Greenfields Petroleum Corporation Announces Third Quarter 2018 Results, Restructuring of Senior Secured Debt and Report on Reserves, Contingent and Prospective Resources

Houston, Texas (November 1, 2018) – Greenfields Petroleum Corporation (the "**Company**" or "**Greenfields**") (TSX VENTURE: GNF), a production focused company with operating assets in Azerbaijan, announces its financial and operating results for the three and nine months ended September 30, 2018 along with the restructuring of its senior secured debt and an updated summary of the Company's reserves, contingent resources and prospective resources.

Selected financial and operational information included below should be read in conjunction with the Company's condensed consolidated financial statements for the three and nine months ended September 30, 2018, with the notes thereto and related management's discussion and analysis ("**MD&A**"), which can be found at **www.Greenfields-Petroleum.com** and on SEDAR at **www.sedar.com**. Except as otherwise indicated, all dollar amounts referenced herein are expressed in United States dollars.

**Third Quarter and Year-to-Date 2018 Highlights**

- The Company's entitlement share of sales volumes (the "**Sales Volumes**") from the offshore block known as the Bahar project (the "**Bahar Project**") resulted in revenue of $8.0 million for the third quarter 2018 and $24.2 million year-to-date. As compared to the same periods in 2017, revenue increased 24% and 7%, respectively.
- Sales Volumes averaged 561 bbl/d for crude oil and 17,742 mcf/d for natural gas or 3,518 boe/d in the third quarter of 2018 and 636 bbl/d, 16,965 mcf/d or 3,463 boe/d year-to-date 2018.
- Realized oil price averaged $69.65/bbl for the third quarter 2018 and $66.43/bbl year-to-date, an increase of 47% and 46% in comparison to the same periods in 2017. The price of natural gas has been contractually fixed at $2.69/mcf since April 1, 2017.
- Operating costs were $5.6 million for the third quarter 2018 and $15.7 million year-to-date, compared to $4.8 million and $16.1 million, respectively, for the same periods in 2017.
- Capital expenditures were $1.8 million for the third quarter and $4.8 million year-to-date, compared to expenditures of $1.8 million and $5.5 million, respectively, for the same periods in 2017.
- After interest and depreciation expenses, the Company realized a net loss of $2.1 million for the third quarter 2018 and $5.6 million year-to-date, which represents a loss per share (basic and diluted) of $0.12 and $0.31, respectively. As compared to the same periods in 2017, the Company realized a net loss of $2.4 million and $6.9 million, respectively, with a loss per share (basic and diluted) of $0.13 and $0.42, respectively.
- Updated summary of the Company's independently assessed reserves in the Bahar Gas Field ("**Bahar**") and Gum Deniz Oil Field ("**Gum Deniz**"), resulting in estimated gross 3P reserves of 155 MMboe, with 52 MMboe in the 1P category.
- The Company's safety record year to date has been excellent; with zero 'Lost Time Incidents' and only two minor 'Reportable Incidents'. This continued improvement is due to our safety conscious operations management and workers in the field.

Commenting on the results, John Harkins, CEO said:

"We continue to build momentum in improving our operating performance and remain focused on realizing the core value attributable to our operations and substantial proven reserves. Production during the quarter showed a positive growth trend and we have a clear growth strategy to materially enhance that trend over future periods.

We continue to drive performance improvements in relation to workovers that have contributed to restoring and stabilizing production. We also continue to recognize the exploration potential in the deeper prospects that we evaluate for future drilling.

Operating netback continues to improve due to increased oil and gas production, coupled with higher market oil prices, and operating costs being managed below forecast. Critical to our industry, we are also very pleased with the safety consciousness in the Bahar Project and we have achieved our best safety record in eight years.

We are pleased to have secured the extension for the maturity of our senior secured debt and thank our senior lenders for their continued support. This agreement provides additional financial security to our business and provides us with better visibility and optionality to execute our growth strategy."

**Operational Review**

- Crude oil production in the third quarter 2018 continued to be affected by a delay in carrying out workovers to reactivate wells from refurbished platforms 409 and 412 in the south Gum Deniz due to the late delivery of heavier rigs ordered in 2017. Bahar Energy Operating Company ("**BEOC**") mobilized these rigs to the offshore in early August 2018 and is currently rigging up another newly arrived A80 rig on the onshore GD-601 well to confirm its capabilities before relocating it to offshore platforms. In the Gum Deniz, five successful recompletions were conducted to mitigate production declines in two key wells. In addition, twelve well services were performed mostly for sand cleanouts and replacement of electric submersible pumps ("**ESP**"). Two workovers and one recompletion were underway at the end of the quarter. BEOC plans to equip seven additional wells with ESPs powered by onsite power generation.
- Gas production from the Bahar in the third quarter 2018 slightly increased as the production from well B-170, successfully recompleted in second quarter 2018, contributed to offset declines on wells B-107 and B-108 which capital workovers failed due to collapsed casing. The reactivation of well B-173 was underway at the end of the quarter. For the Bahar, BEOC's construction efforts continue to focus on platform refurbishment to enable access for workovers and production operations, as well as infrastructural improvement projects related to the causeway, facilities and pipelines.
- BEOC's operating costs were $6.5 million and $18.5 million, respectively, for the third quarter and year-to-date 2018. Administrative expenses for the third quarter and year-to-date 2018 were $0.7 million and $2.9 million, respectively, reflecting an increase of 4% and 28%, respectively, in comparison to the same periods in 2017. The increases in administrative expenses are due to higher professional and technical fees in connection with ongoing corporate initiatives.
- BEOC's capital expenditures were $2.1 million and $5.5 million, respectively, for the third quarter and year-to-date 2018. In comparison to the same periods in 2017, capital expenditures increased 6% and decreased 7%, respectively. While capital expenditures increased slightly during the third quarter, the year-to-date decrease experienced in 2018 mostly relates to the delay in carrying out workovers and recompletions for the south Gum Deniz due to the late delivery of heavier rigs ordered in 2017.
- Waterflood injectivity testing in the Gum Deniz was initiated in September 2018 using the recently acquired high pressure pumps. The injectivity testing, critical to future waterflood design, will continue at surface pressure rates of up to 4,400 psi compared to previous injection of up to 1200 psi.

**Selected Financial Information**

| *(US$000's, except as noted)* | **Three Months Ended September 30,** | | **Nine Months Ended September 30,** | |
|---|---|---|---|---|
| | **2018** | **2017** Restated [1] | **2018** | **2017** Restated [1] |
| ***Financial*** | | | | |
| **Revenues** | | | | |
| Crude oil and natural gas | 8,046 | 6,491 | 24,180 | 22,547 |
| Net loss | (2,077) | (2,383) | (5,559) | (6,880) |
| Loss per share, basic and diluted | ($0.12) | ($0.13) | ($0.31) | ($0.42) |
| ***Operating*** | | | | |
| **Average Entitlement Sales Volumes** [2] | | | | |
| Crude Oil (bbl/d) | 561 | 573 | 636 | 651 |
| *Change with respect to same period in 2017* | *(2%)* | | *(2%)* | |
| Natural gas (mcf/d) | 17,742 | 15,902 | 16,965 | 16,767 |
| *Change with respect to same period in 2017* | *12%* | | *1%* | |
| Barrel oil equivalent (boe/d) | 3,518 | 3,223 | 3,463 | 3,446 |
| *Change with respect to same period in 2017* | *9%* | | *0.5%* | |
| Entitlement to gross sales volumes [3] | 82% | 87% | 86% | 86% |
| **Prices** | | | | |
| Average oil price ($/bbl) | 70.86 | 48.46 | 67.60 | 46.47 |
| Net realization price ($/bbl) | 69.65 | 47.47 | 66.43 | 45.51 |
| *Change with respect to same period in 2017* | *47%* | | *46%* | |
| Brent oil price ($/bbl) | 74.61 | 52.11 | 71.84 | 51.74 |
| Natural gas price ($/mcf) [4] | 2.69 | 2.69 | 2.69 | 3.12 |
| Net realization price ($/boe) [5] | 24.86 | 21.89 | 25.57 | 23.97 |
| Operating cost ($/boe) [5] | (17.28) | (16.28) | (16.70) | (17.21) |
| Operating Netback ($/boe) [5] | 7.58 | 5.61 | 8.87 | 6.76 |

| *Capital Items* | | | | |
|---|---|---|---|---|
| Cash and cash equivalents | 206 | 1,983 | 206 | 1,983 |
| Total Assets | 198,603 | 200,198 | 198,603 | 200,198 |
| Working capital | (3,320) | (2,697) | (3,320) | (2,697) |
| Long term debt and shareholders' equity | 180,991 | 182,773 | 180,991 | 182,773 |

(1) The term *Restated* was added to the 2017 comparative information due to the reclassification of impairment of accounts receivable expense, previously reported on a separate expense line, into operating expense, both within the same group of expenses as reported in the Company's condensed consolidated statements of comprehensive loss. The reclassification was made to conform to the basis of presentation for the current year and resulted in no change to total expenses, loss from operating activities, total comprehensive loss and loss per share reported for the three and nine months ended September 30, 2017. See *Note 15 – Segment Reporting* in the Company's Unaudited Condensed Consolidated Financial Statements for the three and nine months ended September 30, 2018.

(2) Sales Volumes represent the Company's share of entitlement production marketed by the State Oil Corporation of Azerbaijan ("**SOCAR**") after in-kind production volumes delivered to SOCAR as compensatory petroleum and the government's share of profit petroleum. The Company's share of entitlement production includes the allocation of SOCAR Oil Affiliate's ("**SOA**") share of cost recovery production as required by the Carry 1 recovery provisions in the Exploration, Rehabilitation, Development and Production Sharing Agreement (the "**ERDPSA**"). Compensatory petroleum represents 10% of gross production from the ERDPSA and continues to be delivered to SOCAR, at no charge, until specific cumulative oil and natural gas production milestones are attained.

(3) Represents the percentage of Bahar Energy Limited's ("**BEL**") entitlement production volume relative to gross volumes delivered by the ERDPSA.

(4) The natural gas price was contractually fixed at $3.96 per mcf in the first quarter 2017 and then renegotiated to a new 5-year term at $2.69 per mcf effective April 1, 2017.

(5) "Net realization price, operating cost and operating netback" are Non-IFRS measures. For more information see "*Non-IFRS Measures*".

## Restructuring of Senior Secured Debt

The Company also announces that it has executed a thirteenth amending agreement ("**Amendment**") to its loan agreement dated November 25, 2013 (the "**Loan Agreement**") with its senior lender (the "**Lender**"), Vitol Energy (Bermuda) Ltd. ("**Vitol**"). Pursuant to the Amendment: (i) the principal amount plus accrued and unpaid interest under the Loan Agreement as of October 31, 2018, being $53.3 million, was converted to principal (the "**Restructured Amount**"); (ii) the maturity date of the Loan Agreement was extended from January 15, 2020 to January 31, 2021; and (iii) the Lender fee due on November 1, 2018 was extended to January 31, 2019.

## Report on Reserves, Contingent Resources and Prospective Resources

Greenfields is pleased to provide an updated summary of the Company's reserves in the Bahar and Gum Deniz in Azerbaijan as of 31 July 2018 and the Company's contingent and prospective resources in Bahar and Gum Deniz as of 30 July 2018. Reserves numbers presented herein are derived from an independent assessment (the "**GLJ Report**") prepared by GLJ Petroleum Consultants ("**GLJ**"), while contingent and prospective resources presented herein are derived from an independent assessment (the "**ERCE Report**") prepared by ERC Equipoise Ltd. ("**ERCE**"). Both GLJ and ERCE are qualified reserves evaluators as defined in National Instrument 51-101 - *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). Unless otherwise indicated, the figures in the following tables have been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook (the "**COGE Handbook**") and the reserve definitions contained in NI 51-101.

### GLJ Report

The Company's reserves at July 31, 2018 as set forth in the GLJ Report are summarized below:

*Summary of Reserves*

| | Light Oil | | Natural Gas Liquids | | Conventional Natural Gas | |
|---|---|---|---|---|---|---|
| | **Gross Lease** | **Net [1]** | **Gross Lease** | **Net [1]** | **Gross Lease** | **Net [1]** |
| | (Mbbl) | (Mbbl) | (Mbbl) | (Mbbl) | (MMcf) | (MMcf) |
| Proved | | | | | | |
| Developed Producing | 167 | 141 | 13 | 11 | 5,913 | 5,003 |
| Developed Non-Producing | 2,982 | 2,115 | 2,040 | 1,434 | 191,808 | 135,352 |
| Undeveloped | 9,521 | 6,150 | 433 | 219 | 20,565 | 6,139 |
| Total Proved (1P) | 12,670 | 8,407 | 2,483 | 1,664 | 218,286 | 146,494 |
| Total Probable | 14,265 | 5,954 | 1,976 | 793 | 158,410 | 58,845 |
| Total Proved plus Probable (2P) | 26,935 | 14,361 | 4,459 | 2,457 | 376,696 | 205,339 |
| Total Possible [2] | 29,168 | 6,822 | 2,300 | 466 | 175,611 | 22,893 |
| Total Proved plus Probable plus Possible (3P) | 56,103 | 21,183 | 6,759 | 2,923 | 552,307 | 228,232 |

**Notes:**

(1) The Company holds an 80% working interest in the Bahar and Gum Deniz through its 100% ownership of BEOC, an 80% participant in the ERDPSA. Net reserves are net of the interest of SOA and other deductions consisting of operating and capital cost recovery as well as future contributions to the ERDPSA abandonment fund.

(2) Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

*Summary of Net Present Values of Future Net Revenue*

| | Net Present Values of Future Net Revenue | | | | |
|---|---|---|---|---|---|
| | **0%** | **5%** | **10%** | **15%** | **20%** |
| Description | M$ | M$ | M$ | M$ | M$ |
| Proved | | | | | |
| Producing | 8,854 | 8,604 | 8,374 | 8,163 | 7,967 |
| Developed Non-Producing | 228,584 | 173,151 | 134,596 | 107,088 | 86,976 |
| Undeveloped | 233,084 | 143,302 | 87,952 | 52,484 | 29,039 |
| Total Proved | 470,522 | 325,057 | 230,922 | 167,734 | 123,982 |
| Total Probable | 450,470 | 345,031 | 273,142 | 221,437 | 182,833 |
| Total Proved plus Probable | 920,992 | 670,088 | 504,065 | 389,171 | 306,816 |
| Total Possible | 428,931 | 348,676 | 287,430 | 239,863 | 202,359 |
| Total Proved plus Probable plus Possible | 1,349,923 | 1,018,764 | 791,495 | 629,034 | 509,175 |

**Notes:**

(1) Utilizes GLJ's price forecast as of July 31, 2018 as detailed below.

(2) The amounts included herein are the same on a before and after tax basis because, pursuant to the ERDPSA, an income tax equivalent to 20% of the profit is paid by SOCAR on behalf of the Contractor Parties to the government of Azerbaijan. Any US taxes will be partially offset by the tax credits. In addition, the Contractor Parties are exempt from all other taxes, duties and royalties in Azerbaijan, other than certain customs fees, personal income tax and contributions to the state social insurance funds of Azerbaijan.

(3) It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to the Company's reserves estimated by GLJ represent the fair market value of those reserves. All future net revenues are estimated using forecast prices and cost assumptions. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of the Company's reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein.

*Summary of Pricing and Inflation Rate Assumptions – Forecast Prices and Costs*

GLJ used the following pricing and inflation rate assumptions as of July 31, 2018 in its evaluation contained in the GLJ Report in estimating Greenfields' reserves data using forecast prices and costs.

| Period Ending | Brent Oil Price | Net Realized Oil Price | Natural Gas Contract Price | Net Realized NGL Price | % Cost Escalation Operating Expenses | Inflation rate |
|---|---|---|---|---|---|---|
| Forecast | ($/Bbl) | ($/Bbl) | ($/MMBTU) | ($/Bbl) | (%) | (%) |
| 2018 | 76.50 | 68.91 | 2.69 | 70.61 | 0 | 0 |
| 2019 | 72.00 | 64.62 | 2.69 | 65.79 | 2.0 | 2.0 |
| 2020 | 71.25 | 63.85 | 2.69 | 64.37 | 2.0 | 2.0 |
| 2021 | 71.25 | 63.79 | 2.69 | 64.41 | 2.0 | 2.0 |
| 2022 | 72.50 | 64.90 | 2.69 | 66.09 | 2.0 | 2.0 |
| 2023 | 75.00 | 67.19 | 2.69 | 67.77 | 2.0 | 2.0 |
| 2024 | 77.50 | 69.47 | 2.69 | 69.95 | 2.0 | 2.0 |
| 2025 | 80.00 | 71.75 | 2.69 | 72.14 | 2.0 | 2.0 |
| 2026 | 82.50 | 74.04 | 2.69 | 74.46 | 2.0 | 2.0 |
| 2027 | 84.86 | 76.18 | 2.69 | 76.76 | 2.0 | 2.0 |
| 2028 | 86.56 | 77.71 | 2.69 | 78.30 | 2.0 | 2.0 |
| 2029 | 88.29 | 79.26 | 2.69 | 79.86 | 2.0 | 2.0 |

*Future Development Costs*

The following table sets forth development costs deducted in the estimation of the Company's future net revenue attributable to the reserve categories noted below:

| Forecast Development Costs (M$) | | | |
|---|---|---|---|
| Year | Proved Reserves | Proved Plus Probable Reserves | Proved Plus Probable Plus Possible Reserves |
| 2018 | 6,648 | 7,056 | 7,340 |
| 2019 | 47,199 | 47,460 | 68,186 |
| 2020 | 62,898 | 71,978 | 83,481 |
| 2021 | 39,570 | 75,864 | 60,311 |
| 2022-2029 | 64,860 | 79,170 | 96,880 |
| Thereafter | 9,946 | 14,117 | 15,172 |
| **Total Undiscounted** | **231,120** | **295,644** | **331,370** |

The Company typically utilizes three sources of funding to finance its capital expenditure program: internally generated cash flow from operations, debt financing when appropriate and new equity issues, if available on favorable terms. The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and may reduce the reserves and future net revenue to some degree depending upon the funding sources utilized. The Corporation does not anticipate that interest or other funding costs would make the development of a property uneconomic.

**ERCE REPORT**

*Waterflood Development*

Bahar Energy plans to initiate a waterflood of the Fasila reservoir in Bahar (the "**Fasila Reservoir**") in 2020 starting with the implementation of five waterflood pilots. Bahar Energy's proposed development plans, subject to financing, would include the implementation of up to five waterflood pilots from 2020 onwards and assuming a positive, economic reservoir response to the pilot flood, a full-scale water injection project would be implemented by Bahar Energy. Initially the drilling of two down dip injection wells located in the water leg of the Fasila Reservoir would be carried out. The drilling of a total of nine injection wells is envisaged over a five-year period from three existing platforms and one new platform to be constructed on the western flank of the reservoir.

Contingent Resources for the planned pilot water injection followed by a water flood of the Bahar Fasila Reservoir are presented in the tables below.

*Contingent Unrisked Oil Resources, Bahar Field, Fasila Reservoir*

| Interval | Gross Unrisked Contingent Oil | | | Working | Net Unrisked Contingent Oil | | |
|---|---|---|---|---|---|---|---|
| | 1C | 2C | 3C | Interest | 1C | 2C | 3C |
| Bahar Fasila | 10.3 | 20.6 | 41.2 | 80.00% | 8.2 | 16.5 | 32.9 |

**Notes:**

(1) The above table has been disclosed consistent with the classification and reporting requirements of the March 2007 SPE/ EPC/ AAPG/ SPEE Petroleum Resources Management System ("**PRMS**").

(2) The above table is unrisked, in that estimates have not been multiplied by the chance of development.

(3) "**Gross Contingent Resources**" are all volumes estimated to be recoverable from the field without any economic cut-off being applied. There is no equivalent COGEH definition.

(4) "**Net Contingent Resources**" are the Company's working interest fraction of the Gross Contingent Resources. The equivalent COGEH definition disclosed below is "Gross Working Interest Contingent Resources" which is the Company's working interest fraction in Contingent Resources prior to the deduction of royalties.

*Contingent Risked Oil Resources, Bahar Field, Fasila Reservoir*

| RESOURCES PROJECT MATURITY SUB-CLASS | RISKED CONTINGENT RESOURCES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM CRUDE OIL | | | CONVENTIONAL NATURAL GAS | | | NATURAL GAS LIQUIDS | | |
| | Gross (Mbbl) | Gross WI (Mbbl) | Net (Mbbl) | Gross (MMcf) | Gross WI (MMcf) | Net (MMcf) | Gross (Mbbl) | Gross WI (Mbbl) | Net (Mbbl) |
| **CONTINGENT (2C)** Development Unclarified | 14,420 | 11,536 | n/a | n/a | n/a | n/a | n/a | n/a | n/a |

**Notes:**

(1) Contingent Resources are estimates of volumes that are potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies.

(2) The volumes reported here are "risked" in the sense that they have been adjusted for chance of development. The chance of development is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. ERCE determined that a 70 percent chance of development is appropriate for the Contingent Resources.

(3) Gross Contingent Resources are all volumes estimated to be recoverable from the field without any economic cut-off being applied. Gross Weight Interest Contingent Resources is adjusted for the Company's 80% working interest fraction of the Gross Contingent Resources. Net Contingent Resources are adjusted for the Company's working interest share after deduction of royalty obligations.

(4) Project maturity for Contingent Resources has been classified as Development Unclarified.

*Exploration Drilling*

Similarly, the Company has mapped a significant structural closure at Miocene level at a depth of between 4,500 and 5,000 metres (subsea) based on 3D seismic. The prospective horizon is located beneath the oil producing reservoirs of the Gum Deniz and this horizon has not yet been penetrated by a well in the Bahar PSA. The Company is also monitoring the drilling of the Absheron Operating Company Miocene well test which is located approximately 4 km north east of the Bahar Project. The well is being drilled from the same surface location as the 2015 Hovsan 1870 gas discovery well which reportedly encountered high pressure gas of 16 MMscf/d and condensate of 640 B/d in the top of the Miocene at approximately 4,600 metres (subsea). The well reportedly also encountered high bottom hole pressures in excess of 11,000 psi.

ERCE has reviewed the data provided and has made independent estimates of GIIP and Prospective Resources. The below table presents ERCE's estimates of unrisked and risked gross and net gas and condensate Prospective Resources for the Miocene prospect in the Gum Deniz.

*Prospective Resources, Gum Deniz Miocene Prospect*

| | GIIP (Bscf) | | | Gross Unrisked Prospective Gas Resources (Bscf) | | | | Working Interest (%) | Net Unrisked Prospective Gas Resources (Bscf) | | | | COS (%) | Net Risked Prospective Gas Resources (Bscf) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Low | Mid | High | Low | Mid | High | Mean | | Low | Mid | High | Mean | | Low | Mid | High | Mean |
| Miocene Prospect | 78.0 | 332.5 | 1364.5 | 49.9 | 214.4 | 891.2 | 392.0 | 80% | 39.9 | 171.5 | 713.0 | 313.6 | 32% | 12.8 | 54.9 | 228.1 | 100.4 |

| | CIIP (MMbbl) | | | Gross Unrisked Prospective Condensate Resources (MMbbl) | | | | Working Interest (%) | Net Unrisked Prospective Condensate Resources (MMbbl) | | | | COS (%) | Net Risked Prospective Condensate Resources (MMbbl) | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Low | Mid | High | Low | Mid | High | Mean | | Low | Mid | High | Mean | | Low | Mid | High | Mean |
| Miocene Prospect | 4.9 | 22.3 | 96.9 | 2.4 | 10.8 | 47.2 | 20.6 | 80% | 1.9 | 8.6 | 37.7 | 16.5 | 32% | 0.6 | 2.8 | 12.1 | 5.3 |

**Notes:**

(1) The above table has been disclosed consistent with the classification and reporting requirements of PRMS.

(2) "**Gross Unrisked Prospective Resources**" are all volumes estimated to be recoverable from an accumulation. There is no equivalent COGE Handbook definition.

(3) "**Net Unrisked Prospective Resources**" are the Company's working interest fraction of the Gross Unrisked Prospective Resources. The equivalent COGE Handbook definition disclosed below is "Gross Working Interest Prospective Resources" which is the Company's working interest fraction in Prospective Resources prior to the deduction of royalties.

(4) "**Net Risked Prospective Resources**" are the Company's working interest fraction of the Net Unrisked Prospective Resources multiplied by the geological chance of success ("**COS**"). The COS is an estimate of the probability that drilling the prospect would result in a discovery as defined under PRMS. ERCE has assigned a chance of success of 32% to the Prospective Resources. Under COGE Handbook, prospective resources are risked by a chance of commerciality, being the product of the chance of development and the chance of discovery. For further detail, see below notes (2)-(4) of the table entitled "*Prospective Resources, Gum Deniz Miocene Prospect*".

(5) Prospective Resources reported here are both "unrisked" in that they have not been multiplied by the COS and "risked" in that the volumes have been multiplied by the COS.

*Prospective Resources, Gum Deniz Miocene Prospect*

| RESOURCES | RISKED PROSPECTIVE RESOURCES | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | LIGHT AND MEDIUM CRUDE OIL | | | CONVENTIONAL NATURAL GAS | | | NATURAL GAS LIQUIDS | | |
| | Gross (Mbbl) | Gross W.I. (Mbbl) | Net (Mbbl) | Gross (MMcf) | Gross W.I. (MMcf) | Net (MMcf) | Gross (Mbbl) | Gross W.I. (Mbbl) | Net (Mbbl) |
| **PROSPECTIVE** (Best Estimate) | 3,456 | 2,765 | n/a | 68,608 | 54,886 | n/a | n/a | n/a | n/a |

**Notes:**

(1) Prospective Resources are estimates of volumes that are potentially recoverable from undiscovered accumulations by application of future development projects.

(2) The volumes reported here are "risked" in the sense that they have been adjusted for the chance of commerciality, being the product of the chance of development and the chance of discovery. ERCE determined that a 32 percent chance of commerciality is appropriate for the Prospective Resources.

(3) The chance of development is defined as the probability of a project being commercially viable. Quantifying the chance of development requires consideration of both economic contingencies and other contingencies, such as legal, regulatory, market access, political, social license, internal and external approvals and commitment to project finance and development timing. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution.

(4) The chance of discovery is defined as the probability the exploration activities will confirm the existence of a significant accumulation of potentially recoverable resources. Quantifying the chance of discovery requires consideration of certain risks including the chance of success of a play, the chance of success of the prospect specific properties and the prospect specific properties qualities being sufficient to result in a commercially viable discovery. As many of these factors are extremely difficult to quantify, the chance of development is uncertain and must be used with caution.

(5) Gross Prospective Resources are all of the volumes estimated to be recoverable from the field without any economic cut-off being applied. Gross Weighted Average Prospective Resources is adjusted for the Company's 80% working interest fraction of the Gross Prospective Resources. Net Prospective Resources are adjusted for the Company's working interest share after deduction of royalty obligations.

**About Greenfields Petroleum Corporation**

Greenfields is an oil and natural gas company focused on the development and production of proven oil and gas reserves in the Republic of Azerbaijan. The Company is the sole owner of **BEL**, a venture with an 80% participating interest in the **ERDPSA** with **SOCAR** and its affiliate **SOA**, in respect of the Bahar Project, which includes the Bahar Gas Field and the Gum Deniz Oil Field. BEL operates the Bahar Project through its wholly owned subsidiary Bahar Energy Operating Corporation Limited. More information about the Company may be obtained on the Greenfields' website at www.greenfields-petroleum.com.

**Forward-Looking Statements**

*This press release contains forward-looking statements. More particularly, this press release includes forward-looking statements concerning, but not limited to: operational and development plans of the Company; the completion of refurbishments and the anticipated timing thereof; the completion of workovers and anticipated timing thereof; the completion of recompletions and reactivations and the anticipated timing thereof; production; and the completion of waterflood injectivity tests. In addition, the use of any of the words "anticipated", "scheduled", "will", "prior to", "estimate", "believe", "should", "future", "continue", "expect", "plan" and similar expressions are intended to identify forward-looking statements. The forward-looking statements contained herein are based on certain key expectations and assumptions made by the Company, including, but not limited to, expectations and assumptions concerning the success of optimization and efficiency improvement projects, the availability of capital, current legislation and regulatory regimes, receipt of required regulatory approval, the success of future drilling and development activities, the performance of existing wells, the performance of new wells, general economic conditions, availability of required equipment and services, weather conditions and prevailing commodity prices. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct.*

*Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties most of which are beyond the control of Greenfields. Should one or more of these risks or uncertainties materialize, or should assumptions underlying the forward-looking information prove incorrect, actual results, performance or achievements could vary materially from those expressed or implied by the forward-looking information. These risks include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; and health, safety, political and environmental risks), commodity price and exchange rate fluctuations, changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures. Additional risk factors can be found under the heading "Risk Factors" in Greenfields' Management Discussion and Analysis which may be viewed on www.sedar.com.*

*The forward-looking statements contained in this press release are made as of the date hereof and Greenfields undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws. The Company's forward-looking information is expressly qualified in its entirety by this cautionary statement.*

**Non-IFRS Measures**

*Within this document, references are made to terms which are not recognized under IFRS. Specifically, "net realization price", "operating cost" and "operating netback" do not have any standardized meaning as prescribed by IFRS and are regarded as non-IFRS measures. These non-IFRS measures may not be comparable to the calculation of similar amounts for other entities and readers are cautioned that use of such measures to compare issuers may not be valid. Non-IFRS measures are used to benchmark operations against prior periods and are widely used by investors, lenders, analysts and other parties. These non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS. The definition and reconciliation of each non-IFRS measure or additional subtotal is presented herein.*

*"Net realization price", "operating costs" and "operating netbacks" are common non-IFRS measurements applied in the oil and gas industry and are used by management to assess the operational performance and performance of the Company. "Net realization price" indicates the selling price of a good less the selling costs. "Operating cost" provides an indication of the controllable cash costs incurred per boe during a period. "Operating netback" is a measure of oil and gas sales revenue net of royalties, production and transportation expenses. Management believes that these non-IFRS measures assist management and investors in assessing Greenfields' profitability and operating results on a per unit basis to better analyze performance against prior periods on a comparable basis.*

*The Operating Summary on page 12 of the Company's third quarter 2018 MD&A includes a reconciliation of "net realization price", "operating cost" and "operating netback" to the most closely related IFRS measure.*

**Notes regarding Oil and Gas Disclosures**

*Barrels of oil equivalent or "boe" may be misleading, particularly if used in isolation. The volumes disclosed in this press release use a 6 mcf: 1 boe, as such is typically used in oil and gas reporting and is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. The Company uses a 6 mcf: 1 boe ratio to calculate its share of entitlement sales from the Bahar Project for its financial reporting and reserves disclosure.*

***Oil and Gas Advisories***

***Information Regarding Disclosure on Oil and Gas Reserves.*** *The reserves data set forth above is based upon an independent reserves assessment and evaluation prepared by GLJ Petroleum Consultants with an effective date of 31 July 2018 (the "**GLJ Report**") and an independent contingent and prospective resources assessment prepared by ERC Equipoise Ltd. with an effective date of 30 July 2018 (the "**ERCE Report**"). The reserves and contingent and prospective resources were evaluated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook and the reserve definitions contained in National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("**NI 51-101**"). The contingent and prospective resources were also evaluated in accordance with the classification and reporting requirements of PRMS.*

***BOE.*** *Barrels of oil equivalent or "boe" may be misleading, particularly if used in isolation. All volumes disclosed in this press release use a 6mcf: 1boe, as such is typically used in oil and gas reporting and is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

***OOIP Disclosure.*** *The term original-oil-in-place ("**OOIP**") is equivalent to total petroleum initially-in-place ("**TPIIP**"). TPIIP, as defined in the Canadian Oil and Gas Evaluation Handbook, is that quantity of petroleum that is estimated to exist in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered. A portion of the TPIIP is considered undiscovered and there is no certainty that any portion of such undiscovered resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of such undiscovered resources. With respect to the portion of the TPIIP that is considered discovered resources, there is no certainty that it will be commercially viable to produce any portion of such discovered resources. A significant portion of the estimated volumes of TPIIP will never be recovered.*

***Caution Regarding Reserves Information.*** *This press release summarizes the Company's crude oil and natural gas reserves based on the GLJ Report. The recovery and reserve estimates of the Company's crude oil and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas and natural gas liquids reserves may be greater than or less than the estimates provided herein.*

*Reserves are classified according to the degree of certainty associated with the estimates. Proved (1P) reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves. Probable (2P) reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves. Possible (3P) reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions: at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved (1P) reserves; at least a 50 percent probability that the quantities actually recovered will equal or exceed the estimated proved plus probable (1P+2P) reserves; and at least a 10 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable plus possible (1P+2P+3P) reserves.*

***Contingent Resources and Prospective Resources.*** *Contingent resources are the quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology underdevelopment, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage.*

*Estimates related to the Contingent Resources:*

| | *Estimated cost to achieve commercial production* | *General timeline including the estimated date of first commercial production* | *Estimated recovery technology (conventional or unconventional)* | *Basis of project (conceptual or pre-development)* |
|---|---|---|---|---|
| *Bahar Fasila* | *$20,000,000 Pilot<br>$120,000,000 full development* | *2020 Pilot<br>2021 Commercial Production* | *Unconventional* | *Pre-development* |

*Prospective Resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective Resources have both an associated chance of discovery and a chance of development. Not all exploration projects will result in discoveries. The chance that an exploration project will result in the discovery of petroleum is referred to as the chance of discovery. Thus, for an undiscovered accumulation the chance of commerciality is the product of two risk components-the chance of discovery and the chance of development. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources.*

*Estimates of the Contingent Resources and Prospective Resources are based upon the ERCE Report. The estimates of Contingent Resources and Prospective Resources provided in this press release are estimates only and there is no guarantee that the estimated Contingent Resources and Prospective Resources will be recovered. Actual contingent and prospective resources may be greater than or less than the estimates provided in this in this press release and the differences may be material. There is no certainty that any portion of the Prospective Resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the Prospective Resources. There is also uncertainty that it will be commercially viable to produce any part of the Contingent Resources.*

*Estimates of contingent and prospective resources are by their nature more speculative than estimates of proved reserves and would require substantial capital spending over a significant number of years to implement recovery. Actual locations drilled and quantities that may be ultimately recovered from our properties will differ substantially. In addition, we have made no commitment to drill, and likely will not drill, all of the drilling locations that have been attributable to these quantities.*

*Prospective resources estimates that are referred to herein are risked as to both chance of discovery and chance of development. Contingent resources estimates that are referred to herein are risked as to chance of development. Risks that could impact the chance of discovery and chance of development include, without limitation: geological uncertainty and uncertainty regarding individual well drainage areas; uncertainty regarding the consistency of productivity that may be achieved from lands with attributed resources; potential delays in development due to product prices, access to capital, availability of markets and/or take-away capacity; and uncertainty regarding potential flow rates from wells and the economics of those wells. Risk assessment is a highly subjective process dependent upon the experience and judgment of the evaluators and is subject to revision with further data acquisition or interpretation.*

*The following classification of contingent and prospective resources is used in the press release:*

- *Low Estimate (or 1C) means there is at least a 90 percent probability (P90) that the quantities actually recovered will equal or exceed the low estimate.*
- *Best Estimate (or 2C) means there is at least a 50 percent probability (P50) that the quantities actually recovered will equal or exceed the best estimate.*
- *High Estimate (or 3C) means there is at least a 10 percent probability (P10) that the quantities actually recovered will equal or exceed the high estimate.*

*In general, the significant factors that may change the Contingent Resources estimates include further delineation drilling, which could change the estimates either positively or negatively, future technology improvements, which would positively affect the estimates, and additional processing capacity that could affect the volumes recoverable or type of production. Additional facility design work, development plans, and reservoir studies are expected to be completed by Greenfields in accordance with its long-term resource development plan.*

***FOFI Disclosure***

*This press release contains future-oriented financial information and financial outlook information (collectively, "**FOFI**") about Greenfields' prospective results of operations, future production and net present values of future net revenue which are subject to the same assumptions, risk factors, limitations and qualifications as set forth in the above paragraphs. FOFI contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Greenfields' anticipated future business operations. Greenfields disclaims any intention or obligation to update or revise any FOFI contained in this press release, whether as a result of new information, future events or otherwise, unless required pursuant* *to applicable law. Readers are cautioned that the FOFI contained in this press release should not be used for purposes other than for which it is disclosed herein. All FOFI contained in this press release complies with the requirements of Canadian securities legislation, including NI 51-101.*

***Abbreviations***

| | |
|---|---|
| *bbl* | *Barrel(s)* |
| *Mbbl* | *One thousand barrels* |
| *$/ Bbl* | *Dollars per barrel* |
| *bbl/d* | *barrels per day* |
| *Boe* | *Barrels of Oil Equivalent* |
| *MMboe* | *Million barrels of oil equivalent* |
| *Boe/d* | *Barrels of oil per day* |
| *mcf* | *thousand cubic feet* |
| *mcf/d* | *thousand cubic feet per day* |
| *MMcf* | *Million cubic feet* |
| *Tcf* | *Trillion Cubic Feet* |
| *$/MMBTU* | *Dollars per million British thermal units* |

***Neither the TSX Venture Exchange nor its Regulation Services Provider (as that term is defined in the policies of the TSX Venture Exchange) accepts responsibility for the adequacy or accuracy of this release.***

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