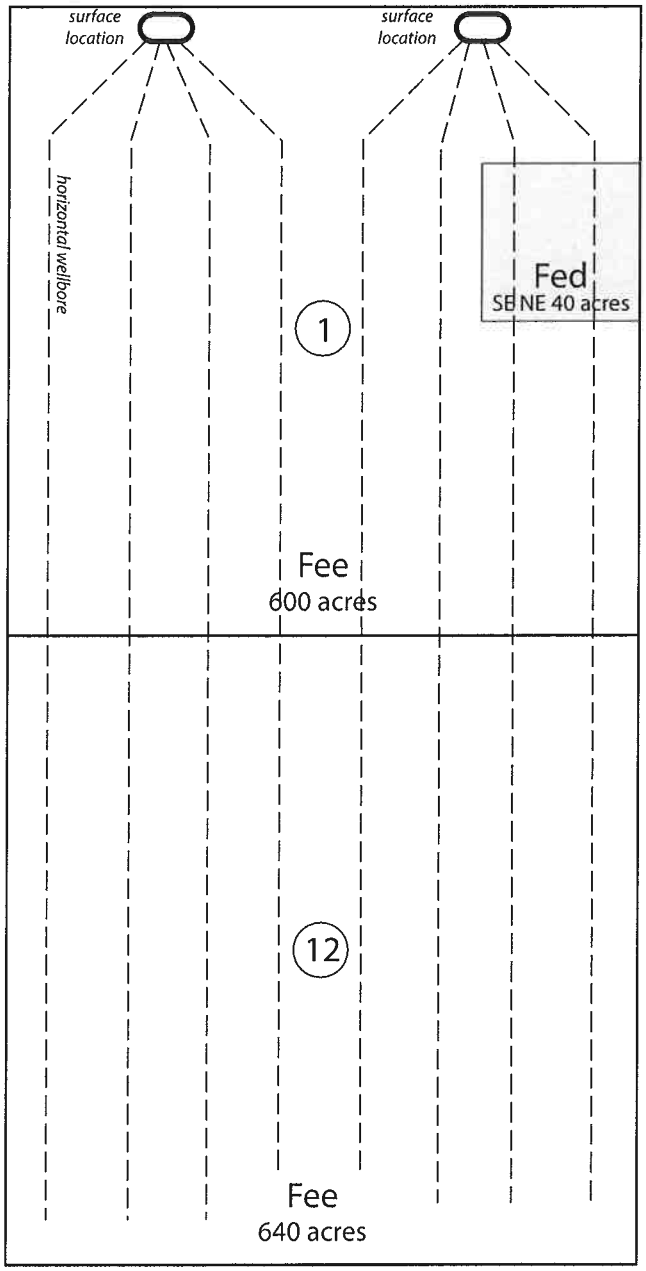


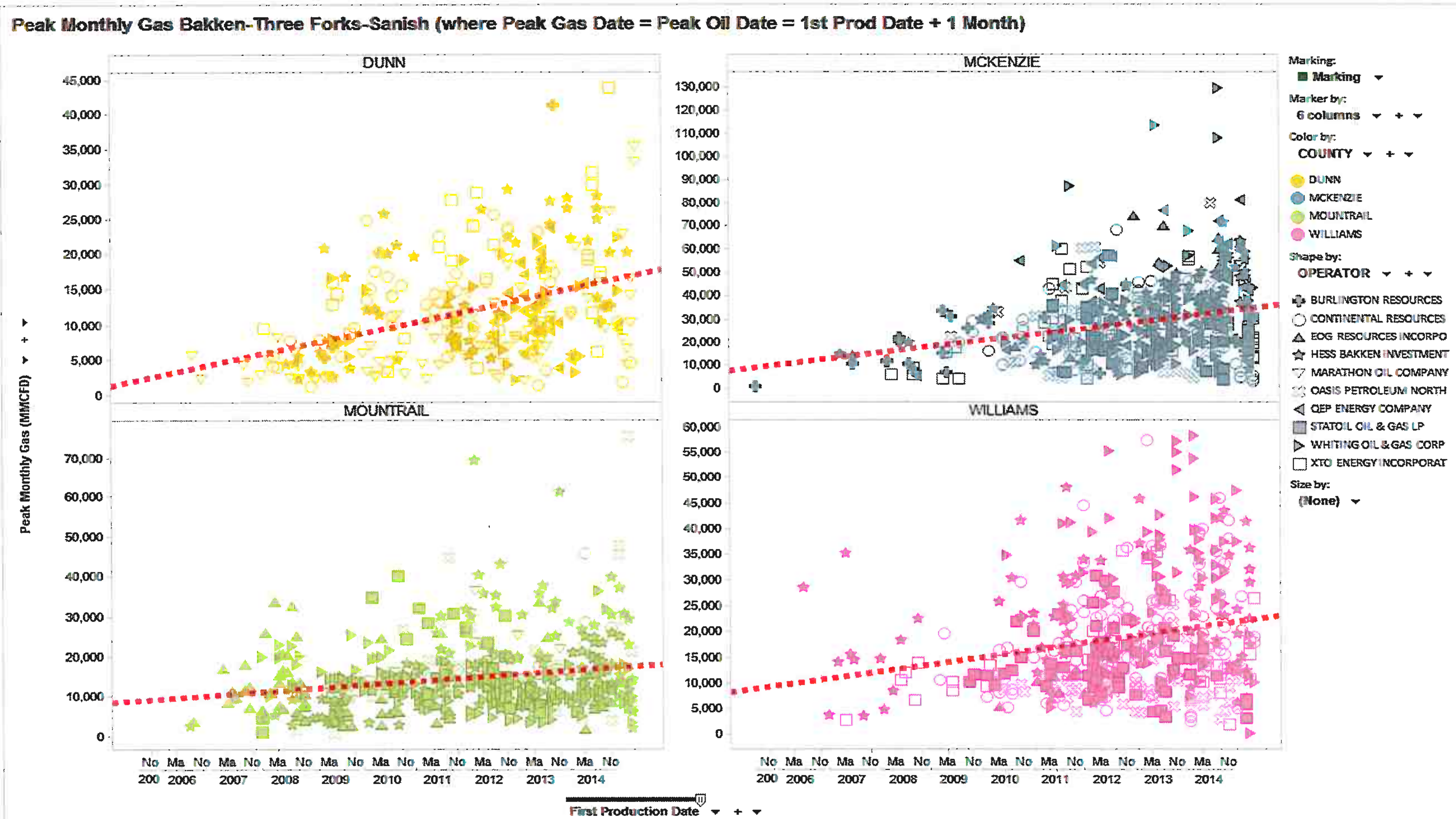
surface location
surface location
horizontal wellbore
Fed
SE NE 40 acres
1
Fee
600 acres
12
Fee
640 acres

EXHIBIT
1

EXHIBIT 2

Production Growth

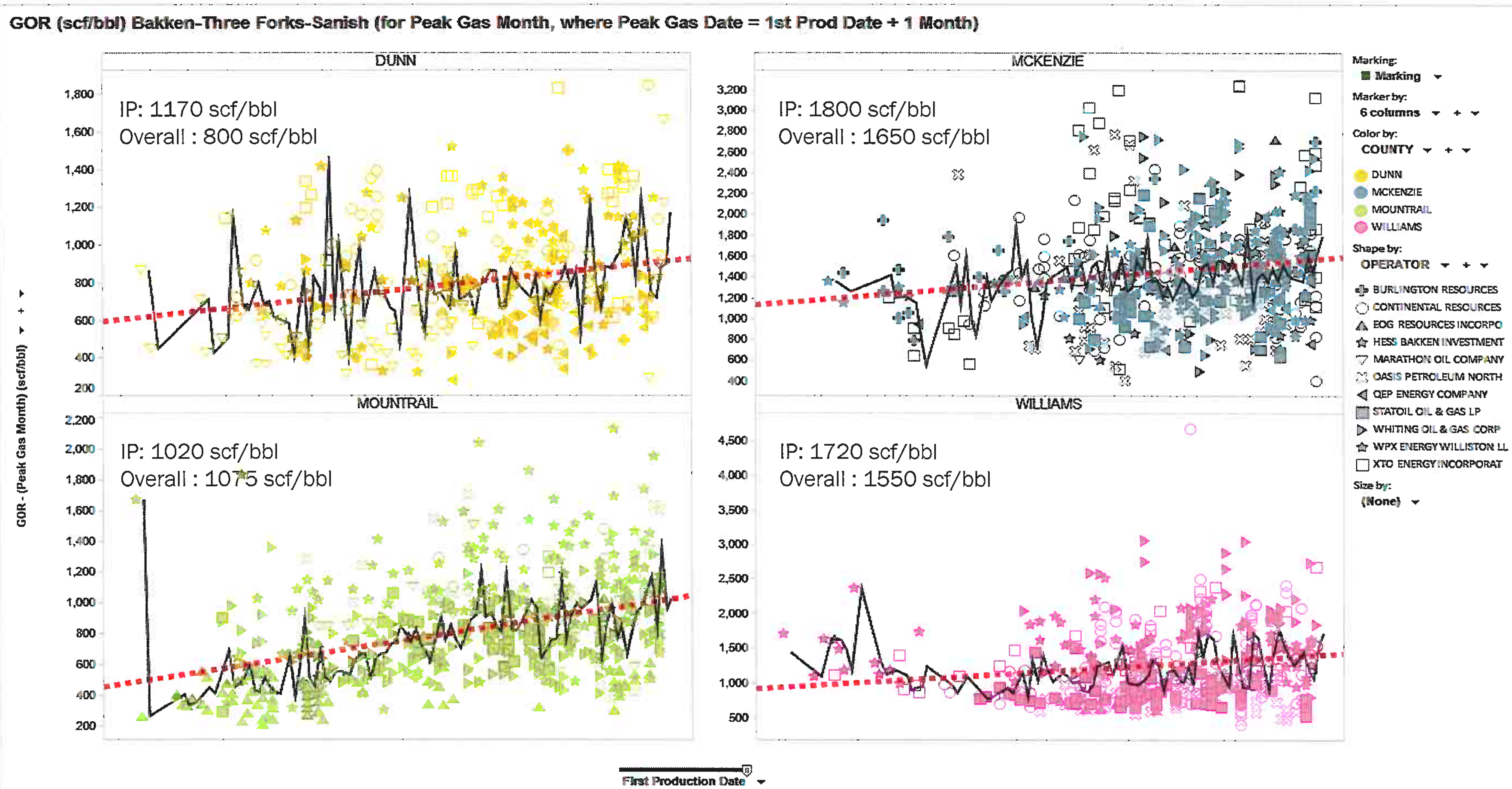
Average IP gas rates continue to increase, driven by improved completions and concentration in hotter core



NORTH DAKOTA PETROLEUM COUNCIL

Production Growth

IP GORs have likewise increased as drilling concentrates in core area



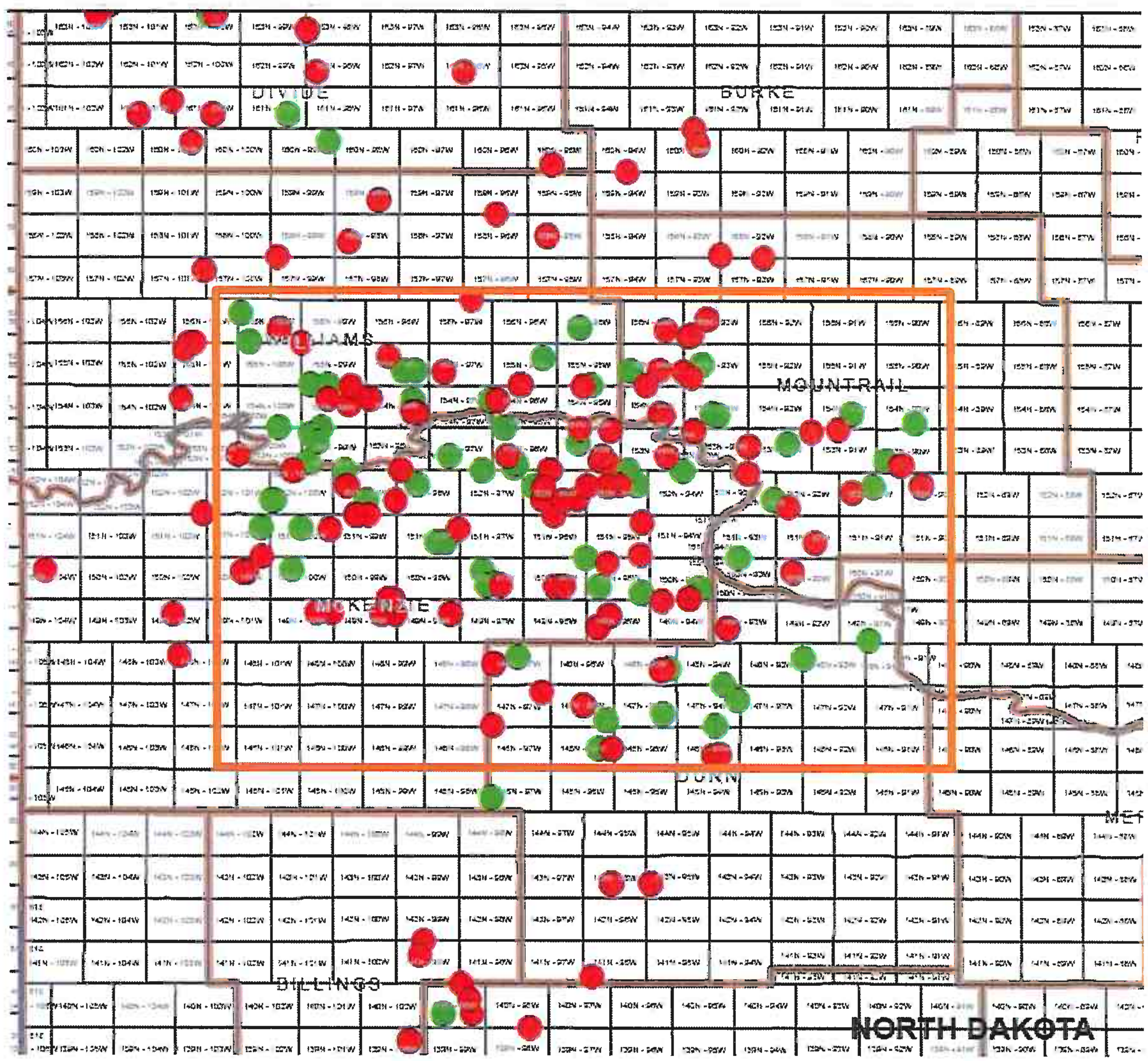
- Reported IP & Overall GORs are most recent oil-weighted values from IHS data (IP) and Operator Surveys (Overall)
- Black line is oil-weighted average IP by month; red line is best fit without weighting

NORTH DAKOTA PETROLEUM COUNCIL

Drilling Concentration

- July 2014 spud locations
  - 207 total spuds
  - 154 in central area (74%)

- August 2015 rig locations
  - 72 total rigs
  - 64 in central area (89%)



UNITED STATES DEPARTMENT OF INTERIOR
BUREAU OF LAND MANAGEMENT

North Dakota Petroleum Council, Inc., et al.	)	
	)	
Appellants,	)	State Director Review of
	)	October 14, 2015 Revised Decision
v.	)	By North Dakota Field Office
	)	Manager Loren Wickstrom to
Bureau of Land Management,	)	Decision Record, FONSI, and EA
	)	Sundry Notice Flaring Requests
Respondent.	)	

STATE OF NORTH DAKOTA)
)ss
COUNTY OF STARK)

DECLARATION OF DARRELL NODLAND

Darrell Nodland, being first duly sworn upon oath, deposes and says:

1. I am a citizen of the United States, a resident of the State of North Dakota, of legal age, and competent to be a witness. I am employed by Marathon Oil Company ("Marathon") as Well Planning and Regulatory Compliance Supervisor, and I submit this Declaration in support of the Appellants Request for State Director Review in North Dakota Petroleum Council, Inc., et al. v. Bureau of Land Management.

2. Marathon currently has approximately 200 unprocessed Sundry notices with NDFO for connected and unconnected wells from September 2013 through February 2015. The impacts of the revised Decision Record on Marathon and Industry as a whole are significant. In addition to unknown and what constitutes retroactively imposed royalty obligations possibly being imposed, other impacts include metering and equipment costs, requirements of uneconomic remote capture equipment, and the lack of consideration of real conditions affecting pipeline capacity and infrastructure constraints.

EXHIBIT
tabbies
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3. The Revised Decision Record would require the installation of metering equipment not previously required by NDFO or NTL-4A. It is estimated that the metering equipment would cost approximately $12,000 per meter, and these costs do not include installation, or the expense and maintenance associated with the meters.

4. Regarding the Decision Record's requirement of remote capture, Marathon has utilized remote capture technology on many occasions in an effort to reduce flaring and to comply with the State of North Dakota's gas capture requirements. The remote capture technologies presently available are uneconomical and they do not entirely resolve gas flaring.

The lease cost of the remote capture units (NGLs) are greater than the value of the natural gas liquids they produce at current market prices. It is my understanding that, at the typical gas volumes we see with a Bakken well, NGL units are uneconomical, and are especially uneconomical on small scales.

There are many limitations of these NGL units, for Marathon and industry:

NGL units are notoriously difficult to winterize and have low winter runtimes. NGL units require semi-stable inlet gas rates to run; many connected sites flare intermittently which would make operation difficult and runtimes low. NGL units require a large footprint to safely operate, which is an issue on smaller pads. Marathon's current NGL vendors are not are able to scale down further than 250 MSCFD, which is greater than the amount of flaring on most connected sites. Additionally, the NGL (liquid) portion is ~45% by volume, ~60% by BTU content; therefore the NGL unit will reduce but not eliminate the flare.

5. Marathon is committed to gas capture. However, producers and gas purchasers face roadblocks with obtaining infrastructure rights-of-way on Federal and fee acreage, especially

within the boundaries of Fort Berthold Indian Reservation. There are numerous examples of pipeline right of way delays, but specific examples affecting Marathon include:

a. Bears Ghost USA 31 pad (currently unconnected). TARGA has been waiting for the BIA to resolve a "trespass issue" on a tribal tract for well over a year, in order to allow them to tie in a short stretch to this pad from their backbone only several hundred feet away.

b. TAT USA 13-23H pad (currently unconnected), TARGA was unable to obtain consents from a specific allottee to gain access to tie in this well. This was two years ago. TARGA since proposed going around this tract, and just recently, on October 19th, 2015, was finally able to get approval to proceed with construction of the pipeline two years later.

6. While a stated goal of the BLM is to facilitate pipeline infrastructure, royalty payments on flared gas likely will not create critical infrastructure. Instead, it will perpetuate the ongoing challenges with prudent gas capture and effective resource capture. Stipulations for equipment in or around view sheds will likely have negative impact on effective gas capture, reservoir management and resource potential, and oil royalties to all mineral interest stakeholders - Federal, State and fee. The state and local economy will also likely_be negatively impacted with lower production and activity levels. In absence of defined listings, view sheds will be subjective and could have broad consequences across the state.

7. The Revised Decision Record fails to consider the reality of market value of gas without a market from an oil field. Flared gas has no value until it reaches the market; consequently, gas without a method to get to market is valueless and is unavoidably flared in order to maintain oil production.

DATE: November 16th, 2015.

BY: Darrell Nodland

Darrell Nodland
Well Planning and Regulatory Compliance Supervisor, Marathon Oil Company

STATE OF NORTH DAKOTA)
)ss
COUNTY OF STARTK)

Subscribed and sworn to before me this 16th day of November, 2015, by Darrell Nodland, Well Planning and Regulatory Compliance Supervisor, Marathon Oil Company.

(S E A L) JESSICA SANCHEZ
NOTARY PUBLIC, STATE OF NORTH DAKOTA
MY COMMISSION EXPIRES FEB 17, 2021

Jessica Sanchez
Notary Public
Stark County, State of North Dakota
My Commission Expires: Feb. 17, 2021

UNITED STATES DEPARTMENT OF INTERIOR
BUREAU OF LAND MANAGEMENT

North Dakota Petroleum Council, Inc., et al. Appellants, v. Bureau of Land Management, Respondent.	)))))))))	State Director Review of October 14, 2015 Revised Decision By North Dakota Field Office Manager Loren Wickstrom to Decision Record, FONSI, and EA Sundry Notice Flaring Requests

STATE OF COLORADO)
)ss
COUNTY OF DENVER)

DECLARATION OF BRENT MILLER

Brent Miller, being first duly sworn upon oath, deposes and says:

1. I am a citizen of the United States, a resident of the State of Colorado, of legal age, and competent to be a witness. I am Senior Operations Manager for Whiting Oil and Gas Corporation ("Whiting") and I submit this Declaration in support of the Appellants Request for State Director Review in North Dakota Petroleum Council, Inc., et al. v. Bureau of Land Management.

2. Whiting has submitted to NDFO 166 Sundries since 2013 which were not processed. In March 2015, NDFO returned all 166 Sundries requesting additional information. Whiting complied with the requests and resubmitted all Sundries. As of this date, 55 of the resubmitted Sundries were processed, but all were rejected requesting yet additional information, with the remaining Sundries still pending.

tabbies EXHIBIT 4

3. Whiting submits this Declaration solely to address the E.A. and Decision analysis recommending remote gas capture as a solution to gas flaring issues. Whiting has utilized remote gas capture technologies in efforts to reduce flaring, comply with North Dakota Industrial Commission Gas Capture Plans, and to evaluate remote gas capture as possible solutions in the future to assist in alleviating flaring volumes and providing an economic alternative to pipeline capacity and other related constraints. Our efforts to date establish that remote capture technology is uneconomic and will not alleviate flaring or resolve pipeline capacity and constraint issues.

4. Under my direction and supervision, Whiting has prepared two gas capture economic analysis as set forth herein. The first example is a theoretical scenario, but is based on average actual costs incurred by Whiting on 15 well site locations during 2014. The second scenario is based on an actual individual well site in 2015. The economic summaries are shown in paragraphs 5 and 6, below, which establish remote capture was uneconomic and cost Whiting substantial sums to implement. In addition, the remote capture efforts do not stop all flaring of gas, as we were required to continue to flare gas at the remote capture sites even though liquids were being captured.

5. <u>Remote Gas Capture Economics: Theoretical Case</u>

This economic model represents a theoretical application in which 12 months of gas capture is required to satisfy regulatory requirements for a new location based on average costs incurred over 15 locations during 2014, and pricing believed to be available in October 2015. A unit with 2,000 Mscfd capacity is selected to match with production forecast in month 4 of production. Prior to month 3, some gas will be flared. After month 3, the equipment will be underutilized. A location gas capture goal of 85% is assumed.

a. Theoretical Economics:

Gas Capture Unit Capacity (2,000 Mscfd)

b. Direct Service Costs including the following:

- Mobilization and Installation Charges:
(i) Costs of moving equipment to location, cranes, pipe, valves, and fittings, roustabout work, electrical installation, hydrostatic testing, and commissioning. Assume equipment is mobilized from gulf coast.

- Monthly Fees to Service Company:
(i) Include lease, operation, and maintenance of compressors (2), mechanical refrigeration unit (2), stabilizer (2), natural gas generators (2), product storage tanks (2), and waste tank (1).

- Project Term (months): 12

- Demobilization Fee at Term End:
(i) Breakdown and removal of piping, electrical, crane and trucks to lift and remove equipment skids from location.

- Total Payments to Gas Capture Operator $750,000

c. Company Costs:

- Site Preparation:

- Company Oversite Billed to Location:
(i) Company gas capture supervisor on location 8 hours per week during operation, plus 1 company consultant on location 8 hours per week during operation. Exclude cost associated with field safety and environmental personnel and G&A.

- Tie-ins to Gas Plant:
(i) Includes custody transfer gas supply meter to gas plant and meter for residue gas stream to flare, and piping required to connect treaters to gas plant.

- Company Costs: $124,430

- Total Costs for Four-Month Operation: $874,430

d. Production Data:

- Equipment Availability Assumed: 90%

- Total Gas Processed: 492,750

(i) Assume that 75% utilization of available capacity is used due to production decline below equipment capacity maximums.

- Average Gallons Extracted Per Mscf processed: 2

- Total NGLs Extracted and Sold (gallons): 985,500

e. Scenario A: 2015 Economics

Average Revenue Per Gallon After TF&M:	$0.22
Total Project Revenue:	$216,810
Total Project Costs:	$874,430
Net Project Profit/(Loss):	**($657,620)**

f. Scenario B: July 2014 Economics

Avenue Revenue Per Gallon After TF&M:	$0.85
Total Project Revenue:	$837,675
Total Project Costs:	$874,430
Net Project Profit/(Loss):	**($36,755)**

6. Remote Gas Capture Economics: Actual Case

The following case study represents an actual remote gas capture project by Whiting Petroleum in McKenzie County, where the contract ran four months from July – October 2015. Most of the costs are rounded for simplicity and some estimates have been made as actual LOE costs were not separated from normal production costs.

Right-of-way for connection to gas gathering system could not be acquired prior to initial flowback. Given high GOR for this area, a gas capture unit was required to maintain regulatory compliance. Pipeline was connected around September 1; however, could not take all gas until October 7, 2015.

Gas capture rate was 86% during contract period.

Gas capture unit capacity (4,500 Mscfd).

a. <u>Direct Service Costs include for the following services and equipment</u>:

- Mobilization and Installation Charges:
  (i) Costs of moving equipment to location, cranes, pipe, valves, and fittings (in this case much of the piping was re-used from previous location), roustabout work, electrical installation, hydrostatic testing, and commissioning.

- Monthly Fees to Service Company:
  (i) Include leased, operation, and maintenance of compressors (2), mechanical refrigeration unit (2), stabilizer (2), natural gas generators (2), project storage tanks (2), and waste tank (1).

- Project Term (months): 4

- Demobilization Fee at Term End:
  (i) Breakdown and removal of piping, electrical, crane and trucks to lift and remove equipment skids from location.

- Total Payments to Gas Capture Operator: $541,000

b. <u>Company Costs including for the following services and equipment</u>:

- Site Preparation:

- Company Oversite Billed to Location:
  (i) Company gas capture supervisor on location 8 hours per week during operation, plus 1 company consultant on location 8 hours per week during operation. Excludes cost associated with field safety and environmental personnel and G&A.

- Tie-ins to Gas Plant:
  (i) Includes custody transfer gas supply meter to gas plant and meter for residue gas stream to flare, and piping required to connect treaters to gas plant.

- Company Costs: $71,792

- Total Costs for Four-Month Operation: $612,792

- Actual Gas Volume Processed (Mscf): 175,159

- Total NGLs Extracted and Sold (gallons): 266,793

c. Scenario A: Actual Economics

Average Revenue Per Gallon After TF&M:	$0.22
Total Project Revenue:	$58,694
Total Project Costs:	$612,792
Net Project Profit/(Loss):	**($554,098)**

d. Scenario B: July 2014 Economics

Average Revenue Per Gallon After TF&M:	$0.85
Total Project Revenue:	$226,774
Total Project Costs:	$612,792
Net Project Profit/(Loss):	**($386,018)**

DATE: November 16, 2015.

BY: ______________________

Brent Miller
Senior Operations Manager for Whiting Oil and Gas Corporation

STATE OF COLORADO)
)ss
COUNTY OF DENVER)

Subscribed and sworn to before me this 16th day of November, 2015, by Brent Miller, Senior Operations Manager for Whiting Oil and Gas Corporation.

____
Notary Public
Denver County, State of Colorado
My Commission Expires: 03-13-2016

(S E A L)

KAREN HELMSIN
NOTARY PUBLIC
STATE OF COLORADO
My Commission Expires 03-13-2016

UNITED STATES DEPARTMENT OF INTERIOR
BUREAU OF LAND MANAGEMENT

North Dakota Petroleum Council, Inc., et al.	)	
	)	
Appellants,	)	
	)	State Director Review of
v.	)	October 14, 2015, Revised Decision
	)	By North Dakota Field Office
Bureau of Land Management,	)	Manager Loren Wickstrom to
	)	Decision Record, FONSI, and EA
Respondent.	)	Sundry Notice Flaring Requests

STATE OF OKLAHOMA)
)ss
COUNTY OF OKLAHOMA)

DECLARATION OF JEFF B. HUME

Jeff B. Hume, being first duly sworn upon oath, deposes and says:

1. I am a citizen of the United States, a resident of the State of Oklahoma, of legal age, and competent to be a witness. I am Vice Chairman of Strategic Growth Initiatives for Continental Resources, Inc. ("Continental"), and I submit this Declaration in support of the Appellants' Request for State Director Review in North Dakota Petroleum Council, Inc., et al. v. Bureau of Land Management.

2. If the October 14, 2015, revised decision (Decision Record Environmental Assessment DOI-BLM-MT-C030-2013-229-EA) (the "Flaring Sundry Decision") of the BLM North Dakota Field Office ("NDFO") is permitted to go into effect, Continental and other members of the North Dakota Petroleum Council will be irreparably harmed by the Flaring Sundry Decision's retroactive and widespread application. Continental has approximately 330 wells which have either pierced federal minerals or are otherwise producing federal minerals by

EXHIBIT
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virtue of their having been included within a communitization agreement. For most of these 330 wells, the Flaring Sundry Decision will require Continental to (1) incur costs ranging between \$10,000 to \$15,000 per well to install metering equipment, which has not previously been required and, therefore, has not been installed at most Continental wells; (2) provide hourly volumes of gas flared between 2008 and 2015 and corresponding justification for the flaring—this is an immense challenge given the fact that, in the absence of metering equipment, hourly volumes of gas flared can only be estimated based on an evaluation of the applicable gas oil ratio and total volume of gas flared on a given day, and justification for any such flaring in many cases will be unavailable because (a), for wells connected to pipelines, the justification will be due to a third party issue not disclosed to Continental (e.g., no capacity on midstream company's pipeline despite a well's gas having been dedicated to the pipeline) or (b), for stranded wells (i.e., wells incapable of being connected to pipelines), the justification will require Continental to conduct a rigorous economic analysis and demonstrate to the BLM NDFO's satisfaction the reasons it was not viable to connect the well to a pipeline or capture the gas using alternate means or technology; and (3) calculate the value of any gas flared between 2008 and 2015, which, for each unconnected well, can only be estimated by reviewing gas sales contracts applicable to nearby wells producing from the same formation and that were connected to pipelines during the period gas was flared from the unconnected well.

3. The BLM NDFO's Flaring Sundry Decision is arbitrary and capricious. The undertaking described in paragraph 2 would require a detailed and technically challenging 7-year review of 330 wells, which would be enormously time-consuming. Continental's assessment of the irreparable harm it will suffer is not mere conjecture: Continental has recent and relevant

experience preparing flaring exemption applications for the North Dakota Industrial Commission ("NDIC"). Although the tedious analyses Continental conducted in connection with its NDIC flaring exemption applications were complicated and time-consuming, they were not nearly as detailed or all-encompassing as the analyses required by the Flaring Sundry Decision, which would impact a far greater number of Continental's wells. Second, the Flaring Sundry Decision's requirements are unjustifiably excessive compared to the far more reasonable flaring sundry information being requested by the BLM NDFO's sister office in Miles City, Montana, which generally requires operators to provide (a) an approximate volume to be flared (mcf/day); (b) an approximate volume used beneficially on lease, if any; (c) a gas analysis including H_2S concentration; and (d) economic justification for not selling the gas (e.g., low volume, no sales line, poor quality).

4. Continental has conducted numerous evaluations of remote capture technologies. Further, Continental's more recent experience preparing NDIC flaring exemption applications required consideration of remote capture technologies. Based on its extensive evaluations of remote capture technologies, Continental has concluded the technologies are not economically viable given their substantial cost in comparison to the nominal value of gas being flared. To the extent they are economically viable at all, remote capture technologies have the greatest likelihood of providing an economically viable alternative to flaring when the technologies are deployed to capture gas flared from stranded wells (i.e., wells incapable of being connected to a pipeline). Unlike wells connected to pipelines, which intermittently and unavoidably flare negligible volumes of gas, stranded wells flare larger volumes of gas; therefore, the capture and sale of gas flared from stranded wells have greater potential to offset the substantial costs of

remote capture technologies. Nevertheless, neither power generation technologies, which have the potential to provide revenue to an operator based on the sale of electricity generated by flared gas, nor liquids stripping technologies, which have the potential to provide revenue to an operator based on the sale of natural gas liquids recovered from flared gas, have proven economically viable – even for Continental's stranded wells.

For example, Continental recently evaluated the costs associated with the purchase and installation of an electric generator fueled by flared gas for one of Continental's stranded wells, which flares approximately 40 mcf/day. Continental was advised by the manufacturer the cost of the generator would total approximately $450,000.00. By contrast, the projected non-discounted revenue to be received over a 2-year period from sale of electricity being produced from the electric generator fueled by the well's flared gas would total approximately $87,000.00, an amount which does not account for transmission costs Continental would be required to pay. Continental also evaluated liquids stripping technologies for this stranded well, but the combination of depressed commodity prices for natural gas liquids and the manufacturer's stated requirement of a minimum daily flared volume of 50 mcf to offset the cost of the technology (most of Continental's stranded wells flare less than 50 mcf/day, and the subject well for which Continental had been evaluating power generation and liquids stripping technologies was flaring approximately 40 mcf/day) would have resulted in Continental's incurring a loss of approximately $1 million over a 2-year period. Simply put, the requirements imposed by the Flaring Sundry Decision are economically implausible.

5. Between January 9, 2014, and February 18, 2015, Continental submitted 107 flaring sundries to the BLM NDFO. None of those sundries has yet been processed by the BLM

NDFO, and all were returned to Continental on March 29, 2015, demanding Continental supplement the flaring sundries with information regarding (a) dates upon which gas was flared from each of the wells; (b), for each such date upon which gas was flared from each of the wells, the precise number of hours gas was flared; and (c) explanations for any such flaring which occurred.

Since March 29, 2015, Continental has submitted an additional 12 sundries with the more detailed flaring data requested by the BLM NDFO; however, none of these flaring sundries has been approved. Upon information and belief, the BLM NDFO has not approved any of Continental's flaring sundries since 2011 when the BLM NDFO first began reevaluating its flaring sundry approval process. Continental has attached as Exhibits "A" and "B" two flaring sundries approved by the BLM NDFO in 2011. Each of these approved flaring sundries reflects BLM NDFO's longstanding position acknowledging the unavoidable flaring which periodically occurs at wells connected to pipelines – a position which is now directly contradicted by the Flaring Sundry Decision.

DATE: November 16, 2015.

BY: Jeff B. Hume
Vice Chairman of Strategic Growth Initiatives

STATE OF OKLAHOMA)
)ss
COUNTY OF OKLAHOMA)

Subscribed and sworn to before me this 16th day of November, 2015, by Jeff B. Hume, Vice Chairman of Strategic Growth Initiatives for Continental Resources, Inc.

(S E A L) TAMMY MCGEE NOTARY # 10001862 EXP. 03/09/18 PUBLIC STATE OF OKLAHOMA

Tammy McGee
Notary Public
Oklahoma County, State of Oklahoma
My Commission Expires: 3-9-18

UNITED STATES DEPARTMENT OF INTERIOR
BUREAU OF LAND MANAGEMENT

North Dakota Petroleum Council, Inc., et al.	)	
	)	
Appellants,	)	State Director Review of
	)	October 14, 2015 Revised Decision
v.	)	By North Dakota Field Office
	)	Manager Loren Wickstrom to
Bureau of Land Management,	)	Decision Record, FONSI, and EA
	)	Sundry Notice Flaring Requests
Respondent.	)	

STATE OF COLORADO)
)ss
COUNTY OF DENVER)

DECLARATION OF SHANE HENRY

Shane Henry, being first duly sworn upon oath, deposes and says:

1. I am a citizen of the United States, a resident of the State of Colorado, of legal age, and competent to be a witness. I am Manager, Government and Regulatory Affairs, U.S. Operations, for Enerplus Resources (USA) Corporation (Enerplus) and I submit this Declaration in support of the Appellants Request for State Director Review in North Dakota Petroleum Council, Inc., et al. v. Bureau of Land Management.

2. In North Dakota, Enerplus operates almost exclusively on the Fort Berthold Indian Reservation (Reservation) and accordingly nearly all of our production is subject to BLM jurisdiction. Currently, Enerplus operates 121 wells, of which 18 wells are not connected to gas gathering pipeline. The reasons for these wells not being connected to pipeline includes:

- The wells are older, experiencing significantly reduced production rates and located a far enough distance from existing development and pipeline infrastructure to make connection uneconomical.

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- Right-of-way (ROW) or other required approvals have not been obtained for pipeline construction. Obtaining ROW approval on the Reservation is further complicated by the multiple authorities involved in the process. Even though many of these approvals are the primary responsibility of Enerplus' third party gas gathering company, the delays directly affect Enerplus.

- Enerplus' third party gas gathering company is in the process of building the gas pipelines, and connections are expected based on applicable construction plans. Several of these construction projects have been affected by right-of-way and other approval delays.

3. All of Enerplus' remaining 100-plus wells are connected to gas gathering pipeline. As mentioned previously, Enerplus relies on third party gas gathering service, with no internal midstream resources in the US. Historically in North Dakota, Enerplus, as well as other operators, have experienced various midstream service disruptions that have necessitated the flaring of gas. The source of these disruptions has ranged from gas gathering capacity bottlenecks and insufficient pipeline compression to needs for gas plant expansions. These issues are managed by our third party midstream companies and out of Enerplus' control.

4. Enerplus has done everything possible to prevent these disruptions, including working closely with its midstream service providers during the well planning and development stages to provide the most accurate estimates on future gas gathering needs. These efforts are evident in Enerplus' strong compliance performance with the North Dakota Industrial Commission's (NDIC) gas capture requirements. In spite of these efforts, the need to flare gas at times has not been eliminated. In accordance with BLM's procedures, Enerplus has submitted the necessary sundry requests to flare gas, as well as the recently requested monthly flare information. Given the unpredictable nature of gas gathering disruptions, the amount of required flaring varies each month at most of our sites.

5. Regarding Right of Way delays, Enerplus does not engage directly in pipeline construction or other related operations, however, our third-party midstream company has experienced numerous delays placing pipeline. Following are a couple of specific examples of such delays as well as a representative schedule with timelines to obtain approval to construct a pipeline.

Example 1

Initial production for two of our wells, located on the same pad, occurred in early April of 2014. The gas gathering pipeline construction was expected to be completed shortly after the wells came on line. However, due to delays in obtaining the necessary right-of-way, the site was not connected to pipeline until that December.

Example 2

Initial production for two of our wells, located on the same pad, occurred at the end of November 2013. Due to delays in obtaining the necessary right-of-way, construction on the pipeline did not commence until the fall of 2014. That same fall, construction operations were stopped by the Three Affiliated Tribes' Employment Rights Office (TERO) because of an employment infraction committed by the third party pipeline construction company. This employment provision at issue is an FBIR-specific requirement. Due to this TERO delay and the subsequent winter season, pipeline construction was not resumed until the following spring, resulting in nearly an eight month delay. The wells were not connected to pipeline until August of 2015, representing a one year, eight month delay in total.

6. The following provides additional details of the process required to obtain approval for pipeline construction on property subject to NEPA jurisdiction, which includes the Fort Berthold Indian Reservation. The timeline is based on an aggregation of actual projects.

1. Obtain permission to survey (PTS) from landowners and submit to BIA-New Town office for approval. *(4 weeks)*
   a. Responsible party: operator's land agent.

2. "Soft stake" the pipeline centerline after PTS has been granted by BIA *(1 week)*

a. Responsible party: surveying company and/or contracted engineer.

3. Schedule EA onsite. ***(1 week)***
   a. A representative from the BIA-New Town office must be present.
   b. Consultants conduct natural and cultural surveys.

4. Prepare final plats. ***(3 weeks)***
   a. Responsible party: surveying company and/or contracted engineer.

5. Prepare and send scoping letter for approved pipeline (if applicable, for trunk lines only, lateral lines to well locations will not require scoping).***(4 weeks)***
   a. Responsible party: consultants.
   b. The EA cannot be submitted until the end of the 30-day comment period.

6. Schedule ROW onsite with the BIA-New Town office.***(1 week)***
   a. A representative from the BIA New Town office must be present.
   b. Responsible party; Operator.

7. Prepare EA and cultural reports; from initial surveys conducted in step 3. ***(12 weeks)***
   a. Responsible party: consultants.
   b. Submit cultural reports to the BIA before the EA is submitted. Unless the THPO office clears the report sooner, there is a 30-day waiting period before the BIA in Aberdeen will review the EA.

8. If habitat for a listed endangered/threatened species is present, an informal consultation with the US Fish and Wildlife Service (USFWS) is required. Project must receive concurrence from USFWS. ***(8 weeks or longer)***

9. Submittal of EA to BIA Aberdeen office and Finding of No Significant Impact (FONSI) is reached. ***(4 weeks)***
   a. Responsible party: consultants.
   b. There is a 30-day notice period after the FONSI is issued.

10. Pipeline Company obtains landowner signatures agreeing to terms and payment. These signatures are then filed in the ROW application that is submitted to the BIA New Town office for approval. ***(4 weeks)***
    a. Responsible party: Pipeline company land agents.

11. Construction operations can begin only after the BIA issues a Notice to Proceed and ROW grant. ***(5 weeks)***

The above-described times for completion of each stage will vary depending on: BIA onsite schedule, completeness of supplementary information, results of resource surveys, results of onsites, completeness of application packages, public response to projects, weather conditions, and, of course, securing proper consents from all necessary landowners.

DATE: November 13, 2015.

BY: ____________________
Shane Henry
Manager, Government and Regulatory Affairs, U.S. Operations, for Enerplus Resources (USA) Corporation

STATE OF COLORADO)
)ss
COUNTY OF DENVER)

Subscribed and sworn to before me this 13 day of November, 2015, by Shane Henry, Manager, Government and Regulatory Affairs, U.S. Operations, for Enerplus Resources (USA) Corporation.

____
Notary Public
Denver County, State of Colorado
My Commission Expires: 11.27.2017

(S E A L)

Devyn Tayler Peterson
Notary Public
State of Colorado
Notary ID 20134074231
My Commission Expires November 27, 2017

WellName	Year	Month	BBLS_OIL	MCF_GAS	MCF_SOLD	MCF_FLARED	BIA_Lease
HOGNOSE 152-94-18B-19H-TF	2016	1	17436	52308	27716	23756	FBR
MATTIE 13-36H	2016	1	13602	22169	881	21288	FBR
MANDAREE 24-13 HZ2	2016	1	24517	44326	20557	20925	FBR
MAGNUM 36-12-MB2	2016	1	14946	16010	636	15374	FBR
PARSHALL 44-1004H	2016	1	12541	13901	0	13394	FBR
SKUNK CREEK 4-18-17-1H3	2016	1	19660	12929	0	12872	FBR
SKUNK CREEK 4-18-17-8H3	2016	1	17343	12912	0	12862	FBR
MAGNUM 36-13-TF2	2016	1	4647	13312	529	12783	FBR
MAGNUM 36-11-TF2	2016	1	4685	12673	504	12169	FBR
SKUNK CREEK 4-18-17-8H	2016	1	16384	11529	0	11480	FBR
MANDAREE 24-13HY	2016	1	24473	33961	19779	11342	FBR
AVALANCHE 36-16-MB2	2016	1	5695	11560	459	11101	FBR
GOLDEN 22-31H	2016	1	20664	10665	0	10665	FBR
HOWO 2-4-33MLH	2016	1	18317	15651	6256	9240	FBR
PANZER 1-20MLH	2016	1	5840	8344	0	8189	FBR
PARSHALL 55-1014H	2016	1	7388	8673	0	8188	FBR
AVALANCHE 36-14-MB2	2016	1	6290	7696	306	7390	FBR
7200 MCF/Month Subtotal			**234428**		**77623**	**223018**	
Gross Revenue ($40/b) ($1.65 mcf flared gas)			**$9,377,120.00**			**$367,979.70**	
30% curtailment/shut-in			**$2,813,136.00**				
Tribal share of flared gas (assumes 100% gas capture and 9% net revenue interest).						**$33,118.17**	
Tribal share of lost revenue on curtailed oil production:							
Tax (5% production tax)			**$140,656.80**				
Lease Royalties (9% NRI)			**$253,182.24**				
Total Tribal curtailed loss			**$393,839.04**	**less $33,118.17 =**	**$360,720.87**		
TWO SHIELDS BUTTE 13-22-33-	2016	1	21514	16450	9313	7077	FBR
CHARGING EAGLE 9-19-18-1H3	2016	1	10345	6930	0	6867	FBR
SKUNK CREEK 4-18-17-1H	2016	1	11217	6827	0	6782	FBR
PARSHALL 53-1014H	2016	1	6633	7108	0	6609	FBR
HIDATSA 150-94-32C-29H	2016	1	9846	14768	6970	6593	FBR
PARSHALL 93-2827H	2016	1	5385	7028	0	6528	FBR
BUCKY 13-36H	2016	1	4765	6691	266	6425	FBR
LUKE 13-36H	2016	1	3396	6625	264	6361	FBR
AVALANCHE 36-15-TF1	2016	1	4944	6393	254	6139	FBR
TAT 150-94-32D-29H	2016	1	11241	16861	9704	5809	FBR
MANDAREE 24-13HZ	2016	1	21713	26220	18098	5578	FBR
TWO SHIELDS BUTTE 13-22-16-	2016	1	17704	13773	8169	5549	FBR
MANDAN 150-94-32C-29H TF	2016	1	8407	12610	6264	5262	FBR
ARIKARA 150-94-32D-29H TF	2016	1	9815	14722	8927	4567	FBR
CACTUS 149-92-35B-05H TF	2016	1	12712	8898	1915	4418	FBR
PARSHALL 91-28H	2016	1	6305	4894	0	4406	FBR
MOCCASIN CREEK 16-3-11H	2016	1	3235	4859	0	4273	FBR
FORT BERTHOLD 151-94-34C-27-	2016	1	3908	4441	0	4224	FBR
PHOENIX 1 SLH	2016	1	5453	4306	0	4151	FBR
ALFRED OLD DOG 19-18HD	2016	1	8052	11329	6474	3771	FBR
GUDBRANSON 1	2016	1	3804	3733	0	3733	FBR
CROW FLIES HIGH USA 31-4H	2016	1	4942	6391	1716	3616	FBR
HAWKEYE 02-2501H	2016	1	10514	69155	65175	3607	FBR
3600 to 7200 MCF wells Subtotal			**205850**		**143509**	**122345**	
Total All wells > 3600 MCF			**440278**		**221132**	**345363**	
Gross Revenue ($40/b) ($1.65 mcf flared gas)			**$17,611,120.00**			**$569,848.95**	
30% curtailment/shut-in			**$5,283,336.00**				
Tribal share of flared gas (assumes 100% gas capture and 9% net revenue interest).						**$51,286.41**	
Tribal share of lost revenue on							
Tax (5% production tax)			**$264,166.80**				
Lease Royalties (9% NRI)			**$475,500.24**				
Total Tribal curtailed revenue loss at 3600 MCF/Month			**$739,667.04**	**less $51286.41 =**	**$688,380.63**		
STEVENSON 24-34TFH	2016	1	20295	19088	13298	3433	FBR
PARSHALL 83-2827H	2016	1	3456	4193	0	3388	FBR
TAT USA 34-22H	2016	1	3266	4199	0	3319	FBR
DANKS USA 11-3H	2016	1	3587	4220	0	3307	FBR
BENSON 16-3H	2016	1	2098	4247	212	3243	FBR
PARSHALL 61-15H	2016	1	2457	3612	0	3120	FBR
BEARS GHOST USA 31-4H	2016	1	2784	3846	0	3026	FBR

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WellName	Year	Month	BBLS_OIL	MCF_GAS	MCF_SOLD	MCF_FLARED	BIA_Lease
FORT BERTHOLD 147-94-2B-11-	2016	1	9622	13218	10110	2968	FBR
MIKKELSEN 11-14H	2016	1	22070	21918	16440	2933	FBR
SANDSTROM 151-94-2HTF	2016	1	10770	10460	7545	2915	FBR
CHARGING EAGLE 15-21-16-3H3	2016	1	3967	2993	0	2905	FBR
FOREMAN 36-35-1-2LL	2016	1	17867	43174	40012	2893	FBR
CHARLIE 24-10H	2016	1	15508	15891	11211	2866	FBR
ERNESTINE USA 11-14TFH-2B	2016	1	17558	33356	27929	2845	FBR
GOOD VOICE 34-27HB	2016	1	6036	9155	5413	2720	FBR
MAGGIE OLD DOG 19-18HW	2016	1	7352	8359	4623	2717	FBR
WOLF FEDERAL 1	2016	1	2689	2903	0	2655	FBR
BEAR DEN 24-13H2	2016	1	9066	11380	7062	2653	FBR
PARSHALL 92-28H	2016	1	2332	2960	0	2626	FBR
CHARGING EAGLE 16-21-16-1H3	2016	1	2688	2711	0	2618	FBR
MORSETTE 35-26HZ	2016	1	6518	6889	3355	2612	FBR
BIRON 20-24H	2016	1	4580	3206	0	2590	FBR
MOCCASIN CREEK 13-34-28-1H	2016	1	4029	2830	202	2555	FBR
EDWARD FLIES AWAY 7-8-9HY	2016	1	15951	12235	7795	2513	FBR
FORT BERTHOLD 152-93-17D-08-	2016	1	4558	11878	9159	2502	FBR
TWO SHIELDS BUTTE 13-22-16-	2016	1	18597	11169	8656	2454	FBR
PARSHALL 45-1004H	2016	1	4005	2944	0	2444	FBR
HAWKEYE 3-2413H	2016	1	8220	25277	22337	2437	FBR
CHARGING EAGLE 16-21-16-	2016	1	2966	2480	0	2397	FBR
BINGO 24-10TFH	2016	1	14472	15400	11285	2384	FBR
BLACKHAWK 1-12HD	2016	1	3728	3499	0	2349	FBR
DOLL USA 12-14H	2016	1	20654	28805	23645	2312	FBR
RIVERVIEW 102-32H	2016	1	19102	22936	16813	2306	FBR
GOOD VOICE 34-27HD	2016	1	12087	15194	11262	2262	FBR
STEINHAUS 24-34H	2016	1	17547	17773	13469	2241	FBR
FORT BERTHOLD 152-93-9C-10-	2016	1	5258	7715	4598	2239	FBR
FORT BERTHOLD 152-94-24D-13-	2016	1	8536	21627	19242	2238	FBR
MANDAREE 6-20H	2016	1	1110	3242	76	2232	FBR
PARSHALL 11-28H	2016	1	2342	2709	0	2209	FBR
DANKS 17-44H	2016	1	1663	2495	0	2154	FBR
FORT BERTHOLD 152-94-24D-13-	2016	1	4146	8380	6043	2148	FBR
HALVORSON 34-34TFH	2016	1	18445	19791	15492	2140	FBR
FORT BERTHOLD 148-94-33D-28-	2016	1	15608	14418	12214	2106	FBR
SALERS FEDERAL 7-27H	2016	1	28971	35238	32909	2096	FBR
KNUCKLE 149-92-19C-18H	2016	1	4183	2928	0	2088	FBR
MANDAREE 30-31H	2016	1	5323	5307	2444	2079	FBR
SALERS FEDERAL 6-27H1	2016	1	27924	35887	33881	2006	FBR
CHARGING EAGLE 9-19-18-2H3	2016	1	2556	2018	0	1985	FBR
MORSETTE 35-26HX	2016	1	5073	6142	3397	1978	FBR
BAKER 20-34H	2016	1	3488	2441	0	1971	FBR
SALERS FEDERAL 5-27H	2016	1	27376	34512	32559	1937	FBR
WOLF 2-4MLH	2016	1	8437	6620	4529	1936	FBR
ALFRED OLD DOG 30-31 HY	2016	1	3589	4529	2103	1884	FBR
HOWLING WOLF 28-33HC	2016	1	3362	2749	0	1832	FBR
STEVE 34-31H	2016	1	4958	4458	1928	1814	FBR
DANKS 20-41H	2016	1	1357	2036	0	1813	FBR
LUCY EVANS 29-32HA	2016	1	7687	11595	8594	1809	FBR
PACKINEAU USA 21-3H	2016	1	7172	6775	4020	1802	FBR
Subtotal -- 1800 to 3600 MCF/Month wells			**521046**		**455862**	**142004**	
TOTAL ALL FBR WELLS > 1800 MCF/Month			**961324**		**676994**	**487367**	
Gross Revenue ($40/b) ($1.65 mcf flared gas)			**$38,452,960.00**			**$804,155.55**	
30% curtailment/shut-in			**$11,535,888.00**				
Tribal share of flared gas (assumes 100% gas capture and 9% net revenue interest).						**$72,374.00**	
Tribal share of lost revenue on curtailed oil production:							
Tax (5% production tax)			**$576,794.40**				
Lease Royalties (9% NRI)			**$1,038,229.92**				
Total Tribal curtailed revenue loss at 1800 MCF/Month			**$1,615,024.32**	**less $72374 =**	**$1,542,650.32**		