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An Interdisciplinary Economic Appraisal of Plug-And-Perf Versus Single-Point Entry Completions Systems Using Simulation

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Abstract

Selecting which formation access and interstage isolation approach is economically superior is difficult to assess due to the complex interactions of these systems' impact on drilling and completions cycle time and cost and well performance. An integrated view is necessary to assess the economics of single-point entry sleeve completions systems and plug-and-perf systems. The difficulty is exacerbated by the uncertainty of the percentage of effective plug-and-perf clusters. This paper documents the use of commercial simulation software to precisely estimate the daily cashflows for the life of a well pad (from rig move to decommissioning) using designs based on each system. The plug-and-perf cluster efficiency percentage is swept, and the percentage at which its economics breakeven with the single-point entry scenario is calculated. This is performed for multiple subsurface areas whose well performance vary differently from one another as effective cluster spacing changes. Using NPV/section, it was discovered plug-and-perf scenarios needed a cluster efficiency between 38-52% to breakeven with the corresponding single-point entry scenario. However, these results are highly dependent on an operator's contractual frameworks, well performance, and well production constraints.

Introduction

The elimination of bridge plug drillouts (or lateral cleanouts) and having 100% cluster effectiveness are major value propositions of single-point entry (SPE) sleeve completions systems. Low cost and high flexibility are major value propositions of plug-and-perf (PnP) systems. Selecting which formation access and interstage isolation approach is economically superior is difficult to assess due to the complex interactions of these systems' impact on cycle time, cost, and production. The uncertainty of the percentage of effective PnP clusters exacerbates this. A lot of work is focused on understanding what the cluster efficiency is and how to improve it [Robinson (2020)]. This paper provides an integrated, multi-disciplinary assessment of the economically optimal system.

The economic superiority of one formation access and interstage isolation system over another cannot be assessed without considering drilling, completions, and production implications. The result is a precise breakeven PnP cluster effectiveness percentage with which operators can assess the risk and opportunity of using one system over the other. Further, because the integration of the various disciplines is inherent in the commercial software, the multi-scenario execution and evaluation are mostly automated.

Several other works have compared PnP and SPE completions technologies. The vast majority of these have focused on fracturing performance [Algadi (2015), Jamaloei (2021)], though some have included high-level cycle time impacts [Griffin (2021)]. Some works highlight benefits of one over under circumstances such as casing deformation [Bagci (2020)].

This paper focuses more on the evaluation methodology than the actual results. The precise results will vary widely based on an operator's contract and cost structures, reservoir performance, and facility capacity. Nonetheless, the methodology is easily repeatable with a similar integrated simulation framework and input parameters tuned for a specific operator.

Study Methodology

This study focused on the operator's two base designs and strategies for completing their North-East British Colombia Montney wells: one using plug-and-perforate (PnP) and the other using single-point entry (SPE) cemented sleeves. The latter utilize one cluster per stage (i.e., it is a single-point entry (SPE) design). Specifically, the SPE cemented sleeves were a combination of graduated-limited ball drop sleeves and graduated-unlimited ball drop sleeves. I.e., the first 36 stages use sleeves whose inner diameter gradually increases such that there is a maximum number that can be used. From stage 36 to the heel, the sleeve technology has a constant inner diameter. The costs vary between the technology.

Through historical data, the operator has a strong understanding of reservoir performance (i.e., what the well type curves will be) for varying stage lengths using their SPE design. By assuming that 100% of the SPE clusters are effective (i.e., 100% of the clusters take proppant, fluid and produce the desired fracture), these varying stage lengths can be thought of as effective cluster spacings. The operator is unsure of the percentage of effective clusters when using the PnP design. This study, by assuming an effective PnP cluster will have the same performance as an effective SPE cluster, sweeps PnP's effective cluster percentage per well and calculate what effective cluster spacing is required to breakeven economically with their SPE design. The majority of financial results (costs, NPV, etc.) will be normalized in some way (e.g., a percentage of a reference).

Estimating NPV/section

This appraisal is fundamentally economic. Any economic key performance indicator (KPI), or combination thereof, could have been selected. The net present value per square mile, or net present value per section (NPV/sq-mi or NPV/section), was used in this appraisal. Because wells' lateral lengths can vary slightly between scenarios (due to rounding up to nearest integer number of stages when varying stage length), NPV/section effectively captures impacts on capital, revenue, and time for an operator's assets.

To calculate the NPV/section for any well design scenario, the following must be estimated for each well under each scenario.

- All capital costs and cycle times
  - Drilling
  - Completions (and production)
  - Facility construction
- Reservoir type curves post choking (all commodities)
- Relevant economic considerations (e.g. commodity price decks, depreciation schedules, on-going OpEx, etc.)

- Subsurface area

This appraisal bucketed other costs and durations between end of hydraulic fracturing (frac) until the well is on production (e.g., cleaning out the well, flowing back the well) within completions costs and durations. Because, within an individual scenario, well spacing and lateral length are the same for every well on the pad, subsurface area is calculated by multiplying number of wells by well spacing and lateral length.

Because unconventional wells are normally drilled and completed in groups and development run, the capital costs and cycle time for each well really depend on the group of wells being drilled, completed, and brought online together. While acknowledging the word "pad" often refers to a geographical location where multiple wells are drilled and completed, this paper will refer to a multi-well pad as a "pad". Per well metrics are taken from average well metrics across the pad. Because each scenario will use the same number of wells and every well in that scenario will have the identical well and stage designs, using the average per well is accurate.

Capital Costs and Cycle Times. The drilling, completions, and facility costs and cycle times needed to be estimated for a pad of wells that had varying stage lengths and stage designs. Because this appraisal would always round to the next integer number of stages, slightly varying lateral lengths needed to be assessed as well. Varying stage designs included varying formation access and interstage isolation (Acc. & Iso.) technologies and techniques.

The fundamental well casing design was held constant for all scenarios. So drilling costs and cycle times could be held mostly constant for all scenarios. Because of slight variations in lateral length, there was a small duration and cost adjustment per unit lateral length. The one significant factor was, for the operator, any SPE technology's sleeve cost hit the drilling budget. Therefore, for each scenario, the total number of sleeves was calculated, and all sleeve costs were added to drilling costs. For SPE scenarios, it is probable that drilling cycle times should also increase slightly to account for making-up sleeves on the rig floor, but, in this analysis, this was considered negligible and omitted.

Varying stage length has a large impact on completions costs and cycle time. For a given lateral length, varying stage length will vary the number of stages and, therefore, the number of Acc. & Iso.) activities (e.g., for PnP, the number of wireline runs) and the amount of non-treatment pumping time (i.e., breaking down the formation, overflush, etc.).

Varying Acc. & Iso.) technologies has enormous impact on pumping flowrates, pressures, and durations (for both non-treatment and treatment pumping) and what kind of surface activities take place and, therefore, in what order stages are completed.

When every stage on a well uses sleeve technology in the studied formations, post completions, the operator does not conduct any lateral cleaning or drillout operations compared to a coil tubing drillout operation with PnP completion technology. This time and cost savings in comparison to PnP was also captured. Depending on how effective their flowback operations are sufficient at cleaning out sand in the lateral, operators may still want to perform lateral cleaning and include those costs and time in the SPE scenarios.

The varying well and stage designs did not have any impact on facility construction cost and cycle time. These are constant for all scenarios.

Reservoir type curves post choking. The operator had P50 type curves (Mscf/day per month and corresponding oil-to-gas ratios, water-to-gas ratios) for several Similar Subsurface Regions (SSR's). For each SSR, there were six P50 type curves corresponding to a well's effective cluster spacing (14m, 28m, 42m, 56m, 70m, and 100m). Both type curves shapes and total productions could vary between SSR and effective cluster spacing. Any well's effective cluster spacing could be calculated and, based on what SSR it was located, the appropriate type curve could be selected or, if not one of the six values, interpolated between the two closest.

Because of slight variations in lateral length due to rounding to integer number of stages, a beta=1 scaling factor is applied, when adjusting production for changing lateral length (i.e., a 1 to 1 scaling factor for production).

A well interference matrix is applied to capture production impacts of various vertical and horizontal well spacings. Because these are constant for the various scenarios considered, the well interference does not have an impact on these results.

Each well had a maximum production rate per commodity (gas, oil, water, and liquid). A choking algorithm would cap production rates while holding lifetime production constant.

The gas shrinkage; heating value; and condensate, butane, and propane yields are captured. But these are assumed constant across scenarios.

Economic considerations. To assess NPV, numerous economic factors must be considered: discount rate, inflation, price decks, tax rates, commodity transport costs, royalties, operating expenses, depreciation schedules, etc. These are assumed constant per scenario (though the various cycle times are captured so wells' online dates can vary significantly, so production acceleration and deceleration are factored into the NPV calculations). NPV is finally normalized by the subsurface area (sq-mi) to calculate NPV/section.

Fundamental Scenario Assumptions

There are three assumptions that are fundamental to this appraisal. Firstly, the assumption that an "effective cluster" is identical between the PnP and SPE designs. The authors find this unlikely, but, without more information, this is the fairest assumption.

Secondly, as will be explained in detail in latter sections, the SPE scenarios leverage a "dual frac" strategy. I.e., during completions, two independent frac spreads with independent blenders, each with their own ball/dart launcher, are present and pumping different stages. For PnP scenarios, only a single frac spread (and wireline and pumpdown crew) are used. At present, the operator cannot deliver water to pads fast enough to handle a dual frac strategy with PnP (PnP stages are pumped at much higher flow rates than SPE stages due to, for example, orifice pressure drops cross SPE sleeve technologies). Further, the operator has lower pumping services charges per pumping minute for the dual frac SPE pads than the PnP single frac pads; the former are about 75-90% the price of the latter. This is a big difference between the options, especially in terms of completions cycle time and pumping services cost, but it accurately reflects the operator's base designs for the competing scenarios.

Related to both of those assumptions is a third assumption. In contrast to the SPE scenarios' dual frac execution, PnP scenarios are executed using a "zipper frac" strategy. Any impact this execution difference has on production type curves is not accounted for.

Overview of Simulation Tool

The PrePad™ software was instrumental in performing the study. Its algorithms can capture the impact on drilling and completions cycle time and costs and several complex interactions of design and strategy choices, including all the ones mentioned in the "Estimating NPV/section" and "Key Scenario Assumptions" subsections. PrePad™ uses operational, design, and contractual inputs with its first-principle physics and discrete-event simulation models to simulate the end-to-end drilling and completions processes and resulting cycle time and costs.

Type curves with various designs and beta scaling factors for various SSR's can be imported into PrePad. All listed economic factors are considered resulting in daily cashflows of the life of the pad, from rig move to well decommissioning, are captured. Every minute and every dollar of every scenario is taken into account.

Reference Designs

Table 1-Summary of reference designs for appraisal Table 1 highlights the primary differences between the two reference scenarios. BDL-BDU refers to the SPE strategy of using graduated-limited ball drop sleeves starting at the toe and changing to graduate- unlimited ball drop sleeves (and a new fluid loading). This transition occurs after 36 graduated-limited stages.

Table 1—Summary of reference designs for appraisal

Parameters	Reference	
	SPE (BDL-BDU)	PnP
# of wells on a pad	6	
Lateral length (m)	3,000	
Fluid loading (m^3/stage)	280, 250	500
Sand loading (MT/stage)	50	120
Clusters/stage	1	6
Cluster spacing (m)	42	14
Cluster Efficiency (%)	100	?
Avg. Frac Treating Rate (m^3/min)	6	8

The following subsections will provide some details into the reference scenario outputs. This will further illuminate the methodology and assumptions of the study. The focus will be on the most significant factors in the comparison (completions and type curve outputs). The drilling and facilities cost and cycle time detailed outputs will not be displayed due to their constant or easily predictable output differences (e.g., sleeve costs being present in drilling costs for SPE scenarios and not present for PnP scenarios).

Plug-and-Perf Reference Details

Given the stage designs, operational inputs, surface equipment activity logic, and if single or dual frac strategy, the simulation software determines an optimal way to complete the stages. A Gannt chart showing the intra-pad completion activities for the entire pad is shown in Figure 1. Each well has two swimlanes: the top one for access-and-isolation-related activities and the bottom one for frac-spread-related activities. For the plug-and-perf scenario, one can see the zipper process occurring between the wells. Figure 2 zooms in on the first stages on the first two wells.

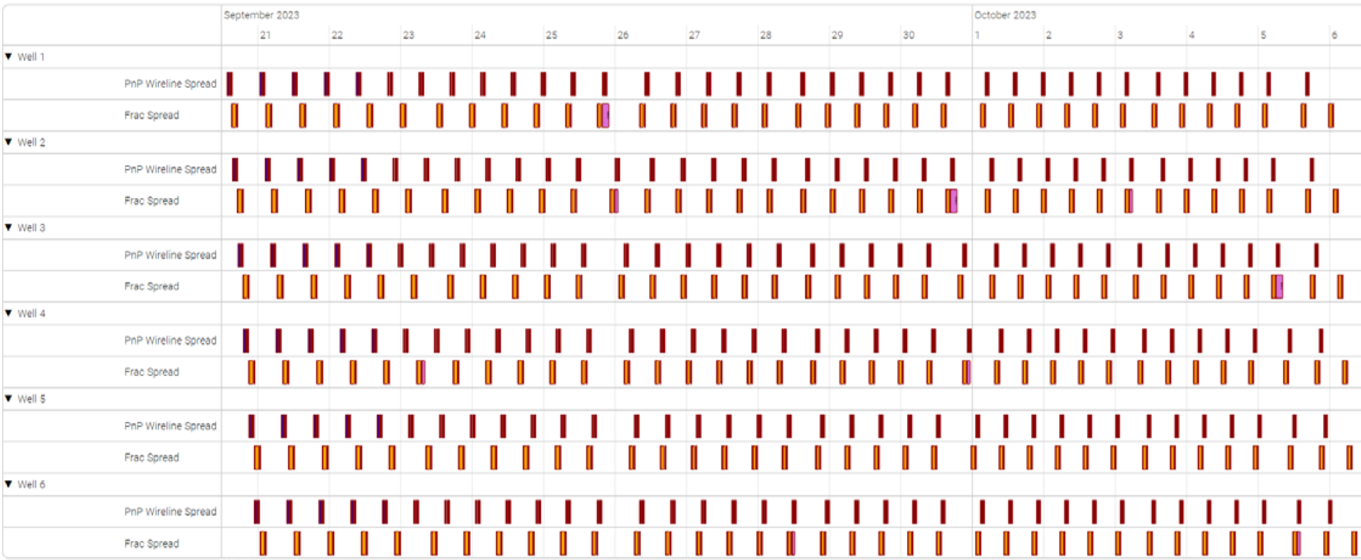

Figure 1—Intra-pad completions Gannt chart of PnP scenario (only relative dates relevant)

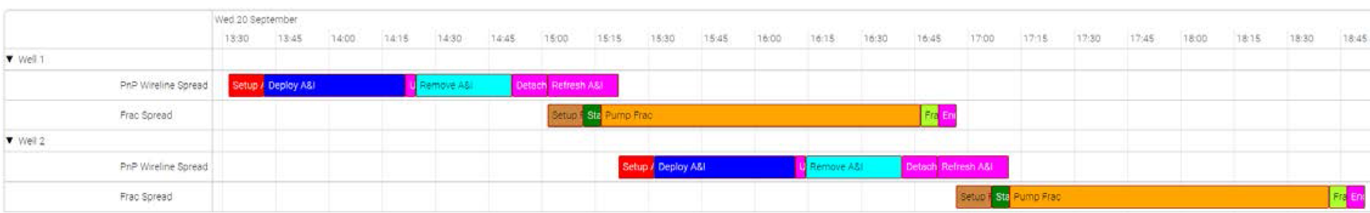

Figure 2—Zoomed in view of PnP scenario's intra-pad completion Gannt chart (only relative dates relevant)

Most operational activity durations are based on set input durations or speed based on historical times. E.g. for PnP, "Setup A&I" is comprised of two activities, "Lift, Move, Connect Pressure Control Equipment (PCE)" and "Pressure Test (PCE or Pumps)", each of which is a fixed duration input per stage (e.g., 5 minutes each). For PnP, "Remove A&I" is comprised multiple activities including "Pull Out of Hole", which has a duration calculated based on a stage's measured depth and a set input, "Pull Out of Hole Speed".

The "Pump Frac" activity is obviously extremely important. The duration is based on an approximate pumping profile that is a combination of inputs regarding a particular access and isolation's non-treatment pumping needs (e.g., seating an isolation device, overflushing the well), pumping plan inputs, first-principle physics predicting treatment pressures and flowrates, and well and stage designs (casing sizes, sand and fluid loadings, etc.). Figure 3 shows an example stage pumping profile. Figure 4 shows the predicted treating pressure and flow rates per stage for a single well.

These are some of the key results that combine with an extensive set of contractual information to estimate several line item costs per phase. The accumulation of these costs by cost code is show in Figure 5 with the costs normalized to what percentage of the overall cost it is.

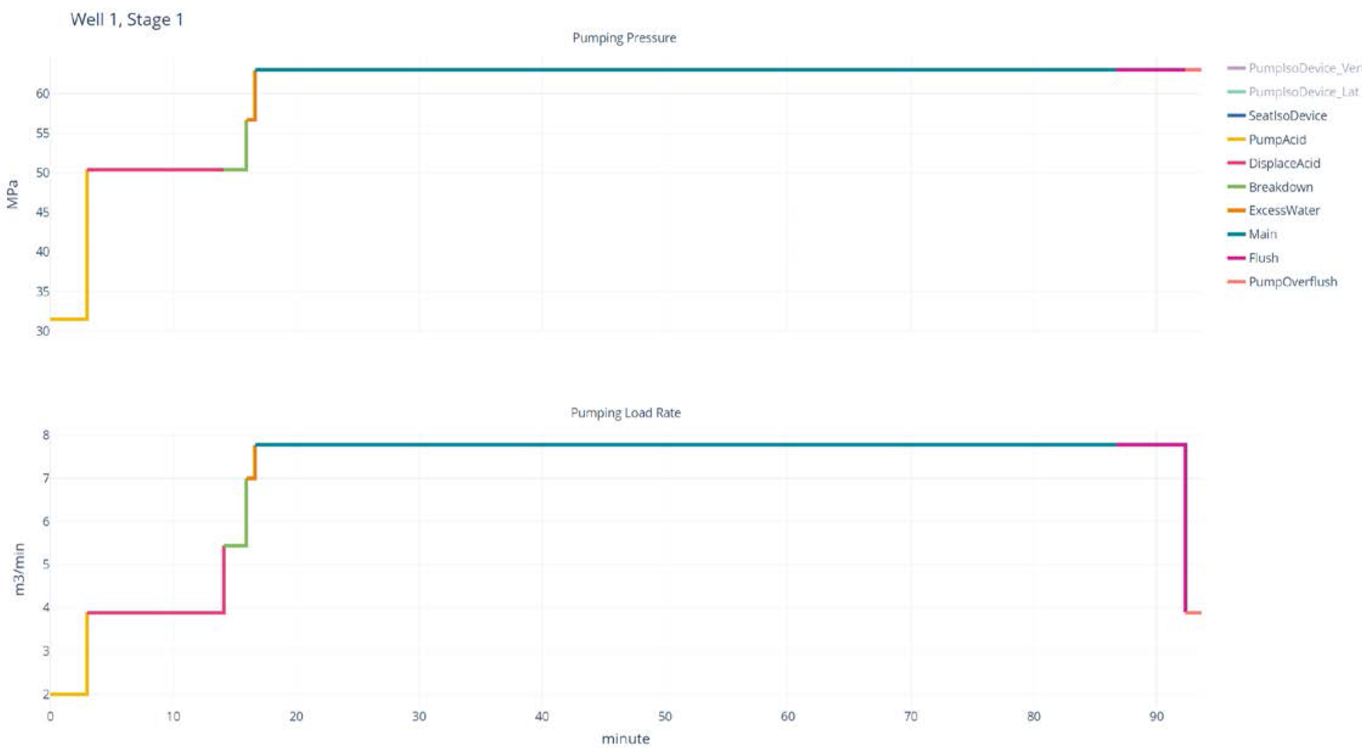

Figure 3—PnP Scenario example stage pumping profiles

Figure 4—PnP scenario avg. treating pressure and flow rates per stage

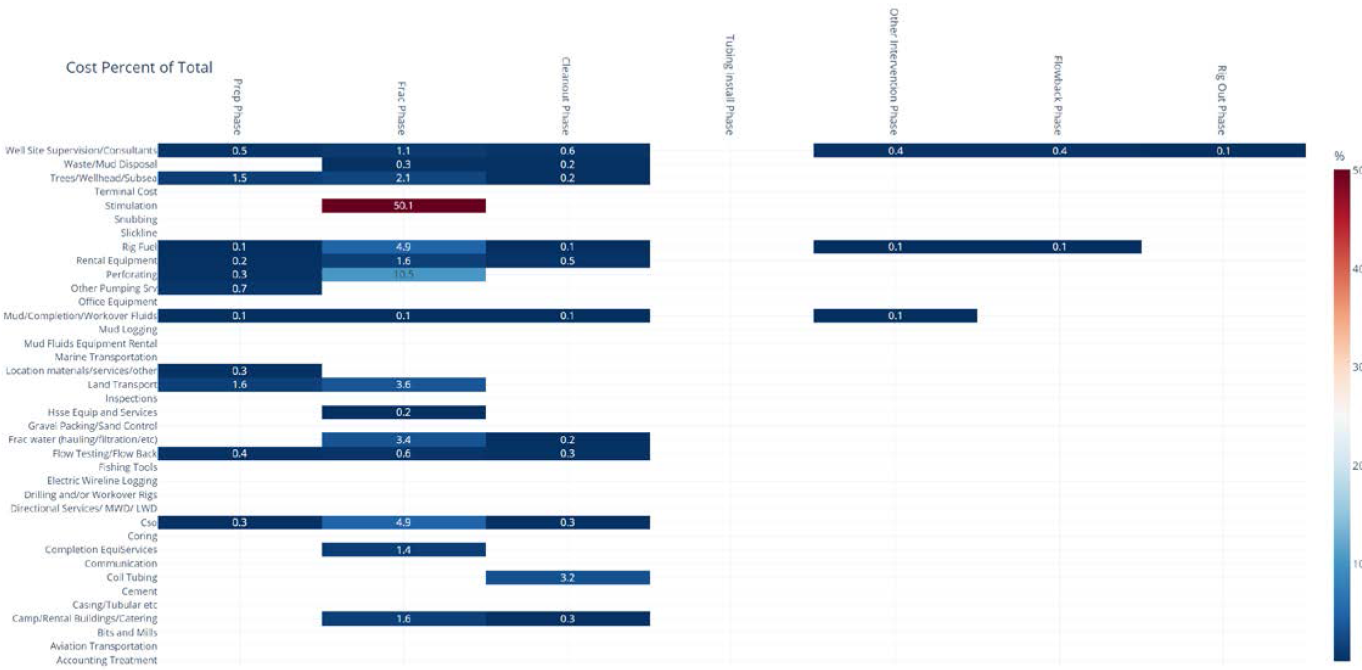

Figure 5—PnP reference scenario completions costs as percentage of total completions costs

The well type curve for the PnP scenario depends on the SSR and the assumed cluster efficiency percentage. Figure 6 shows the type curves for an individual SSR with the cluster efficiency swept from 20% to 100%. The choking algorithm saturates production at 10,000 Mscf/day. For this SSR, the lifetime production always increases (though not linearly) as cluster efficiency increases. Although this is typically the case, it is not for every SSR.

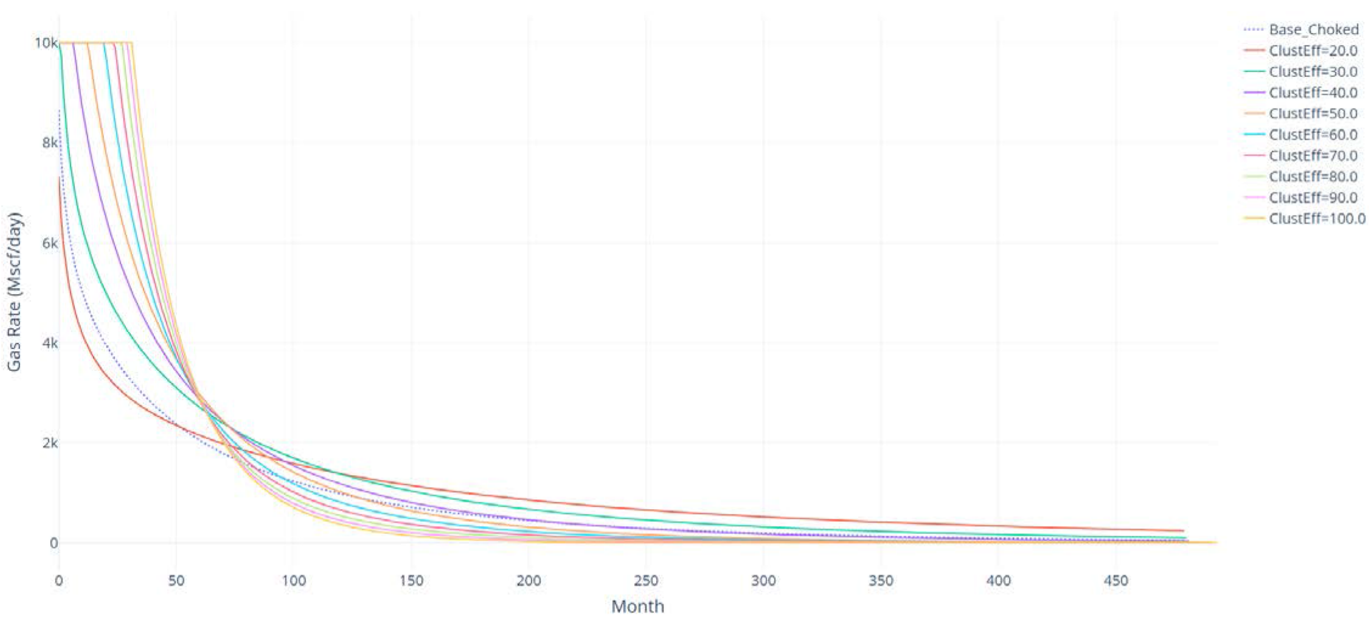

Figure 6—Individual SSR's type curves for PnP scenarios of varying cluster efficiencies

The scenarios' vast array of cost, cycle time, and production outputs combine with the economic inputs to provide daily cashflows for the life of the pad. Figure 7 shows the example cashflow results for one PnP scenario; to make the results more interpretable, only the weekly net cashflows (today's dollars) are shown for seven years starting from the rig move date. For anonymity, no values are displayed, but a general trend and intuition for what the commercial software produces can be seen.

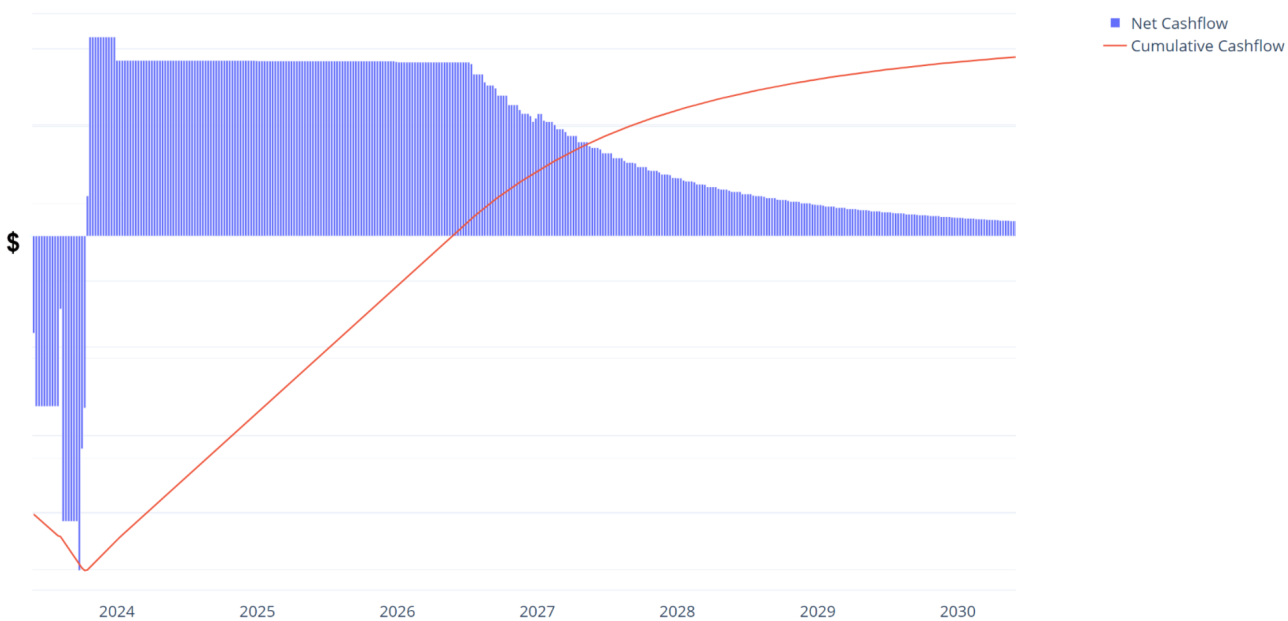

Figure 7—Example PnP scenario's weekly net cashflows for first seven years starting from rig move date.

These cashflows are converted to real terms (discount rate and inflation) and summed to calculate the net present value.

Single Point Entry Reference Details

The SPE scenarios contain the same level of details as shown in the PnP Reference Details subsection. Completions outputs that vary greatly from the PnP reference scenario will be documented below.

The Gannt chart in Figure 8 shows the completion process for dual frac SPE (with an inside-out well priority specification). Notice the very different stage swap times for the ball/dart/collet launcher compared to the wireline crew. The simulation tool determined a stack process was a more optimal process.

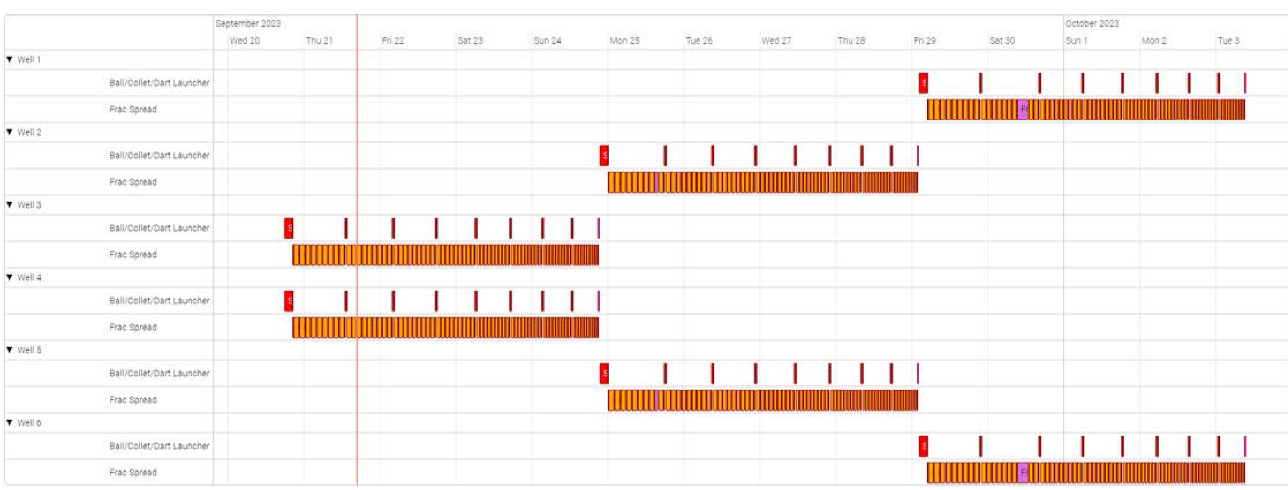

Figure 8—Reference SPE scenario Intra-pad Gannt chart (only relative dates relevant)

Figure 9 shows the pumping profile for the first graduated ball drop stage (the toe stage).

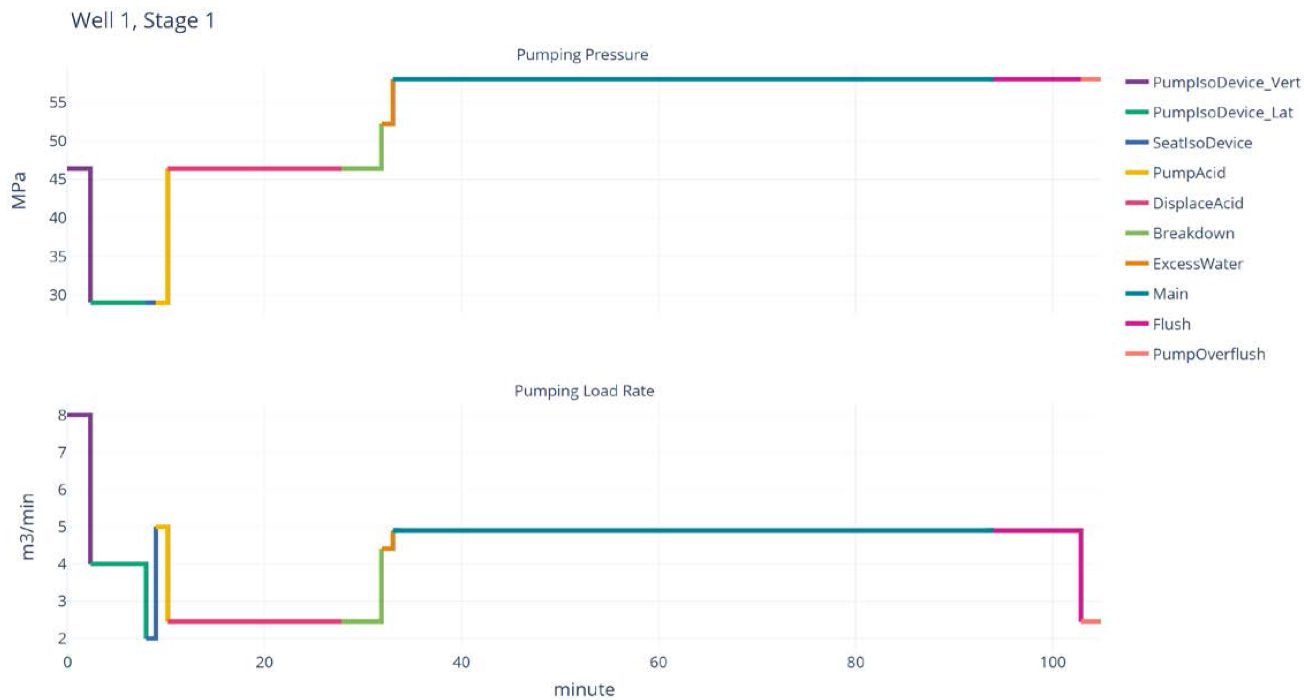

Figure 9—Pumping profile for toe stage of Reference SPE scenario

Starting at stage 37, the sleeve technologies transition to the unlimited sleeve technology. The pumping profile is similar to graduated ball drop sleeves, but the isolation device is pumped at higher flow rates.

Figure 10 shows the average treating pumping pressure and flow rates per stage. The flow rates are typically far lower than PnP due to the reduced internal diameter, causing an orifice pressure drop at each sleeve.

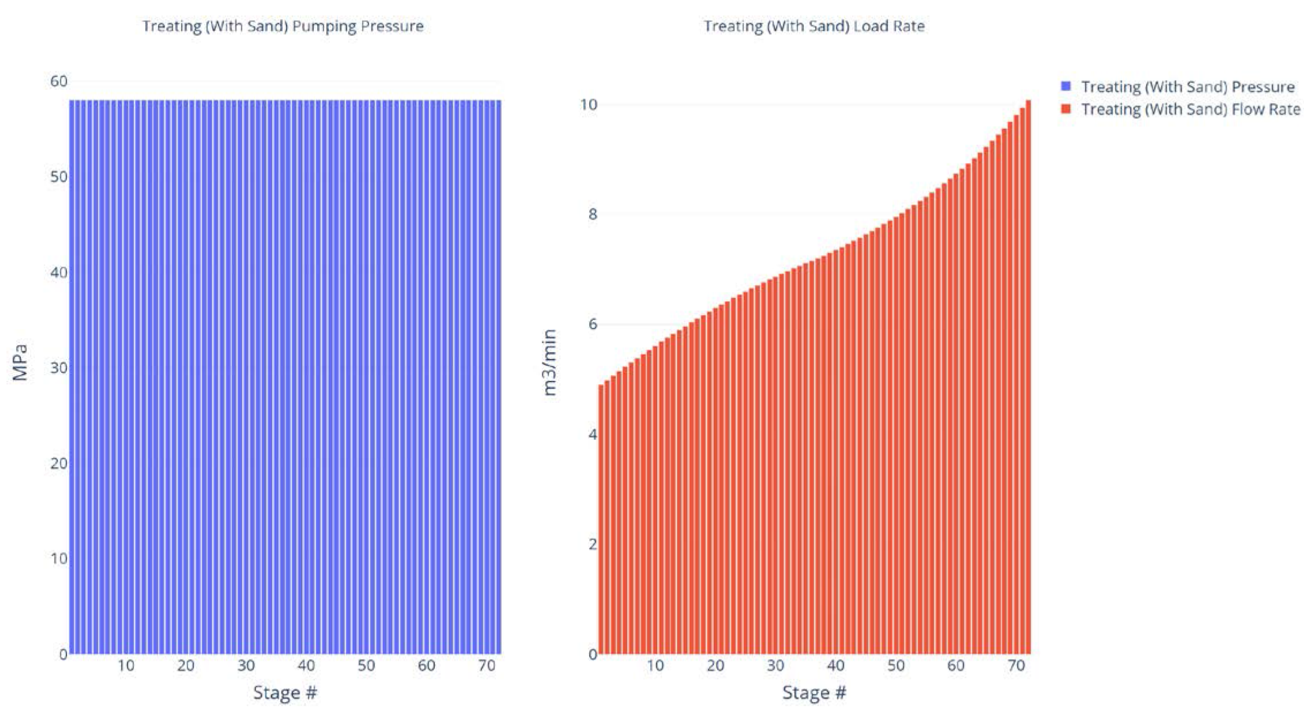

Figure 10—Reference SPE scenario (42m)'s average treating pressure and flowrate per stage

The driving factors for the SPE scenario completion costs differ greatly from the PnP scenario, primarily in not having any costs beyond the Frac Phase except for Rig Out (Figure 11).

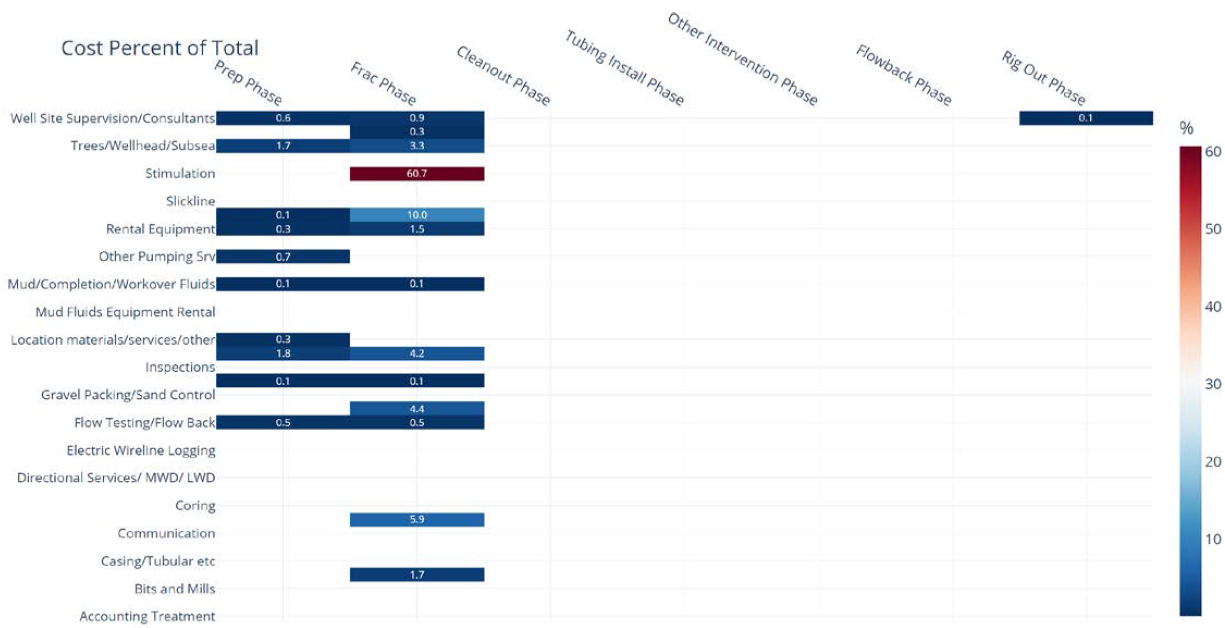

Figure 11—Reference SPE scenario (42m) 's completion cost breakdown by cost code and phase; values are percentages of total completions costs.

However, speaking about a single "reference SPE" scenario is difficult. The operator uses different cluster spacings (which is the same thing as the stage length for SPE) for their different SSR's. As the stage length varies, the cycle times and costs and completions vary wildly; drilling costs vary somewhat due to varying number of sleeves. The cycle time is shown in Figure 12. Figure 13 shows the breakdown of the capital spend for the various SPE stage lengths as a percentage of the 42m spacing. E.g., the 14m stage length scenario has almost double the costs in comparison to the 42m scenario.

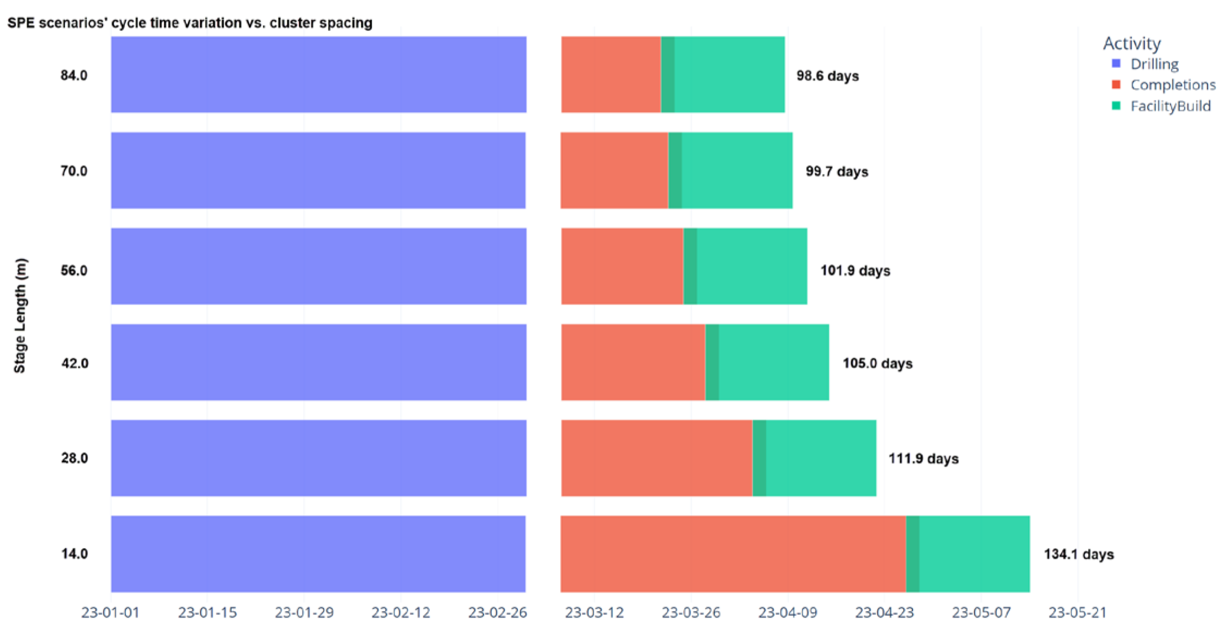

Figure 12—SPE reference scenarios' cycle times (rig move to production online) as cluster spacing is swept. Only relative dates are relevant.

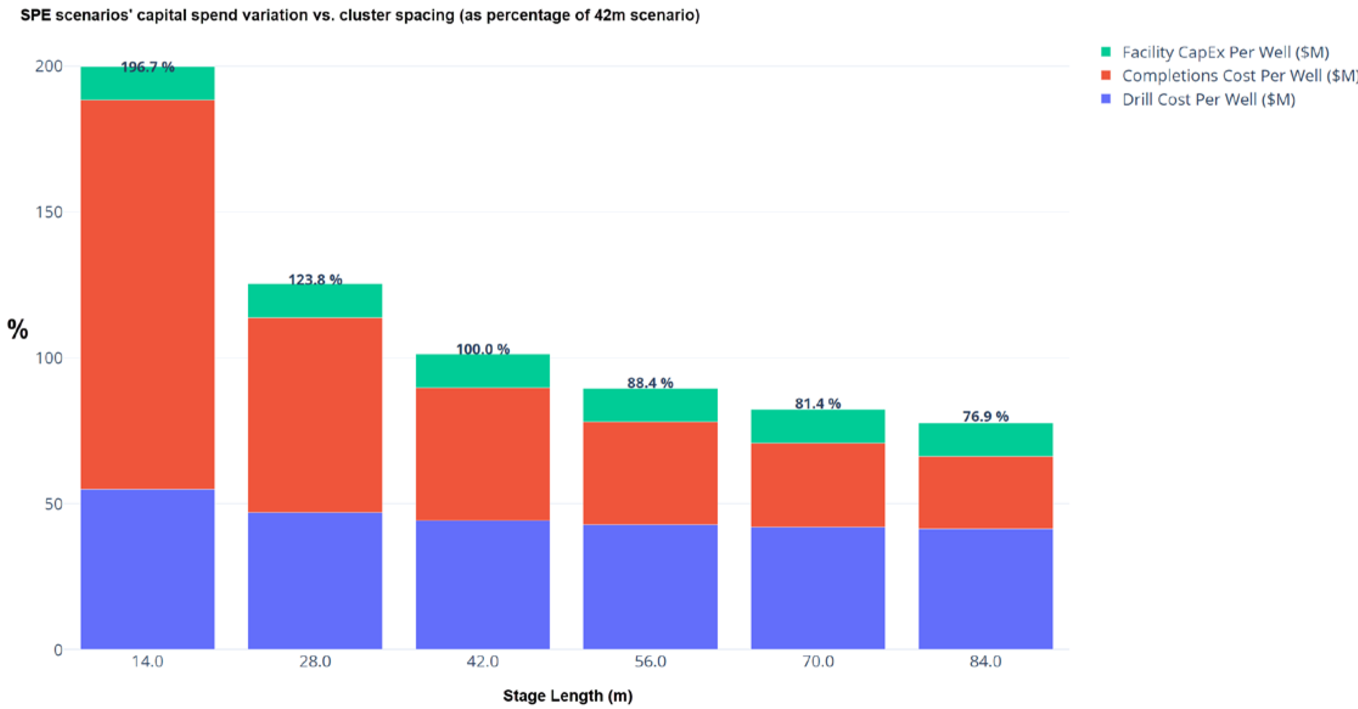

Figure 13—SPE reference scenarios' capital costs as cluster spacing is swept.

This study assumes, for the same SSR, lateral length, and effective cluster spacing, the SPE scenarios will have the same values per well as the PnP scenarios (Figure 6).

Comparison of Reference Scenarios

Primarily because of the dual frac strategy, the SPE scenarios usually have much shorter completions cycle time than the PnP scenario. The lack of cleanout is also a factor. Figure 14 shows the high-level Gannt chart of the drilling, completions, and facility build activities. The absolute dates are arbitrary; the relevant dates are precise. The per well cycle time for all completions phases for SPE (42m) and PnP references scenario is approximately 3.8 days/well and 8.1 days/well, respectively. The decreased cycle time lowers any time-based completions costs and accelerates wells being online. Although this primarily benefits shorter-term financial metrics (e.g., 2-year free cash flow), NPV also benefits due to factoring in the time value of money.

Despite the decreased completions cycle time, the SPE (42m) scenario is about the same amount of capital (Figure 15). The high drilling costs and lower completions costs approximately offset themselves. In this analysis, drilling costs are higher due exclusively to the cost of sleeves. Time-based completions costs are low for SPE (42m) because the dual frac strategy drastically reduces the cycle time. Still, the pumping hours for the SPE (42m) scenario are higher compared to PnP scenario (approximately 33 additional hours per well). Despite the SPE's dual frac pumping charge rate being approximately 15% lower than the PnP single frac charge rates, the SPE reference scenario's total pumping services costs are approximately 67% higher than the PnP scenario.

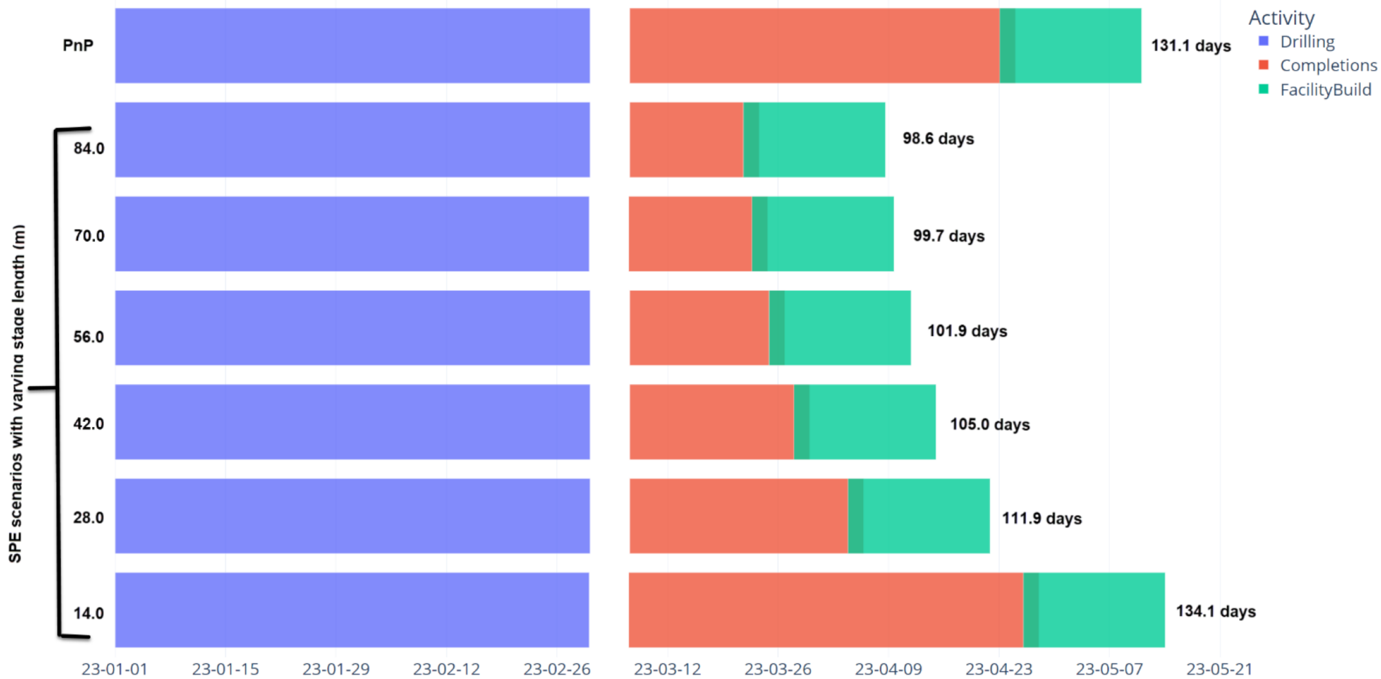

Figure 14—Rig move to wells online Gannt chart between the two reference scenarios (only relative dates relevant)

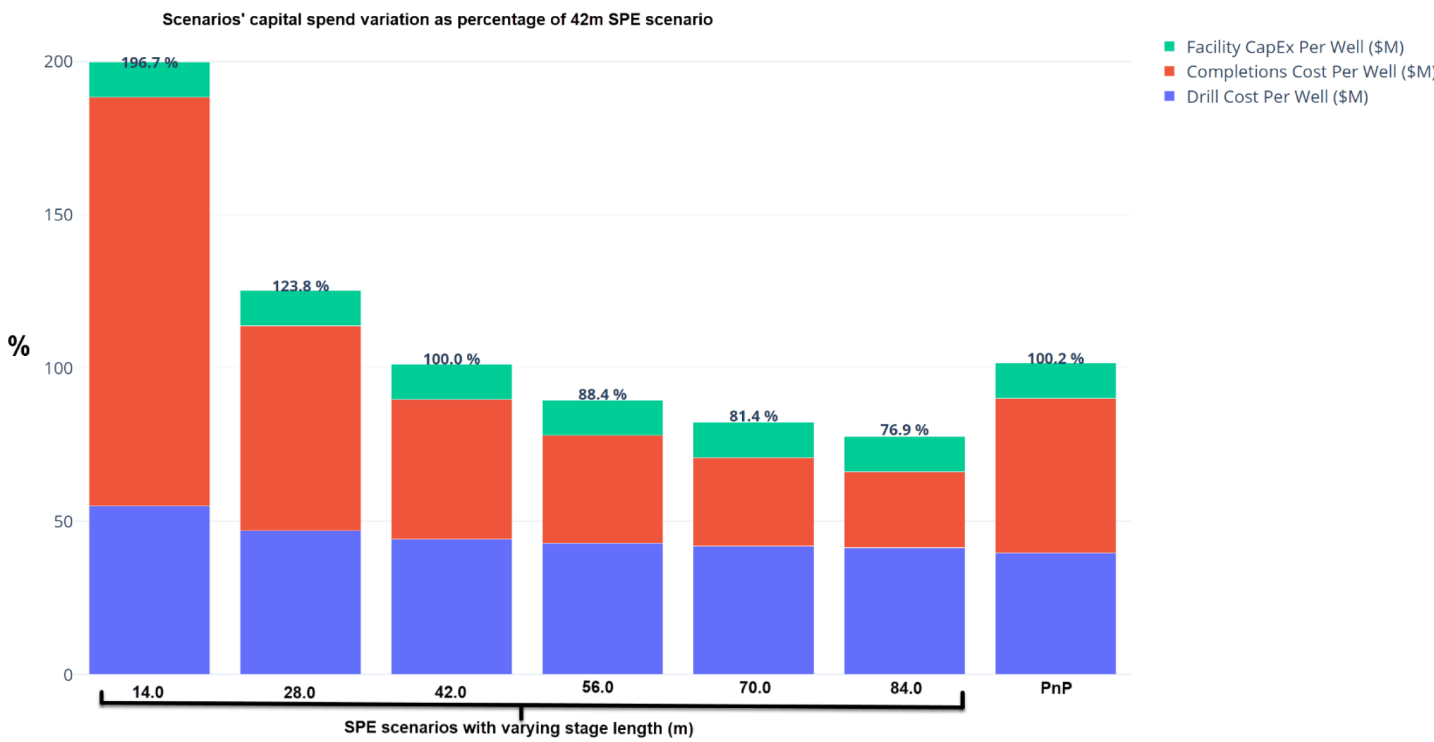

Figure 15—Capital cost comparison of all reference scenarios; costs are shown as percentage of SPE (42m) scenario

The justification for using SPE is the understanding that the improved cluster efficiency increases production more than enough to offset the increased cost. What percentage of PnP clusters must be effective to break even with SPE is the question this paper offers a method for answering.

Best Designs

In order to make a fair assessment, the best cluster spacing per SSR was identified for the SPE design. Different SSR's performance based on effective cluster spacing dictated whether additional capital (lowering cluster spacing) was worth it. Because the simulation tool can precisely predict the capital spend for these stage lengths, total production per SSR (in barrel of energy (BOE)) per total capital spend (Total CapEx) can be plotted (Figure 16). To calculate the present value (PV) of the lifetime BOE, the well's choked production was discounted and summed using the same method as the daily cashflows are to calculate NPV. The BOE (PV) versus Total CapEx varies greatly between various SSR's which directly relates to which SPE cluster spacing maximizes NPV/section for each SSR.

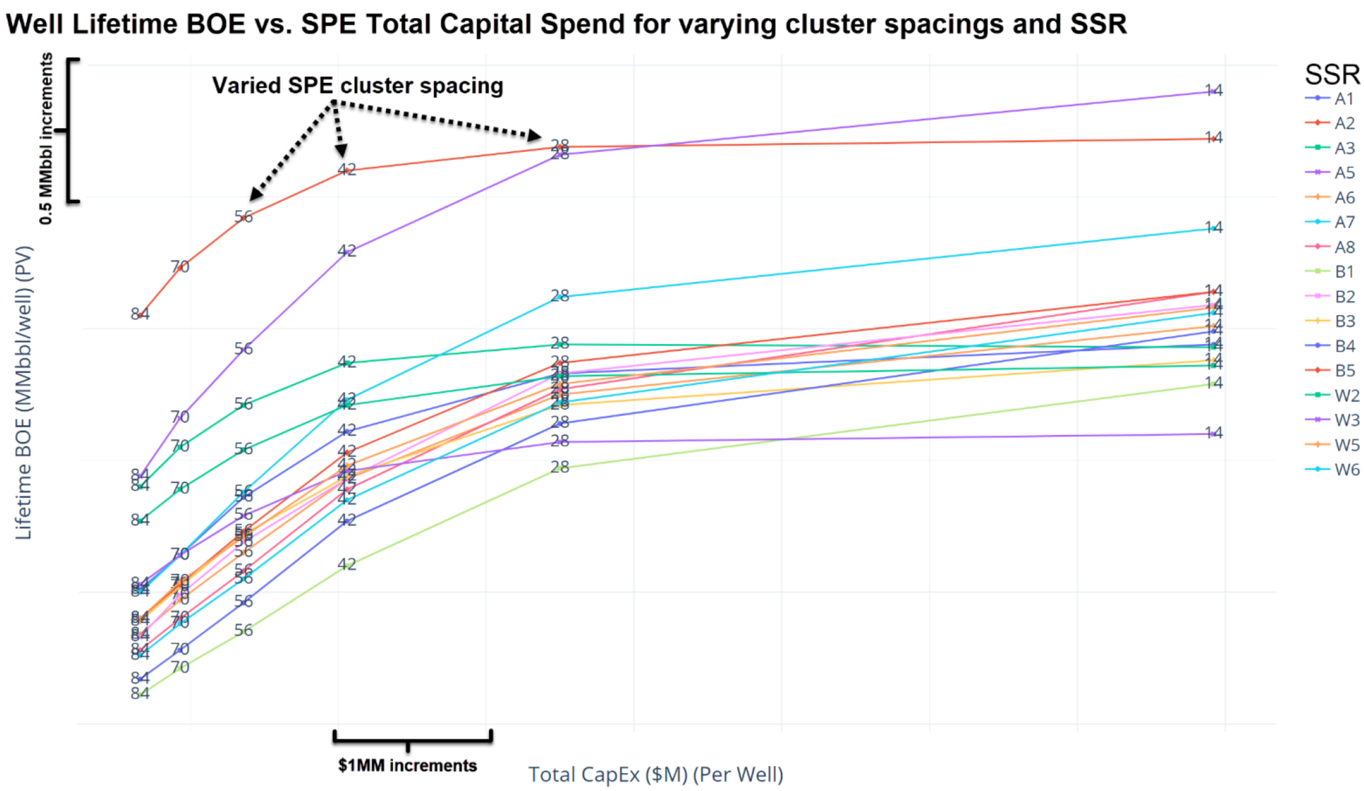

Figure 16—Present value (PV) of lifetime barrel of energy (BOE) vs. SPE capital spend ($1MM increments) by cluster spacing and SSR

Running all the stage lengths for all the SSRs revealed the optimum SPE stage length per SSR based on NPV per section (Table 2).

Table 2—Optimal SPE stage length (i.e., cluster spacing) per SSR based on NPV/section

SSR	Optimal Stage Length
A1	28
A2	42
A3	42
A5	28
A6	28
A7	28
A8	14
B1	14
B2	28
B3	28
B4	14
B5	28
W2	28
W3	28
W5	14
W6	14

The PnP cluster efficiency sweep for each SSR will always be compared with the optimal cluster spacing SPE scenario.

It is not straightforward to pick an optimal stage length (i.e., an optimal combination of cluster spacing and clusters per stage) for PnP. The minimum completions cost could be identified. However, the optimal NPV per section would depend on a fixed cluster efficiency—which is unknown. I.e., the optimal scenario would be for an optimal effective cluster spacing, which is a function of both cluster spacing and the percentage of effective clusters. The optimal effective cluster spacing could be determined per SSR, but the optimal cluster spacing cannot be determined because effective cluster percentage is unknown. Therefore, the base PnP cluster spacing and clusters per stage will be used. This is possibly a disadvantage for PnP, but it does not affect the overall methodology.

Experiment Results

After the base scenarios were calibrated and understood, the PnP cluster efficiency percentage was swept from 20% to 100% (in 10% increments), and the NPV per section (i.e., NPV/section or NPV/sq-mi) was compared to the SPE NPV/section (all NPV/section were normalized by the SPE NPV/section). Basic linear interpolation was used to estimate the precise cluster efficiency percentage at which the PnP scenario matches (and, in most SSR's, continues to exceed), the SPE scenario. This analysis was performed for every SSR.

High-Level Experiment Results for all SSR's

For the reference SPE and PnP scenarios, PnP's NPV/section will be greater, with cluster efficiencies starting between 38% - 53%, depending on the SSR (Table 3). To add additional perspective, the breakeven for 2-Yr free cashflow (FCF) per well is also shown, even though the select SPE cluster spacing was based exclusively on NPV/section. From the perspective of 2-Yr FCF, more optimal SPE cluster spacing existed for some SSR's.

Table 3—PnP Effective Cluster Spacing that breaks even with SPE scenario's NPV/section (per SSR)

SSR	Optimal Stage Length For SPE	Cluster Efficiency of PnP at which breaks even with SPE	
		NPV/section	2-Yr FCF Per Well
A1	28	44%	47%
A2	42	39%	>100%**
A3	42	44%*	37%
A5	28	47%	47%
A6	28	46%	46%
A7	28	47%	47%
A8	14	53%	55%
B1	14	50%	58%
B2	28	47%	47%
B3	28	45%	47%
B4	14	53%	57%
B5	28	46%	47%
W2	28	38%	45%
W3	28	38%	45%
W5	14	49%	54%
W6	14	52%	56%

Not that the operator has an equal number of wells in each of these SSR's, but to provide a general rule for these reference scenarios, the average breakeven PnP cluster efficiency for these SSRs is 46%. So, one could approximate and conclude that, when the PnP cluster efficiency is believed to be 50% or higher, using a PnP approach is more optimal in terms of NPV/section.

Example Sweep Details

The plot in Figure 17 shows the behavior of NPV/section versus PnP cluster efficiency for the majority of the SSR's. The capital expenses and cycle time are constant for all the PnP scenarios. Therefore, for most SSR's, as cluster efficiency goes up, well performance improves, and NPV/section goes up (though the benefits are diminishing).

The A3 SSR was unusual in the NPV/section, peaking and coming back down with increased PnP cluster efficiency (Figure 18). This is a consequence of tighter effective cluster spacing not always improving well performance. Interestingly, under other contract structures and/or stage designs, the PnP NPV/section may never exceed the SPE NPV/section for some SSR's. An important insight is that because most believe effective cluster spacing is controlled better using SPE than PnP, any SSR believed to highly benefit from a very particular effective cluster spacing ought to use SPE.

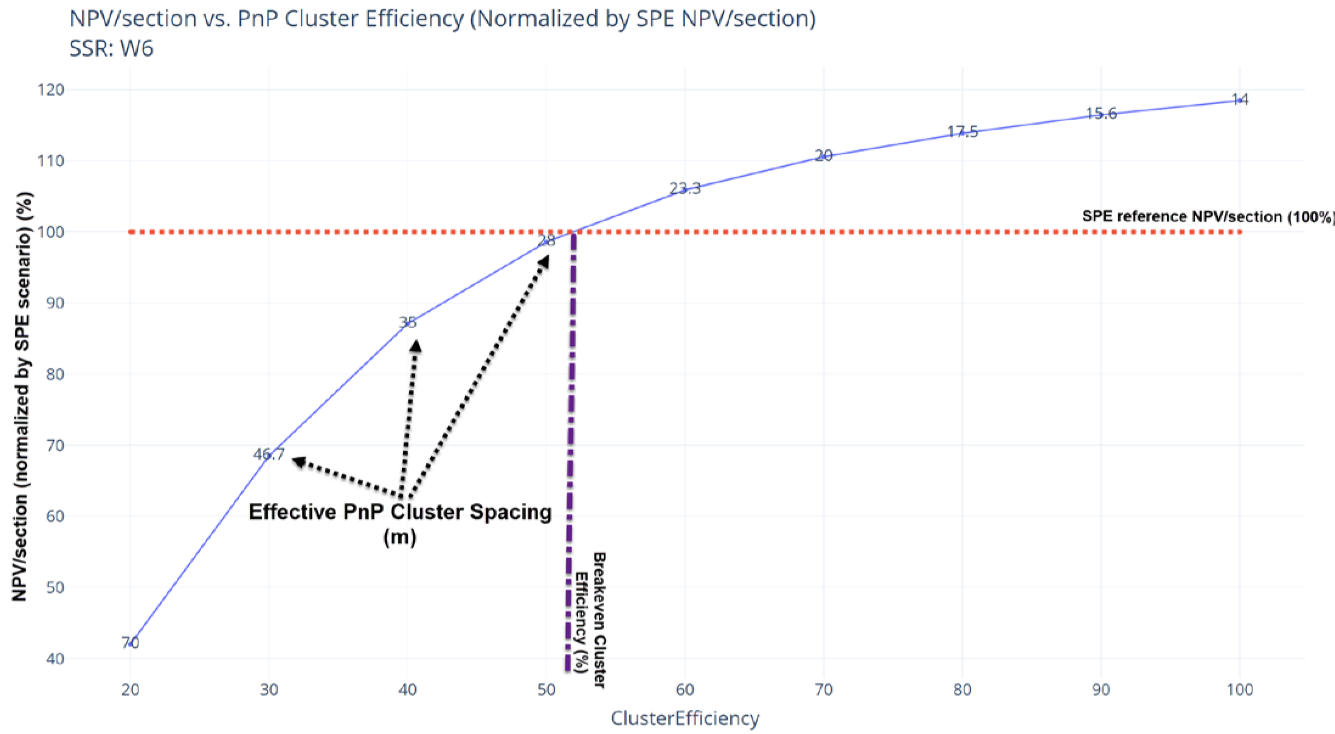

Figure 17—Example PnP cluster efficiency sweep show where the NPV/section breaks even with the SPE scenario for the same SSR; this plot is representative of the sweeps for the majority of SSR's.

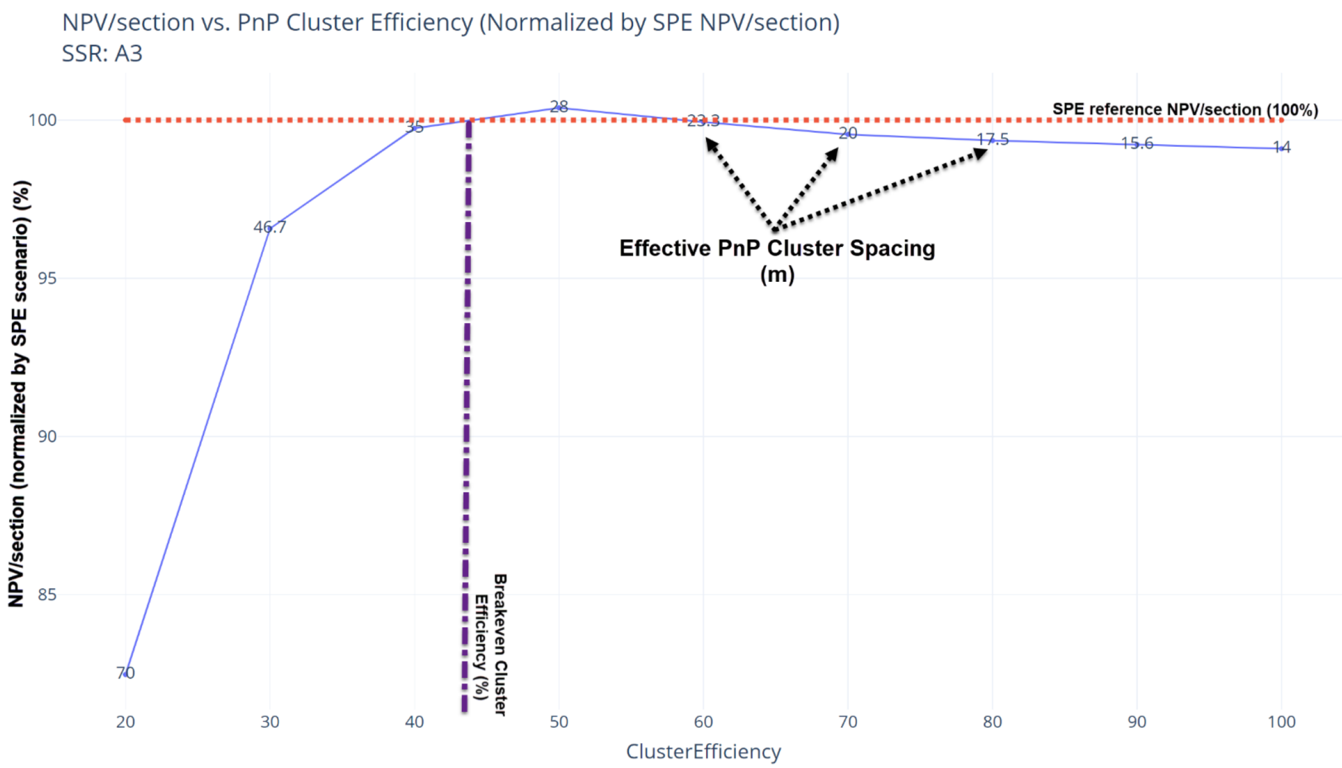

Figure 18—Unique PnP cluster efficiency sweep results showing NPV/section saturation; in other circumstances, SPE scenario may always be superior.

Although this analysis focused on NPV/section, it is worth highlighting that what is optimum can vary if other economic metrics are preferred. The high-level results table also showed breakevens for 2-Yr FCF Per Well. While the breakeven values were largely like those of NPV/section, one SSR (A2) demonstrated that the PnP scenario could not exceed SPE's 2-Yr FCF, regardless of cluster efficiency percentage (Figure 19). In this particular SSR, the production is choked for the first two years even for the 42-m cluster spacing SPE scenario, which has relatively low total capital costs. See the plot in Figure 16 that related lifetime BOE to capital expense and Figure 20 that shows choked well type curves with different effective cluster spacing in that SSR. That behavior is what drives its relatively high 2-Yr FCF. At shorter lateral lengths or higher choking rates, these results could be very different. It is also revealing because other SSR's results may be similar if the lateral length was longer or choking rates lower.

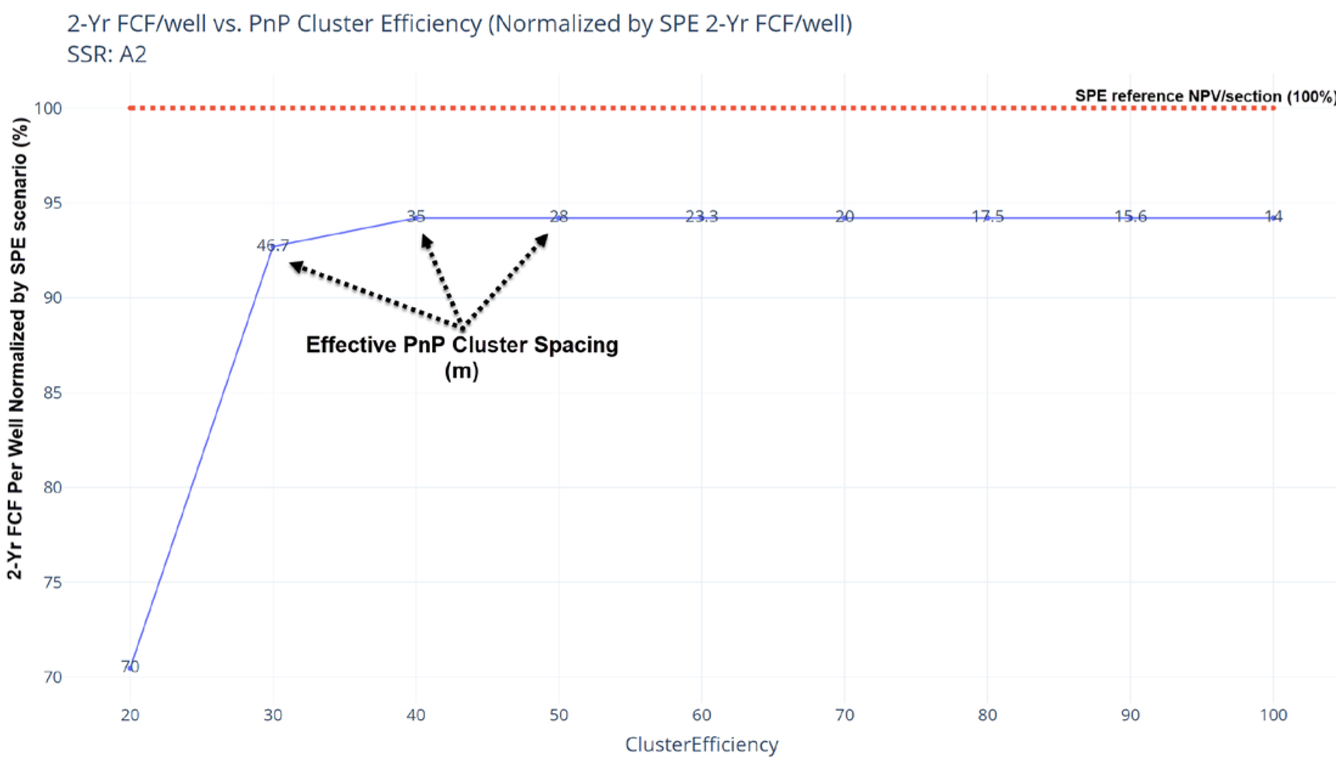

Figure 19—Demonstration of PnP scenario never exceeding SPE 2-Yr FCF regardless of PnP cluster efficiency percentage; this only occurred for one SSR (though the SPE clusters/stage was not selected to optimize 2-Yr FCF.

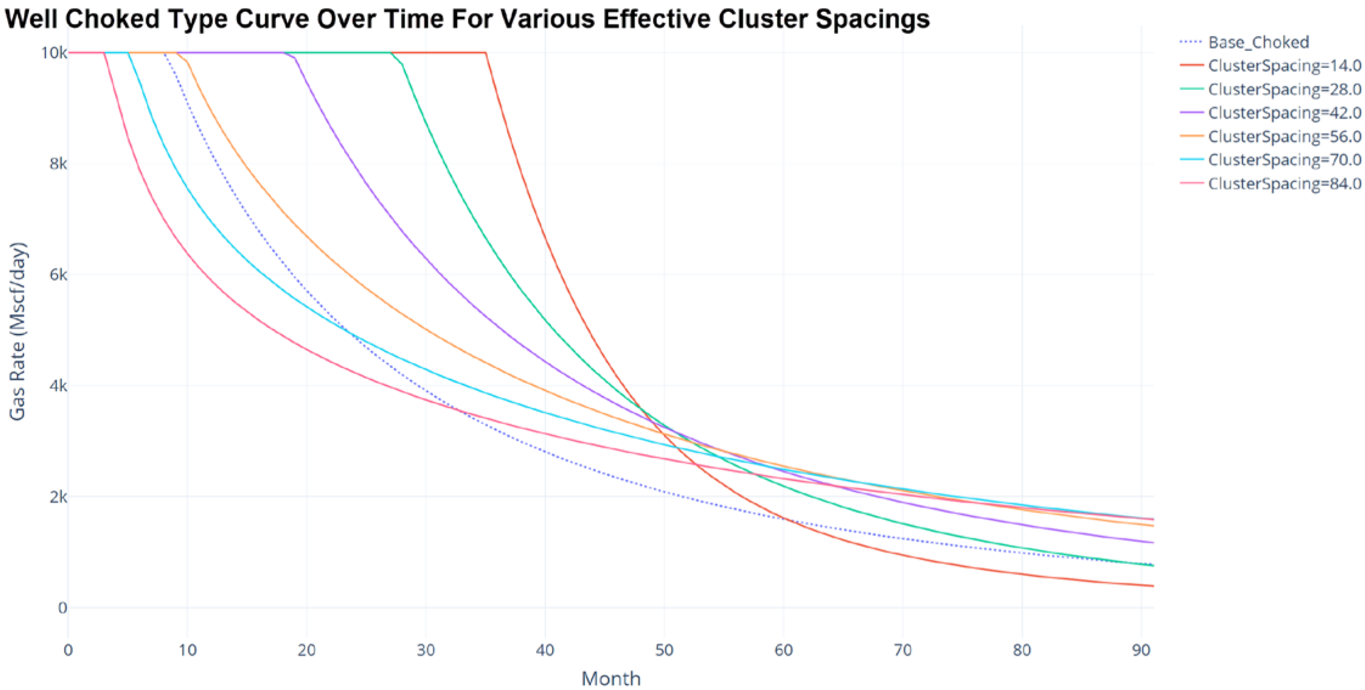

Figure 20—Particular SSR's type curves where type curves are choked for first two years for all effective cluster spacings 42m and above

Conclusion

This paper documented an appraisal between plug-and-perf (PnP) and single-point-entry (SPE) sleeve completions systems using simulation. The appraisal assumed well performance type curves that varied only on lateral length and effective cluster spacing, not completion technology and that 100% of SPE clusters are effective. Not knowing the percentage of effective PnP clusters, this value is swept and determines what percentage of effective clusters is required to breakeven with the SPE scenario based on NPV/section (i.e., NPV/sq-mi).

A simulation tool was used that precisely estimates the cycle time and capital costs for any unconventional well design and imports operators' understanding of well performance for those designs to estimate any well economic metric precisely. Within this tool, the PnP cluster efficiency percentage was swept, and each of those scenarios was compared to a reference SPE scenario for every similar subsurface region (SSR) in which the operator lands wells. The breakeven percentage varied amongst the SSR's from 38% to 53%, with the average being 46%.

However, these precise results are highly dependent on PnP design and strategy, SPE design and strategy, numerous contracts (e.g., pumping services, sleeve costs, time-based costs, etc.), understanding of well performance, facility limits, and economic metric of interest. Under other circumstances, the breakeven percentages could be very different, though the same methodology could be followed.

Further, the operator's understanding of one SSR was such that increasing PnP cluster effectiveness percentage was not necessarily advantageous. There was an actual optimum after which NPV/section went down. This was a function of wells in that SSR preferring a particular effective cluster spacing (not just as tight as cluster spacing as possible). With such SSR's, it may be that SPE is always preferred because it is generally understood that effective cluster spacing can be far more precisely controlled than when using PnP.

Another SSR showed the PnP scenario could not exceed the SPE scenario's 2-Yr FCF per well regardless of percentage of effective PnP clusters. This was partially due to SPE-based wells, in this SSR, producing at the maximum allowed by the facility for the first two years despite the SPE design being amongst the lowest capital required. This was revealing because, for other SSR's, the results could be very different if lateral lengths or choke rates were different.

Future work could repeat this study with well performance type curves specific to PnP with others specific to SPE. This would remove one of the key fixed assumptions of this paper: that an effective PnP cluster has the same performance as an effective SPE cluster.

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