NuVista Energy Ltd

TSX: NVA

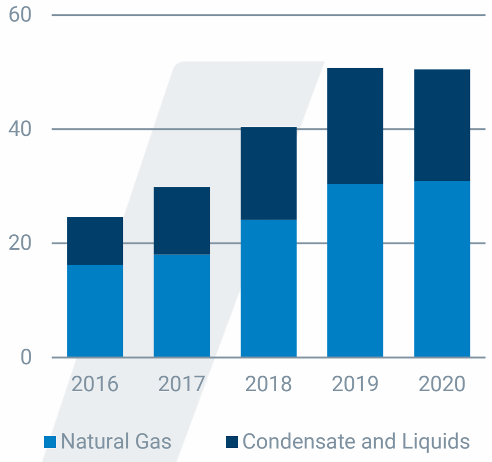
Returns-Focused Sustainable Growth

Corporate Presentation

March 2021

NuVista Corporate Snapshot

Production (MBoe/d)



Balanced Growth & Free Cash Flow Generation

Optimizing Costs to Drive Higher Returns

Corporate Information

TSX Trading Symbol	**NVA**
Shares Outstanding	**225.8 Million**
Credit Facility Capacity	**$440 Million**
Net Debt/Cash Flow [1]	**2.6x**

2021 Guidance

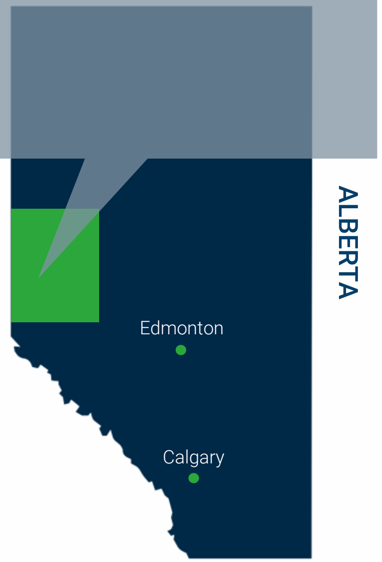
Full Year Production (Boe/d)	**50,000 – 52,000**
Full Year Capital Investment ($MM)	**$230 – $250**

Operations

NuVista Montney

50,000+

Boe/d



[1] December 31, 2020 Net Debt pro forma Q121 divestitures divided by Q420 annualized Cash Flow
See "Non-GAAP Measurements"

Advisory

Forward Looking Statements

This presentation contains forward-looking statements and forward-looking information (collectively, forward-looking statements") within the meaning of applicable securities laws. The use of any of the words "will", "may", "expects", "believe", "plans", "potential", "continue", "guidance", and similar expressions are intended to identify forward-looking statements. More particularly and without limitation, this presentation contains forward looking statements, with respect to: management's assessment of: NuVista's future focus, strategy, plans, priorities, opportunities and operations; the quality and growth potential of NuVista's Montney assets; 2021 - 2024 guidance with respect to production and production mix, net debt, and capital investment; plans to focus on returns resulting in sustainable growth; that the Wapiti asset economics will provide free cash flow and that the Pipestone assets will provide returns-driven growth; that NuVista have sufficient infrastructure in place to support production growth as high as 90,000 BOE/d; our 5-year production outlook; that NuVista will generate free cash flow; expected future returns and capital efficiencies; production decline rates and mix; the impact of improved oil prices; well locations and inventories; expectations that NuVista's record of execution and improvement will continue; type-curves; expected 2021 drilling and completion costs, average horizontal well length and proppant intensity; plans to place proppant more efficiency while increasing completions intensity; well economics; type well rates of returns and payouts; future EURs, CGRs, DCET capital, operating expenses and drilling plans, horizontal well lengths and proppant intensity; plans to allocate maximum growth capital to top-tier economics in the Pipestone area; that existing infrastructure will drive leading point-forward returns; that there is sufficient inventory and infrastructure in place to support long-term production target of 70,000 to 90,000 BOE/d; that improved efficiencies will result in cost reductions of 10% or more; NuVista's 5-year outlook with respect to production, cash flow, capital expenditures, debt to cash flow and free cash flow; NuVista's 2021 capital efficiency model and the components thereof; that NuVista's financial leverage will continue to improve; 2020 year end credit capacity; condensate pricing supply and demand; NuVista's market diversification and risk management program; and ESG plans and targets.

Statements relating to "reserves" and "resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves or resources described exist in the quantities predicted or estimated and that the reserves or resources can be profitably produced in the future.

By their nature, forward-looking statements are based upon certain assumptions and are subject to numerous risks and uncertainties, some of which are beyond NuVista's control, including the impact of general economic conditions, industry conditions, current and future commodity prices and differentials, currency and interest rates, anticipated production rates, borrowing, operating and other costs and adjusted funds flow, the timing, allocation and amount of capital expenditures and the results therefrom, anticipated reserves and resources and the imprecision of reserve and resource estimates, the performance of existing wells, the success obtained in drilling new wells, the sufficiency of budgeted capital expenditures in carrying out planned activities, access to infrastructure and markets, competition from other industry participants, availability of qualified personnel or services and drilling and related equipment, stock market volatility, effects of regulation by governmental agencies including changes in environmental regulations, tax laws and royalties; the ability to access sufficient capital from internal sources and bank and equity markets; obtaining the necessary regulatory approvals to complete the acquisition and other transactions referred to herein on the terms and timing contemplated and including, without limitation, those risks considered under "Risk Factors" in NuVista's Annual Information Form. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. NuVista's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements, or if any of them do so, what benefits NuVista will derive therefrom. NuVista has included the forward-looking statements in this presentation in order to provide readers with a more complete perspective on NuVista's future operations and such information may not be appropriate for other purposes. NuVista disclaims any intention or obligation to update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

NuVista: Focused on Returns

Top Quality Assets & Execution

- Wapiti: Free cash flow engine
  Pipestone: Returns-driven growth
- 30% high-value condensate
- Proven track-record of capital and operating cost reductions

Financial Strength

- Significant liquidity to execute our plan
- Free cash flow for measured growth & debt reduction
- Active risk management & market diversification

Optimal Growth Profile

- Material free cash flow generation with ~15+% production CAGR
- Target to fill existing infrastructure with production up to 90k Boe/d
- Maximize efficiencies and free cash flow generation upon filling existing infrastructure

Commitment to Sustainability

- Environmental excellence
- Community-driven culture & values
- Highest governance standards

See "Non-GAAP Measurements"

TOP QUALITY ASSETS

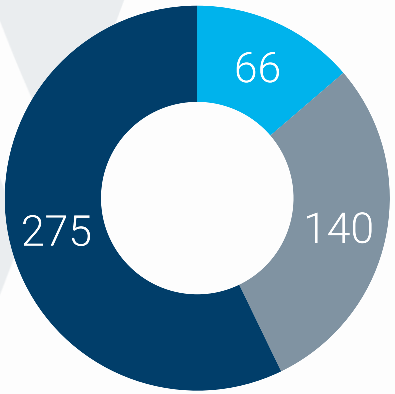
Significant High-Quality Inventory Supports Top-Tier Development

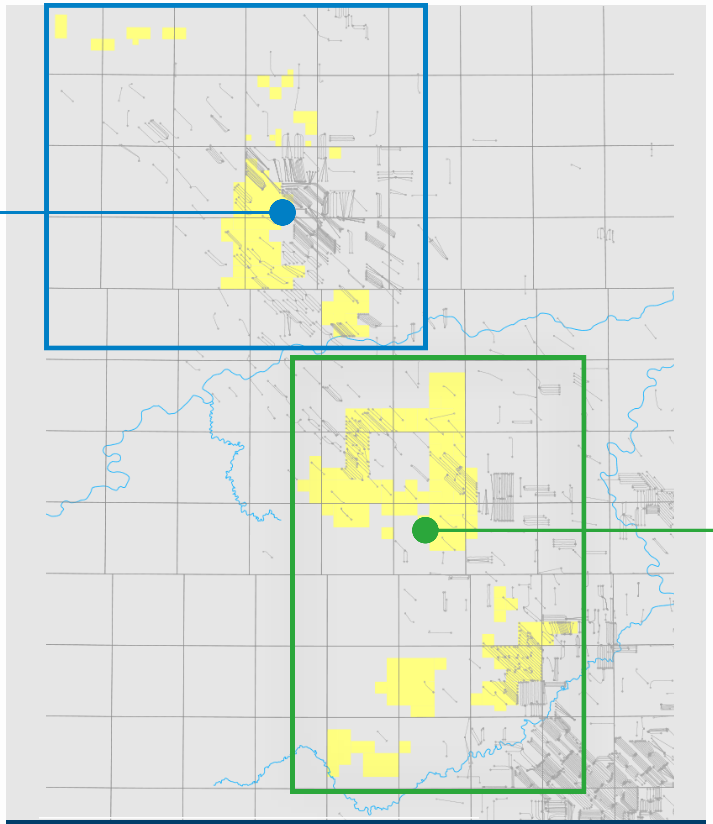
Pipestone

Top-Tier Asset With Measured Growth

Excellent returns & capital efficiencies high-grades NuVista portfolio as production ramps-up

- Developed Wells
- Undeveloped Locations (Proved + Probable)
- Undeveloped Locations (Contingent Resource)





Montney Inventory: **~1,200** locations

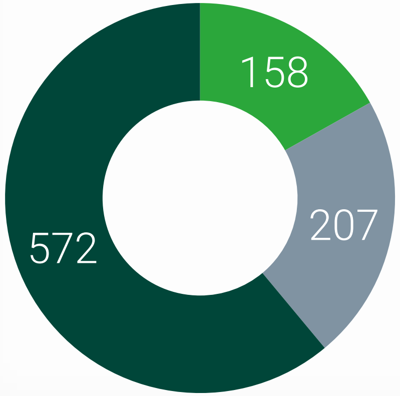
Montney Acreage: **~146,000** net acres

Wapiti

Free Cash Flow Engine

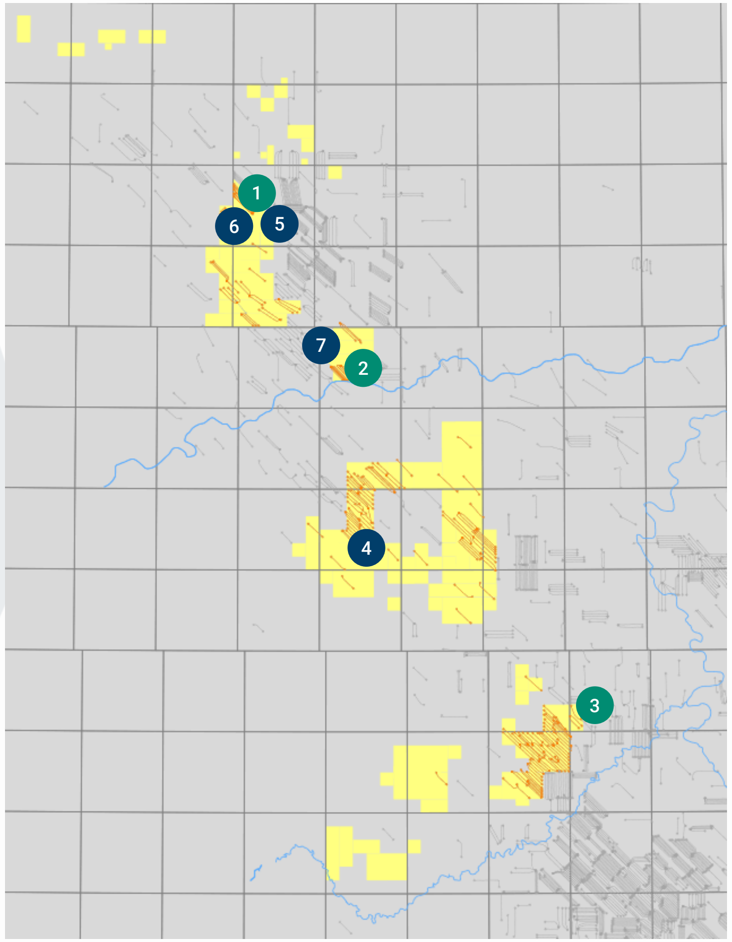
Cash flow driven by low declines, condensate-rich natural gas volumes, and torque to oil prices

- Developed Wells
- Undeveloped Locations (Proved + Probable)
- Undeveloped Locations (Contingent Resource)



See "Advisory Regarding Oil and Gas Information"
See "Non-GAAP Measurements"

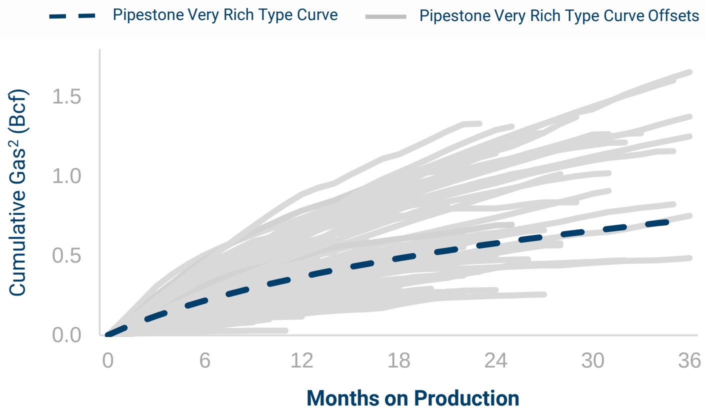
Activity Update: 2021 H1 Program in Full-Swing; Pipestone North Startup Imminent



- **1 Pipestone North | 12-Well Pad**
  Late-Q1 On-Stream
  D&C Costs 40% below 2019 NVA avg.[1]
- **2 Pipestone South | 6-Well Pad**
  Q2 On-Stream
- **3 Bilbo | 4-Well Pad**
  Late-Q1 On-Stream
- **4 Elmworth | 3-Well Pad**
  H2 On-Stream
- **5 Pipestone North | 6-Well Pad**
  H2 On-Stream
- **6 Pipestone North | 6-Well Pad**
  H2 On-Stream
- **7 Pipestone South | 6-Well Pad**
  H2 Drilling

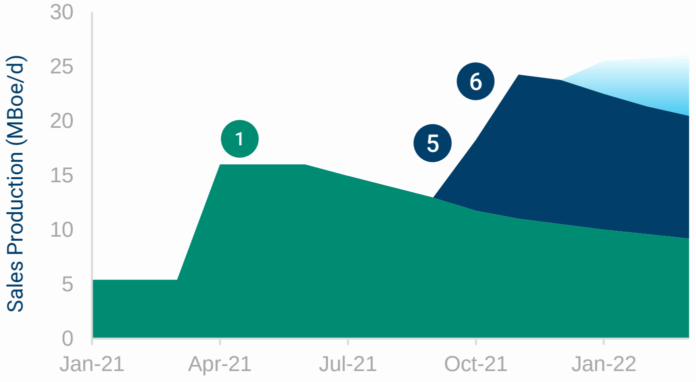
NVA H121 Activity
NVA H221 Activity
NVA Montney IP30
Montney Hz Wells

Pipestone Very Rich Type Curve



Robust Type Curve Supported by Existing Area Offsets

Ramping Up Production in our Top-Tier Pipestone North Asset



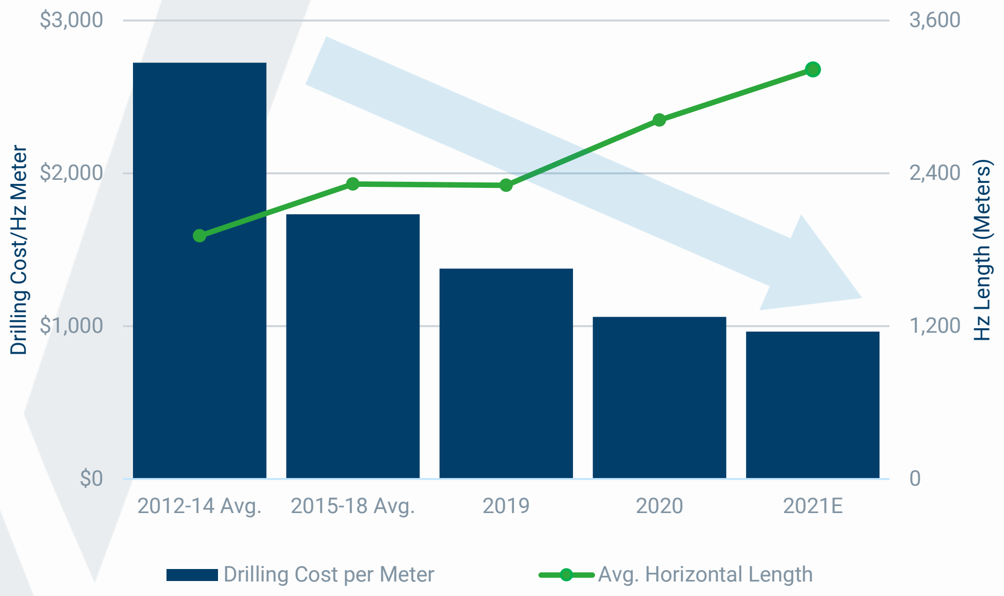
Up to 24 Pipestone Wells On-Stream by Year-End; Continue with Development in 2022 to Support Growth in-excess of ~25k+ Boe/d

[1] Actual well DCE costs per horizontal meter compared to NuVista 2019 historical average DCE costs per horizontal meter
[2] Cumulative Raw Gas production per 1,000m horizontal
See "Advisory Regarding Oil and Gas Information"

EXECUTION FOCUS

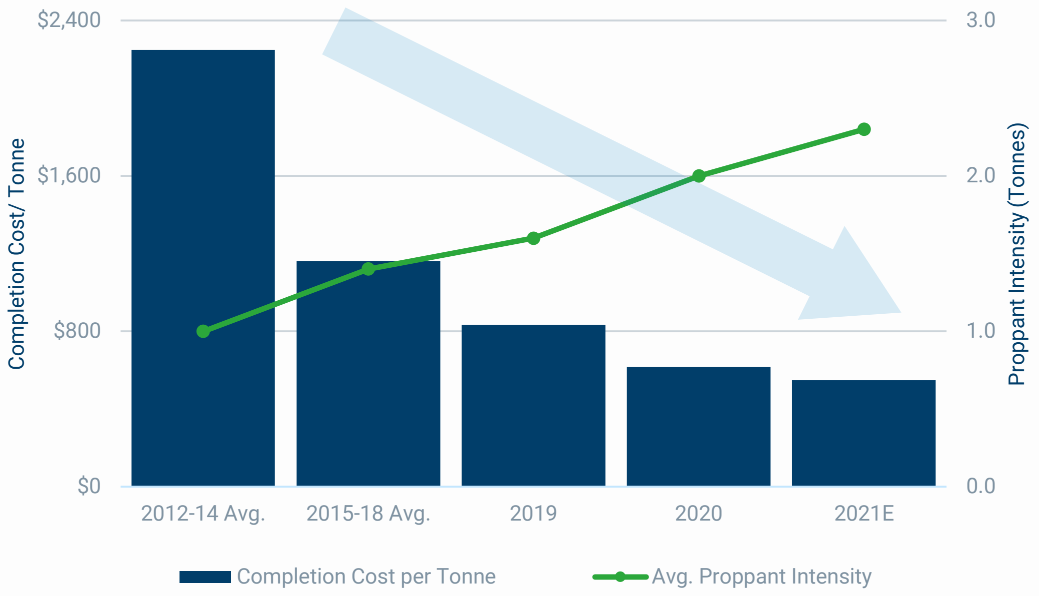
Material Reductions in Costs Drive Improved Capital Efficiencies

Drilling Cost – Going Longer for Less



Track record of continuous improvement in drilling performance underpins stronger returns

Completion Cost – Intensity Up, Costs Down



Focused on placing proppant more efficiently while increasing completions intensity

TOP QUALITY ASSETS

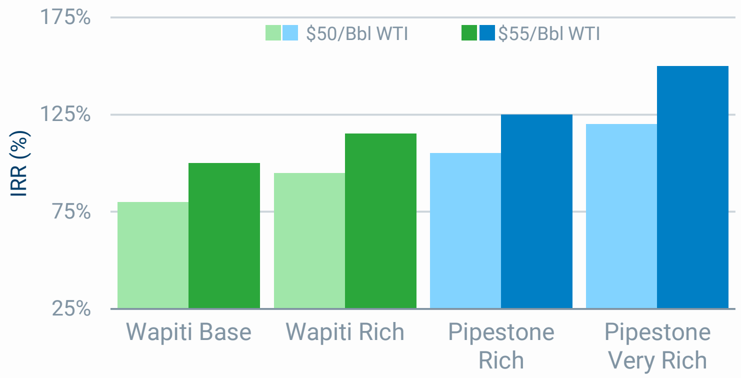
Value Based Capital Allocation to Top-Tier Incremental Economics

Wapiti:
Robust economics support free cash flow generation

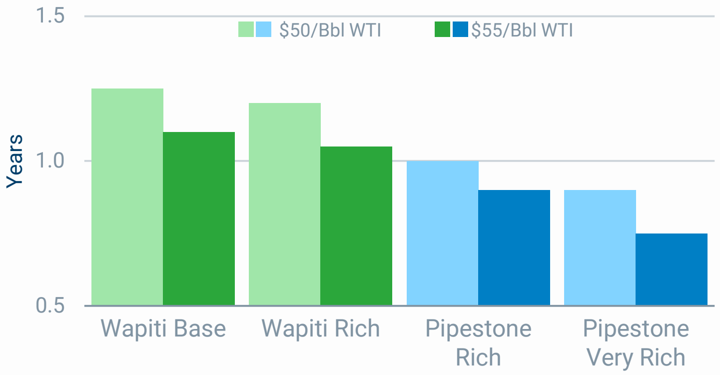
Pipestone:
Allocating growth capital to top-tier economics

Infrastructure:
Already in place to drive leading point-forward returns

Type Well Rate of Return



Type Well Payout



Type Well Parameters

Type Well Parameters	Wapiti Base	Wapiti Rich	Pipestone Rich	Pipestone Very Rich
EUR (Raw Gas) (Bcf)	8.8	6.5	7.0	4.5
CGR (C5+ Bbls/MMcf)	60↓45	115↓70	80↓48	200↓90
DCET Capital ($MM)	$7.9	$7.8	$7.3	$7.3
Horizontal Length (m)	3,000	3,000	3,000	3,000
Proppant Intensity (T/m)	**2.0**	**2.0**	**2.5**	**2.5**

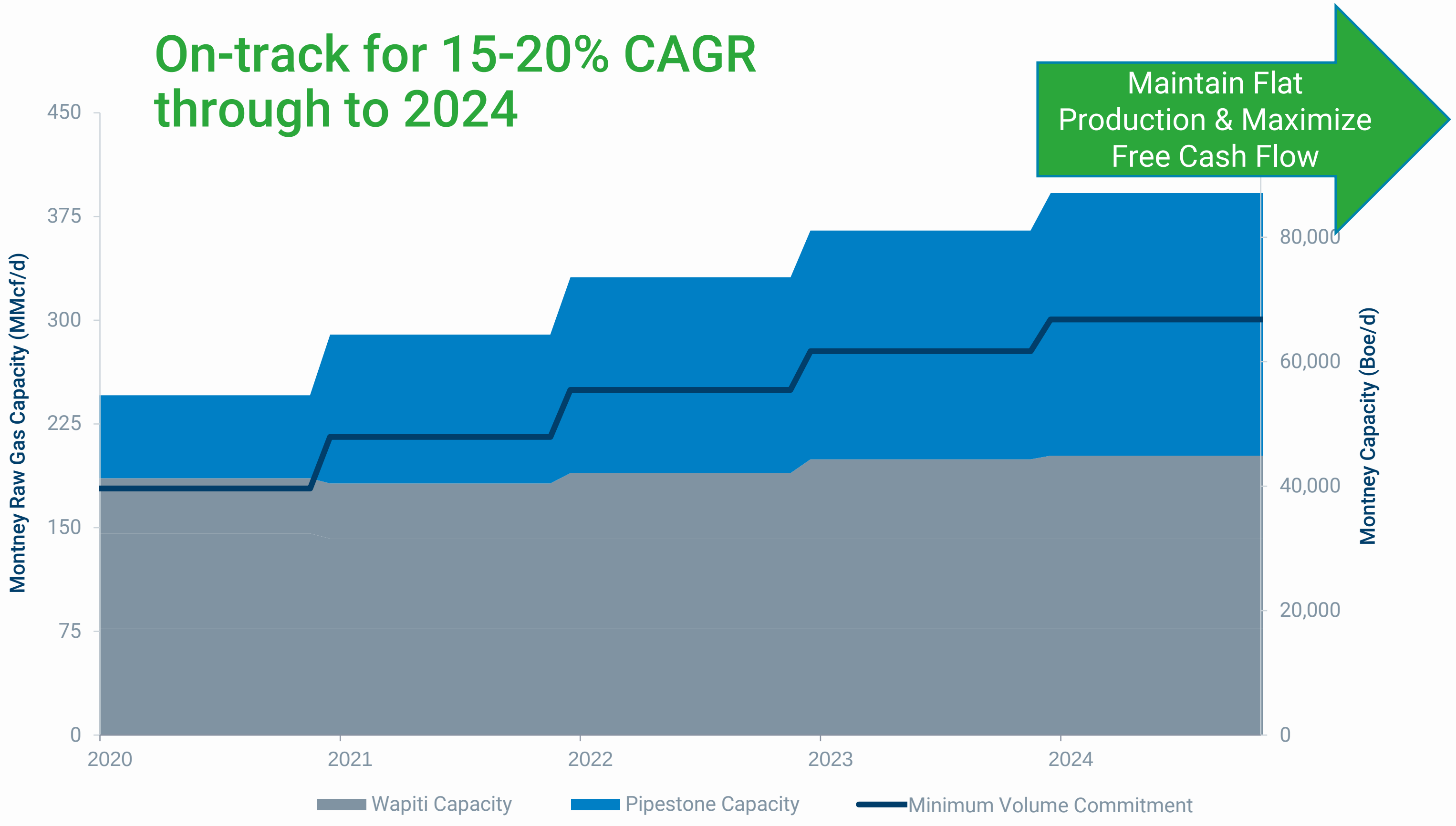
Pricing Assumptions:
$50/Bbl WTI: US$50/Bbl WTI; US$3.00/MMBtu NYMEX
$55/Bbl WTI: US$55/Bbl WTI; US$3.00/MMBtu NYMEX
Fx updated to 1.28 from 1.35 in prior NVA presentation.

See "Economic Input Assumptions" for additional detail.
See "Advisory Regarding Oil and Gas Information"
See "Non-GAAP Measurements"

Capacity Profile: Flexibility to Set Our Capital Program Commensurate with Price Environment

Why Grow?

- ✓ **Maximize free cash flow generation** through prudent and purposeful growth
- ✓ Line of sight to a **15+% cash cost reduction**[1] through improved efficiencies by filling existing infrastructure
- ✓ Growth capital allocated toward top-tier economics with **well under 1-year payout**



[1] Reflects cash costs per Boe (Operating costs, Transportation costs, Interest costs and G&A costs)

Material Change in Corporate Trajectory in 2022 Drives Significant Free Cash Flow

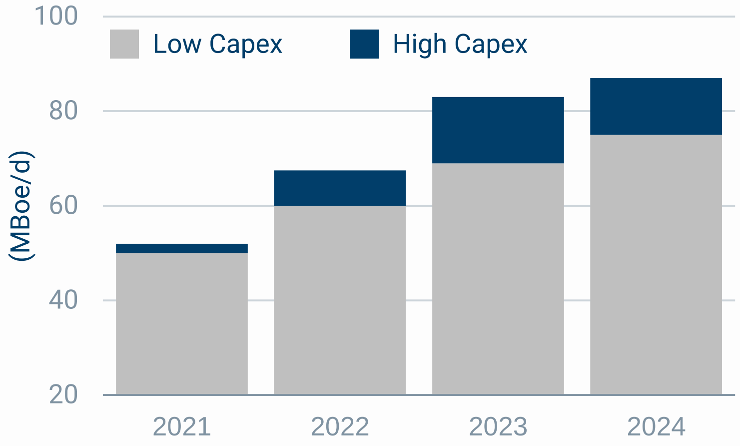
2022 Outlook:

Year-over-year cash flow increase of 40-70%

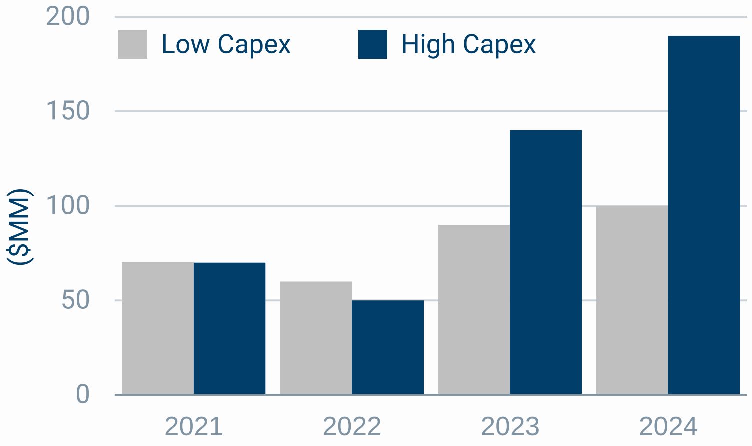
5-Year Plan:

~15+% annual production growth while generating up to $450MM of free cash flow

Corporate Production Outlook



Corporate Free Cash Flow Outlook[3]



Corporate Outlook at $55/Bbl WTI

2022/23 Annual Free Cash Flow Impact +/-US$5/Bbl WTI = ~$50/60MM

	2021 Guidance	2022 Outlook		2023 Outlook		2024 Outlook	
		Low Capex	High Capex	Low Capex	High Capex	Low Capex	High Capex
Cash flow ($MM)	~$220[2]	$310	$375	$365	$490	$400	$510
Capital Investment ($MM)	$230 – $250	$250	$325	$275	$350	$300	$325
Capital Investment : Cash flow[3]	~65%[2]	80%	85%	75%	70%	75%	65%
Net Debt : Cash flow	~2.5x[2]	1.5x	1.3x	1.1x	0.7x	0.8x	0.3x

[1]Pricing Assumptions:
$55/Bbl WTI case: US$55/Bbl WTI; US$3.00/MMBtu NYMEX
Fx updated to 1.28 from 1.35 in prior NVA presentations.
See "Economic Input Assumptions" for additional detail.

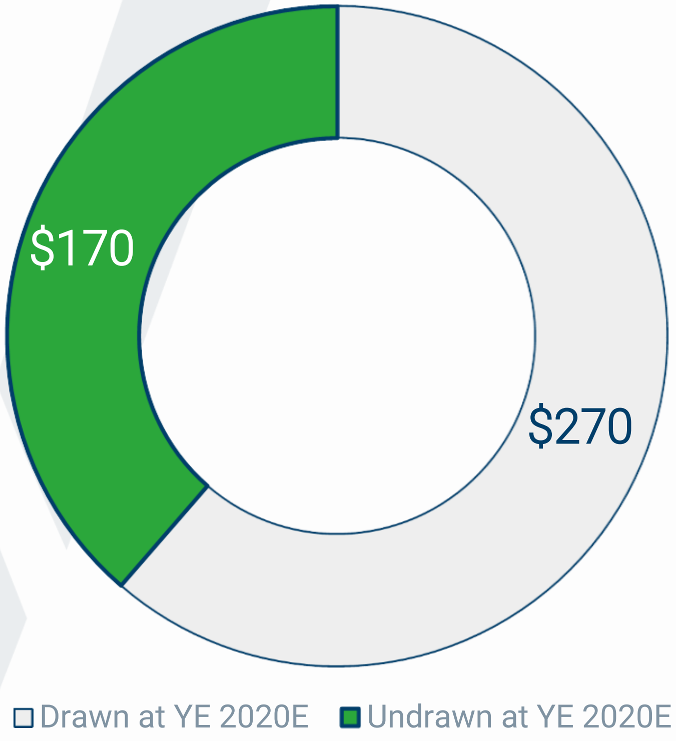
[2]Based on 2021 Production and Capital Investment Guidance midpoint.
[3]Net of Disposition Proceeds.

See "Advisory Regarding Oil and Gas Information"
See "Non-GAAP Measurements"

FINANCIAL STRENGTH

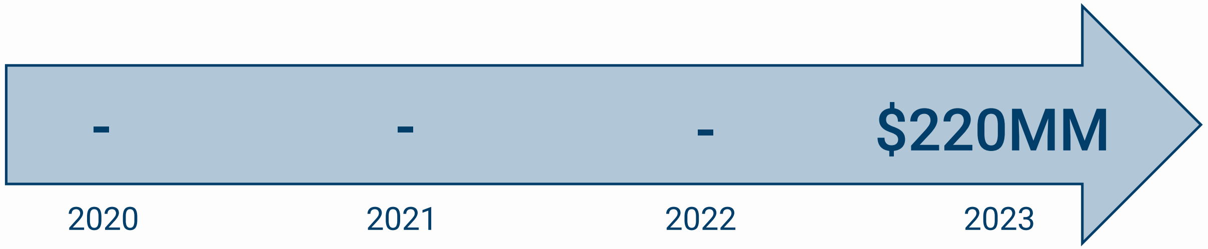
Material Liquidity and Improving Financial Leverage

Reserves Based Credit Facility[1]: C$440 MM



Senior Notes: C$220 MM

Senior Debt Termed Out to 2023



Material liquidity with **no debt maturities for 2 years** provides financial flexibility to manage continued volatility

See "Advisory Regarding Oil and Gas Information"

[1] RBL Facility Amount as at March 1, 2021; YE Drawings Pro-forma Q1 21 Divestitures

Condensate Pricing Market: Supply & Demand Fundamentals

Western Canadian demand far exceeds domestic supply = Premium pricing over the long-term

2021 Western Canadian **demand** forecast of **645k Bbls/d**

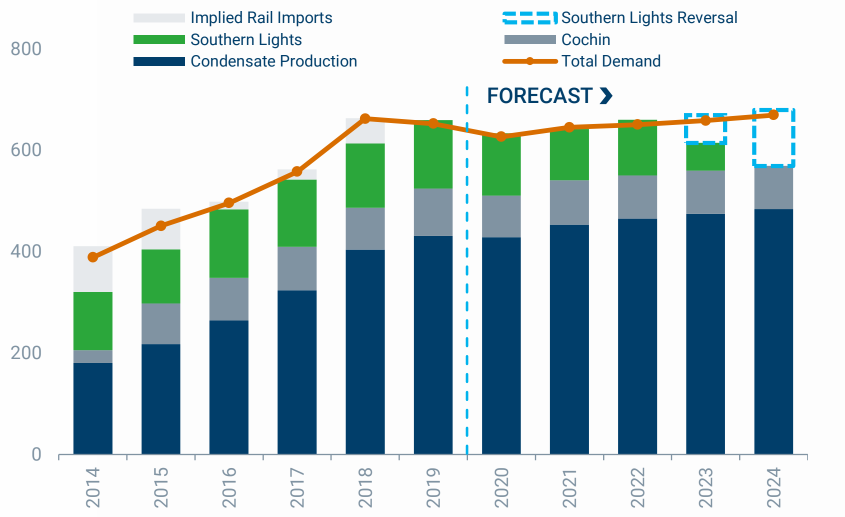
2021 domestic **production** forecast of **454k Bbls/d**

Import capacity on Cochin and Southern Lights up to 280k Bbls/d

Continued demand growth & potential Southern Lights pipeline reversal bode well for long-term pricing

Meagre forecast domestic condensate production growth insufficient to fulfill demand

Western Canada Condensate Supply and Demand (MBbls/d)



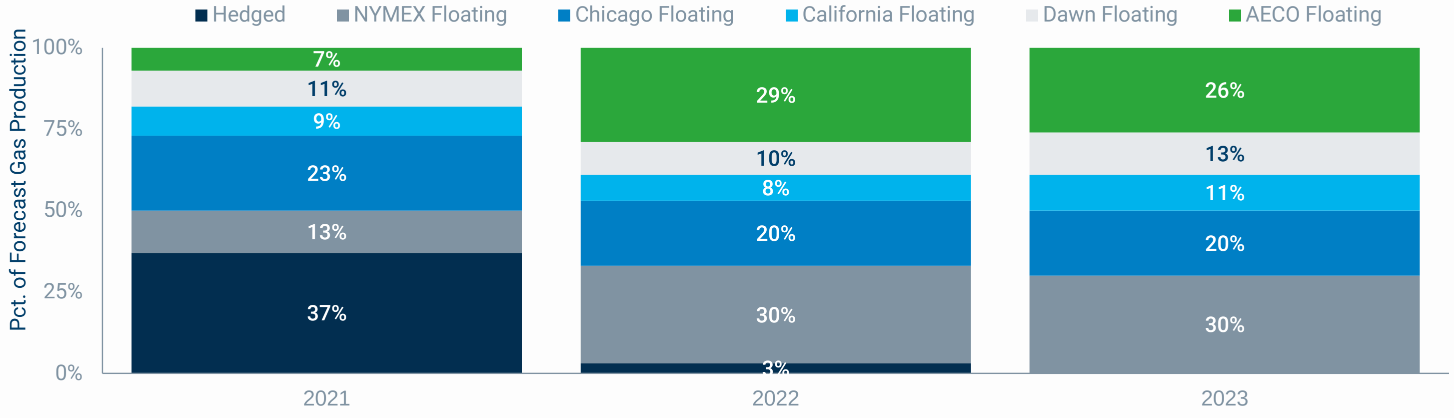
Sources: Government/third-party data, and Peters & Co. Limited estimates.
Note: Demand includes 15 MB/d reduction from USDG/GEI DRU beginning in H2/21

Market Diversification & Risk Management Program

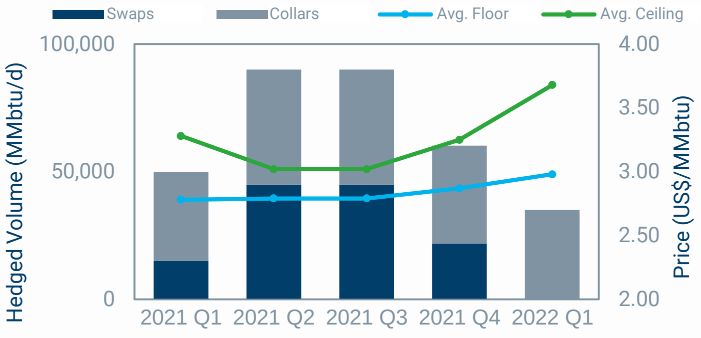
Active marketing program broadens exposure and mitigates local dynamic risk at any individual market

Risk management protects cash flows and project economics

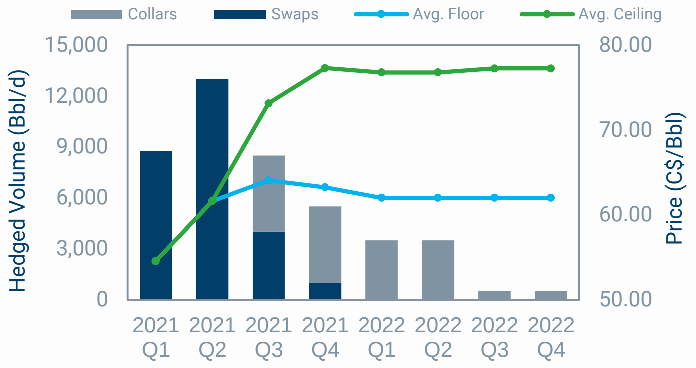
Natural Gas Price Diversification



Natural Gas Hedge Position

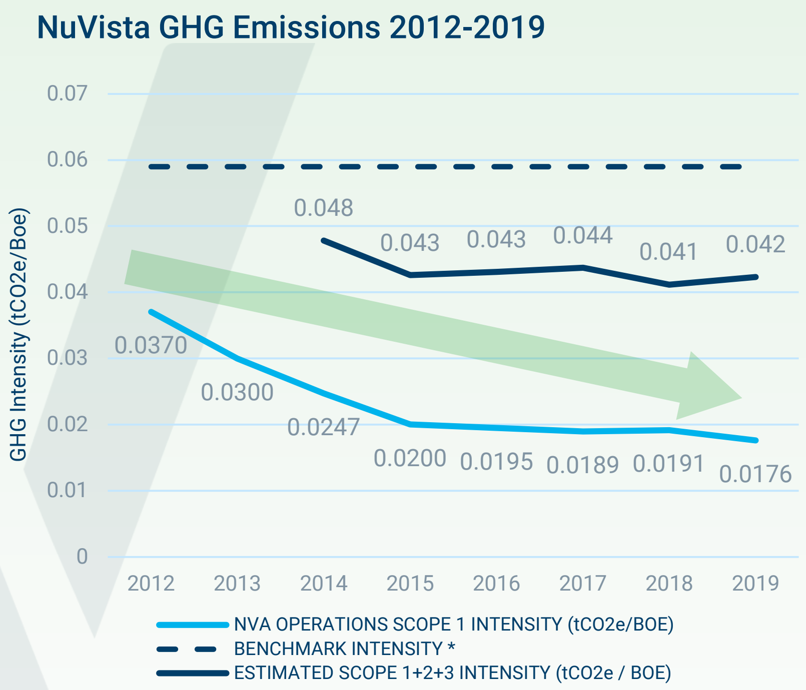


Oil Hedge Position



ESG-Focused Culture[1]

Environmental



Continuing to drive down NVA Operations Scope 1 GHG Intensity

Over 50% Reduction

In Annual Greenhouse Gas Emissions Intensity (Scope 1) from 2012 to 2019

>75,000 Cars

Off the road in 2019

Equivalent Scope 1 GHG intensity reductions since 2012

>22,000 Truckloads

Off the road for fluid transport in 2020

Greater than 7 LMR

Excellent Liability Management Rating

680 NFL Football fields

Equivalent Land Reclaimed since 2012

Governance

Exec. Comp. Alignment

Compensation tied to business & environmental performance

Enterprise Risk Mgmt.

Active Board oversight and ERM process

Board ESG Committee

Oversight of climate, safety and ESG-related risks and opportunities

20% Target

Female board membership by 2021

Social

58% TRIF Decline

Total Recordable Injury Frequency from 1.03 to 0.43 (2014-19 per 200k hours)

Indigenous Engagement

Respectful consultation with continuous efforts to support Indigenous businesses

>$1,000,000 Contributed

Donations, employee volunteering and sponsorships contributed to charities and Indigenous groups since 2017

1 See NuVista's 2018 ESG Report for further details on our ESG commitment and performance

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Commitment to Sustainability

- Environmental excellence
- Community-driven culture & values
- Highest governance standards

See "Non-GAAP Measurements"

NuVista
ENERGY LTD

Thank you

Advisory Regarding Oil and Gas Information

Throughout this presentation the terms Boe (barrels of oil equivalent), MBoe (thousands of barrels of oil equivalent), MMBOE (millions of barrels of oil equivalent), Bcfe (billions of cubic feet of gas equivalent) and Tcfe (trillion of cubic feet of gas equivalent) are used. Such terms may be misleading, particularly if used in isolation. The conversion ratio of six thousand cubic feet per barrel (6 Mcf: 1 Bbl) of natural gas to barrels of oil equivalent and the conversion ratio of 1 barrel per six thousand cubic feet (1 Bbl: 6 Mcf) of barrels of oil to natural gas equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Any references in this presentation to initial production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will continue production and decline thereafter. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for NuVista. NuVista has presented certain type curves and well economics for the Wapiti and Pipestone development blocks. For the Wapiti area the type curves presented are based on NuVista's historical production in the Wapiti development block, in addition to production history from analogous Montney development located in close proximity to the Wapiti area. For the Pipestone development block the rich and very rich type curves and well economics presented are based on initial drilling results but, due to the early stage of development, primarily on drilling results from analogous Montney development located in close proximity to such area.

Such type curves and well economics are useful in understanding management's assumptions of well performance in making investment decisions in relation to development drilling in the Montney area and for determining the success of the performance of development wells; however, such type curves and well economics are not necessarily determinative of the production rates and performance of existing and future wells and such type curves do not reflect the type curves used by our independent qualified reserves evaluator in estimating our reserves volumes. The type curves used by GLJ Petroleum Consultants Ltd. ("GLJ") for NuVista's most recent independent reserves evaluation as of December 31, 2020 for the Wapiti and Pipestone development blocks had an estimate of estimated ultimate recovery that generally compared well to the type curves presented herein.

The type curves presented fall into several categories: (i) Historical Average; (ii) Base; (iii) Rich; and (iv) Very Rich. The expectations for each type curve differ as a result of varying geology, horizontal well length, stage count and stage spacing. Historical Average is the average type curve achieved from the wells previously drilled by NuVista in the area. The Base, Rich and Very Rich type curves represent NuVista's expected type curve from drilling extended reach horizontal wells and utilizing higher proppant intensity fracturing techniques on wells. In addition, with respect to the Pipestone development block this presentation includes well performance and estimated ultimate recoverable volumes associated with Rich and Very Rich type curves, which refers to wells that are expected to have a high and very high relative content of condensate production, respectively. The type curves and well economics associated with Rich and Very Rich wells have been risked by taking a reduced expected resource recovery from increased horizontal length and frac intensity based on applicable actual well data and applying our planned well design.

NuVista is still refining its application extended reach horizontals and high intensity facture techniques and in the early stages of development in respect of the Pipestone development block. As such there is no certainty that such results will be achieved or that NuVista will be able to optimize such drilling results to achieve the optimized type curves, well economics and estimated ultimate recoverable volumes described. In this presentation, estimated ultimate recovery represents the estimated ultimate recovery associated with the type curves presented; however, there is no certainty that NuVista will ultimately recover such volumes from the wells it drills.

Advisory Regarding Oil and Gas Information

In presenting such type curves, inputs and economics information and in this presentation generally, NuVista has used a number of oil and gas metrics which do not have standardized meanings and therefore may be calculated differently from the metrics presented by other oil and gas companies. Such metrics include "DCET", "EUR", "CGR", "Horizontal Length", "Proppant Intensity", "payout" and "IRR". DCET includes all capital spent to drill, complete, equip and tie-in a well. EUR represents the estimated ultimate recovery of resources associated with the type curves presented. CGR means the condensate to gas ratio and provides the barrels of natural gas liquids recovered for each MMcf of gas recovered. Horizontal length is the length of the horizontal leg of a well. Proppant intensity is the tonnes of proppant used per metre in fraccing operations for completing wells. Payout means the anticipated years of production from a well required to fully pay for the DCET of such well. IRR means the rate of return of a well or the discount rate required to arrive at a net present value equal to zero.

This presentation discloses NuVista's drilling locations in two categories: (i) undeveloped proved plus probable (2P) drilling locations; and (ii) undeveloped contingent resources (2C) drilling locations. Undeveloped 2P drilling locations are derived from a report prepared by GLJ, NuVista's independent qualified reserves evaluator, evaluating NuVista's reserves as of December 31, 2020 (the "GLJ Report"), and account for undeveloped drilling locations that have associated proved and/or probable reserves, as applicable. Undeveloped 2C drilling locations are derived from a report prepared by GLJ evaluating NuVista's contingent resources as of December 31, 2020 ("GLJ Contingent Resource Report"), and account for undeveloped drilling locations that have associated contingent resources based on a best estimate of such contingent resources. There is no certainty that we will drill all drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. In the case of the contingent resources estimated in the GLJ Contingent Resource Report, contingencies include: (i) further delineation of interest lands; (ii) corporate commitment, and; (iii) final development plan. To further delineate interest lands additional wells must be drilled and tested to demonstrate commercial rates on the resource lands. Reserves are only assigned in close proximity to demonstrated productivity. As continued delineation drilling occurs, a portion of the contingent resources are expected to be reclassified as reserves. Confirmation of corporate intent to proceed with remaining capital expenditures within a reasonable timeframe is a requirement for the assessment of reserves. Finalization of a development plan includes timing, infrastructure spending and the commitment of capital. Determination of productivity levels is generally required before the company can prepare firm development plans and commit required capital for the development of the contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

Certain information in this presentation may constitute "analogous information" as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* with respect to the certain drilling results, total production in the Montney, number of wells drilled, or offset well production from other producers with operations that are in geographical proximity to or believed to be on-trend with NuVista's Montney assets. Management of NuVista believes the information may be relevant to help determine the expected results that NuVista may achieve within NuVista's lands and such information has been presented to help demonstrate the basis for NuVista's business plans and strategies with respect to its Montney assets. There is no certainty that the results of the analogous information or inferred thereby will be achieved by NuVista and such information should not be construed as an estimate of future production levels, reserves or the actual characteristics and quality of NuVista's Montney assets.

Advisory Regarding Oil and Gas Information

ADVISORY REGARDING OIL AND GAS INFORMATION

The reserves estimates for 2020 presented herein have been evaluated by independent qualified reserves evaluators in accordance with NI 51- 101 and the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook"), are effective December 31, 2020 and are based on an independent evaluation by GLJ using January 1, 2020 forecast pricing. The contingent resource drilling locations are derived from the GLJ Contingent Resource Report. The reserves and resources presented herein have been categorized in accordance with the reserves and resource definitions as set out in the COGE Handbook. The reserves estimates for prior years have also been evaluated on the same basis, are effective as of December 31 of the applicable year and are based on an independent evaluation of GLJ using January 1 forecast pricing of the applicable year. The estimate of future net revenue of NuVista's reserves disclosed in this presentation do not represent fair market value. 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.

ECONOMIC INPUT ASSUMPTIONS

- NuVista's type curve based on management's best estimates
- CGR yield represents the equivalent constant yield for the full life of the well
- Pricing Assumptions:
  - $50/Bbl WTI Scenario:
    - US$50/Bbl WTI
    - US$3.00/MMBtu NYMEX
  - $55/Bbl WTI Scenario:
    - US$55/Bbl WTI
    - US$3.00/MMBtu NYMEX
  - Fx (CAD:USD): 1.28:1 used in all pricing scenarios
  - Price case flat on a real basis; costs inflated at 2% per annum
  - NGL's as % of WTI: C3 = 30%; C4 = 65%; C5+ = WTI -US$1/Bbl
  - Recovered liquids unit transportation cost: C3/C4 = C$6/Bbl; C5+ = $7/Bbl
  - Gas price offset reflects NuVista's aggregate egress pipeline tolls and a $US0.75/MMBtu AECO to NYMEX basis

EMISSIONS BENCHMARK METHODOLOGY

North American Benchmark GHG Intensity (tCO2E/Boe): the weighted average of a relevant gas benchmark and a relevant oil benchmark to reflect NuVista's production (1/3 liquids, 2/3 natural gas). The two benchmarks that contribute to our NVA benchmark are identified below.

1. Average "production and upgrading" emissions for oil in USA refineries: ARC Energy Research Institute: Crude Oil Investing in a Carbon Constrained World: 2017 Update. October 2017 = 0.059 x 1/3

2. Average upstream emissions for Canadian shale gas: Natural Resources Canada, “Shale Gas Update for GHGenius”, August 2011, Prepared by S&T2 Consultants = 0.059 x 2/3

Advisory Regarding Non-GAAP Measurements

NON-GAAP MEASUREMENTS

For ease of readability, in this corporate presentation, adjusted funds flow will be referred to as "cash flow" and capital expenditures will be referred to as "capital investment".

Within this presentation, references are made to terms commonly used in the oil and natural gas industry. Management uses "cash flow", "free cash flow" or "FCF", "cash flow per share", "net debt", "net debt to cash flow", and "stay-flat capex" to analyze performance and leverage. These terms do not have any standardized meaning prescribed by GAAP and therefore may not be comparable with the calculation of similar measures for other entities. These terms are used by management to analyze performance on a comparable basis with prior periods and to analyze the liquidity of NuVista.

Adjusted funds flow

NuVista considers adjusted funds flow to be a key measure that provides a more complete understanding of the Company's ability to generate cash flow necessary to finance capital expenditures, expenditures on asset retirement obligations, and meet its financial obligations. NuVista has calculated adjusted funds flow based on cash flow provided by operating activities, excluding changes in non-cash working capital, asset retirement expenditures and environmental remediation recovery, as management believes the timing of collection, payment, and occurrence is variable and by excluding these items from the calculation, management is able to provide a more meaningful performance measure. More specifically, expenditures on asset retirement obligations may vary from period to period depending on the Company's capital programs and the maturity of its operating areas, while environmental remediation recovery relates to an incident that management doesn't expect to occur on a regular basis. The settlement of asset retirement obligations is managed through NuVista's capital budgeting process which considers its available adjusted funds flow. Adjusted funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, per the statement of cash flows, net earnings (loss) or other measures of financial performance calculated in accordance with GAAP. Adjusted funds flow per share is calculated based on the weighted average number of common shares outstanding consistent with the calculation of net earnings (loss) per share.

Free adjusted funds flow

Free adjusted funds flow is forecast adjusted funds flow less estimated capital expenditures required to maintain production.

Net debt

Net debt is used by management to provide a more complete understanding of the Company's capital structure and provides a key measure to assess the Company's liquidity. NuVista has calculated net debt based on cash and cash equivalents, accounts receivable and prepaid expenses, asset under construction, accounts payable and accrued liabilities, long term debt (credit facility) and senior unsecured notes.

The adjusted funds flow ($/Boe) assumptions used in this presentation to calculate estimated future adjusted funds flow are as follows:

Low Scenario

$/Boe	2021	2022	2023	2024
Net revenues*	$31.40	$32.45	$31.30	$31.40
Operating & Transport expenses	$16.00	$15.40	$14.40	$14.80
G&A & Interest expenses	$3.75	$2.80	$2.40	$2.10
Cash flow	$11.65	$14.25	$14.50	$14.50

High Scenario

$/Boe	2021	2022	2023	2024
Net revenues*	$31.40	$32.50	$30.65	$31.15
Operating & Transport expenses	$16.00	$14.70	$12.50	$13.30
G&A & Interest expenses	$3.75	$2.65	$2.00	$1.70
Cash flow	$11.65	$15.15	$16.15	$16.15

*Net Revenues = Petroleum & Natural Gas Revenue +/- Realized Hedging Gain/Loss - Royalties

Abbreviations and Definitions

AECO	physical storage and trading hub for natural gas in Alberta
Avg	average
B	billion
Bbl or bbls	barrel or barrels
Bcf	billion cubic feet
Boe or BOE	barrels of oil equivalent
C$	Canadian dollars
C2	ethane
C3	propane
C4	butane
C5 or C5+	pentanes plus
CAGR	compounded annual growth rate
Capex	capital expenditures
Capital Investment	capital expenditures
CDN	Canadian
CGR	condensate/gas ratio
CO_2E	carbon dioxide equivalent
d	day
D&C	drill and complete
DCE	drill, case and equip

DCET	drilled, completed, equip and tie-in
DUCS	drilled uncompleted wells
E	estimate
ERM	Enterprise Risk Management
ESG	environmental, social and governance
FCF	free cash flow
G&A	general and administrative
GHG	greenhouse gas
GJ	gigajoule
H1	first half of the year
H2	second half of the year
hz	horizontal
Hz	horizontal
IP	initial production for the number of days specified
IRR	internal rate of return
k	thousands
LMR	liability management rating
m	meter
MBbl or MBbls	thousand of barrels
MBoe	thousands of barrels of oil equivalent

MCF	thousand cubic feet
MM	million
MMBtu	million British thermal units
MMcf	million cubic feet
MVC	minimum volume commitment
NYMEX	New York Mercantile Exchange
Q	quarter
Q1	first quarter of the year
Q2	second quarter of the year
Q3	third quarter of the year
Q4	fourth quarter of the year
T or t	tonne
TRIF	total recordable incident frequency
TSX	Toronto Stock Exchange
US	United States
US$	United States dollars
WTI	West Texas Intermediate
x	times
YE	year end
YTD	year to date
$	Canadian dollars unless otherwise specified