HIGH ARCTIC ENERGY SERVICES

MANAGEMENT'S DISCUSSION & ANALYSIS

FOR THE YEARS ENDED
December 31, 2021 and 2020

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Management's Discussion and Analysis ("**MD&A**") is a summary review of core operations, strategy, outlook, risks, the results of operations, liquidity and capital resources of High Arctic Energy Services Inc. ("**High Arctic**" or the "**Corporation**"). This MD&A is based on information available to March 10, 2022 and should be read in conjunction with the audited consolidated financial statements and notes for the years ended December 31, 2021 and 2020 (the "**Financial Statements**"). Additional information relating to the Corporation including the Corporation's Annual Information Form ("**AIF**") for the year ended December 31, 2021, is available under the Corporation's profile on SEDAR at www.sedar.com. This MD&A and the Financial Statements were reviewed by High Arctic's Audit Committee and approved by the Board of Directors on March 10, 2022. All amounts are expressed in thousands of Canadian dollars ("**CAD**"), unless otherwise noted, and have been prepared in accordance with International Financial Reporting Standards ("**IFRS**") as issued by the International Accounting Standards Board.

Readers are cautioned that this MD&A contains certain forward-looking information. Please refer to the "Forward-Looking Statements" section of this MD&A for the Corporation's discussion on forward looking information including risk factors that could cause actual results to differ significantly and certain assumptions used to underlie the forward-looking information. Definitions of certain non-IFRS financial measures are included on page 22 under the "Non-IFRS Measures" section.

Corporate Profile

Headquartered in Calgary, Alberta, Canada, High Arctic provides oilfield services to exploration and production companies operating in Canada, and Papua New Guinea ("**PNG**"). High Arctic is a publicly traded corporation listed on the Toronto Stock Exchange under the symbol "HWO".

High Arctic is a participant in, and manager of the Seh' Chene Limited Partnership ("**Seh' Chene**") with the Saa Dene Group of northern Alberta being the majority participant in a Joint Arrangement. It is Seh' Chene's mission to execute dependable high-quality energy services, focused on environmental stewardship, while creating opportunity for local Indigenous communities and individuals.

High Arctic conducts its business operations in three separate operating segments: Drilling Services; Production Services; and Ancillary Services. These operating segments are all supported by a Corporate segment.

Drilling Services

The Drilling Services segment consists of High Arctic's drilling services in PNG including the provision of personnel to assist our customer's drilling related operations. High Arctic has operated in PNG since 2007 and controls the largest fleet of tier-1 heli-portable drilling rigs in the country, with two owned rigs and two rigs managed under operating and maintenance contracts for one of the Corporation's customers.

Production Services

The Production Services segment consists of High Arctic's well servicing and snubbing operations. These operations are primarily conducted in the Western Canadian Sedimentary Basin ("**WCSB**") through High Arctic's fleet of well servicing rigs, operating as Concord Well Servicing, and its fleet of stand-alone and rig assist snubbing units.

Ancillary Services

The Ancillary Services segment consists of High Arctic's oilfield rental equipment in Canada and PNG, as well as its Canadian nitrogen services.

In the following discussion, the three months ended December 31, 2021 may be referred to as the "**Quarter**" or "**Q4-2021**", and similarly the year ended December 31, 2021 may be referred to as "**YTD-2021**". The comparative three months ended December 31, 2020 may be referred to as "**Q4-2020"** and similarly the year ended December 31, 2020 may be referred to as "**YTD-2020**". References to other quarters may be presented as "**QX-20XX**" with X being the quarter/year to which the commentary relates.

Q4-2021 and YTD-2021 Highlights

- High Arctic's revenues increased 43% to $23.6 million in Q4-2021 relative to Q4-2020 and were 27% higher than Q3-2021, buoyed by renewed activity in the Drilling Services Segment during the quarter. In contrast, YTD-2021 revenues of $76.4 million were lower by 16% primarily due to significantly lower drilling services activity throughout 2021-year compared to the 2020-year which included a full quarter of pre-pandemic activity.

- High Arctic's oilfield services operating margin as a percentage of revenue was 19.9% in both Q4-2021 and YTD-2021, compared to 23% and 23.5% in the corresponding 2020-periods.

- High Arctic achieved positive EBITDA of $1.2 million and $4.4 million for Q4-2021 and YTD-2021, while the net loss in the respective 2021-periods was $4.6 million and $18.6 million.

- High Arctic returned value to shareholders through a $9.7 million special one-time cash dividend in Q4-2021 while maintaining a strong working capital balance of $29.7 million on December 31, 2021. At year end, High Arctic carried a cash balance of $12.0 million.

- Cost reduction initiatives delivered $2.5 million or 19.4% lower general and administrative costs YTD-2021 over prior year, and $5.5 million lower than pre-pandemic YTD-2019 costs.

- In December 2021, High Arctic completed a $8.1 million mortgage financing of Corporation owned and occupied land and buildings with an initial 5-year term and a fixed interest rate of 4.30%.

2021 Overview

2021 proved to be a challenging, yet promising year in the energy services sector. The year commenced with low and volatile but improving commodity pricing despite Covid-19 variants emerging and continuing to restrain international travel. With the rising commodity price backdrop for oil and gas, most E&P customers prioritized balance sheet repair followed by returns to shareholders over exploration and increased drilling activity globally. The steps taken by High Arctic in 2020 to preserve balance sheet strength and standardize processes within a global management structure position the Corporation for increases in upstream industry spending to maintain and increase production.

Drilling services continued at very low levels for most of 2021. In Q3-2021 High Arctic began mobilizing equipment and personnel within PNG, and in January 2022 began operations with Rig 115. Pre-Covid, in 2019 PNG drilling services segment revenues were $71.5 million relative to only $10.7 million revenue in 2021 (2020 - $25.4 million). There is optimism for the PNG national gas sector as the Corporation anticipates meaningful drilling activity for the coming years. An agreement was reached in 2022 between the Government of PNG and the PNG-LNG partners on terms for the P'nyang gas field development. PNG's development plan phases P'nyang after the Papua LNG project, which could result in nearly a decade of continuous construction activity adding three LNG trains and significant investment in the region.

In Canada oil and gas market conditions continue to improve with the rise in oil prices through the year. Western Canada Select oil price peaked at $79 CAD $/bbl in Q4-2021. With the positive momentum, High Arctic's YTD-2021 Canadian production services segment revenues were only 4% lower than YTD-2020 at $55.4 million, despite 2020 including a full quarter of pre-pandemic activity. These 2021 results would have been markedly better had High Arctic not had to navigate through the twin headwinds of Covid-19 infection site shutdowns and the ongoing labour shortages experienced across the industry. High Arctic's ancillary services in Canada saw strong gains in 2021 as labour issues have less impact on equipment rentals.

The Seh' Chene partnership continued to grow in 2021, generating revenues of $2.1 million in Canada. The partnership was particularly successful in the various provincial well abandonment and site closure programs funded by the Federal Government.

High Arctic was eligible for various government subsidies during 2021, which amounted to approximately $3.3 million YTD-2021 ($6.3 million YTD-2020). As most of the programs had been completed before the end of the year, High Arctic does not expect to receive any subsidy in 2022.

High Arctic's has a relentless focus on quality and is driven to be recognized as a trusted service provider in the energy industry. High Arctic works towards this by defining and measuring results against strategic priorities. Our 2021 strategic priorities and highlights of progress are as follows:

• Safety excellence and focus on quality service delivery through consistent global standards.

✓ High Arctic extended its recordable incident free activity in PNG to 5 years and over 2.5 million work hours, with an incident free rig movement services and recommencement of rig site activity. In Canada we added additional roles to support the growth in activity and continued the roll out of the quality centric approach to operations adapted from the successes in PNG.

• Cost control focused on operating cash flow, while balancing strategic priorities to fuel growth.

✓ High Arctic actively managed its costs including a $2.5 million reduction in G&A expense in 2021 over 2020. High Arctic ensures to scale its operations in line with current and anticipated business activity, as evidenced by the successful PNG restart. Despite lower revenue in 2021, High Arctic maintained a consistent Oilfield services operating margin as a percentage of revenue in 2021-year relative to 2020-year.

• The pursuit of opportunities that secure the Corporation's future as a lower emissions energy services provider.

✓ High Arctic advanced the electric drive service rig design and applied for patent, which is pending. The service rig upgrade is estimated to significantly reduce CO_2 emissions while operating over the wellbore by displacing diesel generators. While this service rig was not fully operational in 2021, a field trial for this technology continues to be a priority heading into 2022.

• Growth and divestiture opportunities that enhance shareholder value, align with our core service offerings, and are located in well understood markets.

✓ High Arctic continuously evaluates opportunities in order to enhance its service offerings. In 2021, High Arctic acquired 17 modern hydraulic catwalks in Cold Lake, where High Arctic has established long term operations.

• Disciplined working capital management and capital stewardship to improve returns for shareholders including dividends and common share buybacks.

✓ On November 5, 2021, the Corporation paid $9.7 million in dividends to shareholders, while preserving a strong capital structure. High Arctic mortgaged its owned properties in Alberta, to add long term low interest debt to the capital structure. As at December 31, 2021 the Corporation had positive working capital of $29.7 million, $8.1 million debt, cash of $12.0 million, and $37.0 million available from the Corporation's credit facility.

Select Comparative Financial Information

The following is a summary of select financial information of the Corporation:

($ thousands, unless otherwise stated and per share amounts)	For the year ended **December 31 2021**	 December 31 2020	 December 31 2019
Revenue	**76,442**	90,834	185,568
Oilfield services operating margin (1)	**15,216**	21,311	35,261
Oilfield services operating margin as a % of revenue (1)	**19.9%**	23.5%	19.0%
Net loss	**(18,607)**	(25,985)	(8,843)
Per share (basic and diluted) (2)	**(0.38)**	(0.52)	(0.18)
EBITDA (1)	**4,429**	10,404	23,065
Adjusted EBITDA (1) (3)	**4,918**	8,529	20,501
Adjusted EBITDA as % of revenue	**6.4%**	9.4%	11.0%
Operating loss (1)	**(19,430)**	(27,510)	(9,391)
Cash (used in) provided by operating activities	**(1,797)**	20,152	13,157
Per share (basic and diluted)	**(0.04)**	0.41	0.27
Funds provided by operations (1)	**3,697**	6,320	15,757
Per share (basic and diluted) (2)	**0.08**	0.13	0.32
Dividends paid	**9,747**	1,638	9,886
Per share (basic and diluted) (2)	**0.20**	0.03	0.20
Capital expenditures	**7,242**	4,874	23,168

(1) Readers are cautioned that Oilfield services operating margin, EBITDA (Earnings before interest, tax, depreciation and amortization), Adjusted EBITDA, and Funds provided from operations do not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 22 for calculations of these measures. EBITDA includes wage and rent subsidies received from the Canadian Government during the year.

(2) The number of common shares used in calculating net loss per share, funds provided from operations per share, and dividends per share is determined as explained in Note 9 of the Financial Statements.

(3) Adjusted EBITDA includes wage and rent subsidies received from the Canadian government during the year.

($ thousands, unless otherwise stated and per share amounts)	As at/ For the year ended **December 31 2021**	 December 31 2020	 December 31 2019
Working capital (1)	**29,724**	44,577	37,442
Cash	**12,037**	32,598	9,309
Total assets	**185,452**	214,159	251,791
Long-term debt	**7,779**	10,000	-
Total long-term financial liabilities	**13,414**	15,926	20,948
Shareholders' equity	**148,851**	177,221	205,586
Per share (basic and diluted)(2)	**3.05**	3.58	4.11
Common shares outstanding, thousands	**48,733**	48,760	49,623

(1) Readers are cautioned that working capital does not have standardized meanings prescribed by IFRS – see "Non IFRS Measures" on page 22 for calculations of these measures.

(2) The number of common shares used in calculating shareholders' equity per share is determined as explained in Note 9 of the Financial Statements.

Outlook

The rebound in global energy demand continued the rally in oil and gas commodity prices, which reached ten-year highs in the early months of 2022. A continuation of the easing of government-imposed restrictions related to the Covid-19 pandemic, periods of extreme cold in Europe, Asia and North America, war in Ukraine, and the underperformance of renewable energy supply in Europe reinforced demand for oil and gas. Coupled with the discipline of OPEC members in maintaining modest supply increases, a continued reduction in drilled-and-uncompleted wells in the USA and several years of underinvestment in upstream oil and gas sources, has set the table for sustained high commodity prices.

Though the impact of Covid-19 cases amongst crews remains unpredictable, and market volatility from global events lingers, High Arctic anticipates continuous improvement in profitability throughout 2022. On the backdrop of high commodity prices, continued economic recovery and the improved balance sheets of E&P companies, demand for energy services grows and High Arctic anticipates continued utilization increases across its service offerings. Improved fleet utilization in Canada, combined with cost inflation, has led to improvements in pricing, as seen in the rise of our hourly revenue during Q4-2021. This pricing trend is continuing in Q1-2022, with further increases being agreed with major customers.

Papua New Guinea continues to be key to High Arctic's long-term business strategy due to the significant LNG investments made by large oil and gas companies in the country and high barriers for entry due to the technical expertise required to operate the heli-portable drilling rigs in remote locations. With Rig 115 operations recently restarting, management is optimistic 2022 will be the start of an upward trend in revenue growth for High Arctic in PNG.

High Arctic anticipates further investments in LNG infrastructure in PNG in the coming years. The Shell LNG market update published in February 2022 highlighted a large and growing supply deficit through 2040 and the need for significant new project investment for supply to meet demand. The PNG-LNG project, commissioned in 2014, has demonstrably de-risked PNG as a source of world-class, low-cost gas supply in a location well positioned for the Asian market. LNG is ideal to both meet demand growth and deliver long-term climate benefits by reducing coal consumption in Asia. The Papua LNG project is underway again with personnel recently remobilised into PNG with indications they are progressing work towards a project FID in 2023. On February 22, 2022, the PNG government and PNG-LNG partners announced the signing of the P'nyang Gas Agreement. The development of P'nyang has been seen as a possible catalyst to expand the existing LNG plant and these two projects alone are anticipated to more than double LNG supply from the country. With Arran Energy announcing intention to make an FID for its Stanley Gas Condensate Development early this year, the stage is set for a meaningful near term ramp up of activity. High Arctic remains exceptionally well positioned to benefit.

Global Developments

Political, economic and pandemic developments have a significant impact on High Arctic's strategy and capital resource allocation. The Corporation's principal markets are in Canada, driven by customers' oil and natural gas production, and in PNG where its customers are restarting drilling operations as new LNG supply is being contemplated. The cyclicality of the oil and gas industry has been acute over the past two years. After a year of tremendous uncertainty in 2020 and prior years of underinvestment in global oil production capacity, oil supply and associated human capital are now in tight supply. Reinvestment needed to sustain productive capacity and balance the pace of energy transition to lower emitting energy sources has gained a sharper focus.

The recent invasion of Ukraine has created a humanitarian crisis and focused the world on ensuring security and prosperity within the western hemisphere. The war has highlighted problems for energy security in Europe, as well as dramatically impacting oil prices.

As we all know, in March 2020 the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("Covid-19"). In 2021, the pandemic continued to impact global commercial activity as vaccine rollouts gained momentum and new variants of COVID-19 emerged. On balance these developments resulted in a significant improvement in worldwide demand for energy throughout the year. Accordingly, oil prices recovered and closed the year at levels above pre-pandemic pricing. While this improvement trend has been positive, global restrictions on travel remain an important factor as the world copes with the COVID-19 endemic and variants as they emerge. In spite of recovery and reduced restrictions, there still remains uncertainty around the ongoing impact of Covid-19.

In world oil markets the Organization of Petroleum Exporting Countries and non-OPEC members ("OPEC+") saw production quotas increase throughout 2021. In July 2021, OPEC+, including Russia, agreed to increase crude oil production by 400,000 barrels per day each month until previous production cuts from 2020 are fully reversed, which would occur by the third quarter of the 2022-year. OPEC+ continues to monitor oil demand recovery and remains steadfast in its plan despite calls from consuming regions, most notably the United States, to increase its production levels and alleviate rising global oil prices.

In Canada, numerous large infrastructure projects stand to significantly increase export capacity in oil and liquified natural gas and benefit High Arctic customers. These large pipeline projects upon completion will help remove excess supply bottlenecks and open new global markets for western Canada oil and gas production. The Enbridge Line 3 Replacement Project to the U.S. entered service October 1, 2021. The LNG Canada pipeline project in the province of British Columbia is under construction and upon completion will provide long awaited tidewater access to Asian markets. The Trans Mountain Expansion Project is under construction in Alberta and British Columbia and like LNG Canada will provide long awaited access to Asian markets for oil production.

Of renewed global focus is the security of supply for oil and natural gas and its vital need to sustain people and economies. The emergence of military conflict in Ukraine, resulting loss of life and condemnation of Russian leadership by many regions around the world is rapidly escalating. Oil and natural gas commodity prices are rising as a security of supply premium is being assessed. Diverse energy supply is of rising strategic importance and High Arctic's positioning in Canada and PNG can provide greater certainty with the current slate of projects underway and being considered with upcoming financial investment decisions.

In November 2021, countries worldwide met in Glasgow as part of the COP 26 global climate summit to discuss the impacts of climate change with the goal to limit temperature rise to 1.5 degrees Celsius. Key takeaways to meet these net-zero targets included a sharpened focus on reducing methane gas emissions. In addition, a declaration was signed by 30 countries and development banks for calls to halt subsidized funding for unabated use of fossil fuels. A rotation of investment capital away from the oil and gas industry has the potential to increase High Arctic's cost of capital and reduce access to growth funding.

The Canada Emergency Wage Subsidy ("CEWS") and Canada Emergency Rent Subsidy ("CERS") programs were enacted on April 11, 2020, and September 27, 2020, respectively, by the federal Government of Canada, and both programs ended on October 23, 2021. These programs were replaced with new programs for the industries hardest hit by Covid-19. The Corporation no longer qualified for government assistance after October 23, 2021.

In 2020, the Canadian federal government announced a $1.7 billion well abandonment and site reclamation stimulus plan. During 2021, High Arctic actively participated in the program as part of its production services segment. With tens of thousands of inactive oil and gas wells across western Canada, we expect that over the stimulus period, High Arctic will continue to participate in these well abandonment operations.

High Arctic's Strategic Objectives

High Arctic's focus remains on being well positioned to navigate through the uncertainty with capacity ready for deployment as markets continue to recover and activity levels increase. Our 2022 Strategic Objectives build on the platform we created in 2021, and include:

- Safety excellence and quality service delivery,
- Actions aimed at generating free cash flow including:
    - Increased utilization of the Corporation's world-class fleet of equipment,
    - Improved efficiency and work force productivity, and
    - Operating cost control,
- Development of new and existing employees to grow our workforce to meet demand,
- Pursuit of opportunities that secure the Corporation's future as a lower emissions energy services provider,
- Pursuit of opportunities for growth and corporate transactions in well understood markets that enhance shareholder value, and
- Disciplined capital stewardship to improve returns for shareholders including dividends and common share buybacks.

High Arctic continues to maintain close working relations with its customers and focus on high quality customer service differentiation as an absolute imperative. These attributes have been, and continue to be, key principles for High Arctic throughout the energy industry economic cycle.

Discussion of Operations

All amounts are expressed in thousands of Canadian dollars ("**CAD**"), unless otherwise noted

Fourth Quarter 2021 Summary:

- High Arctic's consolidated revenue and oilfield services operating margin rose in Q4-2021 to $23,644 and $4,700, respectively, as compared to $16,684 and $3,810 in Q4-2020.
- Net loss of $4,608 in Q4-2021 was lower as compared to net loss of $11,468 in Q4-2020, mainly due to one-off $5.6 million higher depreciation expense in Q4-2020 as a result of a change in depreciation policy, specifically as it related to salvage value estimates.
- Consolidated oilfield services operating margin as a percentage of revenue for Q4-2021 was 19.9% compared to 23.0% in Q4-2020, due to lower profitability in Canada's production services segment.
- Utilization for High Arctic's 50 registered Concord Well Servicing rigs was 40% in the Quarter versus industry utilization of 42% (source: Canadian Association of Oilwell Energy Contractors "CAOEC"). Growth in rig utilization in Q4-2021 was constrained by lower activity with a certain contracted large customer and Covid-19 labour disruptions.
- Adjusted EBITDA of $1,836 in Q4-2021, higher relative to $1,154 in Q4-2020.
- In November 2021, the Corporation paid a one-time special $0.20 per share dividend to shareholders of $9,747.
- In December 2021, the Corporation strengthened its capital structure by securing fixed interest rate mortgage financing of $8,100 of long-term debt. Current portion of the long-term debt on December 31, 2021 is $296.

Year Ended December 31, 2021 Summary:

- For the year ended December 31, 2021, consolidated revenue and oilfield services operating margin fell to $76,442 and $15,216, respectively, as compared to $90,834 and $21,311 in 2020. High Arctic was actively drilling in PNG in Q1-2020, and has since paused all drilling activity with drilling preparation activities recommencing in Q4-2021.
- YTD-2021 oilfield services operating margin as a percentage of revenue was lower at 19.9% compared to 23.5% in 2020, due to lower activity in PNG and lower wage subsidies received in Canada in 2021 versus 2020.
- Utilization for High Arctic's 49 registered Concord Well Servicing rigs was 43% YTD-2021 versus industry utilization of 37% (source: CAOEC).

- High Arctic continues to prioritize cost controls and inflationary influences as part of initiatives undertaken in the 2020 -year, with YTD-2021 general & administrative costs decreasing 19% to $10,298.
- Cash balance decreased by $20,561 YTD-2021 to $12,037 mainly due to $9,787 of dividend payment, a $1,925 reduction to long term debt, and buildup of accounts receivable in Q4-2021.
- All activities in the US ceased during 2020 and Corporation owned property and equipment is in the process of being relocated to Canada or disposed pending continuing assessment of opportunities.

Operating Results

Drilling Services Segment

($ thousands, unless otherwise noted)	Three months ended December 31 **2021**	2020	Year ended December 31 **2021**	2020
Revenue	**$ 6,291**	$1,477	**$ 10,653**	$25,357
Oilfield services expense	**4,831**	1,221	**8,990**	18,827
Oilfield services operating margin (1)	**$1,460**	$256	**$1,663**	$6,530
Operating margin (%)(1)	**23.2%**	17.3%	**15.6%**	25.8%

(1) See "Non-IFRS Measures" on page 22

In Q3-2021, High Arctic began preparation and rig movement services related to drilling Rig 115 in PNG. Rig movement services continued throughout Q4-2021, and drilling operations commenced in January 2022. As a result, both Q4-2021 revenue and oilfield services operating margin increased significantly as compared to inactive drilling operations in Q4-2020.

For the year ended December 31, 2021, revenues decreased 58%, to $10,653 from $25,357 in 2020, due to the stoppage of drilling services and deferral of non-essential work by customers during Q2-2020. Up to this point drilling operations were active and generating substantial revenues in 2020. Accordingly, YTD-2021 oilfield services operating margin decreased from $6,530 in 2020 to $1,663 in 2021. Operating margins were eroded as a certain level of fixed costs were incurred to preserved core operational strength in PNG despite extremely low 2021 customer demand.

The Corporation owns two heli-portable drilling rigs (Rigs 115 and 116) and has an agreement to operate an additional two rigs (Rigs 103 and 104) on behalf of a major oil and gas exploration company in PNG. In Q3 and Q4-2021, rig movement service revenues and expenses were realized related to Rig 115, with drilling activity commencing in January 2022. During 2021, Rigs 103, 104, and 116 all remained cold stacked, whereas during Q1-2020, Rig 103 was operational.

Production Services Segment

($ thousands, unless otherwise noted)	Three months ended December 31 **2021**	2020	Year ended December 31 **2021**	2020
Revenue	**$13,637**	$13,598	**$55,440**	$57,583
Oilfield services expense	**12,721**	11,182	**47,957**	47,644
Oilfield services operating margin (1)	**$916**	$2,416	**$7,483**	$9,939
Operating margin (%)	**6.7%**	17.8%	**13.5%**	17.3%

(1) See "Non-IFRS Measures" on page 22

Operating Statistics – Canada	Three months ended December 31 **2021**	2020	Year ended December 31 **2021**	2020
Service rigs:				
Average fleet (2)	**50**	50	**49**	**50**
Utilization (3)	**40%**	44%	**43%**	**43%**
Operating hours	**18,415**	20,070	**77,179**	**79,683**
Revenue per hour ($)	**630**	581	**603**	**587**
Snubbing packages:				
Average fleet (4)	**8**	8	**8**	**8**
Utilization	**20%**	23%	**22%**	**20%**
Operating hours	**1,445**	1,696	**6,423**	**6,054**

(2) Average service rig fleet represents the average number of rigs registered with the CAOEC during the period.
(3) Utilization is calculated on a 10-hour day using the number of rigs registered with the CAOEC during the period.
(4) Average snubbing fleet represents the average number of packages marketed during the period.

Within the Production Services Segment, well servicing and snubbing revenues in Q4-2021 were $13,637, relatively unchanged as compared to $13,598 in Q4-2020. Lower operating hours for service rigs and snubbing packages were offset by higher revenue per hour in Q4-2021. Canada experienced relatively low usage with its contracted large customer in the Cold Lake region and crew shortages from Covid infections resulting in less hours and higher labour costs. Activities in the US remained inactive, resulting in no revenues in both Q4-2021 and Q4-2020.

In Q4-2021, oilfield services operating margin was $916, lower by 66%, as compared to $2,686 in Q4-2020 due to higher labour rates, fuel prices, services, materials and $976 lower wage subsidies received in Q4-2021 compared to Q4-2020.

YTD-2021, revenues were lower by $2,143 or 3.7%, mainly due to $2,965 lower revenues generated from activities in the US partially offset by higher snubbing revenues. Operating margin percentage decreased to 13.5% YTD-2021 from 17.3% in YTD-2020, primarily due to lower wage subsidies received and higher input costs, particularly hourly labour rates not being completely offset by pricing increases in 2021.

Service Rigs

With improving market activity in Alberta, the corporation relocated Rig 53 from the USA, prepared it for service and deployed it into the Canadian market. Decisions were also enacted to relocated other rigs between operating base areas to exploit improving demand for service.

Pricing increases negotiated during Q3-2021 with certain customers and also applied to the spot market, raised average well servicing revenue per hour 8% to $630 in Q4-2021 as compared to $581 in Q4-2020, which was more than offset by inflationary input costs combined with the one-off expenses incurred in preparing and relocating equipment to regions of higher activity. Revenue per hour increased to $603 for YTD-2021 periods, and $587 and YTD-2020, respectively. Higher revenue per hour in the respective periods is reflective of improved market conditions from higher oil prices and the ability of the Corporation to work with customers on implementing pricing increases.

Servicing rig operating hours were lower in Q4-2021 and YTD-2021 by 1,655 hours and 2,504 hours, respectively, as compared to the same 2020-periods. Lower activity in 2021 resulted from a slow recovery in the Canadian energy services activity due to consolidation in the customer base and the focus of E&P companies on maintaining capital discipline and from the ongoing negative impacts of the Covid-19 pandemic and related government restrictions placed on businesses.

Snubbing packages

Snubbing operating hours of 1,445 hours were lower in Q4-2021 relative to 1,696 hours in Q4-2020. Lower operating hours is reflective of crew shortages experienced in Q4-2021 as well as only marginal increases in demand for snubbing services in Western Canada. Snubbing utilization as a result was lower in Q4-2021 at 20% as compared to 23% in Q4-2020.

YTD-2021, snubbing operating hours and utilization rates were 6,423 hours and 22%, respectively, slightly higher compared to 6,054 hours and 21% in YTD-2020 driven by marginally improving market conditions through the middle of 2021-year.

US geographic segment

Due to previously persistent poor market conditions, High Arctic made the decision in Q3-2020 to cease operations in North Dakota and Colorado where the Corporation has 1 service rig and 6 snubbing packages. There have been no service rig hours or snubbing package hours in the US during 2021, management is in the process of relocating viable equipment to Canada and assessing opportunities for the remaining assets.

Ancillary Services Segment

	Three months ended December 31		Year ended December 31	
($ thousands, unless otherwise noted)	**2021**	2020	**2021**	2020
Revenue[1]	**$4,227**	$1,770	**$12,274**	$9,407
Oilfield services expense	**1,902**	901	**6,204**	4,834
Oilfield services operating margin [2]	**$2,325**	$869	**$6,070**	$4,573
Operating margin (%)	**55.0%**	49.1%	**49.5%**	48.6%

(1) Revenue includes amounts charged to other segments of the Corporation totalling $1,925 ($1,783).
(2) See "Non-IFRS Measures" on page 22

The Ancillary Services segment consists of High Arctic's oilfield rental equipment in Canada and PNG, as well as its Canadian nitrogen operations.

In Q4-2021 activity in PNG began to mobilize which provided $1,993 equipment rental revenues as compared to $273 PNG equipment rental revenues in Q4-2020. Q4-2021 oilfield services operating margin increased 168% to $2,325 from $869 in Q4-2020 primarily due to higher equipment rentals in PNG and contribution from High Arctic's 2021 acquired catwalk machines in Canada

YTD-2021 ancillary services segment revenues were higher by 30% to $12,274 due mainly to higher equipment rental and nitrogen services in Canada. Despite higher revenues, YTD-2021 operating margin percentage is flat at 49.5% versus 48.6% in 2020, as a higher proportion of revenues came from nitrogen services, which have lower margins as compared to equipment rentals.

General and Administrative ("G&A")

	Three months ended December 31		Year ended December 31	
($ thousands, unless otherwise noted)	**2021**	2020	**2021**	2020
G&A expenses	**$2,864**	$2,656	**$10,298**	$12,782
% of revenue	**12.1%**	16.0%	**13.5%**	14.1%

G&A costs in Q4-2021 were higher primarily due to lower CEWS received with the program ended on October 23, 2021 and higher professional fees in the quarter. G&A as a percentage of revenue for Q4-2021 was 3.9% lower relative to Q4-2020.

YTD-2021 G&A expenses decreased by $2,484 and G&A expenses as a percent of revenue decreased relative to 2020-year. Lower G&A expenses in 2021 are primarily due to lower personnel costs and bad debt expense in the period. In 2020, cost initiatives to reduce management and administrative were realized after Q2-2020, in addition a higher credit loss was recorded relating to higher credit risk associated with the oil and gas industry due to the effects of both Covid-19 pandemic and the oil and gas price crisis in 2020.

As reflected in the reduction in G&A, High Arctic remains committed to ensuring these costs are managed and balanced within the overall strategic plan for the Corporation.

Depreciation

Depreciation expense on property and equipment and right-of-use assets totaled $6,005 in Q4-2021, and $23,639 YTD-2021, compared to $12,461 and $35,484 during Q4-2020 and YTD-2020, respectively. Lower depreciation in the 2021 periods is reflective of certain equipment becoming fully depreciated in 2020, and increased depreciation expense in Q4-2020 as a result of revised estimates from the Corporation's review of its depreciation policy in the period.

Share-based Compensation

Share-based compensation expense is the charge to income over the service period relating to stock option or unit plans which generally contemplate the issuance of common shares upon vesting. The recognition methodology used typically front end loads the expense in the early period of the expense realization, with reductions being recorded when significant cancellations or unanticipated forfeitures take place. The Corporation recognized higher share-based compensation in Q4-2021 relative to Q4-2020 due to the one-time special dividend of $0.20 cents per share entitled to holders of PSUs, RSUs, and DSUs. Share-based compensation expense amounted to $413 and $709 during Q4-2021 and YTD-2021, respectively (Q4-2020 and YTD-2020 - $306 and $555).

Interest and Finance Expense

	Three months ended December 31		Year ended December 31	
($ thousands)	**2021**	2020	**2021**	2020
Interest expense and standby fees	**$85**	$ 178	**$280**	$487
Finance expense – lease liabilities	**95**	103	**390**	506
Other	**13**	19	**36**	117
	$193	$300	**$706**	$1,110

In Q1-2021, the Corporation repaid in full cash drawn from its revolving loan facility, and therefore subsequent to Q1-2021, interest expense comprised standby fees and related administrative expense associated with the revolving loan facility. In December 2021, the Corporation obtained long-term mortgage financing of $8,100 on certain High Arctic owned and occupied land and buildings in Canada.

Finance expense on lease liabilities associated with the time value of money for the three months and year ended December 31, 2021 were $95 and $390, respectively (Q4-2020: $103 and YTD-2020: $506), as the liability is initially recorded at its present value.

Other interest and finance expense primarily relates to bank charges in the respective periods.

Income Taxes

	Three months ended December 31		Year ended December 31	
($ thousands)	**2021**	2020	**2021**	2020
Net loss before income tax	**$(5,023)**	$(12,117)	**$(19,916)**	$(26,190)
Current income tax expense	**(348)**	(101)	**(905)**	(1,549)
Deferred income tax recovery	**763**	750	**2,214**	1,754
Total income tax expense	**$415**	$649	**$1,309**	$205
Effective tax rate	**(8.3)%**	(5.4)%	**(6.6)%**	(0.8)%

Tax rates in 2021 were impacted by foreign tax on income earned in foreign jurisdictions as well as unrecognized deferred tax assets with respect to deductible temporary differences in Canada.

Total Canadian non-capital losses carried forward for income tax purposes was $123,949 at December 31, 2021 (2020 - $124,861), which expire in years 2027 through 2041.

At December 31, 2021, the total US non-capital losses carried forward for income tax purposes was USD $6,412 (2020 - $5,910) which can be carried forward indefinitely.

At December 31, 2021 the capital losses carried forward for income tax purposes was $39,694 (2020 - $39,657), which can be carried forward indefinitely, but only used against capital gains.

Other Comprehensive Income (Loss)

The Corporation recorded a $570 foreign currency translation loss in other comprehensive loss for the YTD-2021 (YTD-2020: $840 loss) associated with subsidiaries with functional currencies other than CAD.

The CAD weakened slightly compared to the USD at December 31, 2021, relative to December 31, 2020, and this resulted in a net loss on the net assets held in the subsidiaries with USD as their functional currency.

Liquidity and Capital Resources

($ thousands)	Three months ended December 31 2021	2020	Year ended December 31 2021	2020
Cash (used in) provided by:				
Operating activities	**$(3,472)**	$2,389	**$(1,797)**	$20,152
Investing activities	**(2,722)**	(853)	**(5,572)**	(1,100)
Financing activities	**(2,088)**	(1,307)	**(13,389)**	4,600
Effect of exchange rate changes on cash	**109**	(879)	**197**	(363)
(Decrease) increase in cash	**$(8,173)**	$(650)	**$(20,561)**	$23,289

($ thousands, unless otherwise noted)	As at December 31 2021	December 31 2020
Current assets	**45,132**	55,589
Working capital (1)	**29,724**	44,577
Working capital ratio (1)	**3.1:1**	5.0:1
Cash	**12,037**	32,598
Net cash (1)	**3,962**	22,598
Undrawn availability under revolving credit facility	**37,000**	35,000

(1) See “Non-IFRS Measures” on page 22

The Bank of PNG continues to encourage the use of the local market currency, Kina or PGK. Due to High Arctic’s requirement to transact with international suppliers and customers, High Arctic has received approval from the Bank of PNG to maintain its USD account within the conditions of the Bank of PNG currency regulations. The Corporation continues to use PGK for local transactions when practical. Included in the Bank of PNG’s conditions is for PNG drilling contracts to be settled in PGK, unless otherwise approved by the Bank of PNG for the contracts to be settled in USD. The Corporation has historically received such approval for its contracts with its key customers in PNG. The Corporation will continue to seek Bank of PNG approval for future customer contracts to be settled in USD on a contract-by-contract basis, however, there is no assurance the Bank of PNG will continue to grant these approvals.

If such approvals are not received in future, the Corporation’s PNG drilling contracts will be settled in PGK which would expose the Corporation to exchange rate fluctuations related to the PGK. In addition, this may delay the Corporation’s ability to receive USD which may impact the Corporation’s ability to settle USD denominated liabilities and repatriate funds from PNG on a timely basis. The Corporation also requires the approval from the PNG Internal Revenue Commission (“**IRC**”) to repatriate funds from PNG and make payments to non-resident PNG suppliers and service providers. While delays can be experienced for the IRC approvals, such approvals have been received in the past.

Operating Activities

In Q4-2021, cash used in operating activities was $3,472 (Q4-2020: $2,389 cash from operating activities), of which $1,390 are funds provided by operations (Q4-2020: $859), see “Non-IFRS Measures” on page 22, and $4,862 cash outflow from working capital changes (Q4-2020: $1,530 cash inflow) mainly due to increase in accounts receivable during the Quarter.

YTD-2021, cash used in operating activities was $1,797 (YTD-2020: $20,152 cash from operating activities), of which $3,697 are funds provided by operations (YTD-2020: 6,320), see “Non-IFRS Measures” on page 22, and $5,494 cash outflow from working capital changes (YTD-2020: $13,832 cash inflow) mainly due to increase in accounts receivable during Q4-2021.

Investing Activities

During Q4-2021, the Corporation's cash used in investing activities was $2,722 (Q4-2020: $853). Capital expenditures during the Quarter were $3,134 (Q4-2020: $1,050) partially offset by $213 proceeds on disposal of property and equipment (Q4-2020: $182), and $199 cash inflow relating to working capital balance changes for capital items (Q4-2020: $15 cash inflow).

YTD-2021, the Corporation's cash used in investing activities was $5,572 (YTD-2020: $1,100). Capital expenditures during the period were $7,242 (YTD-2020: $4,874) partially offset by $1,196 proceeds on disposal of property and equipment (YTD-2020: $5,134), and $474 cash inflow relating to working capital balance changes for capital items (YTD-2020: $1,360 cash outflow).

Financing Activities

In Q4-2021, the Corporation's cash used in financing activities was $2,088 (Q4-2020: $1,307). During the quarter the Corporation paid $9,747 for a one-time special dividend, $416 lease liability payments (Q4-2020: $576) and made no purchases of common shares for cancellation (Q4-2020: $731). A total of $8,075 long-term debt proceeds, net of transaction costs, were received during the Quarter.

YTD-2021, the Corporation's cash used in financing activities was $13,389 (YTD-2020: $4,600 cash from financing activities). During 2021-year the Corporation paid $9,747 for a one-time special dividend (YTD-2020: $1,638), paid $1,925 net debt payments with $10,000 paid in Q1-2021 offset by $8,075 net proceeds in Q4-2021 (YTD-2020: $10,000 proceeds), $1,615 lease liability payments (YTD-2020: $2,121), and $102 purchases of common shares for cancellation (YTD-2020: $822). No changes to working capital balance changes for finance activities in 2021 (YTD-2020: $819 cash inflow).

Credit Facility

In December 2021, the Corporation amended its revolving credit facility from a borrowing limit of $45,000 to $37,000 and site-specific assets held as mortgage security for separate mortgage financing have been carved out. In addition, up to $5,000 of the revolving loan shall be available by way of account overdraft outside of covenant requirements described below.

The Corporation's revolving credit facility has a maturity date of August 31, 2023, is renewable with the lender's consent, and is secured by a general security agreement over the Corporation's assets.

Interest on the facility, which is independent of standby fees, is charged monthly at prime plus an applicable margin which fluctuates based on the Funded Debt to Covenant EBITDA ratio (defined below). The applicable margin can range between 0.75% – 1.75% depending on the level of principal outstanding; the higher the ratio the higher the margin. Standby fees also fluctuate based on the Funded Debt to Covenant EBITDA ratio and range between 0.40% and 0.60% of the undrawn balance; the higher the ratio the higher the standby fee percentage.

The facility is subject to two financial covenants which are reported to the lender on a quarterly basis. The first covenant requires the Funded Debt to Covenant EBITDA ratio to be less than 3.0 to 1 and the second covenant requires Covenant EBITDA to Interest Expense ratio to be a minimum of 3.0 to 1. Both are calculated on the last day of each fiscal quarter on a rolling four quarter basis. As at December 31, 2021, the Corporation was in compliance with these two financial covenants.

The financial covenant calculations at December 31, 2021 are:

Covenant	Covenant	**As at December 31, 2021**
Funded debt to Covenant EBITDA [(1)]	< 3.0x	-
Covenant EBITDA to Interest expense [(1)]	>3.0x	11.1

(1) As at December 31, 2021 the Corporation had access to $10,500 of the revolving facility.

Funded Debt to Covenant EBITDA is defined as the ratio of consolidated Funded Debt to the aggregate Covenant EBITDA for the trailing four quarters. Funded Debt is the amount of debt provided and outstanding at the date of the covenant calculation. Interest Expense excludes any impact related to lease liabilities. Covenant EBITDA for the purposes of calculating the covenants is defined as a trailing 12-month net income (loss) plus interest expense, current tax expense, deferred income tax expense (recovery), depreciation and amortization, share-based compensation expense, and non-cash inventory write-downs, less gains from foreign exchange and sale or purchase of assets and lease payments.

Mortgage Financing

	As at December 31, 2021
Current	$296
Non-current	7,779
Total	**$8,075**

In December 2021, the Corporation entered into a mortgage arrangement with the Business Development Bank of Canada (BDC) for $8,100, secured by lands and buildings owned and occupied by High Arctic within Alberta. The mortgage financing provides the Corporation with long term liquidity, and adds to existing cash balances. The mortgage has an initial term of 5 years with a fixed interest rate of 4.30% and an amortization period of 25 years with payments occurring monthly. The mortgage liability and associated financing costs are carved out of all revolving credit facility financial covenant calculations.

The Corporation capitalized $25 in financing fees incurred to set up the loan and applied this to the long-term debt liability. Financing fees will be amortized over the expected life of the mortgage financing.

Commitments and Contingencies

As part of the Corporation's contractual rig management and operations, the Corporation has been supplied an inventory of spare parts with a total value of $7,244 at December 31, 2021 (December 31, 2020: $7,275) by a customer for the Corporation's operations in PNG. The inventory is owned by this party and has not been recorded on the books of High Arctic. At the end of the contract, the Corporation must make a payment to the customer equivalent to any inventory shortfall and return the balance of inventory on hand.

Outstanding Share Data

The Corporation's authorized share capital consists of an unlimited number of common shares and an unlimited number of preferred shares. Directors, officers and certain employees have been granted stock options and incentive shares and units under the Corporation's approved equity compensation plans.

	Year ended December 31, 2021		Year ended December 31, 2020	
Common shares issued and outstanding:	**Shares**	**Amount**	Shares	Amount
Balance, beginning of year	48,759,660	$169,220	49,623,432	$173,071
Issuance of performance share units	52,289	751	273,328	101
Normal course issuer bid	(78,804)	(274)	(1,137,100)	(3,952)
Balance, end of year	**48,733,145**	**$169,697**	**48,759,660**	**$169,220**

The common shares do not have a par value and all issued shares are fully paid.

On December 13, 2021, the Corporation received approval from the Toronto Stock Exchange to acquire for cancellation up to 2,420,531 common shares, representing approximately 10% of the Corporation's public float at the date of approval, under a Normal Course Issuer Bid ("NCIB"). The NCIB is valid for one year, commencing on December 15, 2021 and terminating on December 14, 2022. Pursuant to the NCIB no shares were purchase and cancelled in 2021 under this NCIB.

The Corporation's previous NCIB commenced on December 11, 2020 and terminated on December 10, 2021. Pursuant to this previous NCIB, in total 78,804 common shares have been purchased and cancelled in 2021.

The Corporation's NCIB active during 2020 commenced on December 2, 2019 and terminated on December 1, 2020. Pursuant to this NCIB, in total 1,137,100 common shares were purchased and cancelled in 2020.

At December 31, 2021, 464,500 stock options were outstanding at an average exercise price of $2.02 per share, as well as 740,558 units under the Corporation's Performance Share Unit Plan and 836,743 units under the Deferred Share Unit plan. To the date of this MD&A, no further stock options or units have been issued, except for Deferred Share Units granted in January 2022 settlement of Q4-2021 quarterly director fees pursuant to individual director election instead of cash.

No further common shares have been issued from December 31, 2021 to the date of this MD&A.

Quarterly Financial Review

The following is a summary of selected consolidated financial information of the Corporation for the last eight completed quarters:

	2021				2020			
($ thousands, except per share)	**Q4**	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Revenue	23,644	18,654	16,377	17,767	16,584	18,529	16,109	39,612
Adjusted EBITDA (1)(2)	1,836	1,412	796	874	1,154	3,476	1,147	2,752
Net loss	(4,608)	(4,784)	(4,018)	(5,198)	(11,468)	(6,079)	(6,145)	(2,165)
Per share – basic and diluted	*(0.10)*	*(0.10)*	*(0.08)*	*(0.11)*	*(0.23)*	*(0.12)*	*(0.13)*	*(0.04)*
Cash provided by (used in) operating activities	*(3,472)*	*737*	*2,023*	(1,085)	2,389	1,192	7,678	8,893
Funds provided by operations (1)	1,390	1,077	640	590	859	2,357	871	2,233

(1) See "Non-IFRS Measures" on page 22
(2) Adjusted net loss includes the impact of wages subsidies (CEWS) and rent subsidies recorded during 2020 and 2021

Revenue rose in Q4-2021 relative to Q3-2021 due to rig movement services of personnel and equipment in PNG. Drilling in PNG was paused since Q2-2020 due to the impact of Covid-19 in the region. Revenues from Canada rose slightly due to higher per hour pricing. Due to the global economic downturn in the prior year, management undertook a restructuring process to control costs to address the reduction to revenues and operating cash flows. During the early period of the pandemic the Corporation's activity and pricing had been significantly impacted by the global supply and demand imbalance of oil and natural gas. During 2021, as pandemic restrictions eased in many locations, oil and gas prices rebounded, and High Arctic's customer pricing has begun to recover. High Arctic's outlook is encouraged by the recovery, and management anticipates improved activity in PNG looking forward to 2022. Management also expects a recovery in Canada, hindered by industrywide labour shortages.

Seasonal conditions impact the Corporation's Canadian operations whereby frozen ground during the winter months tends to provide an optimal environment for drilling and many well servicing activities and consequently first quarter activity is typically the strongest. As warm weather returns in the spring, the winter's frost comes out of the ground rendering many secondary roads incapable of supporting the weight of heavy equipment until they have thoroughly dried out. This period is generally referred to as spring break-up.

Road bans, which are generally imposed in the spring, restrict the transportation of heavy equipment onto customer locations thus reducing demand for services in Canadian operations. Therefore, the second quarter is generally the weakest quarter of the year for the Corporation's operations in Canada.

Industry Indicators and Market Trends in PNG

The following table provides information for the last eight quarters to assist with the understanding of the PNG oilfield services industry and the effect that commodity prices have on industry activity levels. In addition, the Corporation's international financial results are impacted by fluctuations in the USD to CAD exchange rate.

	2021				2020			
($)	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and natural gas prices								
(Averages for the quarterly periods):								
Brent Crude Oil (USD $/bbl) (1)	80	73	69	61	45	43	33	51
Japan LNG (USD $/mmbtu) (2)	13.47	11.68	8.75	9.60	6.65	6.82	10.07	9.91
USD/CAD average exchange rate (3)	1.26	1.26	1.23	1.27	1.30	1.33	1.38	1.34

(1) Source: Sproule
(2) Source: YCharts
(3) Bank of Canada

The Corporation's PNG activity has historically been based on longer term, USD denominated contracts and therefore is less affected over the short-term volatility in oil and gas prices. The USD/CAD exchange rate remained essentially flat in Q4-2021 which has had a marginally negatively impact on the Corporation's financial results.

Activity levels for the Corporation's major customers in PNG are less dependent on short term fluctuations in oil and gas prices and instead are based on medium and long-term decisions, particularly with their significant interest in large scale LNG projects both on-stream and in-development. Pricing for oil and natural gas production in PNG is generally tied to world prices such as Brent Crude and Japan LNG.

In Q4-2021, the Brent Crude Oil price average increased to USD $80/bbl and continued to climb into Q1-2022. Japan LNG prices continued to climb in Q4-2021 with average prices breaching USD $15/mmbtu and spot prices reaching over USD $35/mmbtu in the quarter.

Industry Indicators and Market Trends in Canada

The following table provides information for the last eight quarters to assist with the understanding of the Canadian oilfield services industry and the effect that commodity prices have on industry activity levels.

	2021				2020			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Oil and natural gas prices								
($ Avg for the period):								
West Texas Intermediate ("WTI") (USD $/bbl)(1)	77	71	66	58	39	41	28	46
West Canada Select ("WCS") (CAD $/bbl)(1)	79	72	67	57	36	42	22	34
Canadian Light Sweet Oil ("CLS") (CAD $/bbl) (1)	92	84	76	69	45	49	31	52
AECO (CAD $/mmbtu)(1)	4.74	3.75	3.07	3.13	2.65	2.27	2.00	2.03
Other industry indicators:								
Total wells drilled in W. Canada(2) (3)	XX	1,417	654	1,178	719	361	746	1,179
Avg service rig utilization rates (2)	42%	38%	29%	39%	31%	22%	10%	38%
Avg drilling rig utilization rates (2)	41%	39%	24%	27%	16%	9%	4%	35%

(1) Source: Sproule
(2) Source: wells drilled PSAC; Utilization rates CAODC
(3) PSAC stopped providing market information for total well drilled in Q4 2021.

In Q4-2021, WTI, WCS and CLS average prices continued to increase, with average oil prices increasing every quarter in 2021. This contrasts with historically low oil prices in Q2-2020 due to rapidly disjointed supply and demand imbalances for oil from Covid-19. In July 2021, OPEC+, including Russia, agreed to modestly increase crude oil production by 400,000 barrels per day each month until previous production cuts in 2020 are fully reversed, which would occur by the third quarter of 2022. Assuming these OPEC+ planned increases remain in place coupled with expected lowering of Covid-19 restrictions, tightening supply and demand for oil and gas is expected to continue.

In Canada since 2015 the lack of take away pipeline capacity prior to the Covid-19 pandemic, and lower exploration and production company investment confidence, continues to collectively curtail activity relative to historical industry activity levels. Q4-2021 average industry rig utilization rates have improved since Q2-2020 and returned to pre-pandemic levels. With the policies of governments in the US and Canada combined with continued pipeline constraints in Canada the future of the oil and gas industry continues to face headwinds particularly as it relates to Canada as evidenced by the cancelation of the permit allowing the Keystone XL pipeline to cross the border from Canada into the US by the Biden administration in January 2021, and the attempts to shut down Enbridge Line 5 in Michigan, US. In November 2021, countries worldwide met in Glasgow as part of the COP 26 global climate summit to discuss the impacts of climate change with the goal to limit temperature rise to 1.5 degrees Celsius. A declaration was signed at the summit by 30 countries and development banks for calls to halt public subsidies for unabated fossil fuel energy. Despite these headwinds, demand for oil and gas remains, resulting in higher prices and a positive outlook in the short to medium term for the industry.

That said, certain large infrastructure pipeline projects are in progress and positive for the oil and gas industry in Canada. The Enbridge Line 3 Replacement Project to the U.S. entered service October 1, 2021. The LNG Canada pipeline project in the province of British Columbia is under construction and upon completion will provide long awaited tidewater access to Asian markets. The Trans Mountain Expansion Project is under construction in Alberta and British Columbia and like LNG Canada will provide long awaited access to Asian markets for oil production.

Financial Risk Management

Financial and other risks

The Corporation is exposed to financial risks arising from its financial assets and liabilities. This includes the risk associated with the developments relating to Covid-19. Pandemic and/or endemic risk is the risk that operations and/or administration are forced to run at less than full capacity due to an absence or reduction of members of the workforce, either through forced closures by government both within countries and across national borders, by internally imposed rotational schedules and/or quarantine or illness of the workforce. Further, cyber-security risks increase as employees work from home. Such restrictions could significantly impact the ability for the Corporation to operate, and therefore impact financial results.

Market and other related risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market rates of:

a) Interest rate risk

Interest rate risk is the risk that the value of a financial instrument will fluctuate as a result of changes in market interest rates. The Corporation is exposed to interest rate risk as long-term debt includes a floating rate credit facility and fluctuates in response to changes in the prime interest rates. Long-term debt also includes mortgage financing with a fixed rate term subject to renewal interest rate changes. The Corporation had no risk management contracts that would be affected by interest rates in place on December 31, 2021.

b) Commodity price risk

Commodity price risk is the risk that the Corporation's future cash flows will fluctuate due to changes in demand for High Arctic's services, where almost all the Corporation's customers are oil and gas producers. High Arctic's customer's activity and strategic decisions are impacted by the fluctuations of oil and gas pricing.

These prices are sensitive to not only the relationship between the Canadian and US dollar, but more importantly local, regional and world economic events. This includes implications from declining oil demand and over supply, climate change driven transitions to lower emission energy sources, geopolitical events impacting security of supply, the current Covid-19 pandemic which creates a scenario of both downward and fluctuating price pressure as well as the implications of changes to government and government policy including the policy directions that will be taken by the current US President and ongoing negotiations in PNG to build LNG expansion with industry.

While the Corporation recognizes it will be impacted by these risks, the Corporation also strongly believes that there is a significant role for the energy services industry in the current, transitionary, and future phases of energy industry changes.

The Corporation had no risk management contracts that would be affected by commodity prices in place at December 31, 2021.

Foreign currency risk and PNG foreign currency restrictions

Foreign currency risk is the risk that a variation in the exchange rate between Canadian and foreign currencies will affect the Corporation's results. The Corporation has exposure to US dollar ("**USD**") fluctuations and other currencies such as the PNG Kina ("**PGK**") through its international operations. As a result, the Corporation is exposed to foreign exchange gains and losses through the settlement of foreign currency denominated transactions, which is recorded in net earnings (loss), as well as the conversion of the Corporation's subsidiaries with functional currencies other than CAD, into CAD for financial reporting presentation purposes, which is recorded as part of other comprehensive income (loss) within shareholders' equity.

The majority of the Corporation's international revenue and expenses are effectively transacted in USD and the Corporation does not actively engage in foreign currency hedging. For the three months and year ended December 31, 2021, a $0.10 cent change in the exchange rate of the Canadian dollar relative to the USD would have resulted in a change to the net loss amounting to $43 and $560, respectively (December 31, 2020: $299 and $630, respectively).

The average CAD to USD exchange rate for the Quarter was 1.26 compared to 1.30 during Q4-2020. As at December 30, 2021, the CAD to USD exchange rate was 1.26 versus 1.27 as at December 31, 2020.

The impact of exchange rates for the Quarter resulted collectively in a $244 foreign exchange loss (Q4-2020 - $238) being recorded in the statements of earnings (loss) on various foreign currency denominated transactions and on the translation of foreign denominated monetary assets and liabilities. Similarly, during YTD-2021, $197 in foreign exchange losses were recorded (YTD-2020 - $159).

The Corporation's ability to repatriate funds from PNG is controlled by the PNG government through their central bank. There are currently several monetary and currency exchange control measures in PNG that can impact the ability to repatriate funds, as well as establish requirements to transact in the PGK.

As at December 31, 2021, USD $384 (December 31, 2020 – USD $894) was on deposit with a large international bank in PNG. The Bank of PNG ("**BPNG**") has provided approval for High Arctic to maintain a USD bank account in accordance with the BPNG currency regulations.

The Corporation has historically received approval from the BPNG for most of its drilling services contracts with its key customers in PNG to be denominated and settled in USD. However, if such approval is withdrawn in the future, or new contracts do not receive BPNG approval, funds may be converted into PGK and the Corporation would be required to access the foreign currency market in PNG to meet its foreign currency obligations, thus exposing the Corporation to greater foreign exchange exposure for the PGK.

The BPNG currency regulations also limit the amount of foreign currency that companies can maintain to meet their forecasted three-month cash flow requirements, with excess funds required to be held in PGK. While no significant issues have been experienced to date, there is no guarantee such restrictions will not exist or will not impact the Corporation's ability to transact or repatriate funds.

The Corporation's financial instruments have the following foreign exchange exposure at December 31, 2021: ***Balances shown in thousands of foreign currencies***	USD (1)	PGK (2)	Australian Dollars ("**AUD**") (3)
Cash	2,315	1,280	153
Accounts receivable	1,494	21,190	3
Accounts payable and accrued liabilities	(1,545)	(14,202)	(1,039)
Total – Foreign Currency Balance	2,264	8,268	(883)

(1) As at December 31, 2021, one USD was equivalent to 1.2678CAD.
(2) As at December 31, 2021, one PGK was equivalent to 0.3586 CAD.
(3) As at December 31, 2021, one AUD was equivalent to 0.9205 CAD.

Credit risk, customers and economic dependence

Credit risk is the risk of a financial loss occurring as a result of a default by a counter party on its obligation to the Corporation. The Corporation's financial instruments that are exposed to credit risk consist primarily of accounts receivable and cash balances held in banks. The Corporation mitigates credit risk by regularly monitoring its accounts receivable position and depositing cash in properly capitalized banks. The Corporation also institutes credit reviews prior to commencement of contractual arrangements.

The Corporation's accounts receivable is predominantly with customers who explore for and develop petroleum reserves and are subject to industry credit risk consistent with the industry. The Corporation assesses the credit worthiness of its customers on an ongoing basis and monitors the amount and age of balances outstanding.

In providing for expected credit losses ("ECL"), the Corporation uses the historical default rates within the industry between investment grade and non-investment grade customers as well as forward looking information to determine the appropriate loss allowance provision.

The net carrying amount of accounts receivable represents the estimated maximum credit exposure on the accounts receivable balance. The Corporation has a wide range of customers comprised of small independent, intermediate, and large multinational oil and gas producers. Notwithstanding its large customer base, the Corporation provides services to two large multinational/regional customers who individually accounted for greater than 10% of its consolidated revenues during the year ended December 31, 2021 with sales of $24,611, (December 31, 2020 – two customers totaling $40,553).

As at December 31, 2021, these two customers represented a total of $2,737 or 13% of outstanding accounts receivable (December 31, 2020 - two customers represented a total of $2,158 or 17% of outstanding accounts receivable).

For the three-months period ended December 31, 2021, the Corporation provided services to two large multinational/ regional customer who individually accounted for greater than 10% of its consolidated revenues in the period with total sales of $8,676 (2020: two customers totaling $6,470). The aging of the Corporation's accounts receivable is as follows:

($ thousands)		**As at December 31, 2021**		As at December 31, 2020
Less than 31 days	**$**		$	8,045
31 to 60 days		**6,415**		3,131
61 to 90 days		**2,522**		1,208
Greater than 90 days		**675**		1,272
Expected credit losses		**(701)**		(770)
Total	**$**	**20,714**	$	12,886

Liquidity Risk

Liquidity risk is the risk that the Corporation will not be able to meet its financial obligations as they fall due. The Corporation's approach to managing liquidity is to ensure, as far as possible, that it will always have sufficient liquidity to meet its liabilities when due.

Liquidity risk is currently being impacted by uncertainty within capital markets given the Covid-19 pandemic on global economies, economic recession possibilities, geopolitical events, contraction of available capital and reliance on continued fiscal stimulus by governments around the world.

The Corporation's processes for managing liquidity risk include preparing and monitoring capital and operating budgets, working capital management, coordinating and authorizing project expenditures, authorization of contractual agreements, managing compliance to debt finance agreements, and remaining attentive to the relationship with High Arctic's lender. The Corporation seeks to manage its financing based on the results of these processes.

Further, the Corporation currently has up to $37,000 in remaining availability under its credit facility, subject to the bank stipulated margin requirement, to enable execution of strategic direction, see "Credit Facility" section of this MD&A for calculation of the credit facility ratio requirements.

Critical Accounting Judgements and Estimates

Information on the Corporation's critical accounting judgements and estimates can be found in Note 2 Basis of Presentation - Critical Accounting Judgements and Estimates in the annual audited consolidated financial statements for the year ended December 31, 2021.

Impacts of the Covid-19 pandemic described in "Global Developments and High Arctic's Strategic Objectives" section of this MD&A, as well as emissions, carbon and other regulations impacting climate and climate related matters are constantly evolving. With respect to Environmental Social Governance (ESG) and climate reporting, the International Sustainability Standards Board has issued a IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed national instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed, has not yet been quantified.

There remains significant uncertainty around the expected policies to be enforced by large governmental bodies in regard to oil and gas production. While the recovery trend is encouraging and a continuing focus on supply balance for oil and gas producers is warranted, there are significant headwinds surrounding policies to meet climate change emission targets.

These political and pandemic developments impact High Arctic as the Corporation pursues its strategy and allocates resources to support its principal markets in Canada driven by customers' oil and natural gas production and in PNG where its customers are restarting drilling operations, and new LNG supply is being contemplated. In addition, the global focus to address climate change has created a rotation of investment capital away from the oil and gas industry in certain markets with the potential to increase High Arctic's cost of capital and reduce access to growth funding. The direct and indirect costs of climate change relating to High Arctic and its customers is uncertain. Climate change may have an adverse impact on High Arctic and its customers, and creates uncertainty surrounding the estimated useful life and impairment of property and equipment.

At December 31, 2021, High Arctic determined that no indicators of impairment existed within the Corporation's CGUs.

Disclosure Controls and Procedures ("DC&P") and Internal Controls over Financial Reporting ("ICFR")

As at December 31, 2021, an evaluation of the effectiveness of High Arctic's DC&P as defined under the rules adopted by the Canadian securities regulatory authorities was carried out under the supervision and with the participation of management, including the Chief Executive Officer ("**CEO**") and the Chief Financial Officer ("**CFO**"). Based on this evaluation, the CEO and CFO concluded that as at December 31, 2021, the design and operation of the Corporation's DC&P was effective.

ICFR is a process designed by or under the supervision of management and effected by the Board, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and preparation of consolidated financial statements for external purposes in accordance with IFRS. Management is responsible for establishing and maintaining adequate ICFR, which no matter how well designed, has inherent limitations and can provide only reasonably assurance with respect to the preparation and fair presentation of published financial statements. Under the supervision and with the participation of the CEO and CFO, management conducted an evaluation of the effectiveness of its ICFR as at December 31, 2021.

Based on this evaluation, the CEO and CFO concluded that as at December 31, 2021, High Arctic's ICFR was effective. The Internal Control – Integrated Framework (2013) as issued by the Committee of Sponsoring Organizations of the Treadway Commission was utilized for this purpose. As at December 31, 2021 there was no change in our ICFR that materially affected or is reasonably likely to materially affect our ICFR.

Business Risks and Uncertainties

In addition to the financial risks discussed above under "Financial Risk Management", below under "Forward Looking Statements" and elsewhere in this MD&A, High Arctic is exposed to a number of business risks and uncertainties that could have a material impact on the Corporation. Readers of the Corporation's MD&A should carefully consider the risks described under the heading "Risk Factors" in the Corporation's December 31, 2021 AIF, which are specifically incorporated by reference herein. The AIF is available on SEDAR at www.sedar.com, copies of which can be obtained on request, from the Corporation.

Non-IFRS Measures

This MD&A contains references to certain financial measures that do not have a standardized meaning prescribed by IFRS and may not be comparable to the same or similar measures used by other companies. High Arctic uses these financial measures to assess performance and believes these measures provide useful supplemental information to shareholders and investors.

These financial measures are computed on a consistent basis for each reporting period and include the following:

Earnings before interest, taxes, depreciation and amortization ("EBITDA")

EBITDA is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. EBITDA is defined as net loss adjusted for income taxes, interest and finance expense, and depreciation. Management believes that, in addition to net loss reported in the consolidated statements of loss and comprehensive loss, EBITDA is a useful supplemental measure of the Corporation's performance prior to consideration of how operations are financed or how results are taxed or how depreciation and amortization affects results. EBITDA is not intended to represent or be construed as an alternative to net earnings (loss) calculated in accordance with IFRS. Note that EBITDA is inclusive of government wage subsidies and rental subsidies recorded. Refer to table in Adjusted EBITDA below that provides a reconciliation of net earnings (loss), as disclosed in the consolidated statements of loss and comprehensive loss, to EBITDA.

Covenant EBITDA for purposes of long-term debt covenants

Covenant EBITDA, as defined in High Arctic's revolving loan facility agreement, is used in determining the Corporation's compliance with its covenants. Covenant EBITDA is defined as the trailing 12-month net income (loss) plus interest expense, current tax expense, depreciation, amortization, deferred income tax expense (recovery), share based compensation expense, foreign exchange loss, and non-cash inventory write-downs, less lease liability payments, and gains from foreign exchange and sale or purchase of assets. Interest expense excludes any impact of IFRS 16. Note that Covenant EBITDA for purposes of long-term debt covenants is inclusive of CEWS and rental subsidies recorded.

Adjusted EBITDA

Adjusted EBITDA is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Adjusted EBITDA is defined based on EBITDA (as defined above) prior to the effect of share-based compensation, gains or losses on sales or purchases of assets or investments, business acquisition costs, impairment charges, other costs related to consolidating facilities, excess of insurance proceeds over costs and foreign exchange gains or losses. Note that adjusted EBITDA is inclusive of CEWS, and rental subsidies recorded.

Management believes the addback for these items provides a more comparable measure of the Corporation's operational financial performance between periods. Adjusted EBITDA as presented is not intended to represent or be construed as an alternative to net earnings (loss) in accordance with IFRS.

The following table provides a quantitative reconciliation of consolidated net earnings (loss), as disclosed in the consolidated statements of loss and comprehensive loss, to EBITDA and Adjusted EBITDA for the three months and years ended December 31, 2021 and 2020:

($ thousands)	Three months ended December 31 **2021**	2020	Year ended December 31 **2021**	2020
Net loss	**$(4,608)**	**$(11,468)**	**$(18,607)**	**$(25,985)**
Add (deduct):				
Interest and finance expense	193	300	706	1,110
Income taxes	(415)	(649)	(1,309)	(205)
Depreciation	6,005	12,461	23,639	35,484
EBITDA	**$1,175**	**$644**	**$4,429**	**$10,404**
Adjustments to EBITDA:				
Share-based compensation	413	306	709	555
Gain on sale of property and equipment	4	(34)	(417)	(2,589)
Foreign exchange gain	244	238	197	159
Adjusted EBITDA	**$1,836**	**$1,154**	**$4,918**	**$8,529**

Oilfield services operating margin

Oilfield services operating margin is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Oilfield services operating margin is used by management to analyze overall operating performance. Management believes this non-GAAP financial measure provides useful information to investors and others in understating the Corporation's operating performance. Oilfield services operating margin is not intended to represent revenue, net earnings (loss), or other measures of financial performance calculated in accordance with IFRS. Oilfield services operating margin is calculated as revenue less oilfield services expense. Oilfield services operating margin as presented is not intended to represent or be construed as an alternative to revenue or net earnings (loss) in accordance with IFRS. The table disclosed in oilfield services operating margin % below provides a quantitative reconciliation of revenue, as disclosed in the consolidated statements of loss and comprehensive loss, to oilfield services operating margin and oilfield operating margin % for the three months and years ended December 31, 2021 and 2020:

Oilfield services operating margin %

Oilfield services operating margin % is a non-GAAP measure in line with oilfield services operating margin discussed above. Oilfield services operating margin % is used by management to analyze overall operating performance. Oilfield services operating margin % is calculated as oilfield services operating margin divided by revenue.

The following table provides a quantitative calculation of oilfield services operating margin and %:

($ thousands, unless otherwise noted)	Three months ended December 31 **2021**	2020	Year ended December 31 **2021**	2020
Revenue	**$23,644**	$16,584	**$76,442**	$90,834
Less:				
Oilfield services expense	**18,944**	12,774	**61,226**	69,523
Oilfield services operating margin	**$4,700**	$3,810	**$15,216**	$21,311
Oilfield services operating margin %	**19.9%**	23.0%	**19.9%**	23.5%

Operating loss

Operating loss is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Operating loss is used by management to analyze overall operating performance. Management believes this non-GAAP financial measure provides useful information to investors and others in understating the Corporation's operating performance. Operating loss is not intended to represent revenue, net earnings (loss), or other measures of financial performance calculated in accordance with IFRS. Operating loss is calculated as revenue less oilfield services expense, general and administrative expense, depreciation, and share-based compensation. Operating loss as presented is not intended to represent or be construed as an alternative to revenue or net earnings (loss) or other measures of financial performance calculated in accordance with IFRS. The table disclosed below provides a quantitative reconciliation of revenue, as disclosed in the consolidated statements of loss and comprehensive loss, to operating loss for the three months and years ended December 31, 2021 and 2020:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2021**	2020	**2021**	2020
Revenue	**$23,644**	**$16,584**	**$76,442**	**$90,834**
Less:				
Oilfield services expense	18,944	12,774	61,226	69,523
General and administrative expense	2,864	2,656	10,298	12,782
Depreciation	6,005	12,461	23,639	35,484
Share-based compensation	413	306	709	555
Operating loss	**$(4,582)**	**$(11,613)**	**$(19,430)**	**$(27,510)**

Percentage of revenue

Certain figures are stated as a percentage of revenue and are used by management to analyze individual components of expenses to evaluate the Corporation's performance from prior periods and to compare its performance to other companies.

Funds provided from operations

Funds provided from operations is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Funds provided from operations is defined as net cash (used in) provided from operating activities adjusted for changes in non-cash working capital. Management believes that, in addition to net cash generated from operating activities as reported in the consolidated statements of cash flows, cash provided by operating activities before changes in non-cash working capital adjustments ("**funds provided from operations**") is a useful supplemental measure as it provides an indication of the funds generated by High Arctic's principal business activities prior to consideration of changes in items of working capital.

This measure is not intended to represent or be construed as an alternative to net cash generated from operating activities as calculated in accordance with IFRS.

The following tables provide a quantitative reconciliation of net cash (used in) generated from operating activities, as disclosed in the consolidated statements of cash flows, to funds provided from operations for the three months and years ended December 31, 2021 and 2020:

	Three months ended December 31		Year ended December 31	
($ thousands)	**2021**	2020	**2021**	2020
Net cash generated from operating activities	**$(3,472)**	$2,389	**$(1,797)**	$20,152
Less:				
Changes in non-cash working capital balances - operating	**(4,862)**	1,530	**(5,494)**	13,832
Funds provided from operations	**$1,390**	$859	**$3,697**	$6,320

Working capital

Working capital is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Working capital is used by management as another measure to analyze the operating liquidity available to the Corporation. It is defined as current assets less current liabilities. Working capital ratio is defined as current assets dividend by current liabilities. This measure is not intended to represent or be construed as an alternative to current assets as calculated in accordance with IFRS.

The following tables provide a quantitative reconciliation of current assets, as disclosed in the consolidated statements of financial position, to working capital as at December 31, 2021 and 2020:

	As at	
	December 31	December 31
($ thousands)	**2021**	2020
Current assets	**$45,132**	$55,589
Less:		
Current liabilities	**(15,408)**	(11,012)
Working capital	**$29,724**	$44,577
Working capital ratio	**3.1:1**	5.0:1

Net cash

Net cash is a non-GAAP financial measure that does not have a standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Net cash is used by management to analyze the amount by which cash and cash equivalents (if applicable) exceed the total amount of long-term debt and bank indebtedness, or vice versa.

The amount, if any, is defined as cash and cash equivalents less total long-term debt.

The following tables provide a quantitative reconciliation of cash, as disclosed in the consolidated statements of financial position, to net cash as at December 31, 2021 and 2020:

	As at	
	December 31	December 31
($ thousands)	**2021**	2020
Cash	**$12,037**	$32,598
Less:		
Long-term debt [1]	**(8,075)**	(10,000)
Net cash	**$3,962**	$22,598

[1] Long-term debt includes current portion of $296 and non-current portion of $7,779.

Forward-Looking Statements

This MD&A contains forward-looking statements. When used in this document, the words “may”, “would”, “could”, “will”, “intend”, “plan”, “anticipate”, “believe”, “seek”, “propose”, “estimate”, “expect”, and similar expressions are intended to identify forward-looking statements. Such statements reflect the Corporation’s current views with respect to future events and are subject to certain risks, uncertainties and assumptions. Many factors could cause the Corporation’s actual results, performance or achievements to vary from those described in this MD&A.

Should one or more of these risks or uncertainties materialize, or should assumptions underlying forward-looking statements prove incorrect, actual results may vary materially from those described in this MD&A as intended, planned, anticipated, believed, estimated or expected. Specific forward-looking statements in this MD&A include, among others, statements pertaining to the following: general economic and business conditions which will include, among other things, continued improvement in energy services outlook, impact of high commodity prices on demand for and market prices for the Corporation’s services; continued impact of the Covid-19; ability to prioritize a strong balance sheet and liquidity position; activity increases in the medium and long-term in PNG; opportunities to invest and enhance shareholder value; improving and stabilizing economic environment, climate and weather predictions and their effect on energy demand; improving customer pricing trends; the Corporation’s ability to maintain a USD bank account and conduct its business in USD in PNG; market fluctuations in interest rates, commodity prices, and foreign currency exchange rates; restrictions to repatriate funds held in PGK; customer activity to boost production; expectations regarding the Corporation’s ability to raise capital and manage its debt obligations; estimated capital expenditure programs; projections of market prices and costs; expectations for improving customer demand in the near-term, factors upon which the Corporation will decide whether or not to undertake a specific course of operational action or expansion; the Corporation’s ongoing relationship with major customers; treatment under governmental regulatory regimes and political uncertainty and civil unrest; a final Papua LNG investment decision; expectations for the speed and efficacy of distributions relating to Covid-19 vaccines; developments in Ukraine; and estimated credit risks and tax losses.

With respect to forward-looking statements contained in this MD&A, the Corporation has made assumptions regarding, among other things, its ability to: obtain equity and debt financing on satisfactory terms; market successfully to current and new customers; the general continuance of current or, where applicable, assumed industry conditions; activity and pricing; assumptions regarding commodity prices, in particular oil and gas; the Corporation’s primary objectives, and the methods of achieving those objectives; obtain equipment from suppliers; construct property and equipment according to anticipated schedules and budgets; remain competitive in all of its operations; and attract and retain skilled employees.

The Corporation’s actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth above and elsewhere in this MD&A, along with the risk factors set out in the most recent Annual Information Form filed on SEDAR at www.sedar.com.

The forward-looking statements contained in this MD&A are expressly qualified in their entirety by this cautionary statement. These statements are given only as of the date of this MD&A. The Corporation does not assume any obligation to update these forward-looking statements to reflect new information, subsequent events or otherwise, except as required by law.

Abbreviations

The following is a summary of abbreviations used in this Management Discussion and Analysis:

AIF	- Annual information form
AUD	- Australian dollars
bbl	- Barrel
CAD	- Canadian dollars
CAPP	- Canadian Association of Petroleum Producers
CAOEC	- Canadian Association of Oilwell Energy Contractors
CEWS	- Canada Emergency Wage Subsidy
CLS	- Canadian Light Sweet
DCP	- Disclosure controls and procedures
E&P	- Exploration and production
EBITDA	- Earnings before interest, tax, depreciation and amortization
ESG	- Environmental, Social and Corporate Governance
FID	- Final Investment Decision
ICFR	- Internal controls over financial reporting
IFRS	- International Financial Reporting Standards
IRC	- Internal Revenue Commission of PNG
LNG	- Liquified natural gas
MD&A	- Management discussion and analysis
mmbtu	- Million British thermal units
NCIB	- Normal course issuer bid
OPEC	- Organization of petroleum exporting countries
OPEC Plus	- OPEC and ten of the world’s major non-OPEC oil-exporting nations
PGK	- Papua New Guinea Kina
PNG	- Papua New Guinea
US	- United States of America
USD	- United States dollars
WCS	- West Canada Select
WCSB	- Western Canadian sedimentary basin
WTI	- West Texas Intermediate