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July 13, 2017

Ms. Karlene Fine
Executive Director
North Dakota Industrial Commission (NDIC)
600 East Boulevard Avenue, Department 405
State Capitol, 14th Floor
Bismarck, ND 58505-0840

Dear Ms. Fine:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"; Contract No. G-040-080
EERC Fund 22010

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

BPK/rlo

Enclosure

E-Mailed Report Only: Brent Brannan, NDIC Oil and Gas Research Council
Lynn Helms, NDIC Department of Mineral Resources, Oil and Gas Division
Ron Ness, North Dakota Petroleum Council

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July 13, 2017

Mr. Jeffrey Parker
Marathon Oil Company
5555 San Felipe
Houston, TX 77056

Dear Mr. Parker:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

BPK/rlo

Enclosure

E-Mailed Report Only: Faisal Rasdi, Marathon Oil Company
Erin Roehrig, Marathon Oil Company
Jake Stroupe, Marathon Oil Company
Paul Williams, Marathon Oil Company

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July 13, 2017

Mr. Gordon Pospisil
Vice President of Business Development
Liberty Resources LLC
1200 17th Street, Suite 2200
Denver, CO 80202-5854

Dear Mr. Pospisil:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

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July 13, 2017

Mr. Jason Swaren
Vice President of Operations
Oasis Petroleum
1001 Fannin, Suite 1500
Houston, TX 77002

Dear Mr. Swaren:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

BPK/rlo

Enclosure

E-Mailed Report Only: Jim Jolly, Oasis Petroleum
Jay Knaebel, Oasis Petroleum

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July 13, 2017

Ms. Stephanie Erickson
Supervisor, Reservoir Characterization/Base Reservoir Engineering
Williston Asset
Rockies Business Unit
ConocoPhillips
600 North Dairy Ashford
EC3-13-13W086
Houston, TX 77079

Dear Ms. Erickson:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

BPK/rlo

Enclosure

E-Mailed Report Only: Kyree Johansen, ConocoPhillips

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www.undeerc.org

July 13, 2017

Mr. Jeff Herman
Region Land Manager
Petro-Hunt, LLC
400 East Broadway, Suite 414
PO Box 935
Bismarck, ND 58501

Dear Mr. Herman:

Subject: Quarterly Progress Report for the Period of April 1 – June 30, 2017, Entitled "Bakken Production Optimization Program 2.0"

Enclosed please find the Energy & Environmental Research Center (EERC) Quarterly Progress Report for the subject project. If you have any questions, please contact me by phone at (701) 777-5276 or by e-mail at bkalk@undeerc.org.

Sincerely,

Brian P. Kalk
Director of Energy Systems Development

BPK/rlo

Enclosure

BAKKEN PRODUCTION OPTIMIZATION PROGRAM 2.0

QUARTERLY PROGRESS REPORT
April – June 2017

BACKGROUND

The Energy & Environmental Research Center (EERC) was awarded an extension to the existing and highly successful North Dakota Industrial Commission Oil and Gas Research Council (NDIC OGRC)-sponsored Bakken Production Optimization Program (BPOP). The purpose of this extension is to facilitate a 3-year continuation of this program to address emerging threats and issues to petroleum production in North Dakota. The extension is a continuation of the collaborative effort between the state of North Dakota and the North Dakota petroleum industry to apply North Dakota resources to provide North Dakota solutions to North Dakota challenges.

The goals of BPOP 2.0 are to:

- Employ a "system of systems" approach to enhance overall production efficiency, recognizing that improved coordination among various design factors (reservoir management, well design, surface processing, gas management, waste management) can lead to significant improvements in resource recovery efficiency.

- Conduct applied research in topic areas that positively impact the efficiency of production and reduce the environmental footprint of operations.

- Advise industry and state entities on scientific aspects of exploration and production activities, especially as they pertain to economic and environmental impacts.

- Facilitate collaboration on issues that may not otherwise receive collaborative attention from industry and/or the state of North Dakota.

The anticipated outcomes of BPOP 2.0 are 1) increased well productivity and economic output of North Dakota's oil and gas resources, 2) decreased environmental impacts of wellsite operations, and 3) reduced demand for infrastructure construction and maintenance. Specific results will include improved resource recovery efficiency, reduced land use impacts, increased royalties and tax revenue from harnessed associated gas and natural gas liquid streams, and increased revenue from added product streams captured earlier in the well life cycle.

The following quarterly report summarizes the program activities from April through June 2017.

ACCOMPLISHMENTS DURING REPORTING PERIOD

Enhanced Oil Recovery Task

- Continued rock extraction experiments to compare the quantity of crude oil and the ability to mobilize both light and heavy hydrocarbons using rich gas components vs. CO_2 in the "miscible" phase formed at reservoir conditions.

- Studies of minimum miscibility pressure (MMP) using oil samples from the Stomping Horse area were conducted. Gases that were tested included ethane, methane, and propane and mixtures of those gases.

- Evaluated compression options for rich gas injection operations. All options identified at this time require the manufacturing of customized units, which require minimum 36-week lead times and substantial capital investment.

- Liberty Resources provided the EERC with extensive data sets related to reservoir characterization, reservoir production, surface operations, and site infrastructure.

- A geologic model of the Stomping Horse area was developed.

- A proposal was submitted to the U.S. Department of Energy (DOE) for funding to support a rich gas enhanced oil recovery (EOR) pilot project that will be conducted in close collaboration with Liberty Resources. The proposal was approved for funding through the EERC's Joint Cooperative Agreement with DOE at the end of June.

- Liberty Resources–EERC meetings to collaborate on the rich gas EOR pilot:

  – May 17 in Houston at BPOP 2.0 Kickoff Meeting. Liberty provided an update on its efforts to identify compression options and discussed its plans for the rich gas EOR pilot.

  – May 21 in Denver. EERC and Liberty personnel had a working session to discuss direction and scope of the modeling efforts.

  – June 7 in Grand Forks. Discussed modeling efforts to support the planned rich gas EOR pilot. Topics of discussion included progress to date on the development of the Stomping Horse geologic model, next steps for preparation of that model for simulations, potential injection/production scenarios that will be simulated, and the time line for modeling activities.

Refracturing Optimization Task

- No activity reported during this reporting period.

Produced Fluid Characterization Task

- Coordinated with BPOP program leads to identify key information and data needs to support ongoing and planned research efforts.

- Developed partnerships with key industry partners to obtain access for fluid sample collection.

- Conducted sampling activities for both produced water and crude oil from 18 wells in the northern portion of the Williston Basin owned by Liberty Resources, Inc. This activity required EERC staff travel to the Tioga area on April 26–27.

- Initiated analytical activities, with results being used to support program objectives.

Reservoir Performance Modeling Task

- Prepared and delivered a two-part presentation at BPOP 2.0 kickoff meeting covering preliminary results of decline curve analysis for the 400 well database and multivariate analysis to identify production drivers for Bakken and Three Forks completions.

- Based on comments from the BPOP 2.0 kickoff meeting, extracted data from the NDIC Web site to estimate well spacing for each of the 400 wells at the time of their completion. Preliminary results indicate that long-term well performance is affected by well spacing and the timing of when the well was drilled in its DSU (drill spacing unit).

- Currently compiling a draft of the topical report for this task.

- EERC staff traveled to Golden, Colorado, on May 23–25, 2017, to attend an International Reservoir Technologies, Inc., informational meeting. This was in direct support to the reservoir performance modeling task.

Water Injection Reservoir Assessment Task

- Completed history-matching simulations for the 103 saltwater disposal (SWD) wells included in the Inyan Kara reservoir model.

  - Incorporated field wellhead pressure (WHP) data into the model for each of 103 SWD wells and used for comparison to the model-predicted WHP to perform the history matching. Adjustments were made to the reservoir permeability over the entire model area as well as the localized areas surrounding individual SWD wells. Of the 103 wells, 97 were successfully history-matched.

- Finalized Inyan Kara reservoir model simulation cases.

  - Planned four predictive simulation cases:

- ♦ One case will simulate continued injection of all the SWD wells in the modeled area at the last recorded injection rates until the year 2050 to test the potential injection capacity of the Inyan Kara Formation.

- ♦ Three cases will use the current operating wells (93 wells), with predictive simulations based on the current injection rate, maximum allowable injection rate, and maximum allowable injection pressure, respectively.

– Information on the maximum allowable injection rate and pressure for each well was compiled from the well files for each of the 103 SWD wells.

Facility Process Optimization Task

- Conducted process modeling simulations to evaluate the effect of treater operations and atmospheric conditions on crude oil quality. Preliminary results were summarized and shared with BPOP members, and work is ongoing to gather operational data to enable model validation.

- Hosted a meeting of select North Dakota operators in Williston, North Dakota, to discuss the various design and operational factors influencing crude oil volatility. The goal of the meeting was to discuss options and assess the need for a comprehensive process modeling and field validation effort geared toward improving Basin-wide compliance with crude oil volatility specifications. This activity required EERC staff to travel to Williston on May 9–10, 2017.

- Posted a paper summarizing EERC modeling activities assessing the impacts of process operations on tank emissions to the EERC's Web site at www.undeerc.org/Bakken/pdfs/CLM-BPOP%20Process%20ModBrief%20R4-Mar17.pdf.

Aromatic/Aliphatic Study Task

- Obtained and analyzed crude oil samples for aromatic/aliphatic content from five sets of colocated pairs of wells from Williams, Burke, and Divide Counties. In each pair, one well produced from the Three Forks and one well produced from the Middle Bakken:

  – For three of the wells, the Three Forks and Middle Bakken crude oils showed similar, but fairly high, total aromatic/aliphatic ratios (ca. 0.25 to 0.35).

  – For two of the wells, the Three Forks crude oils were also in the high 0.25 to 0.35 range, but the Middle Bakken crude oils had low ratios of only ca. 0.10.

  – These results strongly indicate that all of the Three Forks crude oils and three of the five Middle Bakken crude oils had significant contributions from adjacent shales (because of their relatively high ratios).

  – In contrast, the two Middle Bakken crude oils with low aromatic/aliphatic ratios appear to have little or no production from the adjacent shales.

- Applied the newly developed analytical method for quantitating aromatic and aliphatic hydrocarbon contents to 57 different samples (ranging from Three Forks to Lower, Middle, and Upper Bakken samples) obtained from nine wells. Final data reduction is under way, and additional core samples are in the process of being collected, extracted, and analyzed.

- Performed initial attempts to remove diesel cutting fluids from drill cuttings in order to allow the rock drill cuttings to be used for aromatic/aliphatic analyses. Mild solvent extractions as well as simple evaporation was used. Unfortunately, these approaches were not successful in removing the interferences from the diesel cutting fluids. The operator of these wells has promised a sample of the diesel cutting fluid, which will be used in an attempt to better "clean" the diesel fluid from drill cuttings and allow aromatic/aliphatic analyses to be performed.

Environmental Support Task

- EERC staff collaborated with North Dakota Petroleum Council (NDPC) members, North Dakota Department of Health (NDDH) staff, and representatives of the Northwest Landowner's Association (NWLA) as plans were formulated to promote and execute a series of educational events focused on hydrocarbon spills and hydrocarbon spills remediation.
  - The first education day event is scheduled for July 17, 2017. This first event will focus on the chemistry of produced liquid hydrocarbons, analytical methods employed to characterize produced liquid hydrocarbons, and an introduction to a risk-based approach to remediating hydrocarbon spills.
  - Subsequent education day meetings will cover:
    - ♦ Livestock and crop considerations.
    - ♦ Types of water and uses—considerations in risk-based approach.
    - ♦ A comparison of current regulations across North Dakota and other states and the science behind their employment.

Program Management and Development

- EERC staff traveled to Houston on May 16–18, 2017, to lead a BPOP 2.0 kickoff meeting. The meeting was hosted at Oasis Petroleum offices. EERC staff presented on several aspects of anticipated and ongoing BPOP 2.0 activities to attending and prospective members. The program wishes to formally and publicly thank Oasis for its willingness to host this meeting. Copies of the presentations made during this meeting have been made available on the Members-Only Web site.

- New program members received during this reporting quarter include Petro-Hunt, Hess Corporation, ConocoPhillips, and Oasis Petroleum. They join existing members: NDIC, Liberty Resources, and Marathon Oil.

- A proposal was submitted to DOE for funding to support a rich gas EOR pilot project that will be conducted in close collaboration with Liberty Resources. The proposal was approved for funding through the EERC's Joint Cooperative Agreement with DOE at the end of June.

- EERC staff traveled to Bismarck on May 20–22, 2017, to participate in the meeting between Liberty Resources and the NDIC's Oil & Gas Division regarding permitting of a rich gas injection well for EOR purposes.

- Several discussions were held with BPOP members (and potential members) to discuss the feasibility of high-value material recovery from Bakken produced water. Several members are interested specifically in the recovery of lithium, which occurs at elevated concentrations in several produced water samples analyzed by the EERC.

- A summary of BPOP oil and water decline curve analysis work was presented at the Williston Basin Petroleum Conference in Regina, Saskatchewan, on May 4, 2017.

- EERC staff traveled to Denver on June 12–15, 2017, to participate in the NDPC Executive Committee meeting.

MEMBERSHIP AND FINANCIAL INFORMATION

BPOP is sponsored by the NDIC OGRC and a consortium of Bakken producers and service companies. Table 1 presents the current budget for this program. Marathon Oil's expected in-kind contribution over the project duration is $7,280,000. The EERC is soliciting additional cash cost-share contributions from additional program members. During this reporting quarter, contributions of $100,000 each were received from Petro-Hunt, Hess Corporation, ConocoPhillips, and Oasis Petroleum.

Expenses to date by funding source are listed in Table 2.

Table 1. BPOP – Expected Budget

Sponsors	Y1	Y2	Y3	Total
NDIC Share – Cash	$2,000,000	$2,000,000	$2,000,000	**$6,000,000**
Industry Share – Cash (confirmed participation)	$400,000	$TBD*	$TBD	**$400,000**
Industry Share – In-Kind	$2,500,000	$3,500,000	$1,280,000	**$7,280,000**
Total	**$4,900,000**	**$5,500,000**	**$3,280,000**	**$13,680,000**

* To be determined.

Table 2. BPOP – Expenses to Date

	Funding Source		
	NDIC	Industry	Total
EERC	$1,240,506	$0	$1,240,506
Industry – In-Kind		$0	$0
Total	**$1,240,506**	**$0**	**$1,240,506**

FUTURE ACTIVITIES

The planned activities for the next quarter are detailed below.

Enhanced Oil Recovery Task

- Gas handling and compression strategies will continue to be evaluated with a goal of identifying cost-effective, timely solutions.

- Reservoir, facility, and gas compression modeling activities will be coordinated to ensure the development of an integrated EOR strategy.

- Reservoir modeling activities will be continued. Liberty Resources personnel will spend a minimum of 1 week in Grand Forks working directly with the EERC modeling team.

Refracturing Optimization Task

- EERC staff plans to initiate activity to determine production potential and reservoir impact of refracturing existing Bakken and Three Forks wells.

Produced Fluid Characterization Task

- Sample analysis and data interpretation from recent sampling events will continue.

- Additional sampling of crude and produced water will be initiated on new wells and continue for several months.

- Data collection and additional sampling and analysis will continue as needed to support BPOP program goals.

- Industry partnerships will continue to be developed to further understand specific needs related to Bakken production issues and practices and to expand the geographical extent of the sampling and analysis effort.

Reservoir Performance Modeling Task

- Multivariate analysis for well spacing will be updated, including separate analyses for Bakken and Three Forks wells.

- The task topical report will be completed.

Water Injection Reservoir Assessment Task

- Well information assembled during the current reporting period will be compiled and used to execute planned prediction simulation cases. Model simulations will be conducted, and the results will be used to estimate the effects of long-term SWD on the Inyan Kara formation pressure and resulting impacts on individual SWD well injectivity.

Facility Process Optimization Task

- Facility modeling activities will be performed to assess different strategies and their impact on crude oil quality. Pending participation from BPOP members, computer models for multiple strategies may be developed and preparations made for field trials during the winter of 2017/18.

Aromatic/Aliphatic Study Task

- The EERC will continue collecting and analyzing additional rock samples from a broader geographic distribution of the Bakken Formation. A special emphasis will be to obtain and analyze rock core samples from the Three Forks, Middle Bakken and Upper and Lower Shales collected near the paired Three Forks and Middle Bakken crude oil wells discussed above. Hopefully, these studies will provide validation for using aromatic/aliphatic ratios to determine the source(s) of produced crude oils.

- The operator who agreed to collect crude oil samples for aromatic/aliphatic ratio analyses from the beginning of crude oil production into the decline curve expects to be online in late July or early August. These samples will be used in an attempt to determine the relative contribution of the Upper and Lower Shales to crude production over the life of the well.

- The diesel cutting fluid expected to be provided by the operator who supplied the drill cuttings will be analyzed for the individual aromatic and aliphatic hydrocarbons in detail to see if there are differences from the native rock hydrocarbon compositions that can be exploited to allow diesel-based drill cuttings to be used for aromatic/aliphatic analyses.

Environmental Support Task

- EERC staff will lead several produced liquid hydrocarbon remediation education day events in cooperation with the Department of Mineral Resources, NDDH, and NWLA representatives. The first is scheduled for July 17, 2017.

Program Management and Development

- The EERC will continue to solicit additional industry membership in the BPOP consortium during the coming quarter.

- EERC staff will present a BPOP 2.0 update to OGRC in Bismarck on August 10, 2017.

APPENDIX A

WILLISTON BASIN PETROLEUM CONFERENCE PRESENTATION – TRENDS IN BAKKEN WATER AND OIL PRODUCTION

Energy & Environmental Research Center

TRENDS IN BAKKEN WATER AND OIL PRODUCTION

Bethany Kurz, Christopher Martin, Chantsalmaa Dalkhaa, Lawrence Pekot and Nicholas Azzolina

Williston Basin Petroleum Conference

Regina, Saskatchewan

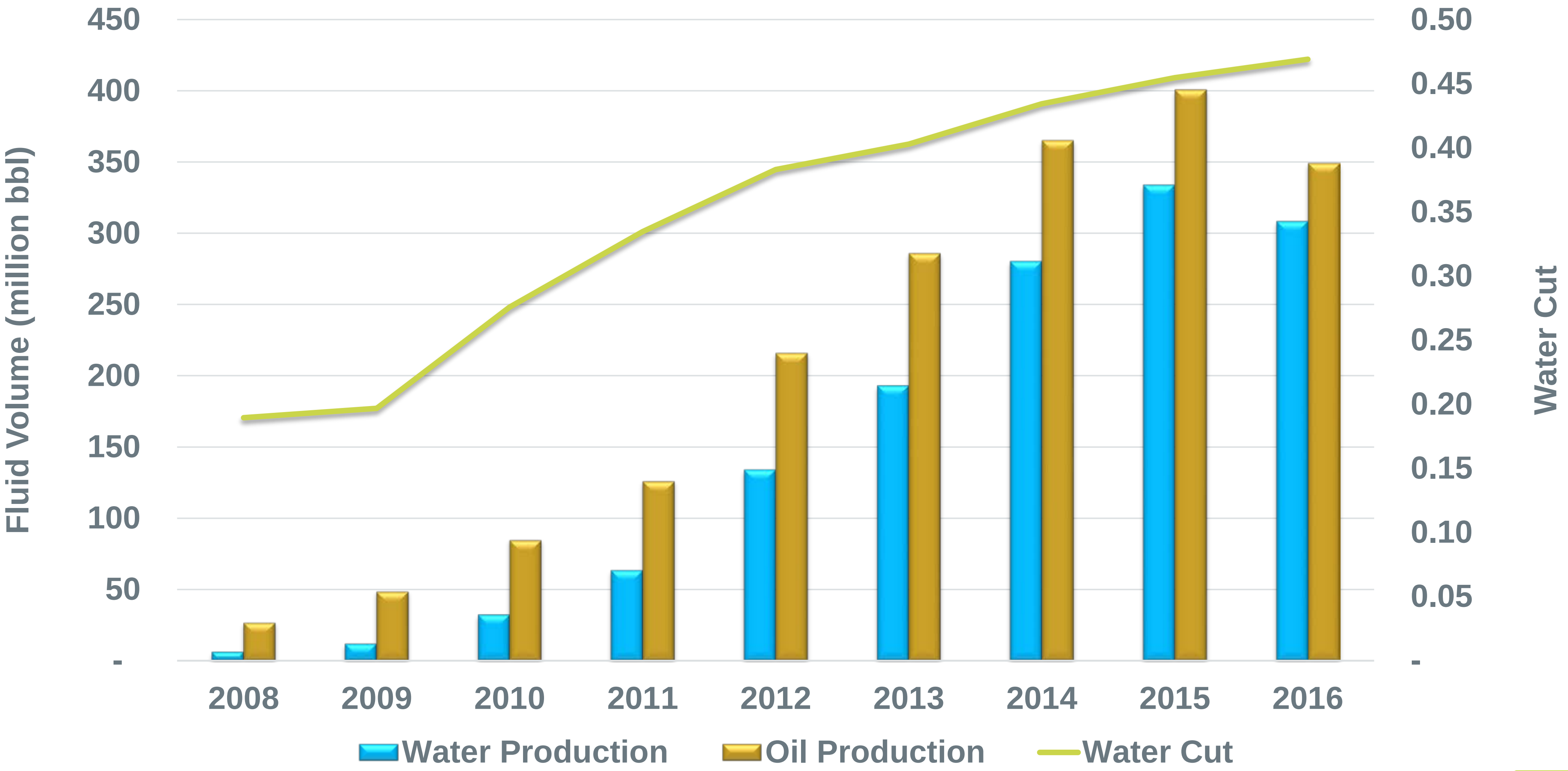
May 2–4, 2017

Critical Challenges. **Practical Solutions.**

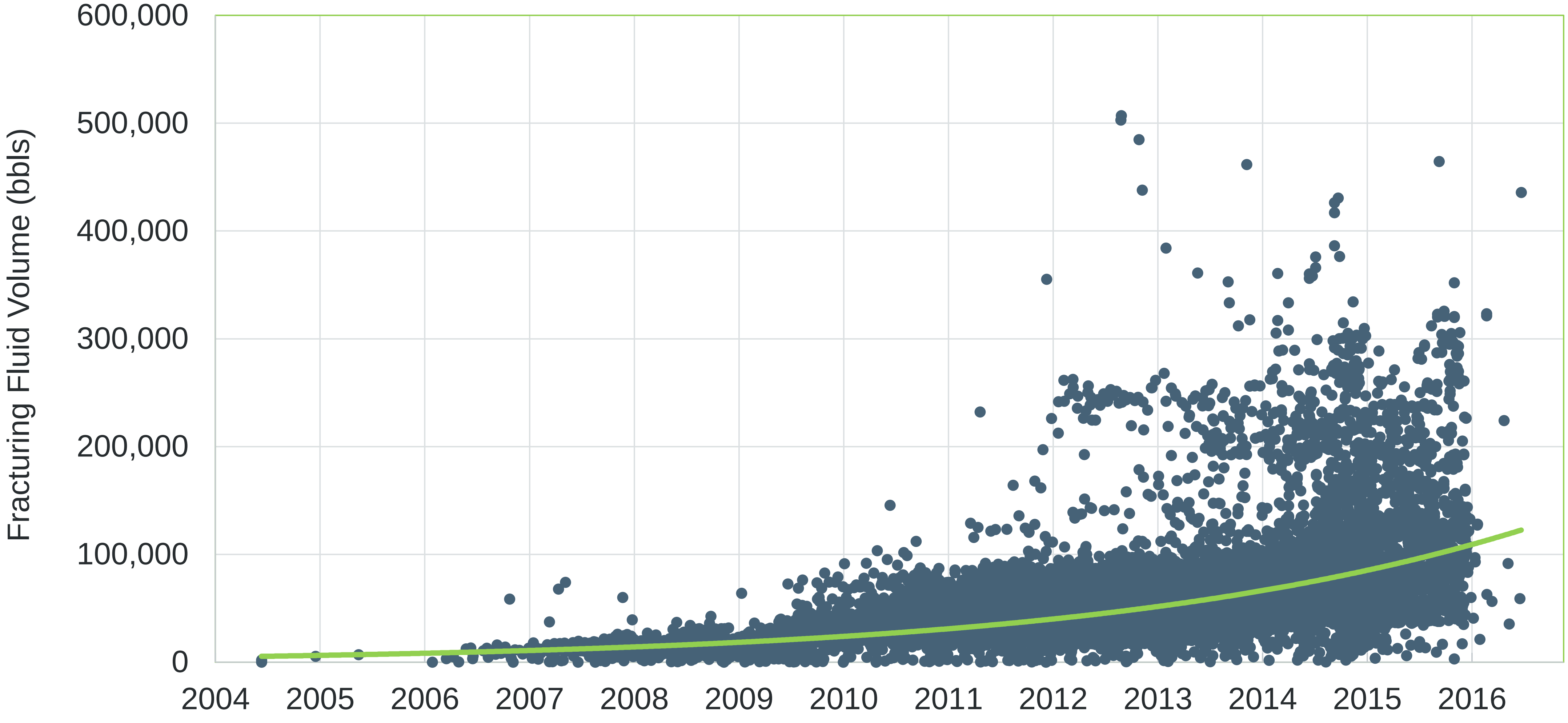
Changes in Bakken Well Completion Practices Over the Past Decade

- Increased lateral lengths and number of stages per well:
  - Single-stage fracturing → multiple-stage fracturing
- Increased fracturing fluid and proppant volumes
- Hydraulic fracturing fluid formulations
  - Linear gels
  - Cross-linked gels
  - Slickwater

North Dakota Bakken Water and Oil Production

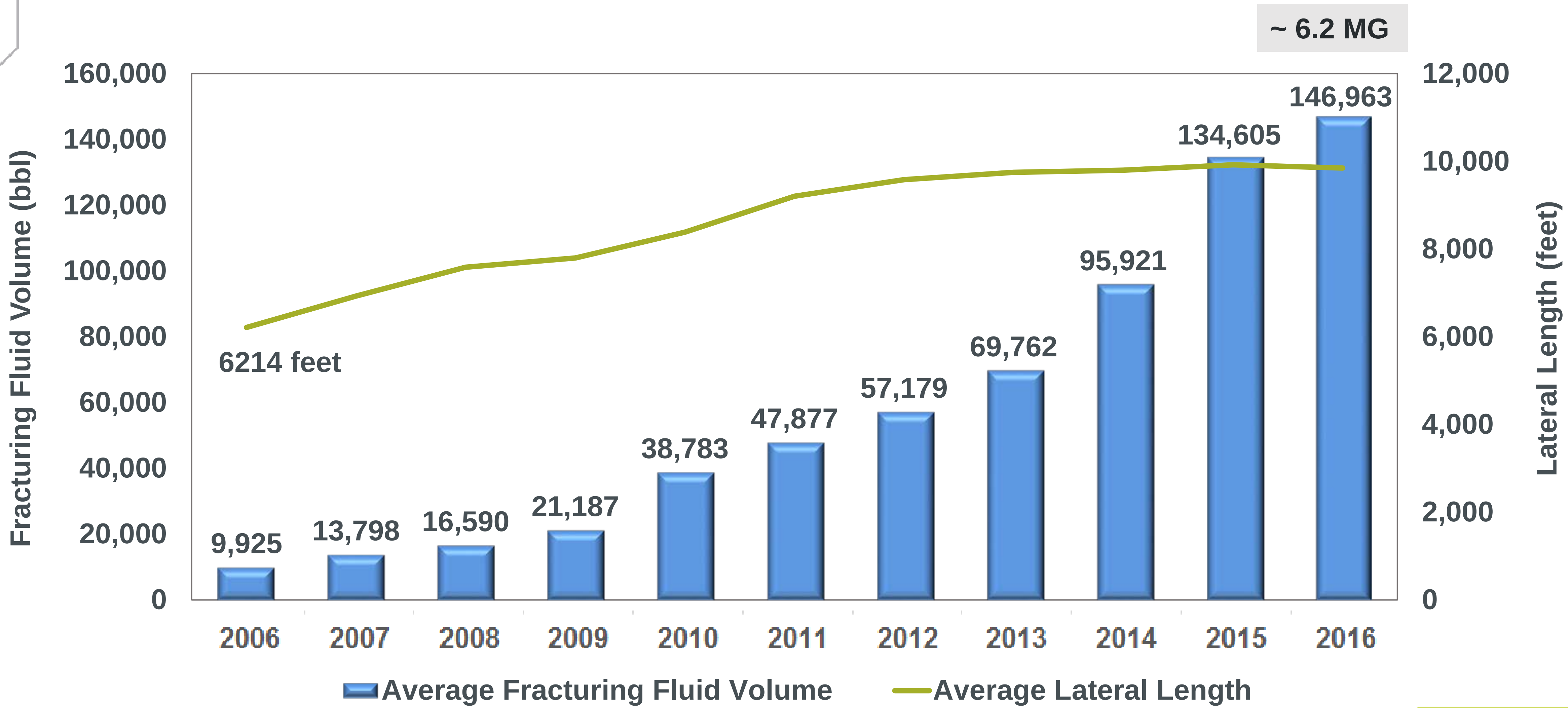


Fracturing Fluid Volumes Used for Individual Wells



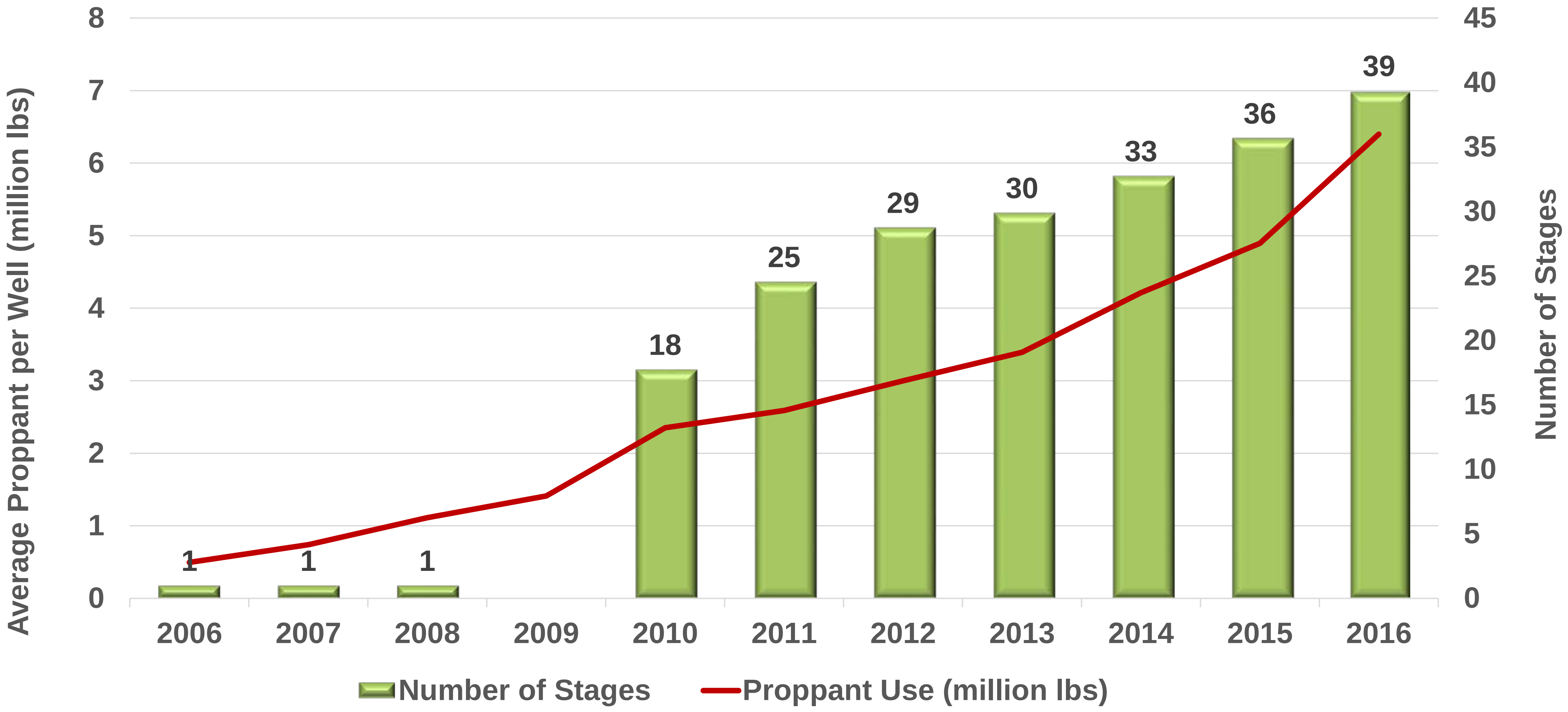
Data Source: NDIC Department of Mineral Resources

Trends in Lateral Length and Fracturing Fluid Volumes



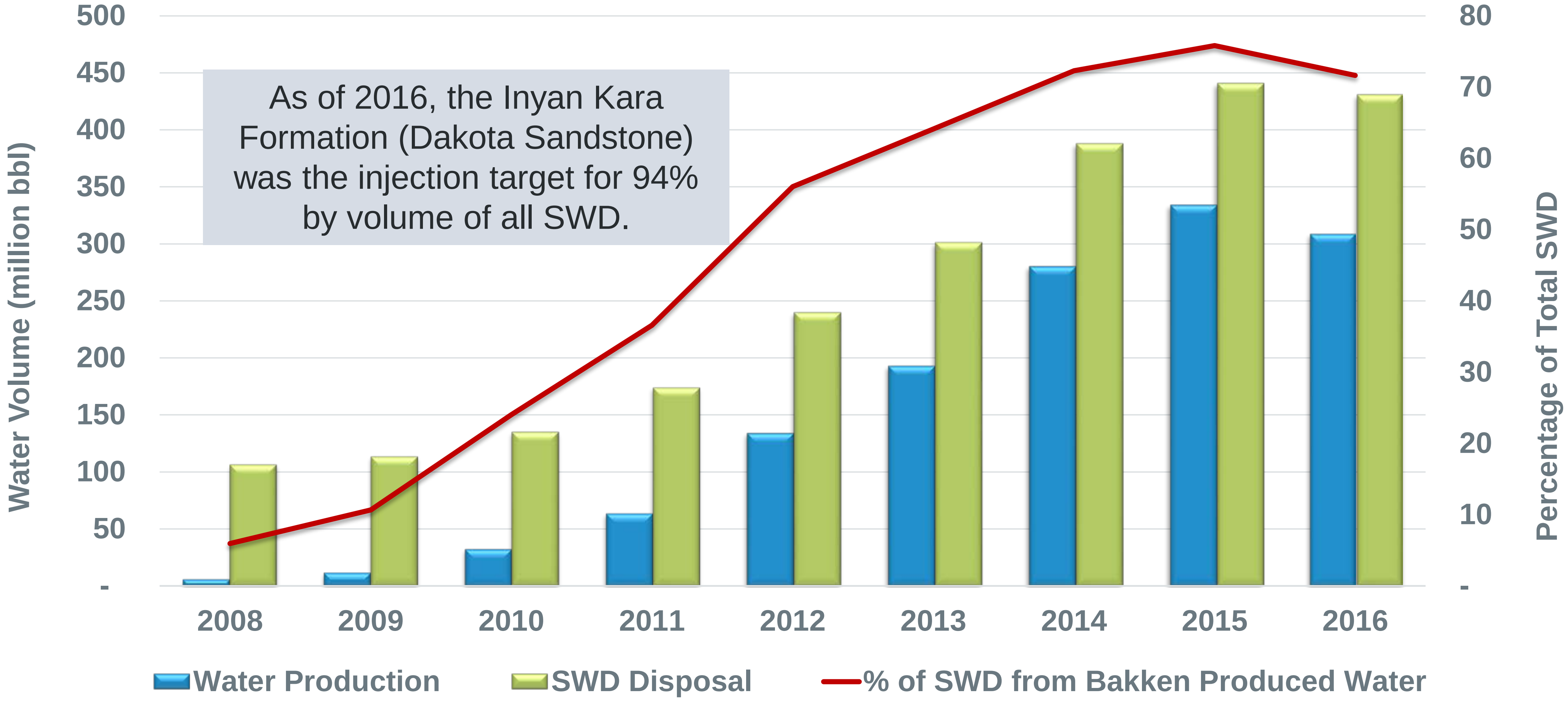
Data Source: NDIC DMR

Trends in Proppant Use and Fracturing Stages



Data Source: NDIC DMR

Bakken Water Production and SWD Volumes in North Dakota



Data Source: ND Office of the State Engineer

Preliminary Decline Curve Analysis (DCA)

- A very preliminary DCA study was conducted to get a feel for some of the many factors that influence oil and water production.
- Key questions:
  - How does well completion technique affect oil and water production, in both the short-term and long-term?
  - How does fluid production change based on well vintage?
  - How does fluid production change based on the spatial location of the well and operator?

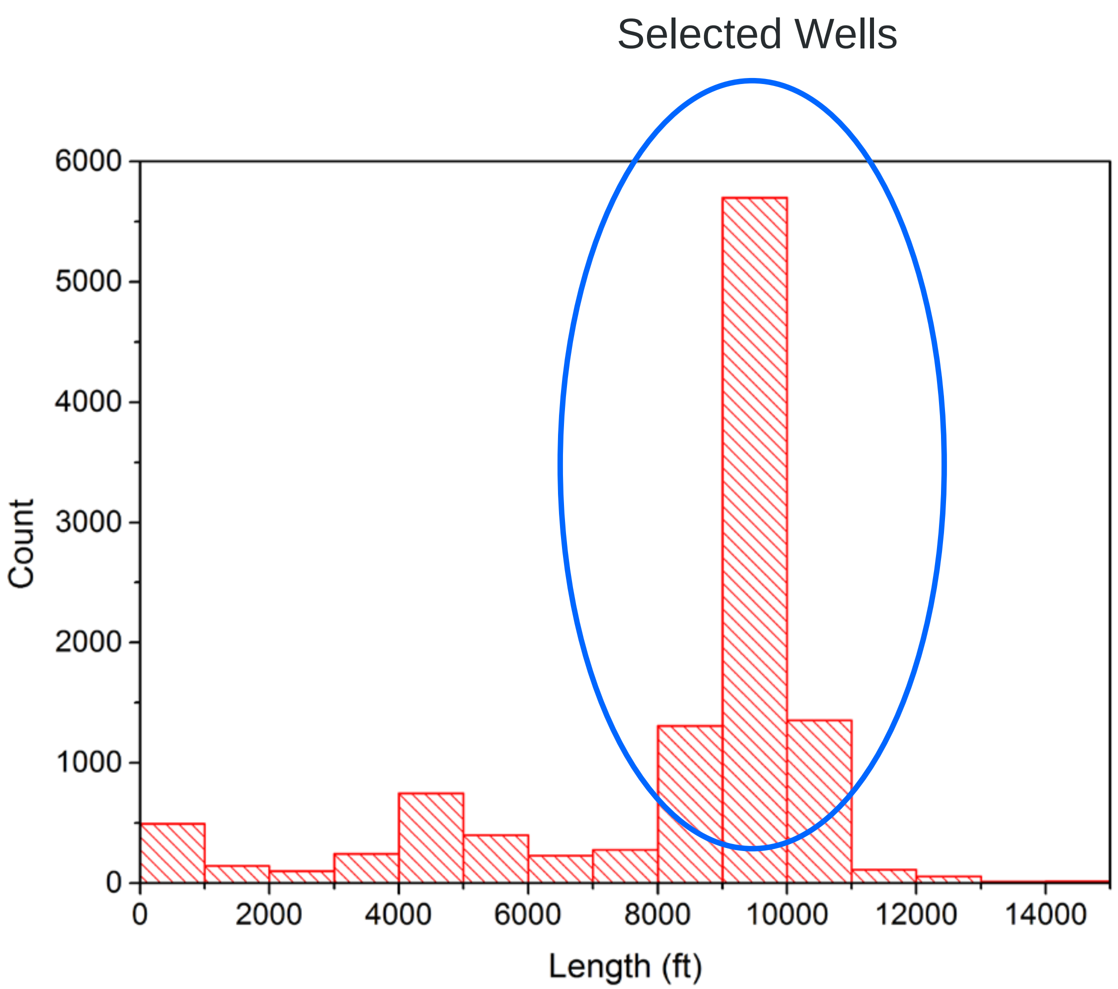
Approach

- Data sets
  - North Dakota Industrial Commission (NDIC) monthly production totals for Bakken/Three Forks wells producing during 2006 to 2016
  - NDIC well stimulation database
- Used DCA software package to automatically fit curves to the production data to estimate fluid production for the first year of production and estimated ultimate recovery (EUR).
  - Assumed well lifetime ended once oil production was less than 5 bbl/day.
  - The oil EUR values determined by the software-generated decline curves were compared to those determined using manually generated decline curves on a subset of 200 wells.
- Year 1 fluid production and EUR values for water and oil were then compared to wells with different completion techniques, well vintage, and a few different field locations.

Data Selection

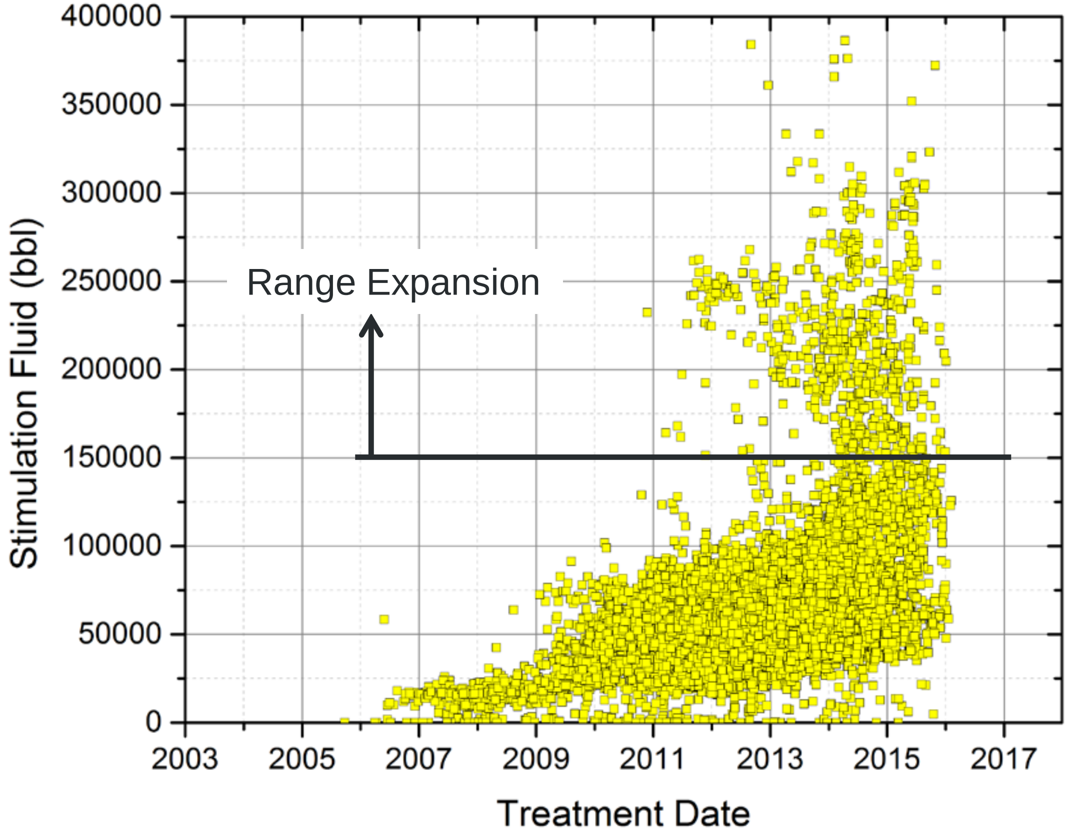
- Selection Criteria:
  - Horizontal wells
  - Bakken and Three Forks Formations
  - Completed January 2006 to July 2016
  - Lateral length between 8000 and 11,000 ft

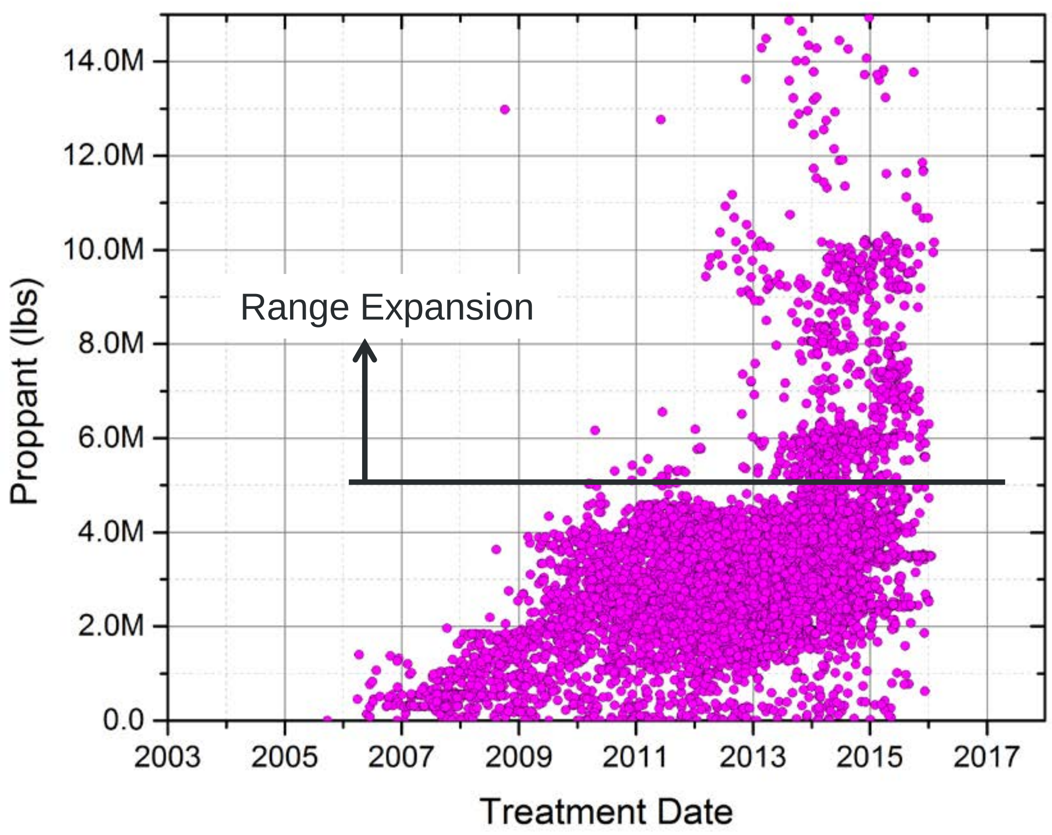
Selection represents 8360 wells, which is 80% of the Bakken/Three Forks wells in the NDIC well index that were active from 2006 to 2016.



Histogram of well length for Bakken/Three Forks wells stimulated 2006–2016.

Stimulation History

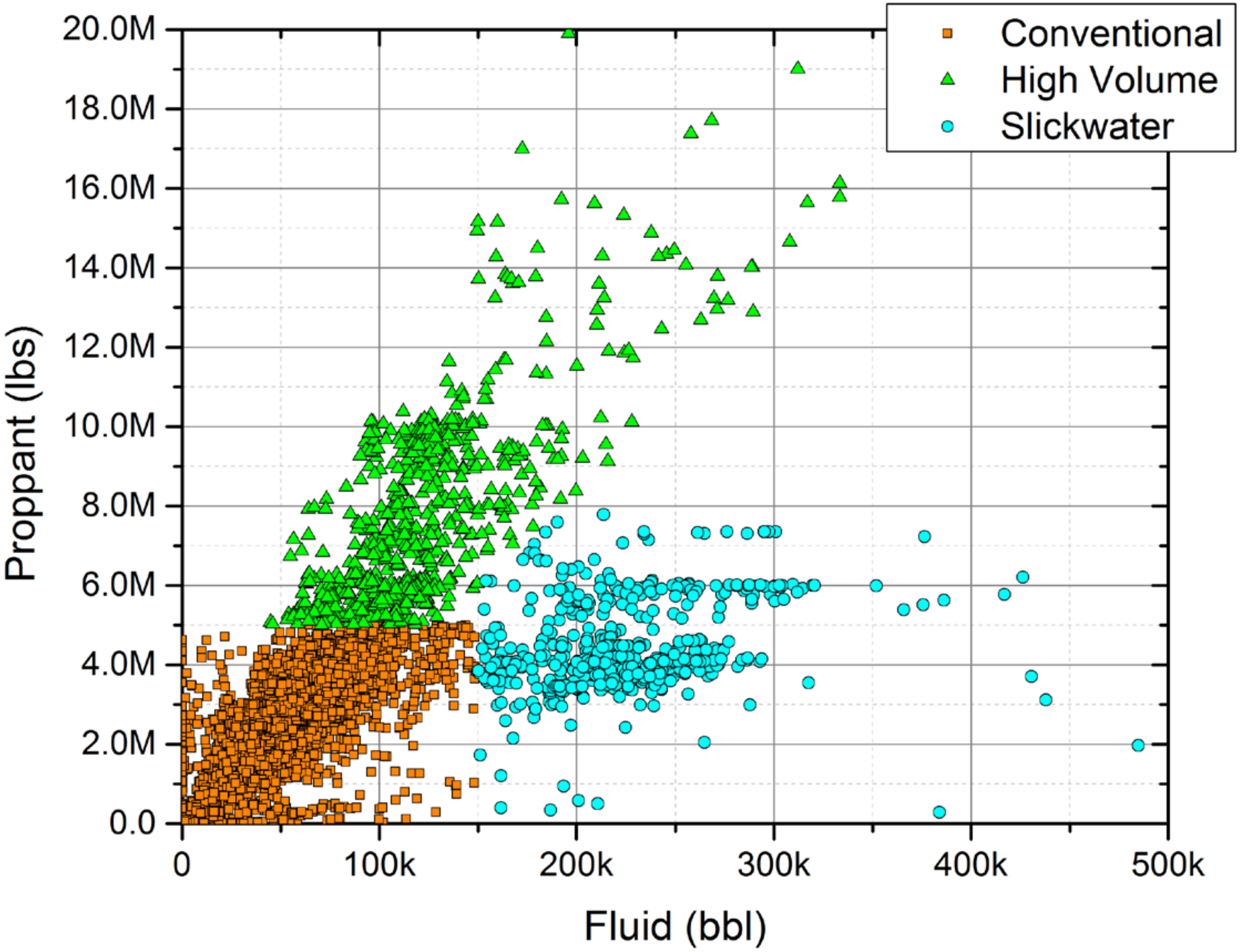




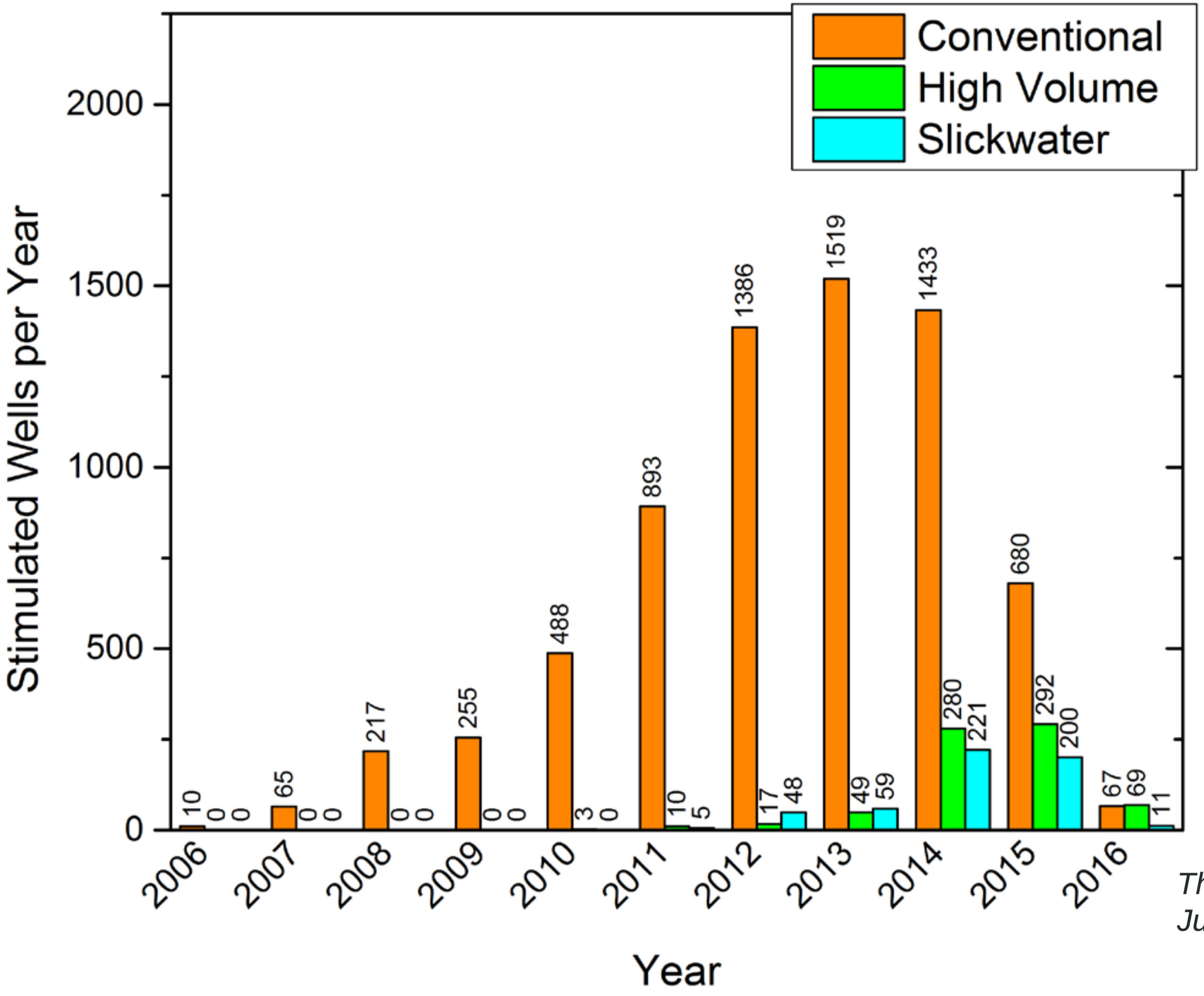
Stimulation Subcategories

Three stimulation subcategories were identified:

- **Conventional**: proppant less than 5M lb; fluid less than 150k bbl.
- **High Volume**: greater than 5M lb proppant; loading between 40 and 140 lb/bbl fluid.
- **Slickwater**: greater than 150k bbl fluid; less than 8M lb proppant; and loading less than 40 lb/bbl.

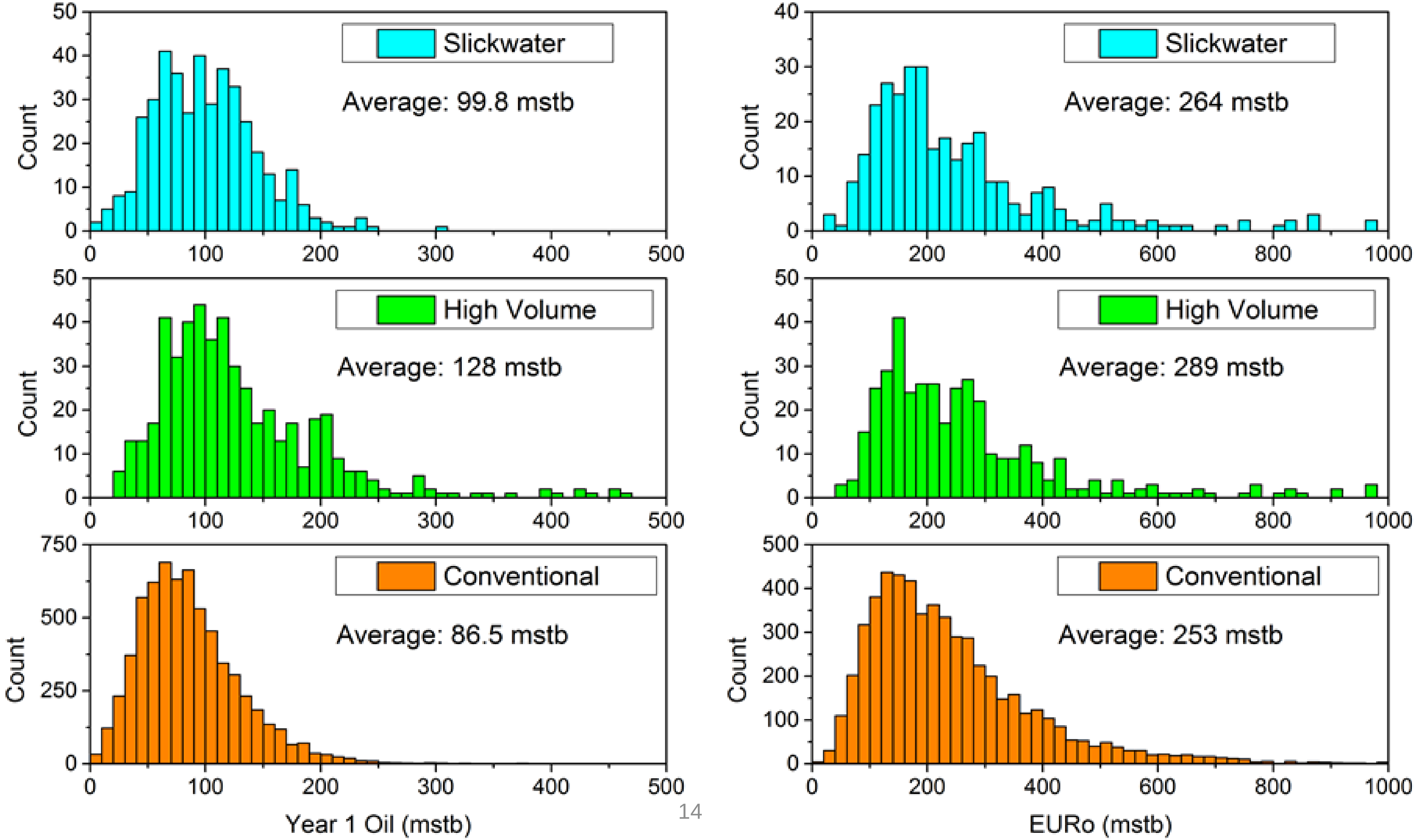


Temporal Distribution of Well Stimulation Subgroups

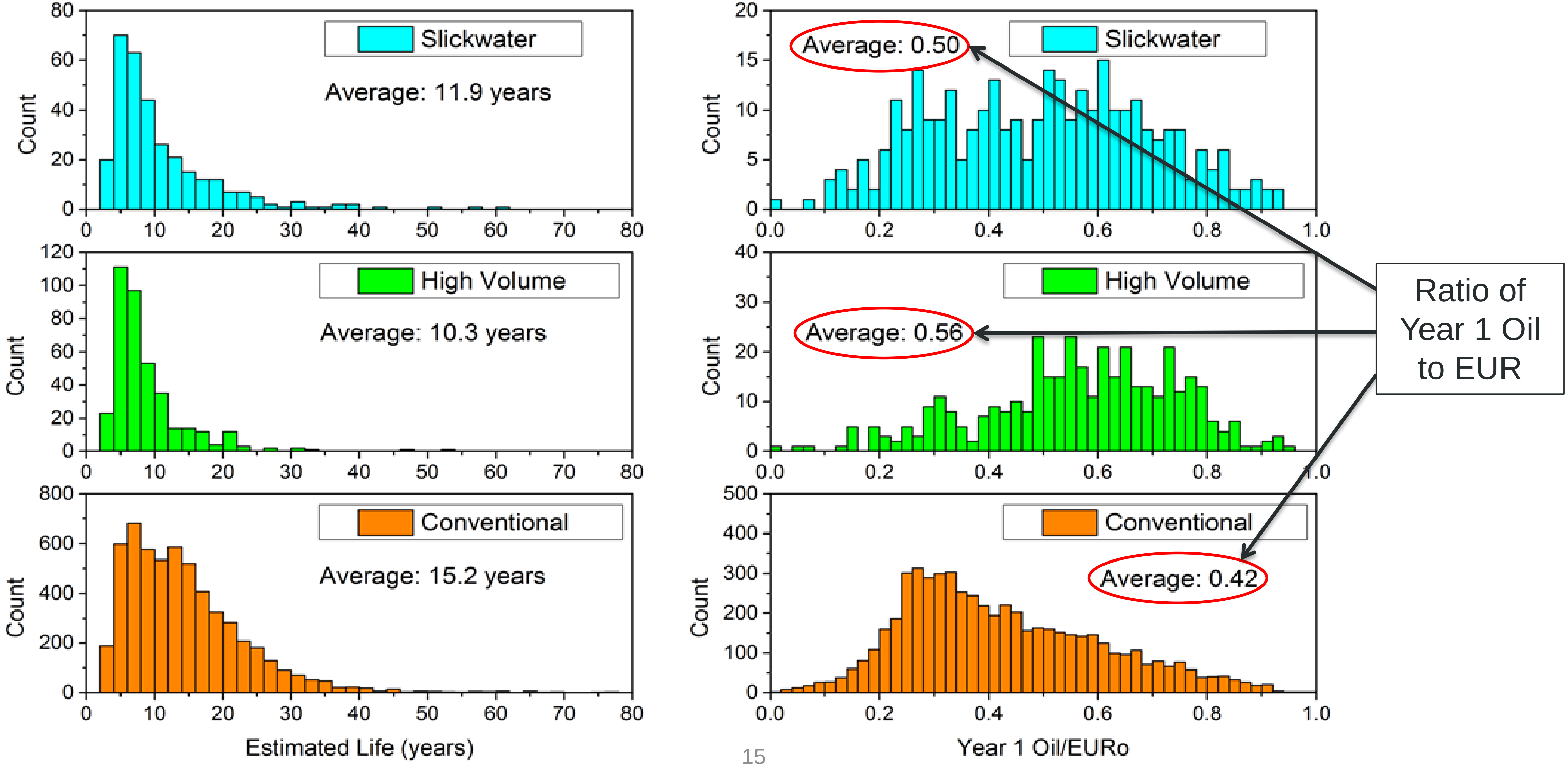


Through July 2016.

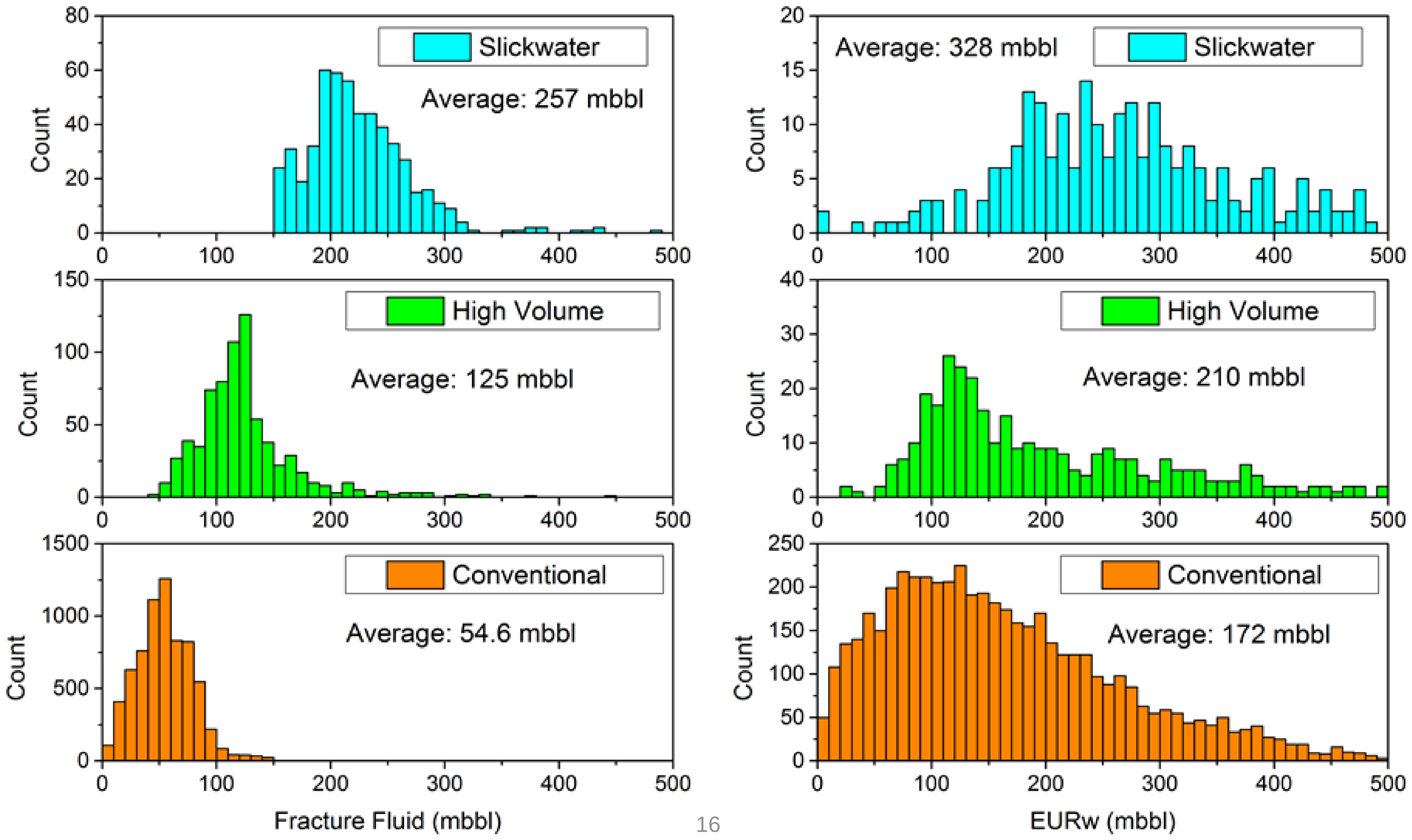
Year 1 Oil Production and EUR



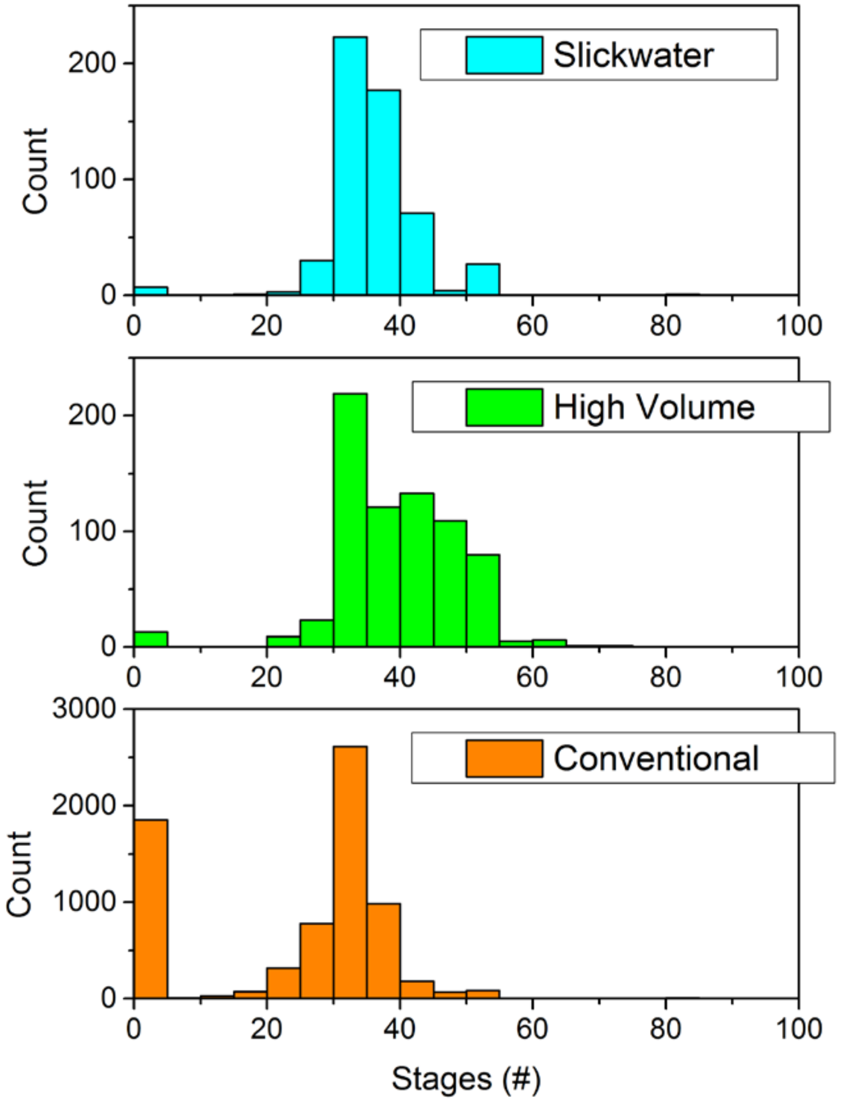
Estimated Economic Well Life

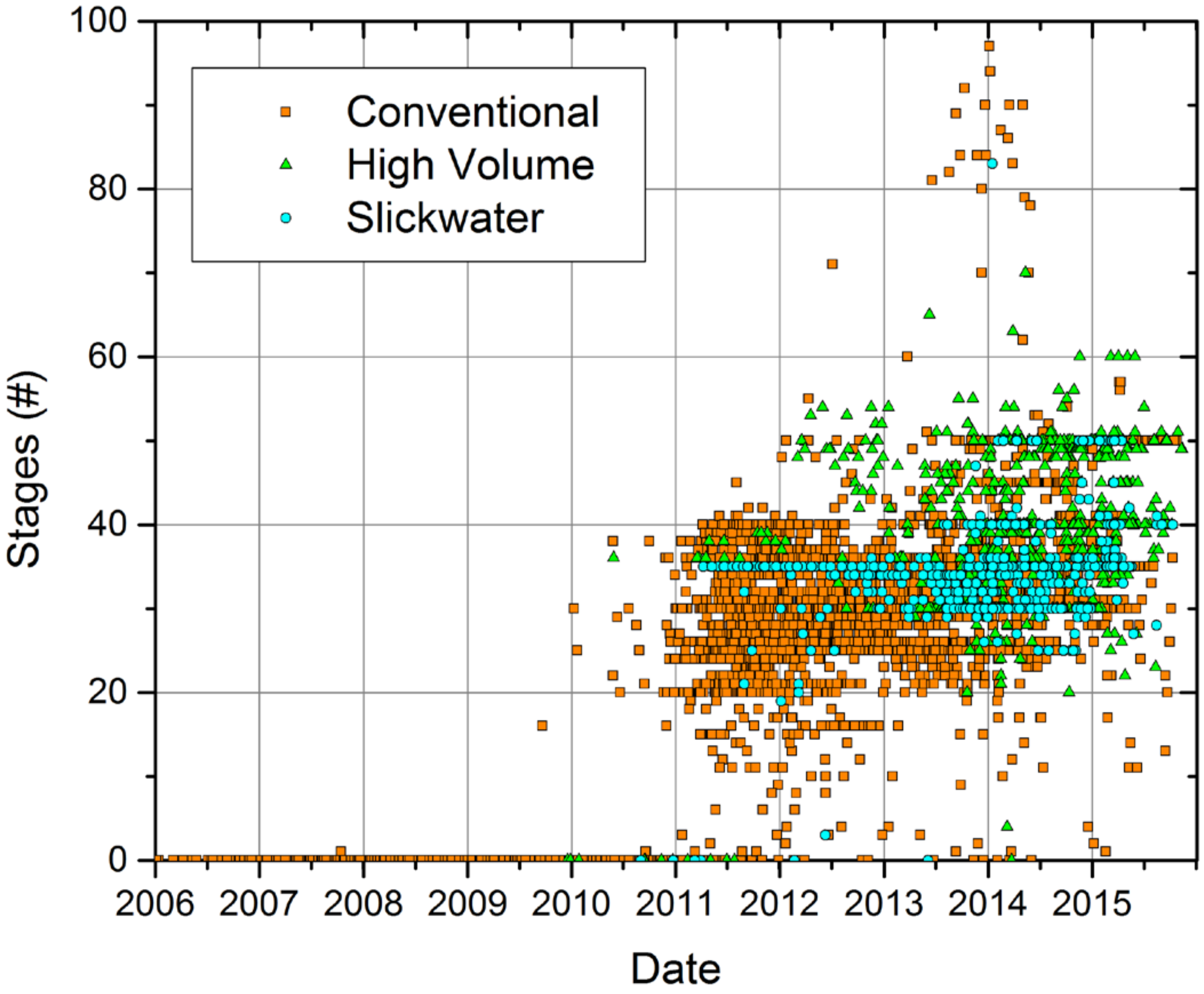


Year 1 Water Production and EURw



Stage Trends





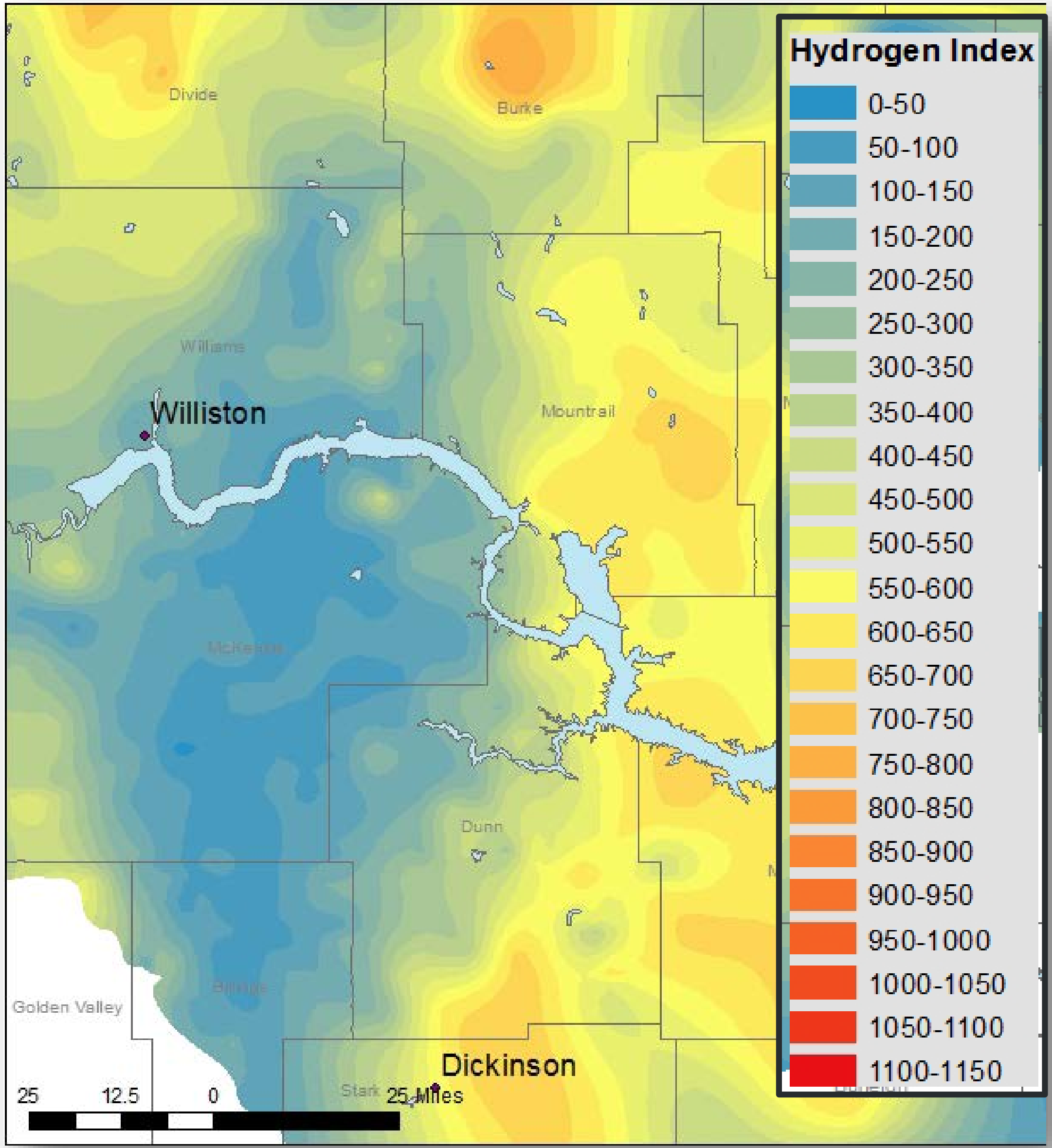
Expanded DCA

- Ongoing work (sorry – no results yet).
- Multivariate statistical approach to determine the performance drivers for production across the Bakken Formation.
- Traditional DCA using Arps' equation to manually fit curves to production data on an individual well basis.
- Data collection and population:
  - Well count: 400 wells from 9 counties producing in Bakken Formation
  - Data sources: NDIC, FracFocus, and North Dakota Geological Survey
  - Well orientation: Horizontal
  - Production period: Minimum of 18 months
  - Production data: IP, 6, 12, 24 month and EUR obtained from DCA

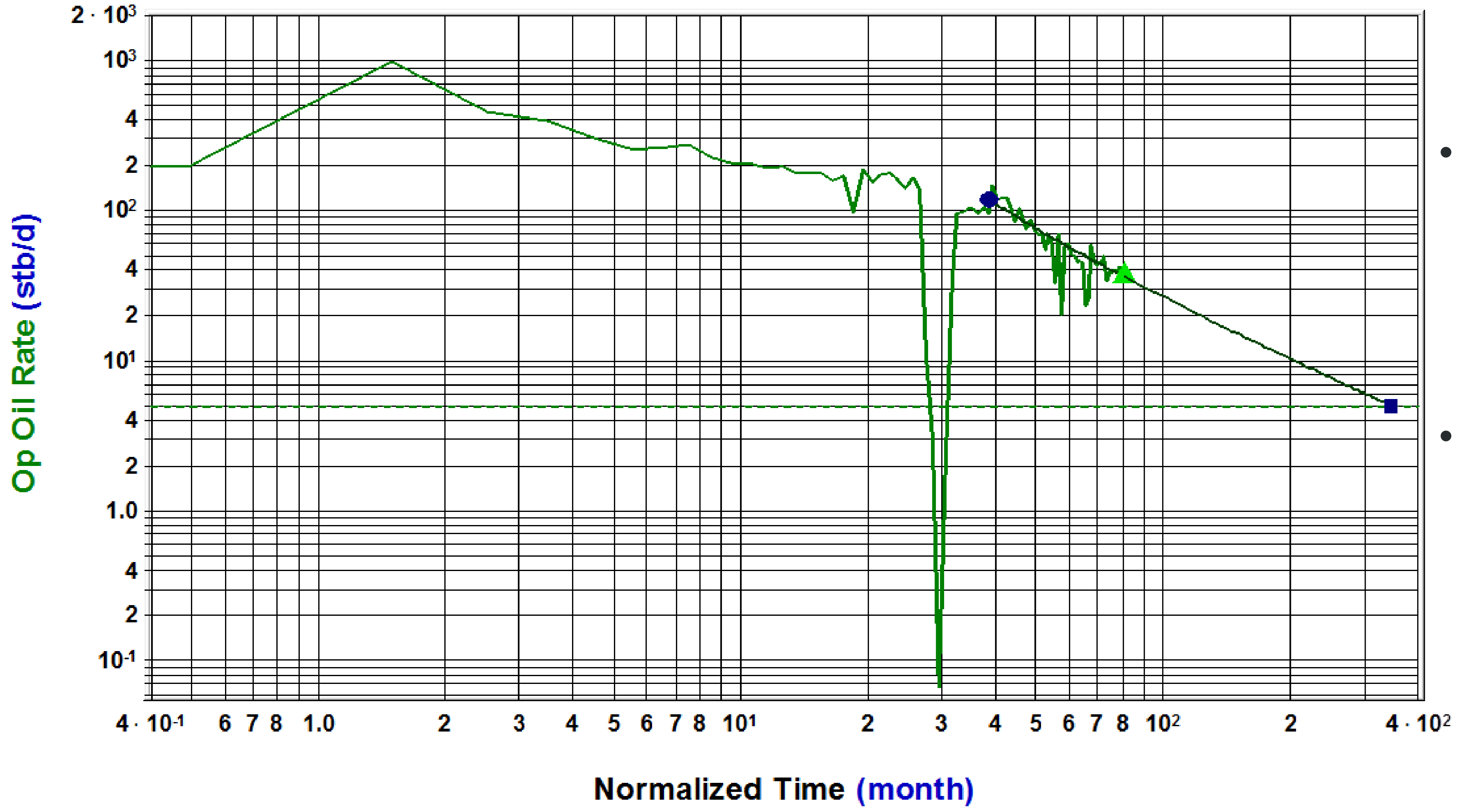
Parameters of Interest

Approximately 30 geologic and technological parameters:

- **Geologic**: structural features (Nesson, Antelope, Billings Nose, Heart River Fault, Pronghorn), overpressured, thickness, temperature, and organic geochemical parameters (HI, TOC and Tmax), etc…
- **Technological**: fracturing fluid volume, proppant amount and size, stage number, lateral length, operator, stimulation fluid (slickwater, cross-linked or linear) and completion type (plug and perf, sliding sleeve or hybrid), etc…



Decline Curve Fitting



- Decline part of production data was captured through DCA, and the ultimate recovery was estimated.
- As an example, this figure shows the fitted oil production data of a well. The ultimate recovery (EUR) is estimated at ~395M stb of oil.

Stay Tuned!

The multivariate statistical analysis work is ongoing. Results to come soon!

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APPENDIX B

PROCESS MODELING OF WELLSITE PRODUCTION OPERATIONS

PROCESS MODELING OF WELLSITE PRODUCTION OPERATIONS
March 2017

ABSTRACT

Process modeling was conducted for wellsite production operations typical of those found in North Dakota's Bakken petroleum system. The objectives of this analysis by the Energy & Environmental Research Center were to study the relative potential for various site operating parameters, particularly treater oil transfer, to cause the unintended release of storage tank vapors. The analysis considered representative oil characteristics, storage tank fill scenarios, and key vapor collection system design parameters. For the range of conditions that were considered, the modeling suggested that dynamic dumps of oil from the treater to the tank battery were unlikely to cause significant tank pressure surges relative to the steady pressure from continuous oil flow at the equivalent average throughput rate. This conclusion implies that the root cause of fugitive emissions is likely due to other factors that could include inadequate system design, equipment malfunction, or flow restrictions within the vapor piping. The model does provide support for condensate formation as a mechanism to restrict vapor flow since the results show that appreciable condensate can form in the vapor piping during cool weather. If these lines are not designed or maintained to drain condensate liquids, then they could likely result in flow restrictions and lead to persistent fugitive emissions.

MODEL DESCRIPTION

A hypothetical multiwell production site was modeled using a petrochemical process simulator, VMGSim V10.0. The site's parameters were not selected to represent any actual installation but rather to be illustrative of a wide range of conditions typical of the Bakken. The process diagram from the simulator is shown in Figure 1 and begins with a feed stream of raw crude labeled "Bakken Generic." The subsequent treater battery represents the 3-phase separation process that partitions streams of oil, gas, and water. On-site, this operation would be handled by multiple parallel treaters, each with its own dump valve for fluid transfer to the storage tanks. However, only a single treater and dump valve were used for modeling in order to generate the worst-case scenario where all the treaters were synchronized to dump oil to the tanks simultaneously. Detailed component modeling began after the treater by including the following: pipe segments that accounted for energy loss between the treater and storage tanks; separate oil storage among individual tanks to approximate actual oil residence time and heat loss; and a common flare pipe train from the tank battery to determine flow resistance.

Specific modeling assumptions included the following:

- A total oil production rate of 3000 bbl/day was assumed for the multiwell site. This was judged to be representative of a 6–8-well pad shortly after the initial production phase when the site's tank vapor control system would likely be taxed the most.

- The modeled oil composition was derived by combining typical compositions of produced oil, associated gas and brine streams to reproduce a whole raw crude composition labeled “Bakken Generic” in Figure 1. The average produced oil composition was determined from a fit of averaged wellsite oil properties reported in 2014 (Turner, Mason and Company, 2014) while a typical composition and quantity of associated gas was retrieved from a previous investigation into flare gas utilization (Energy & Environmental Research Center, 2012). The molar composition of the Bakken Generic composite is shown in Figure 2.

- To account for pressure and heat loss between the treater and individual tanks, parallel runs of exposed connection piping were included in the model. These runs were approximately 275 ft long, 3-inch NPT (National Pipe Thread) pipe size, aboveground with no insulation, and included allowances for fittings, valves, and elevation change.

- The oil tank battery had a nominal capacity equivalent to 1.5 times the daily produced oil throughput or 4500 bbl. This total volume was divided among the six tanks shown in Figure 1 resulting in individual tank sizes of 750 bbl. These modeled tanks are larger than the more typical 500-bbl size and may be refined in future modeling efforts. Vapor headspace in the tank battery was specified by limiting the liquid fill level to 50% capacity or 10 ft of tank liquid level. Each tank was also assumed to be uninsulated and exposed to air in order to estimate heat losses.

- Venting of vapors into and out of the tank battery was modeled using three separate valves to represent the combined action of a pressure and vacuum relief valve and an emergency pressure relief hatch. The set points were specified as follows: the pressure relief to the flare piping opened at 1 osig while the emergency relief opened at 8 osig, and the vacuum relief allowed air to enter the tanks at a negative pressure differential of −0.5 osig (vacuum relief was only needed during tank drawdown and was not a factor in this modeling).

- To account for pressure and heat loss, approximately 480 ft of exposed vapor piping connected the tank battery and the low-pressure flares, which included allowances for fittings, relief valve, flame arrestor, and elevation change. The nominal NPT pipe size for this run was 6 inches, except for cases where the effect of pipe diameter was specifically investigated.

- The flaring system consisted of two low-pressure flares in parallel that operated with air assist.

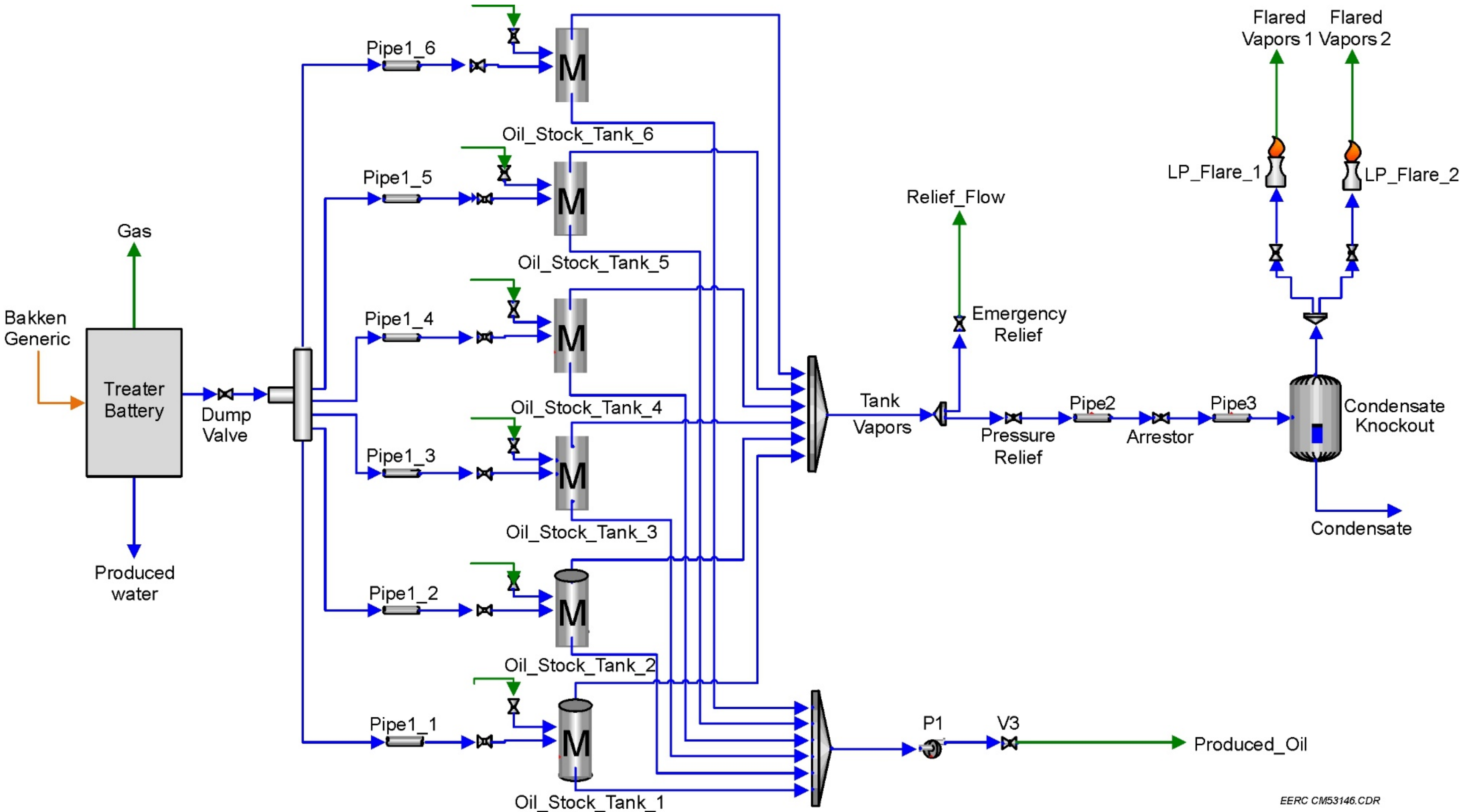

Figure 1. Process diagram for the wellsite modeling.

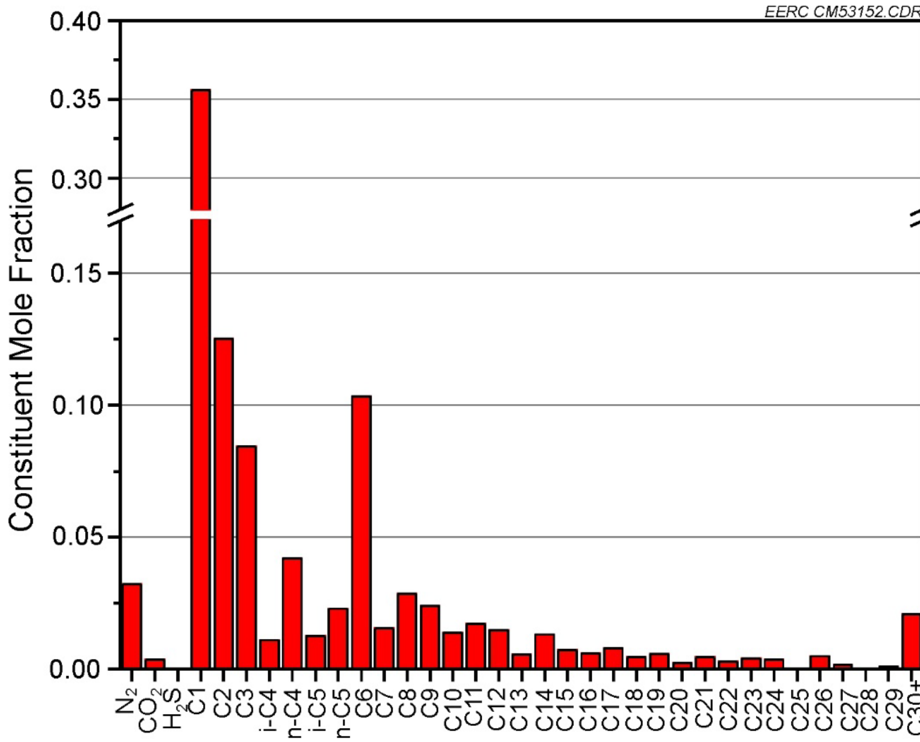

Figure 2. Molar composition of the modeled "Bakken Generic" crude composition.

RESULTS

Tank Vapor Generation

Vapor generation from hydrocarbon storage tanks can be categorized into one of three categories: standing losses, working losses, or vapor flash from throttling the liquid to tank pressure. For the Bakken-relevant conditions that were modeled, flash vapor generation was the dominant source of tank vapors and represented more than 90% of the total. Based on the role that flash vapor generation has, part of the guidance offered to Bakken operators to reduce the risk of fugitive emissions has been to reduce the quantity of flash vapor generation (U.S. Environmental Protection Agency, 2015).

The relative magnitude of tank vapor generation to the associated gas rate from the treater is summarized in Table 1. According to those results, roughly 1.30 mscf of associated gas is produced for each bbl of oil sent to the tank battery. This ratio was, of course, largely determined by the composition of the Bakken Generic stream but is indicative of actual production as noted in a previous study (Energy & Environmental Research Center, 2012). Meanwhile, the equivalent gas to oil ratio (GOR) for the storage tanks was significantly reduced at 46.1 scf/bbl. This reduction in oil volatile content is also reflected in the molecular weight and bubble point values in Table 1. The difference in standard liquid density in Table 1 is largely due to the water cut that is part of the treater inlet stream.

Table 1. Summary Separation Data at Conditions of 40-psig Treater Pressure and 40°F Ambient Temperature

	Treater	Storage Tanks
Entering Crude Properties		
Molecular Weight	65.7	160
Bubble Point, psia	2000	105
Standard Liquid Density, lb/ft^3	59.8	47.5
Vessel GOR, scf/bbl	1300	46.1

Modeled trends of flash tank vapor generation and produced oil vapor pressure are shown in the contour maps of Figure 3 with respect to ambient temperature and treater pressure. Ambient temperature was selected as a key parameter rather than the indicated treater operating temperature to better compare with data from a previous study of Bakken oil properties that showed little correlation of oil vapor pressure to the indicated temperature (Turner, Mason and Company, 2014). However, that report did present data that suggested a correlation between oil vapor pressure and ambient temperature, presumably because ambient temperature influences heat loss, which reduces the energy available to drive flash vapor production in the storage tanks. For this modeling, the treater operating temperature was assumed to remain constant and its performance was calibrated using the 110°–120°F (treater indicated temperature) wellsite data points from the study of Bakken crude properties (Turner, Mason and Company, 2014).

The trends highlighted in Figure 3 show that increased treater pressures resulted in the highest values of tank GOR and the vapor pressure of crude oil at a 4:1 volume ratio (VPCR4) because of the fact that fewer of the dissolved volatiles were released under high pressure. However, the subsequent trends with ambient temperature were opposite in effect. For instance, higher ambient temperatures resulted in less heat loss from the oil as it was sent to storage and this conserved energy helped drive flash vapor generation in the storage tanks. The net result was an increased GOR but decreased VPCR4. On the other hand, lower ambient temperatures led to increased heat loss from the oil that depleted some of the energy available for flash vapor generation. As a result, fewer volatiles were released (lower GOR) and instead remained in solution (higher VPCR4).

To put Figure 3's tank GOR values in context, a 2010 study of Bakken storage tank vapor generation rates determined an average rate of 55.26 scf/bbl for all sites in the survey (North Dakota Department of Health, 2011), which included flash and standing and working losses. However, for emission estimation purposes, the 90th percentile value from that study, 97.91 scf/bbl, was selected as the mandatory default Bakken pool emission factor. Likewise, VPCR4 values can be placed into reference by North Dakota's oil-conditioning rule (North Dakota Industrial Commission, 2014) which limits the vapor pressure of produced oil to be 13.7 psia or less. The rule also sets limits on treater operating pressure to be 50 psig or below and temperature to be 110°F or above in order to avoid the need for routine vapor pressure measurements. According to the VPCR4 trends in Figure 3, limiting separator operation to 50 psig greatly reduces but may not entirely eliminate the potential for high vapor pressure values.

The sensitivity of GOR and VPCR4 to ambient temperature shown in Figure 3 is dependent on the specific modeling assumptions about exposed surfaces and other thermal boundary conditions. Sites with insulated equipment and/or less exposed surface area would be expected to have a reduced ambient temperature sensitivity compared to the estimates in Figure 3, and vice versa for sites with even more exposure.

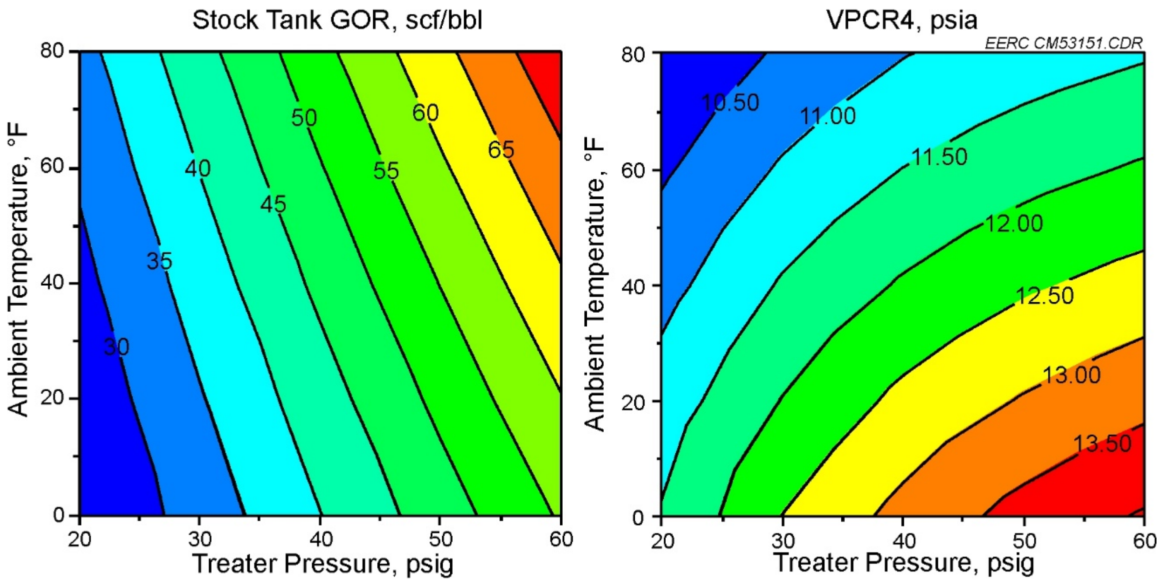

Figure 3. Modeling results for tank vapor emission factor and the produced oil's vapor pressure.

Dynamic Tank Pressure Simulation

Dynamic modeling of the treater dump/stock tank-filling process was used to estimate peak storage tank pressures for a variety of oil transfer scenarios. Figures 4 and 5 illustrate examples of tank filling that span continuous, steady oil transfer (Figure 4) to discrete treater dump cycle intervals (Figure 5). Continuous filling can be approximated in practice by mechanical valves that use a weighted regulator or other feedback mechanism to smoothly control the flow of oil to the storage tanks. Pulse feeding of oil to the storage tanks represents on/off flow control typified by a dump valve that is opened and closed in response to high and low liquid level set points. The pulse transfer of oil to the storage tanks was characterized in terms of bbl per dump cycle where a value of 0 bbl/cycle corresponded to continuous oil transfer.

Figure 4 presents the continuous fill scenario, which is demonstrated by the linear increase in tank level versus time. As a result of this steady filling, tank vapors are continually generated and are forced to the flares by a steady pressurization of the headspace in the tanks. These trends result in the smooth tank pressure and vapor flow profiles in Figure 4. In contrast, Figure 5 illustrates a scenario where oil is transferred from the treater to the tanks in discrete dump cycles. This operation results in the stair-step profile of tank level with time. As each dump of oil enters

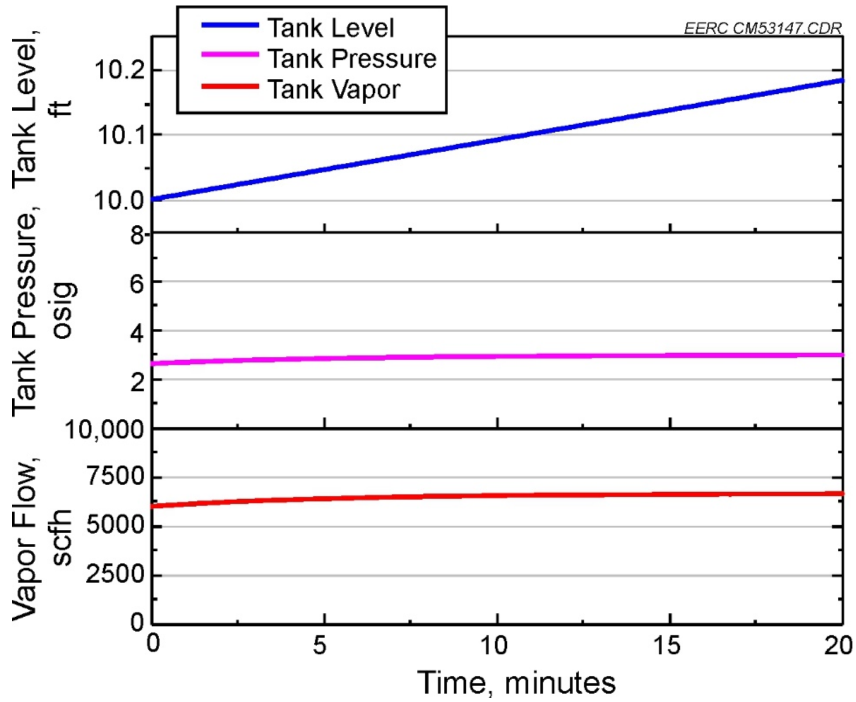

Figure 4. Dynamic modeling of a continuous tank-filling operation. Conditions include 3000-bbl/day oil throughput, 40-psig separator pressure, 40°F ambient temperature, and 6-inch NPT flare piping.

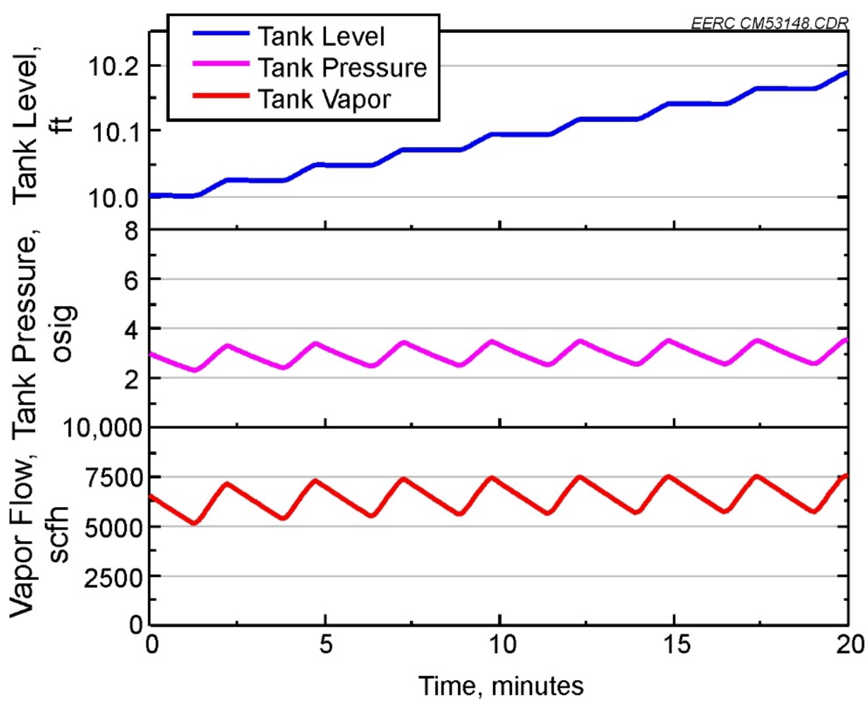

Figure 5. Dynamic modeling of a pulse filling operation. Conditions include 3-bbl oil transfer per dump cycle, 3000-bbl/day oil throughput, 40-psig separator pressure, 40°F ambient temperature, and 6-inch NPT flare piping.

the tank, there is an associated surge in vapor generation and displacement of vapor from the tanks. These feed pulses translate into cycles of tank pressurization and blowdown that are clearly evident in the pressure and flow results of Figure 5.

As evident from comparing Figures 4 and 5, the pulse feed of oil superimposes a cycle of pressure peaks and troughs that fall above and below the steady pressure value associated with continuous filling. Several scenarios of pulse size were modeled in order to generalize the peak pressure increase relative to the continuous fill baseline. This trend of peak pressure versus pulse size is shown in Figure 6 for the 6-inch flare piping condition. As expected, peak pressures do increase with pulse size, but for the range of conditions modeled in Figure 6, the maximum added tank pressure is roughly only 0.5 osi. Therefore, it seems that within the design parameters assumed in this study, fluctuations in tank pressure due to dump valve operation would not lead to emergency relief opening and associated fugitive emissions of tank vapors.

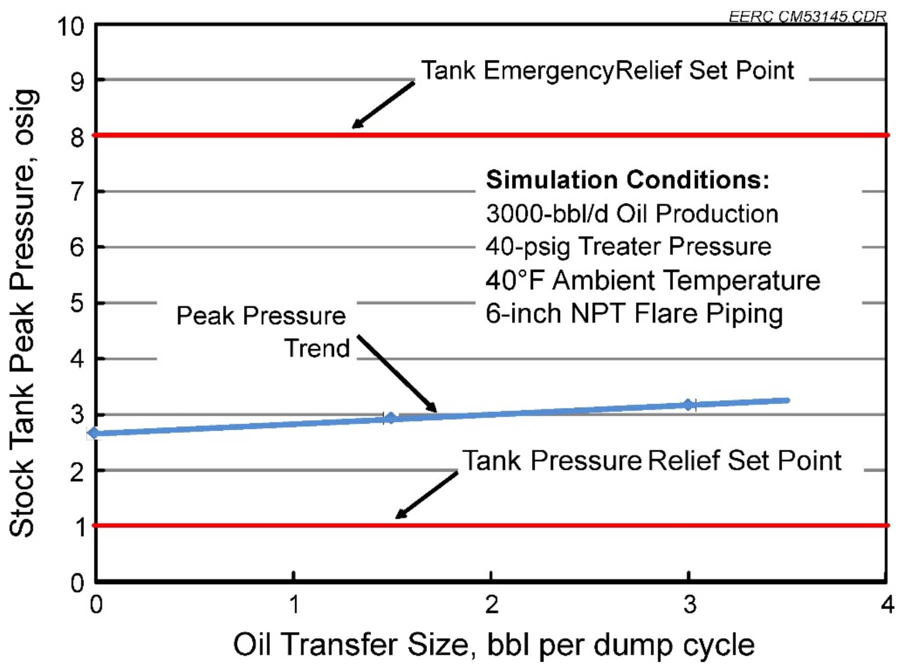

Figure 6. Parametric evaluation results for peak tank pressures. Zero oil transfer size corresponds to a continuous fill scenario.

One factor that was noted to significantly impact tank pressure was the flare vent sizing. Undersized or restricted flare vent piping restricted vapor flow to the flare leading to increased tank pressures and potential fugitive emissions. Figure 7 explores this sensitivity by summarizing the results of simulation runs with several flare pipe sizes. The figure shows a rapid increase in tank pressure as the line becomes smaller and more restricted. This effect is not surprising since piping pressure losses are proportional to the square of the fluid velocity, which itself increases inversely to reductions in cross-sectional flow area.

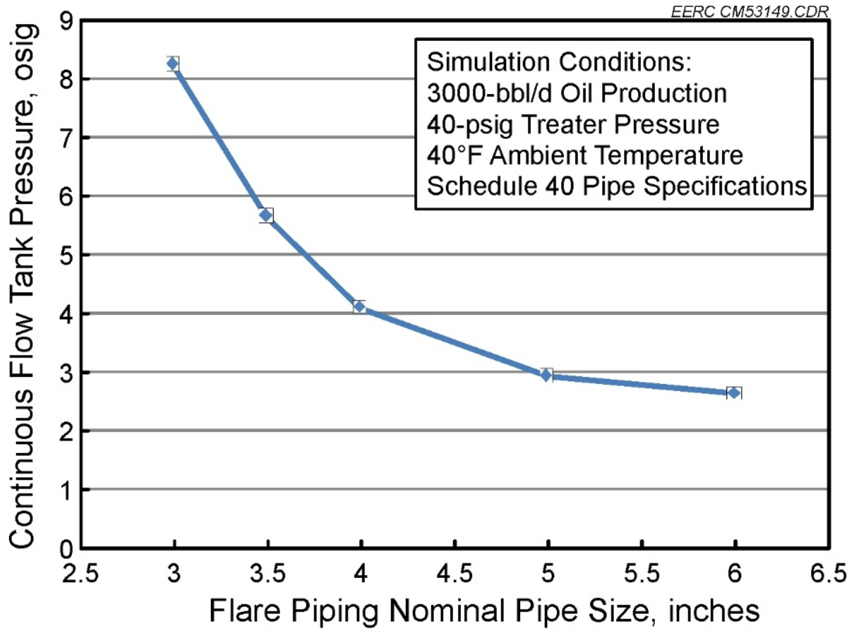

Figure 7. Sensitivity of tank pressure to flare pipe size.

Tank Vapor Condensate

The modeling also indicated that tank vapors were rapidly quenched to near-ambient conditions en route to the flare because of the low tank vapor flow relative to the large surface area and mass of the flare piping itself. Therefore, condensate formed when the ambient temperature fell below the vapor's dew point, which for this modeling had a minimum value of approximately 40°F. Figure 8 presents the calculated maximum rate of condensation as a function of ambient temperature for the modeled conditions. The data show that at an ambient temperature of 20°F, condensate would form at a rate of roughly 15 gallons a day and increase substantially as temperatures decreased further.

If the condensate were allowed to mix with the product oil, the model shows that it only had a minor impact on oil properties such as vapor pressure (heat loss from the oil in exposed pipe connections and storage vessels was much more impactful to vapor pressure). As a result, the most significant effect of condensate at real facilities is not expected to affect the product oil but to potentially act as a restriction in the vapor piping. If not addressed through system design and diligent maintenance (e.g., installing and regularly draining liquid knockouts) this liquid could collect over time and restrict the vapor flow path.

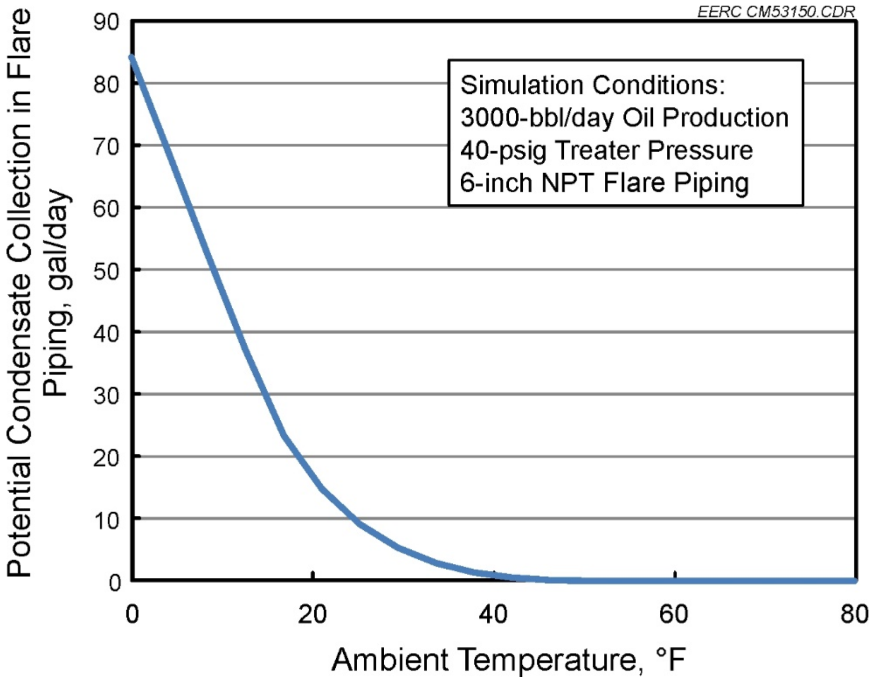

Figure 8. Estimated rates of tank vapor condensate formation.

CONCLUSION

While flash vapor generation is overwhelmingly responsible for producing tank vapors, reducing it through operational changes will probably have limited effectiveness unless changes are made to existing production equipment. For example, heat loss to the environment appears to be an important factor affecting storage tank flash conditions and the resulting oil vapor pressure; but it could only be properly addressed by insulating, and possibly heat tracing, long sections of exposed pipe runs and perhaps even storage tanks and treaters. An additional sensitivity study of the most effective areas to prevent heat loss would be needed to make more definitive recommendations. Likewise, reductions in treater pressure were also shown to reduce the quantity of flash vapor generated in the stock tank, but pressure cannot always be independently reduced without the addition of compressors and/or pumps to keep the produced gases and fluids flowing as needed.

As for the dynamic performance of the vapor control system, modeling did show that pulse feeding of oil from dump valve cycling did result in tank pressure surges above the values that would be expected with a continuous fill process. However, the magnitude of these added pressure peaks was relatively small. For the design conditions modeled in this study, peak pressures were well within the normal operating pressure range of the storage tanks. This finding would suggest that fugitive emissions from an adequately sized vapor control system are the result of other mechanisms, possibly including failures like stuck relief valves (either opened or closed depending on their location in the system), excessive carryover of gas from the treater that overwhelms the system, or the cumulative blockage of flare vent piping from condensate formation and pooling.

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