NOW Inc.
Form 10-Q
August 02, 2018

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark one)

QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
FOR THE QUARTERLY PERIOD ENDED June 30, 2018

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number 001-36325

NOW INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	46-4191184 (I.R.S. Employer Identification No.)

7402 North Eldridge Parkway,

Houston, Texas 77041

(Address of principal executive offices)

(281) 823-4700

(Registrant’s telephone number, including area code)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer		Accelerated filer
Non-accelerated filer	(Do not check if a small reporting company)	Small reporting company
Emerging growth company		

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes No

As of July 26, 2018 the registrant had 108,390,737 shares of common stock (excluding 1,384,492 unvested restricted shares), par value $0.01 per share, outstanding.

NOW INC.

TABLE OF CONTENTS

PART I—FINANCIAL INFORMATION

Item 1. Financial Statements

NOW INC.

CONSOLIDATED BALANCE SHEETS

(In millions, except share data)

	June 30, 2018 (Unaudited)	December 31, 2017
ASSETS		
Current assets:		
Cash and cash equivalents	$ 91	$ 98
Receivables, net	495	423
Inventories, net	604	590
Prepaid and other current assets	23	18
Total current assets	1,213	1,129
Property, plant and equipment, net	109	119
Deferred income taxes	2	2
Goodwill	321	328
Intangibles, net	155	166
Other assets	11	5
Total assets	$ 1,811	$ 1,749
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 315	$ 290
Accrued liabilities	103	103
Other current liabilities	2	1
Total current liabilities	420	394
Long-term debt	195	162
Deferred income taxes	6	7
Other long-term liabilities	1	1
Total liabilities	622	564
Commitments and contingencies		
Stockholders' equity:		
Preferred stock—par value $0.01; 20 million shares authorized; no shares issued and outstanding	—	—
Common stock - par value $0.01; 330 million shares authorized; 108,390,737 and 108,030,438 shares issued and outstanding at June 30, 2018	1	1

and December 31, 2017, respectively		
Additional paid-in capital	2,026	2,019
Accumulated deficit	(714)	(730)
Accumulated other comprehensive loss	(124)	(105)
Total stockholders' equity	1,189	1,185
Total liabilities and stockholders' equity	$ 1,811	$ 1,749

See notes to unaudited consolidated financial statements.

NOW INC.

CONSOLIDATED STATEMENTS OF OPERATIONS (UNAUDITED)

(In millions, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue	$777	$651	$1,541	$1,282
Operating expenses:				
Cost of products	620	527	1,236	1,044
Warehousing, selling and administrative	139	138	280	273
Operating profit (loss)	18	(14)	25	(35)
Other expense	(3)	(3)	(7)	(5)
Income (loss) before income taxes	15	(17)	18	(40)
Income tax provision (benefit)	1	—	2	—
Net income (loss)	$14	$(17)	$16	$(40)
Earnings (loss) per share:				
Basic earnings (loss) per common share	$0.12	$(0.16)	$0.15	$(0.37)
Diluted earnings (loss) per common share	$0.12	$(0.16)	$0.15	$(0.37)
Weighted-average common shares outstanding, basic	108	108	108	108
Weighted-average common shares outstanding, diluted	108	108	108	108

See notes to unaudited consolidated financial statements.

NOW INC.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) (UNAUDITED)

(In millions)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Net income (loss)	$14	$(17)	$16	$(40)
Other comprehensive income (loss):				
Foreign currency translation adjustments	(20)	12	(19)	22
Comprehensive loss	$(6)	$(5)	$(3)	$(18)

See notes to unaudited consolidated financial statements.

NOW INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

(In millions)

	Six Months Ended June 30,	
	2018	2017
Cash flows from operating activities:		
Net income (loss)	$16	$(40)
Adjustments to reconcile net income (loss) to net cash used in operating activities:		
Depreciation and amortization	22	26
Deferred income taxes	(1)	(1)
Stock-based compensation	8	11
Provision for doubtful accounts	2	2
Provision for inventory	5	8
Change in operating assets and liabilities, net of acquisitions:		
Receivables	(79)	(61)
Inventories	(25)	(50)
Prepaid and other current assets	(4)	(5)
Accounts payable and accrued liabilities	31	37
Income taxes receivable, net	—	(1)
Net cash used in operating activities	(25)	(74)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(3)	(1)
Business acquisitions, net of cash acquired	—	(4)
Other, net	1	3
Net cash used in investing activities	(2)	(2)
Cash flows from financing activities:		
Borrowing under the revolving credit facility	391	172
Repayments under the revolving credit facility	(358)	(109)
Other	(8)	—
Net cash provided by financing activities	25	63
Effect of exchange rates on cash and cash equivalents	(5)	4
Net change in cash and cash equivalents	(7)	(9)
Cash and cash equivalents, beginning of period	98	106
Cash and cash equivalents, end of period	$91	$97

See notes to unaudited consolidated financial statements.

NOW INC.

Notes to Unaudited Consolidated Financial Statements

1. Organization and Basis of Presentation

Nature of Operations

NOW Inc. ("NOW" or the "Company") is a holding company headquartered in Houston, Texas that was incorporated in Delaware on November 22, 2013. NOW operates primarily under the DistributionNOW and Wilson Export brands. NOW is a global distributor of energy products as well as products for industrial applications through its locations in the U.S., Canada and internationally which are geographically positioned to serve the energy and industrial markets in over 80 countries. NOW's energy product offerings are used in the oil and gas industry including upstream drilling and completion, exploration and production, midstream infrastructure development and downstream petroleum refining – as well as in other industries, such as chemical processing, power generation and industrial manufacturing operations. The industrial distribution portion of NOW's business targets a diverse range of manufacturing and other facilities across numerous industries and end markets. NOW also provides supply chain management to drilling contractors, E&P operators, midstream operators, downstream energy and industrial manufacturing companies. NOW's supplier network consists of thousands of vendors in approximately 40 countries.

Basis of Presentation

All significant intercompany transactions and accounts have been eliminated. The unaudited consolidated financial information included in this report has been prepared in accordance with accounting principles generally accepted in the United States ("GAAP") for interim financial information and Article 10 of SEC Regulation S-X. The principles for interim financial information do not require the inclusion of all the information and footnotes required by generally accepted accounting principles for complete financial statements. Therefore, these financial statements should be read in conjunction with the financial statements included in the Company's most recent Annual Report on Form 10-K. In the opinion of the Company's management, the consolidated financial statements include all adjustments, all of which are of a normal recurring nature, necessary for a fair presentation of the results for the interim periods. The results of operations for the three and six months ended June 30, 2018 are not necessarily indicative of the results to be expected for the full year.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect reported and contingent amounts of assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Fair Value of Financial Instruments

The carrying amounts of cash and cash equivalents, receivables and payables approximated fair value because of the relatively short maturity of these instruments. Cash equivalents include only those investments having a maturity date of three months or less at the time of purchase. See Note 12 "Derivative Financial Instruments" for the fair value of derivative financial instruments.

7

Recently Issued Accounting Standards

In February 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) 2016-02, Leases (Topic 842). ASU 2016-02 requires lessees to recognize a lease liability and a right-to-use asset for all leases, including operating leases, with a term greater than twelve months on its balance sheet. ASU 2016-02 is effective for annual and interim periods in fiscal years beginning after December 15, 2018, with early adoption permitted, and requires a modified retrospective transition method. The Company continues to assess the impact of ASU 2016-02 on its consolidated financial statements. The Company plans to adopt Topic 842 in the first quarter of fiscal year 2019. Based on the Company’s preliminary assessment, which is subject to change, the Company expects that most of its operating lease commitments will be subject to the new standard and recognized as operating lease liabilities and right-of-use assets upon the adoption of ASU 2016-02, which will increase the total assets and total liabilities that are reported relative to such amounts prior to adoption. The Company does not expect the adoption of this standard to have a material impact on its consolidated statements of operations and cash flows.

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments (Topic 326), which replaces the incurred loss impairment methodology in current GAAP with a methodology that reflects expected credit losses and requires consideration of a broader range of reasonable and supportable information to determine credit loss estimates. ASU 2016-13 requires entities to measure all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions and reasonable and supportable forecasts. Entities will now use forward-looking information to better form their credit loss estimates. ASU 2016-13 is effective for annual and interim periods in fiscal years beginning after December 15, 2019, with early adoption permitted as of December 15, 2018, and requires the modified retrospective transition method. The Company is currently assessing the impact of ASU 2016-13 on its consolidated financial statements.

Recently Adopted Accounting Standards

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606). ASU 2014-09 affects any entity using GAAP that enters into contracts with customers to transfer goods or services or contracts for the transfer of nonfinancial assets unless those contracts are within the scope of other standards (e.g., insurance contracts or lease contracts). This ASU will supersede the revenue recognition requirements in Revenue Recognition (Topic 605), and most industry-specific guidance. The Company adopted this standard as of January 1, 2018, using the modified retrospective transition method resulting in an immaterial increase to the opening accumulated deficit due to the cumulative impact of adopting Topic 606. The adoption of the new standard had no material impact on the measurement or recognition of revenue, however additional disclosures have been added in accordance with Topic 606. See Note 2 “Revenue” for additional details on the Company’s revenue policies.

In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost (Topic 715). ASU 2017-07 requires the disaggregation of the service cost component from the other components of net periodic benefit cost and allows only the service cost component of net benefit cost to be eligible for capitalization. ASU 2017-07 is effective for annual and interim periods in fiscal years beginning after December 15, 2017. The Company sponsors two defined benefit plans in the UK under which accrual of pension benefits has ceased and there will not be a service cost component to the net periodic pension cost. Plan member benefits that have previously been accrued are indexed in line with inflation during the period up to retirement in order to protect their purchasing power. The Company adopted this standard as of January 1, 2018, with no material impact on its consolidated financial statements.

In March 2018, the FASB issued ASU No. 2018-05, Income Taxes: Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118 (Topic 740), which updates the income tax accounting in U.S. GAAP to reflect the Securities and Exchange Commission interpretive guidance released on December 22, 2017, when the Tax Cuts and Jobs Act of 2017 (“Tax Cuts and Jobs Act”) was enacted into law. The Company evaluated the potential impacts of SEC Staff Accounting Bulletin No. 118 (“SAB 118”) along with this ASU and has applied them to its consolidated financial statements and related disclosures. See Note 8 “Income Taxes” for additional information.

2. Revenue

Adoption of ASC Topic 606, Revenue from Contracts with Customers

On January 1, 2018, the Company adopted ASC Topic 606 using the modified retrospective method applied to those contracts which were not completed as of January 1, 2018. Results for reporting periods beginning after January 1, 2018 are presented under ASC Topic 606, while prior period amounts were not adjusted and continue to be reported in accordance with ASC Topic 605, “Revenue Recognition”. The adoption of ASC Topic 606 resulted in $5 million additional receivables and deferred revenue related to the recognition of receivables with unconditional right to payment.

Revenue Recognition

The Company’s primary source of revenue is the sale of energy products and an extensive selection of products for industrial applications based upon purchase orders or contracts with customers. The majority of revenue is recognized at a point in time once the Company has determined that the customer has obtained control over the product. Control is typically deemed to have been transferred to the customer when the product is shipped, delivered, or picked up by the customer. The Company does not grant extended payment terms. Revenue is recognized net of any taxes collected from customers, which are subsequently remitted to government authorities. Shipping and handling costs for product shipments occur prior to the customer obtaining control of the goods, and are recorded in cost of products.

The amount of revenue recognized reflects the consideration to which the Company expects to be entitled to receive in exchange for products sold. Revenue is recorded at the transaction price net of estimates of variable consideration, which may include product returns, trade discounts and allowances. The Company accrues for variable consideration using the expected value method. Estimates of variable consideration are included in revenue to the extent that it is probable that a significant reversal in the amount of cumulative revenue recognized will not occur.

See Note 7 “Business Segments” for disaggregation of revenue by reporting segments. The Company believes this disaggregation best depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors.

Remaining Performance Obligations

Remaining performance obligations represent the transaction price of firm orders for which work has not been performed on contracts with an original expected duration of one year or more. The Company’s contracts are predominantly short-term in nature with a contract term of one year or less. For those contracts, the Company has utilized the practical expedient in ASC Topic 606 exempting the Company from disclosure of the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

Receivables

Receivables are recorded when the Company has an unconditional right to consideration.

Contract Assets and Liabilities

Contract assets primarily consist of retainage amounts held as a form of security by customers until the Company satisfies its remaining performance obligations. These assets were de minimis for the six months ended June 30, 2018 and were included in receivables, net in the consolidated balance sheets. The Company applied the practical expedient to recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that the entity otherwise would have recognized is one year or less. These expenses were not material for the three and six months ended June 30, 2018.

Contract liabilities primarily consist of deferred revenues recorded when customer payments are received or due in advance of satisfying performance obligations, including amounts which are refundable, and other accrued customer liabilities. Revenue recognition is deferred to a future period until the Company completes its obligations contractually agreed with customers. The increase in contract liabilities for the six months ended June 30, 2018 was primarily related to customer deposits of approximately $17 million, partially offset by approximately $11 million of revenue recognized that was deferred at the beginning of the period.

3. Property, Plant and Equipment, net

Property, plant and equipment consist of (in millions):

	Estimated Useful Lives	June 30, 2018	December 31, 2017
Information technology assets	1-7 Years	$45	$ 48
Operating equipment	2-15 Years	90	93
Buildings and land [1]	5-35 Years	96	97
Construction in progress		1	—
Total property, plant and equipment		232	238
Less: accumulated depreciation		(123)	(119)
Property, plant and equipment, net		$109	$ 119

(1) Land has an indefinite life.

4. Accrued Liabilities

Accrued liabilities consist of (in millions):

	June 30, 2018	December 31, 2017
Compensation and other related expenses	$ 32	$ 36
Contract liabilities [1]	29	19
Taxes (non-income)	12	15
Other	30	33
Total	$ 103	$ 103

(1) Previously shown as customer credits and prepayments.

5. Debt

On April 30, 2018, the Company replaced its existing senior secured revolving credit facility and entered into a senior secured revolving credit facility (the "Credit Facility") with a syndicate of lenders with Wells Fargo Bank, National Association, serving as the administrative agent. The five-year Credit Facility provides for a $750 million global revolving credit facility (with a letter of credit subfacility of $60 million, and a swing line subfacility of 10% of the facility amount), of which up to $100 million is available for the Company's Canadian subsidiaries and $40 million for the Company's UK subsidiaries. The Company has the right, subject to certain conditions, to increase the aggregate principal amount of commitments under the credit facility by $250 million. The obligations under the Credit Facility are secured by substantially all the assets of the Company and its subsidiaries. The Credit Facility contains customary covenants, representations and warranties and events of default. The Company will be required to maintain a fixed charge coverage ratio of at least 1.00:1.00 as of the end of each fiscal quarter if excess availability under the Credit Facility falls below the greater of 12.5% of the borrowing base or $60 million.

Borrowings under the Credit Facility will bear an interest rate at the Company's option, at (i) the base rate plus an applicable margin based on the Company's fixed charge coverage ratio (and if applicable, the Company's leverage ratio); or (ii) the greater of LIBOR for the applicable interest period and zero, plus an applicable margin based on the Company's fixed charge coverage ratio (and if applicable, the Company's leverage ratio). The Credit Facility includes a commitment fee on the unused portion of commitments that ranges from 25 to 37.5 basis points. Commitment fees incurred during the period were included in other expense in the consolidated statements of operations.

Availability under the Credit Facility is determined by a borrowing base comprised of eligible receivables and eligible inventory in the U.S and Canada. As of June 30, 2018, the Company borrowed $195 million against the Credit Facility and had approximately $332 million in availability (as defined in the Credit Facility) resulting in the excess availability (as defined in the Credit Facility) of 62% subject to certain limitations. The Company was not obligated to pay back the borrowing against the Credit Facility until the expiration date, as such the outstanding borrowing is classified as long-term debt in the consolidated balance sheets.

The Company issued $6 million in letters of credit under the Credit Facility primarily for casualty insurance expiring in July 2019.

6. Accumulated Other Comprehensive Income (Loss)

The components of accumulated other comprehensive loss are as follows (in millions):

	Foreign Currency Translation Adjustments
Balance at December 31, 2017	$ (105)
Other comprehensive loss	(19)
Balance at June 30, 2018	$ (124)

The Company's reporting currency is the U.S. dollar. A majority of the Company's international entities in which there is a substantial investment have the local currency as their functional currency. As a result, foreign currency translation adjustments resulting from the process of translating the entities' financial statements into the reporting currency are reported in other comprehensive income or loss in accordance with ASC Topic 830, "Foreign Currency Matters."

7. Business Segments

Operating results by reportable segment are as follows (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Revenue:				
United States	$600	$481	$1,162	$920
Canada	75	79	177	175
International	102	91	202	187
Total revenue	$777	$651	$1,541	$1,282
Operating profit (loss):				
United States	$16	$(16)	$19	$(42)
Canada	1	2	5	5
International	1	—	1	2
Total operating profit (loss)	$18	$(14)	$25	$(35)
Operating profit (loss) % of revenue:				
United States	2.7 %	(3.3%)	1.6 %	(4.6 %)
Canada	1.3 %	2.5 %	2.8 %	2.9 %
International	1.0 %	0.0 %	0.5 %	1.1 %
Total operating profit (loss) %	2.3 %	(2.2%)	1.6 %	(2.7 %)

8. Income Taxes

On May 1, 2014, the National Oilwell Varco, Inc. (“NOV”) Board of Directors approved the Spin-Off (the “Spin-Off” or “Separation”) of its distribution business into an independent, publicly traded company named NOW Inc. In connection with the Separation, the Company and NOV entered into a Tax Matters Agreement, dated as of May 29, 2014 (the “Tax Matters Agreement”). The Tax Matters Agreement sets forth the Company and NOV’s rights and obligations related to the allocation of federal, state, local and foreign taxes for periods before and after the Spin-Off, as well as taxes attributable to the Spin-Off, and related matters such as the filing of tax returns and the conduct of IRS and other audits. Pursuant to the Tax Matters Agreement, NOV has prepared and filed the consolidated federal income tax return, and any other tax returns that include both NOV and the Company for all the liability periods ended on or prior to May 30, 2014. NOV will indemnify and hold harmless the Company for any income tax liability for periods before the Separation date. The Company will prepare and file all tax returns that include solely the Company for all taxable periods ending after that date. Settlements of tax payments between NOV and the Company were generally treated as contributions from or distributions to NOV in periods prior to the Separation date.

The effective tax rates for the three and six months ended June 30, 2018 were 6.1% and 9.3%, compared to (0.1%) and 1.0% for the same periods in 2017. Compared to the U.S. statutory rate, the effective tax rate was impacted by recurring items, such as differing tax rates on income earned in foreign jurisdictions that is permanently reinvested, nondeductible expenses, state income taxes, the effects of the enactment of the Tax Cuts and Jobs Act and the change in valuation allowance recorded against deferred tax assets. Due to the continuing uncertainty in the Company's industry and thus the Company's outlook, the Company continues to utilize the method of recording income taxes on a year-to-date effective tax rate for the three and six months ended June 30, 2018. The Company will evaluate its use of this method each quarter until such time as a return to the annualized estimated effective tax rate method is deemed appropriate.

Provisional Amounts in the Effective Tax Rate

The Tax Cuts and Jobs Act was enacted on December 22, 2017. The Tax Cuts and Jobs Act contains several tax law changes that will impact the Company in prior, current and future periods, including a reduction in the U.S. federal corporate tax rate from 35% to 21%, requiring companies to pay a one-time transition tax on earnings of certain foreign subsidiaries that were previously tax deferred, creating new taxes on certain foreign sourced earnings and changes to bonus depreciation, the deduction for executive compensation and interest expense. The Company is applying the guidance in SAB 118 when accounting for the enactment-date effects of the Tax Cuts and Jobs Act. At June 30, 2018, the Company has not completed its accounting for all of the tax effects of the Tax Cuts and Jobs Act; however, in certain cases, as described below, the Company has made a reasonable estimate of the tax effects. As further discussed below, during the six-month period ended June 30, 2018, the Company recognized adjustments of $9 million to the provisional amounts recorded at December 31, 2017 related to the one-time transition tax and the reduction in the corporate income tax rate. The Company will continue to refine its calculations as additional analysis is completed.

The Company originally remeasured its U.S. deferred tax assets and liabilities and recorded a $69 million charge relating to the U.S. federal corporate income tax rate change, with a corresponding decrease to its valuation allowance of $69 million. Similarly, the Company originally recorded a $33 million charge for the one-time, mandatory transition tax on unremitted foreign earnings which was fully offset by foreign tax credits and net operating losses. There was no net impact to the Company's provision for income taxes for these entries at December 31, 2017.

Subsequent guidance was issued by the Treasury Department and Internal Revenue Service in Notice 2018-26 which clarifies that companies may elect-out of using 2017 net operating losses when computing the one-time, mandatory transition tax. The Company refined its one-time, mandatory transition tax calculation, and while the election does not impact the $33 million charge originally recorded, it results in the Company utilizing additional foreign tax credits and preserves the Company's 2017 net operating loss. The Company remeasured its 2017 net operating loss deferred tax asset and recorded an additional charge of $9 million relating to the U.S. federal corporate income tax rate change with a corresponding decrease to its valuation allowance of $9 million. There was no net impact to the Company's provision for income taxes related to this adjustment at June 30, 2018.

The Tax Cuts and Jobs Act subjects a U.S. shareholder to current tax on Global Intangible Low Taxed Income ("GILTI") earned by certain foreign subsidiaries. The FASB Staff Q&A, Topic 740, No. 5 Accounting for Global Intangible Low-Taxed Income, states that an entity can make an accounting policy election to either recognize deferred taxes for temporary basis differences expected to reverse as GILTI in future years or provide for the tax expense related to GILTI in the year the tax is incurred. Given the complexity of the GILTI provisions, the Company is still evaluating the effects of the GILTI provisions and recognized a provisional tax expense of less than $1 million related to GILTI for the six-month period ended June 30, 2018, which is fully offset by prior year losses. The utilization of the Company's prior year net operating losses resulted in a corresponding decrease in the Company's valuation allowance. There was no net impact to the Company's provision for income taxes related to GILTI for the six-month period ended June 30, 2018.

To the extent penalties and interest would be assessed on any underpayment of income tax, such accrued amounts would be classified as a component of income tax provision (benefit) in the financial statements consistent with the Company's policy.

The Company is subject to taxation in the United States, various states and foreign jurisdictions. The Company has significant operations in the United States and Canada and to a lesser extent in various other international jurisdictions. Tax years that remain subject to examination by major tax jurisdictions vary by legal entity, but are generally open in the U.S. for the tax years ending after 2013 and outside the U.S. for the tax years ending after 2011. The Company is indemnified for any income tax exposures related to the periods prior to the Separation under the Tax Matters Agreement with NOV.

9. Earnings Per Share ("EPS")

For the three and six months ended June 30, 2018, approximately 6 million and 6 million, respectively, of potentially dilutive shares were excluded from the computation of diluted earnings per share due to their antidilutive effect. For the three and six months ended June 30, 2017, approximately 8 million and 8 million, respectively, of potentially dilutive shares were excluded from the computation of diluted loss per share due to the Company recognizing a net loss for the period.

Basic and diluted income (loss) per share follows (in millions, except share data):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Numerator:				
Net income (loss) attributable to the Company	$14	$(17)	$16	$(40)
Less: net income (loss) attributable to nonvested shares	—	—	—	—
Net income (loss) attributable to the Company's stockholders	$14	$(17)	$16	$(40)
Denominator:				
Weighted average basic common shares outstanding	108,278,356	107,689,554	108,177,100	107,635,122
Effect of dilutive securities	198,632	—	148,337	—
Weighted average diluted common shares outstanding	108,476,988	107,689,554	108,325,437	107,635,122
Earnings (loss) per share attributable to the Company's stockholders:				
Basic	$0.12	$(0.16)	$0.15	$(0.37)
Diluted	$0.12	$(0.16)	$0.15	$(0.37)

ASC Topic 260, "Earnings Per Share," requires companies with unvested participating securities to utilize a two-class method for the computation of net income attributable to the Company per share. The two-class method requires a portion of net income attributable to the Company to be allocated to participating securities, which are unvested awards of share-based payments with non-forfeitable rights to receive dividends or dividend equivalents, if declared. Net losses are not allocated to nonvested shares in periods that the Company determines that those shares are not obligated to participate in losses. For the periods that the Company recognized net income, net income attributable to the Company allocated to these participating securities was excluded from net income attributable to the Company's stockholders in the numerator of the earnings per share computation.

10. Stock-based Compensation and Outstanding Awards

The Company has a stock-based compensation plan known as the NOW Inc. Long-Term Incentive Plan (the "Plan"). Under the Plan, the Company's employees are eligible to be granted stock options, restricted stock awards ("RSAs"), restricted stock units ("RSUs"), and performance stock awards ("PSAs").

For the six months ended June 30, 2018, the Company granted 1,807,822 stock options with a weighted average fair value of $3.95 per share and 357,481 shares of RSAs and RSUs with a weighted average fair value of $10.82 per share. In addition, the Company granted PSAs to senior management employees with potential payouts varying from zero to 364,518 shares. These options vest over a three-year period from the grant date on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards. The RSAs and RSUs vest on the first and third anniversary of the date of grant. The PSAs can be earned based on performance against established metrics over a three-year performance period. The PSAs are divided into three equal, independent parts that are subject to three separate performance metrics: (i) one-third of the PSAs have a Total Shareholder Return (TSR) metric, (ii) one-third of the PSAs have an EBITDA metric, and (iii) one-third of the PSAs have a Working Capital (WC) metric.

Performance against the TSR metric is determined by comparing the performance of the Company's TSR with the TSR performance of designated peer companies for the three-year performance period. Performance against the EBITDA metric is determined by comparing the performance of the Company's actual EBITDA average for each of the three-years of the performance period against the EBITDA metrics set by the Company's Compensation Committee of the Board of Directors. Performance against the WC metric is determined by comparing the performance of the Company's actual WC average for each of the three-years of the performance period against the WC metrics set by the Company's Compensation Committee of the Board of Directors.

Stock-based compensation expense totaled $4 million and $8 million for the three and six months ended June 30, 2018 respectively, and $5 million and $11 million for the same periods in 2017, respectively.

11. Commitments and Contingencies

The Company is involved in various claims, regulatory agency audits and pending or threatened legal actions involving a variety of matters. The Company has also assessed the potential for additional losses above the amounts accrued as well as potential losses for matters that are not probable, but are reasonably possible. The total potential loss on these matters cannot be determined; however, in the Company's opinion, any ultimate liability, to the extent not otherwise recorded or accrued for, will not materially affect the Company's financial position, cash flow or results of operations. These estimated liabilities are based on the Company's assessment of the nature of these matters, their progress toward resolution, the advice of legal counsel and outside experts as well as management's intention and experience.

The Company's business is affected both directly and indirectly by governmental laws and regulations relating to the oilfield service industry in general, as well as by environmental and safety regulations that specifically apply to the Company's business. Although the Company has not incurred material costs in connection with its compliance with such laws, there can be no assurance that other developments, such as new environmental laws, regulations and enforcement policies hereunder may not result in additional, presently unquantifiable, costs or liabilities to the Company.

The Company does not accrue for contingent losses that, in its judgment, are considered to be reasonably possible, but not probable. Estimating reasonably possible losses also requires the analysis of multiple possible outcomes that often depend on judgments about potential actions by third parties. NOW's management currently estimates a range of loss for reasonably possible losses for which an estimate can be made is between zero and $15 million in the international segment primarily attributable to accounts receivable with one customer. The Company has accrued its best estimate for loss as of June 30, 2018. Factors underlying this estimated range of loss may change from time to time, and actual results may vary significantly from this estimate.

The Company maintains credit arrangements with several banks providing for short-term borrowing capacity, overdraft protection and other bonding requirements. As of June 30, 2018, these credit arrangements totaled approximately $35 million. The Company was contingently liable for approximately $10 million of outstanding standby letters of credit, including bid and performance related bonds and surety bonds. The Company does not believe, based on historical experience and information currently available, that it is probable that any amounts will be required to be paid.

12. Derivative Financial Instruments

The Company is exposed to certain risks relating to its ongoing business operations. The primary risk managed by using derivative instruments is foreign currency exchange rate risk. The Company has entered into certain financial derivative instruments to manage this risk.

The derivative financial instruments the Company has entered into are forward exchange contracts which have terms of less than one year to economically hedge foreign currency exchange rate risk on recognized non-functional currency monetary accounts. The purpose of the Company's foreign currency economic hedging activities is to economically hedge the Company's risk from changes in the fair value of non-functional currency denominated monetary accounts.

The Company records all derivative financial instruments at their fair value in its consolidated balance sheets. None of the derivative financial instruments that the Company holds are designated as either a fair value hedge or cash flow hedge and the gain or loss on the derivative instrument is recorded in earnings. The Company has determined that the fair value of its derivative financial instruments are computed using level 2 inputs (inputs other than quoted prices in active markets for identical assets and liabilities that are observable either directly or indirectly for substantially the full term of the asset or liability) in the fair value hierarchy as the fair value is based on publicly available foreign exchange rates at each financial reporting date. As of June 30, 2018, and December 31, 2017, the fair value of the Company’s foreign currency forward contracts totaled an asset of less than $1 million and less than $1 million, respectively, and is included in prepaid and other current assets in the accompanying consolidated balance sheets; a liability of less than $1 million and less than $1 million, respectively, and is included in other current liabilities in the accompanying consolidated balance sheets.

For the three and six months ended June 30, 2018, the Company recorded a loss of $1 million and $1 million, respectively, related to the changes in fair value. All gains and losses recorded are included in other expense in the accompanying consolidated statements of operations. The notional principal associated with those contracts was $20 million and $37 million as of June 30, 2018 and December 31, 2017, respectively.

As of June 30, 2018, the Company’s financial instruments do not contain any credit-risk-related or other contingent features that could cause accelerated payments when the Company’s financial instruments are in net liability positions. The Company does not use derivative financial instruments for trading or speculative purposes.

Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operations

Forward-Looking Statements

Some of the information in this document contains, or has incorporated by reference, forward-looking statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. Statements that are not historical facts, including statements about our beliefs and expectations, are forward-looking statements. Forward-looking statements typically are identified by use of terms such as “may,” “believe,” “anticipate,” “expect,” “plan,” “predict,” “estimate,” “will be” or other similar words and phrases, althoug forward-looking statements are expressed differently. You should be aware that our actual results could differ materially from results anticipated in the forward-looking statements due to a number of factors, including, but not limited to, changes in oil and gas prices, changes in the energy markets, customer demand for our products, significant changes in the size of our customers, difficulties encountered in integrating mergers and acquisitions, general volatility in the capital markets, changes in applicable government regulations, increased borrowing costs, competition between us and our former parent company, NOV, the triggering of rights and obligations by the Spin-Off or any litigation arising out of or related to the Separation, impairments in goodwill or other intangible assets and worldwide economic activity. You should also consider carefully the statements under “Risk Factors,” as disclosed in our Form 10-K, which address additional factors that could cause our actual results to differ from those set forth in the forward-looking statements. Given these uncertainties, current or prospective investors are cautioned not to place undue reliance on any such forward-looking statements. We undertake no obligation to update any such factors or forward-looking statements to reflect future events or developments.

Company Overview

We are a global distributor to the oil and gas and industrial markets with a legacy of over 150 years. We operate primarily under the DistributionNOW and Wilson Export brands. Through our network of approximately 270 locations and approximately 4,500 employees worldwide, we stock and sell a comprehensive offering of energy products as well as an extensive selection of products for industrial applications. Our energy product offering is consumed throughout all sectors of the oil and gas industry – from upstream drilling and completion, exploration and production (“E&P”), midstream infrastructure development to downstream petroleum refining – as well as in other industries, such as chemical processing, mining, utilities and industrial manufacturing operations. The industrial distribution end markets include manufacturing, aerospace, automotive, refineries and engineering and construction firms. We also provide supply chain and materials management solutions to the same markets where we sell products.

Our global product offering includes consumable maintenance, repair and operating (“MRO”) supplies, pipe, valves, fittings, flanges, gaskets, fasteners, electrical, instrumentation, artificial lift, pumping solutions, valve actuation and modular process, measurement and control equipment. We also offer warehouse and inventory management solutions as part of our supply chain and materials management offering. We have developed expertise in providing application systems, work processes, parts integration, optimization solutions and after-sales support.

Our solutions include outsourcing the functions of procurement, inventory and warehouse management, logistics, point of issue technology, project management, business process and performance metrics reporting. These solutions allow us to leverage the infrastructure of our SAP™ Enterprise Resource Planning (“ERP”) system and other technologies to streamline our customers’ purchasing process, from requisition to procurement to payment, by digitally managing workflow, improving approval routing and providing robust reporting functionality.

We support land and offshore operations for all the major oil and gas producing regions around the world through our network of locations. Our key markets, beyond North America, include Latin America, the North Sea, the Middle East, Asia Pacific and the Former Soviet Union (“FSU”). Products sold through our locations support greenfield expansion upstream capital projects, midstream infrastructure and transmission and MRO consumables used in day-to-day production. We provide downstream energy and industrial products for petroleum refining, chemical processing, LNG terminals, power generation utilities and industrial manufacturing operations and customer on-site locations.

We stock or sell more than 300,000 stock keeping units ("SKUs") through our branch network. Our supplier network consists of thousands of vendors in approximately 40 countries. From our operations in over 20 countries we sell to customers operating in approximately 80 countries. The supplies and equipment stocked by each of our branches are customized to meet varied and changing local customer demands. The breadth and scale of our offering enhances our value proposition to our customers, suppliers and shareholders.

We employ advanced information technologies, including a common ERP platform across most of our business, to provide complete procurement, materials management and logistics coordination to our customers around the globe. Having a common ERP platform allows immediate visibility into the Company's inventory assets, operations and financials worldwide, enhancing decision making and efficiency.

Demand for our products is driven primarily by the level of oil and gas drilling, completions, servicing, production, transmission, refining and petrochemical and industrial manufacturing activities. It is also influenced by the global supply and demand for energy, the economy in general and geopolitics. Several factors drive spending, such as investment in energy infrastructure, the North American conventional and shale plays, market expectations of future developments in the oil, natural gas, liquids, refined products, petrochemical, plant maintenance and other industrial, manufacturing and energy sectors.

We have expanded globally, through acquisitions and organic investments, into Australia, Azerbaijan, Brazil, Canada, China, Colombia, Egypt, England, India, Indonesia, Kazakhstan, Kuwait, Mexico, Netherlands, Norway, Oman, the Philippines, Russia, Saudi Arabia, Scotland, Singapore, the United Arab Emirates and the United States.

Summary of Reportable Segments

We operate through three reportable segments: United States ("U.S."), Canada and International. The segment data included in our Management's Discussion and Analysis ("MD&A") are presented on a basis consistent with our internal management reporting. Segment information appearing in Note 7 "Business Segments" of the notes to the unaudited consolidated financial statements (Part I, Item 1 of this Form 10-Q) is also presented on this basis.

United States

We have approximately 180 locations in the U.S., which are geographically positioned to best serve the upstream, midstream and downstream energy and industrial markets.

We offer higher value solutions in key product lines in the U.S. which broaden and deepen our customer relationships and related product line value. Examples of these include artificial lift, pumps, valves and valve actuation, process equipment, fluid transfer products, measurement and controls, along with many other products required by our customers, which enable them to focus on their core business while we manage their supply chain. We also provide additional value to our customers through the design, assembly, fabrication and optimization of products and equipment essential to the safe and efficient production, transportation and processing of oil and gas and industrial manufacturing.

Canada

We have a network of approximately 55 locations in the Canadian oilfield, predominantly in the oil rich provinces of Alberta and Saskatchewan in Western Canada. Our Canada segment primarily serves the energy exploration, production, mining and drilling business, offering customers many of the same products and value-added solutions that we perform in the U.S. In Canada, we also provide training for, and supervise the installation of, jointed and spoolable composite pipe. This product line is supported by inventory and product and installation expertise to serve our customers.

International

We operate in approximately 20 countries and serve the needs of our international customers from approximately 35 locations outside of the U.S. and Canada, which are strategically located in major oil and gas development areas. Our approach in these markets is similar to our approach in North America, as our customers turn to us to provide inventory and support closer to their drilling and exploration activities. Our long legacy of operating in many international regions, combined with significant expansion into several key markets, provides a competitive advantage as few of our competitors have a presence in most of the global energy producing regions.

Basis of Presentation

All significant intercompany transactions and accounts have been eliminated. The unaudited consolidated financial information included in this report has been prepared in accordance with GAAP for interim financial information and Article 10 of SEC Regulation S-X. The principles for interim financial information do not require the inclusion of all the information and footnotes required by generally accepted accounting principles for complete financial statements. Therefore, these financial statements should be read in conjunction with the financial statements included in the Company's most recent Annual Report on Form 10-K. In the opinion of our management, the consolidated financial statements include all adjustments, all of which are of a normal recurring nature, necessary for a fair presentation of the results for the interim periods. The results of operations for the three and six months ended June 30, 2018 are not necessarily indicative of the results to be expected for the full year.

Operating Environment Overview

Our results are dependent on, among other things, the level of worldwide oil and gas drilling and completions, well remediation activity, crude oil and natural gas prices, capital spending by operators, oilfield service companies and contractors and worldwide oil and gas inventory levels. Key industry indicators for the second quarter of 2018 and 2017 and the first quarter of 2018 include the following:

	2Q18*	2Q17*	% 2Q18 v 2Q17	1Q18*	% 2Q18 v 1Q18
Active Drilling Rigs:					
U.S.	1,038	892			

Exercise price $	Options outstanding Number of options	Weighted-average remaining contractual life (years)	Aggregate Intrinsic Value $	Options exercisable Number of options	Weighted-average remaining contractual life (years)	Aggregate Intrinsic Value $	Expiry
0.73	457,986	0.4	115	457,986	0.4	115	March 5, 2015
2.57	1,251,212	1.3	-	1,251,212	1.3	-	January 28, 2016
1.41	545,000	1.8	-	545,000	1.8	-	July 7, 2016
1.05	674,976	1.9	-	674,976	1.9	-	September 9, 2016
1.04	200,000	2.1	-	200,000	2.1	-	October 24, 2016
0.82	980,071	2.3	167	980,071	2.3	167	January 12, 2017
1.25	200,000	2.3	-	200,000	2.3	-	February 1, 2017
1.06	100,000	2.4	-	100,000	2.4	-	March 1, 2017
0.68	1,359,418	3.2	402	1,359,418	3.2	402	December 7, 2017
0.69	607,044	3.6	174	461,671	3.6	132	April 25, 2018
1.11	100,000	3.8	-	76,000	3.8	-	August 1, 2018
1.08	979,081	4.2	-	531,404	4.2	-	December 27, 2018
1.51	100,000	4.5	-	32,000	4.5	-	

March 31, 2019

1.19	7,554,788	2.6	858	6,869,738	2.4	816

The aggregate intrinsic value of the options in the preceding table represents the total pre-tax intrinsic value for stock options with an exercise price less than the Company's TSX closing stock price of Cdn$1.13 as of the last trading day in the period ended September 30, 2014, that would have been received by the option holders had they exercised their options as of that date. The total number of in-the-money stock options outstanding as of September 30, 2014 was 3,404,519. The total number of in-the-money stock options exercisable as of September 30, 2014 was 3,259,146.

Restricted share units

On June 24, 2010, the Company's shareholders approved the adoption of the Company's restricted share unit plan (the "RSU Plan"). Eligible participants under the RSU Plan include directors and employees of the Company. Under the terms of the RSU Plan, RSUs vest with participants as follows: 50% on the first anniversary of the date of the grant and 50% on the second anniversary of the date of the grant.

19

Table of Contents

Ur-Energy Inc.

Condensed Notes to Unaudited Interim Consolidated Financial Statements

September 30, 2014

(expressed in thousands of U.S. dollars unless otherwise indicated)

Activity with respect to RSUs is summarized as follows:

	Number of RSUs	Weighted average grant date fair value $
Unvested, December 31, 2013	691,610	0.90
Vested	(230,531)	0.93
Forfeited	(38,671)	0.93
Unvested, September 30, 2014	422,408	0.91

As of September 30, 2014, outstanding RSUs are as follows:

Grant date	Number of unvested options	Remaining life (years)	Aggregate Intrinsic Value $
December 7, 2012	179,106	0.19	181
December 27, 2013	243,302	1.24	246
	422,408	0.79	427

Upon RSU vesting, the holder of an RSU will receive one common share, for no additional consideration, for each RSU held.

Warrants

There was no warrant activity during the period ended September 30, 2014.

Table of Contents

Ur-Energy Inc.

Condensed Notes to Unaudited Interim Consolidated Financial Statements

September 30, 2014

(expressed in thousands of U.S. dollars unless otherwise indicated)

As of September 30, 2014, outstanding warrants are as follows:

Exercise price $	Number of warrants	Remaining contractual life (years)	Aggregate Intrinsic Value $	Expiry
0.92	50,000	0.9	6	September 4, 2015
1.12	100,000	1.1	-	November 1, 2015
0.93	25,000	1.4	3	March 5, 2016
1.35	2,354,545	2.2	-	December 19, 2016
1.12	4,294,167	3.7	-	June 24, 2018
1.17	1,550,400	3.9	-	August 27, 2018
	8,374,112	3.3	9	

Share-based compensation expense

Share-based compensation expense was $0.7 million and $0.9 million for the nine months ended September 30, 2014 and 2013, respectively.

As of September 30, 2014, there was approximately $0.3 million of total unrecognized compensation expense (net of estimated pre-vesting forfeitures) related to unvested share-based compensation arrangements granted under the Option Plan and $0.2 million under the RSU Plan. The expenses are expected to be recognized over a weighted-average period of 0.7 years and 1.1 years, respectively.

Cash received from stock options exercised during the nine months ended September 30, 2014 and 2013 was $1.3 million and $0.1 million, respectively.

Fair value calculations

The initial fair value of options granted during the nine months ended September 30, 2014 was determined using the Black-Scholes option pricing model with the following assumptions:

	2014	2013
Expected option life (years)	3.49	3.41
Expected volatility	66%	63%
Risk-free interest rate	1.4%	1.1%
Forfeiture rate (options)	4.5%	4.4%
Expected dividend rate	0%	0%

Table of Contents

Ur-Energy Inc.

Condensed Notes to Unaudited Interim Consolidated Financial Statements

September 30, 2014

(expressed in thousands of U.S. dollars unless otherwise indicated)

The Company estimates expected volatility using daily historical trading data of the Company’s common shares, because this is recognized as a valid method used to predict future volatility. The risk-free interest rates are determined by reference to Canadian Treasury Note constant maturities that approximate the expected option term. The Company has never paid dividends and currently has no plans to do so.

Share-based compensation expense is recognized net of estimated pre-vesting forfeitures, which results in recognition of expense on options that are ultimately expected to vest over the expected option term. Forfeitures were estimated using actual historical forfeiture experience.

There were no RSUs granted in the nine months ended September 30, 2014 or 2013.

18.Sales

Sales have been primarily derived from U_3O_8 being sold to domestic utilities under contracts. In 2013, the Company also assigned its 2013 and 2014 deliveries under two of its contracts to a third party broker.

Sales consist of:

	Nine months ended September 30, 2014 $	
Company A	10,123	44.6%
Company B	2,596	11.4%
Company C	7,197	31.7%
Disposal fees	289	1.3%
Recognition of gain from sale of deliveries under contract	2,507	11.0%
	22,712	100.0%

19.Commitments

In June 2014, the WDEQ and the NRC approved modifications to several reclamation bonds to reflect current obligations and anticipated disturbances during the upcoming year. The total reclamation bonding requirements were therefore increased to $26.7 million. The Company increased its surety performance bonding to that amount. The Company will be increasing the cash securing the security bonds (see note 7) by $2.1 million prior to the end of the current year.

In June, the Company signed an agreement for drilling and completion of a third disposal well. The project commenced in July 2014 with completion expected later this year. It is anticipated that the total cost of the well will be approximately $3.2 million.

Table of Contents

Ur-Energy Inc.

Condensed Notes to Unaudited Interim Consolidated Financial Statements

September 30, 2014

(expressed in thousands of U.S. dollars unless otherwise indicated)

20.Financial instruments

The Company's financial instruments consist of cash and cash equivalents, accounts receivable, restricted cash, deposits, accounts payable and accrued liabilities and notes payable. The Company is exposed to risks related to changes in foreign currency exchange rates, interest rates and management of cash and cash equivalents and short-term investments

Credit risk

Financial instruments that potentially subject the Company to concentrations of credit risk consist of cash and cash equivalents and restricted cash. These assets include Canadian dollar and U.S. dollar denominated certificates of deposits, money market accounts and demand deposits. They bear interest at annual rates ranging from 0.18% to 0.6% and mature at various dates up to February 5, 2015. These instruments are maintained at financial institutions in Canada and the United States. Of the amount held on deposit, approximately $0.9 million is covered by the Canada Deposit Insurance Corporation, the Securities Investor Protection Corporation or the United States Federal Deposit Insurance Corporation, leaving approximately $8.6 million at risk at September 30, 2014 should the financial institutions with which these amounts are invested be rendered insolvent. The Company does not consider any of its financial assets to be impaired as of September 30, 2014.

Liquidity risk (see note 2)

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they come due.

The Company has financed its operations from its inception primarily through the issuance of equity securities and debt instruments. Production commenced in August 2013 after receiving final operational clearance from the NRC. Product sales commenced in December 2013.

As at September 30, 2014, the Company's financial liabilities consisted of trade accounts payable and accrued trade and payroll liabilities of $2.6 million which are due within normal trade terms of generally 30 to 60 days, notes payable which will be payable over periods of 0 to 7 years, and asset retirement obligations with estimated completion dates until 2033.

Sensitivity analysis

The Company has completed a sensitivity analysis to estimate the impact that a change in interest rates would have on the net loss of the Company. This sensitivity analysis shows that a change of +/- 100 basis points in interest rate would have a nominal effect for the nine months ended September 30, 2014. The financial position of the Company may vary at the time that a change in interest rates occurs causing the impact on the Company's results to differ from that shown above.

Table of Contents

Item 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATION

Business Overview

The following discussion is designed to provide information that we believe is necessary for an understanding of our financial condition, changes in financial condition and results of our operations. The following discussion and analysis should be read in conjunction with the MD&A contained in our Annual Report on Form 10-K for the year ended December 31, 2013. The financial statements have been prepared in accordance with US GAAP.

Incorporated on March 22, 2004, Ur-Energy is an exploration stage mining company, as that term is defined in SEC Industry Guide 7. We are engaged in the identification, acquisition, evaluation, exploration, development and operation of uranium mineral properties in the United States. We have constructed and begun operation of our first in situ recovery ("ISR") U_3O_8 mine at our Lost Creek Project in Wyoming. Ur-Energy is a corporation continued under the Canada Business Corporations Act on August 8, 2006. Our Common Shares are listed on the TSX under the symbol "URE" and on the NYSE MKT under the symbol "URG."

Ur-Energy has one wholly-owned subsidiary: Ur-Energy USA Inc, incorporated under the laws of the State of Colorado. Ur-Energy USA has three wholly-owned subsidiaries: NFU Wyoming, LLC, a limited liability company formed under the laws of the State of Wyoming which acts as our land holding and exploration entity; Lost Creek ISR, LLC, a limited liability company formed under the laws of the State of Wyoming to operate our Lost Creek Project and hold our Lost Creek properties and assets; and Pathfinder, incorporated under the laws of the State of Delaware, acquired in December 2013, which holds, among other assets, the Shirley Basin and Lucky Mc properties in Wyoming. Our other U.S. subsidiaries remain unchanged since the filing of our Annual Report on Form 10-K, dated March 3, 2014.

We utilize in situ recovery of the U_3O_8 at our flagship project, Lost Creek, and will do so at other projects where possible. The ISR technique is employed in uranium extraction because it allows for an effective recovery of roll front uranium mineralization at a lower cost. At Lost Creek, we extract and process $U_3O_{8,}$ for shipping to a third-party storage and conversion facility.

Our Lost Creek processing facility, which includes all circuits for the production, drying and packaging of uranium for delivery into sales, is designed to process one million pounds of U_3O_8 annually from the Lost Creek mine. The processing facility has the physical design capacity to process two million pounds of U_3O_8 annually, which provides additional capacity to process material from other sources. We expect that the Lost Creek processing facility will be utilized to process captured U_3O_8 from our Shirley Basin Project.

Currently, we have eight U_3O_8 sales agreements in place with various U.S. utilities for the sale of U_3O_8 at mid- and long-term contract pricing. The multi-year sales agreements represent a portion of our anticipated production from 2013 through 2019. These agreements individually do not represent a substantial portion of our annual projected production, and our business is therefore not substantially dependent upon any one of the agreements. The balance of our Lost Creek production will be sold through spot sales and through additional multi-year agreements.

MINERAL RIGHTS AND PROPERTIES

The following is a summary of significant activities by project for the three and nine months ended September 30, 2014:

Table of Contents

Lost Creek Property

Ten of our U.S. properties are located in the Great Divide Basin, Wyoming, including Lost Creek. Currently we control a total of more than 2,100 unpatented mining claims and four State of Wyoming mineral leases for a total of approximately 42,000 acres (16,997 hectares) in the area of the Lost Creek Property, including the Lost Creek permit area (the "Lost Creek Project" or "Project"), and certain adjoining properties which we refer to as LC East, LC West, LC North, LC South and EN Project areas (collectively, with the Lost Creek Project, the "Lost Creek Property").

During the quarter, production rates at Lost Creek were increased over the previous quarter and maintained at levels permitting us to fulfill our contractual sales requirements. Plant head grades continued to exceed projections, averaging levels of 135 mg/l U_3O_8. Production flow was sourced from six header houses in the first mine unit, with production flow rates deliberately curtailed to manage uranium production rates and waste water generation. The Results of Operations are detailed below.

We continue to address remaining water balance concerns, and commenced the drilling of a third deep disposal well. Currently, we expect the third disposal well to be operational prior to year's end. We continue to anticipate that production rates may fluctuate as commissioning continues and all initial operational issues are identified and addressed.

Work continued on applications to amend existing permits and licenses at Lost Creek to include recovery from the KM horizon and LC East operations, culminating with the submission of these requests for amendments to regulatory authorities in September 2014.

Shirley Basin Project

In July 2014, we completed a uranium resource estimate for our Shirley Basin Project. This mineral estimate identified 8,816,000 pounds of Measured and Indicated resources, averaging 0.23% eU_3O_8 at an average depth to the top of resources of 312 feet below surface. The analysis is based upon 3,200 historic delineation drill holes (1.2 million feet of drilling) completed by Pathfinder prior to its 1992 termination of mining operations at the project. The results of our confirmation drilling program, completed in May 2014, are also included in the analysis.

Pathfinder's historic drilling was focused on two resource areas to support future planned mining operations. These resource areas were the FAB Trend and Area 5. Because of the close-spaced drilling in these resource areas (a 100-ft grid of drill holes), as shown in the table below, 85% of the resources are classified as Measured Resources.

Table of Contents

Shirley Basin Project - Resource Summary July 2014

	MEASURED			INDICATED		
RESOURCE	AVG GRADE	SHORT TONS	POUNDS	AVG GRADE	SHORT TONS	POUNDS
AREA	% eU_3O_8	(X 1000)	(X 1000)	(X 1000)	(X 1000)	(X 1000)
FAB TREND	0.280	1,172	6,574	0.119	456	1,081
AREA 5	0.243	195	947	0.115	93	214
TOTAL	0.275	1,367	7,521	0.118	549	1,295
			MEASURED & INDICATED	0.230	1,915	8,816

1. Sum of Measured and Indicated tons and pounds may not add to the reported total due to rounding.
2. Based on grade cut-off of 0.02 percent eU_3O_8 and a grade x thickness cut-off of 0.25 GT.
3. Measured and Indicated Mineral Resources as defined in Section 1.2 of NI 43-101 (the CIM Definition Standards (CIM Council, 2014)).
4. All reported resources occur below the historic pre-mining static water table.

Resources are classified as Measured and Indicated Mineral Resources as defined in Section 1.2 of Canadian National Instrument 43-101 Standards of Disclosure for Mineral Projects (NI 43-101) and the Canadian Institute of Mining, Metallurgy and Petroleum (CIM) Definition Standards for Mineral Resources and Mineral Reserves (CIM Definition Standards). On August 28, 2014, we filed an independent NI 43-101 Technical Report which discloses this initial uranium resource estimate for the project. There are no material differences in the resources set forth in the Technical Report and our earlier disclosure on July 22, 2014. Western Water Consultants, Inc., d/b/a WWC Engineering, oversaw and supervised preparation of this Technical Report, in accordance with NI 43-101. Mr. Benjamin J. Schiffer, P.G., WWC Engineering, is the independent Qualified Person for the report.

The mineral resource has been estimated utilizing the grade-thickness (GT) contour method. The GT contour method is well accepted within the uranium ISR industry and is suited to guide detailed mine planning and estimates of total resources for roll front type deposits such as the Shirley Basin Project. Uranium minerals to be reported as resources in the analysis must be below the static water level and have a minimum grade of 0.020% eU_3O_8 and a minimum GT of 0.25.

Earlier in 2014, we completed our initial drill program at Shirley Basin which included not only the confirmation drilling included in the Technical Report, but also 12 monitor wells and five pump test wells. Multiple environmental baseline studies continued during the quarter, providing data for our ongoing process of preparing applications to permit the project for further development and mine operations.

Results of Operations

U_3O_8 sales for the quarter were based on selling 100,000 pounds at an average price of $59.96 and U_3O_8 sales for the year were based on selling 417,760 pounds at an average price of $47.67 per pound.

During the quarter, we recorded $3.6 million of gross profit on total sales of $7.3 million, which represents a gross margin of approximately 49%. For the year to date, we have sales of $22.7 million resulting in a gross profit of $8.6 million or approximately 38%. We had an operating loss of $2.8 and $4.7 million after deducting total operating expenses of $6.4 million and $13.3 million for the three and nine month periods ended September 30, 2014, respectively. After recording interest and other expenses, the final net loss for the three and nine months was $3.5 and $6.3 million, respectively.

During the previous quarter, we recorded an out of period adjustment due to the reclassification of severance and ad valorem taxes as a cost of extraction instead of a direct cash cost of sale.

Production costs for the current quarter were up $0.1 million. As a result of this and lower production levels at the plant, production costs per pound were higher this quarter versus the previous quarter. This is also reflected in a higher cost per pound sold (up from $32.54 in 2014 Q2 to $37.52 in 2014 Q3). As production and sales levels stabilize in future quarters, we would expect to see lower cost per pound figures.

Interest expense increased during the quarter because of the additional RMBAH borrowing, but should begin to decrease as we repay the principal on those notes. Our first quarterly principal payment to RMBAH ($0.8 million) was made in June 2014, while the first principal payment on the State Bond Loan ($1.0 million) will be paid in January 2015.

The NRC and the WDEQ approved the Lost Creek bond increase from $8.6 million to $13.3 million earlier this year. We have placed the surety bonds and will be increasing our restricted cash balances to meet our surety bonding requirements over the balance of the year.

In July 2014, we received cash from two sales of uranium made during the previous quarter. In October 2014, we received a cash payment from a sale of U_3O_8 made in September. Our cash position at October 30, 2014 was approximately $4.5 million.

Table of Contents

Three and nine months ended September 30, 2014 compared to the three and nine months ended September 30, 2013

The following tables summarizes the results of operations for the three and nine months ended September 30, 2014 and 2013 (in thousands of U.S. dollars):

	Three months ended	September 30,
	2014	2013
	$	$
		2013 Restatement
Revenue	7,329	Nil
Cost of revenues	(3,752)	Nil
Gross profit	3,577	Nil
Exploration and evaluation expense	(830)	(603)
Development expense	(3,738)	(5,484)
General and administrative expense	(1,469)	(1,236)
Write-off of mineral properties	(329)	-
Net loss from operations	(2,789)	(7,323)
Interest income (Expense) (net)	(921)	(2)
Warrant mark to market gain	210	Nil
Loss from equity investment	(2)	(6)
Foreign exchange gain (loss)	3	(4)
Other loss	(1)	(1)
Net loss	(3,500)	(7,336)
Loss per share – basic and diluted	(0.03)	(0.06)

Table of Contents

	Nine months ended September 30,	
	2014	2013
	$	$
		2013 Restatement
Revenue	22,712	Nil
Cost of revenues	(14,161)	Nil
Gross profit	8,551	Nil
Exploration and evaluation expense	(2,702)	(1,789)
Development expense	(5,023)	(17,066)
General and administrative expense	(5,116)	(4,116)
Write-off of mineral properties	(422)	(262)
Net loss from operations	(4,712)	(23,233)
Interest income (expense) (net)	(2,309)	29
Warrant mark to market gain	786	-
Loss from equity investment	(5)	(977)
Foreign exchange loss	(12)	(6)
Other loss	-	(5)
Net loss	(6,252)	(24,192)
Loss per share – basic and diluted	(0.05)	(0.20)

U_3O_8 Sales and Production

During the nine months ended September 30, 2014, 446,612 pounds of U_3O_8 were captured within the Lost Creek plant. 430,832 of those pounds were packaged in drums and 460,462 pounds of drummed inventory were shipped to the conversion facility where 417,760 pounds were sold to utility customers for sales revenues of $19.9 million. In addition, the Company recognized sales of $1.2 million and $2.5 million for the three and nine months ended September 30, 2014, respectively, from the delivery during the period by a third party of 200,000 pounds of uranium under contractual delivery commitments assigned to that third party in 2013.

Table of Contents

Inventory, Production and Sales	Unit	2014 Q3	2014 Q2	2014 Q1	Year to date
Pounds captured within the plant	lb.	131,331	116,708	198,573	446,612
Cash cost per pound captured	$/lb.	$ 10.09	$ 9.63	$ 9.73	$ 9.81
Non-cash cost per pound captured	$/lb.	$ 10.28	$ 11.56	$ 6.80	$ 9.07
Wellfield cash cost 1	$000	$ 1,325	$ 1,124	$ 1,933	$ 4,382
Wellfield non-cash cost 1	$000	$ 1,349	$ 1,350	$ 1,350	$ 4,049
Pounds packaged in drums	lb.	125,915	133,684	171,233	430,832
Cash cost per pound drummed	$/lb.	$ 13.53	$ 12.15	$ 11.11	$ 12.14
Non-cash cost per pound drummed	$/lb.	$ 4.00	$ 3.76	$ 2.94	$ 3.50
Plant cash cost 2	$000	$ 1,703	$ 1,625	$ 1,902	$ 5,230
Plant non-cash cost 2	$000	$ 504	$ 502	$ 503	$ 1,509
Pounds shipped to conversion facility	lb.	126,499	163,747	170,216	460,462
Cost per pound shipped	$/lb.	$ (0.24)	$ 0.71	$ 0.89	$ 0.52
Distribution cost 3	$000	$ (31)	$ 117	$ 152	$ 238
Pounds sold	lb.	100,000	207,760	110,000	417,760
Average spot price 4	$/lb.	n/a	n/a	n/a	n/a
Average long-term contract price	$/lb.	$ 59.96	$ 34.64	$ 61.12	$ 47.67
Average price	$/lb.	$ 59.96	$ 34.64	$ 61.12	$ 47.67
U_3O_8 sales	$000	$ 5,996	$ 7,197	$ 6,723	$ 19,916
Cash cost per pound sold	$/lb.	$ 23.29	$ 20.56	$ 23.17	$ 21.90
Non-cash cost per pound sold	$/lb.	$ 14.23	$ 11.98	$ 9.99	$ 12.00
Total cost per pound sold	$/lb.	$ 37.52	$ 32.54	$ 33.16	$ 33.90
Cost of sales 5	$000	$ 3,752	$ 6,761	$ 3,648	$ 14,161

Notes:

1 Wellfield costs include all wellfield operating costs, severance and ad valorem taxes plus amortization of the related mineral property acquisition costs and depreciation of the related asset retirement obligation costs. Wellfield construction and development costs, which include wellfield drilling, header houses, pipelines, power lines, roads, fences and disposal wells, are treated as development expense and are not included in wellfield operating costs.

2 Plant costs include all plant operating costs, site overhead costs and depreciation of the related plant construction and asset retirement obligation costs.

3 Distribution costs include all shipping costs and costs charged by the conversion facility for weighing, sampling, assaying and storing the U_3O_8 prior to sale. There are no non-cash costs associated with distribution.

4 There were no spot sales in the nine months ended September 30, 2014.

5 Cost of sales include all production costs (notes 1, 2 and 3) adjusted for changes in inventory values.

Table of Contents

Cash cost per pound and non-cash cost per pound for produced and sold U_3O_8 presented in the table above are non-US GAAP measures. These measures do not have a standardized meaning or a consistent basis of calculation under US GAAP. These measures are used to assess business performance and may be used by certain investors to evaluate the Company's extraction and processing performance. To facilitate a better understanding of these measures, the table below presents a reconciliation of these measures to the financial results as presented in our financial statements.

Sales per the statement of operations include revenue from sources other than the sale of U_3O_8. The sales footnote in the financial statements separates the U_3O_8 sales from other revenues.

Average Price Per Pound Sold Reconciliation	Unit	2014 Q3	2014 Q2	2014 Q1	Year to date
U_3O_8 Sales (a) 1	$000	$ 5,996	$ 7,197	$ 6,723	$ 19,916
Pounds sold (b)	lb.	100,000	207,760	110,000	417,760
Average price per pound sold (a ÷ b)	$/lb.	$ 59.96	$ 34.64	$ 61.12	$ 47.67

Notes:

1 Does not include $2.5 million recognized from the gain on assignment of deliveries under long-term contracts because the additional revenue would distort the average realized price per pound.

Total Cost Per Pound Sold Reconciliation	Unit	2014 Q3	2014 Q2	2014 Q1	Year to date
Wellfield costs	$000	$ 2,675	$ 2,474	$ 3,282	$ 8,431
Plant costs	$000	$ 2,207	$ 2,127	$ 2,405	$ 6,739
Distribution costs	$000	$ (31)	$ 117	$ 152	$ 238
Inventory change	$000	$ (1,099)	$ 2,043	$ (2,191)	$ (1,247)
Cost of sales (a)	$000	$ 3,752	$ 6,761	$ 3,648	$ 14,161
Pounds sold (b)	lb.	100,000	207,760	110,000	417,760

Cost per pound sold (a ÷ b) 1	$/lb.	$ 37.52	$ 32.54	$ 33.16	$ 33.90

Notes:

1 The cost per pound sold reflects both cash and non-cash costs, which are combined as cost of sales in the statement of operations included in this filing. The cash and non-cash cost components are identified in the above inventory, production and sales table.

31

Table of Contents

Overall, costs of sales per pound were higher in Q3 2014 due to the decrease in production necessitated by the remediation of the water disposal issue. As many of our costs are fixed, a lower production level will result in a higher cost per pound. We would expect to see the cost per pound decrease as production levels stabilize.

Cost of Sales

The cost of sales includes all costs of wellfield operations and maintenance, severance and ad valorem taxes, plant operations and maintenance and mine site overhead including depreciation on the related capital assets, capitalized reclamation costs and amortization of mineral property costs, and distribution costs. Wellfield costs, plant costs, site overhead costs and distribution costs are included in inventory and the resulting inventoried cost per pound is compared to the estimated sales prices based on the contracts or spot sales anticipated for the distribution of the product. Any costs in excess of the calculated market value are charged to expense.

The costs included in cost of sales were as projected, however, the costs of sales per pound remained higher than projected due to several factors. Our costs are primarily process based. Therefore, when production levels are lower, the cost per pound will be higher. In addition, all depreciation and amortization is being calculated using a straight line basis and are therefore fixed costs in nature, so while production levels are low, the non-cash portion of the cost per pound will be higher. As production levels increase, the costs per pound sold will decrease so long as production costs remain on target.

Operating Expenses

Total operating expenses for the three and nine months ended September 30, 2014 were $6.4 and $13.3 million, respectively. Operating expenses includes exploration and evaluation expense, development expense, G&A expense and mineral property write-offs. These expenses decreased by $1.0 and $10.0 million compared to the same periods in 2013 due primarily to reductions in the wellfield development and disposal well costs incurred in 2013 in association with the construction of the mine property.

Exploration and evaluation expense consists of labor and associated costs of the exploration and evaluation departments as well as land holding and exploration costs including drilling and analysis on properties which have not reached the permitting or operations stage. These expenses increased $0.2 and $0.9 million for the three and nine months ended September 30, 2014 compared to 2013, respectively. Increases in payroll costs due to the payment of annual bonuses, personnel changes and the discontinuance of allocations of payroll costs to other departments make up the increase for the nine months. All costs associated with the Geology and Geological Information Systems departments as well as the costs incurred on specific projects as described above are reflected in this category.

Development expense includes costs incurred at the Lost Creek Project not directly attributable to production activities, including wellfield construction, drilling and development costs. It also includes costs associated with the Shirley Basin and Lucky Mc properties as they are in a more advanced stage. Development expenses decreased by $1.7 and $12.0 million in the three and nine months ended September 30, 2014, respectively, compared to 2013. The most significant costs associated with this decline are the 2013 costs of constructing and developing the wellfield header houses, production wells, pipelines within the wellfield and to the plant and related facilities, roads, fencing, power lines, and disposal wells, which are reduced significantly in 2014. We will continue to incur similar costs as we drill and expand existing mine units, construct additional header houses and construct the infrastructure including piping and power for newly permitted mine units. In addition, we are adding a third disposal well which was begun during the three months ended September 30, 2014 with approximately $2.0 million of costs being recorded in the three months. This well should be completed prior to the end of the year at an additional cost of $1.2 million.

Table of Contents

These costs are considered development costs despite potential future benefits as we have no proven and probable mineral reserves as defined by Industry Guide 7 and are therefore precluded from capitalizing these expenses under SEC guidance. Other than the construction related costs, bonding expense increased by $0.2 million and land claim costs increased by $0.1 million for the three and nine months ended September 30, 2014. The Company conducted limited drilling at the Shirley Basin Project for baseline measurements and confirmation of historical data. Header house construction has also continued as needed. A limited development drilling program at Lost Creek was conducted during the current period. Because of the drilling and disposal well, development expense will be significantly higher during the second half of 2014 as compared to the first half.

G&A expense relates to administration, finance, investor relations, land and legal functions and consists principally of personnel, facility and support costs. Expenses increased by $0.2 million and $1.0 million for the three and nine months compared to September 30, 2014, compared to the respective periods in 2013. The increase during the three month period was primarily because of additional legal costs while the additional expense for the nine month period was due to the payment of the annual short term incentive plan bonus in 2014 for 2013 and the accrual of certain obligations of future severance (termination) benefits not previously reflected.

Other Income and Expenses

Net interest expense in 2014 is reflective of obtaining financing during 2013 for the completion of the mine, purchase of Pathfinder and production start-up costs.

In December 2013, the Company sold equity units which included one common share and one half warrant for the purchase of stock at US$1.35 per common share. As the warrants were priced in U.S. dollars and not Canadian dollars, which is the currency of the Company’s capital stock, these warrants are considered a derivative and are therefore treated as a liability. The mark to market gain of $0.8 million for the nine months arises from the revaluation of those U.S. dollar warrants to their Black-Scholes calculated value at September 30, 2014.

Loss per Common Share

Both basic and diluted loss per common share for the three and nine months ended September 30, 2014 was $0.03 and $0.05, respectively, compared to $0.06 and $0.20, respectively, in 2013. The diluted loss per common share is equal to the basic loss per common share due to the anti-dilutive effect of all convertible securities outstanding given that net losses were experienced.

Liquidity and Capital Resources

As of September 30, 2014, we had cash resources, consisting of cash and cash equivalents of $3.4 million, an increase of $1.8 million from the December 31, 2013 balance of $1.6 million. The cash resources consist of Canadian and U.S. dollar denominated deposit accounts and money market funds. We used $1.3 million for operating activities during the nine months ended September 30, 2014. During the same period, we used $1.4 million for investing activities and we generated $4.4 million from financing activities.

Prior to the commencement of U_3O_8 deliveries and corresponding sales, we financed our operations primarily through the issuance of equity securities and debt instruments. Initial deliveries and product sales commenced in December 2013 although the first collections under those sales did not occur until January 2014. The

Company will continue to consider additional financing opportunities until it builds sufficient cash reserves to cover the variability of cash receipts that result from a limited number of large sales annually which is typical in this industry.

On October 23, 2013, we closed a $34.0 million Sweetwater County, State of Wyoming, Taxable Industrial Development Revenue Bond financing program (“State Bond Loan”). Prior to closing the State Bond Loan, we had previously obtained interim financing from RMBAH which had been paid off from the proceeds of the State Bond Loan. On December 19, 2013, we redrew $5.0 million from the RMBAH loan facility. As of December 31, 2013, the outstanding balance of the RMBAH loan facility was $5.0 million and the State Bond Loan was $34.0 million. In March 2014, we renegotiated the terms of the RMBAH loan facility which allowed us to draw an additional $1.5 million and to extend the payment terms. In addition, the renegotiated terms allowed us to draw $3.5 million more due to the resources reported at the Shirley Basin Project in the technical report published during the period.

The State Bond Loan calls for payments of interest at a fixed rate of 5.75% per annum on a quarterly basis which commenced January 1, 2014. The principal is payable in 28 quarterly installments commencing January 1, 2015 and continuing through October 1, 2021. The State Bond Loan is secured by all of the assets at the Lost Creek Project. The RMBAH loan facility calls for payments of interest at 8.5% plus the three month LIBOR rate recalculated at the start of each calendar quarter (approximately 8.77% in total) plus eight equal quarterly principal payments commencing June 30, 2014. The RMBAH loan facility is secured by all of the assets of Pathfinder.

During the nine months ended, the Company realized $1.3 million from the exercise of stock options by current and former employees.

On August 19, 2014, we filed a universal shelf registration statement on Form S-3 in order that we may offer and sell, from time to time, in one or more offerings, at prices and terms to be determined, up to $100 million of our common shares, warrants to purchase our common shares, our senior and subordinated debt securities, and rights to purchase our common shares and/or our senior and subordinated debt securities. The registration statement became effective September 12, 2014. As at October 30, 2014, we have not sold any securities under the shelf registration statement.

Operating activities used $1.2 million during the nine months ended September 30, 2014 as compared to using $14.7 million of cash resources during the same period in 2013. Accounts receivable increased by $0.3 million at September 30 compared to December 31 due to a sale occurring in September. This was collected in early October under the terms of the sales contract. Inventory increased by $1.2 million due in part to a higher cost per pound for the quarter. Our payables were higher by $2.2 million at September 30, due to additional payables associated with the drilling of the third disposal well.

During the first nine months of 2014, the Company invested $0.3 million in equipment at the Lost Creek plant.

During the first nine months of 2014, the Company generated $4.4 million from financing activities, primarily from the additional borrowing from RMBAH and exercise of stock options as described above. The Company also repaid approximately $1.6 million to RMBAH under the payment terms of the facility.

Liquidity Outlook

During 2012 and 2013, we completed the construction and startup of the Lost Creek Project. Additional capital investments are therefore not anticipated in the coming years with the exception of the purchase of minor

Table of Contents

equipment to replace or enhance existing assets. Based upon our current capital balance and the expected timing of product sales, we believe we will be able to meet current obligations without additional funding. However, due to the timing of production and sales delivery commitments, additional cash may be required to cover short-term cash fluctuations and to fund our portion of the reclamation surety bond program for both Lost Creek and Pathfinder properties, which is anticipated to be approximately $3.0 million in 2014. The Company has also committed to the construction of a third disposal well at a cost of approximately $3.2 million which should be completed before the end of 2014. Additional cash may be required for the construction and development of Pathfinder's Shirley Basin Project, but no budget or timetable has been established for that project.

We expect that any major capital projects will be funded by operating cash flow, cash on hand or additional financing as required. If these cash sources are not sufficient, certain capital projects could be delayed, or alternatively we may need to pursue additional debt or equity financing and there is no assurance that such financing will be available at all or on terms acceptable to us. We have no immediate plans to issue additional securities or obtain additional funding; however, we may issue additional debt or equity securities at any time.

Looking ahead

Project operational rates were intentionally lowered in 2014 to effectively manage the plant feed rate while we continued to commission waste water systems. We continued to capture uranium in the processing plant while corrective measures were implemented. Through the nine months, production head grades continued to exceed technical projections, averaging levels of 155 mg/l U_3O_8.

As disclosed in our 2013 10-K, 2014 Q1 production was projected to be slightly lower than initially planned as the maintenance of existing systems was conducted to improve plant efficiencies. The primary maintenance was completed during the first quarter and actual production, as expected, was slightly lower than initially planned. During the third quarter, we continued to address water management issues.

As also disclosed in our 2013 10-K, we expected the cost per pound sold to decrease between 5% and 15% as production and sales quantities increased. During the nine months ended September 30, 2014, our cost per pound sold after adjustment for the severance and ad valorem taxes decreased from $38.11 in 2013 Q4 to $33.90

in 2014, or approximately eleven percent (11%).

Production rates at Lost Creek were deliberately controlled at levels that allowed us to fulfill our contractual sales requirements through September 30, 2014 without participating in a weak uranium spot market. We expect to produce approximately 150,000 drummed pounds of U_3O_8 in 2014 Q4, which would bring our 2014 year end production to approximately 580,000 pounds. This will allow the Company to meet its remaining contractual commitments and participate in the uranium spot market minimally, if necessary.

As announced on May 22, 2014, we expect to sell approximately 518,000 pounds U_3O_8 at an average price of $51.10 per pound in 2014 and approximately 630,000 pounds U_3O_8 at an average price of $50.10 per pound in 2015 under existing committments. Any additional sales would be at the then current spot price unless new contract sales are put in place. Although spot prices have improved from below $30.00 per pound in the previous quarter to over $36.00 per pound, the spot market remains weak and the Company would be reluctant to enter into any spot sales at this time.

Our remaining 2014 contract sales will be at higher rates than those received this quarter. The Company anticipates completing contractual deliveries of 100,000 pounds during 2014 Q4 for gross revenues of approximately $6.5 million.

Table of Contents

Operating costs, which includes exploration, evaluation, development and general and administrative expenses, were also generally lower than prior periods although the development costs increased due to drilling at the Shirley Basin site and the disposal well. Development expense will continue to be higher in 2014 Q4 as we complete the third disposal well at the Lost Creek Project.

Transactions with Related Parties

We did not participate in any material transactions with related parties during the period ended September 30, 2014.

Proposed Transactions

As is typical of the mineral exploration and development industry, we will consider and review potential merger, acquisition, investment and venture transactions and opportunities that could enhance shareholder value. Timely disclosure of such transactions is made as soon as reportable events arise.

Critical Accounting Policies and Estimates

We have established the existence of uranium resources at the Lost Creek Project, but because of the unique nature of in situ recovery mines, we have not established, and have no plans to establish the existence of proven and probable reserves at this project. Accordingly, we have adopted an accounting policy with respect to the nature of items that qualify for capitalization for in situ U_3O_8 mining operations to align our policy to the accounting treatment that has been established as best practice for these types of mining operations.

The development of the wellfield includes production and monitor well drilling and completion, piping within the wellfield and to the processing facility, header houses used to monitor production and disposal wells associated with the operation of the mine. These costs are expensed when incurred.

Restatement

The Company has regularly monitored practices followed by peer companies in the industry. As discussed above, the Company has not established, and has no plans to establish the existence of proven and probable reserves at the Lost Creek Project. As a result of this, the Company changed its accounting policy at December 31, 2013 with respect to the nature of items that qualify for capitalization for in-situ uranium mining operations to align its policy to the accounting treatment that has been established as best practice.

The specific costs affected by this change are those associated with the development of the wellfield which, during 2013, was being constructed as a part of the Lost Creek Project. The development of this wellfield includes production and monitor well drilling and completion, piping within the wellfield and to the processing facility, header houses used to monitor production and disposal wells associated with the operation of the mine. These costs are now expensed when incurred.

During the three and nine months ended September 30, 2013, a total of $4.3 million and $14.3 million, respectively, of such expenditures was originally capitalized as part of construction in progress within capital assets. Accordingly, the comparative financial statements have been restated to show the impact of this change in accounting policy and include these amounts in development expense. This increased the loss per share from $0.03 per share to $0.06 for the three months and from $0.08 to $0.20 for the nine months ended September 30, 2013.

Table of Contents

Mineral Properties

Acquisition costs of mineral properties are capitalized. When production is attained at a property, these costs will be amortized over a period of estimated benefit.

As of September 30, 2014, the average current spot and long term price of U_3O_8 was \$35.30 and \$45.00, respectively. This compares to prices of \$34.50 and \$50.00 as of December 31, 2013. Management did not identify any impairment indicators for any of the Company's mineral properties during the nine months ended September 30, 2014.

Development costs including, but not limited to, production wells, header houses, piping and power will be expensed as incurred as we have no proven and probable reserves.

Depreciation

The depreciable life of the Lost Creek plant, equipment and enclosure was determined to be the nameplate life of the equipment housed in the processing plant as plans exist for other uses for the equipment beyond the estimated production at the Lost Creek Project.

Inventory and Cost of Sales

Our inventories are measured at the lower of cost and net realizable value based on projected revenues from the sale of that product. We are allocating all costs of operations of the Lost Creek facility to the inventory valuation at various stages of production with the exception of wellfield and disposal well costs which are treated as development expenses when incurred. Depreciation of facility enclosures, equipment and asset retirement obligations as well as amortization of the acquisition cost of the related property is also included in the inventory valuation. We do not allocate any administrative or other overhead to the cost of the product.

Share-Based Expense

We are required to initially record all equity instruments including warrants, restricted share units and stock options at fair value in the financial statements.

Management utilizes the Black-Scholes model to calculate the fair value of the warrants and stock options at the time they are issued. Use of the Black-Scholes model requires management to make estimates regarding the expected volatility of the Company's stock over the future life of the equity instrument, the estimate of the expected life of the equity instrument and the number of options that are expected to be forfeited. Determination of these estimates requires significant judgment and requires management to formulate estimates of future events based on a limited history of actual results.

New accounting pronouncements

In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers. Under ASU 2014-09, an entity will recognize revenue when it transfers promised goods or services to customers in an amount that reflects what it expects in exchange for the goods or services. It also requires more detailed disclosures to enable users of financial statements to understand the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. This guidance is effective for annual periods beginning on or after December 15, 2016. The adoption of this standard is not expected to have a material impact on the financial statements of the Company.

Table of Contents

Off Balance Sheet Arrangements

We have not entered into any material off-balance sheet arrangements such as guaranteed contracts, contingent interests in assets transferred to unconsolidated entities, derivative instrument obligations, or with respect to any obligations under a variable interest entity arrangement.

Outstanding Share Data

The “Management’s Discussion and Analysis of Financial Condition and Results of Operations” includes information available to October 30, 2014. As of October 30, 2014, we had outstanding 129,284,166 common shares and 7,549,370 options to acquire common shares.

Item 3. Quantitative AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk

Market risk is the risk to the Company of adverse financial impact due to changes in the fair value or future cash flows of financial instruments as a result of fluctuations in interest rates and foreign currency exchange rates. As the U.S. dollar is now the functional currency of U.S. operations, the currency risk has been significantly reduced.

Interest rate risk

Financial instruments that expose the Company to interest rate risk are its cash equivalents, deposits, restricted cash and debt financings. Our objectives for managing our cash and cash equivalents are to maintain sufficient funds on hand at all times to meet day-to-day requirements and to place any amounts which are considered in excess of day-to-day requirements on short-term deposit with the Company's financial institutions so that they earn interest.

Currency risk

We maintain a balance of less than $0.1 million in foreign currency resulting in a low currency risk.

Commodity Price Risk

The Company is subject to market risk related to the market price of U_3O_8. We have eight U_3O_8 supply contracts with pricing fixed or based on inflation factors applied to a fixed base. Additional future sales would be impacted by both spot and long-term U_3O_8 price fluctuations. Historically, U_3O_8 prices have been subject to fluctuation, and the price of U_3O_8 has been and will continue to be affected by numerous factors beyond our control, including the demand for nuclear power, political and economic conditions, and governmental legislation in U_3O_8 producing and consuming countries and production levels and costs of production of other producing companies. The spot market price for U_3O_8 has demonstrated a large range since January 2001. Prices have risen from $7.10 per pound at January 2001 to a high of $136.00 per pound as of June 2007. The spot market price was $36.50 per pound as of October 30, 2014.

Table of Contents

Item 4. Controls and Procedures

(a)Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this MD&A, under the supervision of the Chief Executive Officer and the Chief Financial Officer, the Company evaluated the effectiveness of its disclosure controls and procedures, as such term is defined in Rule 13a-15(e) and Rule 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”). Based on this evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Company’s disclosure controls and procedures are effective to ensure that information the Company is required to disclose in reports that are filed or submitted under the Exchange Act: (1) is recorded, processed and summarized effectively and reported within the time periods specified in SEC rules and forms, and (2) is accumulated and communicated to Company management, including the Chief Executive Officer and the Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure. The Company’s disclosure controls and procedures include components of internal control over financial reporting. No matter how well designed and operated, internal controls over financial reporting can provide only reasonable, but not absolute, assurance that the control system's objectives will be met.

(b) Changes in Internal Controls over Financial Reporting

No changes in our internal control over financial reporting occurred during the nine months ended September 30, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II

Item 1. LEGAL PROCEEDINGS

No new legal proceedings or material developments in pending proceedings.

Item 1A. RISK FACTORS

There have been no material changes for the nine months ended September 30, 2014 from those risk factors set forth in our Annual Report on Form 10-K.

Item 2Unregistered Sales of Equity Securities and Use of Proceeds

None

Item 3. Defaults upon Senior Securities

None

Item 4. MINE SAFETY DISCLOSURE

Our operations and exploration activities at Lost Creek are not subject to regulation by the Federal Mine Safety and Health Administration ("MSHA") under the Federal Mine Safety and Health Act of 1977 (the "Mine Act").

Table of Contents

Item 5. Other Information

None

Table of Contents

Item 6. Exhibits

Exhibit Number	Exhibit Description	Incorporated by Reference Form	Date of Report	Exhibit	Filed Herewith
31.1	Certification of CEO Pursuant to Exchange Act Rules 13a-14 and 15d-14, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.				X
31.2	Certification of CFO Pursuant to Exchange Act Rules 13a-14 and 15d-14, as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.				X
32.1	Certification of CEO Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.				X
32.2	Certification of CFO Pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.				X
101.INS*	XBRL Instance Document				X
101.SCH*	XBRL Schema Document				X
101.CAL*	XBRL Calculation Linkbase Document				X
101.DEF*	XBRL Definition Linkbase Document				X
101.LAB*	XBRL Labels Linkbase Document				X
101.PRE*	XBRL Presentation Linkbase Document				X

In accordance with Rule 406T of Regulation S-T, the XBRL related information in Exhibit 101 to this Quarterly Report on Form 10-Q is deemed not filed or part of a registration statement or prospectus for purposes of sections 11 or 12 of the Securities Act, is deemed not filed for purposes of section 18 of the Exchange Act, and otherwise is not subject to liability under these sections.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

	UR-ENERGY INC.	
Date: November 3, 2014	By:	/s/ Wayne W. Heili Wayne W. Heili President and Chief Executive Officer (Principal Executive Officer)
Date: November 3, 2014	By:	/s/Roger L. Smith Roger L. Smith Chief Financial Officer (Principal Financial Officer and Principal Accounting Officer)