Terrace Energy Corp.

Form 51-101 F1

Statement of Reserves Data

And Other Oil and Gas Information

As of January 31, 2016

Table of Contents

Glossary of Terms

Company, Corporation or we	Terrace Energy Corp.
D&M	DeGolyer and MacNaughton, a qualified reserves evaluator that is independent of the Corporation under NI 51-101.
D&M Report	The report of D&M entitled "Appraisal Report as of January 31, 2016 on Proved and Probable Reserves of Certain Properties owned by Terrace Energy Corp." dated April 22, 2016.
Developed reserves	Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the reserves on production. Developed reserves may be subdivided into Producing and Non-Producing categories.
Future net revenue	Working interest revenues after royalties, development costs, production costs and well abandonment costs, but before administrative, overhead and other such indirect costs. Future net revenue may be presented either before or after tax.
Gross reserves	Estimated reserves before royalties based on working interest.
Net reserves	Estimated reserves after royalties based on working interest.
NI 51-101	National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.
Non-producing reserves	Developed reserves that either have not been on production, or have previously been on production, but are shut-in and the date of resumption of production is unknown.
Probable reserves	Reserves that are less certain than proved reserves at being recovered. 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.
Producing reserves	Developed reserves that are expected to be recovered from completion intervals opens at the time of estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonably certainty.
Proved reserves	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.
Reserves	Estimated reserves of natural gas, natural gas liquids and crude oil.

Undeveloped reserves	Reserves that are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production (e.g., in comparison to the costs of drilling a well). Such reserves must fully meet the requirements of the reserves classification to which they are assigned (proved or probable).
Unproved property	A property or part of a property to which no reserves have been specifically attributed.
Working interest	Those lands in which the Corporation receives its acreage share of net production revenues.

Abbreviations

bbl or barrel	A 42-US gallon barrel of crude oil or natural gas liquids.
bcf	One billion (1,000,000,000) cubic feet of natural gas.
boepd	Barrels of oil equivalent per day.
bopd	Barrels of oil per day.
L&M	Light and medium (crude oil).
M	Thousand (1,000).
MM	Million (1,000,000).
Mbbl	1,000 barrels of oil and/or natural gas liquids.
MMBtu	A unit of heat energy equal to one million British thermal units.
Mcf	1,000 cubic feet of natural gas.
NGL	Natural gas liquids.
Stb/stock tank barrel	A 42-US gallon barrel of crude oil at standard conditions of 1 atmosphere and 60 degrees F.

Caution Regarding Use of Barrels of Oil Equivalent (BOEs)

BOEs/boes may be misleading, particularly if used in isolation. A boe conversion ratio of six (6) Mcf to one (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. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

Form 51-101 F1
Statement of Reserves Data and Other Oil and Gas Information for Terrace Energy Corp.

Part 1 DATE OF STATEMENT

Item 1.1 Relevant Dates

1. Date of Statement: May 30, 2016
2. Effective Date: January 31, 2016
3. Preparation Date: May 25, 2016

The following information is related to the Company's reserves, future net revenue and discounted value of future net cash flow of the light and medium oil, conventional natural gas and natural gas liquids in U.S.A. D&M, independent qualified evaluators of Dallas, Texas estimated the reserves effective January 31, 2016 in the D&M Report. The Company used the reserves in the preparation of its financial statements for the fiscal year ended January 31, 2016.

All of the Company's oil and gas reserves are onshore, U.S.A. Consistent with the Company's Form 51-101F1 for its fiscal year ended January 31, 2015, the Company uses light and medium crude oil, natural gas liquids and conventional natural gas as the three product types to report the Company's reserves herein. The Company and its technical advisors determined that these product types were the most appropriate based on the formations underlying the Company's principal projects in South Texas, USA.

The following tables provide the reserves data and the breakdown of future net revenue by commodities and reserve category using forecast prices and costs, based on the Company's working interest portion before royalties (gross) and/or after royalties (net) (see "Glossary of Terms").

The pricing used in tables that reflect forecast price evaluations is set forth in Item 3.2. All dollar amounts referenced herein, unless otherwise indicated, are expressed in United States dollars.

In certain instances, numbers may not total due to computer-generated rounding. In such cases, differences are not material and amounts presented are as shown in the D&M Report.

All reserves information contained herein has been prepared and presented in accordance with NI 51-101.

The reserves on the properties described herein are estimates only. Actual reserves on the properties may be greater or less than those calculated. The estimated future net revenue contained in the tables herein does not necessarily represent the fair market value of the reserves. There is no assurance that forecast prices and costs

assumed in the D&M evaluation will be attained, and variances could be material. Assumptions and qualifications relating to costs and other matters are summarized in the various tables below. See also "Forward-Looking Information" and "Risk Factors" in Management's Discussion and Analysis of the Company's Financial Condition and Results of Operation for the years ended January 31, 2016 and 2015 ("MD&A"), available at www.sedar.com.

The disclosures contained in this report represent information related to the Company's reserves, future net revenue and discounted value of future net cash flows as of January 31, 2016. During May 2016, as disclosed in the Company's material change report dated May 30, 2016, the Company entered into a transaction whereby the Company relinquished 95% of its equity in the Terrace STS, LLC subsidiary which owned 70.6% of the proved and probable reserves disclosed in this report. This transaction is more fully described in the "INFORMATION REGARDING MATERIAL CHANGE SUBSEQUENT TO EFFECTIVE DATE OF REPORT" section found at the end of this report.

Part 2 DISCLOSURE OF RESERVES DATA

Item 2.1 Reserves Data (Forecast Prices and Costs)

Item 2.1.1 Breakdown of Reserves

Onshore U.S.A.

	L&M Crude Oil		Natural Gas Liquids		Conventional Natural Gas	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
Proved Developed Producing	403	301	170	127	746	557
Proved Developed Non-Producing	119	89	59	44	253	189
Proved Undeveloped	130	95	5	4	64	47
Total Proved	**652**	**485**	**234**	**175**	**1,063**	**793**
Total Probable	351	260	53	39	315	233
Proved + Probable	**1,003**	**745**	**287**	**214**	**1,378**	**1,026**

Figures may be rounded off.

Item 2.1.2 Net Present Value of Future Net Revenue

Onshore U.S.A.

Reserves Category	Before & After Tax NPV @ 0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Producing	10,960	7,304	5,315	4,126	3,353
Proved Non-Producing	986	489	169	-40	-177
Proved Undeveloped	2,140	1,047	473	168	5
Total Proved	**14,086**	**8,840**	**5,957**	**4,254**	**3,181**
Total Probable	6,510	2,812	1,139	317	-101
Proved + Probable	**20,596**	**11,652**	**7,096**	**4,571**	**3,080**

Figures may be rounded off.

The net operating losses for tax exceed the expected undiscounted cash flows resulting in no tax payable at this time.

Item 2.1.3 (a) (b) Additional Information Concerning Future Net Revenue

Onshore U.S.A.

Reserves Category	Revenue after deduction of Royalties* (M$)	Production and Ad Valorem Tax (M$)	Operating Costs (M$)	Development Costs (M$)	Abandon & Reclam. Costs (M$)	Future Net Revenue Before Income Tax (M$)	Future Income Tax Expenses (M$)	Future Net Revenue After Income Tax (M$)
Total Proved	41,782	3,106	18,385	5,578	627	14,086	0	14,086
Total Proved + Probable	66,113	4,874	25,923	13,904	816	20,596	0	20,596

*Royalties were taken by the operator at the wellhead.

Item 2.1.3 (c) Net Present Value of Future Net Revenue by Product Type based on Forecast Prices and Costs

The net present value of future net revenue by product type and on a unit value based on net reserves, forecast prices and costs before deduction of future income tax expenses and using a discount rate of 10% is set forth below:

Onshore U.S.A.

	L&M Oil $/bbl	NGL $/bbl	Natural Gas $/Mcf
Proved	10.20	0.46	0.54
Proved + Probable	8.02	0.49	0.46

Item 2.2 Supplemental Disclosure of Reserves Data (Constant Prices and Costs) - Not applicable.

Part 3 PRICING ASSUMPTIONS

Item 3.1 Constant Prices Used in Supplemental Estimates - Not applicable.

Item 3.2 Forecast Prices Used in Estimates

Item 3.2.1(a)

Forecast Oil and Gas Prices (D&M Report)

	Oil and NGL	Natural Gas
Date	(U.S.$/bbl)	(U.S.$/MMbtu)
2016	44.00	2.60
2017	52.00	3.10
2018	58.00	3.30
2019	64.00	3.50
2020	70.00	3.70
2021	75.00	3.90
2022	80.00	4.10
2023	85.00	4.30
2024	87.88	4.50
2025	89.63	4.60

After 2025, prices are escalated at 2% per year thereafter.

Item 3.2.1(b)

The following table summarizes the weighted average historical product prices for important fields for the year ending January 31, 2016:

Weighted Average Historical Price:

Oil: $39.69 per barrel
NGL: $10.94 per barrel
Natural Gas: $1.89 per Mcf

Item 3.2.2 The oil, condensate, and NGL prices were calculated based on the NYMEX West Texas Intermediate price forecast. The natural gas prices were calculated based on the NYMEX Henry Hub price forecast. These prices were adjusted for historical price differentials experienced in the field. The 2025 prices were escalated at 2 per cent beginning in 2026.

Item 3.2.3 –The pricing assumptions specified in Item 3.2 were derived from published NYMEX data and differentials provided by the Corporation. **Part 4**

RECONCILIATION OF CHANGES IN RESERVES

Item 4.1 Reserves Reconciliation

Onshore U.S.A.

	Gross L & M Oil			Gross NGL			Gross Natural Gas		
	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (Mbbl)	Probable (Mbbl)	Proved + Probable (Mbbl)	Proved (MMcf)	Probable (MMcf)	Proved + Probable (MMcf)
Total									
Opening Balance (January 31, 2015)	2,899	2,148	5,047	1,148	683	1,831	5,251	3,530	8,781
Extension & Improved Recovery	0	0	0	0	0	0	0	0	0
Technical Revisions									
Discoveries	0	0	0	0	0	0	0	0	0
Acquisitions	0	0	0	0	0	0	0	0	0
Dispositions	0	0	0	0	0	0	0	0	0
Economic Factors	-2,114	-1,797	-3,911	-851	-630	-1,481	-3,598	-3,215	-6,813
Production	-133	-	-133	-63	-	-63	-590	-	-590
Opening Balance (January 31, 2016)	**652**	**351**	**1,003**	**234**	**53**	**287**	**1,063**	**315**	**1,378**

Figures may be rounded off.

Part 5 ADDITIONAL INFORMATION RELATING TO RESERVES DATA

Item 5.1 Undeveloped Reserves

Undeveloped reserves were attributed by D&M in accordance with the standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases it will take longer than two years to develop our undeveloped reserves. The D&M Report assumed the drilling of no gross wells in 2016 or 2017.

There are a number of factors that could result in delayed or cancelled development of undeveloped reserves, including the following; 1) changing economic conditions due to, for example, product pricing or operating and capital expenditure fluctuations; 2) changing technical conditions or production anomalies such as water break through or accelerated depletion; 3) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; 4) sale of the properties; and 5) surface access issues effected by weather conditions, permitting and regulatory approvals, and land owners.

Item 5.1.1 The following table outlines the proved undeveloped reserves attributed to the Company's onshore U.S.A. properties:

Onshore U.S.A. (Forecast Case) - Proved Undeveloped Reserves						
	Gross L&M Oil			**Gross Natural Gas**		
	First Attributed	Revisions	Cumulative	First Attributed	Revisions	Cumulative
Year	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)
2014 & Prior	2,699	-	2,699	5,938	-	5,938
2015		-567	2,132		-2,445	3,493
2016		-2,002	130		-3,429	64

Item 5.1.2 The following table outlines the probable undeveloped reserves attributed to the Company's onshore U.S.A. properties:

Onshore U.S.A. (Forecast Case) - Probable Undeveloped Reserves						
	Gross L&M Oil			**Gross Natural Gas**		
	First Attributed	Revisions	Cumulative	First Attributed	Revisions	Cumulative
Year	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(MMcf)
2014 & Prior	3,147		3,147	7,697		7,697
2015		-999	2,148		-4,167	3,530
2016		-1,797	351		-3,215	315

Item 5.2 Significant Factors or Uncertainties Affecting Reserves Data

Item 5.2.1

The process of evaluating reserves is inherently complex. It requires significant judgements and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserve estimates contained herein are based on current production forecasts, prices, and economic conditions. These factors and assumptions include, among others: (i) historical production in the area compared with production rates from analogous producing areas; (ii) initial production rates; (iii) production decline rates; (iv) ultimate recovery of reserves; (v) success of future development activities; (vi) marketability of production; (vii) effects of government regulations; and (viii) other government levies imposed over the life of the reserves.

As circumstances change and additional data becomes available, reserve estimates also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performances, prices, economic conditions, and government restrictions. Revisions to reserve estimates can arise from changes in year-end prices, reservoir performance, and geologic conditions or production. These revisions can be either positive or negative.

Item 5.3 Future Development Costs

Item 5.3.1 (a) (b)

The table below sets out the future development costs deducted in the estimation of future net revenue attributable to proved reserves and proved plus probable reserves using forecast prices and escalated costs:

Onshore U.S.A		
Gross Proved		
	Proved	Proved + Probable
Year	$M	$M
2016	0	0
2017	2,168	3,561
2018	0	0
2019	0	0
2020	3,410	4,546
Total (undiscounted)	**5,578**	**13,904**

Item 5.3.2

The Company intends to primarily use cash on hand, internally generated cash flows as well as funding available in the future through any potential farmout arrangements and/or additional equity or debt financings to fund future development costs. See also the discussion of the Company's plans for development in Part 6 – Other Oil and Gas Information, below. The only cost of funding future development is the interest associated with the Company’s debt financing. The interest associated with debt financing is not included in the reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending on the funding source utilized. The Company does not expect that interest or other funding costs could make development uneconomic.

There can be no guarantee that funding for future development costs will be available or that the Board of Directors will allocate funding to develop all of the reserves. Failure to develop those reserves could have a negative impact on the Corporation's future cash flow.

Item 5.3.3 - Not applicable.

Part 6 OTHER OIL AND GAS INFORMATION

Item 6.1.1 Oil and Gas Properties and Wells

Olmos Tight Sandstone Development Project ("**STS Olmos Project**")

In November 2011, the Company, through a wholly-owned subsidiary, acquired varying working and net revenue interests, which average approximately 26.88% and 20.16%, respectively, in approximately 14,400 gross mineral acres (3,875 net mineral acres) in LaSalle and McMullen Counties, Texas (the "**Original STS Olmos Leases**") and an evaluation well.

Through January 31, 2016, the Company has participated in the reentry and horizontal extension of the evaluation well and the drilling of twenty additional development wells on the Original STS Olmos Leases, all of which were drilled horizontally with lateral lengths averaging approximately 4,500 feet. Seventeen of these wells were successfully completed in the Olmos tight sandstone formation using multi-hydraulic fracturing techniques. The remaining three wells are currently awaiting completion.

In January 2014, the Company, through a wholly-owned subsidiary, acquired a 33.34% working interest and a 24.59% net revenue interest in approximately 199 gross mineral acres "the **Quintanilla Lease**" in the Northwest AWP Area in McMullen County, Texas. On August 3, 2014 the Company spud the Quintanilla OL 1-H well, which was successfully completed during October 2014 and is currently producing at rates consistent with the performance of the STS Olmos wells.

Maverick County Project (Investment in BlackBrush Terrace LP)

The Company and its partner, BlackBrush Oil & Gas, LP ("**BlackBrush**") organized a special purpose limited partnership, the BlackBrush Terrace LP (the "**BTLP**"), to acquire a 50% operated working interest (the "**WI**") in certain oil and gas leases covering approximately 147,000 gross mineral acres in Maverick County Texas, USA (the "**Maverick County Project**") from SWEPI LP ("**Shell Oil**"). The acreage to be acquired includes potential reserves in the Eagle Ford Shale, Buda Limestone and several other intervals of Cretaceous age formations including the newly emerging Pearsall Shale Trend which have been proven productive on a regional basis. The agreement allows BTLP to secure the WI through a combination of cash payments, which have been made, and drilling obligations. The material terms of the farmout agreement between the BTLP and Shell Oil are as follows:

1. the BTLP has the option, but not the obligation, to earn the assignment of the WI in all of the leases by spending an aggregate of $104 million ($52 million net to Terrace), including $52 million ($26 million net to Terrace) representing Shell

Oil's share of costs (the "**Carry Payment**") on certain qualified expenditures as development of the property progresses over time;

2. upon completion of each well drilled under this agreement, the BTLP may request an assignment of 50% of Shell Oil's interest in such well;
3. upon making the Carry Payment in full, the BTLP may request an assignment of 50% of Shell Oil's interest in all of the subject leases and shall have the option, but not the obligation, to participate in a 50% working interest in each subsequent well by paying its proportionate share of all development costs for such well unless Shell Oil elects to convert its working interest in a producing formation into a net profits interest; and
4. Shell Oil has the right, but not the obligation, to assume operatorship of any formation in which production has been established at any time within two years after the later of (i) the Carry Payment being made in full and subsequent assignment of 50% of Shell Oil's interest in the subject leases or (ii) establishment of commercial production from a given formation.

During 2013, the BTLP successfully tested the Eagle Ford formation through the re-entry and completion of the SWEPI Chittim #F-1H, which was previously drilled and shut in by Shell Oil in 2011 and the drilling and completion of a second well to test the Eagle Ford and Buda Limestone Formations. To date, these well have produced in excess of 50,000 BOE (gross) from the Eagle Ford Shale and are continuing to produce. The BTLP also drilled and evaluated an obligatory Pearsall Shale evaluation well, the Chittim #1H which showed numerous positive indications of hydrocarbons, but was not able to be completed as a commercial success.

During 2014, the BTLP also drilled four evaluation wells including two horizontal wells to evaluate the Buda Limestone potential on the southern portion of the ranch and two vertical stratigraphic tests to evaluate several formations from Austin Chalk through Georgetown in a portion of the ranch penetrated by a large serpentine plug (volcanic feature). Most notably, these wells confirm the presence of the Eagle Ford Shale in three separate areas of the project covering at least 50,000 gross acres.

During the current year, the BTLP drilled a new Eagle Ford Shale well, the Chittim #10H, which was successfully completed during July 2015. The well has subsequently been placed into permanent production facilities. As of January 31, 2016, the well has produced approximately 33,533 BOE. The BTLP also performed a minimal completion on one of the previously drilled Buda Limestone wells, the Chittim #4H to evaluate the production potential of the Buda Limestone in that area of the ranch. Prior to these activities, the Company sought and came to an agreement with its partner wherein to preserve capital, the Company would not contribute its share of costs to drill and complete these additional wells. As a result, the Company’s 50% ownership interest in the BTLP will be reduced from 50% to approximately 44%. In accordance with the provisions of the partnership agreement, the Company will not be entitled to any revenue and expense allocations or distribution of revenue proceeds from the Chittim #10H well.

As of January 31, 2016, the BTLP has spent approximately $40 million towards its drilling obligation to Shell. During the current year, the BTLP was also successful in renegotiating the schedule under which its long-term obligations under its farmout agreement are required. Under the Fourth Amendment to the Farmout Agreement, executed during the fourth quarter of 2015, the BTLP has deferred all further material capital expenditure obligations until calendar year 2017, at which point, the BTLP will be obligated to resume expenditures of $25 million in 2017 and the remaining balance of the Carry Payment and drilling obligation (approximately $38 million) in 2018. The BTLP also retains the option to pay approximately $2 million in liquidated damages at the end of 2017 if it chooses not to further defer drilling operations at that point. If the Carry Payment is not satisfied in full by the end of 2018, then the partnership will be required to pay $4 million in liquidated damages and the Farmout Agreement will be terminated.

Item 6.1.2 Gross and net oil and gas wells

Oil Wells

During the Corporation's most recently completed financial year which ended January 31, 2016, the Corporation owned interests in and was engaged in exploration, development and production activities on its two proved properties, the STS Olmos Project and the Maverick County Project, all located onshore, in South Texas, USA. As of the Effective Date, the Corporation owned interests in various wells in respect of these properties as follows:

Category	Gross Wells	Net Wells
Producing	21	5.53
Inactive (depleted)	0	0
Suspended (pending completion)	3	0.81

Item 6.2 Properties with No Attributed Reserves

During October 2015, pursuant to an Area of Mutual Interest agreement with our partner, the Company, through a wholly-owned subsidiary, acquired a 50% non-operated working interest in approximately 8,000 gross acres (4,000 net acres) immediately adjacent to our Original STS Olmos Leases, depth limited to the Olmos Sandstone and shallower formations. This acreage is under a three-year, primary term lease, after which the acreage may continue to be held by a continuous drilling commitment of three completions per year thereafter.

Item 6.2.1 Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves – Not applicable.

Item 6.3 Forward Contracts

As of the Effective Date and the Preparation Date, the Corporation does not have any forward contracts.

Item 6.5 Tax Horizon

The Corporation was not required to pay income tax for the year ending January 31, 2016. The Corporation is primarily in the exploration and evaluation stage of development. It is expected that exploration, evaluation and development expenditures will exceed net revenues from the sale of oil and gas for the foreseeable future. As a consequence, the Corporation does not expect to be taxable in the foreseeable future.

In U.S.A., the Corporation's tax pools have sheltered it from paying current cash income taxes. The Corporation is subject to presumptive income tax and equity tax in U.S.A.

Item 6.6 Costs Incurred

The following table summarizes property acquisition costs, exploration costs and development costs incurred by the Corporation during the year ended January 31, 2016.

Costs Incurred for the Year Ended January 31, 2016

1 (a) Property Acquisition Costs –	
Proved Properties -	$ nil
Unproved Properties -	$ 1,427,228
Property and Equipment -	$ nil
1 (b) Exploration Costs -	$ 594,185
1 (c) Development Costs -	$ 8,519,257

Item 6.7 Exploration and Development Activities

During the year ending January 31, 2016, the Corporation participated in the drilling of four (4) gross development wells (1.08 net wells) in its STS Olmos Project. Three of these wells remain to be completed as producing oil wells as of January 31, 2016.

During the year, the Corporation also finished the completion of one (1) gross (1 net) exploration well in its Big Wells Project which was ultimately determined to be uneconomic and the well was abandoned by year end January 31, 2016.

In the Maverick County Project, the Corporation did not participate in the drilling of any wells during the year ended January 31, 2016.

During the year ending January 31, 2017, the Corporation does not anticipate participating in the drilling of any wells.

Item 6.8 Production Estimates

The following table sets forth gross production (forecast case) of the Company estimated for the first year (January 31, 2016 to January 31, 2017) reflected in the gross proved reserves and gross probable reserves disclosed in Item 2.1:

Onshore U.S.A.	Light & Medium Oil		NGL		Natural Gas	
	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved MMcf	Gross Probable MMcf
2016	54.84	0.00	25.11	0.00	110.09	0.00
Total	**54.84**	**0.00**	**25.11**	**0.00**	**110.09**	**0.00**

Item 6.9 Production History

The following table outlines the gross production from January 31, 2015 to January 31, 2016 for important fields.

Field	**Onshore U.S.A.**			
	Q1	**Q2**	**Q3**	**Q4**
Chittim Heirs				
Oil Production, bbl	581	471	4,160	3,750
Gas Production, Mcf	792	563	1,324	6,573
STS Olmos				
Oil Production, bbl	64,987	40,343	30,051	19,395
NGL Production, bbl	18,815	18,743	15,438	10,117
Gas Production, Mcf	209,976	241,846	228,469	110,359
NW AWP Olmos				
Oil Production, bbl	5,494	6,104	3,266	1,389
Gas Production, Mcf	6,936	10,306	8,300	2,492
Total				
Oil Production, bbl	71,062	46,918	37,476	24,534
NGL Production, bbl	18,815	18,743	15,438	10,117
Gas Production, Mcf	217,704	252,715	238,093	119,424

The following table (Item 6.9.1) outlines as an average per unit volume (for example, \$/bbl or \$/Mcf), the Company's prices received, royalties paid, production costs (as applicable), and resulting netback:

	Oil Unit Values									
	Q1					Q2				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back
Onshore	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl

U.S.A	42.59	10.77	2.08	6.22	23.52	51.06	12.91	2.35	7.66	28.14

	Oil Unit Values									
	Q3					Q4				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back
Onshore	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl
U.S.A	38.00	9.61	1.67	13.54	22.80	27.13	6.86	1.04	29.60	-9.33

	Natural Gas Unit Values									
	Q1					Q2				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back
Onshore	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf
U.S.A	2.13	0.54	0.10	1.01	1.02	2.21	0.56	0.10	1.39	0.72

	Natural Gas Unit Values									
	Q3					Q4				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back
Onshore	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf	$/Mcf
U.S.A	1.96	0.49	0.09	2.25	-0.38	1.24	0.31	0.05	4.80	-3.88

	NGL Unit Values									
	Q1					Q2				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back
Onshore	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl
U.S.A	13.27	3.35	0.65	6.08	3.83	10.06	2.54	0.46	8.30	-1.25

	NGL Unit Values									
	Q3					Q4				
	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back	Price Received	Royalties Paid	Tax & ad Valorem Tax Paid	Opex	Net Back

Onshore	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl	$/bbl
U.S.A	11.27	2.85	0.50	13.68	-5.75	9.14	2.31	0.35	29.05	-22.58

INFORMATION REGARDING MATERIAL CHANGE SUBSEQUENT TO EFFECTIVE DATE OF REPORT

As of January 31, 2016, the Company's subsidiary, Terrace STS, LLC (the "Subsidiary"), was not in compliance with certain covenants under the credit agreement with its lender. The loan was secured by the assets of the Subsidiary, and was non-recourse to Terrace Energy Corp. The Subsidiary's oil & gas assets are limited to the 3,900 net acre Original STS Olmos Leases, the Quintanilla Lease and the associated producing wells and infrastructure.

During May 2016, as disclosed in the Company's material change report dated May 30, 2016, the Company entered into a transaction (the "Transaction") whereby the Company relinquished 95% of the equity of the Subsidiary to the lender who contributed the outstanding debt which is now deemed paid. In addition to the 5% ownership interest retained by the Company in the Subsidiary, the Company has the ability to recognize distributions in excess of its ownership interest once certain return thresholds are achieved by the holder of the 95% equity interest in the Subsidiary.

See below for supplementary information regarding the reserves and future net revenues specifically attributable to the Subsidiary and included in the disclosures above as of January 31, 2016.

Breakdown of Reserves Owned by Terrace STS, LLC

	L&M Crude Oil		Natural Gas Liquids		Natural Gas	
Reserves Category	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)
Proved Developed Producing	394	294	170	127	743	555
Proved Developed Non-Producing	119	89	59	44	253	189
Proved Undeveloped	0	0	0	0	0	0
Total Proved	**513**	**383**	**229**	**171**	**996**	**743**
Total Probable	87	66	42	31	183	136
Proved + Probable	**600**	**449**	**271**	**202**	**1,178**	**879**

Figures may be rounded off.

Net Present Value of Future Net Revenue Before Tax Owned by Terrace STS, LLC

	Before Tax NPV @				
Reserves Category	0% (M$)	5% (M$)	10% (M$)	15% (M$)	20% (M$)
Proved Producing	10,885	7,235	5,253	4,070	3,304
Proved Non-Producing	986	489	169	- 40	-177

Proved Undeveloped	0	0	0	0	0
Total Proved	**11,872**	**7,724**	**5,422**	**4,031**	**3,126**
Total Probable	1,854	801	121	34	-11
Total Proved + Probable	**13,726**	**8,525**	**5,543**	**4,065**	**3,115**

The above reserves and net present values of the Subsidiary were estimated by subtracting the Maverick County Project reserves from the Company's total reserves using the D&M Report. As a result of the Transaction, the net reserves and future net revenues attributed to the Subsidiary as at January 31, 2016 would be reduced by approximately 95%, and the Company's total proved plus probable reserves as at January 31, 2016 reported in Item 2.1.1 above would be reduced by approximately 67.0%.