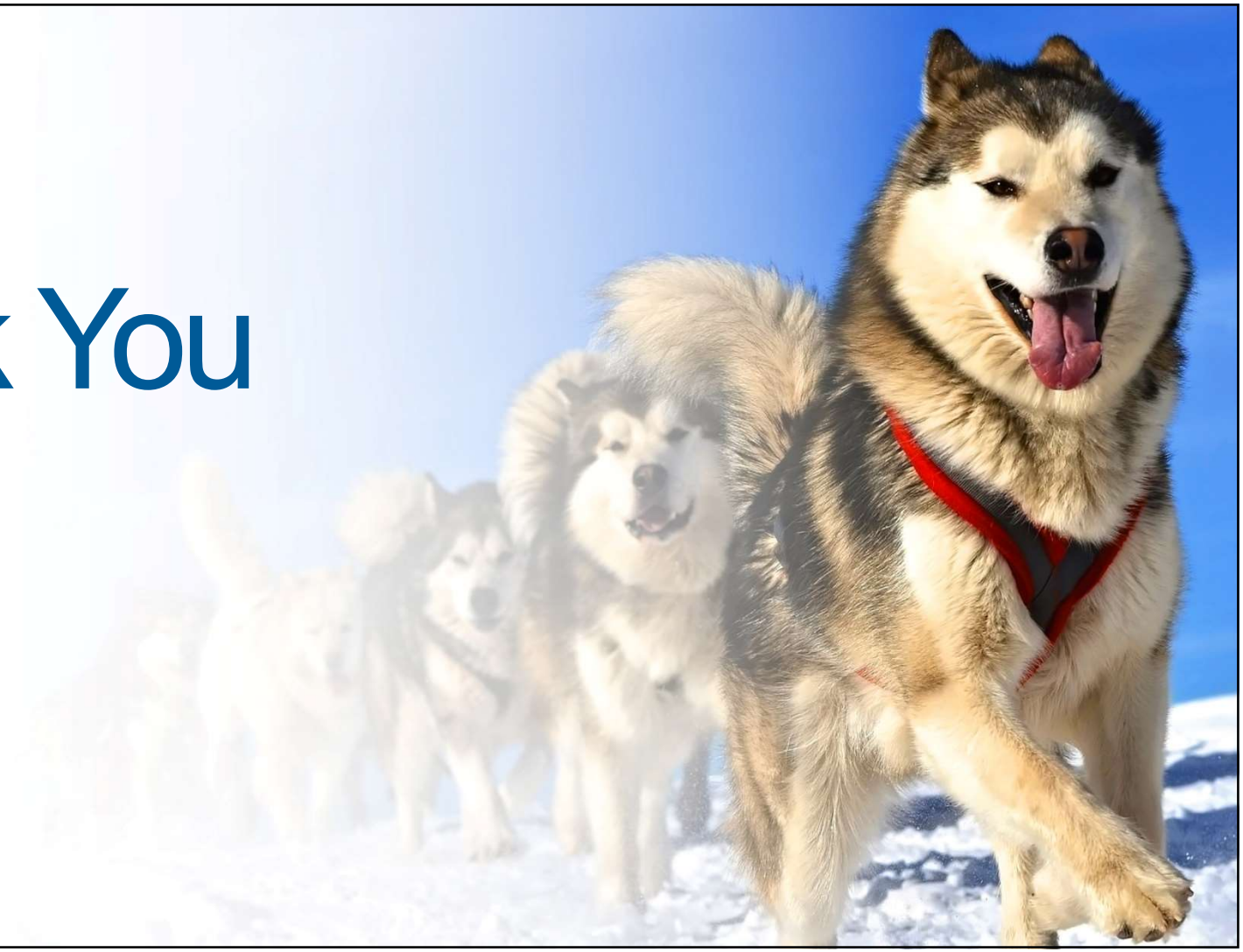
- Liuhua 29-1 start up – 9,300 boe/day
- Spruce Lake Central start up – 10,000 bbls/day
- Spruce Lake North start up – 10,000 bbls/day

Husky

Q&A

Husky

Thank You



Husky

Appendix

2019 Guidance Summary

Last Updated February 25, 2019

Capital Guidance[1] ($ millions)			
Upstream			
Thermal & Oil Sands	730	-	760
Conventional Heavy Oil	100	-	110
Atlantic Region	1,120	-	1,190
Asia Pacific[2]	350	-	370
Western Canada	180	-	190
Total Upstream	**2,480**	-	**2,620**
Downstream			
Canada	145	-	155
U.S	545	-	580
Total Downstream	**690**	-	**735**
Corporate Capital	130	-	145
Total Capital Investment	**3,300**	-	**3,500**
Total Sustaining Capital	**~$1.8B**		

Production Guidance			
Crude Oil and Liquids (mbbls/day)			
Thermal & Oil Sands	129	-	135
Conventional Medium & Heavy Oil	29	-	31
Atlantic Light Oil	18	-	20
WC Resource Play Liquids	20	-	21
Asia Pacific Light and NGLs	9	-	10
Total Crude Oil and Liquids	**205**	-	**217**
Natural Gas (mmcf/day)			
Canada	297	-	307
Asia Pacific	210	-	220
Total Natural Gas	**507**	-	**527**
Total Upstream	**290**	-	**305**

Other Corporate Costs ($ millions)			
Capitalized Interest	175	-	195
Corporate SG&A	210	-	230

Upstream Operating Costs[3] ($/boe)			
Thermal & Oil Sands	11.30	-	12.10
Atlantic	33.00	-	35.00
Western Cda	10.30	-	11.00
Asia Pacific	6.10	-	6.50
Total Upstream Operating Costs	**14.00**	-	**15.00**

Downstream Operating Costs[4] ($/bbl)			
Lloydminster Upgrader	7.00	-	7.50
U.S. Refineries[5]	7.20	-	7.70

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

Price Planning Assumptions

2019 vs. 2018 Five-Year Plan / Stress Case

Benchmark Prices – 2019 Base Case	2019	2020	2021	2022	2023
WTI (US $/bbl)	60.00	60.00	60.00	60.00	60.00
Chicago 3:2:1 (US $/bbl)	18.00	16.00	16.00	16.00	16.00
Heavy crude differential (US $/bbl)	15.00	20.00	20.00	18.00	15.00
AECO (Cdn $/mmbtu)	1.60	1.60	1.60	1.60	1.60
US/CAD exchange rate	0.75	0.75	0.75	0.75	0.75

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

Benchmark Prices – $40 Stress Case	2022
WTI (US $/bbl)	40.00
Chicago 3:2:1 (US $/bbl)	16.00
Heavy crude differential (US $/bbl)	20.00
AECO (Cdn $/mmbtu)	1.60
US/CAD exchange rate	0.75

Husky

Slide Notes & Advisories

Slide Notes

Slide 5

1. 'Offshore' production, operating costs, and netback include amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
2. Netback, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
3. Gross Margin, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 7

1. Global demand forecasts for gasoline, jet fuel, diesel and distillates, and petrochemical feedstock provided by Wood Mackenzie. Asphalt demand is for U.S. market. Data to 2021 provided by Freedonia, extrapolated at 1.5% per year after 2021 based on Freedonia report and estimate of U.S. GDP.

Slide 9

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

Slide 10

1. Asia natural gas demand forecasts is an average of BP's *Energy Outlook 2019* and IEA's *2018 World Energy Outlook*. China natural gas demand forecasts is an average of BP's *Energy Outlook 2019* and OPEC's *World Oil Outlook 2018*.
2. Global oil demand forecast is an average of BP's *Energy Outlook 2019* , IEA's *2018 World Energy Outlook, Exxon's 2018 Energy Outlook, and OPEC's World Oil Outlook 2018.*

Slide 12

1. Operating margin less capital, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
2. Asia Pacific operating margin and capital, as referred to throughout this presentation, do not include amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes, unless otherwise indicated.

Slide 13

1. Supply costs in the BMO report represents the price of crude (Brent equivalent) required to cover finding, development and operating costs including a 10% return on capital.
2. Cash flow break-even, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
3. Sustaining capital, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 14

1. Excludes economic factors. 255 percent including economic factors.

Slide 16

1. Forward looking financial results for the 2019 to 2023 Plan in this presentation are calculated using the Benchmark Prices – 2019 Base Case Pricing Assumptions found in the Appendix, unless otherwise indicated. Forward looking financial results for the 2018 to 2022 Plan in this presentation are calculated using the Benchmark Prices – 2018 Base Case Pricing Assumptions found in the Appendix.
2. Funds from operations ("FFO"), as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
3. Capital spending, as referred to throughout this presentation, does not include capitalized interest or capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes, or capital expenditures for the rebuild of the Superior refinery, unless otherwise indicated.
4. Free cash flow ("FCF"), as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.
5. Production, as referred to throughout this presentation, includes production related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes unless otherwise indicated.

Slide Notes

Slide 18

1. 'Madura' operating margin and capital, as referred to throughout this presentation, represent amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.

Slide 19

1. Forecasted dividend payments to common shareholders, as referred to throughout this presentation, assumes the annual dividends paid to common shareholders in 2019 to 2023 equals $0.50 per share.

Slide 31

1. 2018 data based on draft estimates to be verified in June 2019.

Slide 36

1. Compound annual growth rates (CAGR), as referred to throughout this presentation, are calculated using 2019 forecasted production, FFO, Operating Margin and FCF and 2023 forecasted production, FFO, Operating Margin and FCF, as applicable.

Slide 37

1. FFO and cash flow – operating activities forecasts at $40 WTI for 2019 and 2023 are calculated using the Benchmark Prices – $40 stress case pricing assumptions found in the Appendix.
2. Cash flow sensitivities calculated independently by adjusting one pricing variable at a time, based off the noted benchmark prices.

Slide 39

1. Net debt and net debt to funds from operations, as referred to throughout this presentation, are a non-GAAP measures. Please see *Advisories* for further detail.
2. FFO at $40 WTI is an estimate of funds from operations generated for the full year 2019 using the Benchmark Prices – 2018 Base Case Pricing Assumptions found in the Appendix.

Slide 47

1. Free cash flow yield, as referred to throughout this presentation, is a non-GAAP measure. Please see *Advisories* for further detail.

Slide 87

1. Bitumen reserves from 2005 to 2008 booked under SEC disclosure rules using a flat price deck. Bitumen reserves from 2009 onwards reported using forecast pricing under NI 51-101 and COGEH.

Slide 91

1. Steam-oil ratio (SOR) represents the unit of steam required to generate a unit of produced oil. Please see *Advisories* for further detail.

Slide 97

1. Metrics as defined by RS Energy and calculated on a single well basis. Finding and Development (F&D) costs equals well cost (DCET) divided by expected ultimate recoverable reserves. Capital efficiency equals well cost (DCET) divided by initial production (9 month). Break-even is the AECO price necessary for an IRR of 10%. Peers include Bonavista, Peyto, and Tourmaline.

Slide 98

1. Type curves reflect the unrisked, proved plus probable estimate.
2. Prepared by internal qualified reserves evaluators in accordance with COGEH.

Slide Notes

Slide 100

1. Liquids production reflects the condensate and NGL production relative to total production on a boe basis.
2. Liquids revenue reflects the revenue from the sale of condensate and NGL relative to revenue from the sale of all products.

Slide 101

1. Integrated gas price includes the revenue from Husky's Midstream gas assets.

Slide 114

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

Slide 124

1. Capital guidance include exploration capital in each business unit.
2. Capital expenditures in Asia Pacific exclude amounts related to the Husky-CNOOC Madura Ltd. joint venture, which is accounted for under the equity method for financial statement purposes.
3. Include energy and non-energy costs.
4. Excludes the impact of scheduled turnarounds in 2018.
5. Excludes Superior Refinery

Advisories

Forward-Looking Statements and Information

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

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

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies and the results thereof; forecast cash flow break-even for 2019; forecast FFO, CFOA, FCF, FCF yield, capital expenditures, production and heavy oil processing capacity for 2019 to 2023; forecast operating margins and revenue net of royalties less purchases of crude oil for the Integrated Corridor for 2019 and 2023; forecast growth capital and sustaining capital for 2019 to 2023; safety and operations integrity priorities for the next three months and plans for the next 12 to 18 months; forecast FFO compound annual growth rate for 2019 to 2023; forecast FFO, CFOA, growth capital and sustaining capital in 2019 and 2023 based on US$40 WTI and US$60 WTI; funding priorities for 2019 to 2023; forecast net debt and net debt to FFO in 2023; forecast throughput and production sustaining capital for 2019 to 2023 and associated Downstream and Upstream sustaining capital for the period; forecast free cash flow coverage for 2019 to 2023; forecast Upstream operating costs, Downstream operating costs, cash flow break-even price and consolidated operating margin for 2019 to 2023; target net debt to FFO for 2019 to 2023; the potential for accelerating shareholder returns; general strategic plans and growth strategies for the Integrated Corridor and Offshore businesses; forecast upgrading and refining capacity for 2019 to 2023; forecast production for 2019 to 2023 for Lloyd Thermals, Oil Sands, Western Canada and Conventional Heavy; forecast throughput capacity for 2019 to 2023 for the Lima Refinery, the Toledo Refinery, the Superior Refinery, the Lloydminster Upgrader and the Lloydminster Asphalt Refinery; forecast operating margin less capital for the Integrated Corridor for 2019 to 2023 and for the Offshore business for 2019 to 2026; capital and production guidance ranges for 2019 broken down by region, product type and business segment; Upstream operating costs guidance ranges for 2019 broken down by business segment; Downstream operating costs guidance ranges for 2019 broken down by region; and other corporate costs guidance ranges for 2019;

- with respect to the Company's Downstream operating segment: estimated processing capacity resulting from, and expected completion dates of, the crude oil flexibility project at the Lima Refinery, the Lloydminster Upgrader diesel debottleneck and enhancements at the Superior Refinery; the potential sale of the Canadian retail and commercial fuels business and the Prince George Refinery; the expected timing of demolition and the commencement of rebuild construction and full operations at the Superior Refinery; the estimated cost of the Superior Refinery rebuild; forecast heavy oil blend (in total and by product type) versus Downstream processing and pipeline capacity (in total and by facility) for 2019 to 2023; future heavy oil outlet options; and forecast Downstream operating margin less capital for 2019 to 2023 and annual average Downstream operating margin less capital for the period;

Advisories

- with respect to the Company's heavy oil and thermal developments in the Integrated Corridor: estimated production capacity and expected timing of startup at the Dee Valley, Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 thermal bitumen projects, the Sunrise Phase 1 debottleneck, future Lloyd thermals 1-5 and future Sunrise phases; planned pacing of construction of new thermal developments; the potential to increase steam capacity, the cost reduction target, target production per well pair, drilling plans and the potential to add a cogeneration facility at Sunrise; the cost reduction target and future debottlenecking opportunities at Tucker; forecast operating margin less capital for Heavy Oil & Oil Sands for 2019 to 2023; and forecast thermal production for 2019 to 2026;

- with respect to the Company's Western Canada resource plays in the Integrated Corridor: forecast production (in total and by product type), liquids compound annual growth rate, revenue (in total and by product type) and increase in liquids revenue from Western Canada resource plays for 2019 to 2023; 2019 forecast Ansell Cardium type well production; strategic plans and growth strategy for the Western Canada resource plays; drilling plans at Wembley-Sinclair; and WTI price required to generate 10% internal rate of return at Wembley-Sinclair;

- with respect to the Company's Offshore business in the Atlantic region: estimated production capacity and expected timing of startup at the West White Rose Project; forecast Atlantic production growth (in total and by field) from 2019 to 2026; estimated production capacity at the White Rose development and infill wells; ramp-up plans for the *SeaRose* floating production storage and offloading facility; Atlantic production compound annual growth rate for 2019 to 2023; strategic plans and growth strategy for the Atlantic region; anticipated timing of tow-out and installation at the West White Rose Project; expected benefits of the West White Rose Project once it is on-stream; and forecast operating margin less capital for the West White Rose Project from 2023 to 2028; and

- with respect to the Company's Offshore business in the Asia Pacific region: estimated production capacity and expected timing of startup at Liuhua 29-1 and the Madura fields; forecast production growth for 2019 to 2026; strategy plans and growth strategy for the Asia Pacific region; forecast operating margin less capital for 2019 to 2023; drilling plans at Block 15-33; forecast production growth (in total and by field) for 2019 to 2023; and forecast production growth (in total and by field) for the Madura fields from 2019 to 2023;

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

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

Advisories

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, 2018 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 measures is used to enhance the Company's reported financial performance or position. With the exception of operating margin, operating margin less capital, funds from operations, free cash flow and net debt, there are no comparable measures to these non-GAAP measures in accordance with IFRS. The following non-GAAP measures are considered to be useful as complementary measures in assessing Husky's financial performance, efficiency and liquidity:

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

- "Gross margin" is a non-GAAP measure that is calculated as revenue net royalties less purchases of crude oil and product. This measure assists the Company's investors to evaluate the operating performance of the Integrated Corridor.

- "Operating Margin" is a non-GAAP measure which should not be considered an alternative to, or more meaningful than, "revenue, net of royalties" as determined in accordance with IFRS, as an indicator of financial performance. Operating Margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period. Operating Margin equals revenues net of royalties less purchases of crude oil and products, production, operating and transportation expenses, and selling general and administrative expenses.

Advisories

"Operating margin less capital" is a non-GAAP measure that equals operating margin less capital expenditures. Operating Margin is presented to assist management and investors in analyzing operating performance of the Company in the stated period.

The following tables show the reconciliation of operating margin and operating margin less capital for the periods indicated:

	Q1 2019							
	Upstream				Downstream			Total
	Exploration and Production			Infrastructure and Marketing	Upgrading	Canadian Refined Products	U.S. Refining and Marketing	
($ millions)	Integrated Corridor	Offshore	Total					
Revenue, net of royalties	791	322	1,113	568	400	654	2,283	5,018
Less:								
Purchases of crude oil and products	-	-	-	401	257	503	1,828	2,989
Production and operating expenses	329	86	415	3	52	69	215	754
Selling, general and administrative expenses	70	9	79	1	2	14	7	103
Operating Margin	392	227	619	163	89	68	233	1,172

	Q1 2018							
	Upstream				Downstream			Total
	Exploration and Production			Infrastructure and Marketing	Upgrading	Canadian Refined Products	U.S. Refining and Marketing	
($ millions)	Integrated Corridor	Offshore	Total					
Revenues, net of royalties	523	481	1,004	611	465	721	2,771	5,572
Less:								
Purchases of crude oil and products	-	-	-	421	239	578	2,505	3,743
Production and operating expenses	292	65	357	2	46	60	163	628
Selling, general and administrative expenses	67	9	76	1	2	13	5	97
Operating Margin	163	408	571	187	178	70	98	1,104

Advisories

Offshore ($ millions)	2013 Atlantic	2013 Asia Pacific	2013 Total	2014 Atlantic	2014 Asia Pacific	2014 Total	2015 Atlantic	2015 Asia Pacific	2015 Total
Revenues, net of royalties	1,613	219	1,833	1,451	773	2,224	787	1,243	2,030
Less:									
Purchases of crude oil and products	-	-	-	-	-	-	-	-	-
Production and operating expenses	243	31	274	258	82	341	131	97	228
Selling, general and administrative expenses	6	33	39	9	22	32	25	25	49
Operating Margin	1,364	156	1,520	1,183	668	1,852	631	1,122	1,753
Capital expenditures	(638)	(654)	(1,292)	(746)	(396)	(1,142)	(548)	(46)	(594)
Operating Margin Less Capital Expenditures	726	(498)	228	437	272	710	83	1,076	1,159

Offshore ($ millions)	2016 Atlantic	2016 Asia Pacific	2016 Total	2017 Atlantic	2017 Asia Pacific	2017 Total	2018 Atlantic	2018 Asia Pacific	2018 Total
Revenues, net of royalties	622	756	1,378	808	973	1,781	691	1,082	1,773
Less:									
Purchases of crude oil and products	-	-	-	-	-	-	-	-	-
Production and operating expenses	253	92	346	265	85	350	260	66	327
Selling, general and administrative expenses	(8)	24	17	4	30	33	-	39	39
Operating Margin	376	639	1,015	539	859	1,398	431	977	1,407
Capital expenditures	(244)	(118)	(362)	(484)	(12)	(496)	(989)	(200)	(1,189)
Operating Margin Less Capital Expenditures	132	521	653	55	847	902	(558)	777	218

Advisories

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.

- "Cash flow break-even" reflects the estimated WTI oil price per barrel priced in US dollars required to generate funds flow from operations equal to the Company's sustaining capital requirements and dividends paid to common shareholders 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 flow 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.

- "Free cash flow yield" or "FCF yield" is a non-GAAP measure that equals expected free cash flow for the given period divided by current market capitalization.

- "Sustaining capex" or "sustaining capital" is a non-GAAP measure that represents the capital that is required by the business to maintain production and operations at existing levels. This includes the cost to drill, complete, equip and tie-in wells to existing infrastructure and maintenance for Downstream assets. Sustaining capital does not have any standardized meaning and therefore should not be used to make comparisons to similar measures presented by other issuers.

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

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

- "Growth capital" is a non-GAAP measure that represents expenditures which incrementally increase cash flow or earnings potential of assets, expand the capacity of current operations or significantly extend the life of existing assets. This measure is used by the investment community to assess the extent of discretionary capital spending. For clarity, growth capital is equal to total capital less sustaining capital.

Advisories

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

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

($ millions)	March 31, 2019	December 31, 2018
Short-term debt	200	200
Long-term debt due within one year	1,803	1,433
Long-term debt	4,661	4,114
Total debt	6,664	5,747
Cash and cash equivalents	(3,245)	(2,866)
Net debt	3,419	2,881

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

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves and resources estimates 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, 2018, represent the Company's working interest share and the reserves estimates have been audited and reviewed by Sproule Associates Limited, an independent qualified reserves auditor; (ii) projected and historical production volumes provided are gross, which represents the total or the Company's working interest share, as applicable, before deduction of royalties; (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2018.

Advisories

The Company has disclosed its total reserves in Canada, Indonesia and China in its Annual Information Form for the year ended December 31, 2018, 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.

Sunrise thermal bitumen unrisked best estimate contingent resources consist of 307 million barrels (Husky's working interest) of economic development pending volumes. Husky has a working interest of 50 percent. 29 million barrels of contingent resources are associated with the production from well pairs booked as undeveloped reserves that go beyond the 50 years reserves time frame. The remaining 278 million barrels of development pending resources are associated with well pairs that are scheduled to be developed beyond the 50-year reserves time frame.

The oil at Sunrise is reported as thermal bitumen and has viscosities as high as 1,200,000 cP with gravities between 6 and 9 degrees API. Specific contingencies preventing the classification of contingent resources at Sunrise as reserves include the timing of development which is outside the timing allowed for booking as reserves, final Company approvals of capital expenditures, the formulation of concrete development plans and facility designs to pursue development of the large inventory of opportunities, further delineation drilling requirements and regulatory applications and approvals. Positive and negative factors relevant to the contingent resource estimates include a higher level of uncertainty in the estimates as a result of lower drilling density in parts of the project area. The main risks are the future commodity prices and their impact on the development timing.

Husky's Lloydminster Heavy Oil and Gas thermal bitumen unrisked best estimate contingent resources consist of 302 million barrels of economic development pending, 248 million barrels of economic development unclarified and 470 million barrels of economic status undetermined development unclarified. The figures represent Husky's working interest volumes. The development pending category consists of 9 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 2023 through to 2037. The first three projects have a total capital cost to first production of $1.0 billion based upon the pre-development studies. The estimated total capital to fully develop these 10 development pending projects is approximately $4.5 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 $0.36 billion to achieve commercial production in 2025. The remaining projects are to be developed over more than 50 years in accordance with the conceptual studies for this large resource. In total, 465 million barrels of thermal bitumen are based upon pre-development studies while an additional 573 million barrels of thermal bitumen are based upon conceptual plans. This oil is reported as thermal bitumen and has viscosities ranging from 5,000 centipoise (cP) to as high as 600,000 cP with gravities between 9 and 13 degrees API. 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.

Advisories

There is uncertainty that it will be commercially viable to produce any portion of the resources referred to in the above paragraphs.

The Company uses the term “barrels of oil equivalent” (or “boe”), which is consistent with other oil and gas companies’ disclosures, and is calculated on an energy equivalence basis applicable at the burner tip whereby one barrel of crude oil is equivalent to six thousand cubic feet of natural gas. The term boe is used to express the sum of the total company products in one unit that can be used for comparisons. Readers are cautioned that the term boe may be misleading, particularly if used in isolation. This measure is used for consistency with other oil and gas companies and does not represent value equivalency at the wellhead.

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

The Company uses the terms “proved reserves life index” and “2P reserves life index”, which are consistent with other oil and gas companies’ disclosures. The Company’s proved reserves life index and 2P reserves life index for a given period are determined by taking the Company’s total proved reserves and total proved plus probable reserves, respectively, at the end of that period divided by the Company’s upstream gross production for the same period. Readers are cautioned that the terms proved reserves life index and 2P reserves life index may be misleading, particularly if used in isolation. These measures are used for consistency with other oil and gas companies and do not reflect the actual life of the reserves.

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

The Company uses the term “steam-oil ratio” (or “SOR”), which measures the average volume of steam required to produce a barrel of oil. This measure does not have any standardized meaning and should not be used to make comparisons to similar measures presented by other issuers.

The Company uses the term “finding and development costs” or “F&D costs”, which equals well cost (drilling, completion, equipping and tie-in) divided by estimated ultimate recovery (EUR). EUR is defined as the unrisked best estimate of recovery factor times the best estimate of the petroleum initially in place. The petroleum initially in place is the total quantity of petroleum that is estimated to exist originally in naturally occurring reservoirs. “Estimated ultimate recovery factor” is the fraction of petroleum initially in place that is estimated to be recoverable from a pool. EURs used in preparing development cost, sustaining cost and estimated ultimate recovery factor were prepared internally by a qualified reserves evaluator.

Type well estimates referred to in this presentation have been prepared by internal qualified reserves engineers and in accordance with the Canadian Oil and Gas Evaluation Handbook.

Advisories

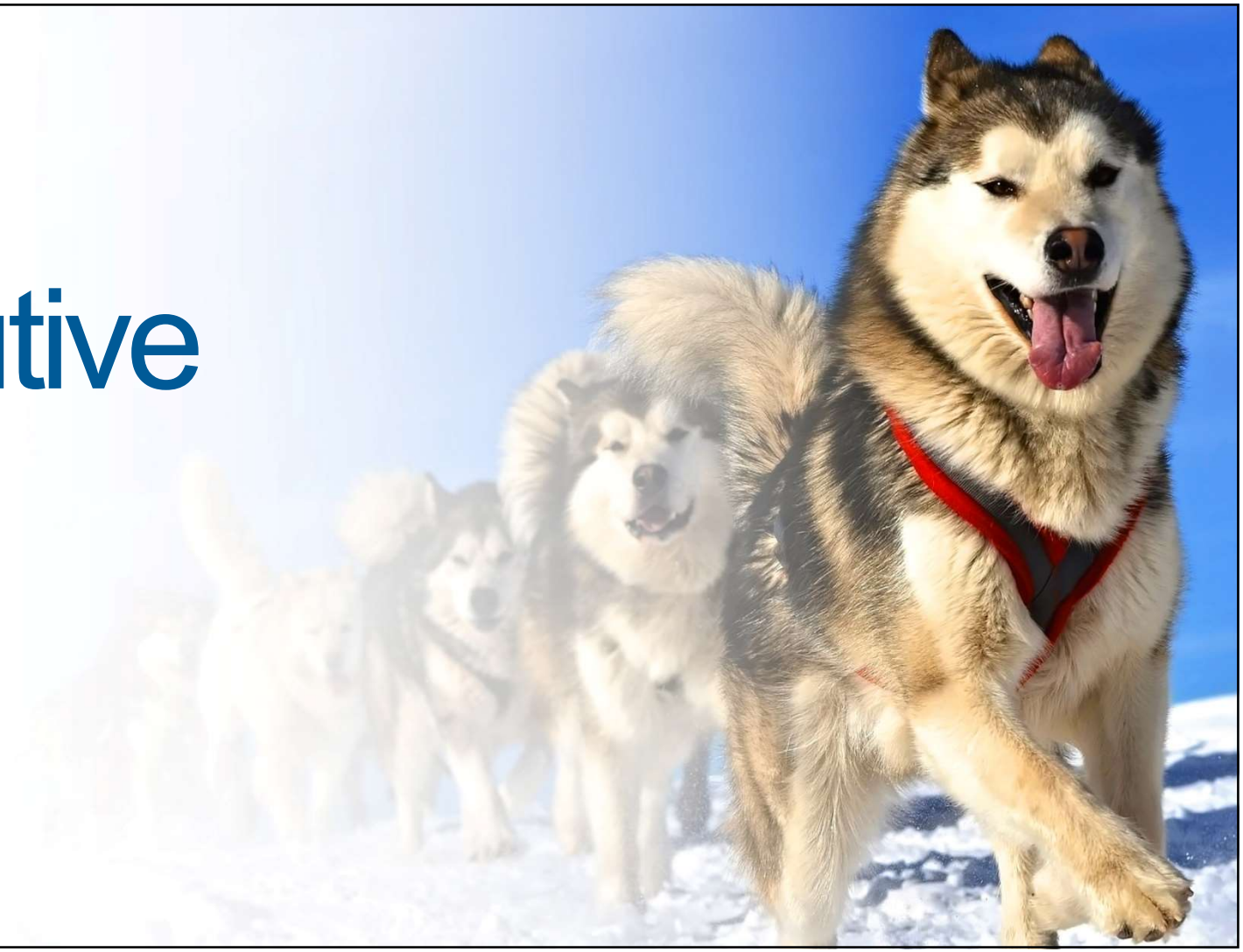
Note to U.S. Readers

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 U.S. Securities and Exchange Commission.

All currency is expressed in Canadian dollars unless otherwise directed.

Husky

Executive Team



Executive Team

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.

Career History and Key Accomplishments

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.

Education

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.

Professional Memberships, Associations and Designations

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).

Executive Team

Jeff Hart

Chief Financial Officer

Responsible for the financial management of Husky, including Controllers, Treasury, Tax, Credit and Internal Audit.

Career History and Key Accomplishments

Appointed as Chief Financial Officer in November 2018, Mr. Hart has extensive experience in progressively senior Finance roles at Husky. Prior to his appointment, Mr. Hart was Acting CFO and VP, Controller for Husky, leading Upstream and Downstream Finance, Finance Process Governance and Projects, as well as Corporate Accounting and Reporting.

He joined the Company in September 2010, serving as Finance Manager for the Heavy Oil and Gas and Atlantic business units. He was promoted to Upstream Controller in October 2012. Prior to joining Husky, Mr. Hart held Finance positions in the offshore, oil sands and petrochemical operations at Statoil, Norsk Hydro and Imperial Oil.

Education

Mr. Hart has a Bachelor of Commerce degree from Saint Mary's University, Halifax, with finance and accounting majors.

Professional Memberships, Associations and Designations

Mr. Hart is a Chartered Professional Accountant and a member of the Chartered Professional Accountants of Alberta.

Executive Team

Robert W.P. Symonds
Chief Operating Officer

Responsible for leading Husky's Upstream (excluding Asia Pacific) and Downstream businesses, Mr. Symonds is also responsible for Exploration, Engineering, Procurement and Project Management.

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 Corporation 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 Team

Peter Rosenthal

Senior Vice President, Safety & Operations Integrity

Responsible for Husky's process and occupational safety, operations integrity and emergency response. He is also responsible for leading Husky's high reliability organization (HRO) culture.

Career History and Key Accomplishments
Mr. Rosenthal was appointed Senior Vice President, Safety & Operations Integrity in April 2019.

Prior to his appointment, Mr. Rosenthal spent seven years with BP, most recently as COO for Atlantic LNG. With BP, he also spent three years as Operations Director, Safety & Operational Risk, and three years seconded to Reliance Industries as Chief Production and Head of Safety & Operational Risk, Upstream.

He has held operations leadership roles with Elf Petroleum (Total) and Hess Corporation, including Country Manager for Hess Denmark and General Manager Hess UK Offshore.

Education
Mr. Rosenthal holds a Master's in Civil Engineering from Aalborg University in Denmark. He has taken post-graduate studies in Risk Management at the University of Waterloo.

Executive Team

James D. Girgulis

Senior Vice President, General Counsel & Secretary

Responsible for the legal function of the Company.

Career History and Key Accomplishments

Mr. Girgulis joined Husky in 1994 and was appointed to the position of Vice President, Legal & Corporate Secretary in 2000. He was previously General Counsel and Corporate Secretary of Husky Oil Ltd.

In 2012, he was made Senior Vice President, General Counsel & Secretary.

Education

Mr. Girgulis graduated from the University of Calgary with a Bachelor of Arts (Honours) in Sociology in 1978 and from the University of Alberta Law School with an LL.B. in 1981. He was appointed Queen's Counsel (Q.C.) in 2005.

Executive Team

Janet E. Annesley

Senior Vice President, Corporate Affairs

Reporting to the Chief Executive Officer, Ms. Annesley is 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 joined Husky as Senior Vice President of Corporate Affairs in 2017. She is also responsible for developing relationships and communicating corporate initiatives to investors, governments, Indigenous communities, stakeholders, and employees in a transparent and effective manner. Prior to joining Husky, Ms. Annesley was Chief of Staff to Canada's Minister of Natural Resources in Ottawa. From 1999 to 2009 she worked at Shell in a variety of Corporate, Downstream and Oil Sands communications, stakeholder engagement and government relations roles. She also served as Vice President of Communications at the Canadian Association of Petroleum Producers, which represents Canada's upstream oil and gas industry.

Education

Ms. Annesley holds a Bachelor of Applied Communications degree from Mount Royal College, and Master's of Business Administration degrees from Queen's University and Cornell University.

Professional Memberships, Associations and Designations

Ms. Annesley serves on the Board of Governors for the Southern Alberta Institute of Technology and on the Canadian Chamber of Commerce board. She is a Fellow of the Royal Canadian Geographical Society.

Executive Team

Jeffrey E. Rinker

Senior Vice President, Downstream

Responsible for leadership and management of Husky's Downstream business.

Career History and Key Accomplishments

Mr. 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 U.S. refined product sales.

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.

Prior to that**, he 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.

Education

Mr. Rinker graduated as a Chemical Engineer with honors from Carnegie Mellon University in 1989.

Executive Team

P. Andrew Dahlin

Senior Vice President, Heavy Oil & Oil Sands

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

Before 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.

Executive Team

Gerald F. 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.

Career History and Key Accomplishments

Mr. Alexander was appointed Senior Vice President, Western Canada 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. 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 Team

Trevor Pritchard

Senior Vice President, Atlantic

Reporting to the Chief Operating Officer, Mr. Pritchard is responsible for Husky's operations in the Atlantic region.

Career History and Key Accomplishments

Mr. Pritchard was appointed Senior Vice President, Atlantic Region in January 2018. Prior to his appointment, he was Vice President of Process and Occupational Safety, overseeing the Company's operational integrity and ensuring a safe work environment, and before that, General Manager, Operations in the Atlantic region.

Before joining Husky, Mr. Pritchard worked at BP Shipping and at Northern Marine on the Seillean floating production, storage and offloading (FPSO) vessel project, becoming the Operations Chief Engineer. At Bluewater Services (UK) he had positions as Project Manager, Offshore Installation Manager and General Manager responsible for four FPSOs. He has supported the offshore industry on steering committees for the UK Step Change in Safety initiative and on a number of sub-committees with the United Kingdom Offshore Operators Association.

Education

Mr. Pritchard has a master's degree in Risk Crisis and Disaster Management from Leicester University.

Professional Memberships, Associations and Designations

Mr. Pritchard is a qualified Chief Engineer for international seagoing vessels.

Executive Team

Robert M. Hinkel

Chief Operating Officer, Asia Pacific

Responsible for managing Husky's Asian assets, including China and Indonesia production operations, exploration and new business development throughout the region, as well as the major development projects at Liwan (China) and Madura (Indonesia).

Career History and Key Accomplishments

With more than 35 years experience in the energy and mining industries, Mr. Hinkel joined Husky in 2010 as Chief Operating Officer, Asia Pacific. Prior to joining Husky, Mr. Hinkel was President and CEO of Enventure Global Technology, a subsidiary of the Shell Group. From 1982 until 2003 Mr. Hinkel was employed by Unocal Corporation, holding positions including Senior Vice President/General Manager of Unocal Indonesia and President and CEO of Molycorp, the company's mining and minerals subsidiary.

Education

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

Professional Memberships, Associations and Designations

Society of Petroleum Engineers (SPE), Lifetime Member

Executive Team

Bradley H. 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. 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 Team

Nancy F. 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

Ms. Foster joined Husky in 2011 and is the Senior Vice President of Human & Corporate Resources. She is an experienced human resources practitioner with extensive oil and gas experience, both domestically and internationally.

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. 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

Over her career, Ms. Foster has served on a number of industry and community related committees, including the Alberta Economic Development Authority, CAPP, the Conference Board of Canada and the University of Calgary. She has also served on numerous charitable committees during her career, including the Alberta Children's Hospital Foundation, Child & Youth Friendly Calgary, Hospice Calgary, the United Way of Calgary & Area, the YWCA, and the Calgary & Area Child Advocacy Centre. Ms. Foster has been a member of the International Women's Forum since 2012.

Executive Team

David A. Gardner

Senior Vice President, Business Development

Reporting to the CEO, Mr. Gardner is responsible for leading business development activities across Husky and 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. He started his BP career in a commercial and business development role for Greater Prudhoe Bay in Anchorage, Alaska. Mr. Gardner started his professional career as a geologist with Exxon in Thousand Oaks, California.

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 Team

Terry J. Manning

Senior Vice President, Engineering, Procurement & Project Management

Responsible for engineering, procurement and project management.

Career History and Key Accomplishments
Mr. Manning was appointed Senior Vice President, Engineering, Procurement and Project Management in May 2018. Prior to this, he was Senior Vice President, Safety, Engineering and Procurement. In his new role, Mr. Manning has responsibility for major projects.

Before 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, and prior to that at Cominco Ltd. where he started his career.

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).

Investor Relations Contacts

Dan Cuthbertson	**Director, External Communications and Investor Relations** **dan.cuthbertson@huskyenergy.com**
Leo Villegas	**Senior Manager, Investor Relations** **leonidas.villegas@huskyenergy.com**
Jenna Pickering	**Investor Relations Specialist** **jenna.pickering@huskyenergy.com**
James Ragan	**Senior Investor Relations Analyst** **james.ragan@huskyenergy.com**

Contact us: | www.huskyenergy.com | investor.relations@huskyenergy.com | 1-855-527-5005