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Augmented Drainage Development (ADD) – An Evaluation of Field Development Applications in the Bakken

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Abstract

Augmented Drainage Development (ADD) utilizes open-hole laterals that offset standard plug and perf (PnP) completions, with all wells/laterals drilled in the same batch. The ADD laterals are passively stimulated by the hydraulic fractures from the offset PnP wells. Cipolla et. al. (2024) showed that ADD wells can produce up to 40% of the offset PnP completions. However, the impact of ADD on field development options was not well understood, including acceleration versus incremental oil recovery and economic viability. This paper extends the work of Cipolla et. al. (2024), evaluating potential field development applications of ADD in the Bakken.

A fully coupled hydraulic fracture and reservoir simulation model was rigorously calibrated using a comprehensive measurement suite from multiple drainage mapping projects, including direct measurements of drainage versus distance. This calibrated model accurately represented the drainage curves and the actual ADD well performance documented by Cipolla et. al. (2024). The calibrated model was used to evaluate ADD options in the Bakken.

The modeling of ADD well performance showed that ADD laterals can increase first-year pad-level production and improve estimated ultimate recovery (EUR). Scoping economics show that if the cost of ADD laterals is 15-50% of the standard well drilling cost, ADD laterals can increase asset value and allow wider frac well (PnP well) spacing. However, the economic viability of ADD requires advances in drilling applications for unconventionals, which could include dual laterals (ADD + PnP lateral), or multi-lateral ADD wells (3+ laterals).

Introduction

The objective of this study was to determine if ADD is a viable development option for the Bakken. Cipolla et. al. (2024) showed the proof-of-concept work, documenting two field trials that demonstrated ADD well performance is a function of distance from the offset frac wells (i.e. – standard PnP completions) and treatment design. However, this initial work did not address issues such as acceleration versus incremental recovery, effect of spacing and treatment size, and ADD compared to standard development options. For example, is wider well spacing plus ADD wells better than a standard development using tighter well spacing?

This work addressed these issues using a fully coupled hydraulic fracture and reservoir simulation model that was calibrated using learnings from multiple drainage mapping projects in the Bakken (Cipolla et. al. 2022, Liang et. al. 2022, and McKimmy et. al. 2025). The model calibrations and workflow are documented by Singh et. al. (2025) and extended by Cipolla et. al. (2025). Details of the model are provided by McClure et. al. (2024a, 2024b). Although the details of the model calibration are beyond the scope of this paper, this work would not have been possible without a very reliable model that accurately predicted ADD well performance.

Model Validation

The first phase of this work was to ensure that the calibrated model accurately predicted ADD well performance. **Figure 1** compares the ADD production for the two wells reported by Cipolla et. al. (2024) and the predicted production from the calibrated model, showing that the model accurately predicts ADD well productivity as a function of distance from the frac wells. ADD well productivity is presented as a percentage of the production from the offset frac wells, showing that the productivity of a closely spaced (250 ft) ADD well is about 40% of the offset frac wells, while increasing the spacing to 785 ft significantly reduces ADD well productivity to about 10% of the offset frac wells. Note that fracture azimuth in the Bakken is N50°-55°E and the distance along the fracture azimuth is 22-30% greater than the E-W well spacing. For example, the drainage distance along the fracture azimuth for the ADD well that is 250 ft E-W offset from the frac well is about 300-325 ft, and for a 785 ft E-W offset the distance along the fracture azimuth is about 960-1020 ft. The impact of fracture azimuth on drainage and ADD well performance is discussed in detail by Cipolla et. al. (2024).

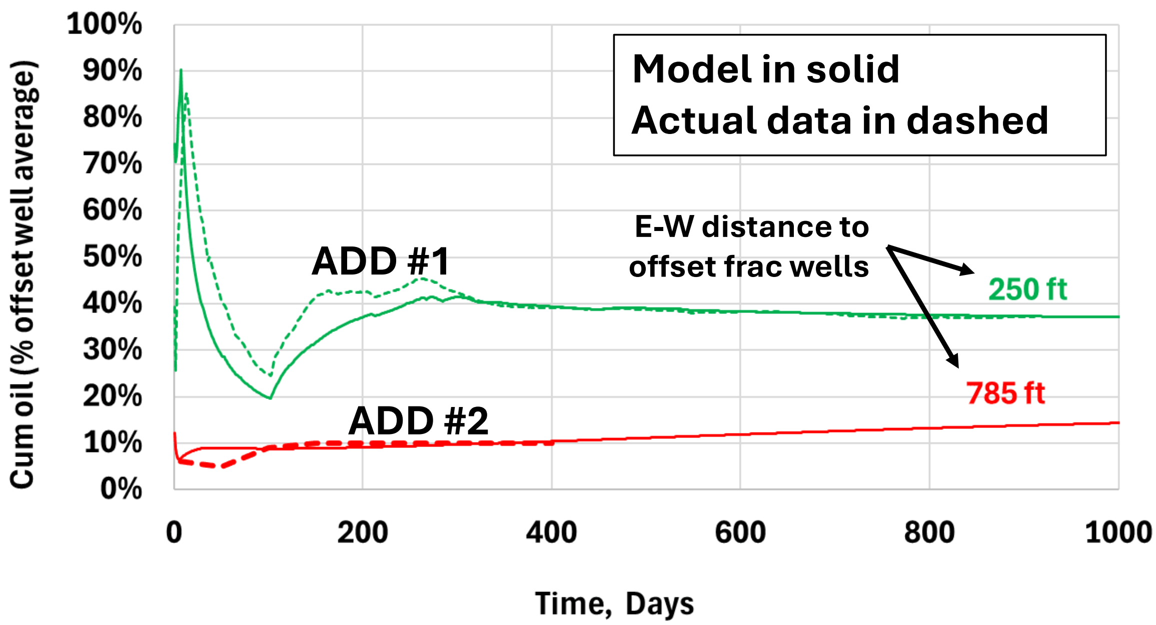


Figure 1 - Comparison of actual ADD production and predicted production from calibrated model

GOR and water-cut were also matched. **Figure 2** compares the model-predicted and actual GOR and water-cut for the "proof-of-concept", closely spaced (250 ft), ADD well documented by Cipolla et. al. (2024). The calibrated model accurately predicts GOR and water-cut for almost three years of production. A similar match of GOR and water-cut was obtained for the widely spaced ADD well.

Figure 3a shows fracture geometry, morphology, and drainage for the large well spacing ADD trail. All the fractures do not intersect the ADD well at this distance, which limits ADD productivity. Although not shown, almost all the fractures intersected the closely spaced ADD well. This illustrates the importance of fracture morphology, as the number of fractures that are propagated in the far-field decreases with distance (Cipolla et al., 2022). Figure 3a also shows the predicted drainage in the hydraulic fractures for the large spacing ADD trial after 400 days of production, illustrating that drainage in the hydraulic fractures is much less effective around the ADD well compared to the frac wells. The ineffective drainage is due to low fracture conductivity in the vicinity of the ADD well. As discussed by Cipolla et. al. (2025), effective drainage in the Bakken appears to be limited to ~700 ft along the fracture azimuth. However, there can be minor drainage at distances of 1000-1400 ft along the hydraulic fracture azimuth that is attributed to un-propped fractures with very low conductivity.

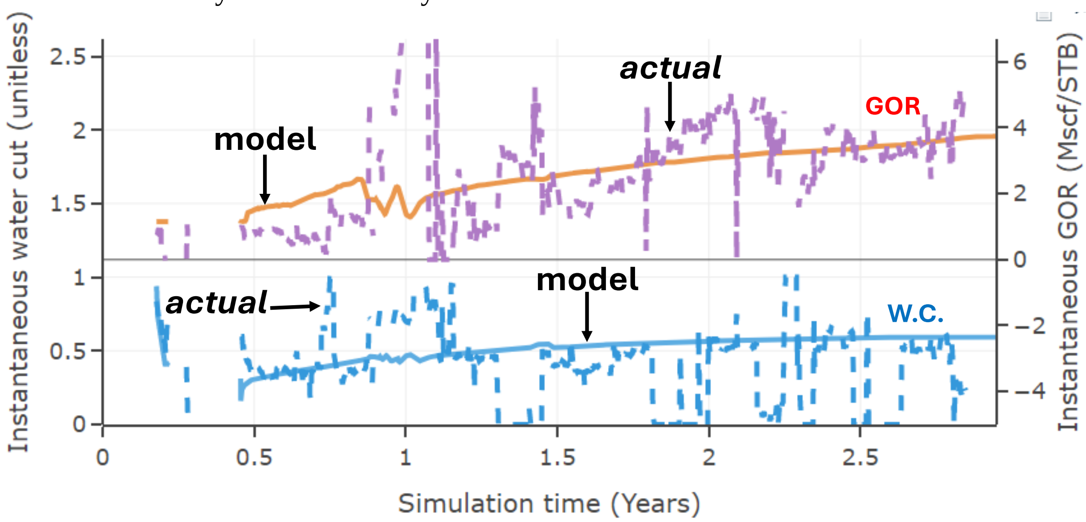


Figure 2 - Predicted and actual GOR and water-cut for closely spaced ADD proof-of-concept well

Figure 3b illustrates the effect of fracture azimuth on ADD well performance, showing that the productive fracture length required to fully exploit the ADD well is 960 ft (N55°E azimuth). The large well spacing significantly reduces ADD well productivity and drainage, as the intersecting fractures are likely un-propped. Cipolla et. al. (2024) presented drainage curves showing that ADD wells at this well spacing would likely intersect regions of very low fracture conductivity (poor drainage). The combination of reduced fracture morphology (i.e. – fewer intersecting fractures) and low conductivity in the farther regions

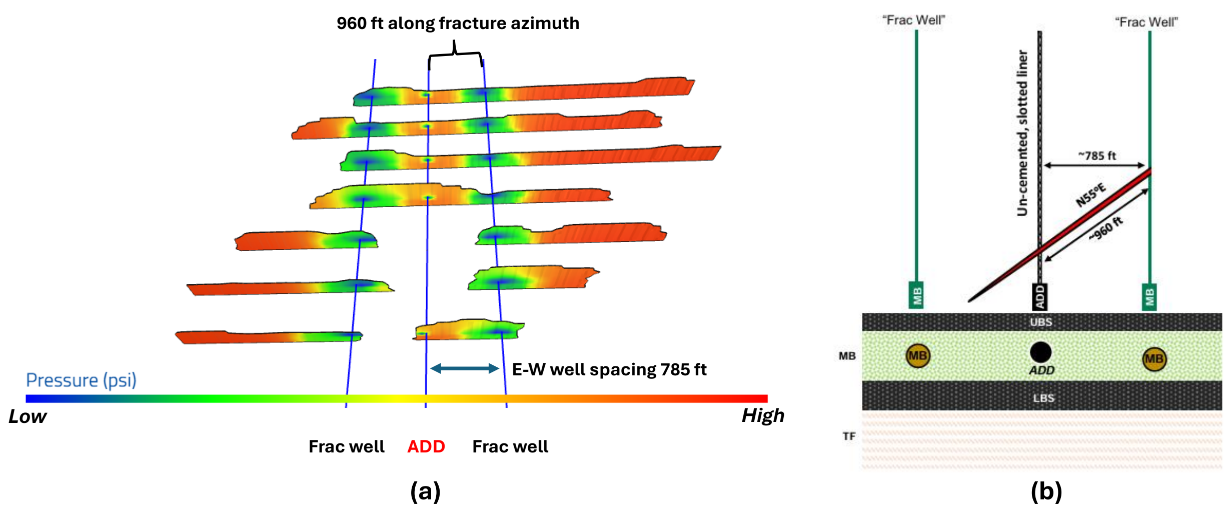


Figure 3 - Fracture geometry, fracture morphology, and drainage for large well spacing ADD trial (MB-MB)

of the fractures results in poor ADD well performance at 785 ft well spacing (960 ft along fracture azimuth). The ability to predict ADD well performance for the two field trials is another validation of the fully coupled hydraulic fracture and reservoir simulation model, as no adjustments to the calibration parameters were required to accurately predict ADD well performance.

ADD Well Performance, Spacing, and Treatment Design

The next phase of this study focused on predicting ADD well performance as a function of well spacing and treatment design. **Figure 4** shows the model setup for the sensitivity study, with four frac wells and one ADD well. **Table 1** lists the well spacings, jobs sizes, and proppant loadings that were evaluated. The wells are assumed to be N-S laterals. The jobs sizes are considered proprietary and described as a ratio of the 400-ft well-spacing design. The jobs consisted of 50% 100-mesh and 50% 40/70-mesh sand. The proppant loading is defined as the total proppant (lbs) divided by the total fluid (gals). Note that the range of proppant loading is different for each well spacing and job size. This is consistent with the operator's practice at the time of this study, with higher proppant loading and smaller jobs sizes for tighter well spacing.

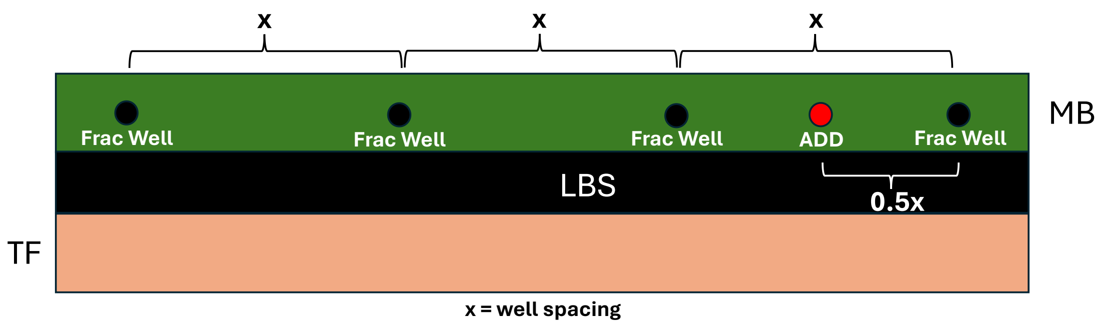
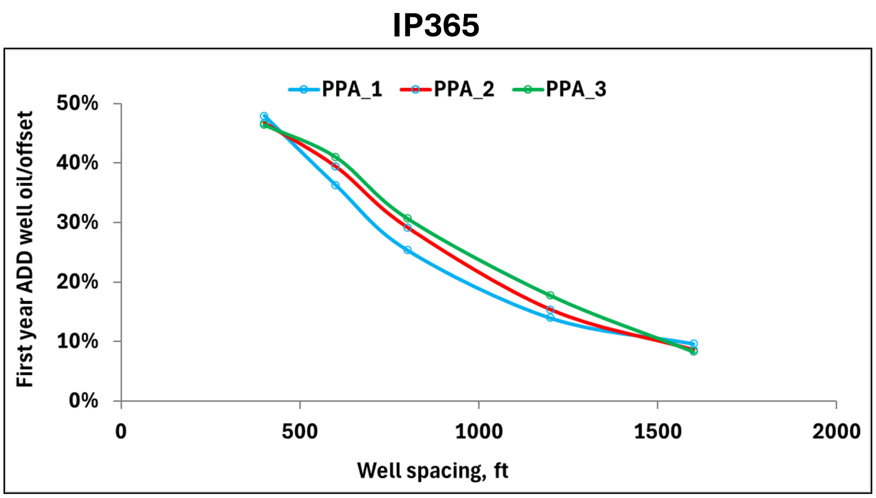


Figure 4 - ADD model setup, depth view showing 4 frac wells and ADD well placement

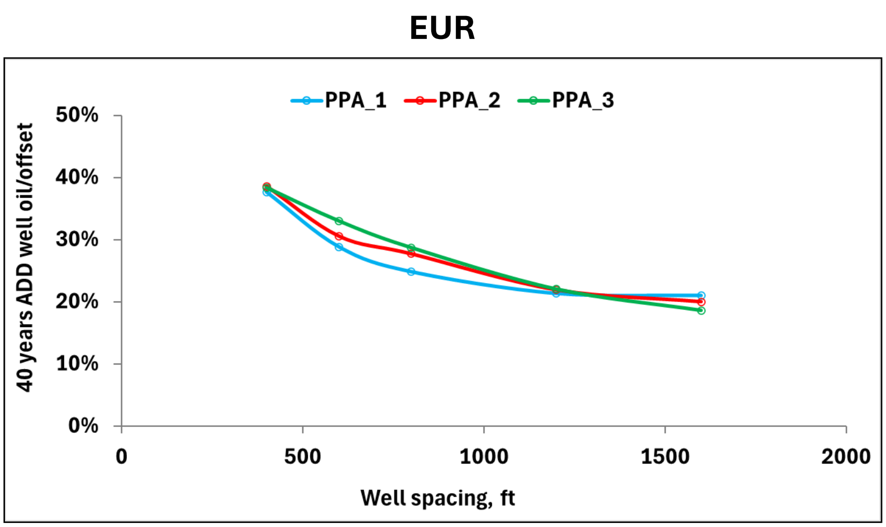
Table 1 - Matrix of well spacing, job size, and proppant loading

Well Spacing (ft)	Job Size (ratio)	PPA-1 (lbs/gal)	PPA-2 (lbs/gal)	PPA-3 (lbs/gal)
400	1.0	0.99	1.11	1.24
600	1.5	0.98	1.10	1.23
800	2.0	0.89	1.00	1.11
1200	3.0	0.66	0.74	0.83
1600	4.0	0.62	0.70	0.78

The results of the sensitivity study are summarized in **Figure 5**, comparing first-year cumulative oil production (IP365) and EUR. The results are presented as a percentage of the offset frac well performance. For example, if the average IP365 of the two offset frac wells was 100,000 bbls and the ADD produced 40,000 bbls the first year, then the ADD well performance would be shown on the figure as 40%. Figure 5a shows that closely spacing ADD wells produce ~48% of the oil compared to the offset frac wells. And that closely spaced ADD wells do not benefit from higher proppant loadings. As well spacing increases, ADD well performance decreases, but the effect of proppant loading becomes more important. For example, at 800-ft well spacing ADD well performance decreases to about ~25% of the offset frac wells using a proppant loading of 0.89 PPA but increases to ~30% with a proppant loading of 1.11 PPA. When well spacing is very large (1600 ft), ADD well performance decreases to ~10% of the offset frac wells and cannot be materially improved using higher proppant loading. Cipolla et. al. (2025) detail the relationship between job size, well spacing, and drainage, showing that effective or propped fracture lengths in the Bakken are likely limited to 700-800 ft. This corresponds to a well spacing of about 1100-1200 ft for N-S laterals and a fracture azimuth of N50°-55°E (reference Figure 3b for an illustration of fracture azimuth and well spacing).



(a)



(b)

Figure 5 - ADD well performance as a function of well spacing and treatment design

Figure 5b compares the EUR for ADD wells, showing that ADD wells can produce up to 39% of the offset frac well EUR for tight well spacing (400 ft), but decreases to 20% for large well spacing (1600 ft). EUR is based on a 40-year cumulative oil. The effect of proppant loading on EUR shows a similar trend compared to IP365, with the biggest impact at moderate well spacing (600-1000 ft). However, the impact of proppant loading on EUR diminishes around 1200-ft well spacing, while there is still an uplift in IP365 using higher proppant loadings at 1200-ft well spacing.

It should be emphasized that the ADD wells compete with the offset frac wells and the interference increases as well spacing decreases. The first-year production and EUR for the ADD wells is a comparison of ADD well performance relative to the offset frac wells and may not be representative of pad-level production acceleration or incremental oil recovery. The results of the sensitivity study provided insights into ADD well placement and frac well treatment designs that were used to guide the final phase of this study, where production acceleration and incremental EUR are quantified.

ADD Development Evaluation

Given the operator's land position and available development options, there were a limited number of well spacing scenarios that needed to be explored. The operator's internal studies, and learnings from multiple drainage measurement projects (Cipolla et. al., 2025), suggest a target well spacing of 600 to 1000 ft for the majority of future Bakken development. The results from the sensitivity study (Figure 5) show that ADD well productivity is about 37-41% of the offset frac well productivity for well spacing of 600 and 19-23% for 1000 ft well spacing, depending on job size. However, drainage measurements suggest that standard frac wells with appropriate treatment designs exhibit good drainage for well spacing of 500-700 ft (Cipolla et. al., 2025); it is unlikely that ADD applications at these well spacings will be viable. Therefore, the final phase of this study will focus on ADD applications using 1000-ft frac well spacing.

The modeling assumed a typical Bakken Drilling Spacing Unit (DSU) that is 1-mile E-W and 2-miles N-S with 10,000 ft laterals and a fracture azimuth of N50°E. **Table 2** lists the cases modeled, showing the frac well spacing, job size, number of ADD wells, and number of frac wells for each case. Job size was varied, shown as a ratio of the smallest job. The jobs sizes are the same as the sensitivity study. Note that the largest job size (ratio 3) was not modeled for the tight well spacing cases (600 ft and 750 ft), as it was deemed excessive and not economically viable. In addition, the base job size (ratio 1) was not modeled for the 4 ADD well cases, as the larger jobs sizes were better suited to stimulate the one outer ADD well (cases 7 and 8 described later in the paper). All cases used the same BHP profile. Throughout this paper, well spacing will always be referenced to the distance between the standard PnP wells or frac wells.

Table 2 - ADD evaluation, matrix of cases

	Well spacing (E-W)	Job Size (ratio)	# of ADD wells	# of frac wells
Case 1 - 3	1000 ft	1, 2, 3	0	4
Case 4 - 6	1000 ft	1, 2, 3	3	4
Case 7 – 8	1000 ft	2, 3	4	4
Case 9 – 10	750 ft	1, 2	0	5
Case 11 – 12	600 ft	1, 2	0	6

A proppant loading of 1.3 PPA, with 50% 100-mesh and 50% 40/70-mesh sand, was used for all the cases. This proppant loading is higher than the upper range used for the sensitivity study; recent modeling (Cipolla et. al., 2025) and limited production data have shown that higher proppant loading may increase well productivity and value. Consistent with the model calibration and sensitivity study, the development evaluation utilized a sector model (Figure 3a). A base-case frac well spacing of 1000-ft was used to evaluate ADD (cases 4-8). The results of the various development options using different well spacing and jobs sizes are compared to five ADD cases to provide insights into the viability of ADD applications.

The base case 1000-ft well spacing and ADD scenarios are shown in **Figure 6**. The figure is oriented in the direction of the fracture azimuth (N50°E) and distances reflect this orientation. For example, for a 1000-ft well spacing the distance between the wells is about 1340-ft along the fracture azimuth. Figure 6 shows the model used for cases 1-3, 1000-ft well spacing and 4 frac wells per DSU, cases 4-6 with 3 ADD wells, and cases 7 and 8 with 4 ADD wells (one outer ADD well). The sector model size and reservoir volume (oil in place) are the same for all models and well spacings.

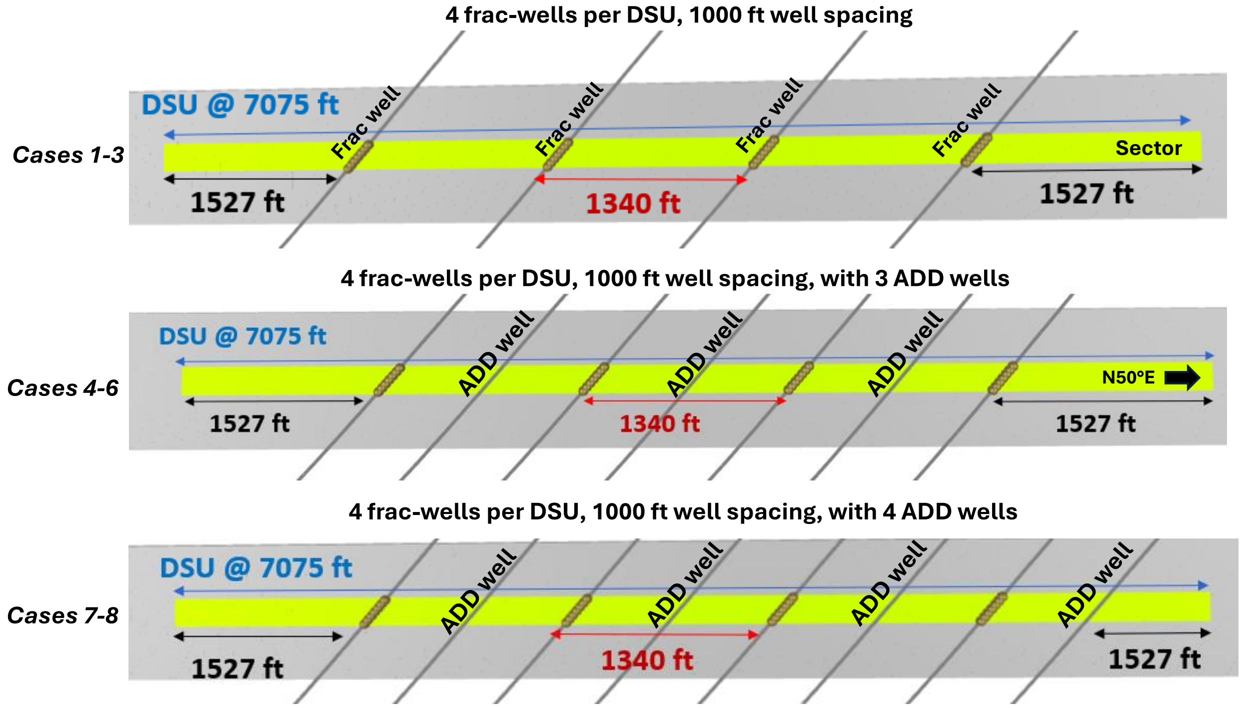


Figure 6 - 1000 ft frac well spacing cases, (a) base case, (b) 3 ADD wells, (c) 4 ADD wells

Figure 7 illustrates the alternate standard development options modeled; 5 wells per DSU (750 ft well spacing) and 6 wells per DSU (600 ft well spacing). This mix of well spacings and job sizes represents a reasonable range of Bakken development scenarios to evaluate the viability of ADD as a development option, providing predictions of production acceleration and EUR improvements (if any). And the modeling also addresses the question, “is wider well spacing plus ADD wells better than a standard development using tighter well spacing?” However, this study is not intended to be a comprehensive optimization of Bakken development with and without ADD.

Comparison of DSU performance

The per-well first-year oil production and EUR for each case are compared in **Figure 8**, presented as a percentage increase above the 600-ft well spacing case with the base job design (ratio 1). The figure shows a significant increase in first-year production and EUR as well spacing and job size increase, about 75% increase in first-year production and EUR with large jobs sizes (ratio 3) and 1000-ft well spacing. The ADD cases are shown in purple and brown and have the highest “per well” first-year production and EUR of all cases. The 4 ADD cases (brown) slightly out-performs the 3 ADD well cases (purple). However, the comparison is very different when the total DSU production and EUR are compared, which is expected.

Figure 9 compares the total DSU production (i.e. – all wells) for the various development options, emphasizing the effect of treatment size and well spacing on DSU-level production and EUR. For example, for smaller treatments, 600-ft well spacing (6 wells per DSU) maximizes first-year production and EUR.

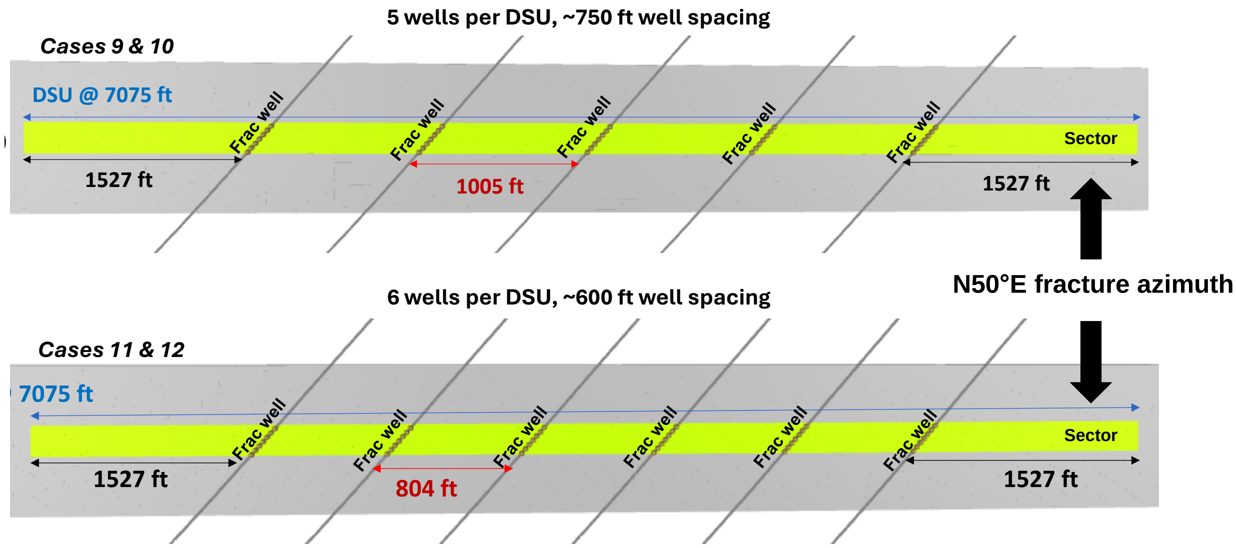


Figure 7 - Alternative development options using 5 and 6 wells per DSU (750 ft and 600 ft well spacing

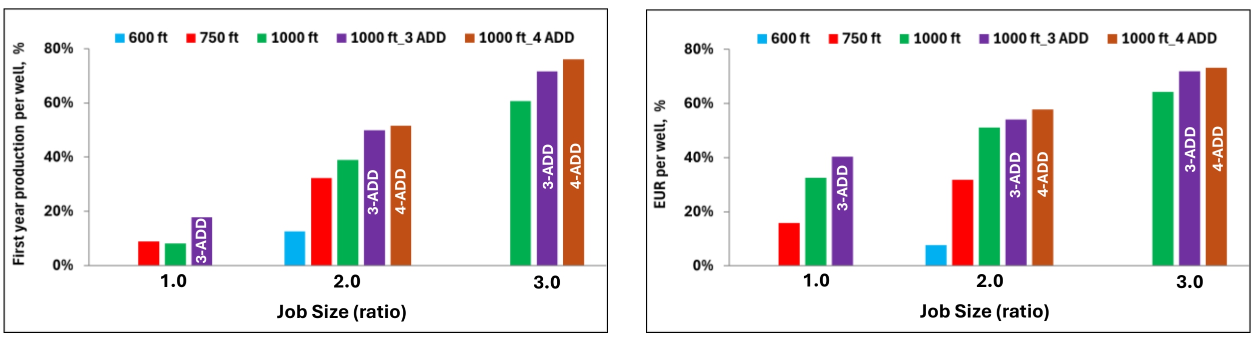


Figure 8 - First-year oil production and EUR for development options (cases 1-12)

However, as job size increases the performance of larger well spacing improves, with the 750 ft well spacing case (5 wells per DSU) and larger jobs (ratio 2) providing similar first-year production and EUR compared to 600 ft well spacing. The 1000 ft well spacing cases, with and without ADD, underperform the tighter well spacing standard development options for the two smaller job sizes (ratio 1 and 2). However, the addition of ADD wells improves DSU production and EUR, compared to 1000-ft spacing without ADD wells. When job size is more appropriate for 1000 ft well spacing (ratio 3), the 1000-ft well spacing shows similar performance compared to the tighter well spacing cases. And the addition of ADD wells results in the highest first-year production and EUR.

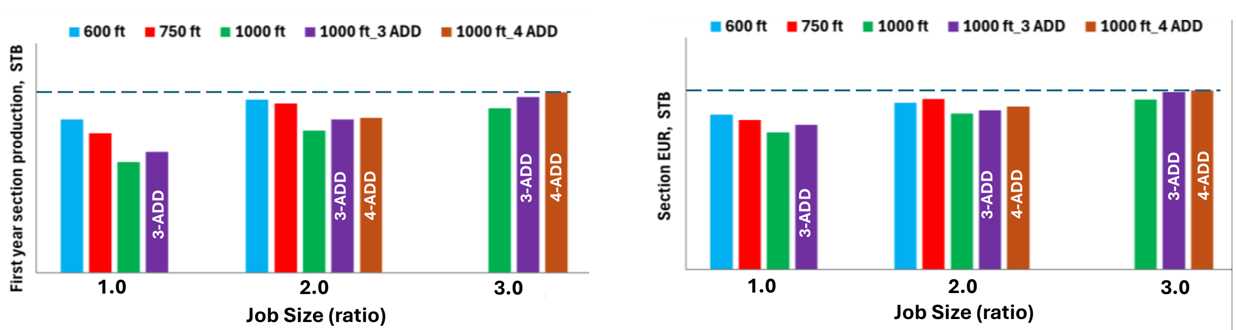


Figure 9 - Comparison of DSU (per section) first year production and EUR for development options (cases 1-12)

Figure 10 compares the first-year production and EUR for the DSU (i.e. – total for all wells), but now the results are shown as a percentage of the base case design (ratio 1) and 600-ft well spacing. The figure shows that DSU production and EUR decrease with wider well spacing when the job designs remain the same (ratio 1). However, the combination of large job sizes (ratio 3), 1000-ft well spacing, and ADD wells results in about 17% increase in DSU first-year production and a about 15% increase in DSU EUR compared to the base case (small job, 600-ft well spacing). The tighter well spacing cases, 600 and 750 ft, with moderate job size (ratio 2) also show improvements in DSU first-year production and EUR.

Tighter well spacing of 600 and 750 ft with moderate jobs size (ratio 2) exhibit higher first-year DSU production and similar DSU EUR compared to the standard 1000-ft well spacing cases with large jobs (ratio 3). However, the modeling suggests that ADD wells can improve first-year DSU production by about 10% and EUR by about 5% when compared to standard development using 1000-ft well spacing and large job sizes. This illustrates the benefit of ADD wells with 1000-ft well spacing, enabling larger well spacing to outperform tighter well spacing. However, the primary consideration when selecting the best development scenario is usually to maximize value or some other economic metric.

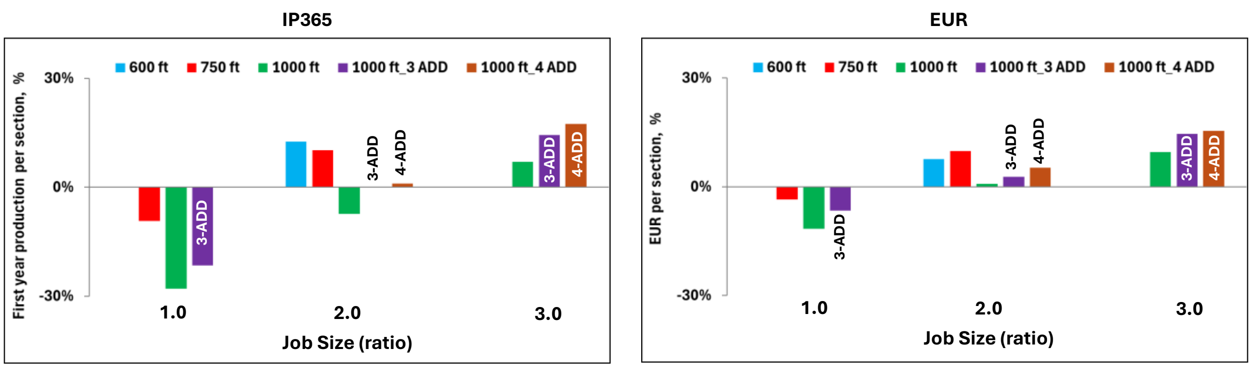


Figure 10 - Comparison of DSU first-year production and EUR for development options (case 1-12)

Comparison of DSU Economics

The details of the economic inputs are confidential, but typical Bakken drilling, completion, production, and gathering costs and taxes were used in this analysis and are representative of the operator's cost and value structure at the time of this study. The only significant uncertainty in the economic analysis is ADD well cost. The initial proof-of-concept ADD wells documented by Cipolla et. al.(2024) were standalone wells and designed to ensure a successful evaluation of ADD well performance, so the well costs are not representative of full-scale ADD applications. ADD could be combined with advanced drilling and completion technology to substantially reduce ADD well cost. For example, ADD could be implemented using dual lateral wells with one lateral used for standard PnP completions (frac wells) and the second used for the ADD wells. Other options include multi-lateral ADD wells and combo wells that use a portion of the lateral for ADD. The details of reducing ADD well costs and advanced drilling applications are beyond the scope of this work. However, the economic evaluation will provide insights into the relationship between well cost and ADD viability.

The economic comparisons evaluated a wide range for ADD well or lateral cost. An upper range of 100% to 200% of the standard well drilling cost was assumed for this study, which might be representative of a standalone ADD well (200%) or the high case incremental cost for an ADD lateral (100%). This study will focus on a lower cost range if 15% to 50% of a standard well drilling that ***may*** reflect an achievable cost per lateral for large-scale ADD using the drilling options discussed above. The lower range, 15% of the standard well drilling cost, ***might*** represent the cost per lateral for an optimized, innovative ADD lateral. The low-cost range assumes that ADD will be implemented using dual laterals (PnP lateral + ADD lateral), multi-lateral ADD wells, or other options such that the facilities and artificial lift costs are significantly less than standard wells. For example, the ADD lateral would not be burdened with facility and artificial lift costs for dual lateral wells (PnP + ADD). Note that the operator's drilling cost is about 40% of the total drilling and completion cost for a standard frac well (PnP well). Since ADD wells/laterals do not require hydraulic fracturing and may be suitable for an open-hole completion (i.e. – no slotted liner), there should be minimal or zero completion cost.

Figure 11 shows the NPV per section (DSU) and discounted return on investment (DROI) for the twelve development options modeled. The left graph shows the results for an ADD lateral cost that is 50% of a standard well drilling cost, illustrating that ADD using 1000-ft frac well spacing and large job sizes provides the highest NPV but a lower DROI compared to the other development options. The right graph shows the economic results when ADD well cost is 15% of a standard well drilling cost, indicating that ADD with 1000-ft well spacing and large jobs provides higher NPV and DROI compared to standard development options.

Incremental cost for ADD lateral = 50% drilling cost *Incremental cost for ADD lateral = 15% drilling cost*

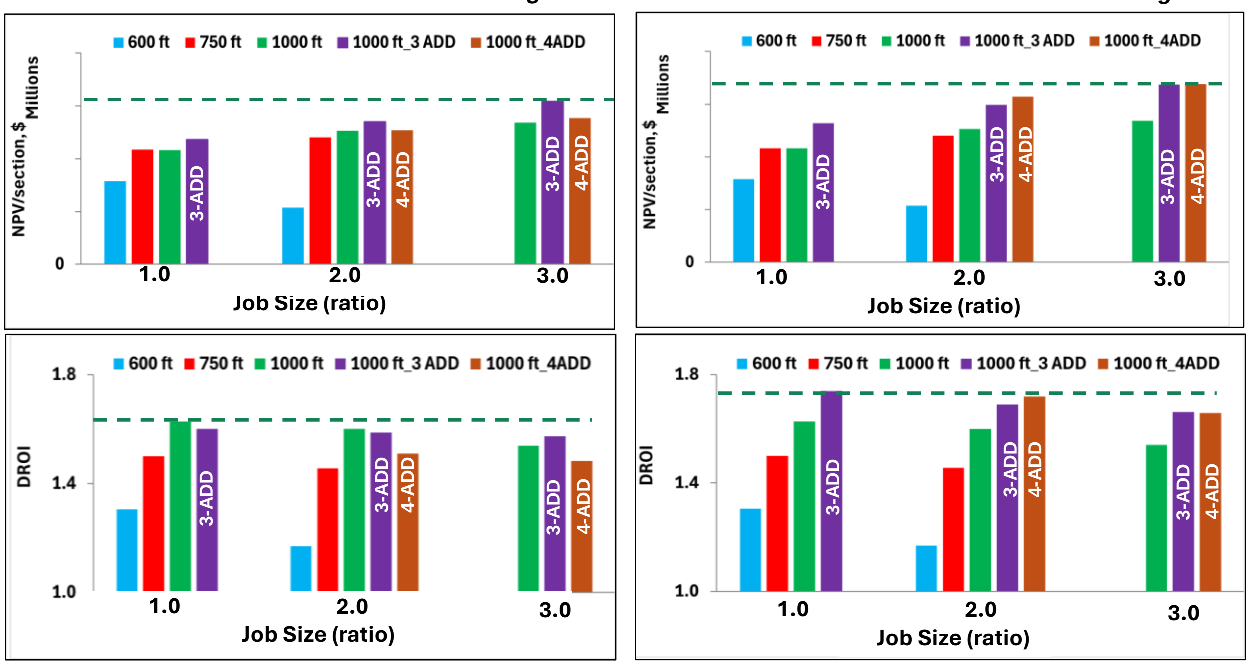


Figure 11 - Comparison of DSU economics for development options (case 1-12), high and low case ADD well costs

Figure 12 compares the economics for standard development and ADD scenarios, showing the results for the complete range of ADD lateral cost, 15% to 200% of standard well drilling costs. The results are presented as a cross-ploy of DROI on the x-axis and NPV on the y-axis to allow an easy comparison. This representation highlights the trade-off, in some cases, between NPV and DROI. The standard development options are shown in block dots, while the ADD options are shown using red dots (15%), green triangles (50%), light blue diamonds (100%), and purple cross (200%). The figure shows that ADD applications may compete with standard development options when ADD well or lateral cost is 50% of a standard well drilling cost. If the incremental cost of ADD laterals is only 15% of the standard well drilling cost, then ADD applications look very attractive.

As ADD lateral cost increases, standard development options may be more attractive. However, ADD applications may still be an option when the incremental cost of ADD laterals is 100% of the standard well drilling cost. These cases show the same NPV per section, but somewhat lower DROI. ADD applications are economically challenged when the incremental cost for ADD laterals is 200% of the standard well drill.

Although the economic inputs and evaluation criteria for each operator will differ, the results suggest that full-scale application of ADD may be viable if ADD well cost is below 50% of a standard well drilling cost. There may be ADD opportunities even if the incremental cost of ADD laterals is 100% of a standard well drilling cost, especially if there are secondary benefits such as EOR, IOR, and/or re-stimulation. Future modeling work is planned to study these secondary benefits.

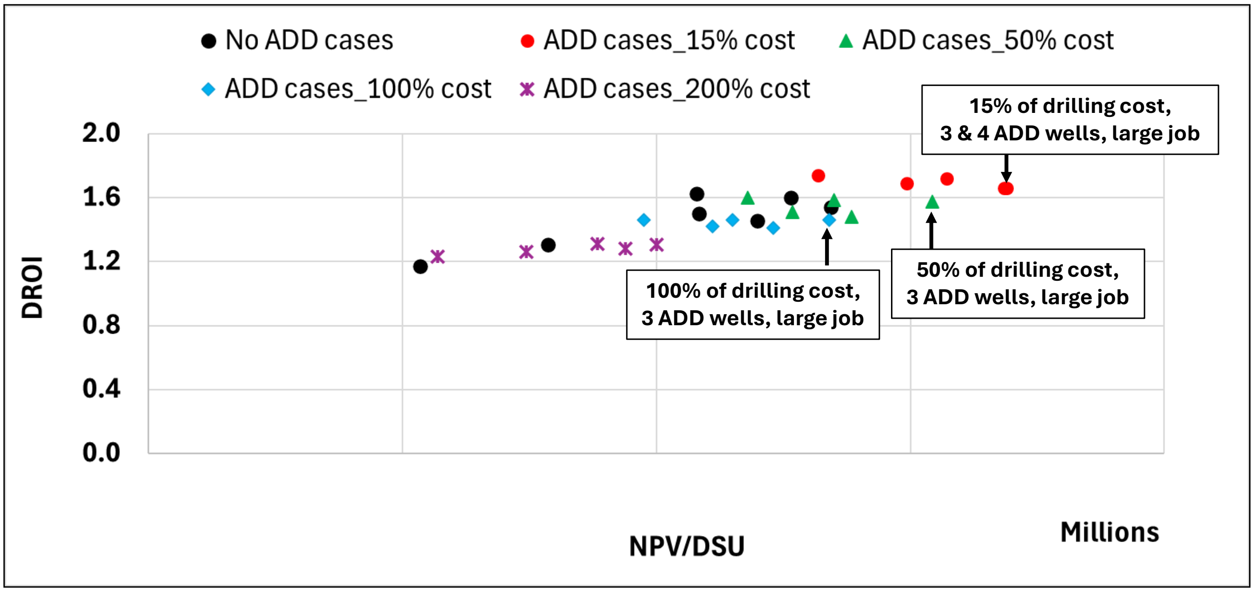


Figure 12 - Economics for incremental ADD lateral cost of 15% to 200% of standard well drilling costs

Summary and Conclusions

This work extends the innovative concept of ADD, providing important insights into potential ADD applications to improve unconventional field development. The modeling provides a comparison between wider frac well (PnP well) spacing enabled using ADD laterals to standard development options, illustrating the potential for ADD applications in the Bakken. The basic insights into ADD applications should be applicable to other unconventional developments. The key enabler of ADD will be cost reductions, possibly with innovative drilling and completion applications such as dual laterals with one frac lateral plus an ADD lateral, or multi-lateral ADD wells. Achieving the significant cost reductions required to enable ADD will be very difficult, likely requiring a combination of advanced drilling technology, innovation, and numerous field trials.

The insights from this work include:

1. ADD wells may improve first-year DSU production by 10% and oil recovery (EUR) by 5% for 1000 ft well spacing, compared to 1000-ft well spacing without ADD wells (laterals).
2. Economic projections show that ADD could be a viable development option in the Bakken if ADD lateral costs are 50% of standard well drilling cost and will likely be an attractive development option when ADD lateral costs are 15% of standard well drilling cost.
3. Economic projections show that ADD may be an opportunity for higher cost scenarios (e.g. – 100% of standard well drilling cost), but if costs approach 200% of standard well drilling cost ADD is probably not economical viable.
4. The combination of widely spaced frac wells plus ADD laterals may improve DSU production, EUR, and value compared to tighter well spacing.

5. Maximizing DSU value requires the appropriate combination of well spacing and fracture treatment design, with job size increasing for larger well spacing.
6. ADD well performance decreases as frac well spacing increases and there is a sweet spot for ADD around 800-1000 ft frac well spacing.
7. ADD well performance can be improved with larger jobs for well spacing of 600 to 1200 ft.

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Nomenclature

ADD	*= Augmented Drainage Development*
BHP	*= bottomhole pressure, F/ L2*
E	*= east*
DROI	*= discounted return on investment*
DSU	*= Drilling spacing unit*
EOR	*= Enhanced oil recovery*
EUR	*= Estimated Ultimate Recovery*
Frac well	*= typical Bakken plug and perf completion*
ft	*= Feet*
GOR	*= gas oil ratio*
IOR	*= Improved oil recovery*
LBS	*= Lower Bakken Shale*
MB	*= Middle Bakken*
Mscf	*= 1000 standard cubic feet, L3*
N	*= North*
NPV	*= net present value*
PnP well	*= typical Bakken plug and perf completion*
PPA	*= pounds of proppant added per gal of fluid*
S	*= South*
STB	*= stock tank barrel, L3*
TF	*= Three Forks*
UBS	*= Upper Bakken Shales*
W	*= west*
xf	*= hydraulic fracture half-length, L*
^{o}	*= degrees*

SI Metric Conversion Factors

acre	x	4.046 873e+03	=	m^2
bbl	x	1.589 874e-01	=	m^3
cp	x	1.0e-03	=	Pa.s
ft	x	3.048e-01	=	m
^oF		(^oF – 32)/1.8	=	^oC
lbm/gal	x	1.198 264e+02	=	kg/cm^2
psi	x	6.894 757e+00	=	kPa

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