EXHIBIT 1

Denbury

Montana Board of Oil & Gas Conservation

October 3, 2018

Cautionary Statements

Denbury

Forward-Looking Statements: The data and/or statements contained in this presentation that are not historical facts are forward-looking statements, as that term is defined in Section 21E of the Securities Exchange Act of 1934, as amended, that involve a number of risks and uncertainties. Such forward-looking statements may be or may concern, among other things, financial forecasts, future hydrocarbon prices and volatility, the sustainability of current oil prices, current or future liquidity sources or their adequacy to support our anticipated future activities, our ability to further reduce our debt levels, possible future write-downs of oil and natural gas reserves, together with assumptions based on current and projected oil and gas prices and oilfield costs, current or future expectations or estimations of our cash flows or the impact of changes in commodity prices on cash flows, availability of capital, borrowing capacity, availability of advantageous commodity derivative contracts or the predicted cash flow benefits therefrom, forecasted capital expenditures, drilling activity or methods, including the timing and location thereof, the nature of any future asset sales or the timing or proceeds thereof, estimated timing of commencement of CO_2 flooding of particular fields or areas, including CCA, or the availability of capital for CCA pipeline construction, or its ultimate cost or its date of completion, timing of CO_2 injections and initial production responses in tertiary flooding projects, development activities, finding costs, anticipated future cost savings, capital budgets, interpretation or prediction of formation details, production rates and volumes or forecasts thereof, hydrocarbon reserve quantities and values, CO_2 reserves and supply and their availability, potential reserves, barrels or percentages of recoverable original oil in place, potential increases in worldwide tariffs or other trade restrictions, the likelihood, timing and impact of increased interest rates, the impact of regulatory rulings or changes, anticipated outcomes of pending litigation, prospective legislation affecting the oil and gas industry, environmental regulations, mark-to-market values, competition, long-term forecasts of production, rates of return, estimated costs, changes in costs, future capital expenditures and overall economics, worldwide economic conditions and other variables surrounding our estimated original oil in place, operations and future plans. Such forward-looking statements generally are accompanied by words such as "plan," "estimate," "expect," "predict," "forecast," "to our knowledge," "anticipate," "projected," "preliminary," "should," "assume," "believe," "may" or other words that convey, or are intended to convey, the uncertainty of future events or outcomes. Such forward-looking information is based upon management's current plans, expectations, estimates, and assumptions and is subject to a number of risks and uncertainties that could significantly and adversely affect current plans, anticipated actions, the timing of such actions and our financial condition and results of operations. As a consequence, actual results may differ materially from expectations, estimates or assumptions expressed in or implied by any forward-looking statements made by us or on our behalf. Among the factors that could cause actual results to differ materially are fluctuations in worldwide oil prices or in U.S. oil prices and consequently in the prices received or demand for our oil and natural gas; decisions as to production levels and/or pricing by OPEC or production levels by U.S. shale producers in future periods; levels of future capital expenditures; effects of our indebtedness; success of our risk management techniques; accuracy of our cost estimates; availability or terms of credit in the commercial banking or other debt markets; fluctuations in the prices of goods and services; the uncertainty of drilling results and reserve estimates; operating hazards and remediation costs; disruption of operations and damages from well incidents, hurricanes, tropical storms, forest fires, or other natural occurrences; acquisition risks; requirements for capital or its availability; conditions in the worldwide financial, trade and credit markets; general economic conditions; competition; government regulations, including changes in tax or environmental laws or regulations; and unexpected delays, as well as the risks and uncertainties inherent in oil and gas drilling and production activities or that are otherwise discussed in this presentation, including, without limitation, the portions referenced above, and the uncertainties set forth from time to time in our other public reports, filings and public statements including, without limitation, the Company's most recent Form 10-K.

Note to U.S. Investors: Current SEC rules regarding oil and gas reserves information allow oil and gas companies to disclose in filings with the SEC not only proved reserves, but also probable and possible reserves that meet the SEC's definitions of such terms. We disclose only proved reserves in our filings with the SEC. Denbury's proved reserves as of December 31, 2016 and December 31, 2017 were estimated by DeGolyer and MacNaughton, an independent petroleum engineering firm. In this presentation, we may make reference to probable and possible reserves, some of which have been estimated by our independent engineers and some of which have been estimated by Denbury's internal staff of engineers. In this presentation, we also may refer to estimates of original oil in place, resource or reserves "potential," barrels recoverable, "risked" and "unrisked" resource potential, estimated ultimate recovery (EUR) or other descriptions of volumes potentially recoverable, which in addition to reserves generally classifiable as probable and possible (2P and 3P reserves), include estimates of resources that do not rise to the standards for possible reserves, and which SEC guidelines strictly prohibit us from including in filings with the SEC. These estimates, as well as the estimates of probable and possible reserves, are by their nature more speculative than estimates of proved reserves and are subject to greater uncertainties, and accordingly the likelihood of recovering those reserves is subject to substantially greater risk.

Denbury – What We Are

Denbury

A Unique Energy Business

- ~60% of production via CO_2 enhanced oil recovery (EOR)
- Vertically integrated CO_2 supply and distribution
- Cost structure largely independent from industry

Extraordinarily Geared to Crude Oil

- 97% oil production, high exposure to LLS pricing

Value Sustaining with Organic Growth Upside

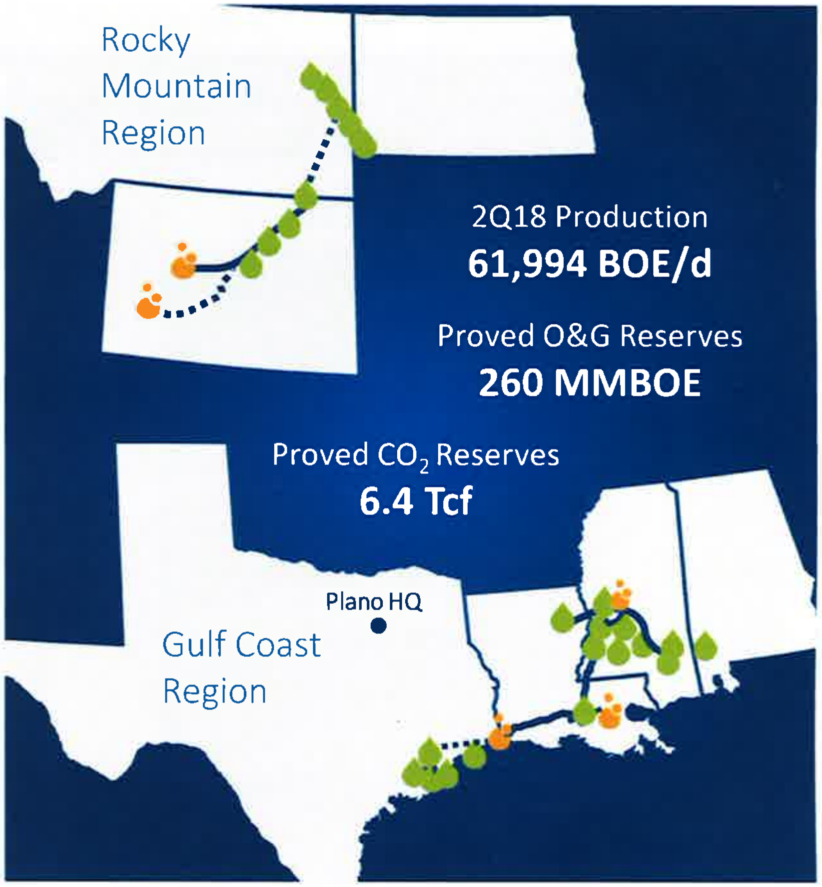
- Over 1 Billion BOE proved + EOR and exploitation potential

Intensely Focused on Execution and Results

- Highly economic project portfolio at $50 oil
- Significant improvements in cost structure
- Track record of spending within cash flow

A Carbon Conscious Producer

- Annually injecting over 3 million tons of industrial-sourced CO_2 into our reservoirs



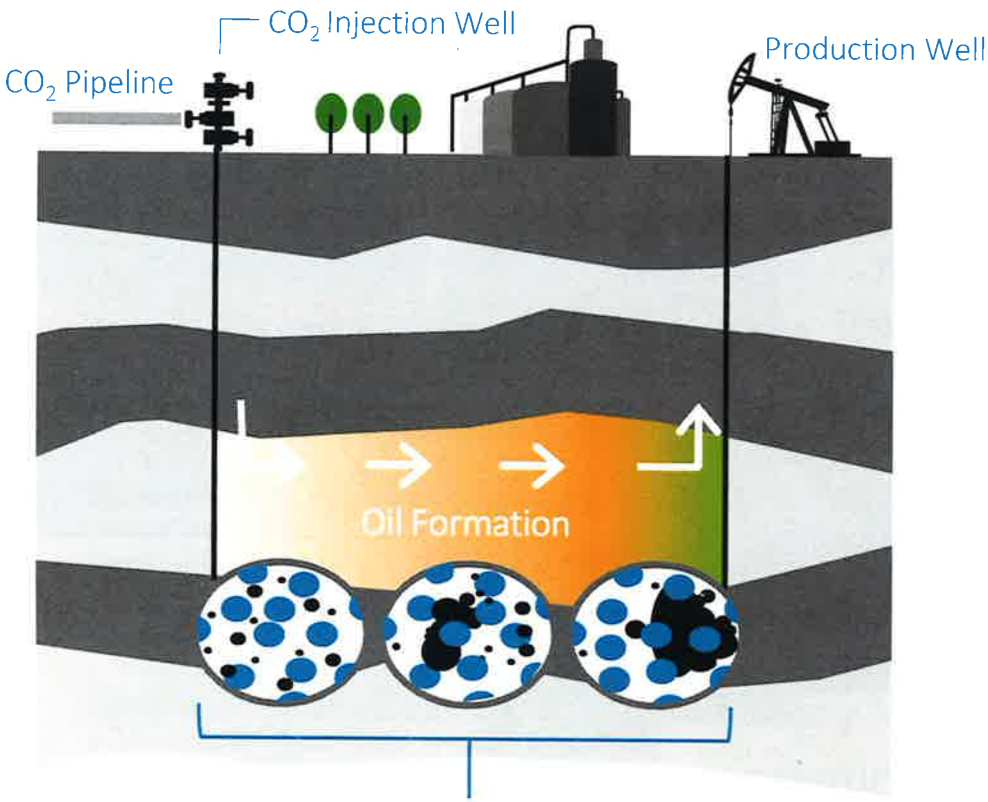
Largest Oil Producer in Montana

Denbury

Total Capital Investment Since 2010 (Net to Denbury):	
Acquisition Costs	> $2.0 Billion
Capital Investment (1)	> $750 Million
Estimated Gross Annual Lease Operating Expenditures (2017)	~$100 Million
Montana Employment (2)	111 Employees
Gross Annual Payroll (2017)	~$14 Million
Annual Average Salary & Benefits (2017)	~$126 Thousand
Estimated Annual Severance Taxes (2017)	~$25 Million
Annual Royalty Payments (2017)	~$26 Million
Estimated Gross Average Daily Production (2017)	~14,500 BOE/d

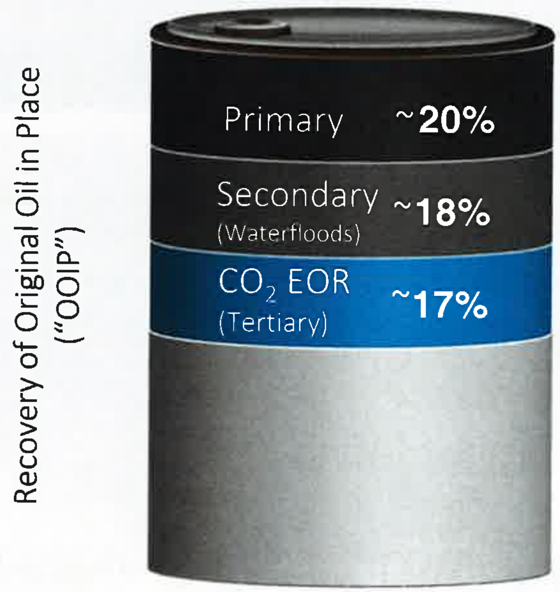
1) Capital investment includes acreage, G&G, rentals, pipeline facilities, drilling, workovers, P&A, and capitalized interest.
2) Montana employment number is representative of any individual employed by Denbury Resources in the State of Montana during the 2017 calendar year.

The CO_2 EOR Process



CO_2 moves through formation mixing with oil, expanding and moving it toward producing wells

CO_2 EOR can produce about as much oil as primary or secondary recovery[1]



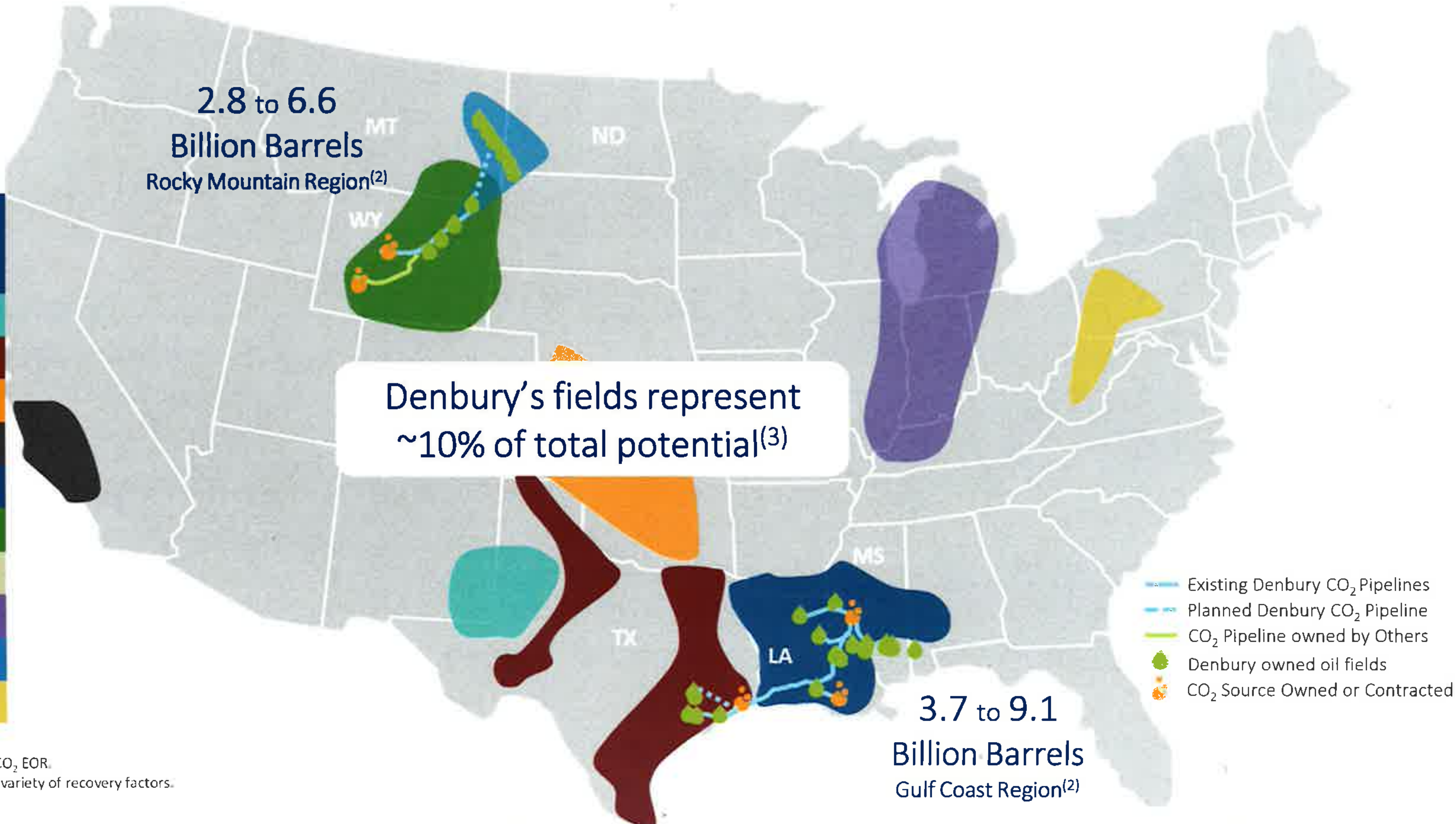
1) Based on OOIP at Denbury's Little Creek Field

Significant Running Room with CO_2 EOR

Denbury

Up to 83 Billion Barrels of Technically Recoverable Oil – U.S Lower 48[1][2]

33-83 Billion of Technically Recoverable Oil[1,2] (amounts in billions of barrels)	
Permian	9-21
East & Central Texas	6-15
Mid-Continent	6-13
California	3-7
South East Gulf Coast	3-7
Rockies	2-6
Other	0-5
Michigan/Illinois	2-4
Williston	1-3
Appalachia	1-2



1) Source: 2013 DOE NETL Next Gen EOR.
2) Total estimated recoveries on a gross basis utilizing CO_2 EOR.
3) Using approximate mid-points of ranges, based on a variety of recovery factors.

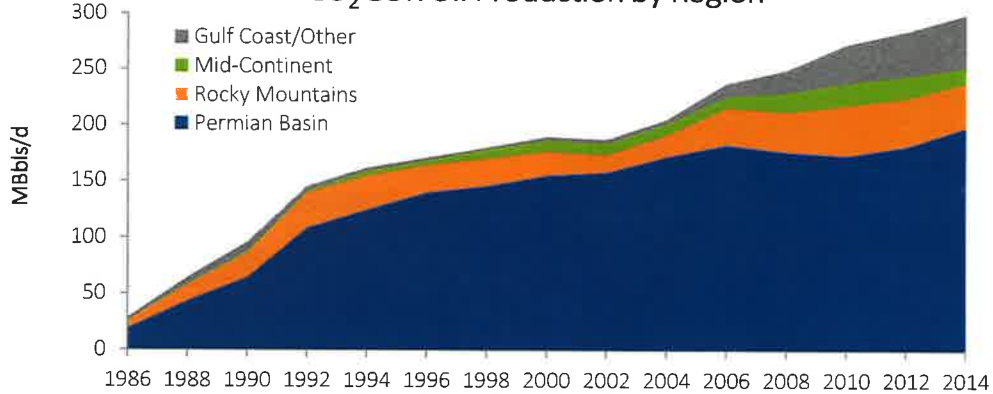
CO_2 EOR is a Proven Process

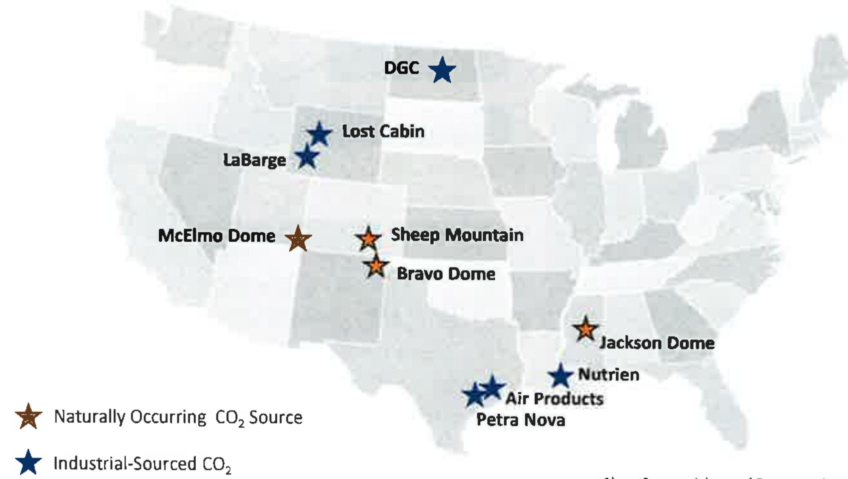
Denbury

Significant CO_2 EOR Operators by Region	
Gulf Coast Region	
» Denbury Resources	» Hilcorp
Permian Basin Region	
» Occidental	» Kinder Morgan
Rocky Mountain Region	
» Denbury Resources	» FDL
» Devon	» Chevron
Canada	
» Whitecap	» Apache

Significant CO_2 Supply by Region
Gulf Coast Region
» Jackson Dome, MS (Denbury Resources)
» Air Products (Denbury Resources)
» Nutrien (Denbury Resources)
» Petra Nova (Hilcorp)
Permian Basin Region
» Bravo Dome, NM (Kinder Morgan, Occidental)
» McElmo Dome, CO (ExxonMobil, Kinder Morgan)
» Sheep Mountain, CO (ExxonMobil, Occidental)
Rocky Mountain Region
» LaBarge, WY (ExxonMobil, Denbury Resources)
» Lost Cabin, WY (ConocoPhillips)
Canada
» Dakota Gasification (Whitecap, Apache)

CO_2 EOR Oil Production by Region[1]

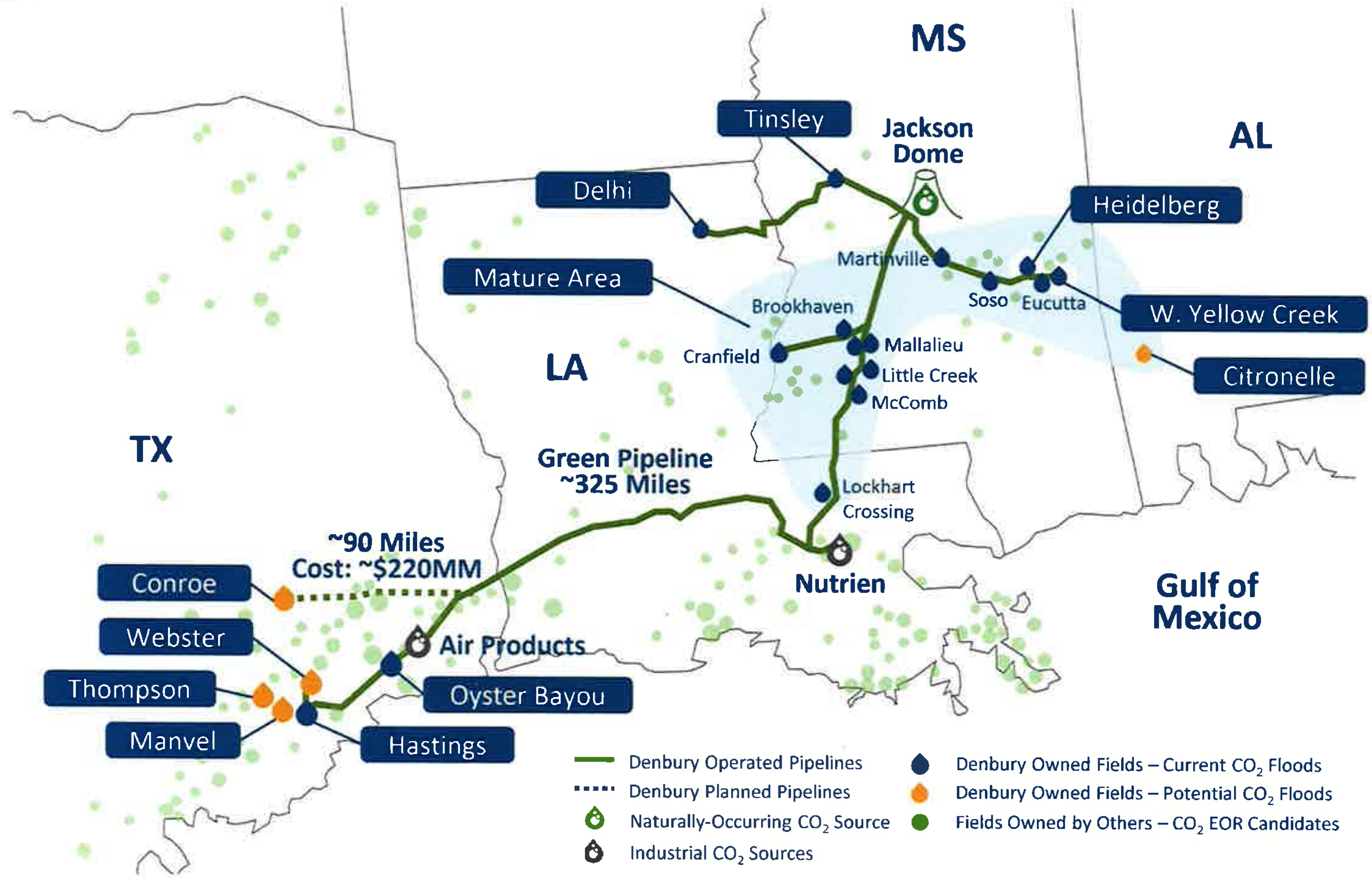




1) Source: Advanced Resources International

Gulf Coast Region

Denbury



Reserves Summary[1] (MMBOE)

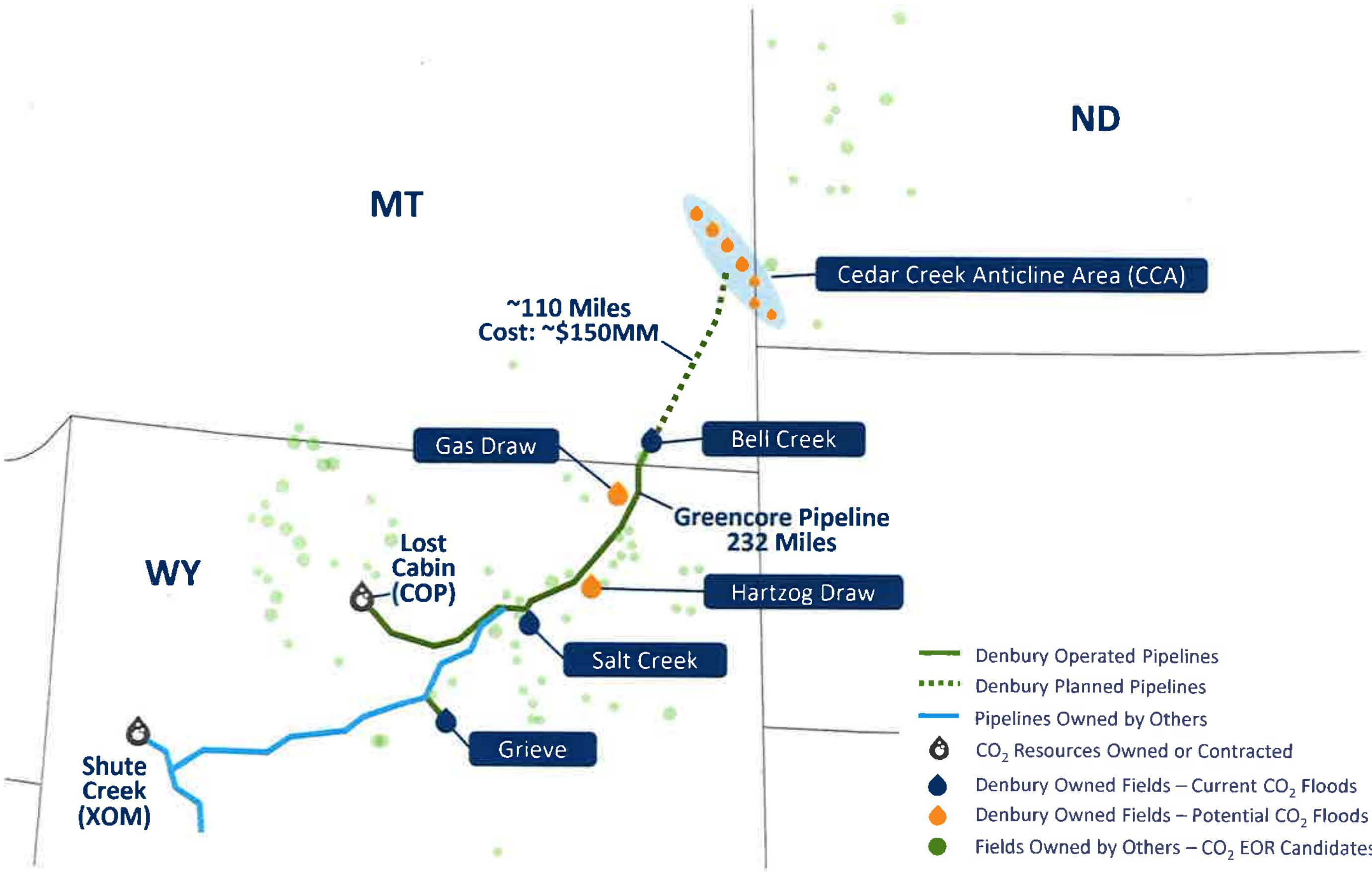
Proved + Tertiary Potential	
Tertiary Reserves	
Proved	127
Potential	308
Non-Tertiary Reserves	
Proved	21
Total MMBOE[2]	456

Tertiary Potential by Field[3]	
Mature Area	30
Citronelle	25
Conroe	130
Delhi	30
Hastings	30 – 70
Heidelberg	25
Manvel	8 – 12
Oyster Bayou	15
Tinsley	25
Thompson	20 – 40
Webster	40 – 75
W. Yellow Creek	5 – 10

Note: See "Slide Notes" on slide 17 in the appendix to this presentation for footnote explanations.

Rocky Mountain Region

Denbury



Reserves Summary[1] (MMBOE)

Proved + Tertiary Potential	
Tertiary Reserves	
Proved	26
Potential	534
Non-Tertiary Reserves	
Proved	86
Total MMBOE[2]	**646**

Tertiary Potential by Field[3]	
Bell Creek	20 – 40
Cedar Creek Anticline Area	400 – 500
Gas Draw	10
Grieve	5
Hartzog Draw	30 – 40
Salt Creek	25 – 35

Note: See "Slide Notes" on slide 17 in the appendix to this presentation for footnote explanations.

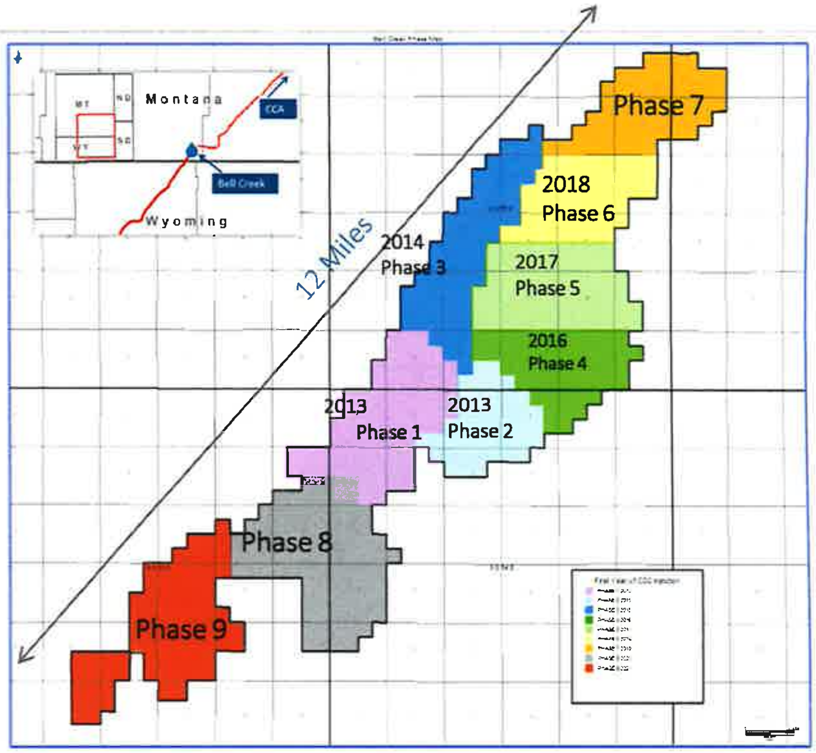
Bell Creek Field

Denbury

Highlights

- Over 300 million barrels of Oil in Place
- 2Q18 average gross production of ~4,700 Bbl/day
- Phase 5 developed in 2017; Phase 6 currently under development
- Severance tax paid post acquisition: $36 MM
- Severance tax paid since first injection 2Q13: $26 MM

Gross Daily Production



Dates reflect first CO_2 injection

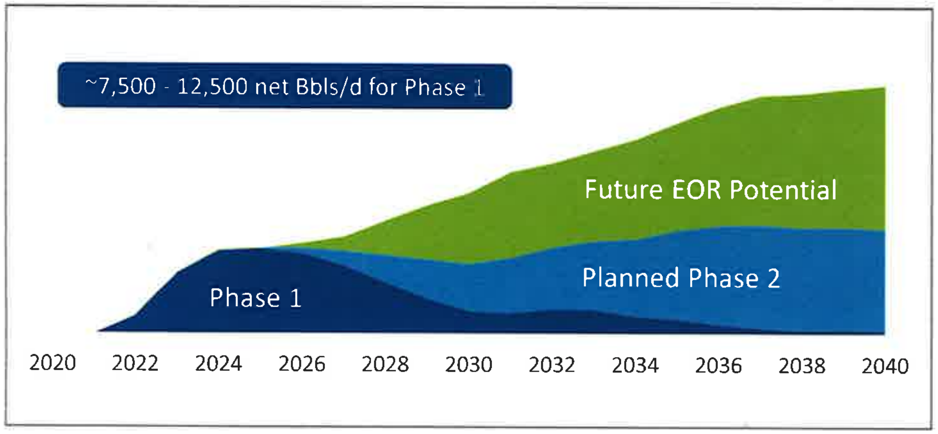
Est. Proved Plus Potential Tertiary Reserves:
20 - 40 MMBbls

Sanctioning CO_2 EOR Development at CCA

Denbury

Est. Incremental EOR Production

- Phase 1 and 2 estimated incremental tertiary production of 7,500 – 12,500 Bbls/d
  - Potential to significantly increase production over time subject to CO_2 availability and other factors



Cedar Creek Anticline Overview

EOR Formation Details	
Initial Formations Targeted	Red River Interlake Stony Mountain
Field Discovery Timeframe (Oil)	1930's (Discovery) 1950's (Development)
Formation Type	Dolomite
Depth	7,000 – 9,000 ft
Original Reservoir Pressure	3,600 – 4,140 psi
CO_2 Flood Type	Miscible
API Gravity	29-38
Average Perm	5 md
Average Porosity	11.4%
OOIP	~5 Billion Barrels
Oil Recovered to Date	~700 Million Barrels
Est. Tertiary Recovery Factor	8 – 15%

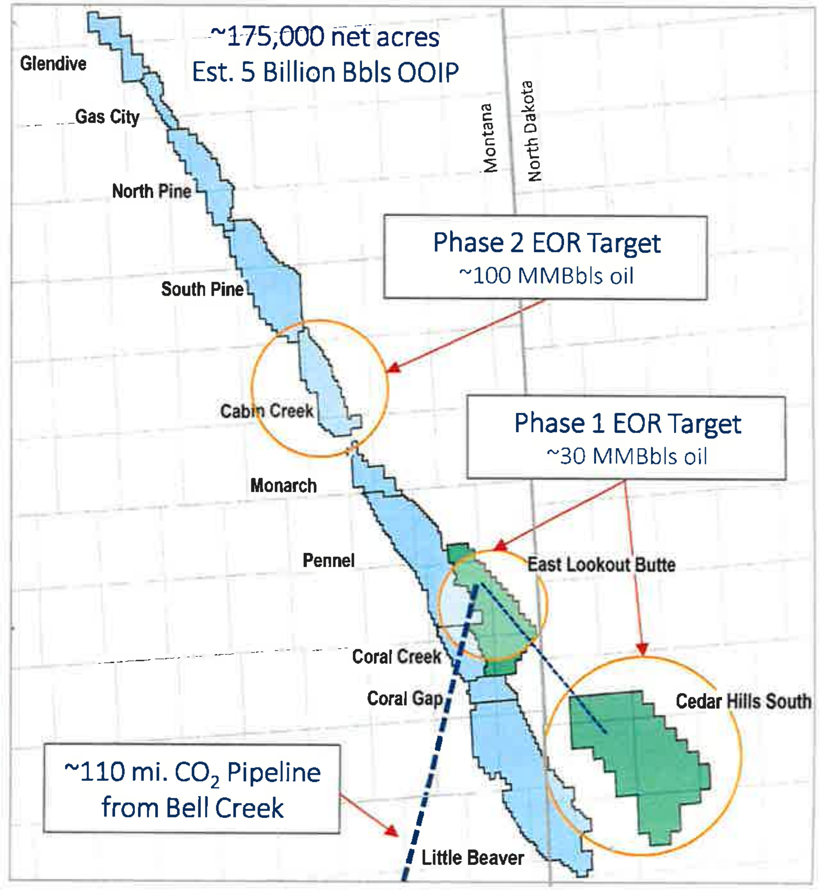
Note: The information included in slides 11 through 13, other than historical facts, are forward-looking statements based on current estimates. See slide 2, "Cautionary Statements" for risks and uncertainties related to this forward-looking information.

EOR Potential >400 MMBBL at Cedar Creek Anticline

Denbury

Planned Development Summary

- **Phase 1 – Red River formation development at East Lookout Butte and Cedar Hills South**
  - Targets ~30 MMBbls of recoverable oil; first tertiary production expected late 2021/early 2022
  - Excluding CO_2 pipeline, ~\$100 MM development capital to initial tertiary production; ~\$400 MM total capital over 15-year period
  - Requires \$150 MM CO_2 pipeline that will service all future CCA EOR development
    - Pipeline cost represents <\$0.50/Bbl across total CCA EOR potential
  - Expect to internally fund development using available cash flow, will also evaluate external capital sources for pipeline
- **Phase 2 - Cabin Creek development in Interlake, Stony Mountain and Red River formations**
  - Targets ~100 MMBbls of recoverable oil
  - Development estimated to begin in 2022; fully funded from Phase 1 cash flow
  - Estimated total capital of \$500 – \$600 MM over multiple decades
- **Future Phases – Remainder of CCA**
  - > 300 MMBbl EOR potential in multiple formations



See "Note" on slide 11 related to the forward-looking information included on this slide.

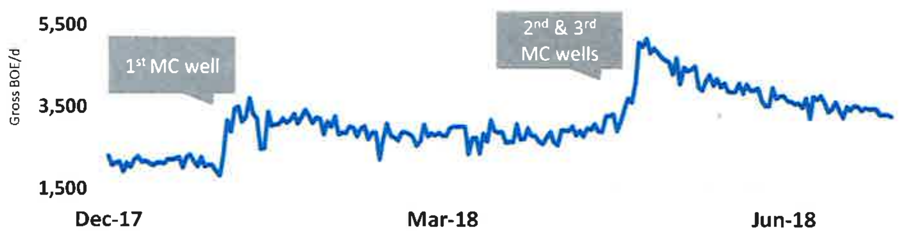
Mission Canyon – Building on Recent Success

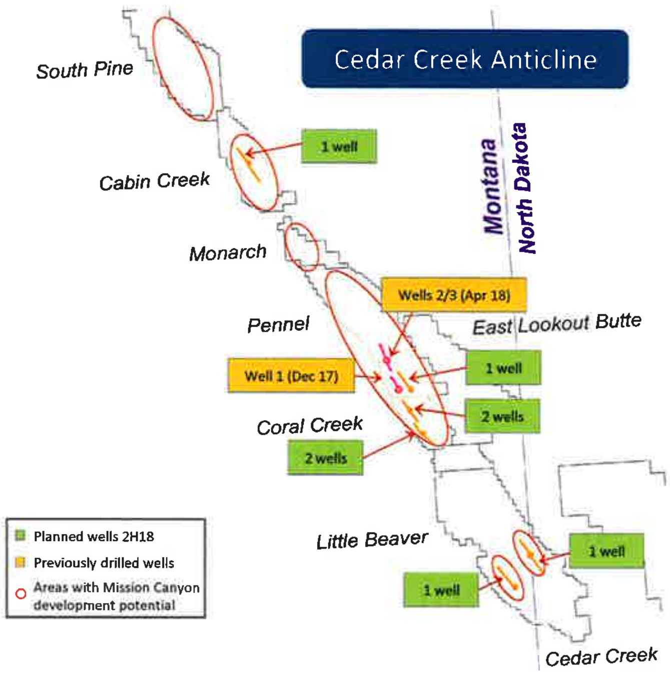
Denbury

Mission Canyon Exploitation

- First 3 wells exceeded expectations, combined gross 30-day IP rate > 3,000 BOPD; 100% oil
- Total initial target of ~24 locations across CCA, potential to increase
- MC resource potential ~9.4 MMBOE based on recent results
- Low drill and complete costs averaging $3.5MM/well
  - High quality reservoir does not require hydraulic fracture stimulation
- Fourth well spud in late August after 2Q drilling pause to comply with BLM & state wildlife stipulations
- Adding 2nd rig in late 3Q
- Upside CO_2 EOR potential after primary production

Pennel Unit Production





Note: See "Note" on slide 11 related to the forward-looking information included on this slide.

Cedar Creek Anticline CO_2 Pipeline Construction

Denbury

For activities associated with construction of the Cedar Creek Anticline CO_2 pipeline (the "Project"):

- Denbury will engage only pre-qualified construction and pipeline service companies who have demonstrated the highest degree of safety, quality and reliability
- Denbury's expectations are that contractors working for the Company are qualified and have received proper technical, environmental and safety training
- Contractors must be capable of constructing the Project within the requirements of federal, state and local permits and regulations and the contracted company must comply with, and in accordance with, contractual specifications

Competitive Tax Rate Policy Drives Capital Investment

Denbury

- Denbury has sanctioned the Phase 1 of CCA CO_2 EOR project
  - Cedar Hills South Unit (CHSU) – North Dakota
  - East Lookout Butte Unit (ELOB) – Montana
  - Pennel Unit Interlake Pilot – Montana
- Majority of Phase 1 CO_2 EOR Oil reserves in CHSU:
  - North Dakota production tax rate on CO_2 EOR barrels is 5%
  - North Dakota extraction tax rate on CO_2 EOR barrels is 0% for first 10 years
    - Increases to 5% after 10 years (or 6% at $86.80/Bbl oil)
  - Montana severance tax rate on CO_2 EOR barrels is currently 9.3% (drops to 6.1% at $54.00/Bbl oil or less)
- Phase 2 of CCA CO_2 EOR project has not yet been sanctioned
  - Phase 2 completely in the State of Montana
  - Phase 2 CO_2 EOR targeting oil reserves of 100 MMBbls
- Montana needs severance tax certainty for major CO_2 EOR investments
  - Current severance tax price trigger should be eliminated, maintaining constant 6.1% on CO_2 EOR barrels
  - Alignment with tax treatment in North Dakota

Note: Montana maintains 9.3% (or 12.8% pre-1999 wells) on baseline production plus 15.1% for all non-working interest barrels.

Denbury

Appendix

Slide Notes

Denbury

Slide 8 – Gulf Coast Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/17 SEC pricing. Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/16 (with the exception of West Yellow Creek, estimated as of 3/31/17), using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.

Slide 9 – Rocky Mountain Region

1) Proved tertiary and non-tertiary oil and natural gas reserves based upon year-end 12/31/17 SEC pricing. Potential includes probable and possible tertiary reserves estimated by the Company as of 12/31/16 (with the exception of Salt Creek, estimated as of 6/30/17), using the mid-point of ranges, based upon a variety of recovery factors and long-term oil price assumptions, which also may include estimates of resources that do not rise to the standards of possible reserves. See slide 2, "Cautionary Statements" for additional information.
2) Total reserves in the table represent total proved plus potential tertiary reserves, using the mid-point of ranges, plus proved non-tertiary reserves, but excluding additional potential related to non-tertiary exploitation opportunities.
3) Field reserves shown are estimated proved plus potential tertiary reserves.

EXHIBIT 2

BEFORE THE BOARD OF OIL AND GAS CONSERVATION AND
THE DEPARTMENT OF NATURAL RESOURCES AND CONSERVATION
OF THE STATE OF MONTANA

In the matter of the amendment of ARM 36.22.307, 36.22.608, 36.22.1015, and 36.22.1016 pertaining to fracturing of oil and gas wells, and the repeal of ARM 36.22.1244 pertaining to the producer's certificate of compliance	NOTICE ~~OF PUBLIC HEARING ON~~ ON PROPOSED AMENDMENT AND REPEAL

TO: All Concerned Persons

1. On August 24, 2018, the Department of Natural Resources and Conservation published MAR Notice No. 36-22-197 to amend ARM 36.22.307, 36.22.608, 36.22.1015, and 36.22.1016 pertaining to fracturing of oil and gas wells, and the repeal of ARM 36.22.1244 pertaining to the producer's certificate of compliance at page 1711 of the 2018 Montana Administrative Register, Issue Number 16.

2. The department has amended and repealed the above-stated rule[s] as proposed.

3. The department has thoroughly considered the comments and testimony received. A summary of the comments received and the department's responses are as follows:

COMMENT 1: A commenter supported the amendment and repeal.

RESPONSE: The board thanks the commenter for the comment.

COMMENT 2: Commenters requested that a minimum of 45-day disclosure of chemicals be used in hydraulic fracturing to provide the land or water well owner the opportunity to perform baseline testing.

RESPONSE: The board thanks the commenters for the comment. During public listening sessions and meetings held by the board and its hydraulic fracturing subcommittee, experts in groundwater characterization and groundwater testing stated that changes in basic water chemistry would establish whether a water well had been impacted by oil and gas operations. The experts stated that a simple, inexpensive, basic baseline water test would establish whether there was an impact on water wells.

Testing for specific chemicals that might be used in hydraulic fracturing a nearby well would significantly increase testing costs. If a water well were impacted by any stage of oil and gas production, or by another activity not connected to oil and gas production, the advance tested chemicals may or may not be present in subsequent tests, depending on the source of the chemicals. However, if a change in basic water chemistry is detected after hydraulic fracturing or another activity, additional directed testing can be performed to determine the specific source of the chemicals.

The board is concerned that the elevated cost of specific advance testing would deter the use of simple baseline testing. According to the experts, a basic water test can be done at any point prior to drilling or completion. Because the board's current disclosure requirements already require disclosure of chemicals used for hydraulic fracturing, the chemicals actually used in the stimulation would be available, should an adverse change in basic water chemistry be identified. Moreover, the experts also stated that significant background water chemistry data are available through numerous publicly available projects and studies. Any impact to water sources from drilling or completion activities could be identified through changes from the basic chemical analysis.

Some studies have documented impacts to ground water from oil and gas production, but these impacts were attributed either to practices that are no longer used or to activities other than hydraulic fracturing. The board knows of no cases of contaminated water wells related to hydraulic fracturing under Montana's regulations. In reviewing materials provided to the board during this rulemaking, and through the board's own research, the board found no documented case in which chemicals uniquely related to the hydraulic fracturing process were found in water wells. One event identified in the submitted literature (Beak et. al., 2015) involved a casing failure during hydraulic fracturing of a well located in North Dakota; chemicals related to hydraulic fracturing were found in monitor wells drilled after the failure. This incident occurred prior to the board's adoption in 2011 of hydraulic fracturing rules, which included engineering, operational, and environmental requirements to prevent a similar failure.

Two other technical papers alleged water well contamination from hydraulic fracturing operations. DiGiulio and Jackson, 2016, discussed sampling in Pavillion, Wyoming, performed by the United States Environmental Protection Agency. The Wyoming Department of Environmental Quality completed a subsequent study that concluded evidence was lacking for hydraulic fracturing being the cause of an impact to water-supply wells in the Pavillion area. See http://deq.wyoming.gov/wqd/pavillion-investigation/resources/investigation-final-report/

Llewellyn et al., 2015, reported possible well contamination related to hydraulic fracturing in Pennsylvania. A later statement by the authors identified possible leakage of drilling fluids from offsetting wells or from other sources as the likely source of the contamination. See https://www.energyindepth.org/major-research-gaps-in-new-groundwater-study/?154.

In the absence of any evidence that a chemical unique to hydraulic fracturing has been found in a Montana water well, the advance disclosure of specific hydraulic fracturing chemicals is unnecessary. The board believes that its current engineering, operational, and environmental requirements for drilling and hydraulic fracturing safeguard against water well contamination. The board also believes that current notice requirements provide ample time for water wells to undergo water chemistry testing prior to drilling or hydraulic fracturing activities. The chemical disclosure requirements already required by statute and rule protect a water well owner's ability to properly investigate any possible contamination.

COMMENT 3: Commenters noted that companies are only required to disclose chemicals 48-hours prior to hydraulic fracturing in the case of a wildcat or exploratory well.

RESPONSE: The board thanks the commenters for the comment. Hydraulic fracturing with 48-hour notice to the board under ARM 36.22.608 occurs after required notice to nearby landowners, after approval of the application for permit to drill, and after the well was drilled. The purpose of the 48-hour notice is to confirm that well construction followed the approved construction plan, to apply additional stipulations or requirements that may be necessary, and to schedule an inspection during the time the hydraulic fracturing is to occur.

The decision to hydraulically fracture an exploratory well can only be made only after the potential producing formation has been evaluated by drilling or testing. The characteristics of the targeted formation may be found to be different than expected, or the target geologic zone may be different from that originally targeted. The decision to hydraulically fracture is part of the ongoing process of evaluating and completing a well. It would not be practical to require a 45-day notice for each possible fracture stimulation when the work is being performed as a continuous well completion activity.

COMMENT 4: Commenters stated that baseline water well testing prior to hydraulic fracturing is necessary to protect water well owners and the oil and gas operator.

RESPONSE: The board thanks the commenters for the comment. The board notes that many owners of domestic water wells test the water quality of their wells. The board also notes that various state and federal agencies have authority to investigate contamination of water. The board does not believe that additional, mandatory baseline testing would provide additional, meaningful protections to water owners or to oil and gas operators.

By statute, the board requires measures to prevent contamination from oil and gas activities, including requiring all pertinent engineering, operational, and environmental information to be available at the time an application for permit to drill is under review. The involvement of the land or water well owners can play an important role in the prevention of contamination. Notice requirements have been established to inform landowners of planned activity so they can communicate their concerns to the operator or to the board's staff. Should these concerns not be adequately addressed during the permit review process, the application for permit to drill can be referred to the board for notice and hearing.

The identification of water wells within one-half mile of a proposed location must be provided by the operator as part of the application for permit to drill. Water well locations and depths to aquifers are independently confirmed by the board's staff during permit and environmental review. Potential contamination pathways are dependent upon the geologic setting of the well. Drilling permits and hydraulic fracturing proposals are evaluated to assure protection for existing water wells and other aquifers at the proposed well location. Additional construction requirements or operational stipulations are applied as necessary.

COMMENT 5: Commenters asked that the drilling of all oil and gas wells, not just wells subject to hydraulic fracturing, require mandatory water well testing prior to drilling, as in neighboring states, if the 45-day chemical disclosure prior to hydraulic fracturing is not adopted.

RESPONSE: The board thanks the commenters for the comment. The request in this comment exceeds the scope of the current rulemaking, which is limited to hydraulic fracturing. The board knows of no state that requires testing for specific chemicals proposed for use in hydraulic fracturing prior to drilling.

COMMENT 6: Commenters requested that the rules include notice to adjacent landowners so they can sample their water in advance of hydraulic fracturing activities.

RESPONSE: The board thanks the commenters for the comment. Existing rules and statutes require notice to the surface owner of the proposed well, published notice in a Helena newspaper and a newspaper of general circulation in the county where drilling is to occur if the well is not located in a previously delineated oil or gas field, and direct notice to the owners of occupied structures within one-quarter mile of the well. The board believes that individuals directly impacted by drilling activities will receive notice through one or more of the existing notice requirements. This notice protects the ability of those individuals to sample and test water in advance of hydraulic fracturing activities.

COMMENT 7: Commenters supported the proposed rules and stated that current drilling notice requirements and surface activities taking place before a well is hydraulically fractured provided sufficient opportunity for water well testing.

RESPONSE: The board thanks the commenters for the comment.

COMMENT 8: Commenters requested that the methodology of trade secret verification be made public.

RESPONSE: The board thanks the commenters for the comment. The requirements for evaluating confidentiality requests for the chemical composition of components of a fracturing fluid are established in § 82-10-604, MCA, and are summarized as guidelines, which are available on the board's website.

COMMENT 9: Some commenters requested that the administrator be required to release a chemical list to medical professionals in response to an emergency. Other commenters requested full chemical disclosure in the event of a transportation or occupational accident.

RESPONSE: The board thanks the commenters for the comment. Timely release of chemical information in an emergency is addressed in ARM 36.22.1016. That rule requires compliance with state and federal laws for chemical disclosure, including for emergency purposes. Unless required by a state or federal law, the administrator may not disclose trade secret information.

COMMENT 10: Commenters requested that full chemical disclosure to the public be required with no allowance for consideration of a trade secret.

RESPONSE: The board thanks the commenters for the comment. Trade secret protections are established in both federal and state law and are required under § 82-10-601, MCA, et seq.

/s/ Robert Stutz
ROBERT STUTZ
Rule Reviewer

/s/ Ronald S. Efta
RONALD S. EFTA
Chair
Board of Oil and Gas Conservation

Certified to the Secretary of State [Month Day, 20##].

EXHIBIT 3

MONTANA BOARD OF OIL AND GAS CONSERVATION
FINANCIAL STATEMENT
As of 9/30/18
Fiscal Year 2019: Percent of Year Elapsed - 25%

		Budget	Expends	Remaining	%
Regulatory	Personal Services	1,216,149	1,031,475	184,674	84.8
UIC	Personal Services	266,959	222,418	44,541	83.3
	Total Expended	**1,483,108**	**1,253,893**	**229,215**	**84.5**
Regulatory	Equipment & Assets	46,371	335	46,036	0.7
UIC	Equipment & Assets	10,179	74	10,105	0.7
	Total Expended	**56,550**	**409**	**56,141**	**0.7**
Regulatory	Operating Expenses:				
	Contracted Services	168,795	23,123	145,672	13.7
	Supplies & Materials	45,164	12,509	32,655	27.7
	Communication	63,337	8,516	54,821	13.4
	Travel	36,206	3,801	32,405	10.5
	Rent	25,877	4,368	21,509	16.9
	Utilities	16,770	2,168	14,602	12.9
	Repair/Maintenance	24,633	5,469	19,164	22.2
	Other Expenses	26,216	7,088	19,128	27.0
	Total Operating Expenses	406,998	67,042	339,956	16.5
UIC	Operating Expenses:				
	Contracted Services	37,051	4,451	32,600	12.0
	Supplies & Materials	9,915	2,745	7,170	27.7
	Communication	13,902	2,254	11,648	16.2
	Travel	7,947	493	7,454	6.2
	Rent	5,680	959	4,721	16.9
	Utilities	3,681	476	3,205	12.9
	Repair/Maintenance	5,407	1,163	4,244	21.5
	Other Expenses	5,754	1,374	4,380	23.9
	Total Operating Expenses	89,337	13,915	75,422	15.6
	Total Expended	**496,335**	**80,957**	**415,378**	**16.3**

	Budget	Expends	Remaining	%
Carryforward FY17				
Personal Services	63,132	-	63,132	0.0
Operating Expenses	63,132	-	63,132	0.0
Equipment & Assests	30,000	-	30,000	0.0
Total	**156,264**	-	**156,264**	**0.0**
Carryforward FY18				
Personal Services		-	-	###
Operating Expenses		-	-	###
Equipment & Assests		-	-	###
Total	-	-	-	###

Funding Breakout	Regulatory Budget	Regulatory Expends	UIC Budget	UIC Expends	2018 Total Budget	2018 Total Expends	%
State Special	1,669,518	1,098,852	366,475	236,406	2,035,993	1,335,258	65.6
Federal	-	-	96,420	54,852	96,420	54,852	56.9
Total	1,669,518	1,098,852	462,895	291,258	2,132,413	1,390,110	**65.2**

REVENUE INTO STATE SPECIAL REVENUE ACCOUNT

	FY 19	FY 18
Oil & Gas Production Tax	$ 5,898	$ 247,832
Oil Production Tax		2,238,184
Gas Production Tax		235,648
Drilling Permit Fees	1,700	15,500
UIC Permit Fees	-	239,800
Interest on Investments	3,345	11,133
Copies of Documents	74	658
Public Information Request	-	-
Miscellaneous Reimbursements	-	23,045
TOTAL	$ 5,119	$ 2,763,968

REVENUE INTO DAMAGE MITIGATION ACCOUNT

	FY 19	FY 18
RIT Investment Earnings:	$ -	$ 131,005
July	-	-
August	-	12,531
September	-	9,947
October	-	10,149
November	-	12,509
December	-	10,203
January	-	10,392
February	-	11,740
March	-	9,234
April	-	11,055
May	-	11,940
June	-	21,305
Bond Forfeitures:	-	210,381
Interest on Investments	1,359	9,663
TOTAL	**$ 1,359**	$ 351,049

INVESTMENT ACCOUNT BALANCES

Regulatory Account	$ -	$ 1,330,918
Damage Mitigation Account	$ -	$ 771,173

REVENUE INTO GENERAL FUND FROM FINES

		FY 19
FRANK MILLER	**7/6/2018**	**$ 60**
SCOUT ENERGY MANAGEMENT LLC	**7/10/2018**	**4,140**
WHITE ROCK OIL AND GAS LLC	**7/20/2018**	**140**
BALLANTYNE VENTURES LLC	**7/27/2018**	**140**
NINE POINT ENERGY LLC	**7/27/2018**	**220**
SCOUT ENERGY MANAGEMENT LLC	**7/27/2018**	**4,140**
HAWLEY OIL LLP	**8/10/2018**	**440**
SONKAR INC	**8/10/2018**	**90**
GREAT PLAINS ENERGY INC	**8/10/2018**	**60**
GERALD W PAUGH	**8/22/2018**	**70**
QUINGUE OIL	**8/31/2018**	**60**
GEORGE CAMPANELLA	**8/31/2018**	**110**
HAWLEY OIL LLP	**8/31/2018**	**110**
GEORGE CAMPANELLA	**8/31/2018**	**110**
BERNICE MCPHILLIPS	**8/31/2018**	**110**
CRAZY MOUNTAIN OIL AND GAS LLC	**8/31/2018**	**370**
GRASSY BUTTE	**8/31/2018**	**70**
MYSTIQUE RESOURCES COMPANY	**9/7/2018**	**60**
INTERMOUNTAIN LEASING INC.	**9/28/2018**	**120**
TOTAL		$ 10,620

DAMAGE MITIGATION CONTRACTS

Name	Authorized Amt	Expended	Balance	Status	Expiration Date
Beery 2 and Beery 22-24 Wells Plug and Reclaim	176,500	156,853	19,647	Under Contract	6/30/2019
Krone-Augusta 31-32-1 Well Plug and Reclaim	600,000	393,590	206,411	Completed	9/30/2018
TOTAL	$ 776,500	$ 550,442	$ 226,058		

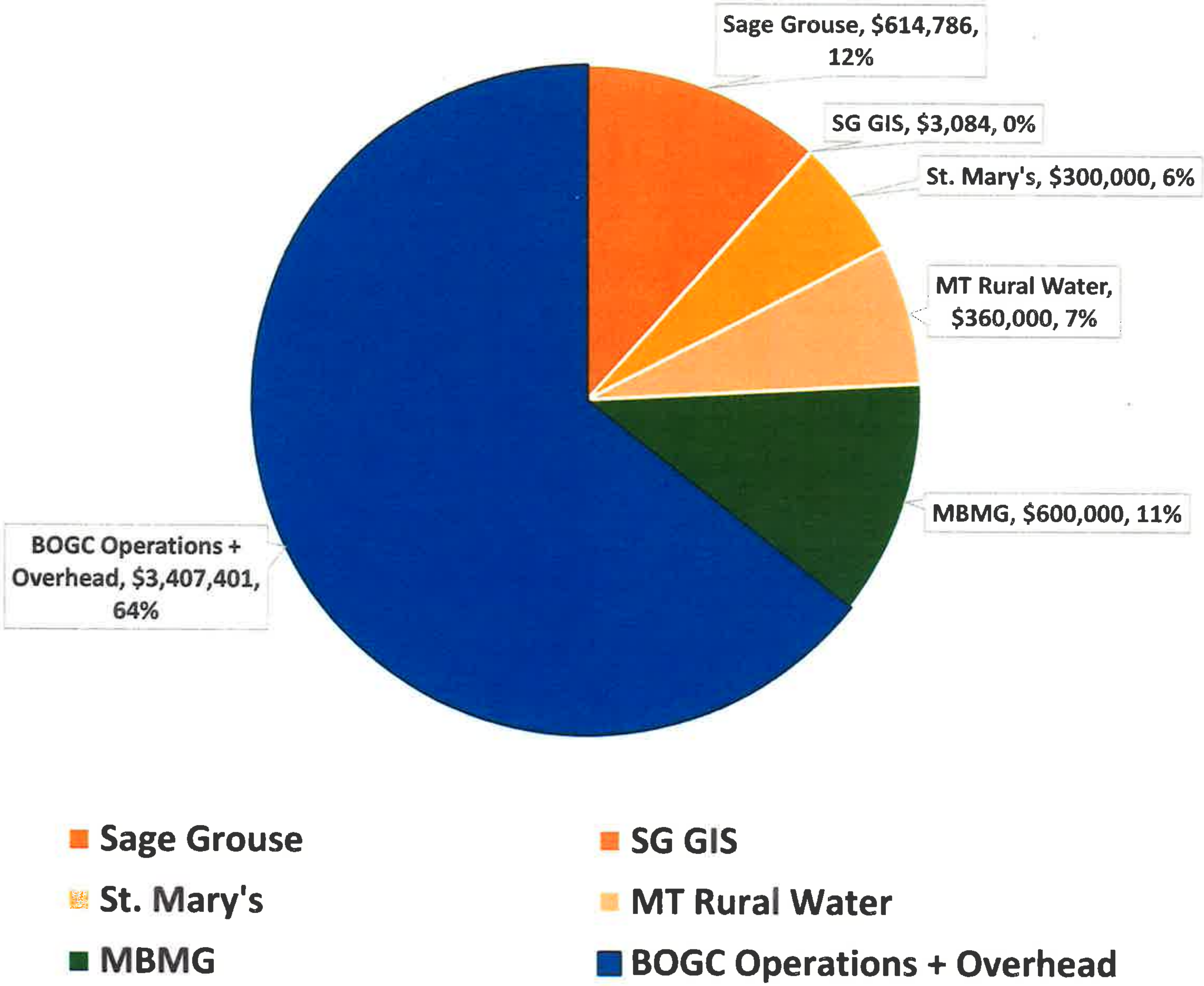
CONTRACTS

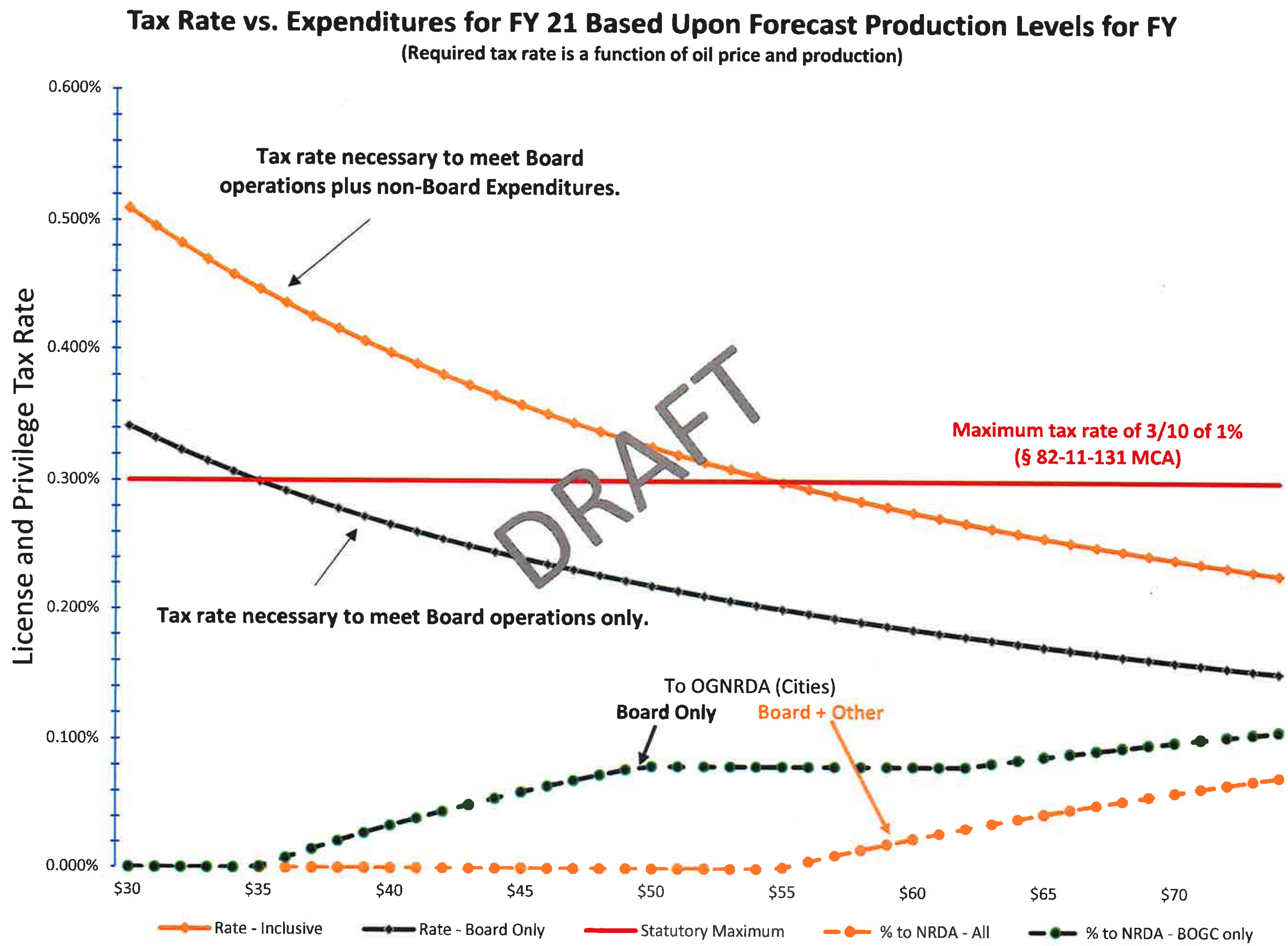
Name	Authorized Amt	Expended	Balance	Status	Expiration Date
MT Tech - Elm Coulee EOR Study (MOU 127220)	$ 863,905	$ 703,048	$ 160,857	Under Contract	12/31/2019
Agency Legal Services 2019	70,000	1,085	68,915	Under Contract	6/30/2019
COR Enterprises - Billings Janitorial	48,664	33,096	15,568	Under Contract	6/30/2019
Production and Injection Form Data Entry	26,000	10,252	15,748	Under Contract	2/28/2019
TOTAL	$ 1,008,569	$ 747,480	$ 261,089		

Agency Legal Services
Expenditures in FY18

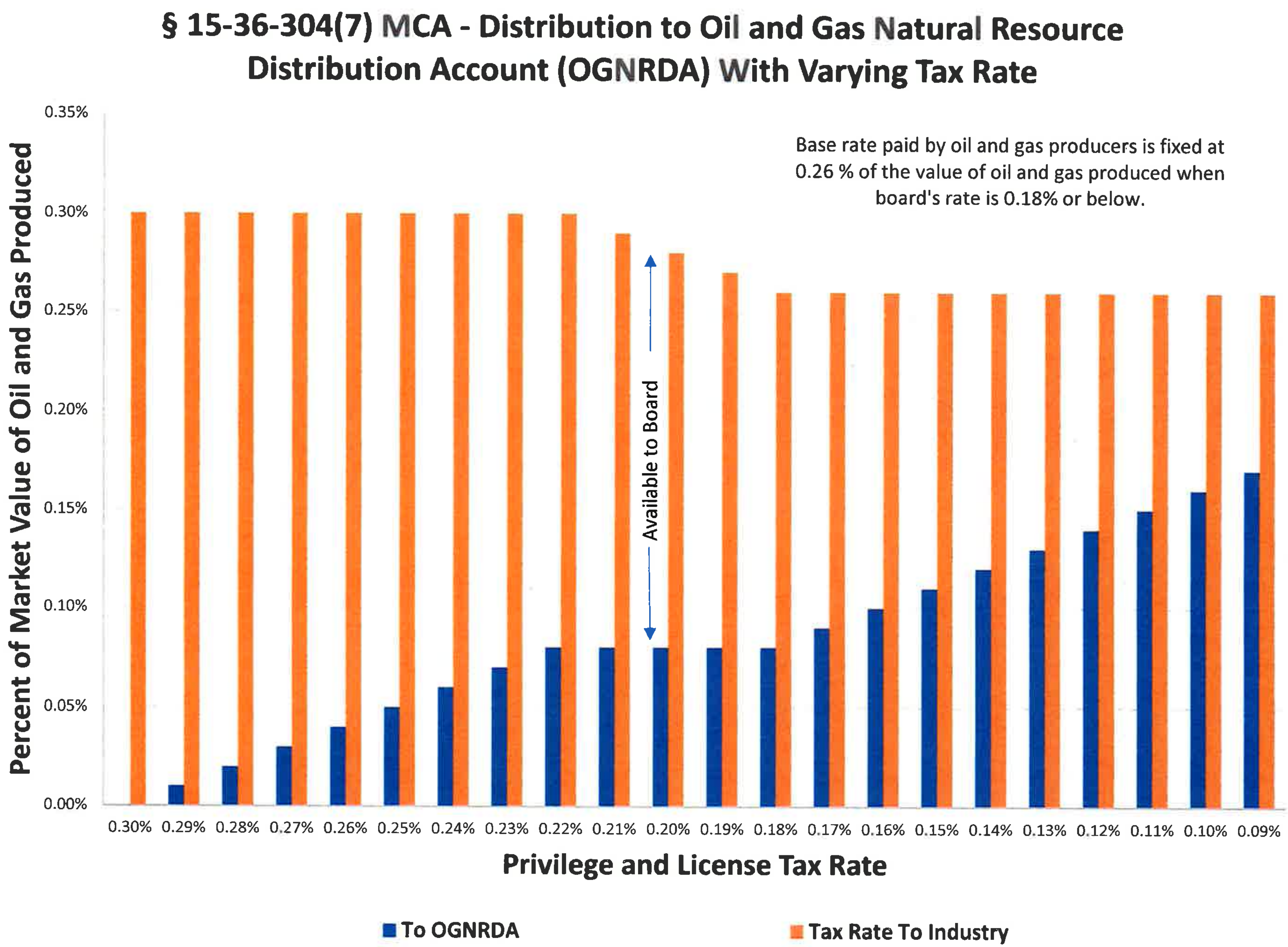
Case	Amt Spent
BOGC Duties	$ 1,085
Malsam	-
MEIC	-
Total	$ 1,085

Expenditures, Board's Special Revenue Account, FY 18 19





Tax Rate vs. Expenditures for FY 21 Based Upon Forecast Production Levels for FY
(Required tax rate is a function of oil price and production)
0.600%
0.500%
0.400%
0.300%
0.200%
0.100%
0.000%
License and Privilege Tax Rate
Tax rate necessary to meet Board operations plus non-Board Expenditures.
DRAFT
Maximum tax rate of 3/10 of 1% (§ 82-11-131 MCA)
Tax rate necessary to meet Board operations only.
To OGNRDA (Cities)
Board Only
Board + Other
$30
$35
$40
$45
$50
$55
$60
$65
$70
Rate - Inclusive
Rate - Board Only
Statutory Maximum
% to NRDA - All
% to NRDA - BOGC only



§ 15-36-304(7) MCA - Distribution to Oil and Gas Natural Resource Distribution Account (OGNRDA) With Varying Tax Rate
Base rate paid by oil and gas producers is fixed at 0.26 % of the value of oil and gas produced when board's rate is 0.18% or below.
Available to Board
Percent of Market Value of Oil and Gas Produced
0.35%
0.30%
0.25%
0.20%
0.15%
0.10%
0.05%
0.00%
0.30% 0.29% 0.28% 0.27% 0.26% 0.25% 0.24% 0.23% 0.22% 0.21% 0.20% 0.19% 0.18% 0.17% 0.16% 0.15% 0.14% 0.13% 0.12% 0.11% 0.10% 0.09%
Privilege and License Tax Rate
To OGNRDA
Tax Rate To Industry

Montana Board of Oil and Gas Conservation
Summary of Bond Activity

EXHIBIT 4

8/7/2018 Through 10/1/2018

Approved

East End Colony, Inc.		845 D1	Approved	9/21/2018
Havre MT			Amount:	$10,000.00
			Purpose:	Domestic Well Bond
Certificate of Deposit	$10,000.00	Independence Bank		ACT
Falcon Energy Partners LLC		844 G2	Approved	9/19/2018
Casper WY			Amount:	$10,000.00
			Purpose:	Single Well Bond
Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK		ACT
Falcon Energy Partners LLC		844 G1	Approved	9/19/2018
Casper WY			Amount:	$10,000.00
			Purpose:	Single Well Bond
Certificate of Deposit	$10,000.00	First Interstate Bank (Mills, WY)		ACT
Glacier Energy LC		843 L1	Approved	9/21/2018
Oklahoma City OK			Amount:	$20,000.00
			Purpose:	Limited Bond
Surety Bond	$20,000.00	RLI INSURANCE COMPANY		ACT
Goldrock Minerals LLC		842 G1	Approved	9/13/2018
Billings MT			Amount:	$1,500.00
			Purpose:	One-Well Bond
Certificate of Deposit	$1,500.00	STOCKMAN BANK, BILLINGS		ACT
Great Plains Energy, Inc.		753 G2	Approved	8/24/2018
Lincoln NE			Amount:	$10,000.00
			Purpose:	Single Well Bond
Certificate of Deposit	$10,000.00	FIRST INTERSTATE BANK		ACT

Released

Cirque Resources LP		583 G1	Released	8/13/2018
Denver CO			Amount:	$1,500.00
			Purpose:	Single Well Bond
Surety Bond	$1,500.00	FIDELITY & DEPOSIT CO. OF MD		ACT
Energy Corporation of America		626 T3	Released	8/27/2018
Charleston WV			Amount:	$10,000.00
			Purpose:	UIC Single Well Bond
Surety Bond	$10,000.00	U.S. Specialty Insurance Co.		ACT

EXHIBIT 5

Incident Report

Company	Responsibility	Date	Incident	Oil Released	Water Released	Source	Contained	Latitude	Longitud	County	T-R-S
Denbury Onshore, LLC	BOG	8/7/2018	Spill or Release	21 Gallons	2 Barrels	Flow Line - Production	No	46.70425	-104.51003	Wibaux	11N-57E-14 NWSE
Denbury Onshore, LLC	BOG	8/14/2018	Spill or Release	2 Barrels	10 Barrels	Flow Line - Production	No	46.58084	-104.43152	Fallon	10N-58E-33 NENW
Continental Resources Inc	BOG	8/15/2018	Fire	10 Gallons		Flare Pit	Yes	47.74592	-104.55192	Richland	23N-56E-20 NENE
Denbury Onshore, LLC	BOG	8/16/2018	Spill or Release	20 Barrels	50 Barrels	Flow Line - Production	No	46.46108	-104.31087	Fallon	8N-59E-11 NWSE
Continental Resources Inc	BOG	8/18/2018	Fire			Other	No	47.89713	-104.60662	Richland	25N-55E-22 SWSW
Alta Vista Oil Corporation	OTR	8/19/2018	Spill or Release		475 Barrels	Tank or Tank Battery	No	45.02410	-106.71746	Big Horn	9S-41E-21 SESW
Denbury Onshore, LLC	BOG	8/23/2018	Spill or Release		200 Barrels	Flow Line - Injection	No	46.33005	-104.22794	Fallon	7N-60E-29 NWSE
Denbury Onshore, LLC	BOG	8/23/2018	Spill or Release		20 Barrels	Flow Line - Injection	No	46.40671	-104.27257	Fallon	8N-60E-31 NENW
Denbury Onshore, LLC	OTR	8/27/2018	Spill or Release	1 Barrels		Flow Line - Production	No	45.14638	-105.08444	Powder River	8S-54E-15 NWNE
White Rock Oil & Gas, LLC	BOG	8/27/2018	Spill or Release		200 Barrels	Tank or Tank Battery	Yes	47.90586	-104.70054	Richland	25N-54E-23 SENE
Denbury Onshore, LLC	BOG	8/28/2018	Spill or Release		1 Barrels	Flow Line - Injection	No	46.26972	104.18750	Fallon	6N-60E-15 SESW
Denbury Onshore, LLC	BOG	8/30/2018	Spill or Release		50 Barrels	Flow Line - Injection	No	46.94389	-104.75583	Dawson	14N-55E-28 NWNE
Denbury Onshore, LLC	BOG	9/2/2018	Spill or Release		8 Barrels	Flow Line - Injection	No	46.29433	-104.19487	Fallon	6N-60E-10 NWNW
Denbury Onshore, LLC	BOG	9/6/2018	Spill or Release	5 Gallons	30 Gallons	Flow Line - Production	No	46.85064	-104.67240	Prairie	13N-56E-30 NWSE
Anadarko Minerals, Inc.	BOG	9/7/2018	Spill or Release	20 Barrels	40 Barrels	Treater	Yes	48.41800	-106.00814	Valley	31N-44E-28 W2NE
Denbury Onshore, LLC	BOG	9/13/2018	Spill or Release		150 Barrels	Flow Line - Injection	No	46.60257	-104.44744	Fallon	10N-58E-20 NWSE
Denbury Onshore, LLC	BOG	9/17/2018	Spill or Release		3 Barrels	Flow Line - Injection	No	46.12502	-104.04980	Fallon	4N-61E-8 NWNE
Denbury Onshore, LLC	BOG	9/27/2018	Spill or Release		50 Barrels	Flow Line - Injection	No	46.39640	-104.26162	Fallon	8N-60E-31 SESE
Slawson Exploration Company Inc	BOG	9/28/2018	Spill or Release	18 Barrels		Treater	Yes	47.78969	-105.04532	Richland	23N-52E-4 NENE

Docket Summary

57-2018	Kraken Operating, LLC	Permanent spacing unit, Bakken/Three Forks Formation, 28N-59E-5: all, 8: all (Katie Rose 5-8 #1H).	*TSU, Order 47-2010.* *Related applications, Dockets 57, 58-2018.*	☐
58-2018	Kraken Operating, LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 28N-59E-5: all, 8: all (Katie Rose 5-8 #1H). Non-consent penalties requested.	*Related applications, Dockets 57, 58-2018.*	☐
59-2018	Kraken Operating, LLC	Permanent spacing unit, Bakken/Three Forks Formation, 28N-59E-4: all, 9: all (Danielle 4-9 #1H).	*TSU, Order 46-2010* *Related applications, Dockets 59, 60-2018.*	☐
60-2018	Kraken Operating, LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 28N-59E-4: all, 9: all (Danielle 4-9 #1H). Non-consent penalties requested.	*Related applications, Dockets 59, 60-2018.*	☐
61-2018	Kraken Operating, LLC	Permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-6: all, 7: all (RKT Carda 7-6 #1H).	*TSU, Order 193-2014.* *Related applications, Dockets 61, 62-2018.*	☐
62-2018	Kraken Operating, LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-6: all, 7: all (RKT Carda 7-6 #1H). Non-consent penalties requested.	*Related applications, Dockets 61, 62-2018.*	☐
63-2018	Kraken Operating, LLC	Permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-17: all, 20: all (Mayson Phoenix 17-20 #1H).	*TSU, Order 363-2011.* *Related applications, Dockets 63, 64-2018.*	☐
64-2018	Kraken Operating, LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-17: all, 20: all (Mayson Phoenix 17-20 #1H). Non-consent penalties requested.	*Related applications, Dockets 63, 64-2018.*	☐
65-2018	Kraken Operating, LLC	Exception to drill up to four additional wells, permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-4: all, 9: all, 200' heel/toe, 500' lateral setbacks.	*PSU Order: 32-2018*	☐
66-2018	Kraken Operating, LLC	Exception to drill up to four additional wells, permanent spacing unit, Bakken/Three Forks Formation, 25N-59E-5: all, 8: all, 200' heel/toe, 500' lateral setbacks.	*PSU Order: 34-2018*	☐
67-2018	Behm Energy, Inc.	Permanent spacing unit, Sawtooth Formation, 35N-20E-26:SWSW (Federal 1-26-35-20).	*Drilled under statewide* *Related applications, Dockets 67, 68-2018.*	☐
68-2018	Behm Energy, Inc.	Pooling, permanent spacing unit, Sawtooth Formation, 35N-20E-26:SWSW (Federal 1-26-35-20). Non-consent penalties requested.	*Related applications, Dockets 67, 68-2018.*	☐
69-2018	Alta Vista Oil Corporation	Permanent spacing unit, Mowry Formation, 9S-41E-28: all (Slaughterville #1H).	*Drilled under statewide.* *Related applications, Dockets 69, 70-2018.*	☐
70-2018	Alta Vista Oil Corporation	Pooling, permanent spacing unit, Mowry Formation, 9S-41E-28: all (Slaughterville #1H).	*Related applications, Dockets 69, 70-2018.*	☐

71-2018	Continental Resources Inc	Overlapping temporary spacing unit, Bakken/Three Forks Formation, 26N-54E-15: all, 22: all, 27: all, 500'/200' setbacks. Apply for permanent spacing within 90 days of successful completion.	**Withdrawn**	*Sections 15 & 22: PSU by order 428-2006* *Section 27: PSU by order 289-2008* *Application withdrawn, email received 9/27/18.*	☐
72-2018	Continental Resources Inc	Overlapping temporary spacing unit, Bakken/Three Forks Formation, 26N-54E-14: all, 23: all, 26: all, 500'/200' setbacks. Apply for permanent spacing within 90 days of successful completion.	**Withdrawn**	*Sections 14 & 23: PSU by order 120-2012* *Section 26: PSU by order 160-2008* *Application withdrawn, email received 9/27/18.*	☐
73-2018	Denbury Onshore, LLC	Approval of Mystery Creek (Red River) enhanced recovery unit; underlying certain lands in Fallon County, Montana (8158.28 acres). Order to become effective when the applicant presents proof of the requisite approval by the cost-bearing and cost-free owners of interests within the time limit specified by statute.	**Continued**	*Application continued, email received 10/2/18.*	☐
74-2018	Denbury Onshore, LLC	Temporary spacing unit, Madison Group, 10N-58E-5: SWSW, 6: SE, 7: NE, N2SE, SESE, 8: W2, W2SE, SESE, 17: N2, 660' setbacks.			☐
75-2018	Denbury Onshore, LLC	Vacate all well spacing and setback requirements as to the Mission Canyon Formation for lands located within applicant's Pennel Unit area, 660' setback to unit boundaries.			☐
76-2018	Denbury Onshore, LLC	Convert the Unit 41-28 well, T14N-R55E-28: NENE, 484' FNL, 891' FEL, (API # 021-21194) to a Class II injection well, Mission Canyon - Lodgepole Formation.	**Default**		☐
21-2018	Montana Land & Exploration, Inc.	Temporary spacing unit, Upper Bowes Formation test well, 34N-21E-5: SWSWNE, SESENW, NENESW, NWNWSE. Well to be located approximately 170' FSL, 77' FWL of SWNE in Section 5.		*Approximate location 2470 FNL, 2563 FEL in Section 33* *Application continued, email received 5/30/18 & 7/11/18*	☐
42-2018	Kraken Oil & Gas LLC	Permanent spacing unit, Bakken/Three Forks Formation, 27N-57E-14: all, 23: all (Della 14-23 #1H).		*TSU, Order 25-2017* *Related applications, Dockets 42, 43-2018.* *Application continued, email received 7/31/18.*	☐
43-2018	Kraken Oil & Gas LLC	Pooling, permanent spacing unit, Bakken/Three Forks Formation, 27N-57E-14: all, 23: all (Della 14-23 #1H). Non-consent penalties requested.		*Related applications, Dockets 42, 43-2018.* *Application continued, email received 7/31/18.*	☐
77-2018	Pronghorn Petroleum Joint Venture	Show Cause: order to appear, Pronghorn Petroleum Joint Venture; consideration of injection permit recocation and why should not plug well due to failure to pay annual injection fee.			☐
78-2018	Shadwell Resources Group, LLC	Show Cause: why penalties should not be imposed for failure to remedy the field violations at the Velma SWD 1-10H well located in the NW¼NW¼ of Section 10, T23N, R58E, Richland County, Montana			☐
79-2018	Wind River Hydrocarbons, Inc.	Show Cause: why its plugging and reclamation bond should not be forfeited for failure to begin to plug and abandon its Cornwell 1-14 well located in the NW¼NW¼ of Section 10, T30N, R38E, Valley County, Montana			☐

80-2018	Intermountain Leasing, Inc.	Show Cause: why additional penalties should not be imposed for failure to pay the administrative penalty assessed for delinquent reporting	**Dismissed**	*Fine received 9/26/18*	☐
81-2018	Bensun Energy, LLC	Show Cause: why additional penalties, which may include a plugging and reclamation bond increase, should not be imposed for failure to remedy the field violations at the Loucks 33-27 well, T36N-R52E-27: NWSE, Sheridan County, Montana as well as any other outstanding field violations			☐
60-2017	Black Gold Energy Resource Development, LLC	Show Cause: why its plugging and reclamation bond should not be forfeited for failure to begin to plug and abandon its Indian Mound 1 SWD well located in the NE¼SW¼SW¼ of Section 15, T23N, R55E, Richland County, Montana as required by Board Order 45-2017, in accordance with § 82-11-123(5), MCA.			☐
77-2017	Hinto Energy, LLC	Show Cause: failure to file production reports and pay administrative fees.			☐

EXHIBIT 7

GAS FLARING

October 3, 2018

Company	Wells Flaring over 100	Wells Flaring over 100 w/o Exception	Current Exceptions (over 100)	Exception Requests	Wells over 100 Hooked to Pipeline
Kraken	5	5	0	6	2
Petro-Hunt	3	3	0	2	0
Whiting	1	0	1	3	0
Totals	9	8	1	11	2

Flaring Requests

Summary

There are 9 wells flaring over 100 MCFG per day based on current production numbers.

4 of the 9 wells have approved exceptions due to distance, pipeline capacity issues, or time to connection.

There are 11 exceptions requested at this time.

Kraken

Fred 15-22 #1H – API #25-085-21977, 27N-57E-11

1. Flaring 221 MCF/D.
2. Completed: 4/2018.
3. Estimated gas reserves: 515 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Contracted/connected with Hiland Partners Holding LLC, Kraken has had very limited success selling gas into the line due to sales line pressure.

Doris 10-3 #1H – API #25-085-21984, 27N-57E-11

1. Flaring 185 MCF/D.
2. Completed: 4/2018.
3. Estimated gas reserves: 471 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Contracted/connected with Hiland Partners Holding LLC, Kraken has had very limited success selling gas into the line due to sales line pressure.

Katie Rose 5-8 #1H – API #25-085-21991, 28N-59E-04

1. Flaring 375 MCF/D.
2. Completed: 5/2018.
3. Estimated gas reserves: 596 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Connected to pipeline in September, should be under flaring limit currently.

Danielle 4-9 #1H – API #25-085-21992, 28N-59E-04

1. Flaring 385 MCF/D.
2. Completed: 5/2018.

3. Estimated gas reserves: 639 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Connected to pipeline in September, should be under flaring limit currently.

Mayson Phoenix 17-20 #1H – API #25-083-23353, 25N-59E-07

1. Flaring 536 MCF/D.
2. Completed: 5/2018.
3. Estimated gas reserves: 815 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Connected to pipeline in June, Kraken has had very limited success selling gas into the line due to sales line pressure.

RKT Carda 7-6 #1H – API #25-083-23352, 25N-59E-07

1. Flaring 533 MCF/D.
2. Completed: 5/2018.
3. Estimated gas reserves: 801 MMCF.
4. Proximity to market: Connected to pipeline.
5. Flaring alternatives: None.
6. Amount of gas used in lease operations: 6 MCF/D.
7. Justification to flare: Connected to pipeline in June, Kraken has had very limited success selling gas into the line due to sales line pressure.

Petro-Hunt

Borntrager 2C-2-1 – API #25-021-21193, 19N-54E-2

1. Flaring 116 MCF/D.
2. Completed: 9/2012.
3. Proximity to market: >25 miles pipeline.
4. Estimated gas price at market: ~$2/MCF.
5. Estimated cost of marketing the gas: ~$3.2 million.
6. Flaring alternatives: None.
7. Amount of gas used in lease operations: 25-30 MCF/D.
8. Justification to flare: Uneconomic to connect due to lack of infrastructure in the area.

Walter Senner 19-54 – API #25-021-21192, 19N-54E-18

1. Flaring 116 MCF/D.
2. Completed: 8/2012.
3. Proximity to market: >25 miles pipeline.
4. Estimated gas price at market: ~$2/MCF.
5. Estimated cost of marketing the gas: ~$3.2 million.

6. Flaring alternatives: None.
7. Amount of gas used in lease operations: 25-30 MCF/D.
8. Justification to flare: Uneconomic to connect due to lack of infrastructure in the area.

Whiting Oil & Gas

Buxbaum 21-5-3H – API #25-083-23315, 24N-60E-5

1. Flaring 107 MCF/D.
2. Completed: 2/2015.
3. Estimated gas reserves: 798 MMCF.
4. Proximity to market: 11,000 ft to pipeline.
5. Estimated gas price at market: ~$2.58/MCF.
6. Estimated cost of marketing the gas: ~$250,000.
7. Flaring alternatives: None.
8. Amount of gas used in lease operations: 2 MCF/D.
9. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Malsam 14-18-3H – API #25-083-23265, 24N-60E-18

1. Flaring 84 MCF/D.
2. Completed: 1/2015.
3. Estimated gas reserves: 410 MMCF.
4. Proximity to market: 1,500 ft to pipeline.
5. Estimated gas price at market: ~$2.58/MCF.
6. Estimated cost of marketing the gas: ~$250,000.
7. Flaring alternatives: None.
8. Amount of gas used in lease operations: 2 MCF/D.
9. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Palmer 24-21-4H – API #25-083-23250, 26N-57E-21

1. Flaring 96 MCF/D.
2. Completed: 7/2014.
3. Estimated gas reserves: 574 MMCF.
4. Proximity to market: 16,400 ft to pipeline.
5. Estimated gas price at market: ~$2.58/MCF.
6. Estimated cost of marketing the gas: ~$2500,000.
7. Flaring alternatives: None.
8. Amount of gas used in lease operations: 2 MCF/D.
9. Justification to flare: Insufficient compression capacity on Oneok's system in this area.

Plugging and Reclamation Bonds With Well List

APEX ENERGY LLC 820 **Bond:** **M1** $50,000.00 Multiple Well Bond Active **Wells:** **11** **Allowed:**

Surety Bond Active Lexon Insurance Company $50,000.00 Approved 6/21/2017

API #	Operator	Well	Location						Field	TD	PBTD	Status	
021-21069	Apex Energy LLC	Buxaum #1	19 N	56 E	27	C SE NE	1980N	660E	Burns Creek, South	11892	11540	SI	OIL
083-21700	Apex Energy LLC	FLB Spokane 4	22 N	59 E	12	SE NE	1525N	875E	Mon Dak, West	9280		PR	OIL
083-21188	Apex Energy LLC	FLB Spokane 1	22 N	60 E	7	C NE SE	1980S	660E	Mon Dak, West	12565	12530	SI	OIL
083-21598	Apex Energy LLC	Propp 10-41X	23 N	59 E	10	SW NE NE	790N	990E	Sidney	9407	9300	PR	OIL
083-21521	Apex Energy LLC	Iverson 1-13	23 N	59 E	13	NE NE	510N	810E	Ridgelawn	9363		PR	OIL
083-21573	Apex Energy LLC	Fort Gilbert 8	24 N	59 E	32	NE SW	1980S	1980W	Fort Gilbert	9662	9620	PR	OIL
083-21561	Apex Energy LLC	Sundheim 29-1	25 N	58 E	29	C SE SW	660S	1980W	Sioux Pass, South	12837	12738	PR	OIL
083-21660	Apex Energy LLC	Lois Roberta Bailey 32-2	25 N	58 E	32	NW SE NW	1650N	1350W	Sioux Pass, South	12710	12708	PR	OIL
083-21673	Apex Energy LLC	Vanderhoof 1-20	25 N	59 E	20	SW SW	660S	975W	Fairview	12850	12741	SI	OIL
083-21060	Apex Energy LLC	A. Engen 1	25 N	59 E	29	NW NW	1000N	660W	Fairview	12875	12748	SI	OIL
083-21696	Apex Energy LLC	Engen 1-A	25 N	59 E	29	NW NW	990N	900W	Fairview	12852	12725	SI	OIL

Comment:

Buxaum: Weeds in/on flare pit. (last reported production was in May 2017)
Propp 10-41X: Windblown tin at treater. (last reported production was in July 2018)
Sundheim 29-1: Junk snow blower, wood and pipe at treater, junk treater, dozier, metal. (last reported production was in July 2018)
Lois Roberta Bailey 32-2: Exposed wires and conduit, contaminated soil at recycle pump, 5-gallon bucket with oil, contaminated soil at Ajax motor. (last reported production was in July 2018)
A Egen 1: Junk crane counter weights, pumpjack, Ajax, misc. iron. (last reported production was in May 2018)
Egen 1-A: Junk crane and parts, junk iron. (last reported production was in April 2001)