Bakken Production Optimization Program

FINAL REPORT

November 2016 – MAY 2020

EERC

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ACKNOWLEDGMENTS

The EERC would like to thank all state and industry program members for their active participation in this program. Without active engagement from all partners, this program would not have been able to accomplish the numerous tangible, high-impact results described in this final report. Although the EERC led this effort, it could not have achieved this success alone. The successes of this program were made possible only by enthusiastic participation of partner companies and state agencies.

The EERC would specifically like to thank the following companies and North Dakota State agencies:

- ConocoPhillips
- Equinor
- Hess Corporation
- Liberty Resources
- Marathon Oil
- North Dakota Industrial Commission
- Oasis Petroleum
- Oil and Gas Research Council
- Petro-Hunt
- WPX Energy
- XTO Energy

Additionally, the program received extensive support, collaboration, and cooperation from the U.S. Department of Energy, the North Dakota Petroleum Council, and the North Dakota Pipeline Authority. Cover page flare image is courtesy of Prairie Public Broadcasting.

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EXECUTIVE SUMMARY

The Bakken Production Optimization Program (BPOP) was established in June 2013 to facilitate Bakken petroleum system (BPS) oil recovery while simultaneously reducing the environmental footprint of oil and gas development. This program is administered by the Energy & Environmental Research Center (EERC), with funding from the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP), the U.S. Department of Energy (DOE), and the North Dakota petroleum industry. The overall purpose of the program is to address emerging opportunities and challenges related to Bakken development. In early 2020, BPS oil and gas producers became faced with a severe economic downturn driven by an unprecedented tandem of events: a price war between major foreign producers and a collapse in petroleum demand associated with the global COVID-19 pandemic. In this challenging environment, reducing capital and operating costs by optimizing operations is essential for maintaining BPS production. The knowledge derived from BPOP can assist industry and the state of North Dakota during times like this. The goals of BPOP are to:

- Develop knowledge that will enhance overall production efficiency, recognizing that improved coordination among various design factors (reservoir management, well design, surface processing, waste management) can lead to significant improvements in resource recovery efficiency while reducing potential health, safety, and environment impacts.

- 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.

Significant achievements directly attributable to this program have made measurable, positive impacts to how the business of oil and gas exploration and production is accomplished in North Dakota. Specific achievements between November 2016 and May 2020 include:

- Liberty Resources conducted a rich gas injection pilot test for enhanced oil recovery (EOR) at its Stomping Horse complex in Williams County, North Dakota. BPOP-supported laboratory, modeling, and field-based investigations provided key lessons for future pilots in unconventionals, including the following:
  - Injectivity was readily achieved in all test wells and was not an operational constraint.
  - Adequate supply of working fluid is essential to build and maintain reservoir pressure.

  - Starting EOR operations when reservoir pressures are less depleted may be preferable.
  - Laboratory evaluations made valuable contributions to the pilot design and operation.

- In close consultation with the North Dakota Department of Mineral Resources, a primer on the regulatory process for obtaining the necessary permits needed to conduct an EOR pilot operation in a BPS reservoir in North Dakota was developed.

- An analysis of refrac activities yielded selection criteria for candidate wells and identified effective treatment approaches.

- Produced fluid characterization was used to gain a better understanding of the resource and support facilities process modeling and reservoir modeling.

- Fugitive emission issues were examined, including assessment of emission measurement and control technologies.

- Reservoir performance data analytics and modeling were used to identify and assess key reservoir and well performance metrics across the Bakken play.

- Assessments of formations and wells used for produced water disposal were conducted, including identification of key reservoir and well performance metrics to enable better planning of surface facility development.

- Oil composition (ratios of aromatic to aliphatic compounds) was evaluated as a potential means of identifying the source of produced oil (shales vs. nonshales).

The state of North Dakota has opted to extend this program for an additional 3 years. DOE has signed on as an anchoring partner, while the EERC anticipates ongoing support from industry partners. The EERC recognizes the unprecedented economic and social challenges confronting Bakken oil and gas producers, and the state of North Dakota, in 2020 and into 2021. Reducing capital and operating costs by optimizing operations is essential to maintaining economic viability. With committed support from a triad of institutions (state, federal, and industry), BPOP is uniquely structured to address those challenges through targeted research activities.

As America and the world emerge from the economic shadow cast by the COVID-19 pandemic, demand for petroleum products will recover, and the oil and gas industry will once again take its integral place in society. The goals of the next phase of BPOP are to provide industry, the state, and DOE with science-based insight to bring the Bakken back online as efficiently as possible and maintain the long-term economic and environmental sustainability of the Bakken play in North Dakota. Through BPOP, the EERC will strive to provide stakeholders with the knowledge needed to plan and implement innovative development strategies to lead the Bakken, and North Dakota, out of a period of pandemic-driven doldrums and into the next decade of economic growth.

BAKKEN PRODUCTION OPTIMIZATION PROGRAM
Final Report, November 2016 – May 2020

INTRODUCTION

The Bakken Production Optimization Program (BPOP) was established in June 2013 to facilitate Bakken petroleum system (BPS) oil recovery while simultaneously reducing the environmental footprint of oil and gas development. This program is administered by the Energy & Environmental Research Center (EERC), with funding from the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program (OGRP) and the North Dakota petroleum industry. Through BPOP, the EERC is working closely with a consortium of industry partners and the state to address emerging opportunities and challenges related to Bakken development. Currently, oil and gas producers in the BPS face an unprecedented economic downturn related to a price war between major foreign producers and the impacts associated with the global pandemic caused by a coronavirus (COVID-19). The combination of these events has created a challenging operating environment for Bakken producers. Reducing capital and operating costs by optimizing operations provides one means for maintaining production. BPOP is structured to assist industry and the state of North Dakota during times like this. The goals of BPOP are to:

- Develop knowledge that will 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 while reducing potential health, safety, and environment impacts.

- 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.

As a premier partnership program, BPOP has been cited as an exemplary model by others nationwide. BPOP is a public–private partnership harnessing North Dakota research scientists and industry to maximize productivity of the Bakken oil play while simultaneously reducing its environmental footprint. This program has demonstrated that state lawmakers, state regulators, and industry can work together for positive results for shareholders and taxpayers alike.

Significant achievements directly attributable to this program have made measurable, positive impacts to how the business of oil and gas exploration and production is accomplished in North Dakota. The following is a small sampling of concrete examples of these impacts:

- Liberty Resources (Liberty) conducted a rich gas injection pilot test for enhanced oil recovery (EOR) at its Stomping Horse complex in Williams County, North Dakota. BPOP-supported laboratory, modeling, and field-based investigations provided key lessons for future pilots in unconventionals, including the following:
  - Injectivity was readily achieved in all tested wells and was not a constraint on operations.
  - Adequate supply of working fluid is essential.
  - Beginning EOR operations sooner rather than later, when reservoir pressures are less depleted, may be preferable.
  - Laboratory evaluations made valuable contributions to the pilot design and operation.

- The analysis of refrac activities developed selection criteria for candidate wells and identified effective treatment approaches.

- Produced fluid characterization was used to gain a better understanding of the resource and support facilities process modeling and reservoir modeling.

- Fugitive emissions issues were examined, including assessment of emission measurement and control technologies.

- Reservoir performance data analytics and modeling were used to identify and assess key reservoir and well performance metrics across the entire North Dakota portion of the Bakken play.

- Assessments of formations and wells used for produced water disposal were conducted, including identification of key reservoir and well performance metrics to enable better planning of surface facility development.

- Oil composition (ratios of aromatic to aliphatic compounds) was evaluated as a potential means of identifying the source of produced oil (shales vs. nonshales).

This report, summarizing BPOP achievements at the end of the second BPOP contract, was produced as a final report on the second phase of the program. The program initiated in June 2013 with the first phase extending through December 2016. The program continued as BPOP 2.0 during the period spanning from November 2016 to May 2020, the subject phase of this report. The program will again continue during the period from May 2020 to April 2023. Many of the efforts begun under BPOP 2.0 will continue into the next phase. This summary is intended for public distribution and is intended to highlight the important work of this public–private partnership in advancing North Dakota's economic and environmental interests directly related to exploration and production of oil from the Bakken and Three Forks Formations.

A comprehensive list of BPOP products is presented in Appendix A.

RESULTS AND DISCUSSION

Program Management

Partnership

NDIC committed $6.0 million in matching funds over 3½ years to expand the scope and continue support of the highly successful BPOP Program that optimizes petroleum production in North Dakota. The program is a continuation of the collaborative effort between the state of North Dakota, North Dakota's petroleum industry, and the U.S. Department of Energy (DOE) to develop solutions to challenges in the Bakken. The BPOP 2.0 Program cultivated and maintained the support of nine of the top oil-producing companies in North Dakota, including ConocoPhillips, Equinor, Hess, Liberty Resources, Marathon Oil Company, Oasis, Petro-Hunt, WPX Energy, and XTO Energy.

This was a partner-driven program with the goal of conducting research focused on solutions to optimize petroleum production and reduce the environmental impacts of the development of Bakken resources in North Dakota. Employing a consortium approach for these issues minimized corporate financial and staffing input, made solutions available to consortium companies without dedicating staff resources, and ensured transparency and continued cooperative efforts with the state of North Dakota to assist producers in getting the most out of wellsite economics.

Partnership participation was solicited in the following categories:

- $100,000 a year for large producers with 150 wells or more
- $50,000 a year for small producers with fewer than 150 wells
- $25,000 a year for service companies and nonproducers

Program partner benefits included:

- Ability to guide research efforts to issues highest on individual company priority lists.
- Expedient information sharing among consortium partners.
- Engagement with professional researchers focused on high-priority wellsite productivity issues.
- Access to all program products via the partners-only BPOP web page

Partnership in this consortium-facilitated program during the second phase of BPOP is shown in Figure 1.

Outreach

Bakken Production Optimization Program Website

A revision of the BPOP website, as shown in Figure 2, went live May 3, 2019. This website has an updated look and is mobile-friendly. Brief information on BPOP, areas of interest, and current activities are provided. Links to additional Bakken resources are available on the home page.

Figure 1. BPOP Phase 2 partners.

A key feature of the revamped site is access to all free and premium BPOP products through the searchable product directory, Figure 3. The product directory includes products created through all years of BPOP as well as products from other EERC Bakken projects. All products are accompanied by a public abstract for a preview of the content. Access to each product is shown by a tag of free or premium, described as:

- Free (public) products are available for download by all.

- Premium (members-only) products are available exclusively to partners on the website for 15 months following an internal and partner-driven external review process prior to release to the public.

Individual logins are provided to interested people within partner companies. This login provides individuals access to view/download premium products.

Presentation of BPOP Activities

EERC staff attended, participated in, and/or presented results of BPOP activities at over 60 conferences, meetings, workshops, and forums in the United States and Canada, highlighting the value of this unique state–industry consortium. The presentations also demonstrated North Dakota's leadership in developing unconventional shale resources.

Included in this outreach were regularly scheduled briefings to state and federal government agencies on program results, ensuring a truly engaged state member of the consortia-based program. The federal briefings demonstrated North Dakota government's leadership in shale development practices and policies to such agencies such as DOE. During this phase of the program, BPOP briefings were given to such state institutions such as NDIC, the OGRP, the Department of Mineral Resources (DMR), the Legislative Management Energy Development and Transmission Committee, the EmPower Commission, the Water Topics Overview Committee, the North Dakota Department of Health (NDDH), and others.

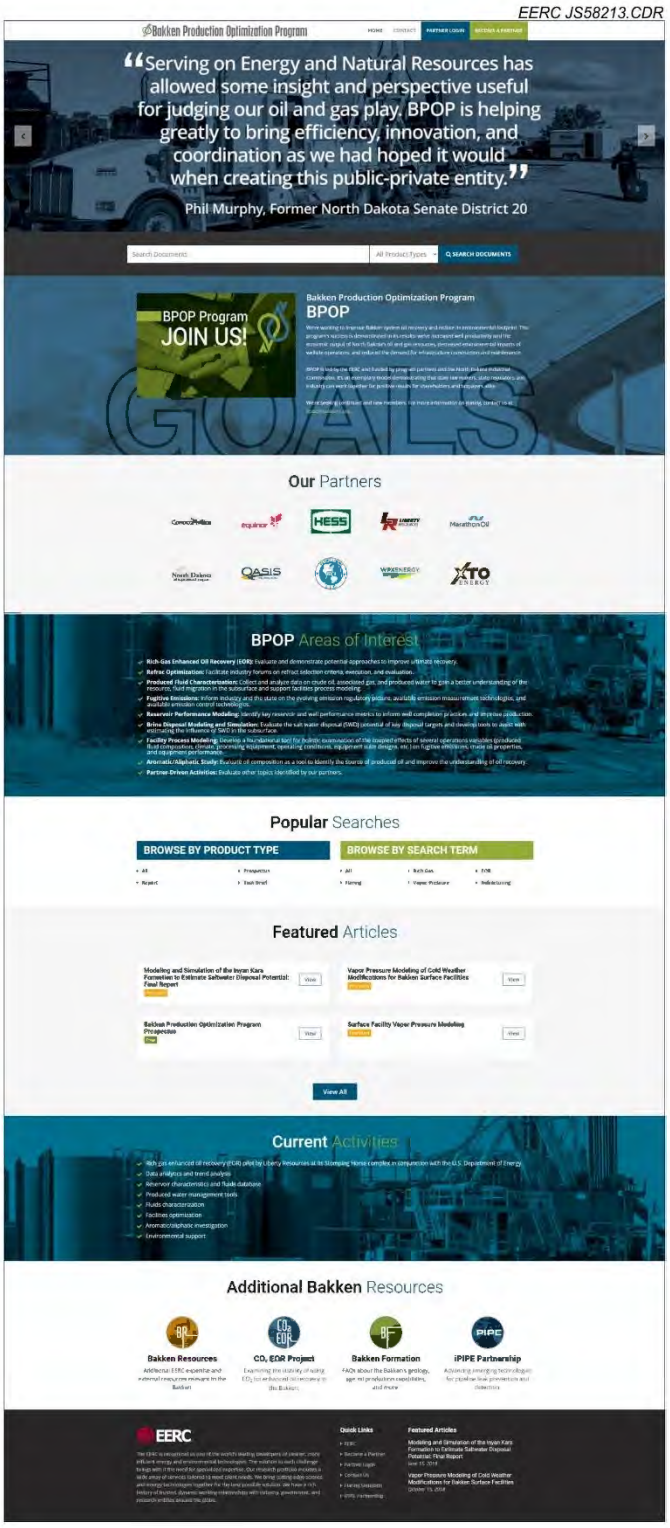

Figure 2. Screenshot of the Bakken Production Optimization Program website, http://undeerc.org/Bakken/Optimization/.

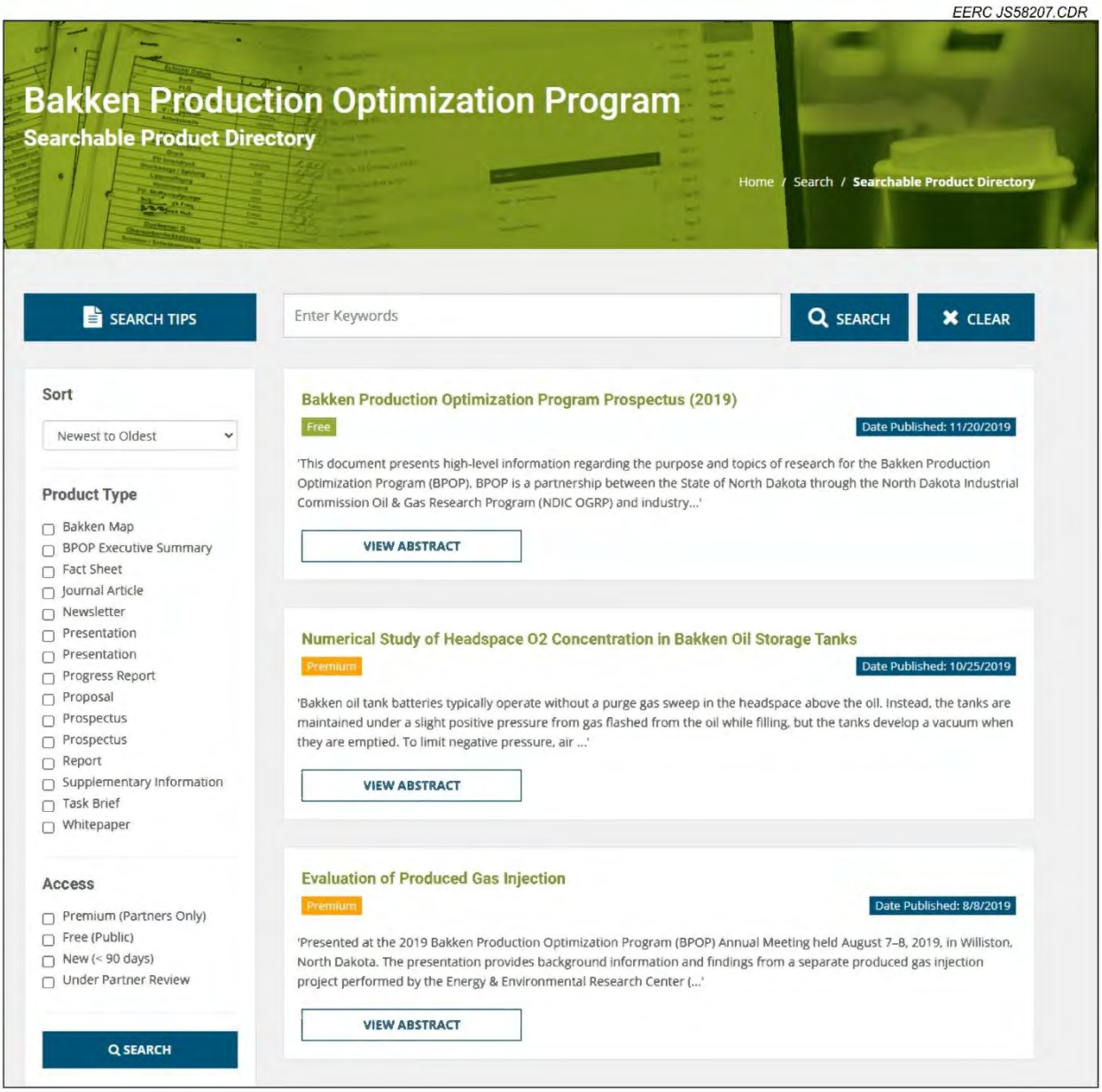

Figure 3. Screenshot of the Searchable Product Directory (example view).

The EERC provided testimony to the North Dakota House Energy and Natural Resources Committee on House Bill 1257 in Bismarck, North Dakota, on February 3, 2017. This bill related to approval requirements for utilization plans, lowering the threshold for unitization approval to 55%. The bill was passed by the North Dakota House and Senate and signed into law by Governor Doug Burgum.

Platform for Technical Industry Forums

Oil and gas industry research consortia are often faced with challenges with respect to the open exchange of information and ideas. This is partly because of the competitive nature of petroleum exploration and resource development and partly because of regulatory limitations imposed by the U.S. Securities and Exchange Commission. In some instances, dialogue among participants can be constrained by the need to avoid potential violations of federal antitrust laws. One of BPOP's greatest successes was its ability to serve as a platform for open technical exchanges during hosted industry forums. BPOP specifically targeted these open exchanges in its effort to elicit earnest conversation on issues affecting all producers. The EERC then utilized information gleaned from these exchanges to develop new approaches to issues experienced broadly by industry on its quest to optimize Bakken production. The EERC was told by multiple BPOP member companies that previous industry forums had not met this level of success in facilitating open technical discussion.

Examples of technical industry forums include the North Dakota/Montana Environmental Peer Group (EPG) meeting, the North Dakota Petroleum Council (NDPC) task forces, and the NDPC Technical Solutions Group (TSG). The EPG meetings are a convening of environmental staff from oil and gas companies operating in the Williston Basin. The intent and value in EERC staff attending these meetings included 1) introducing and reinforcing EERC expertise to the industry when presenting to the group and 2) gathering valuable information from exchanges between industry peers. The NDPC task forces and NDPC TSG are described in more detail here.

NDPC Hydrocarbon Remediation Task Force

NDDH, in conjunction with NDPC and Northwest Landowners Association, established the Brine Remediation Task Force in 2014. The Brine Remediation Task Force spent approximately 2 years negotiating appropriate guidance for remediating brine spills in the oil field, resulting in a guidance document published by NDDH and a more comprehensive "companion" document published by the EERC entitled "North Dakota Remediation Resource Manual." The Hydrocarbon Remediation Task Force is a continuation of the Brine Remediation Task Force with a focus on hydrocarbon guidance/regulation.

EERC staff have been participating as subject matter experts providing input and presenting educational information at the Hydrocarbon Remediation Task Force meetings. The level of participation of EERC staff varied from strictly an attendee to providing presentations to the group as a subject matter expert. The purpose of the Hydrocarbon Remediation Task Force was to convene stakeholders to discuss hydrocarbon spill remediation and work toward general agreement of how hydrocarbon spills should be regulated by NDDH. Additional stakeholders include NDPC members and staff, representatives of the Northwest Landowner's Association, staff from the

North Dakota DMR, staff from the North Dakota Department of Agriculture and, on occasion, staff from the Governor's Office.

As a result of preparing educational information for the Hydrocarbon Remediation Task Force, a body of technical work was compiled that would greatly enhance and improve the previously published, evergreen North Dakota Remediation Resource Manual. EERC staff continued the process of updating this with additional hydrocarbon remediation text based on information presented on NDDH education days. The updated North Dakota Remediation Resource Manual was republished in March 2019 (Figure 4).

NDPC Flaring Task Force

The EERC has provided technical guidance to companies with wellsite-scale gas capture technologies to assist their efforts to tailor technologies and approaches to the reality of flared gas. The EERC supported the latest efforts of the NDPC Flaring Royalties Work Group by presenting information related to small-scale gas utilization technologies to the U.S. Bureau of Land Management (BLM).

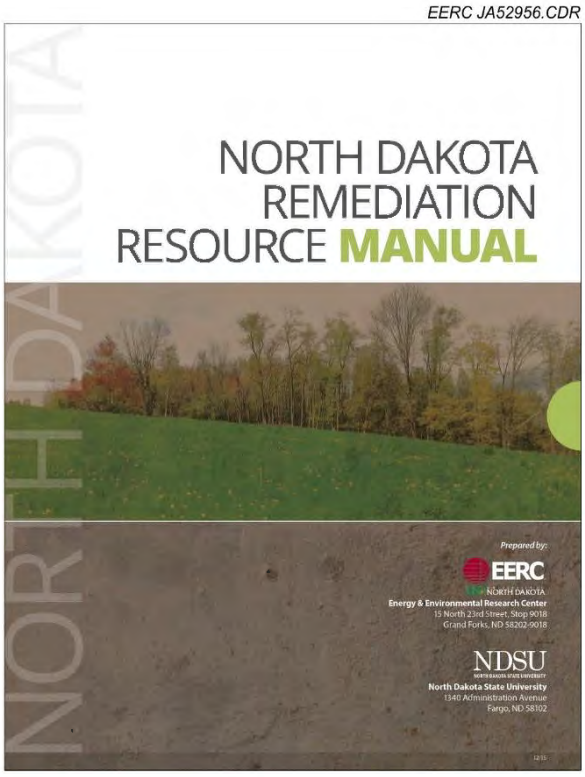

Figure 4. Updated North Dakota Remediation Resource Manual cover, released March 2019.

NDPC Technical Solutions Group

In addition to providing technical support to NDPC Task Forces, the EERC has provided technical and administrative support to the NDPC TSG by serving as a cochair, helping to organize quarterly meetings, arranging speakers, and facilitating discussion. The NDPC TSG serves Bakken operator efforts to apply technology to address facility optimization by providing a forum where technology providers can share information about their technology, answer questions about implementation, and gather information about operational challenges in the Williston Basin. The mission of the NDPC TSG dovetails closely with work being conducted within the BPOP related to facility optimization, gas capture, emission reduction, produced fluid characterization, and environmental support.

EERC staff have provided direct technical support to TSG meetings, presenting information on topics including flare mitigation technologies, tank vapor management, crude oil conditioning strategies for vapor pressure management, and crude oil characterization. Information about the NDPC TSG, including presentations from quarterly meetings, can be found at the NDPC website: www.ndoil.org/technical-solutions-group/.

Enhanced Oil Recovery

Total in-place oil for the Bakken petroleum system (BPS) (which includes the Bakken and Three Forks Formations) has been estimated to be 600 billion barrels (bbl) (Nordeng and Helms, 2010).[1] However, BPS wells have decline rates as high as 85% over the first 3 years of their lives, and primary recovery factors typically range from 3% to 10% of original oil in place. Given the low initial recovery rates, even small incremental productivity improvements could dramatically increase technically recoverable oil in the BPS. One potential solution is EOR using gas injection, such as carbon dioxide (CO_2) or hydrocarbon (HC) gases. While common in conventional reservoirs in areas such as West Texas and Saskatchewan, CO_2 EOR in unconventional tight oil reservoirs has been limited to pilot tests. EOR using rich gas (mixture of methane, ethane, and propane) has also been employed in numerous pilots in several unconventional plays and has recently been successfully applied in the Eagle Ford play. If successful, large-scale gas-based EOR in the BPS could dramatically increase oil productivity and recovery factors and extend the life of the play for decades.

While CO_2 may be a technically suitable working fluid for EOR in the BPS, supplies are limited and costs for using CO_2 in EOR pilots are prohibitively high. Meanwhile, produced gas flaring has proven to be a significant challenge for BPS operators in North Dakota. The North Dakota Industrial Commission (NDIC) has a stated goal of reducing the amount of flared rich gas to 10% or less of the total associated gas produced in the state by 2020. Analysis conducted by the North Dakota Pipeline Authority indicates that the current gas-gathering infrastructure in North Dakota is insufficient to accommodate all of the associated gas that is produced from the BPS. The geographically isolated location of North Dakota relative to large natural gas markets, combined with continued low natural gas prices, has made it economically challenging for industry to invest capital in expanding gas-gathering infrastructure in the state. These circumstances led to a research

[1] Nordeng, S.H., and Helms, L., 2010, Bakken source system – Three Forks Formation assessment: Bismarck, North Dakota, North Dakota Department of Mineral Resources, 22 p.

program conducted by the EERC in partnership with Liberty Resources, with funding from NDIC through BPOP, as well as funding from DOE, to examine the potential to use rich gas injection for EOR and mitigate flaring.

The rich gas EOR pilot test was designed and executed by Liberty Resources at its Stomping Horse development area in Williams County, North Dakota, from July 2018 through May 2019. A total of 160 million standard cubic feet (MMscf) of rich produced gas was injected into the BPS using five different wells in a sequential injection strategy. Liberty Resources' Leon–Gohrick drilling spacing unit (DSU) was used as the test site. The test was operated by Liberty Resources, with regulatory oversight by NDIC. Technical support was provided by the EERC through a series of laboratory-, modeling-, and field-based activities.

Laboratory-based examinations of rich gas interactions with reservoir fluids and rocks (including oil-rich shales) were conducted, with an emphasis on determining the ability of various rich gas mixtures to mobilize oil in the tight reservoir rocks and shales of the BPS. Injection fluid composition was shown to have a large impact on reservoir oil minimum miscibility pressure (MMP); enriching produced gas with additional ethane and/or propane before injection will favorably alter reservoir response. Injection of rich gas (ca. 70/20/10 methane/ethane/propane) produced from the BPS can achieve MMP at pressures similar to the pressures required by CO_2, approximately 2420 psi. Methane requires very high pressures to achieve MMP, 4200 psi. Ethane requires approximately 1350 psi and propane about 550 psi to achieve MMP. Adding natural gas liquids (NGLs) like ethane and propane to produced gas is an efficient way to lower MMP if excess NGLs are available.

Iterative modeling of surface infrastructure and reservoir performance using data generated by the various project activities were conducted. A geologic model of the Stomping Horse area was built; history matching of oil, gas, and water production was performed; and simulations of various injection and production scenarios were conducted. The modeling results were used to support Liberty Resources' design and operation of the EOR pilot and to provide insight regarding optimization of future commercial-scale Bakken EOR design and operations.

Data collected from a variety of reservoir surveillance techniques were analyzed and interpreted. The ability to inject gas into BPS reservoirs and build pressure was demonstrated. MMP was not achieved in the reservoir during the pilot test. Achieving MMP in a reservoir at an advanced state of depletion requires considerable quantities of injection gas. Starting EOR operations sooner rather than later, when reservoir pressures are less depleted, may be preferable. Reservoir surveillance and monitoring data also demonstrate that the injected gas was contained within the DSU.

The results from the Stomping Horse rich gas EOR pilot activities indicate that developing an effective, economical EOR approach for the BPS will require more field tests. Another key lesson learned from the Stomping Horse tests is that detailed pre- and posttest data on reservoir conditions and fluids production are essential for test and offset wells. Robust reservoir characterization provides information that is crucial to creating realistic geomodels and conducting valid dynamic simulations of potential EOR scenarios. A detailed understanding of the completions and production history of offset wells also is necessary for valid test result

interpretations. This knowledge is essential to designing the operational parameters of injectivity tests and interpreting the results. A conformance control strategy is also essential to success.

There is great reason to be optimistic about the future of EOR in the Bakken. The results of the laboratory studies suggest significant potential for high rates of oil mobilization using produced field gas injection under the right conditions. The results of the lab studies, combined with rigorous statistical analysis of well production data and associated modeling efforts, confirm the notion that fluid mobility within the reservoir is controlled by fractures. As more knowledge is gained about the nature and distribution of fracture networks in the Bakken, the industry will be in a better position to predict and ultimately influence fluid mobility. New field tests are necessary to develop a more complete understanding of those conditions. Thoughtful and creatively engineered field tests within a well-characterized geologic setting will yield the fundamental knowledge needed to take Bakken oil production to the next level.

North Dakota Regulatory Primer

A regulatory primer entitled "Bakken Pilot Testing for the Purpose of Enhanced Oil Recovery: A North Dakota Regulatory Primer," designed to inform project developers of the regulatory process for the purpose of EOR for permitting a pilot-scale injectivity test into the Bakken pool, was added to the BPOP website in May 2020.

From the perspective of the NDIC DMR, the Bakken and Three Forks Formations in North Dakota are considered to be a single source of crude oil supply, known as BPS. For regulatory purposes, BPS is collectively referred to as the Bakken pool. The regulatory approval process for a pilot injection test for EOR in the Bakken and Three Forks Formations can be separated into two applications: 1) the application to inject into the Bakken pool, also known as an injectivity test, and 2) the individual injection well application. The regulatory permitting process for a pilot injection test, including the permitting of individual injection wells in North Dakota, from the time the applications are filed with NDIC to the date the applications are approved typically takes 3 to 6 months (see Figure 5). The evaluation of approved pilot injection test permit applications indicates that, for the most part, any delays in the permitting process are related to the operator requesting to continue the hearing (i.e., reschedule to the next available hearing date) or the NDIC Oil and Gas Division requesting supplemental information for the record. The primer is designed to help improve the latter by informing project developers of the regulatory process and identifying all required data and information necessary to expedite the regulatory permitting process by ensuring the application is filed complete and in compliance with all applicable laws and regulations.

Pilot projects are typically performed by a single company on its owned and operated DSUs. However, the siting of DSUs may limit the areal extent of a commercial injection project to remain within those DSUs and not allow outside impact beyond a company's leasehold. Field validation of an EOR process in the BPS requires the operator of the successful pilot to assess its leasehold, DSUs, infrastructure, operations personnel, and capital program to determine whether to proceed with fieldwide scale-up for a commercial EOR project. Regulations for scale-up from a pilot to a fieldwide commercial EOR project need to be put in place to promote the aggregation of the project area, address the rights of the participants, and conserve resources.

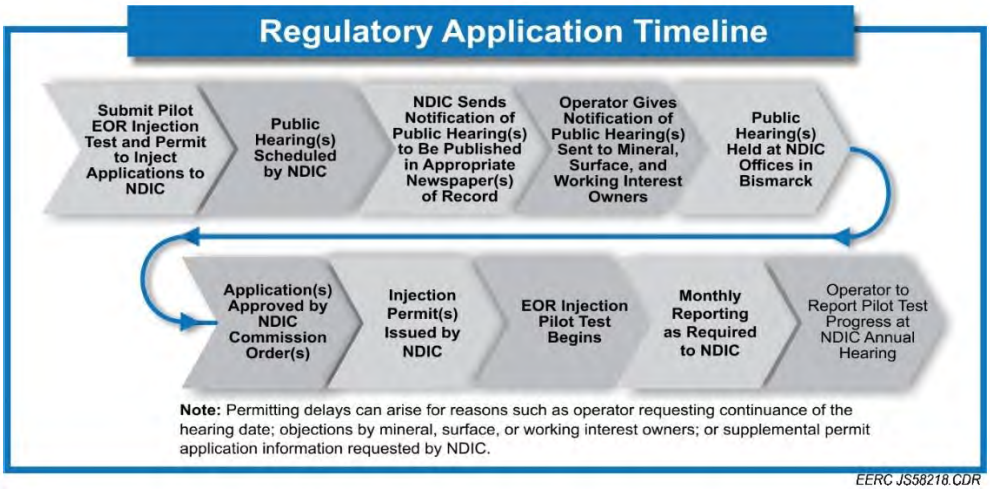

Figure 5. 6-month regulatory timeline to receive all necessary permit approvals for a Bakken pool pilot injection test for the purpose of EOR.

Aromatic/Aliphatic Study – Turtles and Snakes

Crude oil hydrocarbons recovered from the Upper (UBS) and Lower Bakken Shale (LBS) rocks consistently have higher proportions of aromatic hydrocarbons (ring-shaped molecules, a.k.a., "turtles") compared to aliphatic hydrocarbons (chain-shaped molecules, a.k.a., "snakes") than are present in the adjacent Middle Bakken (MB) and Three Forks target drilling zones. Laboratory studies showed that the slower migration of aromatic turtles from source shales as compared to the aliphatic snakes was caused by molecular shape filtration—i.e., aliphatic snakes were able to migrate more rapidly through the molecular-sized shale pore throats than the same-sized (i.e., same carbon number) aromatic turtles. Consequently, measuring aromatic/aliphatic (A/A) ratios in rock samples collected from wells provides additional data that may help to better understand the thermal maturity and the migration of oil hydrocarbons over geological time in the BPS. In addition, quantifying A/A ratios in produced crude oil samples collected over time from the same well or set of wells may provide information that can be used as a reservoir management tool to perhaps quantify the contributions of the source shales to produced oil. These crude oil measurements could be used to evaluate completion performance or as input for revising estimates of oil reserves in the UBS and LBS rocks.

The report entitled "Turtles and Snakes: Using Molecular Shape to Understand Oil Migration and Production in the BPS" describes a set of rock core and crude oil samples that were analyzed for target aromatics and n-alkanes (aliphatics), discusses specific A/A ratios used to account for vaporization losses during sample collection, and presents a detailed analysis of the A/A ratios in rock and crude oil samples using machine learning and binary mixing models. In addition, reduced A/A ratios using a subset of the target analytes were evaluated, which greatly simplifies the analytical challenges of measuring the several hundreds of aromatic isomers present in crude oil and rocks from UBS/LBS source shales and Three Forks/MB target zones.

These efforts were ongoing in 2019–2020 and are expected to continue. Future work using additional rock core and temporal crude oil samples collected from a larger set of targeted wells may provide greater insights about the relationships between A/A ratios and other rock characteristics or geospatial trends in A/A ratios across the BPS, as well as providing further insights into the value of tracking A/A ratios in produced crude oil as a tool for well management and resource valuation.

Refracturing Data Analysis

A refracturing optimization study was conducted and reported in an initial report providing the results of 1) a literature survey to understand well selection criteria for identifying candidate wells for refracturing, 2) a review of existing wells completed in the Bakken Formation in North Dakota that were refractured, and 3) an evaluation of production performance of Bakken refractured wells and analysis of refracturing economics, which together inform the overall potential for Bakken-wide implementation of refracturing. Partner review of the initial report on refracturing in North Dakota wells yielded several additional questions. Therefore, the scope of work focused on refracturing was expanded and resulted in a second report entitled "Refracturing in the Bakken – An Analysis of Data from Across North Dakota."

The second report on refracturing presents the results of 1) an expanded compilation and review of the wells that have been refractured in the North Dakota portion of the BPS, 2) an evaluation of production performance of the refractured wells, 3) an analysis of the impact of refracturing on offset wells (secondhand refracturing), 4) an assessment of refrac economics using a decision-tree modeling approach, and 5) an assessment of the potential economic impact of a broad refracturing program applied throughout the BPS.

As of May 2019, 272 wells have been refractured in the North Dakota portion of the BPS. The number of refractured wells has increased considerably over the past 2 years, with 104 refracs conducted in 2017 and 2018, as compared to 168 refractured wells from 2009 through 2016. Production data for these 272 wells were compiled into a BPOP refracturing database that provided the basis for the expanded analysis.

The production analysis of the refractured wells investigated several metrics to evaluate refrac performance, including 1) a comparison of pre- and postrefrac peak oil rates, 2) a change in daily production data following the refrac operation, 3) a change in gas-to-oil ratio (GOR), and 4) incremental estimated ultimate recoveries (EURs) (i.e., the change in EUR between pre- and postrefrac forecasts). In addition to summarizing the results across all refractured wells, the refracturing production performances were compared between wells that were originally completed as barefoot vs. nonbarefoot wells. Barefoot completions are believed to be understimulated during the original treatment and to have a greater undrained area and larger remaining hydrocarbon volume, resulting in commensurately better postrefrac production performances. Furthermore, refracs conducted on wells with barefoot completions are technologically easier and less costly to implement, which makes this group of wells potentially the best candidate for refracturing.

The economic analysis focused on discounted net oil revenue, defined as the oil revenue after deducting royalties (16.67% applied pretax) and state tax (10% applied after deducting royalties), assuming an annual discount rate of 10% per year. A decision-tree modeling approach was used to evaluate the overall economic performance given a set of probabilities assigned to each potential outcome.

An initial screening of existing wells in the BPS identified 400 wells as potential candidates for refracturing using a simple set of criteria: specifically, wells that had single-stage completions, older completion dates, and barefoot completions. The potential economic impact from refracturing all of these candidate wells resulted in an estimated discounted net oil revenue of approximately $2 billion, which reflects the median outcome after deducting the refrac cost, taxes, and royalties. These results show that refracturing has significant production potential in the Bakken, particularly if single-stage, older, barefoot wells are targeted.

Produced Fluid Characterization

In support of wide-ranging activities associated with BPOP research efforts, the EERC assembled all available physical and chemical property data pertaining to Bakken Formation produced fluids: crude oil, associated gas, and produced water. This included public information housed at the North Dakota DMR, public information housed at the U.S. Geological Survey (USGS), data developed via other EERC projects and programs, and data provided to EERC staff by industry. Collaboration continued with key industry partners to obtain access to fluids (crude, water, and/or gas), sample collection from numerous wells at multiple locations, and acquisition of existing compositional data.

Available data sets were further refined to provide formation-specific information on both the Bakken and Three Forks reservoirs independently. The data set currently contains over 1000 produced water samples, 500 crude oil samples, and 1000 produced gas analyses. All data were used to update the previously created geographic information system (GIS)-based database. The GIS-based capability allows EERC personnel to construct maps derived from various data sets to evaluate basinwide characteristics specific to the Bakken and Three Forks Formations. To identify statistical correlations between the fluids data and geological properties, the water, oil, and gas data were compared to geologic variables based on data compiled from a total of 13,181 wells, including 9012 Bakken and 4169 Three Forks wells.

Efforts were made to monitor fluids over time from several wells made available by BPOP industry partners. Collection and analyses of fluid samples (gas, crude, and water) focused on two primary efforts: a temporal evaluation of newly installed Bakken and Three Forks wells and an evaluation of potential differences in chemistry and production statistics between a stimulated and unstimulated well originating from the same pad in the same formation. Figure 6 shows EERC personnel conducting sample collection activities of fluids from a well separator. A few key findings of fluid compositional differences include:

- Produced gas composition changes throughout the first few years of production, with an increase in methane concentration and a decrease in ethane, propane, butanes, etc. These

Figure 6. Fluid sample collection activities on a well separator.

findings were similar to, and used to validate, a separate EERC-conducted basinwide gas composition forecasting effort.

- Produced water production volumes and chemistry differed significantly between the stimulated and unstimulated well completed in the same formation (Bakken). This finding may indicate that overlying/underlying formations, such as the Lodgepole and Birdbear Formations, are contributing to the produced water budget of stimulated wells.

A methods development activity to enhance analytical capabilities for detailed hydrocarbon compositional analyses was conducted. Crude oil fingerprinting analytical methods, using high-resolution gas chromatography (GC), were developed, modified, and used to analyze samples of crude collected from a few Bakken wells and extracted from a select number of Bakken cores in an attempt to determine oil origination and subsurface migration potential during production activities. Several pairs of oil samples were fingerprinted and compared using star diagrams. Data interpretation models were created for geochemical characterization of the oil samples, and pressure, volume, temperature (PVT) calculations were used to assist in interpretation of the results derived from whole oil fingerprinting GC methods. Figure 7 illustrates a typical chromatogram display and star plot for compositional ratio determinations. Key accomplishments of the crude oil fingerprinting effort were:

- Established methods reliably identified compositional differences between crude oils of the Bakken and Madison Formations, representing different petroleum systems.

- Modifications to the method approach were successful in identifying subtle differences in fluids from the Bakken Formation in different geographical areas.

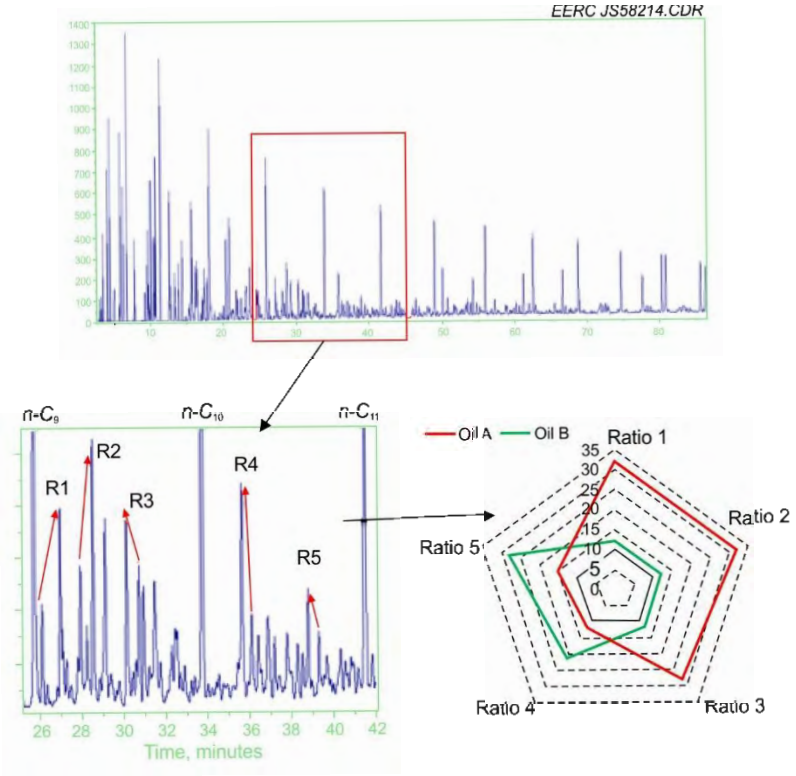

Figure 7. Example of crude fingerprinting chromatogram and plot.

Further use of these methods to investigate produced oil and oil extracted from core samples of the Bakken shales, the Middle Bakken, and the Three Forks Formation will allow researchers to potentially determine oil origination and migration potential and timing from contributing portions of the reservoir and/or Bakken shales.

Bakken/Three Forks Production Analysis Using Data Analytics and Machine Learning

Initial efforts on Bakken/Three Forks production analysis focused on statistical analysis of the key factors that could affect Bakken well performance, summarized in the BPOP report entitled "Bakken Production Evaluation Using Multivariate Statistical Analysis," which was provided to partners in November 2018 and will be available to the public on the BPOP website in June 2020. Presentation of the results from that effort at the BPOP partner meeting in August 2019 generated much discussion and comments, prompting a second round of Bakken data analysis. The scope of work for the second round of data analysis greatly expanded the number of wells included in the evaluation (from 400 to over 12,000) and focused on understanding the possible correlations between well performance and engineering factors such as well spacing, parent–child well relationships, field location, and completion design.

A major goal of this study was to better understand BPS historical production and completion trends and to identify opportunities for operational optimization. Since 2016, through BPOP, the EERC has been evaluating BPS oil production and well completion data using statistical

and machine learning (ML) methods. The objective of these investigations is to apply data analysis methods to a broad data set with the aim of exploring historical trends and drawing inferences about the effects of well completion practices on oil production. The data analysis activities completed in 2020 included a broad database of wells, a more complete set of completion features, and a multifaceted data analysis approach that used several complementary statistical and ML methods. The approaches used in the study represent the state of the art for drawing inferences about past BPS operational factors that can shed light on potential optimal strategies for the future of BPS production. The study included four main thrusts:

1. Analysis of well production and completion trends over time.

2. Application of ML algorithms to identify and rank important well completion parameters for predicting 6-month oil production.

3. Multilevel regression analysis to identify and rank important features for predicting 6-month oil production while accounting for the clustered data structure of wells located within DSUs which are themselves located within fields.

4. Application of ML algorithms to identify optimized completion parameter values using areas of the BPS representing lower, average, and higher oil production regions.

Multiple commercially available and open-source software packages and algorithms were used to implement data analysis. Using multiple tools allowed for a comparative assessment that ranked various data analysis techniques based on their performance and ability to answer the question or solve the problem. Analyses were applied to both individual wells and aggregated performance metrics for DSUs.

Six ML algorithms were evaluated for their ability to predict 6-month cumulative oil production from completion parameters. The top five most important completion-related features were total proppant, total fluid, total fluid per interval length, number of wells within one DSU, and upper perforation. Sensitivity analysis showed that oil production generally increased with more intense completion practices. The data analytics also showed that, all other inputs being equal, a well completed in the Three Forks Formation was estimated to have an 8% lower oil production than an equivalent well completed in the Bakken. Models for aggregated DSU-level data suggested only asymptotically greater oil production beyond seven or eight wells per DSU.

Analytics to identify approaches for optimization of future resource development was conducted using wells located in three subareas of the BPS representing low-, moderate-, and high-productivity regions. Partial dependence plots were used to identify optimal values for each completion feature for the three subareas, defined as the value of the feature that maximized the target variable while minimizing the feature, i.e., the greatest oil production for the least investment (cost) for the completion feature. The results suggest different optimal configurations for the subareas. The high-productivity subareas benefit from higher total proppant, lower total fluid, and higher maximum treatment pressure. In contrast, the moderate- and low-productivity subareas maximize oil production with less total proppant, greater total fluid, and lower maximum treatment pressure. Overall, the results obtained from the data analytics activities conducted under

BPOP 2.0 can help oil and gas operators to significantly reduce their costs and maximize production.

Inyan Kara Saltwater Disposal Potential

The rapid increase in oil and gas production within the BPS has resulted in a substantial increase in the volume of produced brine requiring disposal in western North Dakota. As of 2016, approximately 94% of produced brines (by volume) was disposed of via deep well injection into the sandstone units of the Inyan Kara Formation, raising questions about the long-term viability of the Inyan Kara as a disposal target. Through BPOP, the EERC developed a reservoir simulation model of a portion of the Inyan Kara Formation to evaluate the effects of current and possible future saltwater disposal (SWD) operations on reservoir pressure and long-term disposal potential. These efforts were reported in "Modeling and Simulation of the Inyan Kara Formation to Estimate Saltwater Disposal Potential: Final Report," which is available on the BPOP website.

The reservoir simulation model developed for this effort encompassed most of McKenzie County and a portion of northwestern Dunn County. The geologic model was built using Schlumberger's Petrel software, and a numerical simulation model was developed using Computer Modelling Group's (CMG's) GEM software. The data inputs for the geologic model included well logs, formation tops, and core sample descriptions and analyses, as well as injected volumes and pressure measurements at individual SWD wells. Injection rate, volume, and pressure data were compiled for the 103 SWD wells in the modeled area and used to history-match the numerical simulation model. Adjustments were made in the model to better account for local permeability and porosity and to account for skin factor and periodic well operations such as acid treatment.

The simulation model was used to estimate the current distribution of reservoir pressure and injected salinity plumes beginning in 1961 as a result of SWD beginning in 1961. Several potential future scenarios were also simulated to evaluate the distribution of pressure and salinity within the Inyan Kara Formation and to evaluate long-term disposal potential out to the year 2050. Three simulation scenarios were evaluated: one that assumed that each of the 103 SWD wells in the area (both those that are currently operational and those that have ceased injection) continued injecting until 2050 at their last reported rate, one scenario that assumed that only the operational SWD wells in the area (93 total) continued injecting at their last reported rate, and one scenario that assumed that the 93 active SWD wells operated at their maximum allowable rate (based on wellhead injection pressure) until 2050. Each of the three primary scenarios had two cases. One case assumed that all boundaries surrounding the model were open, meaning no impediments to fluid flow along the model boundaries. The second case in each scenario assumed closed boundaries (no fluid flow allowed) on all but the eastern edge, which was considered open because it is adjacent to an area with a low occurrence of SWD wells.

In addition to the results generated by the simulation model, a simplistic equation was used to calculate the volumetric storage potential of the Inyan Kara within the modeled area under closed boundary conditions. This calculation assumed that all of the available pore space would be accessible via injection wells and that the formation fluid pressure would be at the maximum allowable without exceeding the permitted injection pressure. This simple estimate of maximum

storage potential under closed boundary conditions was calculated for comparison to the disposal potential estimated by the reservoir simulation model.

The cumulative water injection into the Inyan Kara at the beginning of 2017 was approximately 644 million barrels (bbl). Results of the numerical simulation suggest the cumulative brine injection at the end of 2050 would range from 3.86 to 5.27 billion bbl based on the different scenarios evaluated. This represents an increase of 500% to 670% over the 2017 cumulative injection volume for all of the simulation cases. Comparison of the results from the numerical simulation to the estimated storage potential using the volumetric approach also indicates that there would be pore space available for storage at the end of 2050. The closed system volumetric estimate was 7.19 billon bbl, compared to the highest predicted cumulative injection volume of 5.27 billion bbl. Although the closed system estimate is highly conservative (and likely low) because it assumes no flow from the model boundaries or resulting pressure dissipation, a comparison of the estimate storage potential suggests that as much as 73% of the storage potential (of a closed system) could be utilized by 2050. A comparison of the simulated injection rates over time indicates that, in each case, rates of injection will have to decline to avoid exceeding injection pressure limitations.

Despite the large predicted storage potential of the Inyan Kara, maps of the predicted reservoir pressure indicate that localized areas of pressurization have already occurred, and predictive model simulations suggest that the areas of elevated pressure could expand in size and magnitude with continued long-term injection, especially in the northern portion of McKenzie County. These areas exhibit behavior of a system with semiclosed boundary conditions, and continued injection could result in operators curtailing injection rates and/or injected volumes to avoid exceeding the injection pressure limitations established by the North Dakota DMR. The model predictions also suggest that there is a large portion (e.g., southern half) of the simulated area that could support an additional pressure increase even after more than 30 years of injection.

Maps depicting the brine plume extents surrounding individual SWD wells illustrate the influence of geology of the brine migration pathways. Many of the brine plumes appear to follow preferential flow pathways that result from variability in the extent and thickness of the sandstone layers within the Inyan Kara. Model results reinforce the importance of understanding the local geology prior to siting a SWD well.

Facility Process Optimization

The EERC conducted a variety of activities to address the general topic of facility process optimization of wellsite operations. Activities were driven by common needs of the program partners and performed with input and cooperation with those partners. Specific topics addressed within this task included wellsite emission management, crude oil vapor pressure management, tank vapor management, stranded gas for power production, and centralized facilities.

The goal of this work was to explore approaches that have the potential to reduce wellsite costs, improve production and efficiency, and reduce adverse impacts to the environment. Following is a summary of the major activities in which BPOP was engaged.

Wellsite Emissions

To examine facility optimization, the EERC developed a hypothetical wellsite process using Aspen HYSYS® process simulation software. A thorough understanding of this step in the production cycle is important since wellsite operations are central to many concerns, including crude oil and gas marketability, waste management, and environmental impacts from air emissions. Development of this "typical" wellsite process model was achieved with participation from BPOP partners and included defining process equipment and operational conditions common in North Dakota. Trends predicted by the static model were validated by comparing them to field observations from the partner company, and the model has served as the basis for many of the studies conducted over the subsequent 3 years.

Additional model development was conducted using a dynamic modeling package, VMGSim Dynamics™ software. This dynamic modeling package was utilized in analyzing conditions not accurately represented by steady-state operation, such as tank fill and truck-loading operations.

With these tools, the EERC conducted an analysis of the impact that operating parameters have on fugitive emissions from storage tanks. The objectives of this analysis 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. A paper summarizing the modeling exercise and its results entitled "Process Modeling of Wellsite Production Operations" was posted to the BPOP website for partners in March 2017 and made available to the public on the website in June 2018.

In addition to analysis of fugitive emissions, a detailed study was conducted to evaluate the relative impact that different equipment and operations have on air pollutants and associated permitting requirements on wellsites. Emissions of criteria pollutants from wellsite equipment were estimated using the North Dakota Department of Environmental Quality (DEQ) emission tool with specific emphasis on combustion equipment. Analysis included estimating emissions from standard flares with 98% destruction efficiency, high-efficiency flares achieving 99.5% destruction efficiency, and gas-fired electrical generators. A PowerPoint slide deck summarizing the study methodology and results entitled "How Does Increasing Flare Efficiency or Removing NGLs from the Gas Stream Affect the Maximum Allowable Oil Production for a Single Well?" was prepared.

Wellsite Gas Capture

As gas capture requirements continue to be more stringent and operators work to improve gas utilization and reduce environmental impacts of gas flaring, wellsite gas capture has again become an important topic to BPOP partners. The EERC has continued to maintain the Flaring Solutions database, which contains technical and contact information for companies offering alternative gas use technologies. The database serves as a clearinghouse of technologies, providing BPOP partners a convenient source of information on gas use technologies and providers. Additionally, the EERC continues to communicate with technology providers, seeking information about the nature of gas flaring in North Dakota and working to tailor their technology and business model to stranded gas in North Dakota.

Recently, EERC staff focused an investigation into power generation for mobile data centers. This is an emerging technology, and at the request of BPOP partners, EERC staff prepared a slide deck describing these systems and outlining how they can aid BPOP partners to meet their gas capture goals. This slide deck is entitled "Exploration of a Novel Avenue Toward Wellsite Gas Capture – Power Generation for Mobile Data Centers."

Crude Oil Vapor Pressure

The topic of crude oil vapor pressure management was an important topic during the project period. While Sandia National Laboratories pursued a study to assess crude oil characteristics and combustion properties, EERC researchers worked with program partners to determine operational and environmental factors that had the greatest influence on oil vapor pressure.

On May 10, 2017, the EERC hosted a meeting of BPOP partners in Williston, North Dakota, to discuss the various design and operational factors influencing crude oil volatility. The meeting content included a review of the science of vapor pressure, the role of computational process modeling in optimizing vapor pressure management, lessons learned from field experience, and strategies to develop a basinwide understanding of crude oil volatility.

With this background, the EERC team worked with two BPOP partners that provided vapor pressure data, operating conditions, and wellsite design data. The EERC created computation models to predict crude oil vapor pressure based on different design features, operational conditions, and environmental conditions. The models were validated using site-specific data collected from two BPOP partner sites. Results from this study were summarized into a short technical brief and an accompanying set of presentation slides. The vapor pressure modeling work was presented to BPOP partners during the Annual Members Meeting August 8, 2018.

A short technical brief entitled "Vapor Pressure Modeling of Cold Weather Modifications for Bakken Surface Facilities" and an accompanying set of presentation slides entitled "Surface Facility Vapor Pressure Modeling" were uploaded to the BPOP website.

Tank Vapor Management

The EERC performed a comprehensive analysis of the impacts of operating conditions and environmental factors on tank vapors. Computational modeling was conducted to assess conditions that could lead to flammable mixtures of hydrocarbon vapors in tanks and vent lines, and field data from BPOP partners provided model validation. Results from this work have been shared with partner companies and provide a basis for facilities and operations engineers to implement engineering controls and operating practices necessary to ensure continued safe operation. A short technical brief entitled "Numerical Study of Headspace O_2 Concentration in Bakken Oil Storage Tanks" was uploaded to the BPOP partners-only website in October 2019. Additionally, an accompanying set of presentation slides entitled "Tank Headspace Flammability Considerations" was shared with partners.

Facility Optimization

A daylong workshop was held on November 12, 2019, in Williston, North Dakota, at the TrainND facility and included participants from ConocoPhillips, Equinor, Hess Corporation, Liberty Resources, Marathon Oil, and WPX Energy. Meeting content included an EERC presentation summarizing prior work relevant to facility optimization, group discussion about operational challenges in North Dakota, development of project ideas that could help address those challenges, and a prioritization of topics by each partner. The complete list of project topics included 1) gas capture, 2) flare/thermal oxidizer destruction efficiency validation, 3) assessment of centralized facility paradigm, 4) thief hatch evaluation, 5) process control algorithm for vapor pressure compliance, 6) data analytics of wellsite operational data, 7) well site automation and control, and 8) artificial lift.

Based on the partner priorities identified during the meeting, EERC staff developed detailed project scopes for the first three priorities listed. Activities related to gas capture are summarized under the subsequent topic heading "Environmental Support Task." Activities related to the second priority of assessing high-destruction efficiency flare devices was described previously under the subheading "Wellsite Emissions." Work associated with assessing centralized facilities, the third listed priority, is described here.

The use of centralized production facilities has the potential to provide some economy-of-scale benefit over the more common wellsite-based facilities. This is especially true in shale oil production when rapid production decline curves make matching production rate with facilities capacity challenging. The EERC developed a notional centralized facility design and production plan and compared the equipment utilization factor, emission implications, and capital cost for both centralized and wellsite-based configurations. The results from this analysis have been summarized in a PowerPoint presentation entitled "Analysis of Central Production Facilities." This information will be presented to BPOP partners in the next phase of the program, and additional analysis may be conducted to refine the analysis and document the advantages and challenges to implementation in North Dakota.

Partnership and Financial Information

BPOP was sponsored by the NDIC Oil and Gas Research Council, Marathon Oil (Marathon), and a consortium of Bakken producers and service companies. As shown in Table 1, the originally proposed budget for this program was $13,280,000. Marathon's expected in-kind contribution was $7,280,000. Marathon ultimately reported in-kind contributions of $12,615,401, which represents a 73% increase over the original commitment.

As the program progressed, the EERC retained some existing, and gained additional, industry partners and was able to secure an additional $2,050,000. In addition, the EERC secured $2,000,000 from DOE to complement the ongoing work to determine the feasibility of reinjecting captured rich gas into a Bakken reservoir to enhance oil recovery. Liberty provided in-kind contributions that support this programmatic scope for a total of $3,255,937.

Table 1 enumerates the evolution of the budget over the course of the program. The increase in scope and additional cost share resulted in an increase of approximately 95% over the original budget.

Table 1. BPOP – Budget Evolution

	Proposed Budget*	Final Budget
NDIC – Cash	$6,000,000	$6,000,000
Marathon – In-Kind	$7,280,000	$12,615,401
Industry Partners – Cash	TBD**	$2,050,000
Liberty – In-Kind	NA***	$3,255,937
DOE – Cash		$2,000,000
Totals	**$13,280,000**	**$25,921,338**
NDIC Share	45%	23%
Industry Share	55%	69%
DOE Share	NA	8%

* EERC Proposal 2016-0105.
** Additional cash and/or in-kind contributions from industry were anticipated and would be reported to NDIC as received.
*** Not applicable, not in proposed budget.

Cash contributions from industry totaling $2,050,000 were as follows:

- $300,000 each from ConocoPhillips, Equinor, Hess Corporation, Oasis Petroleum, Petro-Hunt, LLC, and WPX Energy for a total of $1,800,000.

- $250,000 from XTO Energy.

Expenses to date by funding source are listed in Table 2. Please note that, because of timing of receipt of industry membership payment, the EERC is estimating to carry over $100,000 of industry cash contributions to BPOP 3.0. It is estimated that the remaining funds will be spent through the end of May 2020.

Table 2. BPOP – Expenses to Date

	Final Budget	Expenses to Date*
NDIC – Cash	$6,000,000	$5,999,645
Marathon – In-Kind	$12,615,401	$12,615,401
Industry Partners – Cash	$2,050,000	$1,949,581
Liberty – In-Kind	$3,255,937	$3,255,937
DOE – Cash	$2,000,000	$1,999,849
Totals	**$25,921,338**	**$25,820,413**

* As of the date of this report, not all expenses have posted. Expenses above are an estimate as of June 15, 2020.

CONCLUSION

BPOP represents a highly successful, award-winning collaboration between the state of North Dakota and the petroleum industry. The work performed within BPOP has achieved the stated goal of continuing to address emerging threats and issues to petroleum production in North Dakota. This premier partnership program has been cited as an exemplary model by others nationwide. It has demonstrated that state lawmakers, state regulators, and industry can work together for positive results for shareholders and taxpayers alike.

At the time of this report, the state of North Dakota has opted to extend this successful program for an additional 3 years. DOE has signed on as an anchoring partner, while the EERC anticipates ongoing support from partners and continues to solicit additional, substantial partners interested in leveraging their corporate research power with this collaborative state–industry framework.

The future of the Bakken can be viewed through two distinct lenses: one focused on the near-term and the other focused on the long-term. The EERC recognizes the unprecedented economic and social challenges confronting Bakken oil and gas producers, and the state of North Dakota, in 2020 and, likely, into 2021. Many operators are in a mode of financial preservation. Now more than ever, reducing capital and operating costs by optimizing operations is essential to maintaining economic viability. With committed support from a triad of institutions (state, federal, and industry), BPOP is uniquely structured to address those near-term challenges through targeted research activities.

A view through the long-term lens requires the context of history. For over a century, the oil and gas industry has played an essential role in building and maintaining the high standards of living that have come to be expected by generations of Americans. As America and the world

emerge from the economic shadow cast by the COVID-19 pandemic, demand for petroleum products will recover, and the oil and gas industry will once again take its integral place in society. The goals of the next phase of BPOP are to provide that industry, and its state and federal partners, with science-based insight to bring the Bakken back online as efficiently as possible and maintain the long-term economic and environmental sustainability of the Bakken play in North Dakota. Through BPOP, the EERC will strive to provide stakeholders with the knowledge needed to plan and implement innovative development strategies to lead the Bakken, and North Dakota, out of a period of pandemic-driven doldrums and into the next decade of economic growth.