



April 8, 2010

Ms. Karlene Fine
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State Capitol, 14th Floor
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Dear Ms. Fine:

Subject: Final Report Summary Entitled "Bakken Water Opportunities Assessment – Phase 1"
Contract No. G018-036; EERC Fund 14699

We certify that the Energy & Environmental Research Center (EERC) agreements for this project include the following:

Sponsor	Award	Expended
North Dakota Industrial Commission	\$25,000	\$25,000
North Dakota Petroleum Council	\$10,000	\$9616
U.S. Department of Energy	\$25,000	\$24,949

Enclosed is the subject final report summary for your review.

If you have any questions, please contact me by phone at (701) 777-5247 or by e-mail at dstepan@undeerc.org.

Best regards,

Daniel J. Stepan
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DJS/hmv

Enclosure

c/enc: Ron Ness, North Dakota Petroleum Council
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BAKKEN WATER OPPORTUNITIES ASSESSMENT – PHASE 1

Final Report Summary

(for the period of June 19, 2009, through March 15, 2010)

Prepared for:

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BAKKEN WATER OPPORTUNITIES ASSESSMENT – PHASE 1

PROJECT SUMMARY

The Energy & Environmental Research Center (EERC) Northern Great Plains Water Consortium (NGPWC) identified a potential opportunity to economically treat and reuse water that is used in hydraulic fracturing operations in the Bakken oil formation in North Dakota. The Bakken Water Opportunities Assessment project was undertaken with funding provided by the North Dakota Industrial Commission Oil and Gas Research Council, the North Dakota Petroleum Council, and the U.S. Department of Energy. The project compiled information on the current water use practices for hydraulic fracturing (frac) in the Bakken play, collected and analyzed frac flowback water data from five different oil producers operating at various locations in the Bakken, assessed potentially applicable mobile fracture water-recycling technologies, worked with industry to disseminate information about the project, and developed recommendations and plans for a Phase 2 evaluation.

Traditional sources of freshwater for hydraulic fracturing include glacial and bedrock aquifer systems, surface waters, and municipal supplies. The continued use of these sources to satisfy the increasing demand for freshwater will not be practical if future demands are to be met. The largest source of freshwater in the Bakken play is Lake Sakakawea, but access to this supply and its proximity to future drilling and fracturing activities make the lake less desirable as a long-term supply.

Treatment and recycling of frac flowback water was investigated as a means to reduce the demand for freshwater and provide a supplemental supply near drilling and fracturing activities. The character of the frac flowback water with respect to both quantity and quality presented significant challenges for widespread water-recycling opportunities. A relatively small percentage (17% to 47%) of the water used in hydraulic fracturing in the Bakken is typically recoverable in a reasonable time (2 to 10 days). Further, the dissolved solids levels in the frac flowback water increase rapidly and to levels as high as 220,000 mg/L. These factors provide significant challenges for developing cost-effective treatment strategies, even with the most robust technologies. While there will certainly be niche opportunities using certain technologies to recycle frac flowback water, widespread recycling will not likely be economically viable.

The regional and national importance of providing sufficient volumes of water for such an extremely high-value use cannot be overstated. These water supplies will need to come from a variety of resources. One opportunity is to upgrade marginal-quality groundwater resources to satisfy a portion of the demand. An evaluation of a membrane technology for the treatment of nonpotable groundwater to supply water for hydraulic fracturing in the same geographic area is being conducted as a Phase 2 Bakken Water Opportunities Assessment project.

BAKKEN WATER OPPORTUNITIES ASSESSMENT – PHASE 1

INTRODUCTION

Water is the most critical limiting resource throughout the world. Sufficient quantities of good-quality water are needed for several competing uses, including energy production, growing and processing high-value crops, industrial manufacturing, and expanding populations. The Northern Great Plains Water Consortium (NGPWC) is a partnership between the Energy & Environmental Research Center (EERC), the U.S. Department of Energy (DOE), and key stakeholders representing oil and gas companies, power generation utilities, industry, municipalities, and other entities interested in addressing critical water issues in the north-central United States. The primary goal of the NGPWC is to assess, develop, and demonstrate technologies and methodologies that minimize water use and reduce impacted water discharges from a range of energy technologies, including coal combustion, coal gasification, coalbed methane, and oil and natural gas production.

The NGPWC identified a potential opportunity to economically recover and reuse water that is used in the oil field to pressurize and fracture oil-bearing formations to increase permeability and enhance the flow and recovery of oil. In North Dakota's Bakken play, water used in hydraulic fracturing ranges from approximately 10,000 to 60,000 barrels (bbl) (0.5 to 3 million gallons), depending on the number of stages in the fracture. Multistage fractures, which require more water than single-stage fractures, are increasingly being employed in the Bakken Formation because they generate fractures more effectively.

Relatively low-total-dissolved-solids and bacteria-free water is required for hydraulic fracturing. Typically, the freshwater comes from glacial and bedrock aquifer systems, surface waters, and municipal supplies. The use of municipal supplies can have a profound effect on small community water supplies, many of which have a relatively low treatment capacity. The additional demand on shallow groundwater systems can also have a significant impact, particularly on small glacial channel aquifers that have low recharge rates.

Recycling the water used to hydraulically fracture oil wells could have a positive effect on available resources, conserving the supply for other beneficial uses. Fracture water is typically hauled to the well site in 7500- to 8000-gallon (180- to 190-bbl) tanker trucks. Once the formation fracturing is completed, the water flows back (frac flowback) as the pressure in the well is released. After sand removal and oil recovery, the frac flowback water is typically disposed of via deep-well injection. Transportation costs, particularly for long haul distances, can be excessive for both freshwater and flowback water. Treatment and reuse of frac flowback water may be an extremely attractive economic alternative to disposal via deep-well injection.

OBJECTIVE

The overall goal of the project was to provide industry with data and information on the technical and economic potential to recycle frac flowback water. Specific Phase 1 objectives

included 1) gathering data on current water use practices, 2) investigating flowback water quality with respect to time and location, 3) assessing current water-handling costs, 4) assessing the use of water-recycling technologies and evaluating technical and economic suitability for application to Bakken Formation flowback water, 5) evaluating the current state of existing water-recycling technologies, 6) developing plans for a full-scale field evaluation at a host Bakken location, and 7) information dissemination.

RESULTS AND DISCUSSION

Task 1 – Current Water Use Practices

There are different types of fracture fluids used in the Bakken play, and each has a different formulation. While fracture fluids can range from water to slickwater to gels, they require freshwater as a makeup fluid. This ensures the ability of individual producers to develop consistency in the composition of the fracturing fluid and the desired fracture results.

Common freshwater acquisition points for frac fluid makeup are from existing water depots and municipalities. Figure 1 depicts the location of existing and proposed water depots, as well as the permitted (or requested) water allocation at each location. While some municipalities have extra capacity to provide water to the oil industry, they must first request an industrial permit from the North Dakota State Water Commission (SWC), and it should be noted that the additional available capacity would still not meet all of the industry needs.

In response to the increasing demand for freshwater, SWC has received numerous permit applications for additional groundwater appropriation for withdrawals at existing water depots as well as permit applications for new water wells. Prescribed permitting procedures require a published public notice, followed by a 30-day comment period. New permit applications are being contested by environmental groups, which results in significant delays in the overall permitting process. Permits that would normally be issued within a 70- to 90-day period are taking in excess of 9 months.

SWC is also concerned about mining of fresh groundwater resources, specifically surficial glacial aquifers (which are of limited extent in western North Dakota) and the Fox Hills–Hell Creek Aquifer. The Fox Hills–Hell Creek Aquifer is a widespread, reliable artesian aquifer. Because it is artesian and flows at the surface, it provides a valuable supply of water for remote areas with no electricity for pumping. However, over the past several decades, the hydraulic pressure of the formation has been declining as a result of the large number of wells that are withdrawing water from the formation (Honeyman, 2007). SWC estimates that at the current rate of decline in hydraulic pressure, wells screened in the Fox Hills–Hell Creek Formation will stop flowing within the next 100 years (Honeyman, 2007). Because of the low recharge rate of the Fox Hills–Hell Creek Aquifer, SWC is reluctant to permit new appropriations for withdrawals from this formation, particularly for industrial use.

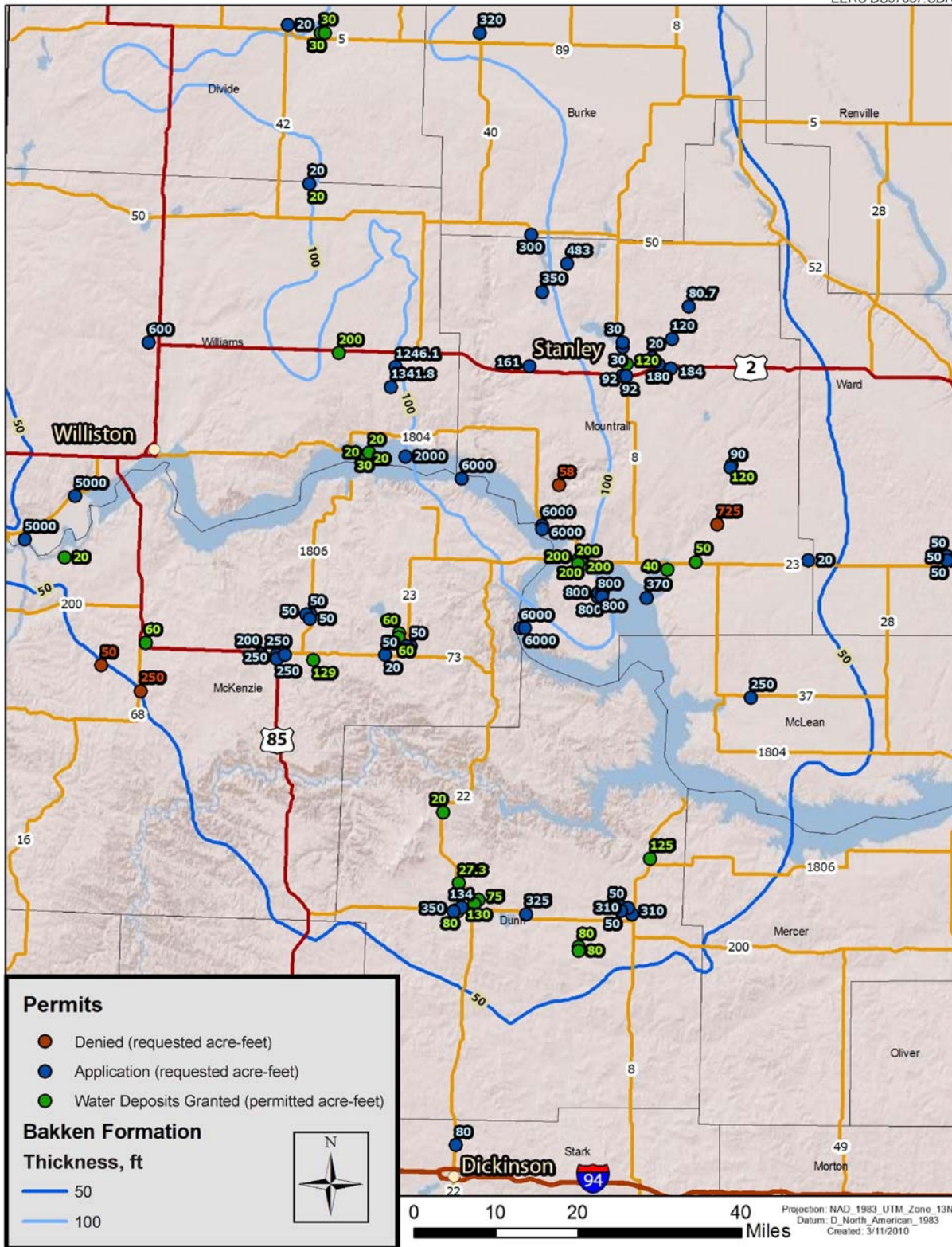


Figure 1. Existing and proposed water depots as of March 2010 (Source: North Dakota State Water Commission).

With the exception of the Missouri River system, most surface waters in the Bakken region do not provide a reliable source of water because of seasonal flow variations. Sufficient flows exist only in the spring of the year, during periods of snowmelt. Given the concerns over mining of surficial aquifers, groundwater-permitting issues, and the relative lack of surface water supplies in many areas of the state, SWC is encouraging the oil industry to seek withdrawals from the Missouri River System for use in Bakken development. However, there are several issues related to using Lake Sakakawea water, key among them being access to the lake and proximity of the resource to drilling locations.

While SWC handles water appropriations from the lake, permission for access at a particular point of diversion must be granted by the U.S. Army Corps of Engineers (Corps). This creates additional delays in accessing the resource because having to obtain permission from multiple agencies can slow the permitting process. In addition, it is not yet clear where access to the lake may or may not be allowed because of the potential disturbance of cultural sites and/or threatened and endangered species. SWC is working with the Corps and the U.S. Fish and Wildlife Service to identify corridors of access to the lake for industrial purposes and to publish access maps. It is unclear at this time when these maps will be available.

It is interesting to note that in late 2009 and early 2010, several permit applications were submitted to SWC for allocations exceeding 1000 acre-feet from Lake Sakakawea. These requests are primarily to supply water to the oil industry. The largest requested appropriation of 24,000 acre-feet was made by International Western Company, a Texas-based company, which has identified four proposed points of diversion on Lake Sakakawea (each at a requested appropriation of 6000 acre-feet) from which it is planning to pump water into a series of small reservoirs interconnected by underground pipeline (International Western Company, personal communication, February 2010). The reservoirs will be strategically located near areas of drilling activity, including locations south of Tioga, northwest and southwest of New Town, and north of Dodge.

The city of Dodge is also in the process of applying for a permit to allow its additional water capacity to be used for the oil industry. It currently estimates that it has an additional capacity of nearly 1500 acre-feet from the appropriation that it receives via the Southwest Pipeline project.

While there are some projects in the works that will improve the availability of freshwater resources for use in Bakken development, in the near-term, there appears to be a significant water shortage. The Missouri River System has more than enough water available for Bakken development, but preferred access points to the lake are still undefined by the Corps. Additionally, there will be high costs associated with long transportation distances from the lake to new drilling locations. Given the current need for water, coupled with high water acquisition, transportation, and disposal costs, nontraditional options for water supplies may be viable, such as municipal wastewater treatment or treatment of nonpotable groundwater resources.

Task 2 – Flowback Water Characteristics

Task 2 was designed to identify information and collect new data regarding the quantity and quality of Bakken play hydraulic fracture flowback water. The hope was that sufficient data could be collected to evaluate the effect of geographic, geologic, and hydraulic fracture characteristics (e.g., water frac, gel frac, slickwater frac, length of shut-in) on the quantity and quality of water recovered. These quantity and quality data could then be used to help assess the potential for treatment and reuse of the water in additional hydraulic fracture events.

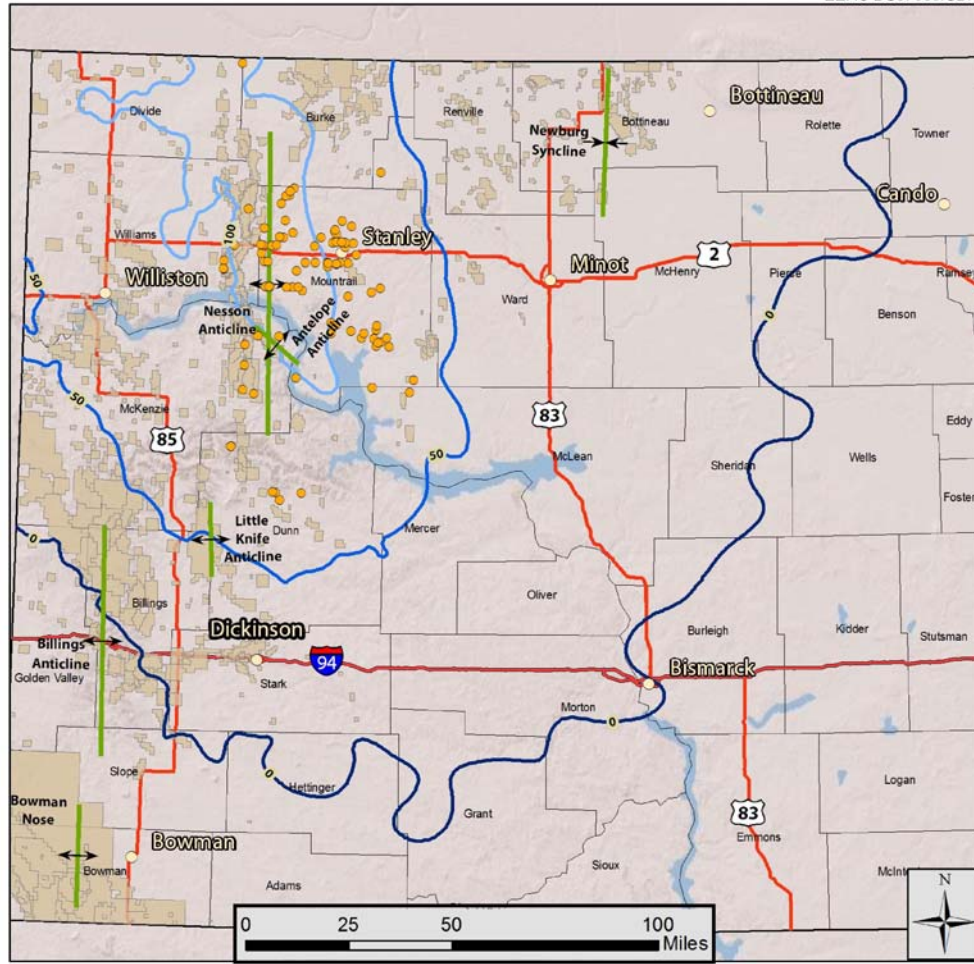
Five different companies that practice hydraulic fracturing in the Bakken participated in this assessment by providing frac flowback water information and data from a total of 89 wells (Figure 2). While the data were extensive, they were not comprehensive. Table 1 presents a summary of the data collected. The data varied in detail with respect to quantity and quality, with portions of the data set lacking the information critical for a detailed and accurate assessment but adequate for use as a basis in making generalized conclusions. Water samples from several frac flowback events were sent to a contract laboratory for detailed chemical analysis to document water quality changes over time and flowback volume. EERC personnel attended the flowback event from one long-shut-in time hydraulic fracture event. Very little flowback water was recovered during the flowback period, and the system was quickly converted from flowback to production mode because the well was producing mostly oil. Samples collected during that flowback period were also submitted for detailed chemical analysis.

This section of the report presents representative data concerning flowback water quantity, flowback water quality, and a generalized interpretation of what the quantity and quality information collected suggests regarding the potential for Bakken hydraulic frac flowback water treatment and reuse.

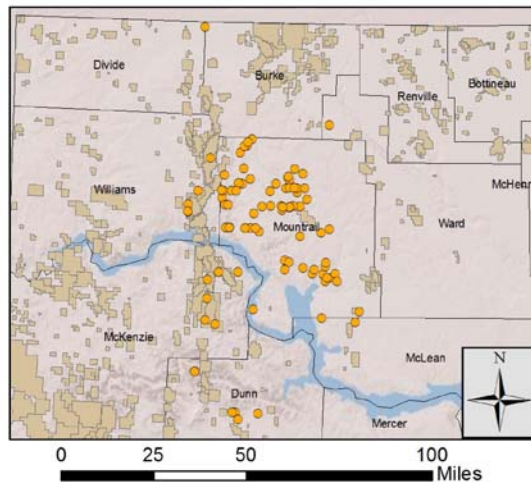
General Description of Hydraulic Fracturing

After wells have been drilled, a well field service company comes in with large water-holding tanks and pumps. Water is brought in (usually by tanker truck) to fill the water tanks. This water is mixed with sand (proppant) and chemicals (e.g., surfactants, gels, oil) and injected at a high flow rate and pressure into the formation in order to hydraulically fracture the formation. This opens channels in the formation and increases the near-field porosity to provide flow paths for the oil. The fluid pumped into the formation may be pumped in all at once (single-stage fracture) or in several stages (multistage fracture) over a period of one to several days (up to five is common). The fluid is then shut in for a period of time before it is allowed to flow back. The length of time from finishing the fracturing process to the start of flowback can be as short as 4 hours (no shut-in) to as long as 30 days. The most common shut-in procedures seem to be none, overnight, and over-the-weekend shut-in times.

After the shut-in period is over, the fracture fluid is allowed to flow back out of the formation. In the Bakken, this typically occurs without the need for pumping because of the formation pressure and residual pressure associated with fracturing operations; hence, pumping in the Bakken is not required. The material that comes out of the well during flowback includes residual proppant (sand), water (enriched in dissolved salts from the formation), oil, and gas. The



Well Focal View



Legend

- Wells (89 total)
- ↕ Structural Features

Bakken Formation Thickness (ft)

- 0
- 50
- 100

■ North Dakota Oil Fields

Projection: NAD_1983_UTM_Zone_13N
Datum: D_North_American_1983
Created: 3/11/2010

Figure 2. Locations of Bakken oil wells where frac flowback data and information were used in the assessment.

Table 1. Summary of Data Types Collected

Company	Frac Fluid Volume	Flowback Volume	Flowback Salinity or TDS	Detailed Chemistry	Location	Closed-In Time or Frac Water Contact Time	Number of Wells
A	Estimated	Versus time	Salinity	Yes	X		
B	Known (three of five wells)	Versus time	TDS ¹		X		5
C	Estimated	Versus time	Salinity and TDS	Yes	X	30 days	
D	Known	Total and initial volume to TDS cutoff	Only as cutoff at TDS = 60,000 ppm		X		62 in 10 areas
E ²	Known	Versus time	Salinity		X	4 hours to 7 days	4
E ³	Unknown	Unknown	TDS	Major ions, hardness	X		7

¹ Total dissolved solids.

² Service Provider A performed hydraulic fracture.

³ Service Provider B performed hydraulic fracture.

sand and gas are typically separated from the oil and water in a cyclone or gravity separator, and the gas is utilized on-site, sent to a gas-processing facility, or flared. The oil and water are separated in an API (American Petroleum Institute) oil–water separator. The water is collected in a pit and/or in fracture tanks used to hold the water prior to the fracture event. The water collected during flowback is the focus of this investigation. The oil is sent to the production separators (heater–treaters) for the removal of any remaining water and collected in tanks in preparation for shipping to a refinery. Because the Bakken Formation has little to no free water, any water collected over time with the oil might be considered flowback because its origin was likely the fracture event. However, operationally, the period of flowback is considered over when the well operation switches to a normal production mode. The actual fraction of water in the produced fluid that is consistent with the end of flowback might vary from operator to operator but, commonly, it can be considered to occur when the liquid well product contains less than 25% water.

Flowback Water Quantity

Flowback consists of both water and oil. Initially, frac flowback is water, but the amount of oil in the flowback increases over time. The relative amount of oil in the flowback typically dictates the length of flowback operations and, thus, the corresponding period of time when water recovery may be feasible based on the relative amount of water in the flowback. Figure 3 presents frac flowback data from a selected well. The figure shows cumulative total flowback (oil plus water), cumulative water flowback, cumulative oil flowback, the volume of frac water not recovered, and the percent of oil in a grab sample of flowback versus time. In the example, 12,775 bbl of water was injected during hydraulic fracturing, and the duration of the flowback period was approximately 45 hours, at which time the well was switched to a production mode. At that point, the total flowback contained 63% oil and 37% water. The water recovered during the flowback period represented 33% of the total used in the fracturing process.

Flowback quantity data, similar to those presented in Figure 3, were obtained for a total of 12 wells from data provided from four of the participating producers. The volume of freshwater used in the fracturing was known for seven of those wells. For the other five wells, a frac water volume of 23,000 bbl was assumed. Plots of these data (similar to Figure 3) are provided in Appendices A-1 (known frac fluid volume) and A-2 (assumed 23,000 bbl frac fluid volume). Additional flowback quantity data were provided for 62 additional wells, but the nature of those data did not allow for a similar analysis. Data from these wells will be discussed later.

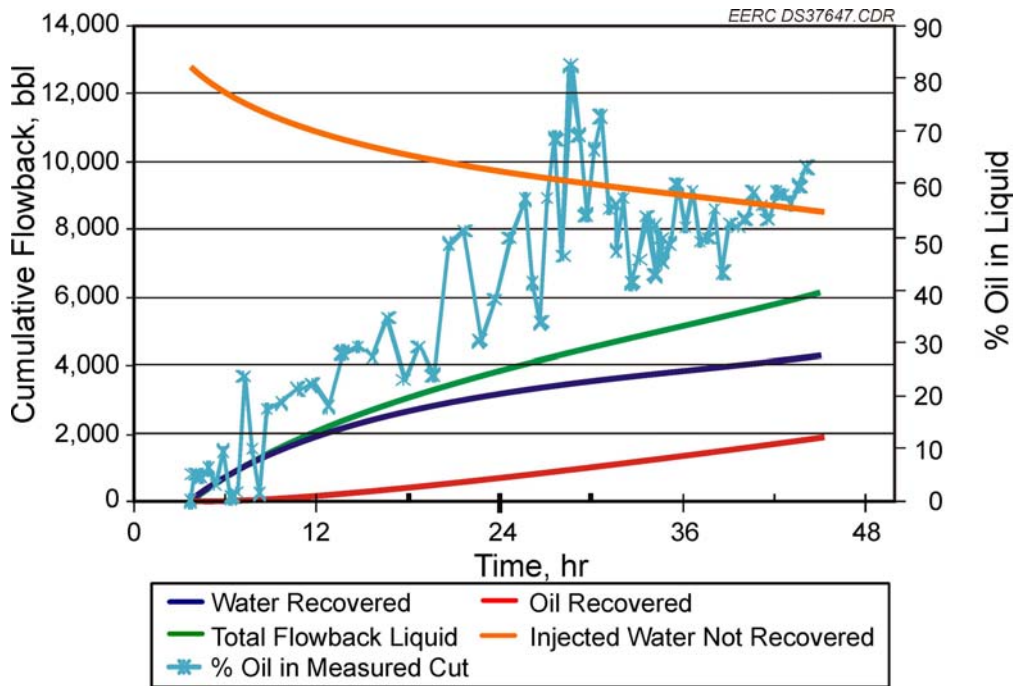


Figure 3. Cumulative flowback of oil and water for a typical hydraulic fracture event. Flowback continued until the proportion of oil in the fluid being produced was 63%. At that point, 33% of the injected water had been recovered.

Table 2 summarizes the flowback water quantity data, including fracture fluid volume, the duration of flowback, and percent water recovery at the end of flowback, as well as statistical information (maximum, minimum, mean, median, standard deviation) for four of the producers. The observed flowback periods ranged from around 2 days to as long as 10 days, with a median time of almost 2 days and an average of 3 days. During the first 24 hours of flowback, the amount of water recovered ranged from as little as 3% to as much as 26%, with a median value of 12%. At the end of the flowback period (as indicated by the end of flowback data collection by the producer), flowback water recovery ranged from 5% to 41% of the fracture water injected, with a median value of 17%.

Table 3 summarizes flowback water recovery information from data provided for 62 wells from a single producer. These data were originally provided as barrels of water recovered that had TDS levels of less than 60,000 ppm and barrels of water at the end of the flowback period and the duration of flowback. The flowback period for this producer ranged from nearly 3½ to almost 18 days, with a median flowback period of just over 9½ days, much longer than those reported by the other producers. The percentage of water recovered ranged from 7% to 75% of the original fracture water injected, with a median value of 47%, which was also higher than typical values of the other producers. The water recovered with TDS <60,000 mg/L represented 0% to 39% of the injected volume, with a median of 5%. Five of the 62 wells produced no water with salinity levels under 60,000 ppm, and the median well produced only 974 bbl of water at less than 60,000 mg/L of TDS, which represented 5% of the injected water volume for that well. Overall, of the 1,088,590 bbl of water injected during fracturing operations, only 10.5% (114,172 bbl) was recovered at a salinity of less than 60,000 mg/L.

Table 2. Summary of Flowback Quantity for Producers A, B, C, and E

Producer	Well	Fracture Fluid	Length of	Water Recovered	Cumulative Water
		Volume	FlowBack	in 24 hours	Recovered
		bbl	hours	% of injected	% of injected
A	1	23,000	124.0	3	13
	2	23,000	120.0	4	9
B	1	19,105	95.0	25	41
	2	19,007	95.5	23	33
	3	19,106	93.5	22	36
C	1	23,000	36.5	4	5
	2	23,000	33.5	7	8
	3	23,000	37.5	4	5
E	1	8326	36.0	16	21
	2	12,775	45.2	25	33
	3	52,000	44.0	4	6
	4	13,065	36.0	26	30
		Minimum	33.5	3	5
		Maximum	124.0	26	41
		Median	44.6	12	17
		Mean	66.4	14	20
		Standard Deviation	36.0	10	14

Table 3. Summary of Flowback Quantity for Producer D

	Fluid Pumped, bbl	Duration of Flowback, days	Flowback Water with TDS <60,000 mg/L, %	Total Flowback Water Recovered, %
Minimum	10,966	3.42	0	7
Maximum	36,333	17.75	39	75
Median	17,476	9.58	5	47
Mean	17,587	9.92	12	45
Standard Deviation	4417	3.21	12	16

In general, the volume of water recovered in the flowback is significantly less than what was originally anticipated. The reason for the low initial water recovery is not readily understood, but can be attributed in part to the formation being oil-wet (little to no free formation water), and the water being retained in the fracture and pore space and in spaces where salts were dissolved by frac water. Based on the available data, it was not possible to develop a correlation between flowback water recovery and shut-in time, nor was it possible to develop any correlation between well location and the amount of flowback water recovered. While the water may be recovered over a long period of time with continued oil production, the amount of water that can be readily recovered and recycled in a timely manner is typically a relatively small percentage of the original water used to fracture the formation. This will significantly impact the widespread economic viability of frac flowback water recycling in the Bakken play. The low recovery of water, however, will reduce the overall cost for disposal by reducing the total volume requiring disposal.

Flowback Water Quality

Oil producers typically measure frac flowback water quality in terms of salinity using a refractometer. Salinity and/or conductivity levels of flowback water versus time were provided by four of the five participating producers, and one of the producers provided data in terms of water recovered with salinity levels less than 60,000 ppm. Selected samples of frac flowback water over time from two of the producers were submitted to contract laboratories for a more detailed chemical characterization. A third producer provided concentration data for major ions.

Figures 4–7 illustrate dissolved solids content of the flowback water versus flowback water throughout the flowback period. Figure 3 presents the data in terms of specific conductance and TDS concentration calculated as the sum of measure ion concentrations, and the other figures show salinity values. There is a wide range in the concentration of dissolved salts in the frac flowback water, not only between different producers, but among different wells of a single producer (Figure 7). These data show that the flowback water salinity values typically range from 60,000 ppm to over 200,000 ppm. Values around 100,000 ppm are typical, and levels greater than 200,000 ppm are not uncommon. Very little frac flowback was shown to have salinity levels less than 60,000 ppm. Additional plots of salinity versus time of flowback are provided in Appendix B. The data in Appendix B are from the same flowback events as the data in Appendix A.

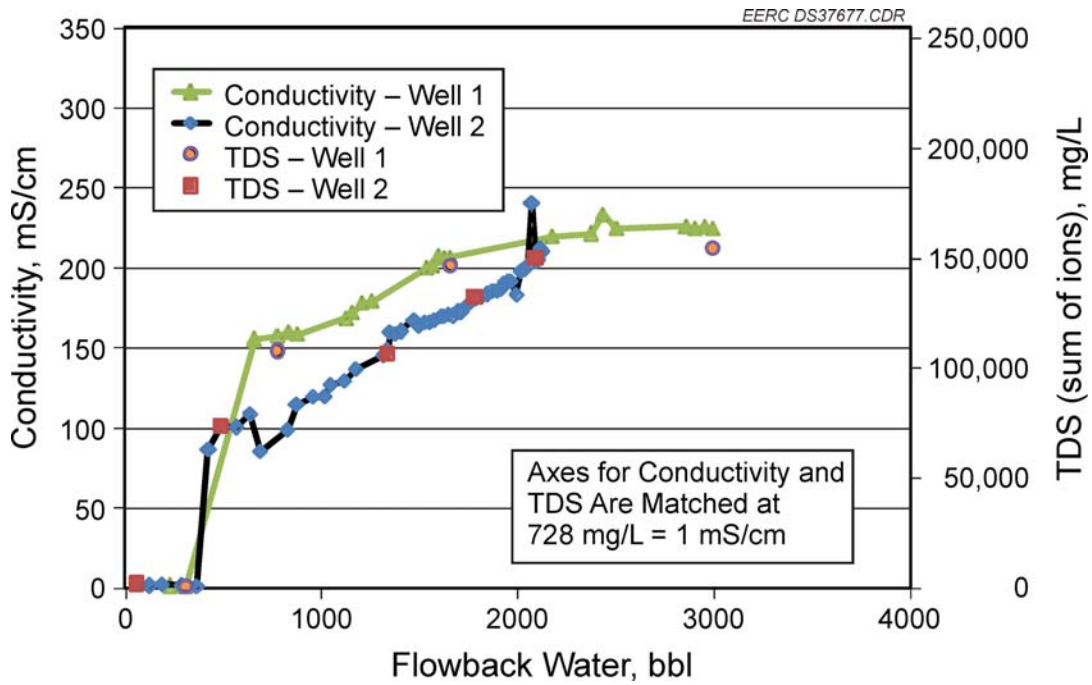


Figure 4. Conductivity and TDS versus flowback water volume, Producer A.

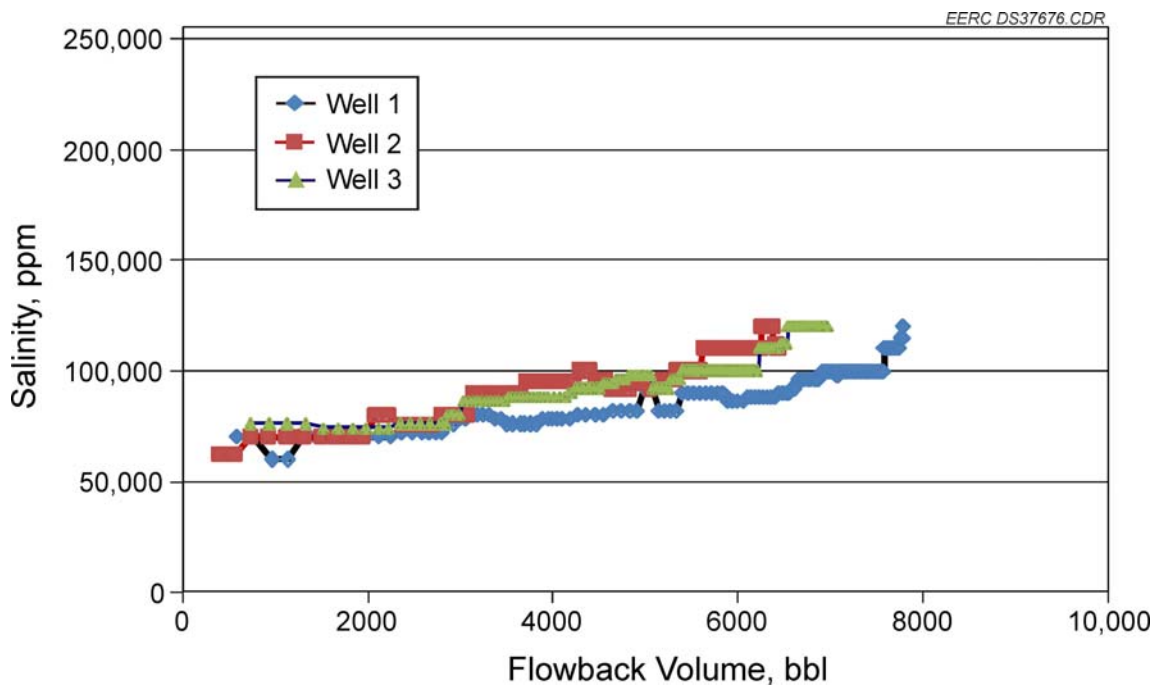


Figure 5. Salinity versus flowback water volume, Producer B.

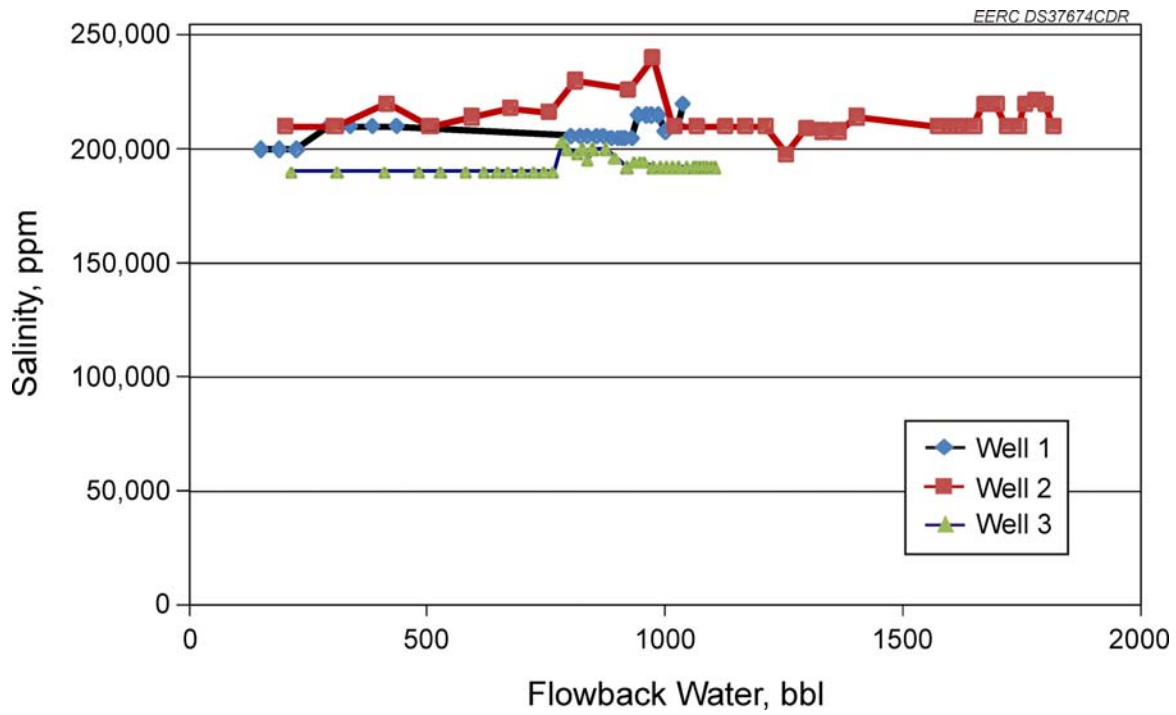


Figure 6. Salinity versus flowback water volume, Producer C.

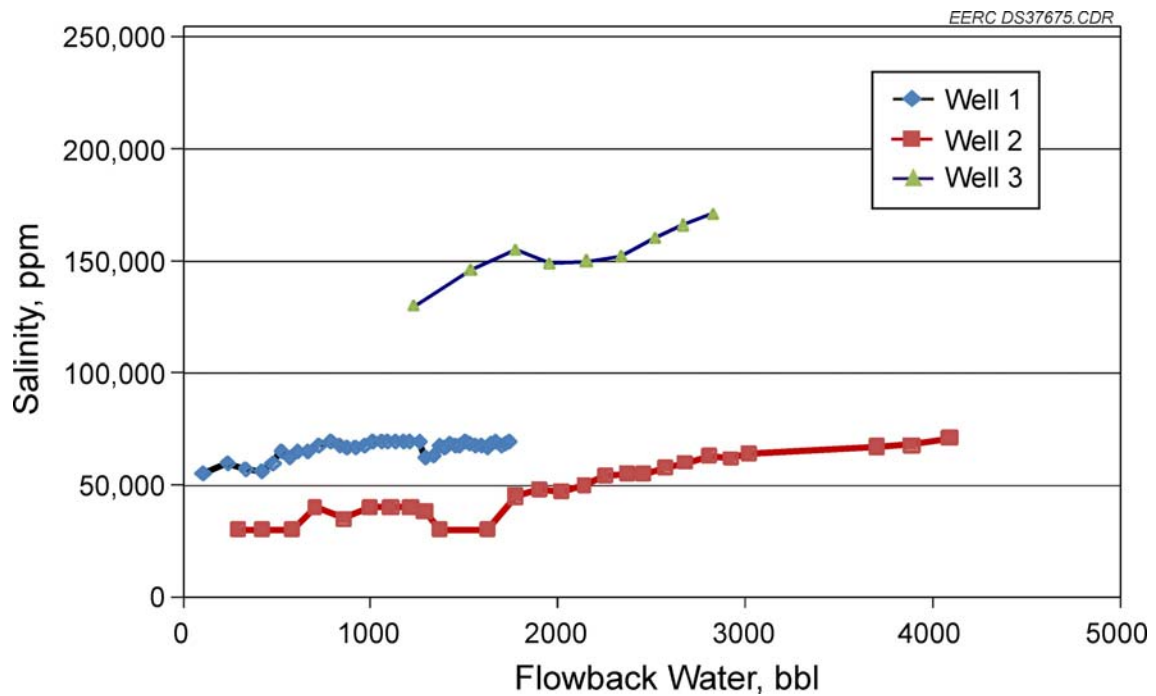


Figure 7. Salinity versus flowback water volume, Producer E.

Detailed chemical composition data were collected on selected flowback water samples from three of the producers participating in the project. Characterization results from representative samples collected at a time around 3500 bbl of cumulative total flowback are listed in Table 4, with the major ion concentrations compared graphically in Figure 8. All analyses were confirmed to have charge balance errors (CBE) of less than $\pm 5\%$ (see explanation of CBE in Appendix C). Sodium chloride (NaCl) is the dominant salt comprising 91.1%, 89.8%, and 95.0% of the TDS in the Producer A, C, and E well flowback waters, respectively. Calcium is present at concentration ranges between 7540 and 13,500 mg/L. Other ions detected at concentrations of 1000 ppm or greater in at least one sample are magnesium, potassium, strontium, and sulfate. Boron, bicarbonate, and iron were each detected at concentrations above 100 ppm in at least one sample. The pH was found to be mildly acidic, ranging from 5.47 in the sample from Producer E to 6.53 in the sample from Producer A.

Table 4. Flowback Water Chemical Analytical Results on Three Select Wells

Producer/Well	A/2	C/2	E/
Total Flowback, bbl	3688	3283	Unknown
Water Flowback, bbl	2090	1611	Unknown
Charge Balance Error, %	1.74	-0.752	-0.220
Cations/Conc.	mg/L	mg/L	mg/L
Calcium (Ca)	8010	13,500	7540
Barium (Ba)	7	24.6	0
Magnesium (Mg)	630	1440	1750
Iron (Fe)	ND ¹	72	120
Potassium (K)	3140	5770	0
Sodium (Na)	47,100	62,700	74,600
Phosphorus (P)	ND	0.03	NR ²
Silica (Si)	7	6.41	NR
Strontium (Sr)	518	1010	NR
Boron (B)	192	39.9	NR
Manganese (Mn)	4	10.2	NR
Copper (Cu)	ND	0.21	NR
Molybdenum (Mo)	ND	<0.2	NR
Zinc (Zn)	2	11.3	NR
Aluminum (Al)	ND	<1	NR
Anions/Conc.	mg/L	mg/L	mg/L
Sulfate	680	300	1000
Chloride	90,000	133,000	133,000
Bicarbonate	122	140	610
Other Measurements			
pH	6.53	5.62	5.47
Specific Gravity	1.0961	1.155	1.14
Specific Cond., mS/cm	205	220.8	NR
TDS (calculated), mg/L	150,000	218,000	219,000

¹ Not detected,

² Not reported.

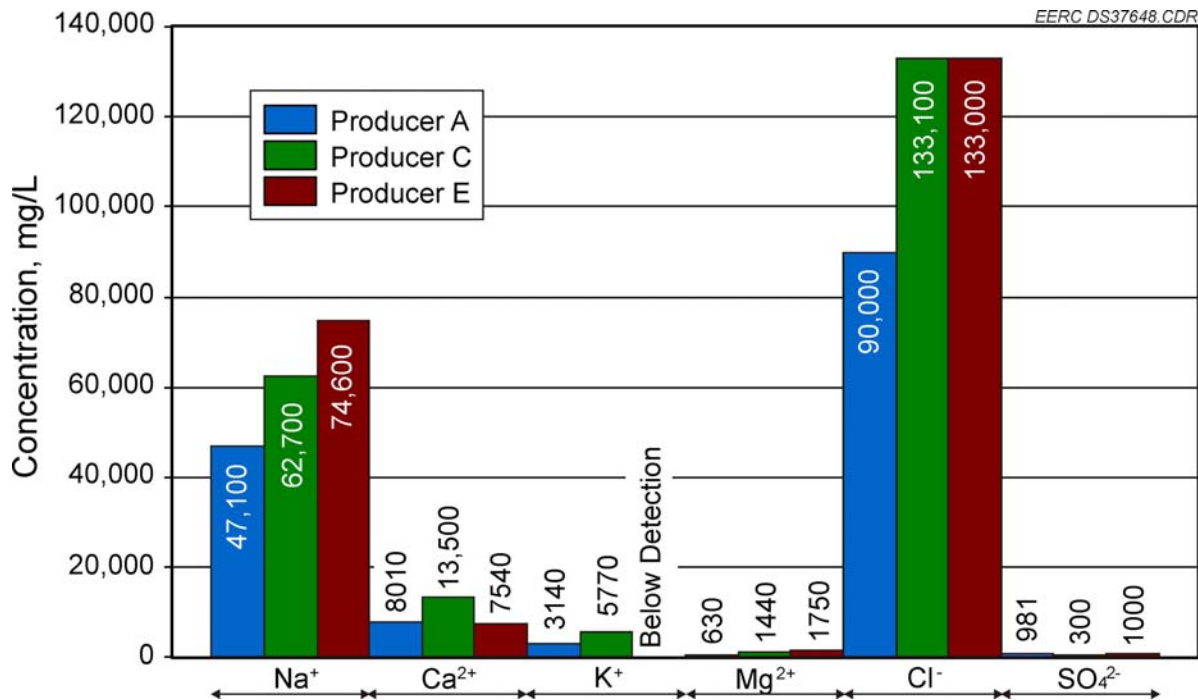


Figure 8. Major ion distribution for wells in Table 4.

Table 5 presents detailed chemical characterization data over time during the flowback period from Producer A, Well 2 (Figure 3). Figure 9 shows the changes in specific ion concentration and illustrates increasing concentration with time during the flowback period.

The very high TDS levels in the Bakken frac flowback water will present a significant treatment challenge. Figure 10 presents information on the applicability of desalination technologies over a range of TDS concentrations. Traditional desalination technologies such as reverse osmosis (RO) typically are capable of treating waters with TDS levels up to 40,000 mg/L. Thermal treatment technologies such as mechanical vapor recompression (MVR) are more applicable to treating high-TDS waters, such as those found in certain Bakken flowback situations, particularly if MVR is coupled with pretreatment to reduce the concentration of divalent ions typically associated with scaling. Even with pretreatment, the very high sodium chloride in Bakken flowback water will require special consideration of metallurgy for treatment components. Expensive metals such as titanium that are resistant to corrosion and chloride stress corrosion will be required for high-temperature thermal recovery processes treating chloride Bakken flowback water.

Table 5. Analytical Results for Producer A, Well 2, Samples Versus Time

Sample No.	1	2	3	4	5
Total Cumulative Flowback Water, bbl	54	487	633	2778	3688
CBE, %	5.35	-1.54	1.03	0.418	1.74
Cations/Conc.	mg/L	mg/L	mg/L	mg/L	mg/L
Calcium (Ca)	105	3496	5350	6740	8010
Barium (Ba)	<1	2	5	6	7
Magnesium (Mg)	36	290	425	537	630
Iron (Fe)	3	8	40	ND	ND
Potassium (K)	28	1816	2466	2790	3138
Sodium (Na)	540	22,285	33,225	40,980	47,080
Phosphorus (P)	18	2	2	ND	ND
Silica (Si)	12	16	16	8	7
Strontium (Sr)	4	225	351	441	518
Boron (B)	1	102	147	174	192
Manganese (Mn)	<1	3	4	4	4
Copper (Cu)	ND	ND	ND	ND	ND
Molybdenum (Mo)	ND	ND	ND	ND	ND
Zinc (Zn)	ND	ND	ND	1	2
Aluminum (Al)	ND	ND	ND	ND	ND
Anions/Conc.	mg/L	mg/L	mg/L	mg/L	mg/L
Sulfate	627	688	742	719	681
Chloride	500	45,000	64,000	80,000	90,000
Bicarbonate	244	229	183	151	122
Other Measurements					
pH	7.11	6.98	6.92	6.66	6.53
Specific Gravity	1.0010	1.0495	1.0696	1.0860	1.0961
Specific Cond., mS/cm	3	102	149	182	205

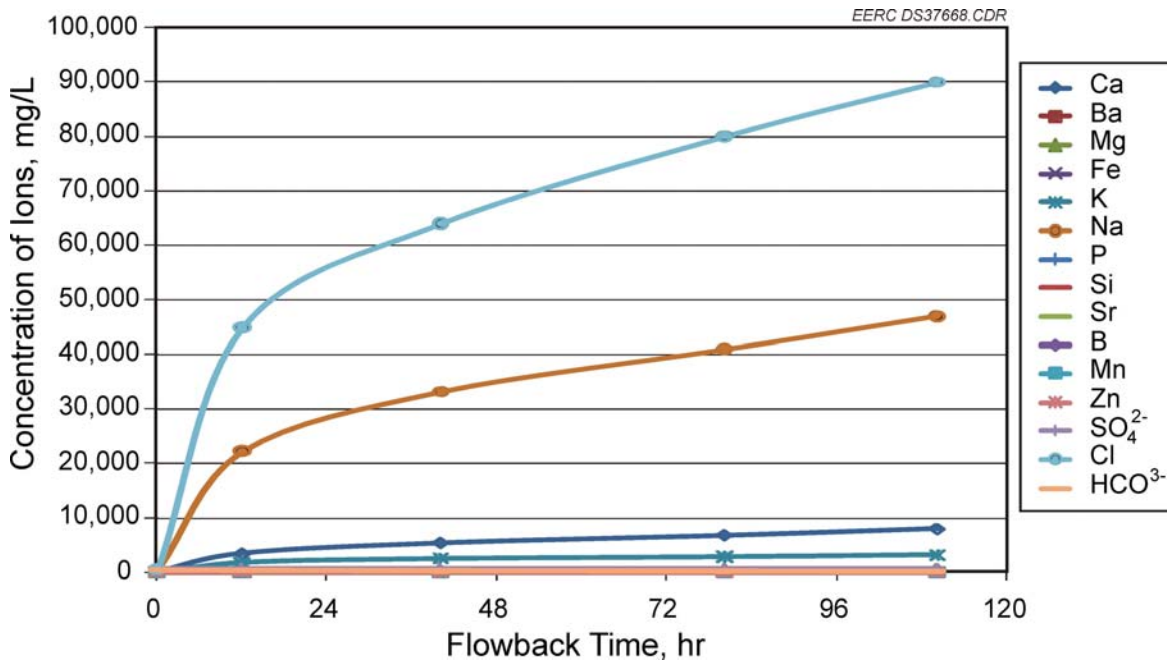


Figure 9. Changes in specific constituent concentration in frac flowback water versus time.

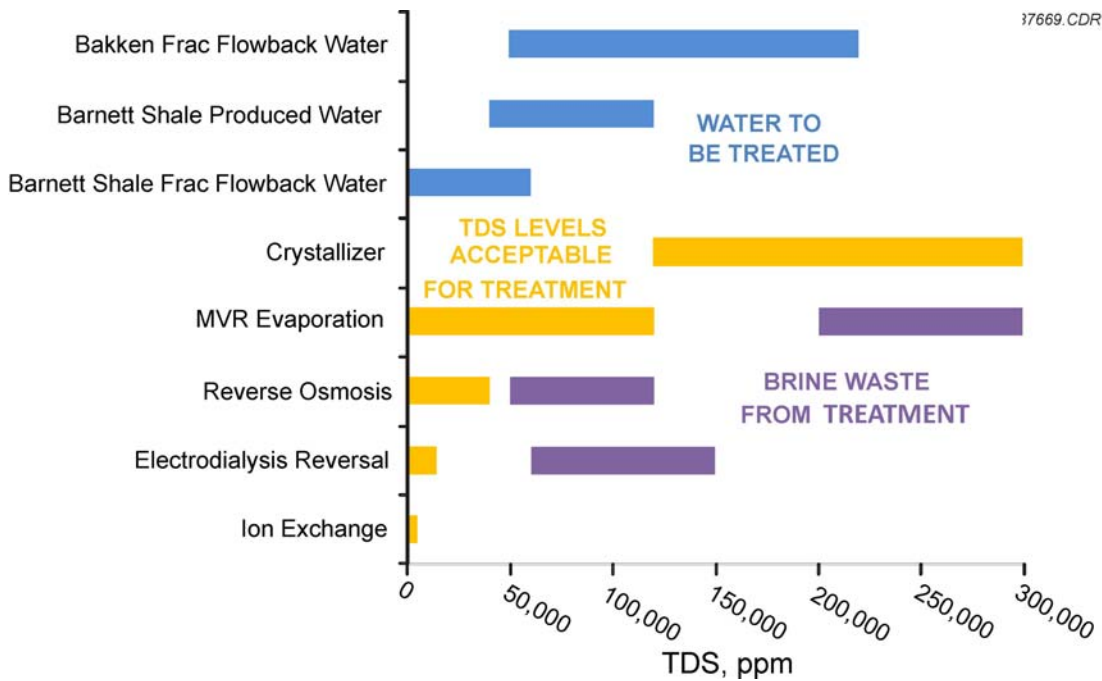


Figure 10. Applicability of various desalination technologies.

Task 3 – Current Water-Handling Costs

Cost data were provided by several of the participating producers. The reported costs of current water handling for hydraulic fracturing can vary significantly, depending on acquisition costs, transportation costs (including wait time), and disposal costs. Table 6 lists a range of current water-handling costs for Bakken fracture water. The cost to purchase raw water ranged from \$0.25/bbl up to \$1.75/bbl, and the cost of transporting that water to the fracture location ranged from \$0.63/bbl up to an estimated \$5.00/bbl. Transportation costs represented the highest level of variability in water acquisition costs and depend on several factors, including trucking charges, haul distances, and wait time. Trucking charges were reported to range from \$110 to \$150/hr, and the charges that are incurred during wait time are included in the overall transportation costs. The costs for deep-well injection ranged from \$0.50/bbl to \$1.75/bbl. Again, transportation costs were the most significant cost for disposal, and the higher overall transportation costs were associated with long wait times to unload at a disposal facility. It is unlikely that water-handling costs would consistently be as high as \$16/bbl, but considering that transportation costs represent anywhere from 56% to 84% of the total water-handling costs, an assessment of the economic potential of frac flowback water recycling is justified. Recycling could reduce the overall transportation and disposal costs through a reduction in the amount of water that would require disposal.

Table 6. Water-Handling Costs

	Cost, \$/bbl
Acquisition Costs	
Raw Water	\$0.25–\$1.05
Transportation	\$0.63–\$5.00
Disposal Costs	
Transportation	\$0.63–\$9.00
Deep-Well Injection	\$0.50–\$1.75
Total Costs	\$2.00–\$16.80

Task 4 – Review of Flowback Water-Recycling Technologies

A review of available literature and Internet searches revealed that frac flowback water-recycling technologies were in various stages of development. These technologies, however, were being evaluated for use in treating frac flowback from natural gas-bearing shale formations such as the Barnett and Marcellus shales. Because the Bakken Formation contains oil-wet rock with little to no free water, the chemical composition of the flowback water is very different from the natural gas shales. Bakken flowback waters are more highly concentrated with salts than are comparable gas formations. Preliminary Bakken flowback water data collected early in the study showed relatively low concentrations of salts in the flowback water, albeit at relatively low volumes, but there still appeared to be a limited opportunity for recycling.

Treatment of Bakken flowback water will require extremely robust technologies built on highly mobile platforms. Based on the character of the Bakken flowback water, the most

applicable technologies include thermal or membrane processes coupled with pretreatment to reduce levels of scale-forming constituents. Pretreatment will be required of any technology treating Bakken frac flowback water.

Thermal Treatment

Thermal treatment uses heat to distill high-salt-content water to steam, which is condensed into clean water. The process also produces a lower-volume concentrate, or brine stream. Thermal treatment processes have high energy input requirements, which would normally make it economically impractical for the treatment of frac flowback water. However, the use of associated gas that would normally be flared early in flowback operations to power thermal treatment processes makes distillation an economical alternative.

Several companies offer thermal treatment processes for the treatment of flowback and produced waters. Thermal treatment technology vendors in this assessment included AltelaRainSM, Aqua-Pure, and 212 Resources.

AltelaRain

AltelaRain desalinates and decontaminates water using a low-pressure, low-temperature countercurrent-flow evaporation/condensation process (Figure 11). Altela claims this configuration provides 3 gallons of treated water from the same amount of heat energy that would normally be required to produce 1 gallon of water through a 300% energy reuse. Individual Altela treatment units process about 8 barrels per day (bpd), but units can be deployed in parallel when treating larger volumes of water (Veil, 2008). The standard Altela system ARS-4000 is delivered in a single, portable 45- × 8-foot shipping container and has been used to treat 4000 gallons/day (~100 bpd) of produced water in New Mexico. Altela systems can operate on low-grade waste heat or wellhead natural gas. This reportedly lowers Altela's operating costs relative to high-pressure, high-electricity-cost technologies such as RO and mechanical vacuum compression (MVC). The system reportedly uses no pressure, high temperatures, filters, or membranes, allowing it to be manufactured from plastics rather than metals. The applicability of the technology to Bakken flowback water is very uncertain.

Aqua-Pure

Fountain Quail Water Management (FQWM) is a technology service provider that developed the Nomad mobile evaporator platform based on Aqua-Pure's patented process (Figure 12). The following process description was taken from Aqua-Pure's Web site (www.aqua-pure.com, 2010):

Mechanical Vapour Recompression (MVR) Evaporation is an energy efficient process that produces pure distilled water from wastewater containing dissolved solids. With evaporation, pure water is boiled from wastewater and can be later condensed as distilled water. The dissolved solids remain in solution and are removed from the system as concentrated blowdown. In an MVR Evaporator, a

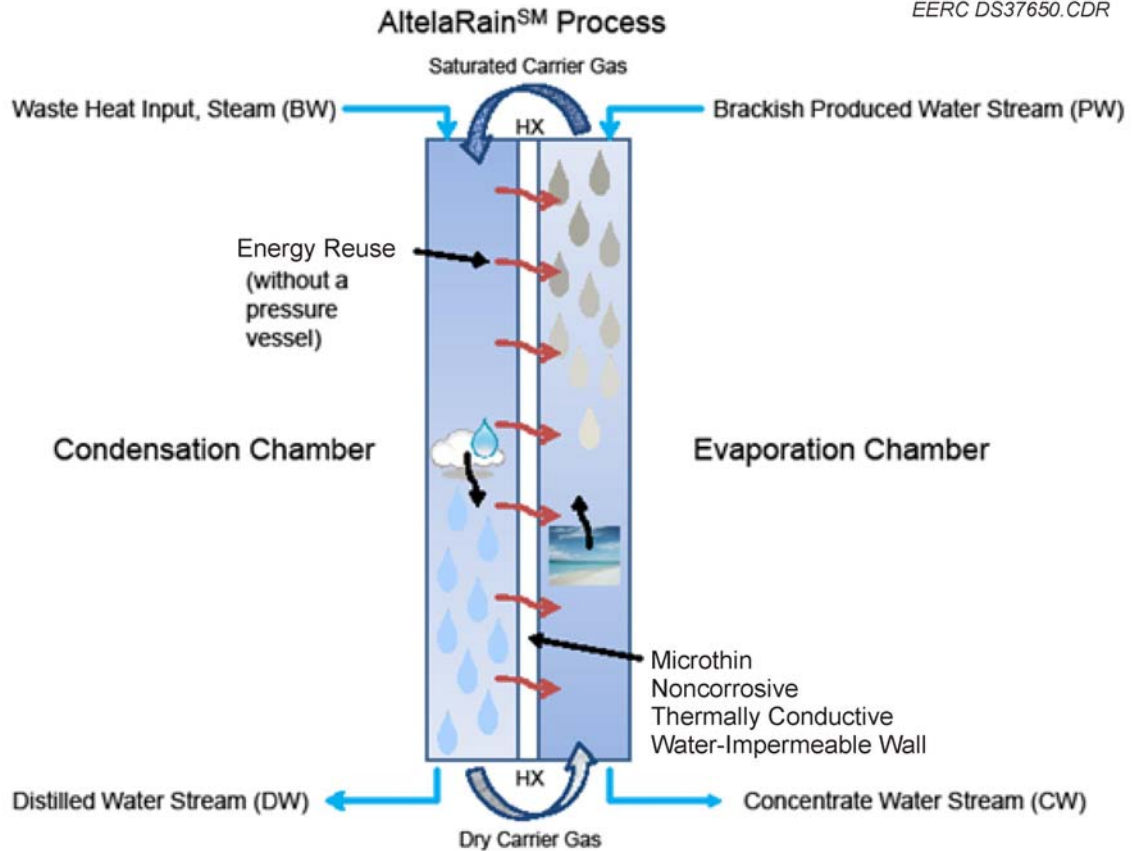


Figure 11. AltelaRain process diagram (www.altelainc.com, 2010).

compressor is used to add the energy required to boil water. The feedwater passes through two preheat exchangers where sensible heat is absorbed from the distillate and concentrate products leaving the system. The feed then passes through a de-aerator column where dissolved gases are vented. The feed then passes into a recirculation loop where concentrate circulates through an evaporator exchanger and a vapour/liquid separator. A portion of the concentrate is boiled to steam in the evaporator exchanger and separated from the liquid in the separator vessel. A compressor draws the steam off the separator and boosts the pressure, which results in an increase in temperature. The steam is driven through the opposite side of the evaporator exchanger where it condenses to distilled water, releasing its latent heat to the boiling concentrate. The distilled water is then pumped through the preheat exchanger where remaining sensible heat is transferred to the incoming feed. Concentrate is continually pumped from the recirculation loop out of the unit to prevent the solution from reaching saturation. The concentrate also passes through a preheat exchanger where remaining sensible heat is transferred to the incoming feed.

Producing distilled water from direct-fired distillate requires 1000 BTU/lb of heat energy. Due to the sophisticated heat exchanger configuration in MVR

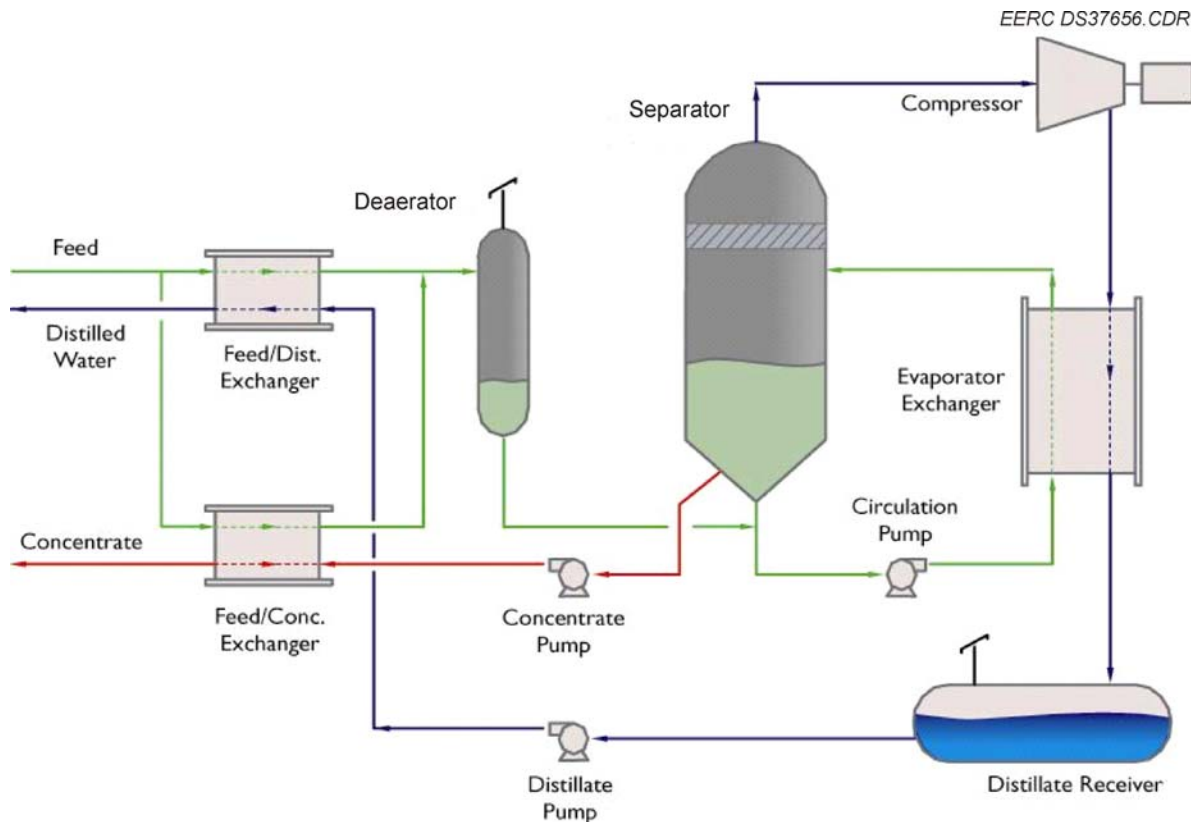


Figure 12. Aqua-Pure mechanical vapor recompression technology process diagram (www.aqua-pure.com, 2010).

evaporation, distilled water can be theoretically produced with only 25-28 BTU/lb, 1/40th the energy.

The Nomad 2000 MVR units are designed to produce 2000 bpd of treated water from nominally 2300 bpd of feedwater. The systems are portable, with each consisting of three skids that can be transported with tractor-trailers. The Nomad system uses available wellhead natural gas as an energy source so no three-phase power is required. The Nomad can also be monitored and controlled remotely via cell phone.

212 Resources

212 Resources owns and operates the platform technology that employs patented vapor compression flash evaporation systems. 212 Resources claims to have solved the fouling/scaling operational concern through a minimum-fouling, minimum-scaling, high-velocity evaporation system. Each unit contains a specially designed heat exchanger along with a high-powered pump to cycle water under pressure at many times the evaporation rate. A process flow diagram for the 212 Resources vapor compression system is shown in Figure 13 (www.212resources.com, 2010).

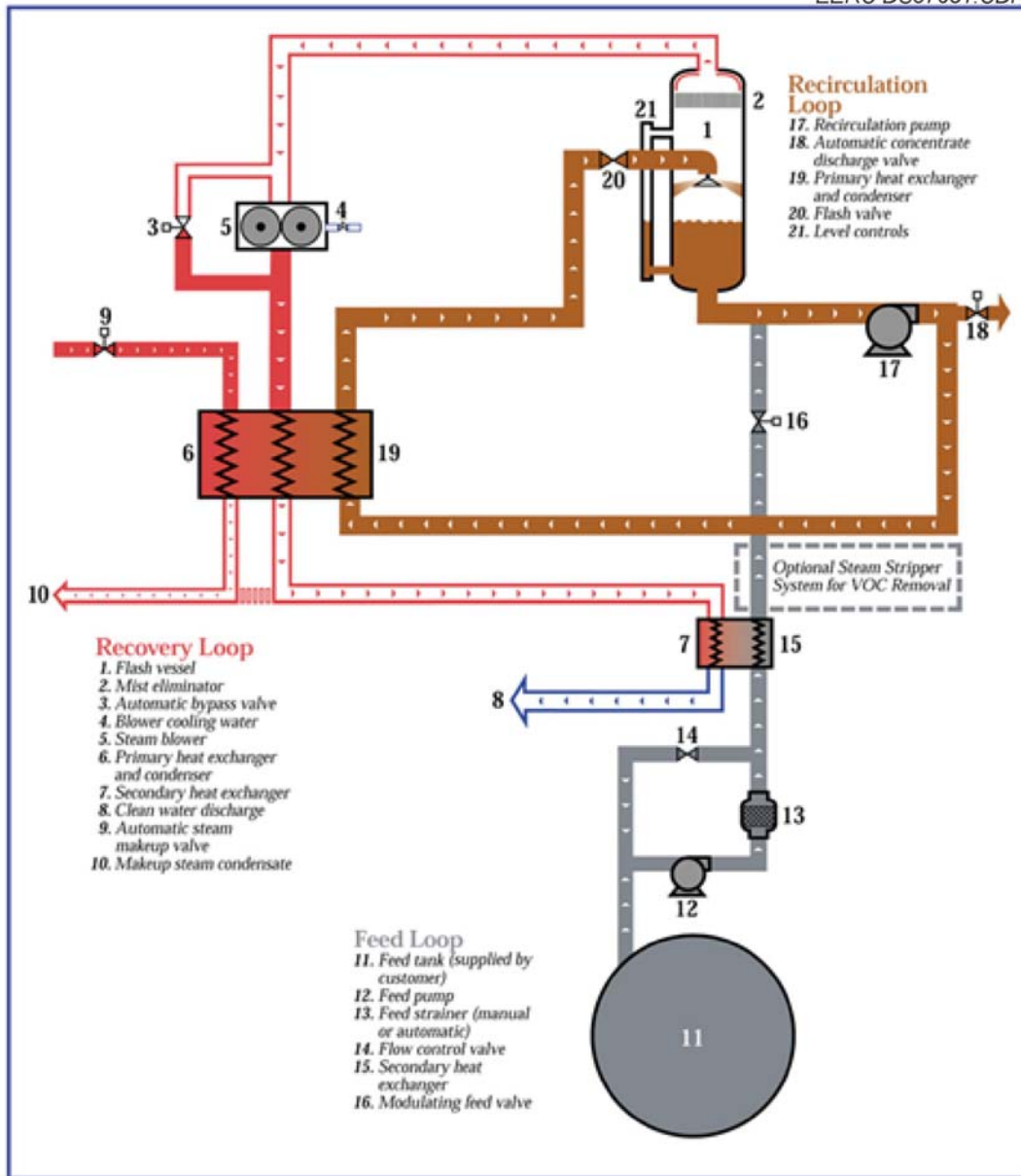


Figure 13. 212 Resources vapor compression process flow diagram (www.212resources.com, 2010).

While thermal processes are capable of producing a high-quality effluent, there remains a concern regarding the treated water yield that is actually possible when treating high-TDS waters like Bakken flowbacks. Pretreatment of these waters will enhance thermal treatment processes by both reducing the levels of scale-causing constituents and, ultimately, providing higher-treated water yields.

Membrane Treatment

Membrane technologies are much younger in development than thermal technologies and were developed primarily for commercial and municipal water supplies in the 1970s. As the name implies, membrane treatment removes dissolved minerals, such as salts, from solution using filtration through a semipermeable membrane. The three main types of membrane treatment include RO, electrodialysis (ED), and nanofiltration (NF).

Of the membrane technologies commonly employed for seawater desalination, RO accounts for about 81%, while ED and NF account for 11% and 8%, respectively. RO is a membrane-based technology that employs dynamic pressure to overcome the osmotic pressure of the saline feedwater. RO uses thin, semipermeable membranes to separate the feed stream into two streams, a low-TDS permeate and a high-TDS concentrate. Pressure forces pure water through a membrane that rejects dissolved salts.

ED is one of the three common membrane processes in desalination and is primarily used to treat brackish water. ED involves the selective movement of ions through a membrane in response to a direct electric current. Electric energy is consumed in proportion to the quantity of salts to be removed. Economics usually limit its application to feedwaters of less than 10,000 mg/L TDS. The electrodialysis reversal (EDR) process is based on the same principles of electrochemistry as ED. The fundamental difference is that during the EDR process, the polarity of the cell is periodically reversed, usually three to four times an hour, to alter the flow of ions across the membrane. This action improves the tolerance of the technology to treat scaling-prone or turbid feedwater. EDR has largely replaced ED in the United States and in some overseas markets. EDR has a permeate recovery capacity and a salt rejection rate of 90%. A significant disadvantage of EDR treatment is the cost, which is approximately twice that of RO (Hanson, E., GE Osotics, personal communication, 2008).

NF is a membrane process that primarily removes divalent salt ions (such as calcium, magnesium, and sulfate) from solution, but not monovalent ions (such as sodium and chloride). As a result, NF is most commonly used for water softening and for nondesalting applications, such as removal of organic compounds.

The use of membrane filtration for treating Bakken frac flowback water will likely have limited application. However, the Texas A&M University Global Petroleum Research Institute (GPRI) has developed an advanced membrane treatment process for the desalination of oil field brine. GPRI licensed the technology and reached a long-term agreement with M-I SWACO to commercialize the technology. David Burnett, Director of GPRI, indicated that the process can desalinate waters with less than 40,000 ppm TDS, much lower levels than are found in Bakken flowback water.

Ecosphere Technologies, Inc., has developed the Ozonix™ mobile frac flowback water treatment system. The advanced oxidation system uses a combination of ozonation, ultrasound, electroprecipitation, centrifugation, filtration, and RO to improve the quality of frac flowback and produced water. The water is first filtered to remove suspended solids and then treated in the Ozonix unit which employs ozone, ultrasound, and electroprecipitation technologies. In the

presence of an ultrasonic cavitation field, ozone decomposes into two hydroxyl radicals and oxygen gas. The hydroxyl radical oxidizes organic compounds and kills bacteria in the water. The electroprecipitation causes some chemical species to come out of solution, and the precipitated material is removed in the centrifugal separation, media, and cartridge filtration units. The final processing step is RO, which removes nearly all remaining dissolved solids.

Task 5 – Flowback Water Treatment Technology Assessment

Based on the review of existing frac flowback water treatment technologies and evaluation factors, including 1) stage of development; 2) demonstrated application of oil field compatibility; 3) mobility; 4) robustness, particularly considering climate extremes in North Dakota; and 5) discussions with producers, technology vendors, and industry experts, the EERC focused continued assessment efforts on thermal treatment processes and, in particular, the Aqua-Pure MVR process. In April 2009, EERC staff visited sites near Decatur, Texas, in the Barnett shale region where Devon Energy was using FQWM and its Aqua-Pure technology to recycle frac flowback and produced water.

Devon collects frac flowback water and transports it by tanker truck to a centralized facility location, where it is unloaded into aboveground storage impoundments (Figure 14). Suspended solids are allowed to settle during storage. Flowback water is pumped from the storage impoundment to a pretreatment process that consists of flocculation, coagulation, gravity settling, and dewatering. Figure 15 shows the pretreatment system. Coagulants are used to produce a chemical flocculant that is removed in an inclined plate settler. Supernatant from the settler is pumped to the Nomad MVR units. Underflow from the settler is pumped to a filter press that dewateres the flocculated solids. Water from the filter press is also conveyed to the



Figure 14. Frac flowback water storage impoundment.



Figure 15. Pretreatment system consisting of coagulation/flocculation, settling, and filter press.

Nomad MVR units (Figure 16). The Nomad MVR units operate as described in the previous section. During the site visit, FQWM was treating water that was a blend of frac flowback and produced water. The feedwater had a TDS level of around 60,000 mg/L. With a throughput of 2300 bpd, each unit was able to produce approximately 2000 bpd of high-quality treated water. Figure 17 is a photograph of system feedwater, treated water, and concentrate from the MVR units.

Continued discussions with FQWM focused on the timing of a potential demonstration of the Nomad MVR technology at a Bakken host site. At the same time, active data collection and assessment activities were providing information that suggested less of an opportunity than originally envisioned for widespread frac water-recycling opportunities in the Bakken play. That, coupled with the marginal economics of recycling frac water in the Barnett shale, led the EERC to refocus research efforts on a more promising opportunity.

Task 6 – Recommendations for Phase 2 Project Deployment

The purpose of this task was to develop detailed plans for the field evaluation of the most technically and economically sound mobile frac flowback water-recycling process. The Phase 1 frac water-recycling feasibility assessment, however, documented significant challenges for demonstrating cost-effective treatment and recycling strategies, even with the most robust available technologies. While there will certainly be niche opportunities using certain technologies to recycle frac flowback water, widespread recycling will not likely be economically viable. The increasing demand for limited supplies of freshwater in western North Dakota, the often long distances between freshwater sources and well sites (and associated



Figure 16. Aqua-Pure Nomad 2000 mechanical vapor recompression unit.



Figure 17. Water samples: frac flowback (left), treated water (center), and MVR concentrate (right).

transportation costs), and the time constraints associated with obtaining new permits to pump from fresh groundwater sources all create significant challenges to the oil industry.

The regional and national importance of providing sufficient volumes of water for such an extremely high-value use cannot be overstated. These water supplies will need to come from a variety of resources. One opportunity is to upgrade marginal-quality groundwater resources to satisfy a portion of the demand. An evaluation of a membrane technology for the treatment of abundant supplies of nonpotable groundwater has been proposed as a Phase 2 Bakken Water Opportunities Assessment project. The EERC is teaming with an oil industry partner to investigate the treatment of moderately saline groundwater from the Dakota Formation with pretreatment and RO technology. The proposed pilot-scale demonstration will treat up to 215 gpm of groundwater to produce approximately 160 gpm of permeate, assuming an estimated 75% recovery rate.

Task 7 – Information Dissemination Activities

Throughout the course of this project, the EERC has worked proactively with industry sponsors to inform the public and others about water issues and opportunities in the Bakken. These activities have ranged from general discussions with citizens, to presentations at town hall meetings, to technical presentations and at national meetings and conferences. The following is a listing of the venues where Bakken Water Opportunities Assessment dissemination and outreach activities have been conducted:

- DOE National Energy Technology Laboratory (NETL) Water/Power Nexus Workshop, Pittsburgh, Pennsylvania, October 27–28, 2008
- NGPWC Kickoff Meeting, NETL, Pittsburgh, Pennsylvania, October 29, 2008
- Series of townhall meetings in western North Dakota’s oil country – November 12–13, 2008
- Milestones and Challenges, 45th Annual Joint North Dakota Water Convention and Irrigation Expo, Bismarck, North Dakota, December 2–5, 2008
- North Dakota Petroleum Council Annual Meeting – Medora, North Dakota, September 1–3, 2009
- North Dakota Solid Waste and Recycling Symposium – Minot, North Dakota, September 17, 2009
- Great Plains Energy Expo – Bismarck, North Dakota, November 9–10, 2009
- Water Resource Opportunities Meeting – Bismarck, North Dakota, December 10, 2009
- Oil and Gas Research Council Meeting – January 20, 2010

In addition, the EERC developed a NGPWC Water Use Fact Sheet that presents a comparison of water use for hydraulic fracturing to more traditional water uses such as center-pivot irrigators and municipal uses, along with unit conversion factors to illustrate the relative magnitude of water use in various activities. The fact sheet can be found in Appendix D.

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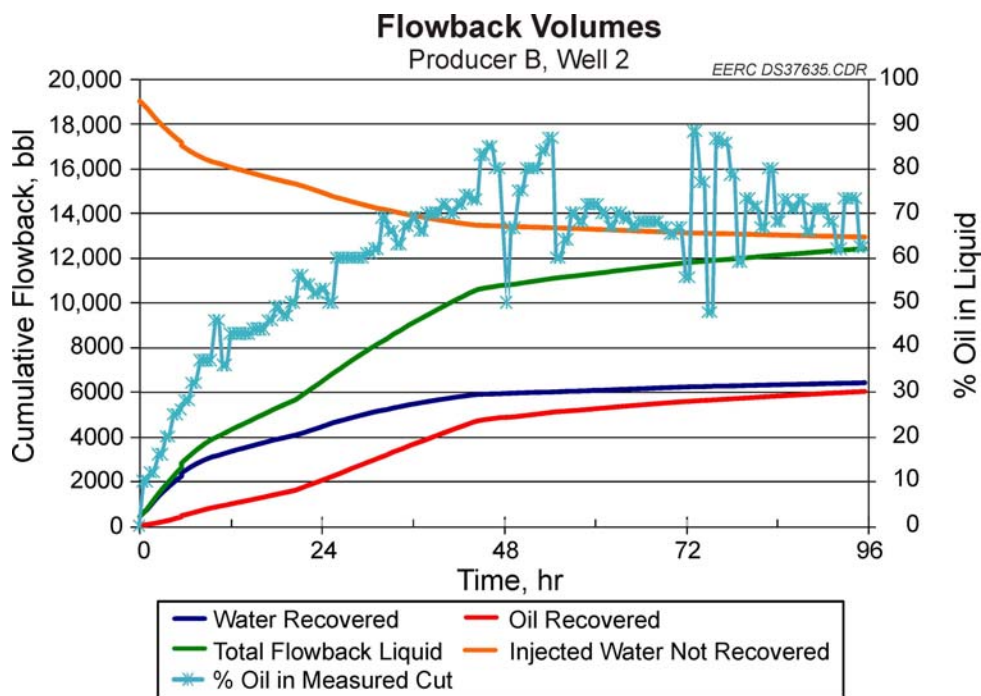
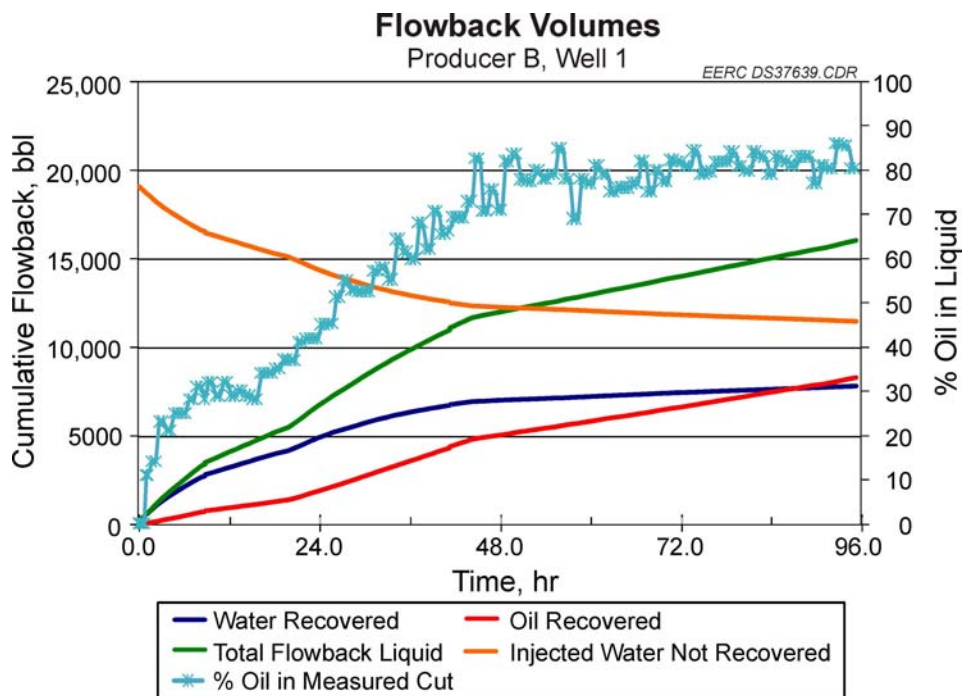
APPENDIX A

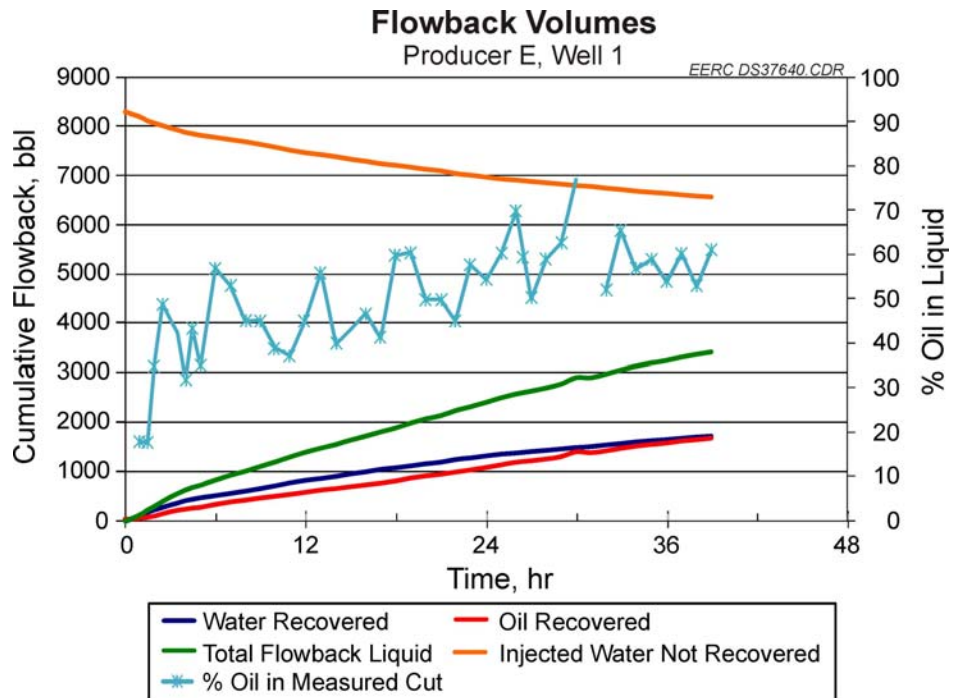
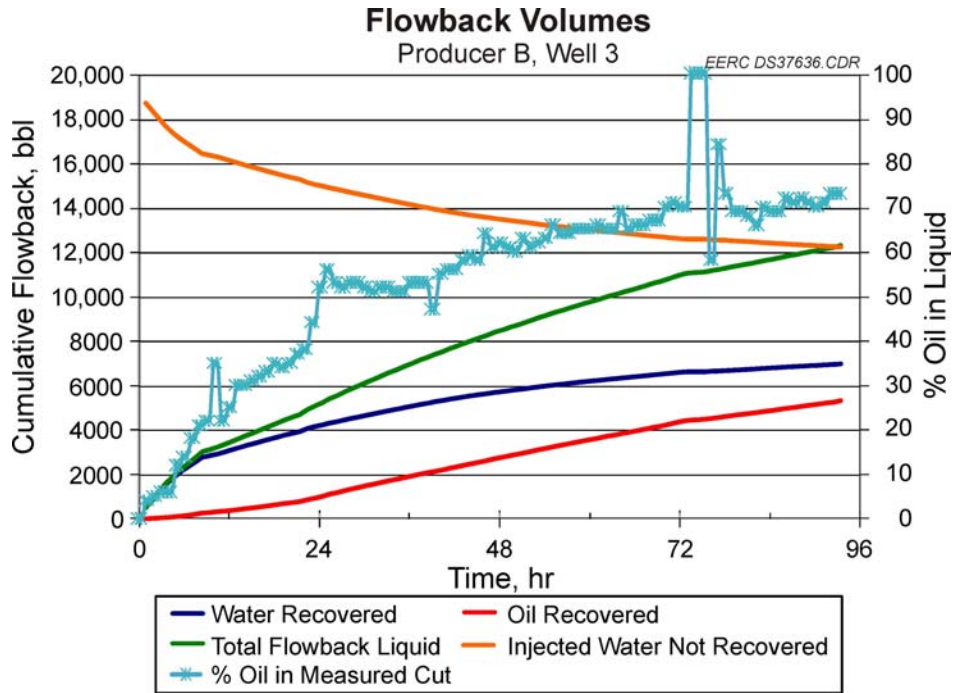
**BAKKEN FRAC FLOWBACK WATER SALINITY-
VERSUS-TIME PLOTS**

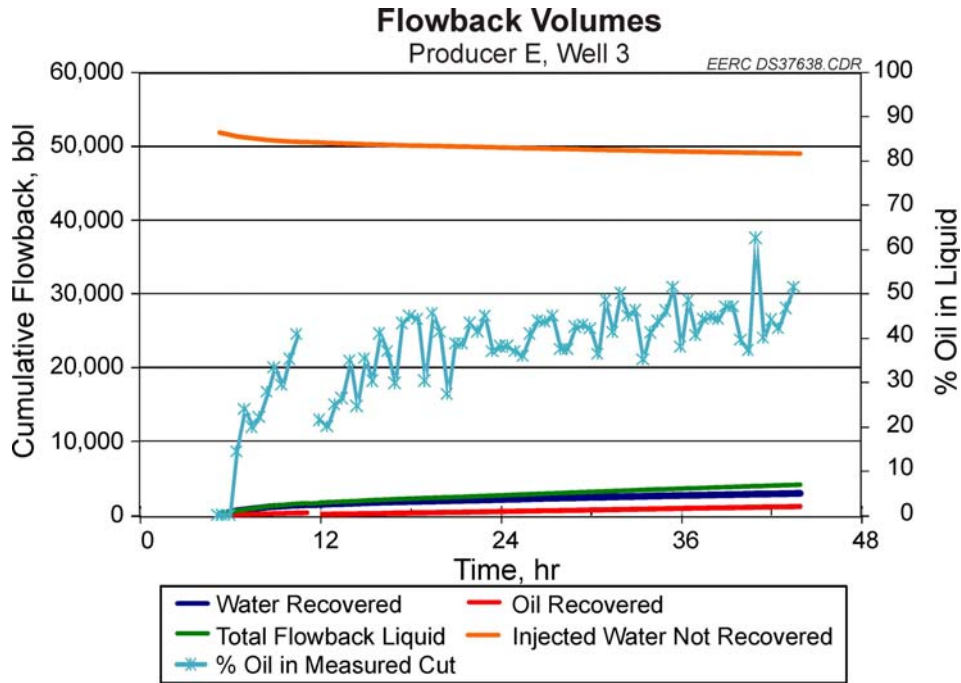
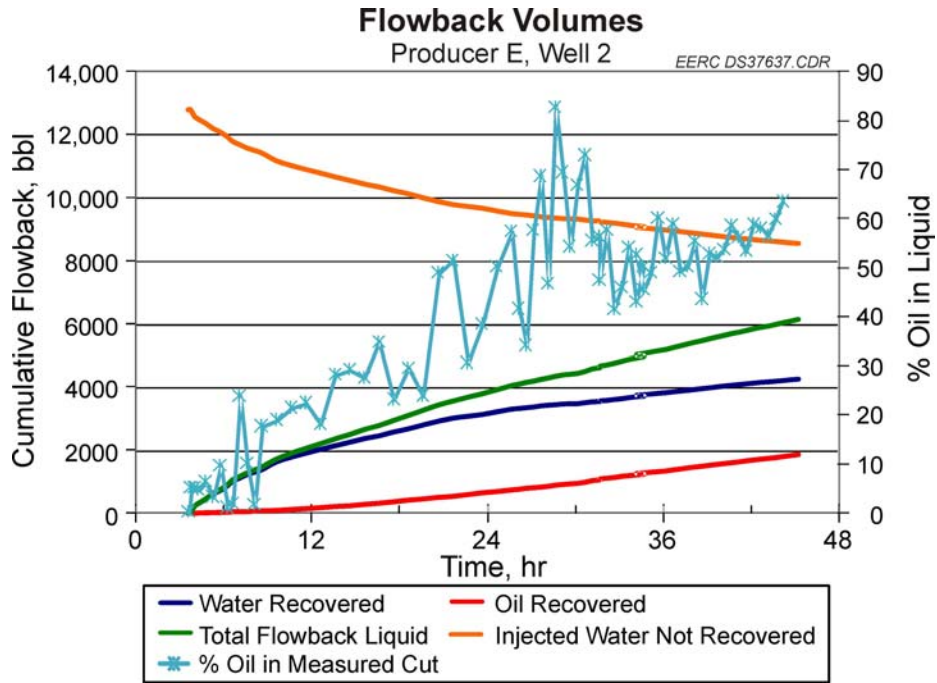
APPENDIX A-1

**CUMULATIVE FLOWBACK PLOTS FOR
HYDRAULIC FRACTURE EVENTS WITH
KNOWN INJECTION VOLUMES**

CUMULATIVE FLOWBACK PLOTS FOR HYDRAULIC FRACTURE EVENTS WITH KNOWN INJECTION VOLUMES



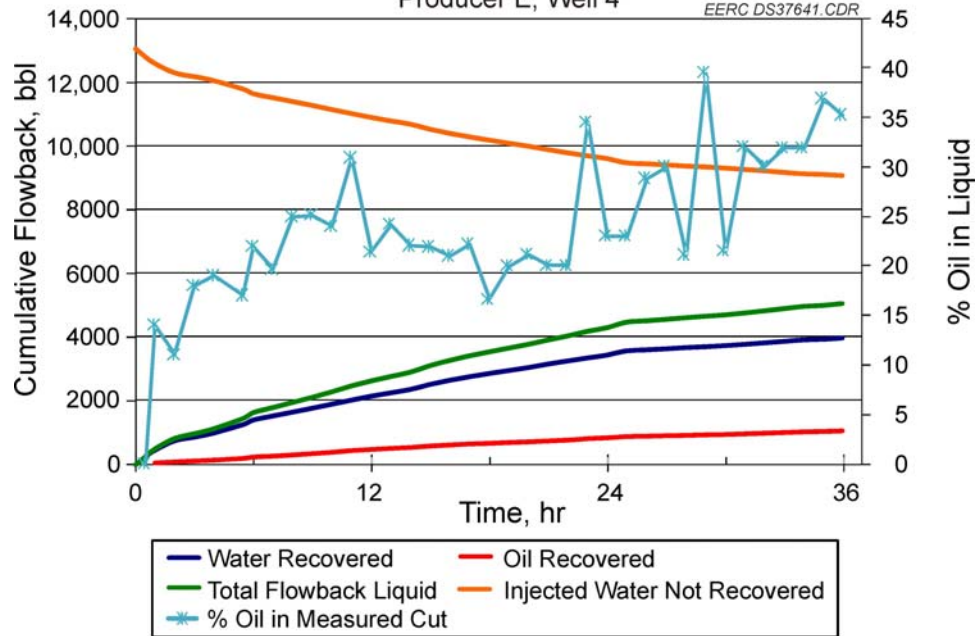




Flowback Volumes

Producer E, Well 4

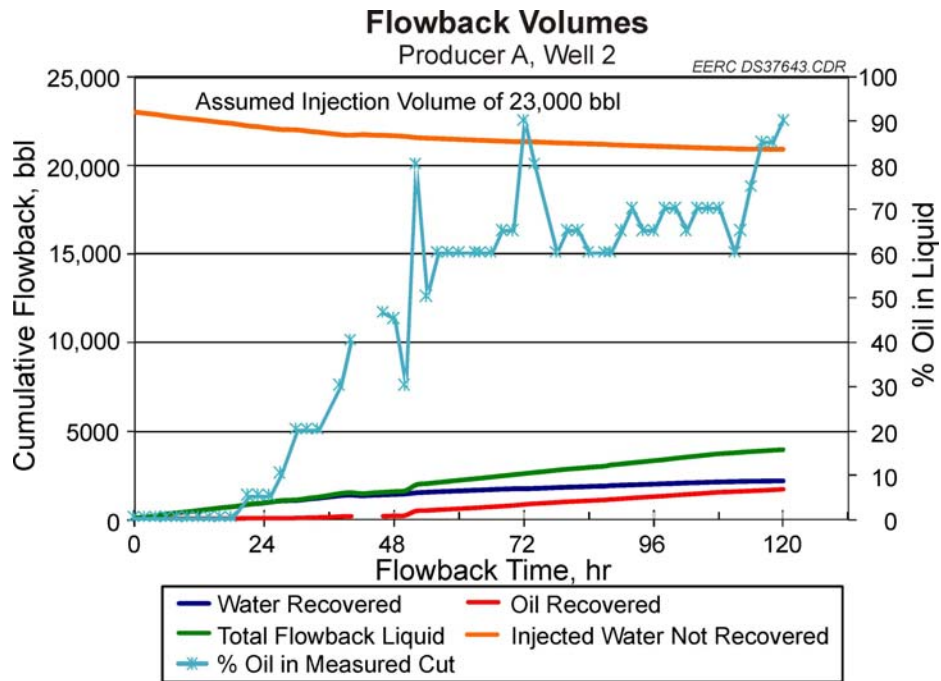
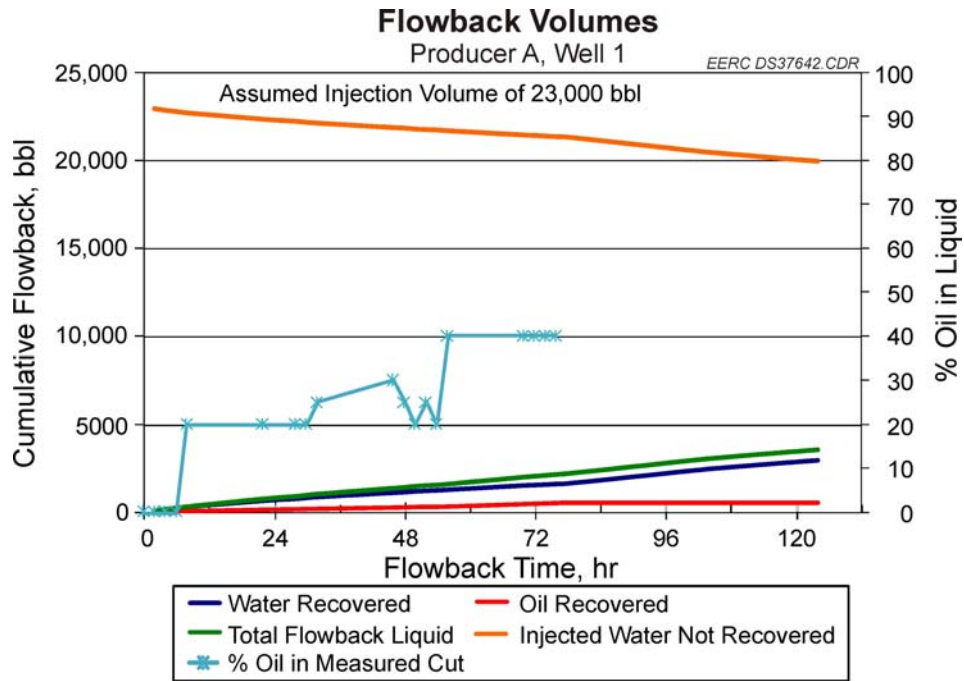
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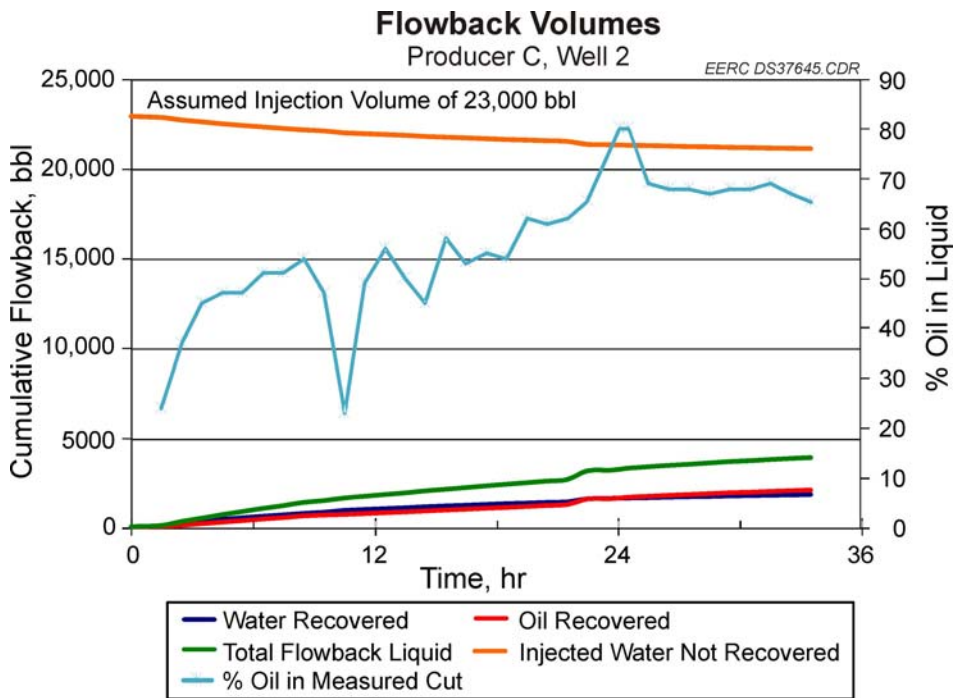
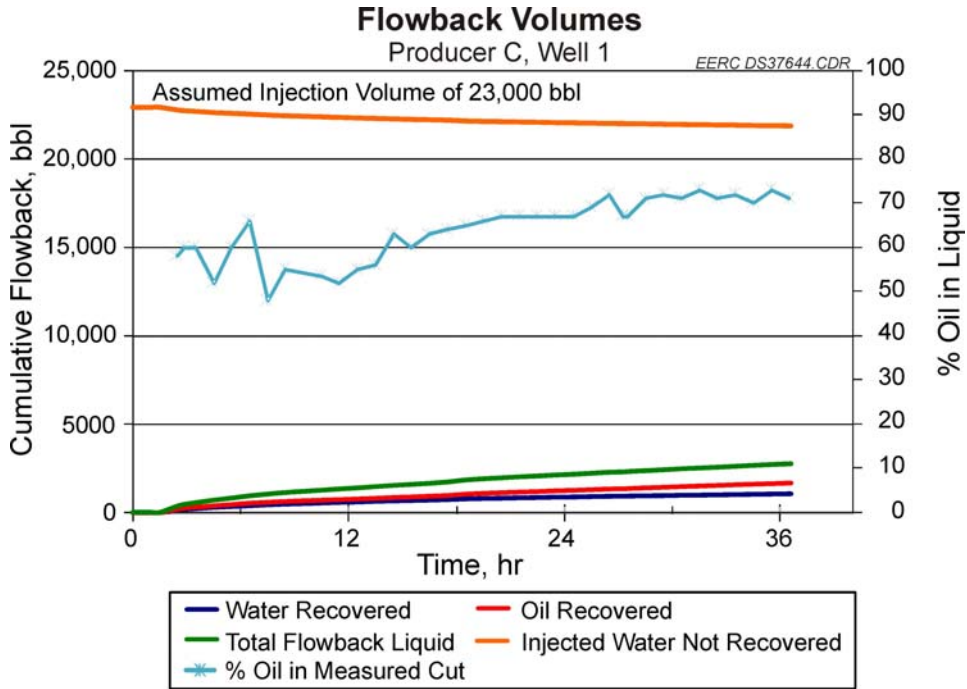


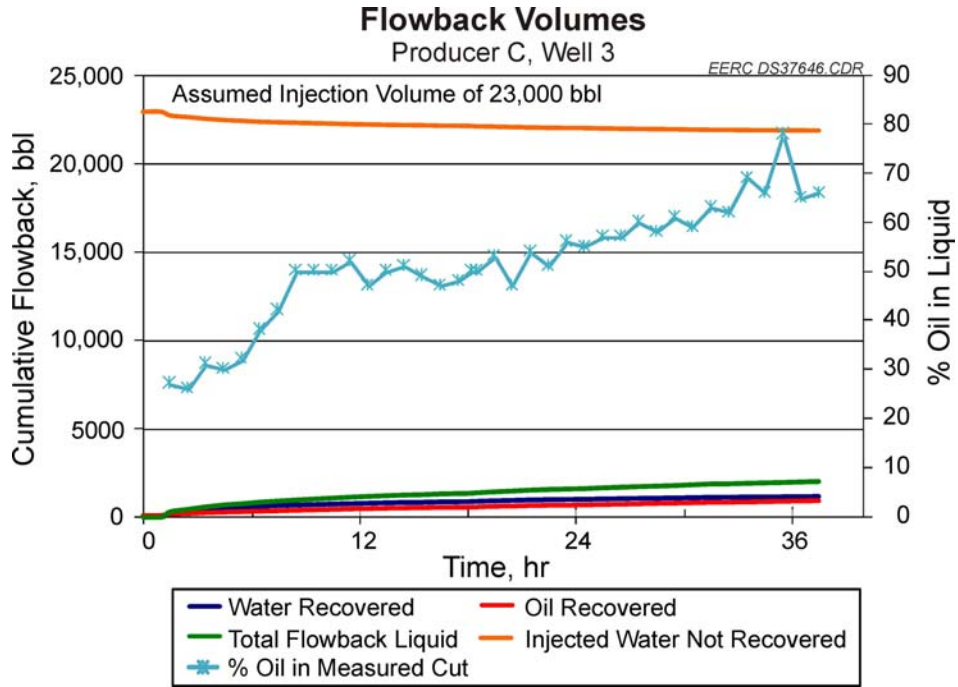
APPENDIX A-2

**CUMULATIVE FLOWBACK PLOTS FOR
HYDRAULIC FRACTURE EVENTS WITH
ASSUMED INJECTION VOLUME OF 23,000 bbl**

CUMULATIVE FLOWBACK PLOTS FOR HYDRAULIC FRACTURE EVENTS WITH ASSUMED INJECTION VOLUME OF 23,000 bbl



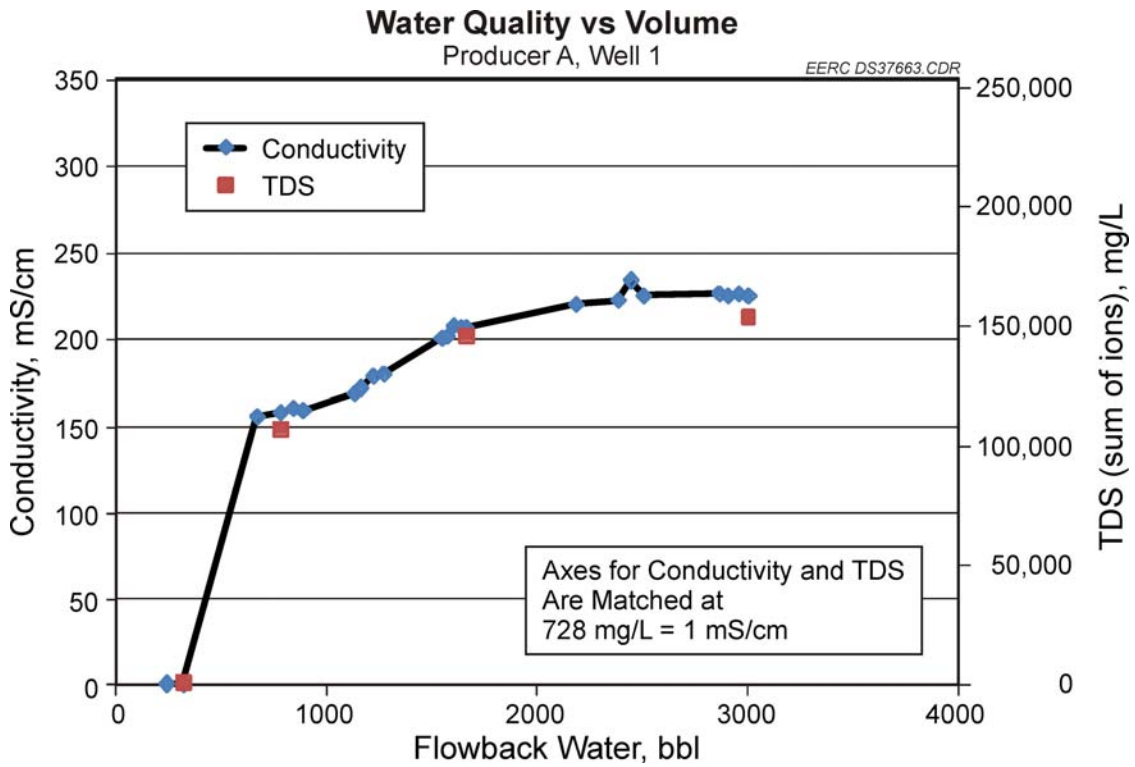
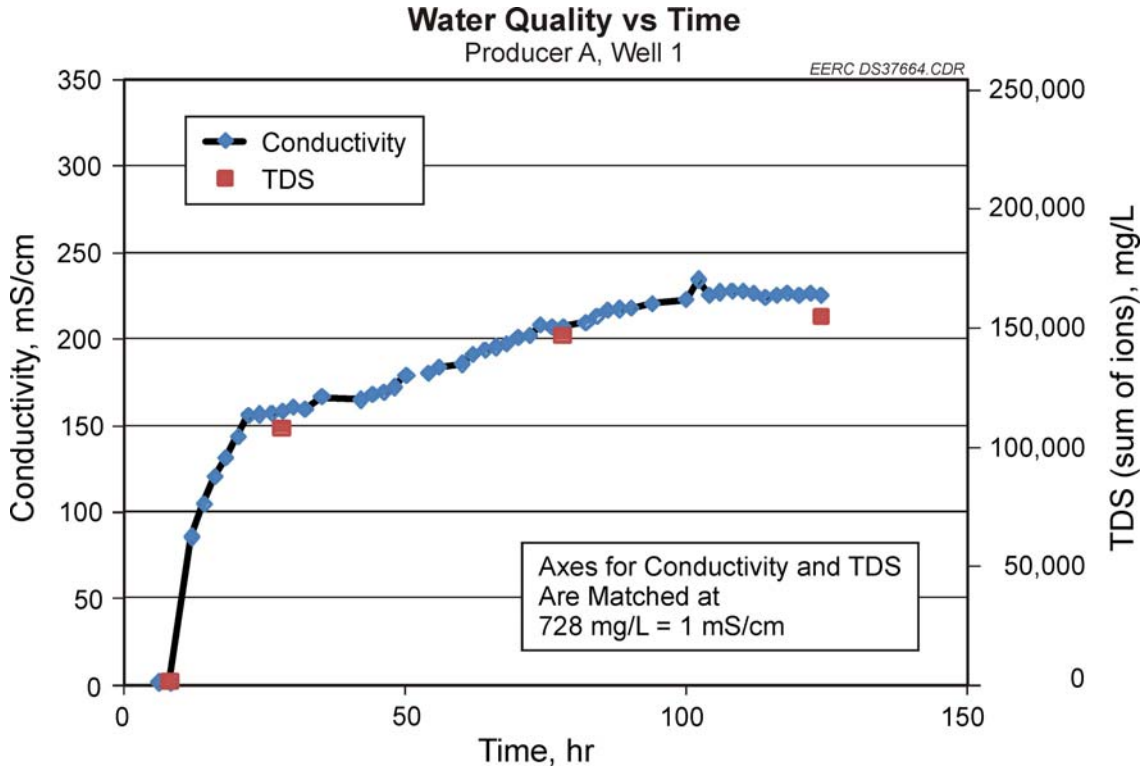


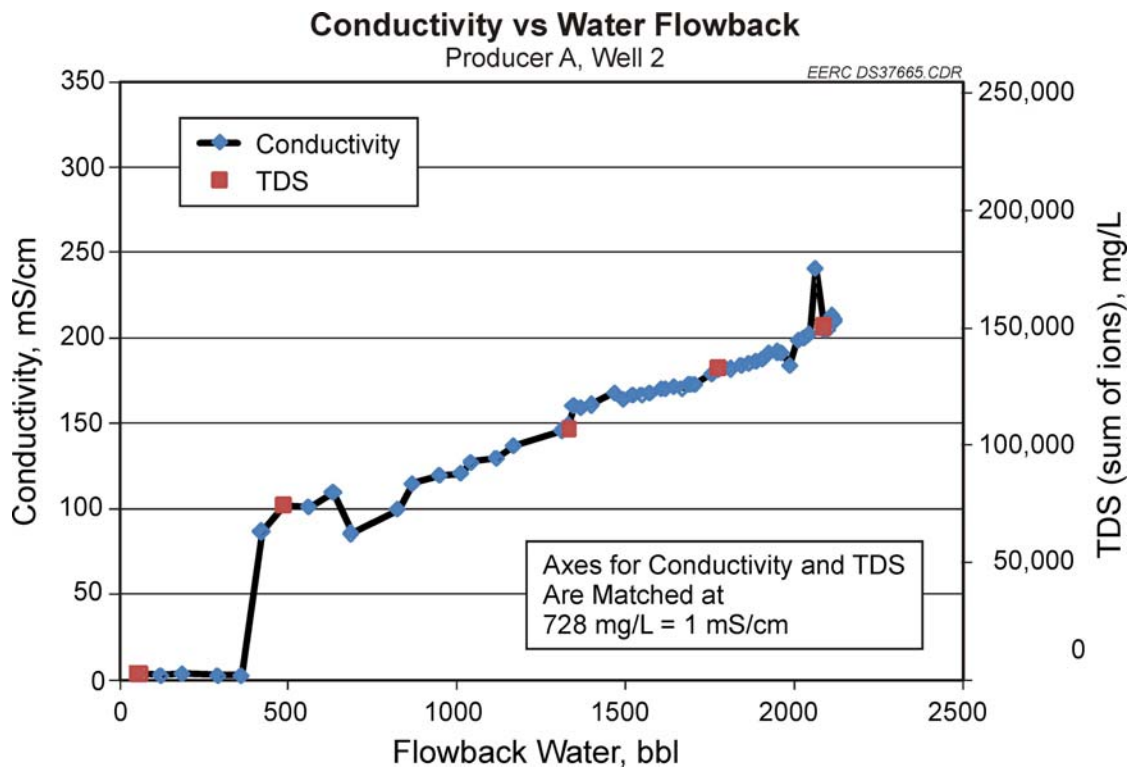
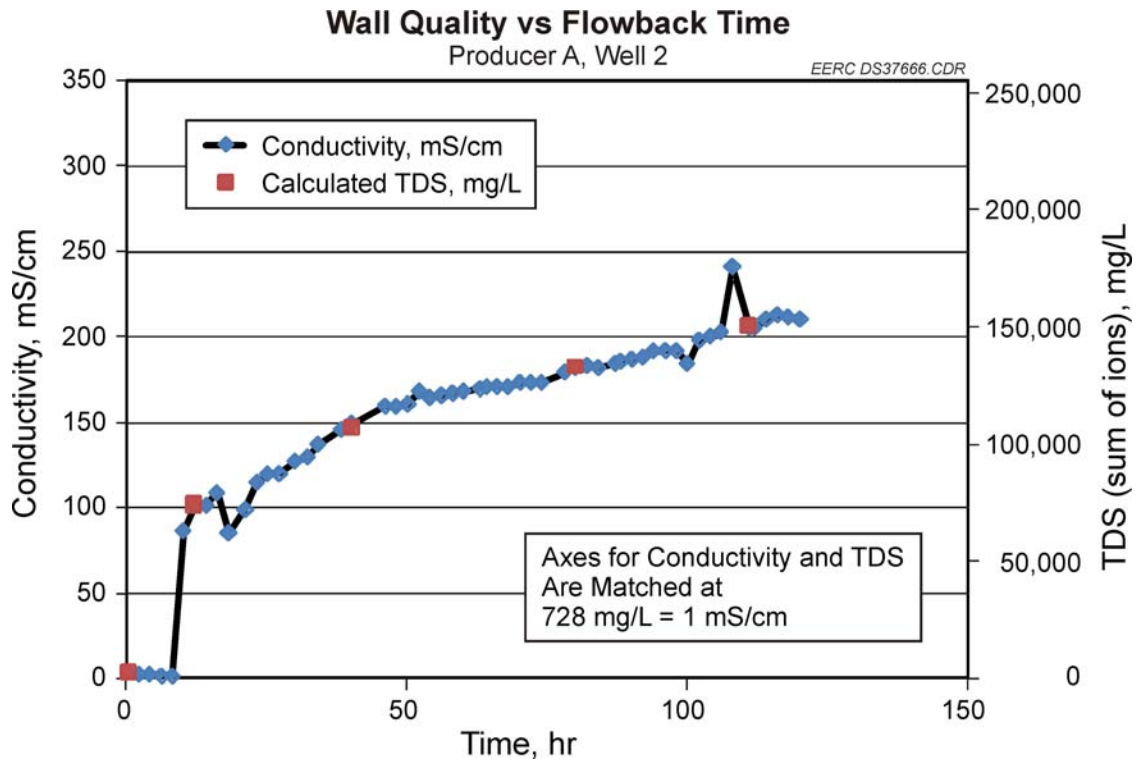


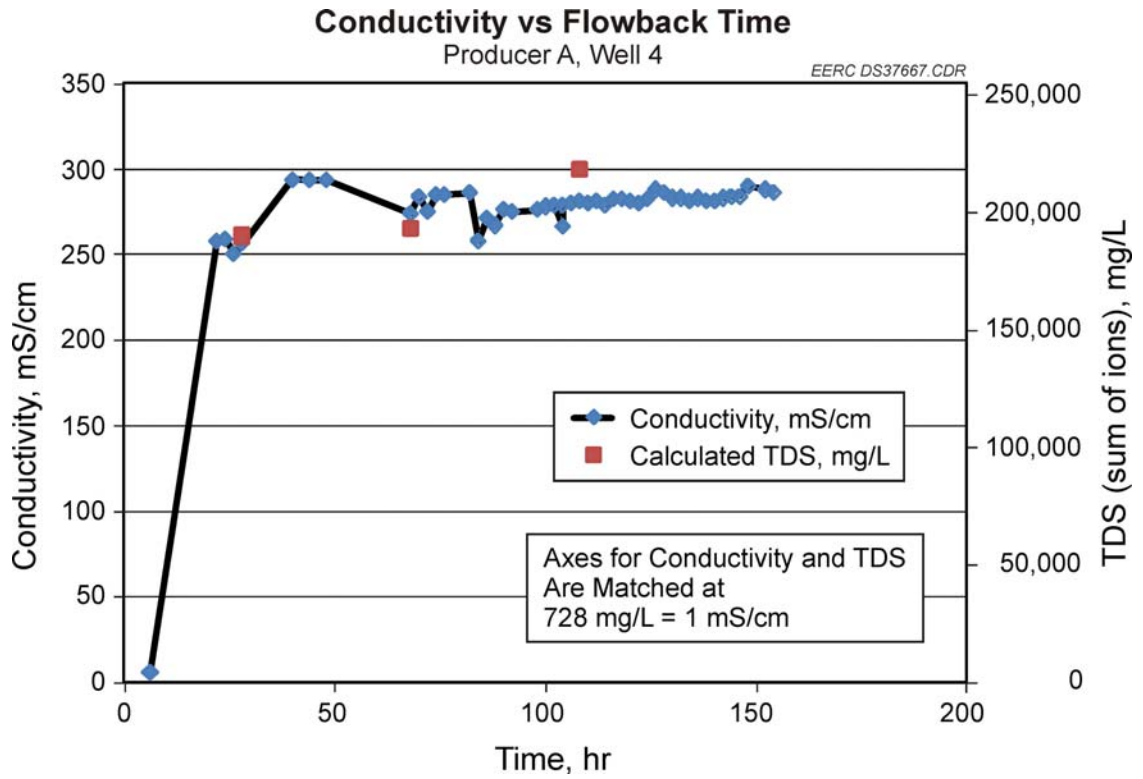
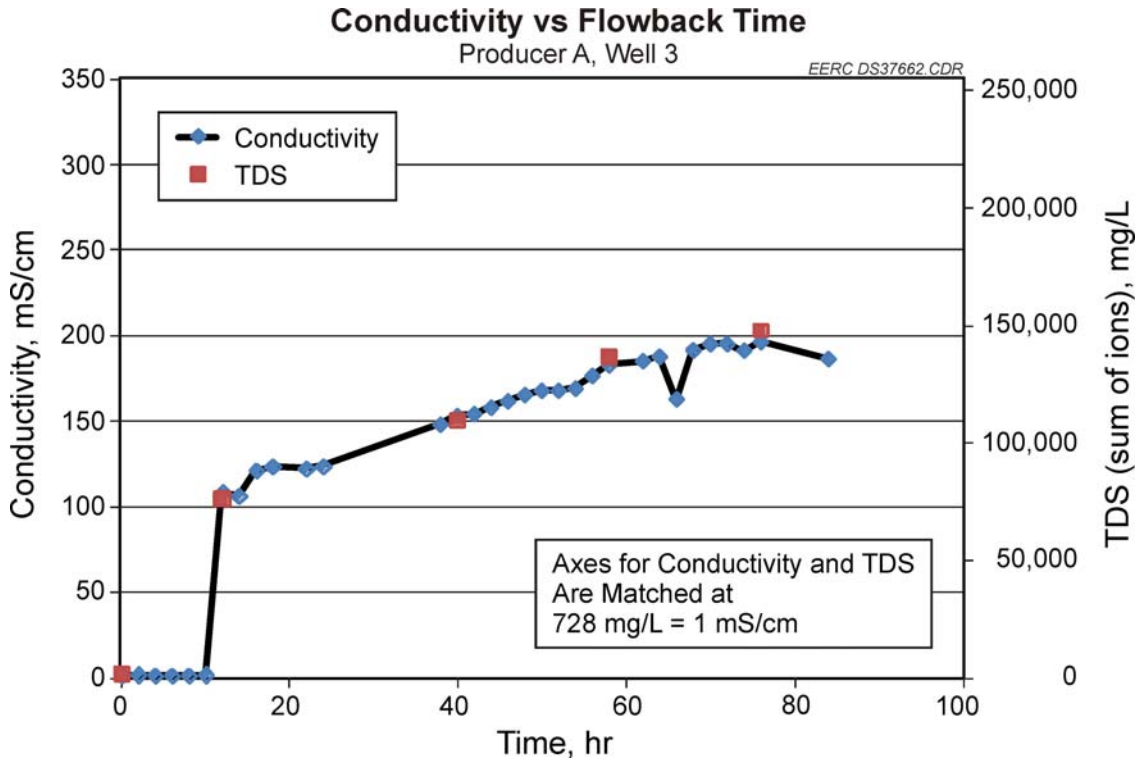
APPENDIX B

BAKKEN FRAC FLOWBACK WATER SALINITY VERSUS TIME DATA PLOTS

BAKKEN FRAC FLOWBACK WATER SALINITY VERSUS TIME DATA PLOTS



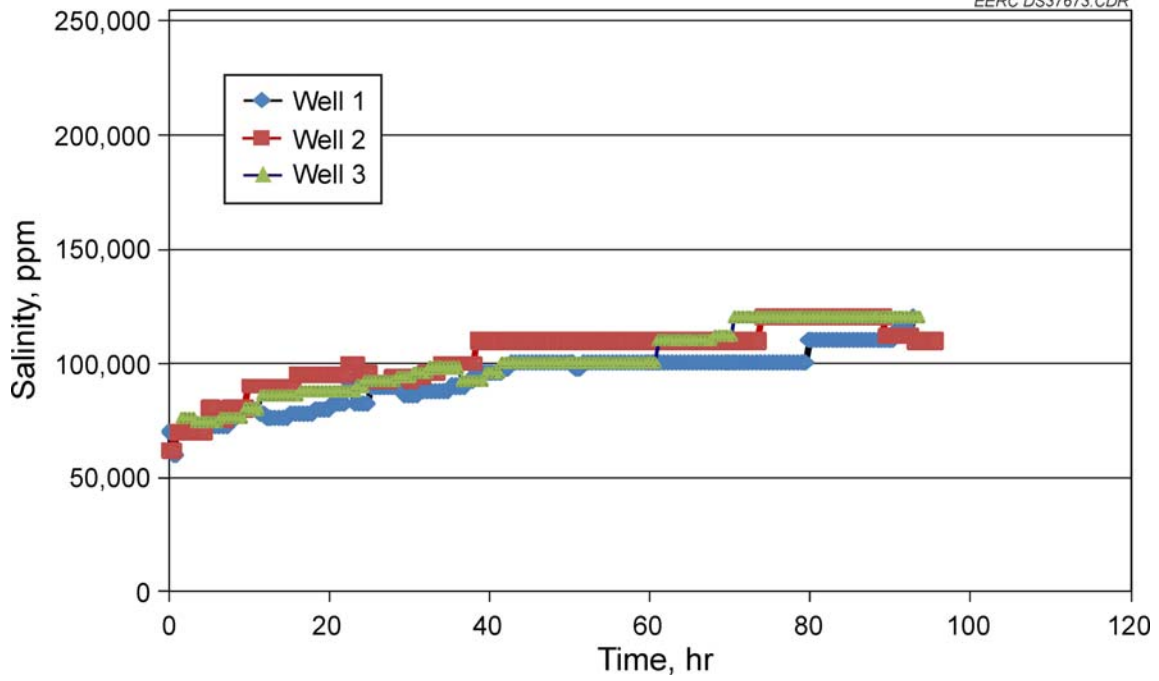




Salinity Concentrations

Producer B

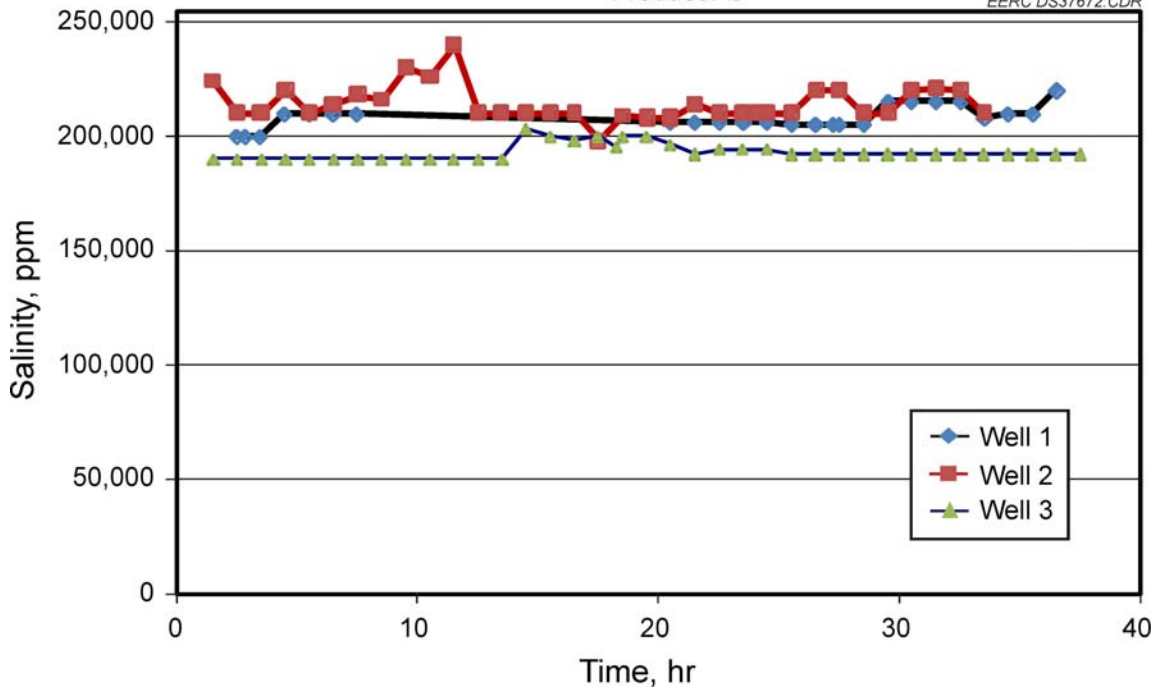
EERC DS37673.CDR



Salinity Concentrations

Producer C

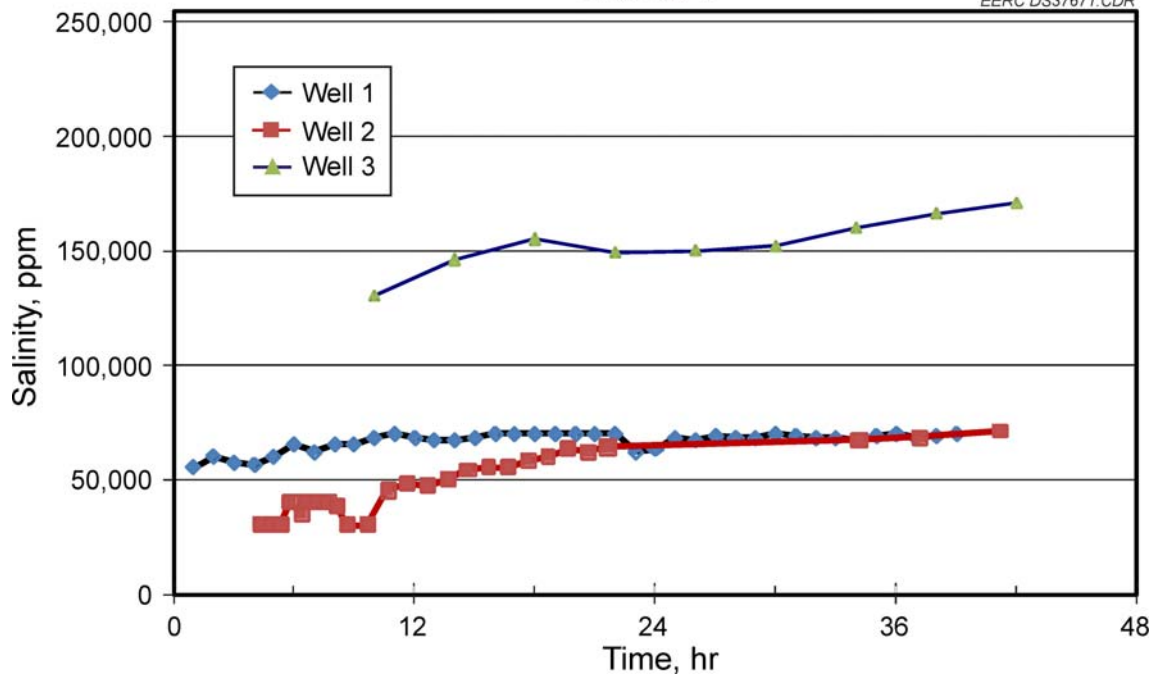
EERC DS37672.CDR

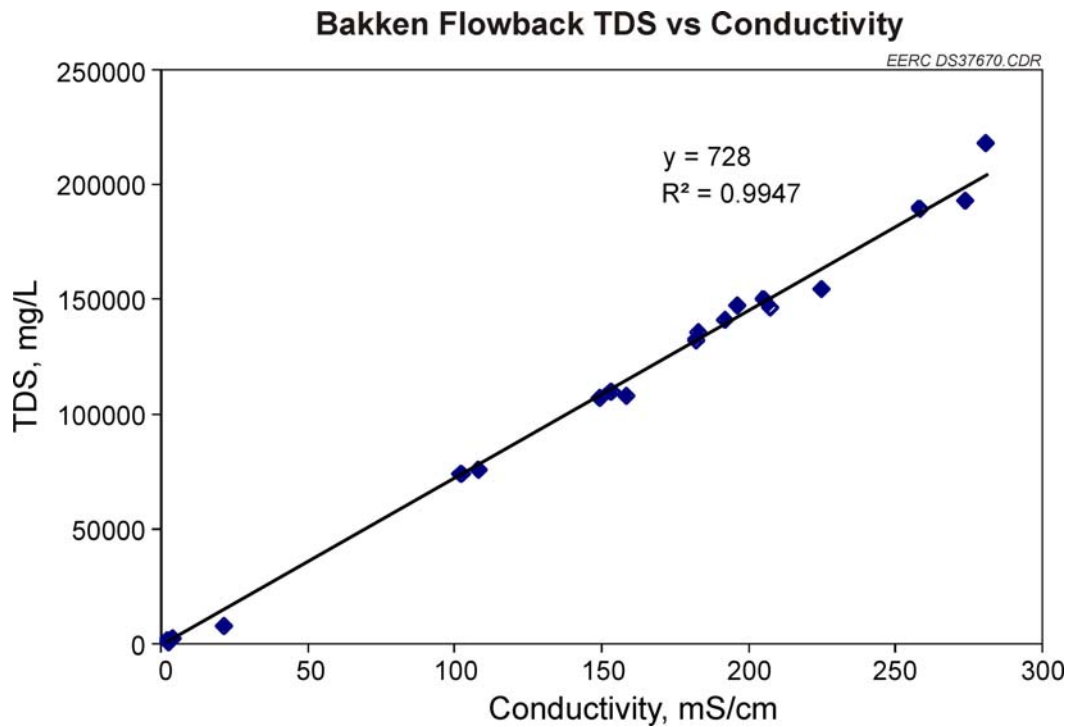


Salinity Concentrations

Producer E

EERC_DS37671.CDR





Note: This figure contains data for samples of Bakken frac flowback water that were analyzed for both TDS and electrical conductivity. This relationship was used to coordinate the conductivity and TDS axes on the plots presented for Producer A flowback water. The magnitude of a conductivity to TDS conversion factor depends on the particular distribution of ions in a given water. The literature reports values ranging from 510 to 970 mg/L TDS/(mS/cm). The value calculated for the Bakken flowback water was 728 mg/L TDS/(mS/cm).

APPENDIX C
CHARGE BALANCE ERROR

CHARGE BALANCE ERROR

Aqueous solutions must be electrically neutral. The sum of all negative charges must equal the sum of all positive charges. An indicator of the quality of a water analysis is the charge balance error (CBE). CBE is calculated based on the following formula:

$$\text{CBE} = \frac{\sum m_c z_c - \sum m_a z_a}{\sum m_c z_c + \sum m_a z_a} * 100$$

The cations and anions in the above equation have units of milliequivalents per liter (m). This value is then multiplied by the valence of the ion (z).

CBE may be negative or positive, depending on whether anions or cations are more abundant in the analysis. For instance, a negative CBE value indicates that the water sample has a higher concentration of anions than cations. A CBE of $\pm 5\%$ is acceptable for most groundwater samples (Freeze and Cherry, 1979). If the CBE exceeds 5%, it may be because of an anion or cation not included in the analysis, an error in the analysis, or a data recording error. Produced water flowback after hydraulic fracture is highly brackish. Brackish water can often lead to a higher CBE than normal groundwater. However, in the case of these three samples, the CBE was very small, an indication likely all of the cations and anions in solution have been accounted for.

REFERENCE

Freeze, R.A., and Cherry, J.A., 1979, Groundwater: Englewood Cliffs, New Jersey, Prentice-Hall, Inc., 604 p.

APPENDIX D
WATER USE FACT SHEET



Northern Great Plains Water Consortium

Water Use Fact Sheet

The Demand for Water

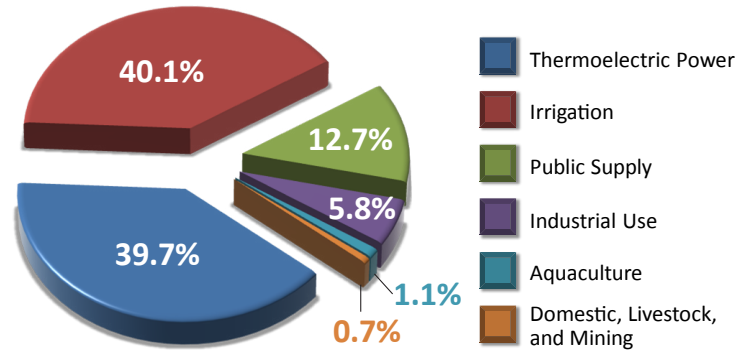
Water is the most critical limiting resource throughout the world. Sustainable economic growth requires a reliable supply of water for energy, agriculture, and a growing population. Water is necessary for urban development, power production, growing and processing high-value crops, oil and gas development and processing, and industrial manufacturing. Satisfying all of these competing needs requires a better understanding of water resources and new approaches to water management. Energy, agriculture, industry, and municipalities all urgently need a scientifically valid basis upon which to make management and regulatory decisions related to water use and quality.

The Energy & Environmental Research Center (EERC) is developing a partnership between the U.S. Department of Energy (DOE) and key energy-producing entities in the northern Great Plains to address issues related to water availability, reducing freshwater use, and minimizing the impacts of facility and industry operations on water quality. The key goals of this partnership, called the Northern Great Plains Water Consortium (NGPWC), are:

- To evaluate water demand and consumption from competing users in the northern Great Plains region, including energy production, agriculture, industry, and domestic/municipal users.
- To assess, develop, and demonstrate technologies and methodologies that minimize water use and reduce wastewater discharge from energy production and agricultural processing facilities.
- To identify nontraditional water supply sources and innovative options for water reuse.

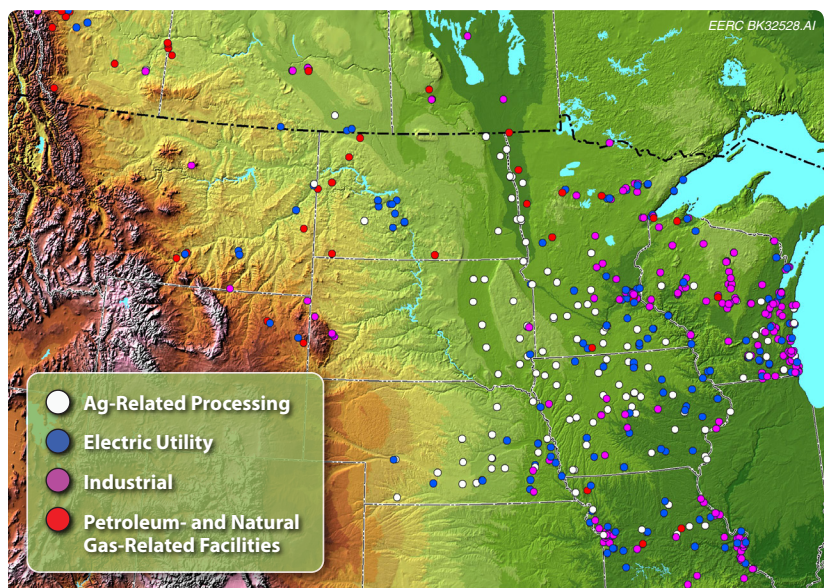
Thinking Outside the Box to Address Water Issues

As the United States continues to pursue economic development and the population increases, demand for ever-increasing amounts of energy to support that growth will require water. In areas where water resources are limited or become scarce because of overallocation and/or drought,



The major users of freshwater within the United States (aquaculture is the farming of aquatic organisms).

competing interests for water could limit energy development and production. With the vibrant oil, gas, and utility interests in the region, potential water reuse synergies among energy-related industries should be explored. For example, thermoelectric power generation is second only to agriculture as the largest domestic user of water, accounting for approximately 40% of all freshwater withdrawals in the United States, as illustrated in the figure above. A portion of that cooling water effluent could be used in other industries, perhaps even prior to cooling, to capitalize on the waste heat. Significant volumes of water are also used in the drilling and completion of oil and gas wells. Wastewater from other industries could be used to supply water needed for drilling operations, and options may exist to treat and reuse the produced water from oil and gas operations. Finding innovative solutions that expand water resource options for the energy industries in the region is one of the key goals of the NGPWC.



NGPWC region showing the locations of key energy, agricultural, and industrial facilities.

Putting Regional Water Use in Perspective

The various industries and water users within the region often use different units of reference when referring to water consumption and discharge. To gain a perspective on the relationship between municipal, industrial, and

agricultural water use, it is helpful to compare some common units and examples of water use among the sectors.

Approximate Volumetric Equivalents

barrels	gallons	acre-feet	cubic feet	cubic meters
1	42	0.000129	5.6146	0.15897
7758	325,851	1	43,560	1233
23,810	1,000,000	3.1	133,681	3785

Conversion Factors

1 cubic foot = 7.4805 gallons
 1 gallon = 3.785 liters
 1 cubic meter = 1000 liters
 1 acre = 43,560 square feet

Approximate Flow Equivalents

barrels per day (bbl/day)	million gallons per day (Mgd)	gallons per minute (gpm)	cubic feet per second (cfs)	cubic meters per second (m ³ /s)
23,810	1.0	694.4	1.55	0.04381
34.3	0.00144	1.0	0.0022	0.00006
100	0.0042	2.9167	0.0065	0.000184

Water Use Comparisons

Use	gallons (millions)	barrels (thousands)	acre-feet	cubic meters
Typical Daily Use for a 50,000-Person Midwestern City	10	238.1	30.7	37,850
Daily Pumping Volume for a Center-Pivot Irrigator for 130 Acres (irrigated portion of ¼ section)	1.008	24	3.1	3815
Average Daily Water Withdrawal for Once-Through Cooling at a 400-MW Coal-Fired Power Plant	365	8691	1120	1,381,525
Water Used to Fracture the Formation for an Oil Well in the Bakken Formation (one-time use)	0.5–1.0	11.9–23.8	1.5–3.1	1893–3785
Proposed Maximum Daily Volume of Water Imported for the Red River Valley Water Supply Project	77.56	1,847	238	293,556

Interested in Joining?

The EERC is actively seeking charter members to complement DOE funding and to help direct the program's efforts. The NGPWC is currently engaged in Phase I of the program, wherein future program efforts and demonstration projects will be selected and prioritized. Phase II of the effort, scheduled to begin in 2010, will focus on demonstrating the water minimization and beneficial reuse strategies and technologies prioritized in Phase I.

The NGPWC is a partnership of key public and private water users in the northern Great Plains region. New members are welcome. To learn more, contact:

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