President’s Message

Although Bill 21 was enacted during the quarter, the Quebec election is now over. There could be an opportunity for a less political approach to energy security by the Quebec Government. The growing demand for clean energy in North America, including Quebec, and, more urgently in Europe only highlights the value of our project. Concurrently, to protect our legal rights we are advancing the claim for breach of contract and unjust enrichment. A Superior Court judge was appointed last month to separately manage all the claims related to Bill 21. A hearing date for our claim should be set shortly. We remain open to a political and business solution.

Effective the end of the quarter, we converted our royalty interest in the four original farm-in wells at Kakwa North into a 50% working interest. This should add approximately 500 boe/d over the remainder of this year. Based on our discussions with the operator, drilling on a new three-well pad is planned for late next year.

Highlights

- Questerre converts Kakwa North royalty interest to working interest adding 500 boe/d for remainder of the year
- Government of Quebec enacts Bill 21 and revokes exploration licenses
- Average daily production of 1,629 boe/d and adjusted funds flow from operations of $5.2 million

As the European Union is preparing for widespread blackouts in its member states this winter, the current energy crisis is one of several places where our Quebec Utica project could help make a difference.

During the German Chancellor’s visit to Canada to discuss energy supplies this August, the Prime Minister commented about the difficulties of LNG exports from Canada’s East Coast. In our press release issued during the visit, we reiterated the proximity of our discovery to a LNG export facility with a successful environmental review. It would have shorter delivery times to the proposed offshore terminals near Hamburg, Germany than any of the LNG export facilities in the United States. To mitigate the financial and logistical challenges of greenfield onshore terminals, we have been assessing floating LNG vessels.

In the long term, demand and the infrastructure for hydrogen as a clean fuel is likely to grow. Our Clean Gas can be used to produce zero-emissions or blue hydrogen at large scale. It will compare favorably on an environmental basis with green hydrogen, when considering ecological indicators as well as emissions.

In the medium term, there are growing concerns about future electricity shortages in Canada. A recent report by the Polytechnique Montreal’s Institut de l’energie Trottier notes that many provinces will be incapable of meeting their electricity needs. The Quebec premier recently acknowledged that the province could indeed be short on electricity. With a secure supply of local natural gas, our Clean Gas could help Quebec free up critical electricity.

Although the Government of Quebec perhaps did not prioritize these strategic benefits, they nonetheless recognized the value. In their 2009-2010 budget released shortly after we made the discovery, the Government estimated the production value at $45 billion using $5/MMbtu gas prices on an undiscounted basis. Of interest, the budget is still available online and the reference is found on pages F74 and F75.

Our legal claim is that by enacting Bill 21 and revoking our exploration licenses, with no meaningful compensation, the province has been 'unjustly enriched' by the value of our discovery. As we have previously noted, the discovery once made, cannot be undiscovered and it has tremendous value to whoever owns it. Our expert witness is working to quantify the value of this discovery and our resulting damages. This should be finalized early in the new year and submitted with our revised pleadings to the Superior Court.

With our investee company, Red Leaf Resources Inc., we are evaluating their assets in the oil-producing Uinta Basin in the state of Utah. These include over 7,000 acres of surface rights in the basin and a permit for a 40,000 bbl/d upgrader. A study we commissioned for the upgrader suggests the original business case still exists. It is a niche opportunity to capitalize on the locally produced crude as a feedstock for high value lubricants and supply motor fuels to a regional market. The current shortage of diesel in North America is supportive of this project. We are expanding this study and intend to move the project forward in the new year.

Operating & Financial

Production volumes in the third quarter increased to 1,629 boe/d over 1,363 boe/d last year with the three (0.75 net) new Kakwa wells brought on stream in May. By comparison, production in the prior quarter was 1,909 boe/d reflecting flush production from these wells. Production in the quarter was also impacted by an unexpected compressor outage at Kakwa.

Although realized prices declined by 20% over the second quarter, they averaged over $77/boe for the quarter and $87/boe year to date. Operating costs were incrementally $1.5 million higher than last year reflecting a successful workover program at Antler and escalating fuel and water handling costs at Kakwa. We generated $5.2 million in adjusted funds flow from operations for the quarter and $21.7 million year to date. The increased cash flow from operations funded our capital investment in these wells and translated to a working capital surplus of $14.4 million at the end of the quarter.

Outlook

Assuming commodity prices remain relatively stable, the incremental cash flow from Kakwa North production will improve our working capital position. Along with our undrawn credit facility, we should be well positioned to fund a future 50/50 drilling program at Kakwa North later next year.

We appreciate that our shareholders' top concern is the status of our legal claim. While the timing and eventual outcome is uncertain, we remain committed to realizing, either through production or compensation, the value of our discovery.

Michael Binnion
President and Chief Executive Officer

(1) Refer to Non-GAAP Measures disclosures included in the Management's Discussion and Analysis

Environmental, Social and Governance

Questerre believes the oil and gas industry can go from laggards to leaders on the global environment.

From today to 2050, the world's population is estimated to grow from 7.5 billion to almost 9.5 billion people who will expect a better standard of living. We believe providing the increased energy needed tomorrow, with lower environmental impacts than today, is the challenge of our times. Transforming our energy diet to lower emissions is essential to meet this challenge and we believe the oil and gas industry has the biggest improvements to make.

Our Clean Tech Energy project was designed to deliver the world's first zero emissions natural gas production and consumption. It is an example of meeting this global challenge. It will have a dramatic impact on emissions in addition to other environmental criteria.

It requires a new way of thinking to become leaders on environmental issues. Our industry runs most of today's energy systems. We have the experience, expertise, capital and technology to meet the world's energy and environmental challenges. Delivering on projects like our zero emissions natural gas project is just one example of how our industry can be leaders on transforming our global energy systems.

Questerre has also taken leadership in working with communities and First Nations for local benefits. We have committed to share our profits with them. We have also engaged with local First Nations to include them in our contracting and benefits program.

We unilaterally made the decision not to work in communities where the plurality of the community does not want development. Our approach of consulting first and applying for permits second is consistent with this approach.

People know they need energy to maintain progress for their families and communities. They want to know the providers of that energy are being responsible and sustainable in the way it is produced. Questerre is an entrepreneurial leader in making the seemingly impossible task of producing more with less impact, possible.

Management's Discussion and Analysis

This Management's Discussion and Analysis ("MD&A") was prepared as of November 9, 2022. This interim MD&A should be read in conjunction with the unaudited condensed consolidated interim financial statements of Questerre Energy Corporation ("Questerre" or the "Company") for the three and nine month periods ended September 30, 2022 and 2021, and the audited annual consolidated financial statements of the Company for the year ended December 31, 2021 and the MD&A prepared in connection therewith. Additional information relating to Questerre, including Questerre's Annual Information Form ("AIF") for the year ended December 31, 2021, is available on SEDAR under Questerre's profile at www.sedar.com.

Questerre is an energy technology and innovative company. It is leveraging its expertise gained through early exposure to low permeability reservoirs to acquire significant high quality resources. Questerre is committed to the economic development of its resources in an environmentally conscious and socially responsible manner. The Company's Class "A" Common voting shares ("Common Shares") are listed on the Toronto Stock Exchange and the Oslo Stock Exchange under the symbol "QEC".

Basis of Presentation

Questerre presents figures in the MD&A using accounting policies within the framework of International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"), representing generally accepted accounting principles ("GAAP"). All financial information is reported in Canadian dollars, unless otherwise noted.

Forward-Looking Statements

Certain statements contained within this MD&A constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified using the use of words such as "anticipate", "assume", "believe", "budget", "can", "commitment", "continue", "could", "estimate", "expect", "forecast", "foreseeable", "future", "intend", "may", "might", "plan", "potential", "project", "will" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Management believes the expectations reflected in those forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this MD&A should not be unduly relied upon. These statements speak only as of the date of this MD&A.

Management has not adjusted or revised any forward-looking statements in this MD&A to account for the potential disruption to the Company's business from the coronavirus ("COVID-19") pandemic, the impact of which is not immediately known or quantifiable.

This MD&A contains forward-looking statements including, but not limited to, those pertaining to the following:

- Government of Quebec's enactment of Bill 21 and revocation of exploration licenses;
- drilling plans and the development of producing assets;
- drilling and completion costs;
- planned facilities;
- the pursuit by the Company of available remedies to protect its legal rights in Quebec and its plans to assist other stakeholders;
- the seeking of opportunities to work with the Government of Quebec to advance the Company's Clean Tech Energy Project;
- future production of oil, natural gas and natural gas liquids, including anticipated production increases and declines;
- future commodity prices in light of decisions by OPEC and non-OPEC member countries, including Saudi Arabia and Russia on production levels, the war in Ukraine and related sanctions, as well as the impacts of COVID-19;
- the timing of capital budget finalization;
- tightness in the supply of oil and natural gas and market volatility;
- legislative and regulatory developments in the Province of Quebec;
- the transfer of wells drilled in 2022 from the proved undeveloped to the proved producing category;
- the development of producing assets to execute the Company business strategy;
- hedging policy;
- liquidity and capital resources;
- the Company's compliance with the terms of its credit facility;
- timing of the next review and expected renewal of the Company's credit facility by its lender;
- ability of the Company to meet its foreseeable obligations;
- capital expenditures and the funding thereof;
- Questerre's reserves;
- impacts of capital expenditures on the Company's reserves;
- average royalty rates;
- commitments and Questerre's participation in future capital programs;
- the Company's objectives when managing its capital;
- risks and risk management;
- potential for equity and debt issuances and farm-out arrangements;
- counterparty creditworthiness and expected credit losses;
- the timing of receivables from joint venture partners;
- insurance;
- use of financial instruments; and
- critical accounting estimates.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A, the AIF, and the documents incorporated by reference into this document:

- drilling plans and the development of producing assets;
- future production of oil, natural gas and natural gas liquids;
- future commodity prices in light of decisions by OPEC and non-OPEC member countries, including Saudi Arabia and Russia on production levels, the war in Ukraine and related sanctions, as well as the impacts of COVID-19;
- legislative and regulatory developments in the Province of Quebec including the enactment of Bill 21 and revocation of exploration licenses;
- the transfer of wells drilled in 2022 from the proved undeveloped to the proved producing category;
- the development of producing assets to execute the Company business strategy;
- hedging policy;
- liquidity and capital resources;
- the Company's compliance with the terms of its credit facility;
- timing of the next review of the Company's credit facility by its lender;
- ability of the Company to meet its foreseeable obligations;
- capital expenditures and the funding thereof;
- Questerre's reserves;
- impacts of capital expenditures on the Company's reserves;
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- potential for equity and debt issuances and farm-out arrangements;
- counterparty creditworthiness;
- the timing of receivables from joint venture partners;
- insurance;
- use of financial instruments; and
- critical accounting estimates.

Statements relating to reserves are by their nature deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described can be profitably produced in the future.

Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward-looking statements contained in this MD&A and the documents incorporated by reference herein are expressly qualified by this cautionary statement. We do not undertake any obligation to publicly update or revise any forward-looking statements except as required by applicable securities law. Certain information set out herein with respect to forecasted results is "financial outlook" within the meaning of applicable securities laws. The purpose of this financial outlook is to provide readers with disclosure regarding the Company's reasonable expectations as to the anticipated results of its proposed business activities. Readers are cautioned that this financial outlook may not be appropriate for other purposes.

BOE Conversions

Barrel of oil equivalent ("boe") amounts may be misleading, particularly if used in isolation. A boe conversion ratio has been calculated using a conversion rate of six thousand cubic feet of natural gas ("Mcf") to one barrel of oil ("bbl"), and the conversion ratio of one barrel to six thousand cubic feet is based on an energy equivalent conversion method application at the burner tip and does not necessarily represent an economic value equivalent 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 equivalent of six to one, utilizing a conversion on a six to one basis may be misleading as an indication of value.

Non-GAAP Measures

This document contains certain financial measures, as described below, which do not have standardized meanings prescribed under GAAP. As these measures are commonly used in the oil and gas industry, the Company believes that their inclusion is useful to investors. The reader is cautioned that these amounts may not be directly comparable to measures for other companies where similar terminology is used.

This document contains the term "adjusted funds flow from operations", which is an additional non-GAAP measure. The Company uses this measure to help evaluate its performance.

As an indicator of the Company's performance, adjusted funds flow from operations should not be considered as an alternative to, or more meaningful than, net cash from operating activities as determined in accordance with GAAP. The Company's determination of adjusted funds flow from operations may not be comparable to that reported by other companies. Questerre considers adjusted funds flow from operations to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund operations and support activities related to its major assets.

Adjusted Funds Flow From Operations Reconciliation

	Three months ended September 30,		*Nine months ended September 30,*	
($ thousands)	**2022**	2021	**2022**	2021
Net cash from operating activities	**$ 8,413**	$ 4,202	**$ 23,477**	$ 10,287
Interest received	**(134)**	(54)	**(242)**	(152)
Interest paid	**2**	111	**41**	367
Change in non-cash operating working capital	**(3,098)**	(681)	**(1,622)**	185
Adjusted Funds Flow from Operations	**$ 5,183**	$ 3,578	**$ 21,654**	$ 10,687

This document also contains the terms "operating netbacks", "cash netbacks" and "working capital surplus (deficit)", which are non-GAAP measures.

The Company considers netbacks a key measure as it demonstrates its profitability relative to current commodity prices. Operating and cash netbacks, as presented, do not have any standardized meaning prescribed by GAAP and may not be comparable with the calculation of similar measures for other entities. Operating netbacks have been defined as revenue less royalties, transportation and operating costs. Cash netbacks have been defined as operating netbacks less general and administrative costs. Netbacks are generally discussed and presented on a per boe basis.

The Company also uses the term “working capital surplus (deficit)”. Working capital surplus (deficit), as presented, does not have any standardized meaning prescribed by GAAP, and may not be comparable with the calculation of similar measures for other entities. Working capital surplus (deficit), as used by the Company, is calculated as current assets less current liabilities excluding any outstanding risk management contracts and lease liabilities.

Select Information

As at/for the period ended September 30,	*Three months ended* **2022**	2021	*Nine months ended* **2022**	2021
Financial ($ thousands, except as noted)				
Petroleum and Natural Gas Sales	**11,602**	7,376	**38,189**	21,517
Net Income	**2,759**	2,006	**14,232**	5,806
Basic and diluted ($/share)	**0.01**	–	**0.03**	0.01
Adjusted Funds Flow from Operations	**5,183**	3,578	**21,654**	10,687
Basic and diluted ($/share)	**0.01**	0.01	**0.05**	0.02
Capital Expenditures	**1,653**	541	**9,422**	1,488
Working Capital Surplus(1)	**14,433**	1,698	**14,433**	1,698
Total Assets	**196,258**	192,709	**196,258**	192,709
Shareholders' Equity	**166,235**	158,922	**166,235**	158,922
Common Shares Outstanding (thousands)	**428,516**	428,516	**428,516**	428,516
Weighted average - basic (thousands)	**428,516**	428,516	**428,516**	427,871
Weighted average - diluted (thousands)	**430,727**	428,516	**430,591**	427,992
Operations (units as noted)				
Average Production				
Crude Oil and Natural Gas Liquids (bbls/d)	**987**	833	**986**	898
Natural Gas (Mcf/d)	**3,852**	3,178	**3,739**	3,655
Total (boe/d)	**1,629**	1,363	**1,609**	1,507
Average Sales Price(2)				
Crude Oil and Natural Gas Liquids ($/bbl)	**106.23**	80.30	**125.06**	80.12
Natural Gas ($/Mcf)	**5.52**	4.18	**6.18**	3.39
Total ($/boe)	**77.40**	58.83	**86.91**	52.34
Netback ($/boe)				
Petroleum and Natural Gas Sales(3)	**77.40**	58.83	**86.91**	52.34
Royalty Expense(3)	**(6.68)**	(4.12)	**(6.83)**	(2.54)
Percentage	**9%**	7%	**8%**	5%
Operating Expense(3)	**(27.41)**	(20.62)	**(22.67)**	(19.74)
Operating Netback	**43.31**	34.09	**57.41**	30.05
Wells Drilled				
Gross	**–**	1.00	**–**	1.00
Net	**–**	0.25	**–**	0.25

(1) Refer to the Current Assets and Current Liabilities in the Balance Sheet as at September 30, 2022 and December 31, 2021.
(2) Refer to the Petroleum and Natural Gas Sales table in the MD&A for the periods ended September 30, 2022 and 2021.
(3) Refer to Consolidated Statement of Net Income and Comprehensive Income for the periods ended September 30, 2022 and 2021.

Highlights

- Questerre converts Kakwa North royalty interest to working interest adding 500 boe/d for remainder of the year
- Government of Quebec enacts Bill 21 and revokes exploration licenses
- Average daily production of 1,629 boe/d and adjusted funds flow from operations of $5.2 million for the quarter

Third Quarter 2022 Activities

Kakwa, Alberta

Following the completion and tie-in of the three (0.75 net) wells at Kakwa Central last quarter, the operator plans to drill two (0.5 net) wells this winter from the same surface location. Largely reflecting the inflation in the service sector and, to a lesser extent, optimization of the completion program, these new well costs are projected to increase by approximately 25% to $16 million per well. Additionally, the operator's proposed 2023 capital program includes facilities to mitigate the increased costs and risks of lean natural gas supply experienced this year. The planned facilities will be a new refrigeration unit and natural gas liquids bullet at an estimated cost of $1.0 million net to Questerre. The Company anticipates finalizing its capital budget for 2023 early in the new year.

Effective the end of the third quarter, the operator of Kakwa North advised that it had recovered 100% of the capital and operating costs associated with the initial four farm-in wells. The Company has since elected to convert its 5% royalty interest in these wells to a 50% working interest. For the third quarter, gross daily production from these wells averaged 1,396 boe/d consisting of 5.2 MMcf/d of natural gas and 538 bbl/d of condensate and natural gas liquids. The operator anticipates that drilling at Kakwa North could resume in the fourth quarter of next year with a proposed 3 (1.5 net) well program.

Subject to its review of the proposed drilling programs outlined above and commodity prices, the Company plans to participate in future drilling at both its Kakwa joint ventures.

St. Lawrence Lowlands, Quebec

Though the Company is seeking opportunities to work with the Government of Quebec to advance its Clean Tech Energy project, its primary goal is to protect its legal rights following the enactment of Bill 21, *An Act mainly to end petroleum exploration and production and the public financing of those activities* ("Bill 21") by the Government of Quebec.

Bill 21 was enacted on August 23, 2022. It revokes petroleum exploration and production licences, including the 16 exploration licenses held by the Company. It provides that the Government must establish a compensation program pertaining to the revocation of licences. The Act requires, in particular, the holders of a revoked licence to permanently close wells and restore sites according to the terms and conditions determined by the Government. Bill 21 validates the regulations made under the authority of the *Petroleum*

Resources Act, certain decisions which effectively limit or prohibit, directly or indirectly, exploration for petroleum and underground reservoirs and production of petroleum and brine as well as the collection by the Minister of the annual fees for oil and gas activities.

During the quarter, the Attorney General of Quebec requested the Superior Court order the special case management of all litigation related to Bill 21. The Senior Associate Chief Justice of the Superior Court appointed a single judge to separately manage all the litigation by licensee holders, including Questerre, in early October. The litigation includes the judicial review application for the regulations of the *Petroleum Resources Act* and the claim for expropriation filed by Questerre in 2018 and 2022 respectively.

The Company is pursuing available remedies to protect its legal rights. It is seeking just compensation for the value of its licenses including the significant discovery. The Company plans to assist other stakeholders and partners including the First Nations and local royalty holders to ensure their rights are also protected against the Government's actions.

Production

Three months ended September 30,	**2022**			2021		
	Oil and Liquids (bbls/d)	**Natural Gas (Mcf/d)**	**Equivalent (boe/d)**	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)
Alberta	**693**	**3,852**	**1,335**	554	3,178	1,084
Saskatchewan and Manitoba	**294**	**–**	**294**	279	–	279
	987	**3,852**	**1,629**	833	3,178	1,363

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Nine months ended September 30,	**2022**			2021		
	Oil and Liquids (bbls/d)	**Natural Gas (Mcf/d)**	**Equivalent (boe/d)**	Oil and Liquids (bbls/d)	Natural Gas (Mcf/d)	Equivalent (boe/d)
Alberta	**683**	**3,739**	**1,306**	602	3,655	1,211
Saskatchewan and Manitoba	**303**	**–**	**303**	296	–	296
	986	**3,739**	**1,609**	898	3,655	1,507

Both on a quarterly and year to date basis, volumes increased over the prior year as three (0.75 net) wells were brought on production at Kakwa this year. These were 15% higher in the prior quarter largely due to flush production from the new wells.

Kakwa continued to account for over 80% of corporate volumes. This includes royalty production from Kakwa North of 85 boe/d in the quarter (2021: 127 boe/d) and 93 boe/d (2021: 90 boe/d) year to date. These volumes are attributable to the four original farm-in wells. Effective the beginning of the fourth quarter, the Company elected to convert its 5% royalty interest in these wells into a 50% working interest.

The remaining 20% of corporate volumes are attributable to light oil production from Saskatchewan and Manitoba. Recently completed workovers in both locations contributed to nominally higher volumes for both the three and nine months ended September 30, 2022. As a result, the Company's oil and liquids weighting remained at 60%, unchanged from last year.

Following the conversion of the royalty interest into a working interest, the Company anticipates its production volumes will increase by approximately 500 boe/d over the remainder of the year. Subject to its review of the drilling program proposed by the operator of Kakwa Central this fall and commodity prices, the Company plans to participate in the program.

Third Quarter 2022 Financial Results

Petroleum and Natural Gas Sales

Three months ended September 30,	2022			2021		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Alberta	$ 6,515	$ 1,957	$ 8,472	$ 4,008	$ 1,201	$ 5,209
Saskatchewan and Manitoba	3,130	–	3,130	2,167	–	2,167
	$ 9,645	$ 1,957	$ 11,602	$ 6,175	$ 1,201	$ 7,376

Note: Oil and liquids includes light & medium crude oil and natural gas liquids. Natural gas includes conventional and shale gas.

Nine months ended September 30,	2022			2021		
($ thousands)	Oil and Liquids	Natural Gas	Total	Oil and Liquids	Natural Gas	Total
Alberta	$ 21,334	$ 6,730	$ 28,064	$ 11,868	$ 3,463	$ 15,331
Saskatchewan and Manitoba	10,125	–	10,125	6,186	–	6,186
	$ 31,459	$ 6,730	$ 38,189	$ 18,054	$ 3,463	$ 21,517

Compared to last year, higher commodity prices and production volumes resulted in higher petroleum and natural gas sales this year. Commodity prices accounted for more than two thirds of the change in the quarter over last year, with production volumes representing the remainder of the nearly 60% increase. Of the nearly 80% increase year to date, commodity prices represented 90% of the change with only 10% attributable to the increase in production volumes. Sales declined over the prior quarter by over 30% due lower production volumes and prices.

Pricing

	Three months ended September 30,		Nine months ended September 30,	
	2022	2021	**2022**	2021
Benchmark prices:				
Natural Gas - AECO, daily spot ($/Mcf)	**4.72**	3.38	**5.18**	3.03
Crude Oil - Mixed Sweet Blend ($/bbl)	**119.34**	83.93	**124.83**	78.23
Realized prices:				
Natural Gas ($/Mcf)	**5.52**	4.18	**6.18**	3.39
Crude Oil and Natural Gas Liquids ($/bbl)	**106.23**	80.30	**125.06**	80.12

Although they declined from the second quarter, crude oil prices in the third quarter still increased over the prior year. The benchmark West Texas Intermediate ("WTI") averaged US$93.68/bbl for the quarter (2021: US$70.91/bbl) and US$98.79/bbl for the first nine months of the year (2021: US$64.75/bbl).

The risks of an economic slowdown driven in part by rising inflation and the associated monetary policy response weighed on oil prices in the quarter. Prices were also impacted by concerns about the recovery in demand by China, the world's second largest oil consumer, given their zero COVID policy and weaker than expect US gasoline demand, another major component of global demand, this summer. In Canada, the differential over the quarter between WTI and benchmark condensate prices widened to US$4.46/bbl from US$1.32/bbl last year due to reduced demand for diluent.

Questerre's liquids production consists primarily of condensate and light oil. As a result, realized prices closely tracked the benchmark prices with discounts of less than 10% for both the three and nine month periods in the current year.

Consistent with the first quarter, natural gas prices also rose over the prior year with the benchmark Henry Hub averaging US$7.99/MMBtu (2021: US$4.36/MMBtu) in the quarter and US$6.74/MMBtu (2021: US$3.62/MMBtu) year to date.

Natural gas prices in the United States were supported by an overall tight supply demand balance. Growing demand, particularly for power generation, as well as exports via LNG and pipelines to Mexico outpaced supply which reached a record 100 Bcf/d in September this year. In Canada, ongoing maintenance on the primary pipeline system in Western Canada during the quarter reduced access to interruptible transportation service and saw the differential with Henry Hub grow materially in the period.

Realized natural gas prices, reflecting the higher heat content from Kakwa production, averaged $5.52/Mcf (2021: $4.18/Mcf) compared to the AECO price of $4.72/Mcf (2021: $3.38/Mcf).

Royalties

($ thousands)	*Three months ended September 30,* **2022**	2021	*Nine months ended September 30,* **2022**	2021
Alberta	**$ 728**	$ 362	**$ 2,242**	$ 597
Saskatchewan and Manitoba	**273**	155	**761**	449
	$ 1,001	$ 517	**$ 3,003**	$ 1,046
% of Revenue:				
Alberta	**9%**	7%	**8%**	4%
Saskatchewan and Manitoba	**9%**	7%	**8%**	7%
Total Company	**9%**	7%	**8%**	5%

Commensurate with the increase in petroleum and natural gas sales, gross royalties increased over the prior year for the three and nine month periods ended September 30, 2022. As a percentage of revenue this increased to 9% from 7% for the quarter and to 8% from 5% for the year to date.

Royalties in Alberta primarily reflect the Crown and overriding royalties payable on production from Kakwa. Crown royalties increased due to the expiration of incentive programs for older wells last year that now incur royalty rates of 40% for condensate revenue offset by incentives received for newer wells that qualify for rates of 5% for condensate revenue. As a percentage of revenue, royalties in Saskatchewan and Manitoba also increased due to higher freehold royalties payable on production from Manitoba.

Operating Costs

($ thousands)	*Three months ended September 30,* **2022**	2021	*Nine months ended September 30,* **2022**	2021
Alberta	**$ 2,910**	$ 1,991	**$ 7,102**	$ 6,038
Saskatchewan and Manitoba	**1,100**	493	**2,572**	1,807
Quebec	**98**	102	**287**	272
	$ 4,108	$ 2,586	**$ 9,961**	$ 8,117
$/boe:				
Alberta	**23.70**	19.96	**19.91**	18.28
Saskatchewan and Manitoba	**40.63**	19.23	**31.08**	22.38
Total Company	**27.41**	20.62	**22.67**	19.74

Increased production volumes also contributed to higher gross operating costs in the quarter and year to date compared to the prior year.

In Kakwa, these costs rose by 50% or over $1 million over the prior year in the following three categories: produced water trucking and disposal costs related to the higher production volumes from new wells, fuel costs related to the increased cost of natural gas and workovers. The operator is assessing opportunities to mitigate these increases through long term contracts for water disposal and the installation of additional facilities to provide lean gas for in-field consumption.

At Antler, Saskatchewan operating costs increased by 100% or $0.5 million over the prior year largely due to a nine well workover program that restored nearly 60 bbl/d of production and went over budget by approximately 25%. Operating costs also increased due to an expanded chemical program that, based on past experience, is expected to reduce the frequency and severity of workovers.

Operating costs in Quebec remained relatively stable for the quarter and year to date and relate to the supervision and maintenance of the Company's non-producing wells in the province.

General and Administrative Expenses

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2022**	2021	**2022**	2021
General and administrative expenses, gross	**$ 1,148**	$ 951	**$ 3,119**	$ 2,463
Capitalized expenses and overhead recoveries	**(58)**	(210)	**(174)**	(731)
General and administrative expenses, net	**$ 1,090**	$ 741	**$ 2,945**	$ 1,732

For the period ended September 30, 2022, gross general and administrative expenses ("G&A") increased 20% for the quarter and 26% year to date over the prior year. These amounts remained unchanged over the prior two quarters in the current year.

The increase over last year is due to higher costs for consulting and legal fees related to Quebec. Capitalized overhead in the current year represents costs associated with the Company's assets in Alberta and Jordan. These declined materially in the current year following the introduction of Bill 21 in Quebec and the impairment of the carrying value of the Company's exploration and evaluation assets in the province as at December 31, 2021. The resulting increase in net G&A reflects the combination of the higher gross expenses and lower capitalization in the periods.

Depletion, Depreciation, Accretion and Impairment

Questerre recorded depletion, depreciation and accretion expense ("DD&A") of $2.3 million for the quarter ended September 30, 2022 (2021: $1.4 million) and $6.6 million for the nine months then ended (2021: $4.6 million). Depletion accounts for over 95% of these amounts. The variance is both periods is due to the increased production and the increase in the depletable base, on a unit of production basis, to $14.56/boe from $10.81/boe year to date. The former reflects the higher book cost for the Company's plant, property and equipment assets arising from the reversal of previously incurred impairment expense of $91.7 million following the impairment test completed as of December 31, 2021.

Interest expense, other income and share based compensation expense

During the nine months ended September 30, 2022, the Company incurred interest expense of $0.04 million (2021: $0.4 million). The amounts relate to its credit facilities with a Canadian chartered bank. The lower expense in the year reflects the reduction in amounts outstanding under these facilities. As at September 30, 2022, the amount drawn on the facilities was $0.03 million (September 30, 2021: $7.4 million) and the effective interest rate was 4.78% (2021: 3.45%). The Company also earned interest income of $0.1 million (2021: $0.1 million) on its cash and term deposits for the period.

Year to date, the Company recorded share based compensation expense of $1.6 million (2021: $0.4 million) net of $0.3 million in expense capitalized during the period (2021: $0.8 million).

Other Comprehensive Income and Expenses

In 2022, the Company recorded other comprehensive income of $1 million for the quarter (2021: $0.4 million loss) and $1.2 million year to date (2021: $0.01 million loss). These amounts relate to the impact of changes in foreign exchange for the respective periods. The appreciation of the Jordanian dinar resulted in a gain of $0.6 million (2021: $0.1 million) on the Company's dinar denominated assets in the country for the quarter. For the same period, the appreciation in the US dollar resulted in a gain of $0.5 million (2021: $0.2 million gain) on its US dollar denominated investment in Red Leaf Resources Inc. ("Red Leaf"). On a year to date basis, the other comprehensive income reflects the smaller change in the preceding two quarters.

Net Income and Total Comprehensive Income

Net income for the current quarter was $2.8 million (2021: $2 million) and year to date was $14.2 million (2021: $5.8 million). On a quarterly basis, the higher petroleum and natural gas sales was largely offset by the higher expenses in all categories including operating, G&A and DD&A. Year to date, the higher revenue and lower expenses in the prior quarters, particularly the second quarter, contributed to a more substantial increase in net income over last year. Including other comprehensive income, the total comprehensive income for the third quarter of the year was $3.8 million (2021: $2.4 million) and year to date was $15.4 million (2021: $5.8 million).

Cash Flow from Operating Activities

For the nine months ended September 30, 2022, net cash from operating activities was $23.5 million compared to $10.3 million last year. The variance is due to the higher adjusted funds flow from operations in the current year offset by an increase in non-cash working capital compared to a small decrease last year. For the quarter ended September 30, 2022, the change over the prior year is attributed to a more nominal increase in adjusted funds flow from operations and a more substantive increase in non-cash working capital.

Cash Flow used in Investing Activities

Cash flow used in investing activities for the third quarter increased to $4.4 million this year from $0.4 million last year reflecting the higher capital spending at Kakwa as well as a reduction in related non-cash working capital. The higher capital spending year to date also accounts for the increase in cash used in investing activities over the prior year with the reduction in non-cash working capital slightly decreasing in the current year.

Cash Flow used in Financing Activities

For both the current year and prior year, net cash used in financing activities reflects the net repayment of its credit facilities of $3.4 million and $7.9 million, respectively. With its credit facility effectively undrawn at the beginning of the current quarter, cash used in financing activities for the quarter were nominal compared to the same period last year when the Company repaid $4.6 million in the period.

Capital Expenditures

	Three months ended September 30,		Nine months ended September 30,	
($ thousands)	**2022**	2021	**2022**	2021
Alberta	**$ 1,325**	$ 306	**$ 8,859**	$ 402
Saskatchewan, Manitoba and Jordan	**343**	31	**449**	88
Quebec	**(15)**	204	**114**	998
Total Company	**$ 1,653**	$ 541	**$ 9,422**	$ 1,488

For the first nine months of 2022, the Company incurred capital expenditures of $9.4 million as follows:

- In Alberta, $8.9 million was incurred to finalize drilling and completion operations on three (0.75 net) wells at Kakwa Central; and
- $0.5 million was invested in maintenance for the Company's other assets.

For the nine months ended September 30, 2021, the Company incurred nominal capital investment of $1.5 million as follows:

- In Quebec, $1 million for capitalized overhead related to engineering and securing social acceptability for its Clean Tech Energy project; and
- $0.5 million was invested in maintenance for the Company's other assets.

Share Capital

The Company is authorized to issue an unlimited number of Common Shares. The Company is also authorized to issue an unlimited number of Class "B" Common voting shares and an unlimited number of preferred shares, issuable in one or more series. At September 30, 2022, there were no Class "B" Common voting shares or preferred shares outstanding. The following table provides a summary of the outstanding Common Shares and options as at the date of the MD&A, the current quarter-end and the preceding year-end.

(thousands)	November 10, 2022	September 30, 2022	December 31, 2021
Common Shares	**428,516**	**428,516**	428,516
Stock Options	**35,347**	**35,347**	30,307
Weighted average common shares			
Basic		**428,516**	428,034
Diluted		**430,591**	428,034

A summary of the Company's stock option activity for the nine months ended September 30, 2022, and the year ended December 31, 2021 follows:

	September 30, 2022			December 31, 2021		
	Number of Options *(thousands)*		**Weighted Average Exercise Price**	Number of Options *(thousands)*		Weighted Average Exercise Price
Outstanding, beginning of period	**30,307**	**$**	**0.35**	25,351	$	0.38
Granted	**11,490**		**0.34**	8,350		0.18
Forfeited/cancelled	**–**		**–**	(2,344)		0.18
Expired	**(6,450)**		**0.69**	(50)		0.18
Exercised	**–**		**–**	(1,000)		0.18
Outstanding, end of period	**35,347**	**$**	**0.28**	30,307	$	0.35
Exercisable, end of period	**20,506**	**$**	**0.28**	20,866	$	0.42

Liquidity and Capital Resources

The Company's objectives when managing its capital are firstly to maintain financial liquidity, and secondly to optimize the cost of capital at an acceptable risk to sustain the future development of the business.

Although commodity prices have well surpassed pricing prior to the COVID-19 pandemic, they remain volatile as a result of recent geopolitical events. The Company continues to manage its financial liquidity through ensuring capital expenditures can be financed through a combination of cash flow from operations and available debt facilities.

At September 30, 2022, $0.03 million (December 31, 2021: $3.4 million) was drawn on the credit facilities and the Company is compliant with all its covenants under the credit facilities. Under the terms of the credit facilities, the Company has provided a covenant that it will maintain an Adjusted Working Capital Ratio greater than 1.0. The ratio is defined as current assets (excluding unrealized hedging gains and including undrawn Credit Facility A availability) to current liabilities (excluding bank debt outstanding and unrealized hedging losses). The Adjusted Working Capital Ratio at September 30, 2022 was 4.44 and the covenant was met. See Note 11 of the Financial Statements.

While the credit facilities are expected to be renewed at $16 million, the facilities could be reduced at their next review scheduled during the second quarter of 2023. The credit facilities are a demand facility and can be reduced, amended or eliminated by the lender for reasons beyond the Company's control. Should the credit facilities be reduced or eliminated, the Company would need to seek alternative credit facilities or consider the issuance of equity to enhance its liquidity. In the current market, the Company may be unable to secure additional financing on acceptable terms, if at all.

The Company believes that it has access to sufficient financial liquidity to meet its foreseeable obligations in the normal course of operations over the next 12 months.

The Company is committed to the 2022 future development costs associated with proved reserves in its independent reserves assessment as of December 31, 2021. It anticipates that, as a result, reserves associated with wells drilled in 2022 will be transferred from the proved undeveloped to the proved producing category.

For a detailed discussion of the risks and uncertainties associated with the Company's business and operations, see the Risk Management section of the MD&A and the AIF.

Commitments

A summary of the Company's net commitments at September 30, 2022 are as follows:

($ thousands)	2022	2023	2024	2025	2026	Total
Transportation and Processing	$ 790	$ 3,162	$ 2,884	$ 2,015	$ 1,240	$ 10,091

In order to maintain its capacity to execute its business strategy, the Company expects that it will need to continue the development of its producing assets. There will also be expenditures in relation to G&A and other operational expenses. These expenditures are not yet commitments, but Questerre expects to fund such amounts primarily out of adjusted funds flow from operations and its existing credit facilities.

Risk Management

Companies engaged in the petroleum and natural gas industry face a variety of risks. For Questerre, these include risks associated with commodity prices, exploration and development drilling as well as production operations, foreign exchange and interest rate fluctuations. Unforeseen significant changes in such areas as markets, prices, royalties, interest rates and government regulations could have an impact on the Company's future operating results and/or financial condition. While Management realizes that all the risks may not be controllable, Questerre believes that they can be monitored and managed. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF and Note 6 to the audited consolidated financial statements for the year ended December 31, 2021.

Volatility in the oil and gas industry is a major risk facing the Company. Market events and conditions, including global oil and natural gas supply and demand, actions taken by OPEC and non-OPEC member countries' decisions, including recent decisions by Saudi Arabia and Russia, on production growth and spare capacity, market volatility and disruptions, weakening global relationships, the war in Ukraine and related sanctions, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. These events and conditions have been a factor in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax and royalty changes and other environmental regulations.

In addition, the difficulties in obtaining the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of the Company's reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have previously reduced the Company's cash flow leading to a reduction in funds available for capital expenditures. As a result, the Company may not be able to replace its production with additional reserves and both the Company's production and reserves could be reduced on a year over year basis. Any decrease in value of the Company's reserves may reduce the borrowing base under its credit facilities, which, depending on the level of the Company's indebtedness, could result in the Company having to repay all or a portion of its indebtedness. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, the Company may have difficulty raising additional funds in the future to raise funds on unfavourable and highly dilutive terms.

Another significant risk for Questerre as a junior exploration company is access to capital. The Company attempts to secure both equity and debt financing on terms it believes are attractive in current markets. Management also endeavors to seek participants to farm-in on the development of its projects on favorable terms. However, there can be no assurance that the Company will be able to secure sufficient capital if required or that such capital will be available on terms satisfactory to the Company.

As future capital expenditures will be financed out of adjusted funds flow from operations, borrowings and possible future equity sales, the Company's ability to do so is dependent on, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry, and the Company's securities. To the extent that external sources of capital become limited or unavailable, or available but on onerous terms, the Company's ability to make capital investments and maintain existing assets may be impaired, and its assets, liabilities, business, financial condition and results of operations may be materially and adversely affected. Based on current funds available and expected adjusted funds flow from operations, the Company believes it has sufficient funds available to fund its projected capital expenditures. However, if adjusted funds flow from operations is lower than expected, or capital costs for these projects exceed current estimates, or if the Company incurs major unanticipated expense related to development or maintenance of its existing properties, it may be required to seek additional capital to maintain its capital expenditures at planned levels. Failure to obtain any financing necessary for the Company's capital expenditure plans may result in a delay in development or production on the Company's properties.

Questerre faces several financial risks over which it has no control, such as commodity prices, exchange rates, interest rates, access to credit and capital markets, as well as changes to government regulations and tax and royalty policies.

The Company uses the following guidelines to address financial exposure:

- Internally generated cash flow provides the initial source of funding on which the Company's annual capital expenditure program is based.
- Equity, if available on acceptable terms, may be raised to fund acquisitions and capital expenditures.
- Debt may be utilized to expand capital programs, including acquisitions, when it is deemed appropriate and where debt retirement can be controlled.
- Farm-outs of projects may be arranged if management considers that a project requires too much capital or where the project affects the Company's risk profile.

Credit risk represents the potential financial loss to the Company if a customer or counterparty to a financial instrument fails to meet or discharge their obligation to the Company. Credit risk arises from the Company's receivables from joint venture partners and oil and gas marketers. In the event such entities fail to meet their contractual obligations to the Company, such failures may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Credit risk also arises from the Company's cash and cash equivalents. In the past, the Company manages credit risk exposure by investing in Canadian banks and credit unions. Management does not expect any counterparty to fail to meet its obligations.

Poor credit conditions in the industry may impact a joint venture partner's willingness to participate in the Company's ongoing capital program, potentially delaying the program and the results of such program until the Company finds a suitable alternative partner if possible.

Substantially all of the accounts receivable are with oil and natural gas marketers and joint venture partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally extends unsecured credit to these customers and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by entering into transactions with long-standing, reputable counterparties and partners.

Accounts receivable related to the sale of the Company's petroleum and natural gas production is paid in the following month from major oil and natural gas marketing and infrastructure companies and the Company has not experienced any credit loss relating to these sales to date. The Company has a provision of $0.04 million at September 30, 2022 for its expected credit losses related to its accounts receivable.

Receivables from joint venture partners are typically collected within one to three months after the joint venture bill is issued. The Company mitigates this risk by obtaining pre-approval of significant capital expenditures.

Exploration and development drilling risks are managed through the use of geological and geophysical interpretation technology, employing technical professionals and working in areas where those individuals have experience. For its non-operated properties, the Company strives to develop a good working relationship with the operator and monitors the operational activity on the property. The Company also carries appropriate insurance coverage for risks associated with its operations.

The Company may use financial instruments to reduce corporate risk in certain situations. Questerre's hedging policy is up to a maximum of 40% of total production at management's discretion.

As at September 30, 2022, the Company had no outstanding commodity risk management contract in place.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases of emissions and regulation on the storage and transportation of various substances produced or utilized in association with certain oil and natural gas industry operations, which can affect the location and operation of wells and facilities, and the extent to which exploration and development is permitted. In addition, legislation requires that well and facility sites are abandoned and reclaimed to the satisfaction of provincial authorities. As well, applicable environmental laws may impose remediation obligations with respect to property designated as a contaminated site upon certain responsible persons, which include persons responsible for the substance causing the contamination, persons who caused the release of the substance and any past or present owner, tenant or other person in possession of the site. Compliance with such legislation can require significant expenditures, and a breach of such legislation may result in the suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage, the imposition of fines and penalties or the issuance of clean-up orders. The Company mitigates the potential financial exposure of environmental risks by complying with the existing regulations and maintaining adequate insurance. For more information, please refer to the "Risk Factors" and "Industry Conditions" sections of the AIF.

Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. The federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing the Company's operating expenses, each of which may have a material adverse effect on the Company's profitability and financial condition. Further, the imposition of carbon taxes puts the Company at a disadvantage with the Company's counterparts who operate in jurisdictions where there are less costly carbon regulations.

Interest Rate Risk

Interest rate risk is the risk that changes in the applicable interest rates will impact the Company's interest expense related to its credit facilities. Given the immateriality of interest expense relative to net income, a 0.5% change in interest rates applicable to its credit facilities would have a negligible impact on net income. At September 30, 2022, the Company had credit facilities outstanding of $0.03 million (December 31, 2021: $3.4 million) with an effective rate of 4.78% (2021: 3.45%).

Disclosure Controls and Procedures and Internal Controls over Financial Reporting

The Company's Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Company is made known to the Company's CEO and CFO by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation.

The Company's CEO and CFO have designed, or caused to be designed under their supervision, internal controls over financial reporting to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The Company is required to disclose herein any change in the Company's internal controls over financial reporting that occurred during the period beginning on July 1, 2022 and ended on September 30, 2022 that has materially affected, or is reasonably likely to materially affect, the Company's internal controls over financial reporting. No material changes in the Company's internal controls over financial reporting were identified during such period that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting.

It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

Quarterly Financial Information

($ thousands, except as noted)	Sept 30 2022	June 30 2022	Mar 31 2022	Dec 31 2021
Production (boe/d)	**1,629**	1,909	1,288	1,398
Average Realized Price ($/boe)	**77.40**	97.95	82.56	69.11
Petroleum and Natural Gas Revenue	**11,602**	17,013	9,574	8,887
Adjusted Funds Flow from Operations	**5,183**	12,183	4,290	3,790
Net Income (Loss)	**2,759**	9,051	2,423	(10,107)
Basic and Diluted ($/share)	**0.01**	0.02	0.01	(0.02)
Capital Expenditures, net of acquisitions and dispositions	**1,653**	2,843	4,926	3,177
Working Capital Surplus	**14,433**	10,564	1,192	1,834
Total Assets	**196,258**	194,419	186,201	184,264
Shareholders' Equity	**166,235**	161,969	151,862	148,961
Weighted Average Common Shares Outstanding				
Basic (thousands)	**428,516**	428,516	428,516	428,516
Diluted (thousands)	**430,727**	428,747	432,112	428,516

($ thousands, except as noted)	Sept 30 2021	June 30 2021	Mar 31 2021	Dec 31 2020
Production (boe/d)	1,363	1,479	1,679	1,851
Average Realized Price ($/boe)	58.83	52.72	46.62	35.85
Petroleum and Natural Gas Revenue	7,376	7,095	7,046	6,105
Adjusted Funds Flow from Operations	3,578	4,224	2,885	1,857
Net Income (Loss)	2,006	2,892	908	(75)
Basic and Diluted ($/share)	–	0.01	–	–
Capital Expenditures, net of acquisitions and dispositions	541	450	497	1,621
Working Capital Surplus (Deficit)	1,698	(1,243)	(5,449)	(7,705)
Total Assets	192,709	194,053	194,417	196,177
Shareholders' Equity	158,922	156,316	153,108	152,120
Weighted Average Common Shares Outstanding				
Basic (thousands)	428,516	427,571	427,516	427,516
Diluted (thousands)	428,516	427,743	427,879	427,516

The general trends over the last eight quarters are as follows:

- Petroleum and natural gas revenues and adjusted funds flow from operations have fluctuated with production volumes and realized commodity prices. With the exception of the current quarter, revenue has increased each quarter primarily due to the recovery in commodity prices.
- Production volumes reflect the capital investment in drilling and completing wells at Kakwa in preceding quarters. In 2021, with the increase in prices, capital investment increased in the fourth quarter with the effect of increased production volumes realized in the second quarter of 2022. In

2020, with non-essential capital investment largely suspended, production volumes declined quarter over quarter.

- The working capital surplus (deficit) has generally decreased when capital expenditures and other investments have been higher than adjusted funds flow from operations and cash from financing activities.
- With no new equity capital raised in the last three years, shareholders' equity has generally changed with net income or losses sustained in the period.

Off-Balance Sheet Transactions

The Company did not engage in any off-balance sheet transactions during the period ended September 30, 2022.

Related Party Transactions

The Company paid fees of $0.1 million for the nine months ended September 30, 2022 (year ended December 31, 2021: $0.2 million) to a law firm where a director of the Company is currently a partner.