ITHACA ENERGY

H1 2021 Financial Results

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HIGHLIGHTS

56 kboe/d	**$18/boe**	**$378M**	**$1.01Bn**
H1-2021 Production	H1-2021 Unit Opex	H1-2021 EBITDAX	30 June 2021 Net Debt

- Production of 56 thousand barrels of oil equivalent per day ("kboe/d"), 67% liquids, for the first half of the year. Second quarter production performance was impacted by planned Forties Pipeline System summer shutdown
- Unit operating costs of $18/boe
- EBITDAX of $378 million including realised gains of $66 million on the commodity hedging instruments that were reset in 2020
- Results for the period include the $174 million non-cash impairment reversal arising from the strengthening view of future commodity prices
- 17 million barrels of oil equivalent (66% oil) hedged from Q3 2021 into 2023 at an average price floor of $47/bbl oil and 44p/therm gas
- Net debt at 30 June was $1.01 billion, down from $1.07 billion at 31 March following a further repayment of RBL debt of $50 million. The company also declared and paid a dividend of $15m on 13 May
- Following the period close, a significant refinancing program was successfully completed in July which included amending and extending the Reserves Based Lending facility of $1.225 billion to 2026 and putting in place a new $625 million bond (senior notes). The refinancing program will enable us to continue to pursue our business growth ambitions, focus on our production and our projects
- As part of the refinancing we repaid the $250 million Subordinated Shareholder Loan to Delek Group Ltd on 3 August
- On 5 August, the WilPheonix rig spudded the Fotla exploration well. The Fotla prospect is located 12km south of the Alba field

SUMMARY STATEMENT OF INCOME

		H1 2021	H1 2020
Average Production	kboe/d	56.4	72.8
Average Realised Oil Price [1]	S/bbl	65	44
Revenue [2]	M$	564	610
Revenue [2]		**564**	**610**
Opex [3]	M$	(180)	(192)
G&A and Foreign Exchange	M$	(6)	(19)
EBITDAX	**M$**	**378**	**399**
DD&A	M$	(209)	(218)
Impairment reversal/(charge)	M$	174	(1,187)
Finance Costs	M$	(100)	(120)
Other Non-Cash Costs	M$	8	(6)
Taxation	M$	(111)	362
Earnings	**M$**	**140**	**(770)**
Fair value (loss)/gain on hedges	M$	(274)	293
Taxation	M$	110	(117)
Total Comprehensive expense	**M$**	**(24)**	**(595)**

(1) Average realised oil price before hedging
(2) Revenue, realised hedging gains/losses and inventory movements net of royalty costs and tanker costs
(3) Opex costs net of tariff income and exclude tanker costs

SUMMARY BALANCE SHEET

M$	30 Jun 2021	31 Dec 2020
Cash and Equivalents	8	1
Other Current Assets	276	255
PP&E	2,703	2,655
Goodwill	722	722
Deferred Tax Asset	377	382
Other Non-Current Assets	243	250
Total Assets	**4,329**	**4,265**
Current Liabilities	(611)	(368)
Borrowings	(1,242)	(1,437)
Asset Retirement Obligations	(1,417)	(1,416)
Other Non-Current Liabilities	(137)	(83)
Total Liabilities	**(3,407)**	**(3,304)**
Net Assets	**922**	**961**
Share Capital	1,250	1,250
Cashflow Hedge Reserve	(120)	44
Retained Earnings	(208)	(333)
Shareholders' Equity	**922**	**961**

OPERATIONAL REVIEW

H1 2021 production was 56.4 kboe/d compared to 72.8 kboe/d for H1-2020

		H1-2021 Production	H1-2020 Production
Daily Production	***kboe/d***	**56.4**	**72.8**
▪ Liquids	*kbbl/d*	37.6	44.3
▪ Gas	*kboe/d*	18.8	28.5
Total Production	***MMboe***	**10.2**	**13.2**

Daily Production	***kboe/d***	**56.4**	**72.8**
▪ Captain	*kboe/d*	20.4	24.2
▪ GSA	*kboe/d*	10.8	10.5
▪ Other Operated[1]	*kboe/d*	9.1	12.0
▪ Britannia & Satellites[2]	*kboe/d*	10.3	16.7
▪ Other Non-Operated[3]	*kboe/d*	5.8	9.3

1. Other-operated assets comprises Erskine, Cook and Alba
2. Includes the Ithaca Energy-operated Alder field subsea tie-back to the Britannia platform
3. Other non-operated assets comprises Elgin / Franklin, Jade, Pierce and the Dons

The producing asset portfolio has performed well during H1 2021 although average production of 56.4 kboe/d (67% liquids – 62% oil / 5% NGL) is lower than the equivalent period in 2020. This was due to a number of fields in the portfolio being shut in due to the seven week Forties Pipeline System shutdown.

H1 2021 also saw the impact of production from the Vorlich field (34% working interest) in the Greater Stella area following production start up in November 2020 and the impact of the well drilled on the Harbour-operated Callanish field (16.5% working interest) at the end of 2020.

As previously reported, production operations from the Enquest operated Dons Area ceased in March 2021. The Dons contributed approximately 0.8 kboe/d or under 2% to the Company's total production in 2020.

ACTIVITY OVERVIEW

Developments

Captain Enhanced Oil Recovery ("EOR") Programme

Based on the performance and incremental production achieved as a result of the Stage I polymer EOR programme on the Captain field (85% working interest), work is progressing on extending this to a second stage of activities. The "Stage II" programme involves the drilling of up to ten additional wells (four producers and six injectors) to optimise oil recovery from the area of the Upper Captain Sands reservoir that is produced using subsea wells. The overall work programme involves the installation of approximately six kilometre subsea pipelines and umbilicals to the two subsea areas of the field in order to provide polymer injection capacity and the installation of additional polymer storage tanks and pumps on the Captain platform and floating production, storage and offloading ("FPSO") vessel.

Following attainment of Oil and Gas Authority FDPa approval and full sanction in Q1, the project continues to focus on supply chain activities for the Stage II work programme, with the award of Subsea Engineering, Procurement, Installation and Commissioning and Topsides Construction contracts during Q2 2021. The rig hire contract is being progressed in Q3 2021. Significant milestones have been achieved despite the challenges facing the industry because of Covid-19. The development involves a multi-year programme of drilling activities aimed at maximising oil recovery from the field into the 2030s.

GSA Satellite Field Developments

Engineering and procurement activities are progressing for the Abigail (formerly known as Hurricane) field. We expect the rig hire agreement to be confirmed during Q3 2021. Key long lead items (XT, flowbase, wellhead etc) are on schedule for delivery in October 2021.

FDP has been submitted for approval on the sanctioned Abigail development which is expected in the next quarter. First oil is now expected in Q3 2022.

With respect to the other subsequent GSA satellite fields, Austen and Courageous, various subsurface and engineering studies are being progressed to advance the necessary development plans. These studies are scheduled to continue during 2021, along with the evaluation of additional development opportunities across the portfolio.

Exploration and Appraisal

Fotla

The Fotla Prospect is within licence P2373 and is located ~12km south of the Ithaca operated Alba North Platform. The licence and the well are operated by Ithaca on behalf of the joint venture which comprises ourselves and Spirit Energy. Exploratory drilling began on 5 August using the Awilco WilPhoenix semisubmersible rig. The target interval for the gas prospect is remobilized sands of the Eocene Caran Formation, which also form the principal reservoir in the Alba oil field.

Isabella

As announced in March 2020, an exploration well drilled on the "Isabella" prospect (10% working interest) identified hydrocarbons in the Upper Jurassic and Triassic sandstone reservoirs. This is an encouraging high-pressure high-temperature gas condensate discovery in a location close to existing infrastructure. Further analysis of the well results is being performed by the licence Operator, TOTAL E&P North Sea UK Limited ("TOTAL"), to determine future appraisal activity and recoverable resource estimates. The well, in which Ithaca Energy had a carried cost interest as a result of prior farm-out agreements with TOTAL and Euroil Exploration Limited, has been plugged and abandoned.

Decommissioning

Jacky

The Jacky field, which ceased production in 2014, is located in the Inner Moray Firth area of the UK North Sea (Block 12/21c). The main decommissioning activities that remain to be completed on the field involve removal and recycling of the suction-piled, monopole unmanned platform. This work has been scheduled to take place during September 2021. Preparatory works are well under way to meet scheduled removal date.

Anglia

In June 2020 approval was received from the Offshore Petroleum Regulator for Environment and Decommissioning ("OPRED") for the Ithaca-operated Anglia field (30% working interest) decommissioning programme. The Anglia field, which ceased production in 2015, is located in Blocks 48/19b and 48/18b in the Southern North Sea. The facilities to be removed consists of a normally unmanned platform and a number of platform and subsea wells.

Dons

Following the cessation of production operations in March 2021, the Northern Producer floating production facility that served the Enquest operated Dons Area has sailed to Kishorn where the owner prepares the vessel for future plans.

HEALTH, SAFETY & ENVIRONMENT

The Company monitors and manages the Lost Time Injury Frequency ("LTIF") and Total Recordable Injury Frequency ("TRIF") associated with its operated assets as a means of evaluating the health and safety performance of the Company and the suppliers working on the assets.

The first quarter's strong safety performance has continued into Q2 2021 with no recordable injuries; potential fatalities; nor potential serious injuries.

		Q2-2021	Q1-2021
Safety			
▪ Lost Time Injury Frequency (LTIF)	*lost time injuries per million man hours (rolling 12 months to end of quarter)*	1.12	1.08
▪ Number of recordable injuries	*number*	Nil	Nil
▪ Total recordable injury frequency (TRIF)	*recordable injuries per million man hours (rolling 12 months to end of quarter)*	1.49	1.45

The Company's environment stewardship planning for 2021 includes a commitment to analysing and executing various emissions reduction projects to realise Ithaca's goal of reducing emissions by 25% by 2025. To assist with understanding and reporting the impact, the atmospheric emissions data are now reported on a carbon intensity basis for Ithaca's operated assets on the basis of CO2 equivalent (CO2e) per million boe produced.

		YTD at end of Q2-2021	YTD at end of Q1-2021
Environmental			
▪ Carbon intensity of operated assets	*ktonnes CO_2e per million boe produced*	21.87	18.4
▪ Hydrocarbon spills to sea rate	*bbls spilled per million boe produced*	0.06	0.08

The increase in Q2 2021 emissions is due to increased use of diesel on Alba and Captain (due to a planned Solar engine replacement on Captain plus import fuel gas from Britannia being unavailable to Alba) plus increased flaring on Captain due to a gas cooler failure. The carbon intensity increase is also due to reduced availability of higher production wells. The asset teams continue to pursue emissions reduction projects as part of the asset's business plans.

Note that the component of CO2e due to diesel use is provisional as it is based on diesel delivered to the installations rather than utilized.

H1 2021 FINANCIAL REVIEW

Revenue

Revenues in the first half stand at $564 million, decreasing by $46 million (H1 2020: $610 million). Total H1 2021 production was 10.2 MMboe, down 23% on H1 2020 production of 13.2 MMboe. Water injection on Captain has been constrained in H1 2021. The scheduled shutdown of Forties Pipeline System in Q2 2021 has impacted all Britannia and satellite fields. This is coupled with prolonged shutdowns on FPF1 and Erskine as a result of the annual maintenance programs. Overall natural field decline is also being seen across the portfolio. This has been offset by production from the Vorlich field which came online in November 2020. Prices have increased on H1 2020 which has generated higher oil and gas revenues. Average realised oil prices increased to $65/bbl in Q1 2021 from $44/bbl H1 2020. Average realised gas prices trebled from 17p/therm in H1 2020 to 57p/therm in H1 2021. The impact of increased commodity prices has been offset by losses in relation to the Group hedging portfolio which have reduced from a $217 million gain H1 2020 to a $13 million loss in H1 2021.

Operating Costs

Operating costs decreased to $180 million in H1 2021 (H1 2020: $192 million) as the focus is on continuing to carefully control costs. The corresponding unit cost of $18/boe in the period is higher than H1 2020 of $15/boe. This increase is largely driven by lower production volumes in H1 2021.

Depreciation, Depletion and Amortisation ("DD&A")

Total DD&A expense for the period was $209 million (H1 2020: $217.5 million). This decrease was driven by the 23% reduction in production volumes. The DD&A rate has increased from $16/boe in H1 2020 to $20/boe in H1 2021 due to the asset impairments in Q1 2020 followed by the impairment reversals recognised in Q4 2020.

Impairment

During H1 2021, the Group recorded an impairment reversal of $173.8 million (H1 2020: $1,187 million impairment charge) relating to oil and gas assets. An impairment review was carried out at the end of Q2 2021 driven by the higher forward curve for both oil and gas prices resulting in reversals of $173.8 million. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 9.75%. The impairment charge of $1,187 million in H1 2020 was driven by the lower forward curve for both oil and gas prices resulting in impairments across the oil and gas portfolio of $980 million coupled with a write-down of the value of Goodwill by $207 million. The review was carried out on a fair value less cost of disposal basis using risk adjusted cash flow projections discounted at a post-tax rate of 10.5%.

Financial Instruments

The Company cash flow hedge accounts for both commodities and interest rate instruments, while accounting for foreign exchange instruments is on a mark-to-market basis. This effectively means that the accounting impact relating to financial instruments is split between the Income Statement (IS) and the Statement of Other Comprehensive Income (SOCI). The Company executed an oil hedging re-set programme in response to the decline in oil prices in March and April 2020. Hedges with a value of $155 million were re-set, which was received in cash during the period H1 2020. All the hedges that were re-set were replaced with new positions at the forward curve prices prevailing at the time. During H1 2021 $65.6 million of hedging gains were recognized in the income statement in relation to these re-sets. Offsetting hedging losses of $79 million reported in H1 2021 are primarily driven by realised oil swaps which are hedged at an average of $38.6/bbl. Given the current average Brent price of $64.8/bbl, this has resulted in losses for H1 2021.

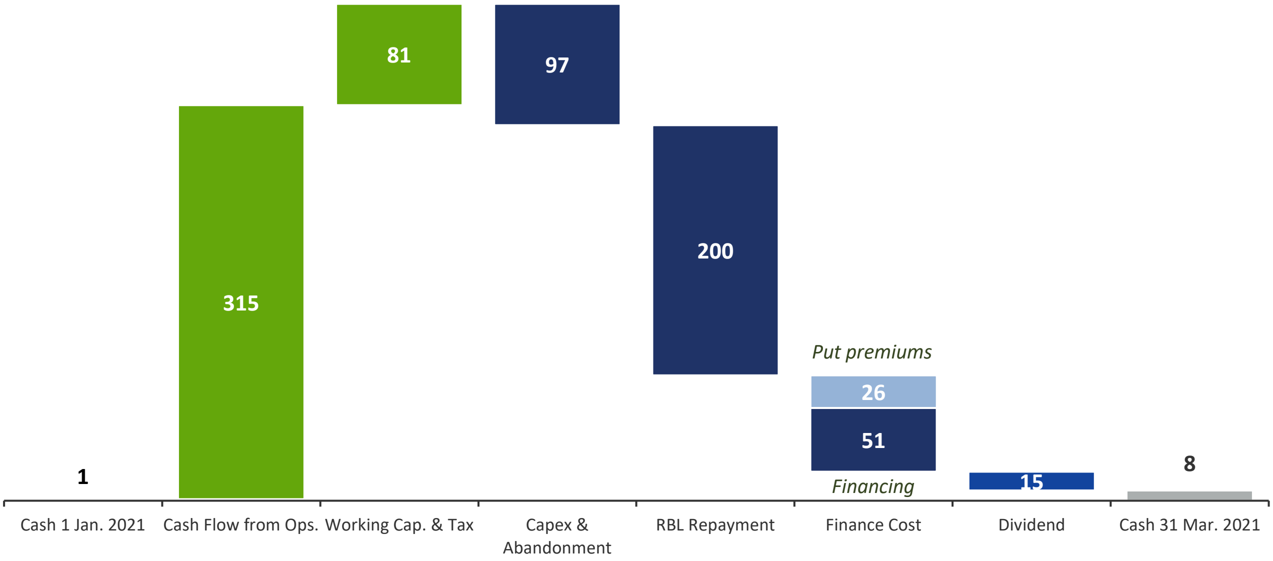
		H1 2021 IS gain/(loss)	H1 2021 Cash in/(out)	H1 2020 IS gain/(loss)	H1 2020 Cash in/(out)
Realised hedging gains/(losses)					
▪ Hedging instruments realised in the period	*$ million*	($79)	($79)	$217	$217
▪ 2020 resets	*$ million*	$66	-	-	$155

Capital Investments

Capital investment in the first half of 2021 stands at $81.4 million (H1 2020: $52.3 million), of which $59.3 million relates to Development and Production and $22.1 million relates to Exploration and Evaluation assets. The H1 2021 capital expenditure programme continues to focus on the Captain Enhanced Oil Recovery project and GSA satellite investment on the Abigail field.

2021 Cashflow Movements

During the six months ended 30 June 2021 there was a cash inflow from operating, investing and financing activities of approximately $7 million (H1 2020 outflow of $5 million); as set out in the following graph:



Cash flow from operating activities was $315 million. Revenues from the producing asset portfolio have been supported by carefully controlled operating costs.

Movements in working capital resulted in an inflow of cash totalling $81 million in the period. This was primarily driven by timing of receipt of payments for oil and gas hedges. During the second quarter the Company made a tax payment of $10 million relating to IOGL 2019 taxable profits.

Cash spend on capital expenditure in the period was $97 million, with the key investments being on Captain and Abigail.

The Company aims to maintain minimal cash on hand and prioritises repayment of the RBL facility with excess cash. During the period $200 million of drawn RBL was repaid.

During H1 2021, the Company paid finance costs totalling $77 million. This was split $51 million in interest paid to lenders and $26 million paid in deferred premiums on oil and gas put options.

Subsequent Events

A significant refinancing program for the Group successfully completed in July. This involved amending and extending the Reserves Based Lending facility and issuing a new bond (senior notes). The RBL availability was reduced from $1.65 billion to $1.225 billion and a new $625 million bond replaced the existing $500 million bond. The maturity of both the RBL and bond was extended from 2024 to 2026. The refinancing program will enable us to continue to pursue our business growth ambitions, focus on our production and our projects. On the 3rd August 2021 as part of the refinancing, we also repaid the $250 million Subordinated Shareholder Loan to Delek Group Ltd.

ADDITIONAL READER ADVISORIES

The information in this MD&A is provided as of 30 August 2021. The H1 2021 results have been compared to the results for the same period in 2020. This Management Discussion and Analysis should be read in conjunction with the Company's audited consolidated financial statements as at 31 December 2020 together with the accompanying notes.

CRITICAL ACCOUNTING ESTIMATES

Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses. These accounting policies are discussed below and are included to aid the reader in assessing the critical accounting policies and practices of the Company and the likelihood of materially different results being reported. Ithaca Energy's management reviews these estimates regularly. The emergence of new information and changed circumstances may result in actual results or changes to estimated amounts that differ materially from current estimates.

The following assessment of significant accounting policies and associated estimates is not meant to be exhaustive. The Company might realise different results from the application of new accounting standards promulgated, from time to time, by various rule-making bodies.

Capitalised costs relating to the exploration and development of oil and gas reserves, along with estimated future capital expenditures required to develop proved and probable reserves are depreciated on a unit-of-production basis, by asset, using estimated proved and probable reserves as adjusted for production.

A review is carried out at each reporting date for any indication that the carrying value of the Company's D&P and E&E assets may be impaired. For assets where there are such indications, an impairment test is carried out on the Cash Generating Unit ("CGU"). Each CGU is identified in accordance with IAS 36. The Company's CGUs are those assets which generate largely independent cash flows and are normally, but not always, single developments or production areas. The impairment test involves comparing the carrying value with the recoverable value of an asset. The recoverable amount of an asset is determined as the higher of its fair value less costs of disposal and value in use, where the value in use is determined from estimated future net cash flows. Any additional depreciation resulting from the impairment testing is charged to the Statement of Income.

Goodwill is tested annually for impairment and also when circumstances indicate that the carrying value may be at risk of being impaired. Impairment is determined for goodwill by assessing the recoverable amount of each CGU to which the goodwill relates. Where the recoverable amount of the CGU is less than its carrying amount, an impairment loss is recognised in the Statement of Income. Impairment losses relating to goodwill cannot be reversed in future periods.

Recognition of decommissioning liabilities associated with oil and gas wells are determined using estimated costs discounted based on the estimated life of the asset. In periods following recognition, the liability and associated asset are adjusted for any changes in the estimated amount or timing of the settlement of the obligations. The liability is accreted up to the actual expected cash outlay to perform the abandonment and reclamation. The carrying amounts of the associated assets are depleted using the unit of production method, in accordance with the depreciation policy for development and production assets. Actual costs to retire tangible assets are deducted from the liability as incurred.

All financial instruments are initially recognised at fair value on the balance sheet. The Company's financial instruments consist of cash, accounts receivable, deposits, derivatives, accounts payable, accrued liabilities, contingent consideration and borrowings. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

The determination of the Company's income and other tax liabilities / assets requires interpretation of complex laws and regulations. Tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded on the financial statements.

The accrual method of accounting will require management to incorporate certain estimates of revenues, production costs and other costs as at a specific reporting date. In addition, the Company must estimate capital expenditures on capital projects that are in progress or recently completed where actual costs have not been received as of the reporting date.

ADDITIONAL INFORMATION

Non-IFRS measures

"EBITDAX" referred to in this MD&A is not prescribed by IFRS. EBITDAX includes Earnings Before Interest, Taxes, Depreciation (or Depletion), Amortization, and Exploration Expense. EBITDAX may not be comparable to other similarly titled measures of other companies, and accordingly EBITDAX may not be comparable to measures used by other companies.

"Cashflow from operations" referred to in this MD&A are not prescribed by IFRS. This non-IFRS financial measure does not have any standardised meaning and therefore are unlikely to be comparable to similar measures presented by other companies. As an indicator of the Company's performance, cashflow from operations should not be considered as an alternative to, or more meaningful than, net cash from operating activities as determined in accordance with IFRS. Cashflow from operations is determined by adding back changes in non-cash operating working capital to cash from operating activities.

"Net working capital" referred to in this MD&A is not prescribed by IFRS. Net working capital includes total current assets less trade and other payables. Net working capital may not be comparable to other similarly titled measures of other companies, and accordingly Net working capital may not be comparable to measures used by other companies.

"Net debt" referred to in this MD&A is not prescribed by IFRS. The Company uses net drawn debt as a measure to assess its financial position. Net drawn debt includes amounts outstanding under the Company's debt facilities and senior notes, less cash and cash equivalents. Subordinated debt of $250m from Delek Group Limited is ranked with equity.

BOE Presentation

The calculation of boe is based on a conversion rate of 5.8 thousand cubic feet of natural gas ("mcf") to one barrel of crude oil ("bbl"). The term boe may be misleading, particularly if used in isolation. A boe conversion ratio of 5.8 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 5.8 mcf: 1 bbl, utilising a conversion ratio at 5.8 mcf: 1 bbl may be misleading as an indication of value.

Reserves

The Company's reserves and resources as of 31 December 2020 were independently evaluated by Netherland Sewell & Associates Inc. ("NSAI"), a qualified reserves evaluator, in accordance with the definitions and guidelines set forth in the 2018 Petroleum Resource Management System (PRMS) approved by the Society of Petroleum Engineers (SPE). The estimates of reserves for individual properties may not reflect the same confidence level as estimates of reserves for all properties, due to the effects of aggregation.

Well Test Results

Well test results represent short-term results, which may not necessarily be indicative of long-term well performance or ultimate hydrocarbon recovery therefrom. Full pressure transient and well test interpretation analyses may not have been completed and as such flow test results should be considered preliminary until such analyses have been completed.

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Ithaca Energy (UK) Limited
Hill of Rubislaw, Aberdeen, AB15 6XL
www.ithacaenergy.com